PVNGS

Palo Verde Nuclear Generating Station
Units 1, 2, and 3

Updated Final Safety Analysis Report

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Digitally signed by Cox, Matthew S(Z05628)
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Date: 2017.07.13 10:57:38 -07'00'

Revision 19 Corrected

Redacted per RIS 2015-17

July 2017

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FOREWORD

The Palo Verde Nuclear Generating Station (PVNGS) has developed the Updated Final Safety Analysis Report (UFSAR) in accordance with Title 10, Code of Federal Regulations (10CFR), Part 50.71, Maintenance of Records, Making of Reports, Paragraph (e). The UFSAR is analogous in content and format to the original PVNGS FSAR submitted as part of the joint application for the operation licenses for Units 1, 2, and 3, NRC Docket Nos. STN 50-528/529/530.

The original PVNGS FSAR content and format was specified by 10CFR50.34(b) and NRC Regulatory Guide 1.70, Revision 3. Content of the Updated FSAR is controlled in accordance with Regulatory Guide 1.181. Also, in accordance with NRC policy statement entitled Methods for Achieving Standardization of Nuclear Power Plants, dated March 5, 1973, appropriate sections of the Combustion Engineering Standard Safety Analysis Report (CESSAR), NRC Docket Nos. STN 50/470, were incorporated by reference.

Numerical values in the UFSAR may be nominal in nature, provided to give the reader a sense for the value of the parameter or accuracy of the measurement and should not be viewed as actual values observable in the field. Plant operation at values other than that presented in the UFSAR is acceptable provided that actual values are within established technical specifications, design bases and administrative limits.

The content and format of the UFSAR is specified by 10CFR50.71(e) and NRC Generic Letter 81-06. Pursuant to

Paragraph (4) of 10CFR50.71(e), the PVNGS UFSAR reflects changes up to 6 months prior to the required filing of the UFSAR. The UFSAR includes the effects of: approved license amendments; changes that were made to the facility or procedures as described in the FSAR that did not require a license amendment pursuant to 10 CFR 50.59(c)(1); engineering evaluations and safety analyses performed by the licensee in support of license amendments; and the analyses of new nuclear safety issues performed at the Commission's request.

No new analyses other than those originally prepared during the development and license review process of the original publication of the FSAR, or prepared and submitted pursuant to NRC requirements, have been incorporated into the UFSAR. Analyses that are provided in the UFSAR have been revised to correct known inaccuracies or errors.

The responses to NRC questions, contained in the original FSAR by appendix, are incorporated into the body of the updated FSAR as appropriate. The questions have been retained within their respective appendices, and references have been added when responses were deleted to provide direction to where the responses are incorporated.

Descriptions of physical changes to PVNGS are included in the UFSAR.

The PVNGS revision 0 UFSAR did not include identification of the subsequent supplements and amendments to the original FSAR. The 17 amendments and supplements to the original FSAR were appropriately incorporated, without identifying revision bars, into the FSAR to create a single, complete, and integral

document. Revision bars were used to identify noneditorial changes between the original FSAR, through amendment 17, and the initial UFSAR. The revision bars will preserve the history and bases of changes to the UFSAR. For the initial UFSAR, beside each revision bar is the number "0". This symbol will identify those changes incorporated into the initial UFSAR.

The UFSAR is updated in accordance with 10CFR50.71(e). Each replacement page includes both a change indicator for the area changed, e.g., a bold line vertically drawn in the margin adjacent to the portion actually changed, and page change identification (date of UFSAR revision and revision number).

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CHAPTER 1

INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

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FIGURES

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1. INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 INTRODUCTION

This Final Safety Analysis Report (FSAR) is submitted in support of the joint application filed in Docket Nos. STN 50-528, 50-529, and 50-530 by Arizona Public Service Company (APS) for operating licenses for three nuclear power units to be located at Palo Verde Nuclear Generating Station (PVNGS) in Maricopa County, Arizona, west of the Phoenix metropolitan area.

The joint application for construction permits and operating licenses for PVNGS Units 1, 2, and 3 (PVNGS) was filed with the Nuclear Regulatory Commission (NRC) on July 11, 1974. Construction permits were subsequently issued for PVNGS 1, 2, and 3 on May 25, 1976, as CPPR-141, CPPR-142, and CPPR-143, respectively, in Docket Nos. STN 50-528, 50-529, and 50-530.

Each of the PVNGS units will utilize a System 80 pressurized water reactor nuclear steam supply system (NSSS) provided by Combustion Engineering, Inc., (C-E) and described in the Combustion Engineering Standard Safety Analysis Report – Final Safety Analysis Report (CESSAR).

PVNGS, including each of the three units and all property and facilities located thereat, is jointly owned or leased pursuant to sale and leaseback transactions approved by the NRC by the following seven utilities as tenants in common in PVNGS 1, 2, and 3 in the percentages indicated:

• Arizona Public Service Company	29.1
• Salt River Project Agricultural Improvement and Power District	17.49
• Southern California Edison Company	15.8
• El Paso Electric Company	15.8
• Public Service Company of New Mexico	10.2
• Southern California Public Power Authority	5.91
• Department of Water and Power of the City of Los Angeles	5.7

The rights, duties, and obligations of such utilities in respect to the construction, operation, and maintenance of PVNGS are established by the Arizona Nuclear Power Project (ANPP) Participation Agreement, dated as of August 23, 1973, as amended (a copy of which is included with the General Information accompanying the PVNGS License Application). In addition to the ownership arrangements, the provisions of the Participation Agreement that are most significant to the application are those that designate APS as the Project Manager and Operating Agent of PVNGS with full authority and responsibility to engineer, design, construct, operate, and maintain PVNGS and all related facilities other than transmission and switchyard facilities. Additionally, under the terms of the Participation Agreement, APS is responsible for obtaining all licenses, permits, and approvals required to construct, operate, and maintain PVNGS and is authorized to submit and prosecute on its own behalf and as agent for all other participants all applications therefor. Accordingly,

APS, as Project Manager and Operating Agent of PVNGS, is the applicant for permits and licenses to construct, operate, and maintain PVNGS and also is the applicant for itself and all other joint owners in PVNGS to acquire and own, or lease pursuant to sale and leaseback transactions approved by the NRC, undivided interests in said units as tenants in common in the percentages hereinabove set forth.

With respect to transmission and switchyard facilities required for PVNGS, the participants collectively are planning and coordinating transmission and interconnection arrangements suitable for the delivery to the participants of the power and energy generated by PVNGS and compatible with the transmission systems of the participants.

PVNGS, as established by the ANPP Participation Agreement, is neither a corporate entity, partnership, nor joint venture; but rather it is a jointly owned facility, consisting of all equipment, structures, nuclear fuel, and other property and rights that are or may be used or useful in the operation and maintenance of the facility, but excluding the high voltage switchyard and all transmission facilities connected thereto. Each joint owner has the sole and exclusive right to a percentage equal to its ownership interest of the generating capability of each of the PVNGS units. Accordingly, no sales of power and energy will be made by PVNGS or by APS as agent for other participants in PVNGS. Instead, all sales of power and energy from any PVNGS generating unit will be made by the various joint owners, individually, to their respective customers and to third parties separately from and independent of the ANPP Participation Agreement.

INTRODUCTION

1.1.1 TYPE OF LICENSE REQUESTED

The application is for a Class 103 license for each of the PVNGS Units 1, 2, and 3.

1.1.2 PROPOSED STATION LOCATION

PVNGS is located on a site situated in Section 34 and portions of Sections 26, 27, 28, 33, and 35 in Township One North, Range Six West of the Gila and Salt River Base and Meridian, and Section 3 and portions of Sections 2, 4, 9, and 10 in Township One South, Range Six West of the Gila and Salt River Base and Meridian, Maricopa County, Arizona.

This location is approximately 34 miles west of the nearest boundary of the city of Phoenix, Arizona. The closest population center of more than 25,000 residents is Sun City, which is approximately 34 miles east-northeast of the PVNGS site.

1.1.3 CONTAINMENT TYPE

The containment for each unit is a single containment system consisting of a steel-lined, prestressed concrete, cylindrical structure, with a hemispherical dome. The containment structures are designed by Bechtel Power Corporation (Bechtel).

1.1.4 THERMAL POWER LEVELS AND ELECTRICAL OUTPUT

NSSS rated core thermal power is 3990 MWt. Heat from nonreactor sources, primarily pump heat, is 23 MWt.

The turbine-generator electrical output for 4013 MWt (3990 MWt23 WMt) is 1411 MWe (1443 MWe valves wide open) at 3.5 inches Hg abs backpressure. The nominal net output is 1346 MWe (1378 MWe valves wide open).

1.1.5 SCHEDULED COMPLETED AND COMMERCIAL OPERATION DATES

The scheduled completion or fuel loading dates and the scheduled commercial operation dates for PVNGS Units 1, 2, and 3 are as follows:

PVNGS Unit	Operating License Date	Commercial Operation Date[a]
1	Licensed December 31, 1984	January 28, 1986
2	Licensed December 9, 1985	September 19, 1986
3	Licensed March 25, 1987	January 8, 1988

a. ANPP terminology is firm power operation date in lieu of commercial operation date.

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1.2 GENERAL PLANT DESCRIPTION

1.2.1 PRINCIPAL SITE CHARACTERISTICS

1.2.1.1 Site Location

The site is located approximately 34 miles west of the nearest boundary of the city of Phoenix in Maricopa County, Arizona. Buckeye Salome Road is north of the site and runs in a northwest to southeast direction. A paved county road, Wintersburg Road, runs north to south along the west edge of the site, and Ward Road (paved), sometimes called Elliot Road, runs east to west at the southern end of the site. A Union Pacific railroad line runs southwest to northeast 5 miles south of the power plant complex. Figure 1.2-1 shows the general site location. Figure 1.2-2 provides a general site vicinity map. Engineering drawings 13-C-ZVA-005 and 13-P-OOB-001 show the site general arrangement.

1.2.1.2 Plant Surroundings

The general area consists of a broad valley or basin surrounded by a series of intermittent hills. Relief of the Palo Verde Hills is relatively low (250-foot maximum); the basin area averages about 950 feet in elevation and the adjacent hills rise to about 1200 feet in elevation (see figure 1.2-2). The hills about 5 miles northwest of the site area are the most rugged in the area, and the highest ridges reach approximately 2100 feet above sea level. The basin floor slopes very gently (28 feet per mile) to the south and is dissected by a number of ephemeral stream channels that converge and flow toward the Gila River about 10 miles to the south.

1.2.2 SYSTEM 80 SCOPE AND DESCRIPTION

Combustion Engineering (CE) System 80 includes the NSSS and many of its auxiliary and safety systems. The original scope of design for CE System 80 systems and components is listed in Table 1.2-1 entitled "CESSAR Design Scope Systems and Equipment." The seismic category and the safety and quality classification of mechanical components within the System 80 scope are listed in Table 3.2-1 entitled "Quality Classification of Structures, Systems, and Components." Summary descriptions of the CE System 80 systems are presented below and detailed in the appropriate sections. Information related to the safe design of structures, systems and components which affect these systems, but not within the scope of CE-supplied equipment, is identified in the appropriate UFSAR sections under the heading "Interface Requirements."

TABLE 1.2-1

(Sheet 1 of 7)

ORIGINAL CESSAR DESIGN SCOPE SYSTEMS AND EQUIPMENT

1. Reactor Coolant System

   a) Reactor Vessel Assembly

      1. Reactor Vessel Internals
      2. Fuel and Fuel Assemblies
      3. Surveillance Specimens and Holders
      4. Neutron Sources
      5. Control Element Assemblies
      6. Control Element Drive Mechanisms
      7. Reactor Vessel Supports
      8. Closure Studs, Nuts and Washers
      9. Reactor Vessel Head Closure Seal

   b) Steam Generator Assembly

      1. Steam Generator Internals
      2. Steam Generator Supports

   c) Pressurizer Assembly

      1. Pressurizer Heaters
      2. Pressurizer Supports

   d) Reactor Coolant Pumps

      1. Reactor Coolant Pump Supports
      2. Reactor Coolant Pump Instrumentation and Component Controls(2)

   e) Reactor Coolant Piping Including Pipe Stop Weld Buildups

   f) Main Steam and Feedwater System Instrumentation and Component Controls(2)

TABLE 1.2-1 (Cont'd)

(Sheet 2 of 7)

ORIGINAL CESSAR DESIGN SCOPE SYSTEMS AND EQUIPMENT

- g) RCS Instrumentation and Component Controls(2)
- h) Spray Line Valves
- i) Insulation

2. Engineered Safety Features Systems
   - a) Safety Injection System
     1. Safety Injection Tanks
     2. High Pressure Safety Injection Pumps
     3. Low Pressure Safety Injection Pumps
     4. Associated Valves
     5. Instrumentation and Component Controls(2)
   - b) Containment Isolation System(1)
     1. Safety Injection System High and Low Pressure Injection Lines
     2. Containment Sump Suction Lines
     3. Shutdown Cooling Suction Lines
     4. Letdown Line
     5. Charging Line
     6. Reactor Coolant Pump Seal Water Injection and Return Lines
     7. Reactor Drain Tank Discharge Line
     8. Makeup Water Supply Line to the Reactor Drain Tank
     9. Safety Injection Tank Fill and Drain Line
3. Fuel Handling System
   - a) Refueling Machine
   - b) Transfer Carriage System
     1. Transfer Carriage
     2. Upending Machine
     3. Hydraulic Power Unit

TABLE 1.2-1 (Cont'd)

(Sheet 3 of 7)

ORIGINAL CESSAR DESIGN SCOPE SYSTEMS AND EQUIPMENT

c) Fuel Transfer Tube, Valve and Flange

d) CEA Change Platform

e) Long and Short Fuel Handling Tools

f) Reactor Vessel Head Lifting Rig

g) Upper Guide Structure Lifting Rig

h) Core Barrel Lifting Rig

i) Spent Fuel Handling Machine

j) New Fuel Elevator

k) Underwater Television

l) Dry Sipping Equipment

m) Refueling Pool Seal

n) In-Core Instrumentation and CEA Cutter

o) Extension Shaft Uncoupling Tool

4. Chemical and Volume Control System

a) Pumps

1. Charging Pumps
2. Boric Acid Makeup Pumps
3. Reactor Makeup Water Pumps
4. Holdup Pumps
5. Reactor Drain Pumps

b) Tanks

1. Volume Control Tank
2. Boric Acid Batching Tank
3. Refueling Water Tank
4. Holdup Tank
5. Reactor Makeup Water Tank
6. Reactor Drain Tank
7. Equipment Drain Tank

Table 1.2-1 (Cont'd)

(Sheet 4 of 7)

ORIGINAL CESSAR DESIGN SCOPE SYSTEMS AND EQUIPMENT

c) Heat Exchangers

1. Regenerative Heat Exchanger
2. Letdown Heat Exchanger
3. RCP Seal Injection Heat Exchanger

d) Ion Exchangers

1. Purification Ion Exchangers
2. Deborating Ion Exchanger
3. Preholdup Ion Exchanger
4. Boric Acid Condensate Ion Exchanger

e) Filters

1. Purification Filters
2. Boric Acid Filter
3. Reactor Makeup Water Filter
4. Reactor Drain Filter
5. Seal Injection Filters

f) Gas Stripper Package

g) Boric Acid Concentrator Package

h) Process Radiation Monitor

i) Boronometer (Abandoned in-place)

j) Deleted

k) Instrumentation and Component Controls[(2)]

l) Valves

m) Chemical Addition

5. Shutdown Cooling System

a) Shutdown Cooling Heat Exchangers

b) Instrumentation and Component Controls[(2)]

c) Valves

Table 1.2-1 (Cont'd)

(Sheet 5 of 7)

ORIGINAL CESSAR DESIGN SCOPE SYSTEMS AND EQUIPMENT

6. Test Programs

    a) Preoperational Tests for CESSAR Design Scope Systems

    b) Startup Tests for CESSAR Design Scope Systems

7. Reactor Protective System

    a) Variable Overpower Trip

    b) High Logarithmic Power Trip

    c) High Pressurizer Pressure Trip

    d) Low Pressurizer Pressure Trip

    e) Low Steam Generator Pressure Trip

    f) Low Steam Generator Water Level Trip

    g) High Steam Generator Water Level Trip

    h) High Containment Pressure Trip

    i) Low DNBR Trip in DNBR/LPD Calculator System

    j) High Local Power Density Trip in DNBR/LPD Calculator System

    k) Manual Trip

8. Supplementary Protection System

    a) High Pressurizer Pressure Trip

9. Engineered Safety Features Actuation System

    a) Containment Isolation Actuation Signal

    b) Emergency Feedwater Actuation Signal

    c) Main Steam Isolation Signal

    d) Safety Injection Actuation Signal

    e) Recirculation Actuation Signal

    f) Containment Spray Actuation Signal

Table 1.2-1 (Cont'd)

(Sheet 6 of 7)

ORIGINAL CESSAR DESIGN SCOPE SYSTEMS AND EQUIPMENT

10. Control Systems

    a) Reactor Regulating System
    b) Control Element Drive Mechanism Control System
    c) Pressurizer Pressure Control System
    d) Pressurizer Level Control System
    e) Feedwater Control System
    f) Reactor Power Cutback System
    g) Steam Bypass Control System
    h) Boron Control System(3)

11. Monitoring Systems

    a) Plant Monitoring System
    b) Core Operating Limit Supervisory System
    c) In-core Instrumentation System

        1. Fixed In-core Instrument System

12. Nuclear Instrumentation

    a) Source Range Channels
    b) Power Range Channels - Control
    c) Logarithmic and Linear Safety Channels

13. Other Protective Instrumentation

    a) Shutdown Cooling System Suction Line Isolation Valve Interlocks
    b) Safety Injection Tank Isolation Valve Interlocks

Table 1.2-1 (Cont'd)

(Sheet 7 of 7)

ORIGINAL CESSAR DESIGN SCOPE SYSTEMS AND EQUIPMENT

NOTES

1. There is no one particular system for complete containment isolation. Containment isolation is achieved by applying acceptable common criteria to penetrations for CESSAR design scope systems and by using a containment isolation signal to actuate appropriate valves. Containment isolation is within the CESSAR scope for the lines listed under "2.b" above.
2. There is no implication that all instrumentation and controls within the CESSAR scope are safety related. The text defines what instrumentation is considered to be safety related.
3. Because of the relatively slow response of the system to changes in boron concentration, the boron control system is manual with the operator controlling boron concentration based on periodic sampling.

1.2.3 NUCLEAR STEAM SUPPLY SYSTEM

The NSSS generates power as described in section 1.1.4, producing saturated main steam. The NSSS contains two independent primary coolant loops, each of which has two reactor coolant pumps, a steam generator, a 42-inch ID outlet (hot) pipe and two 30-inch ID inlet (cold) pipes. An electrically heated pressurizer is connected to one of the loops, and safety injection lines are connected to each of the four cold legs and the two hot legs. Pressurized water circulates by means of electric-motor-driven, single-stage, centrifugal reactor coolant pumps, downward between the reactor vessel shell and the core support barrel, upward through the reactor core, through the tube side of the vertical U-tube (with an integral economizer) steam generators, and back to the reactor coolant pumps. The saturated steam produced in the steam generators is passed to the turbine.

1.2.3.1 Reactor Core

The reactor core is fueled with uranium dioxide pellets enclosed in zircaloy or zirlo tubes with welded end caps. The tubes are fabricated into assemblies in which end fittings limit axial motion and grids limit lateral motion of the tubes. The control element assemblies (CEAs) consist of Alloy 625 absorber rods, which are guided by tubes located within the fuel assembly. The core consists of 241 fuel assemblies which will be initially loaded with three different U-235 enrichments. The NSSS full-thermal output is specified in section 1.1.4. The neutron absorber is either all boron carbide (B_4C) in Feltmetal® CEAs, or a combination of B_4C and

Silver-indion-cadmium (AIC) in AIC CEAs. Only one design at a time will be used in each of the three units.

Design criteria are established to ensure the following:

A. The minimum departure from nucleate boiling ratio during normal operation and anticipated operational occurrences is not less than 1.19.

B. The maximum fuel centerline temperature evaluated at the design overpower condition is below that value which could lead to centerline fuel melting. The melting point of the UO_2 is not reached during normal operation and anticipated operational occurrences.

C. Fuel rod clad is designed to maintain cladding integrity throughout fuel life.

D. Each reactor system is designed so that any xenon transients will be adequately damped.

E. The reactor coolant system is designed and constructed to maintain its integrity throughout the expected plant life.

F. Power excursions that could result from any credible reactivity addition incident do not cause damage either by deformation or rupture of the pressure vessel, or impair operation of the engineered safety features.

G. The combined response of the fuel temperature coefficient, the moderator temperature coefficient, the moderator void coefficient, and the moderator pressure coefficient to an increase in reactor thermal power is a decrease in reactivity. In addition, reactor power transients remain

bounded and damped in response to any expected changes in any operating variable.

The reactor core is further discussed in Chapter 4.

1.2.3.2 Reactor Internals

The internal structures include the core support barrel, the lower support structure & ICI nozzle assembly, the core shroud, and the upper guide structure assembly. The core support barrel is a right circular cylinder supported by a ring flange from a ledge on the reactor vessel. It carries the entire weight of the core. The lower support structure transmits the weight of the core to the core support barrel by means of a beam structure. The core shroud surrounds the core and minimizes the amount of bypass flow. The upper guide structure provides a flow shroud for the CEA's, and limits upward motion of the fuel assemblies during pressure transients. Lateral snubbers are provided at the lower end of the core support barrel assembly.

The principal design bases for the reactor internals are to provide the vertical supports and horizontal restraints during all normal operating, upset, and faulted conditions.

The core is supported and restrained during normal operation and postulated accidents to ensure that coolant can be supplied to the coolant channels for heat removal.

Reactor internals are further discussed in Sections 3.9, 4.5, 19.1.21.B, and Table 19.5-1, Item 23B.

1.2.3.3 Reactor Coolant System (RCS)

The RCS is arranged as two closed loops connected in parallel to the reactor vessel. Each loop consists of one 42-inch ID outlet (hot) pipe, one steam generator, two 30-inch ID inlet (cold) pipes, and two pumps. An electrically heated pressurizer is connected to one of the loops, and safety injection lines are connected to each of the four cold legs and two hot legs.

The RCS operates at a nominal pressure of 2250 psia. The reactor coolant enters near the top of the reactor vessel, then flows downward between the reactor vessel shell and the core barrel, up through the core, leaves the reactor vessel, and flows through the tube side of the two vertical U-tube (with an integral economizer) steam generators where heat is transferred to the secondary system. Reactor coolant pumps return the reactor coolant to the reactor vessel.

Two steam generators, using heat generated by the reactor core and carried by the primary coolant to each steam generator, produce steam for driving the plant turbine-generator. Each steam generator is a vertical U-tube heat exchanger with an integral economizer which operates with the reactor coolant on the tube side and secondary coolant on the shell side.

Each unit is designed to transfer heat from the Reactor Coolant System to the secondary system to produce saturated steam when provided with the proper input feedwater. Moisture separators and steam driers on the shell side of the steam generator limit the moisture content of the steam during normal operation at full power.

Hot reactor coolant from the reactor vessel enters the steam generator through the inlet nozzle in the primary head. From here it flows through the U-tubes, where it gives up heat to the secondary coolant, to the outlet side of the primary head where the flow splits and leaves through the two outlet nozzles. A vertical divider plate separates the inlet and outlet plenums of the primary head. An integral economizer is employed on the cold leg of the U-tube steam generator to enhance the generator thermal effectiveness. With fixed reactor coolant conditions, the use of an economizer enables the steam generator to operate at a higher steam pressure without an increase in heating surface.

The steam generator with integral economizer is in most respects similar to earlier U-tube recirculating steam generators. The basic difference is that instead of introducing feedwater only through a sparger ring to mix with the recirculating water flow in the downcomer channel, feedwater is also introduced into a separate, but integral section of the steam generator. A semi-cylindrical section of the tube bundle, at the cold leg or exit end of the U-Tubes, is separated from the remainder of the tube bundle by vertical divider plates. Feedwater is introduced directly into this section and pre-heated before discharge into the evaporator section. Feedwater flow enters the economizer through two nozzles into the distribution box. Discharge ports in the distribution box are sized and spaced to provide a uniform rate of discharge over the full half circumference of the economizer. The flow after leaving the distribution box passes radially across the tube sheet. A flow baffle acts as the

upper boundary of this radial pass. This baffle is sized to evenly distribute flow through the axial region of the economizer. Flow passes upward through the annuli formed by the tubes and baffle plate into the axial flow region. This region is basically a counter-flow heat exchanger, with feedwater directed upward outside the tubes and primary flow directed downward inside the tubes. Feedwater then exits the economizer slightly subcooled and enters the boiling region of the steam generator.

The remainder of the steam generator differs little from previous recirculating U-tube steam generators manufactured by C-E, except that the lower portion of the evaporator section and the downcomer channel occupy only one-half of the steam generator cross-section. The effect of this non-symmetry is factored into the design of tube support structures. The steam-water mixture leaving the vertical U-tube heat transfer surface enters the separators which impart a centrifugal motion to the mixture and separate the water particles from the steam. The water exits from the perforated separator housings and recirculates through the downcomer channel to repeat the cycle. Final drying of the steam is accomplished by passage of the steam through dryers. The steam generator dryers employ a Peerless hook vane design.

An integral flow restrictor has been installed in each steam generator steam nozzle to reduce flow area.

The reactor coolant is circulated by four electric-motor-driven single-stage centrifugal pumps. The pump shafts are sealed by

mechanical seals. The seal performance is monitored by pressure and temperature sensing devices in the seal system.

The RCS is further discussed in Chapter 5.

1.2.4 ENGINEERED SAFETY FEATURES

Engineered safety features function in the highly unlikely event of an accidental release of radioactive fission products from the reactor system, particularly as the result of loss-of-coolant accidents. These safeguards function to localize, control, mitigate, or terminate such accidents to hold exposure levels below 10CFR100.

1.2.4.1 Containment System

1.2.4.1.1 Containment Building

See section 1.2.12.

1.2.4.1.2 Safety Injection System

In the highly unlikely event of a loss-of-coolant accident, the safety injection system (SIS), including high-pressure and low-pressure safety injection pumps and safety injection tanks, injects borated water into the reactor coolant system. This provides cooling to limit core damage and fission product release and ensures adequate shutdown margin. The SIS also provides continuous long-term, post-accident cooling of the core by recirculation of borated water from the containment sump.

The SIS is discussed further in Section 6.3.

1.2.4.2 Additional PVNGS Engineered Safety Features

In addition to the engineered safety features (ESF) described above, the PVNGS units are provided with the following features:

A. The essential fuel building ventilation system features redundant filter trains that are actuated by an accident signal. By maintaining the lower levels of the auxiliary building at a negative pressure, the system minimizes the offsite radiation dose following a loss-of-coolant accident (LOCA). By maintaining the fuel building at a negative pressure, the system prevents exfiltration of unfiltered air and minimizes the offsite radiation dose following a fuel handling accident in the fuel building. A more complete discussion appears in section 9.4.

B. The containment building purge (both refueling and power access) can be stopped and the containment purge inlet and exhaust lines isolated in the event of high airborne radiation. The containment purge isolation actuation signal (CPIAS) is generated to minimize the offsite radiation dose following a fuel handling accident in the containment building or a LOCA during operation.

C. Control building essential ventilation can be isolated from normal ventilation trains in the event of a high radiation signal. The control room is maintained at a positive pressure to prevent infiltration of unfiltered air and to minimize the radiation dose to

control room personnel. The control building ventilation system is discussed in sections 9.4 and 6.4.

D. The containment hydrogen control system is used to prevent the concentration of hydrogen in the containment from reaching 4% by volume following a LOCA accident. The system is comprised of two full-capacity, independent, parallel loops, each loop containing a hydrogen recombiner with the capability of keeping the containment H_2 concentration below 3.5% by volume. The hydrogen purge subsystem serves as a backup to the hydrogen recombiners. Hydrogen purge is designed to maintain the hydrogen concentration of the containment atmosphere below the flammability limit following a postulated LOCA, even without the use of either recombiner. The hydrogen control system is discussed in detail in subsection 6.2.5.

E. AC Auxiliary Power System

Engineered safety features ac loads are divided into two independent and redundant load groups. Each group consists of one 4.16 kV bus and associated 480V load centers and motor control centers. The normal plant ac loads are supplied by two 13.8 kV buses, two 4.16 kV buses, and associated 480V load centers and motor control centers.

Standby ac power is supplied by two diesel generators. Each ESF load group is supplied by a separate diesel

generator. Each diesel generator is sized to meet the maximum demand of its ESF load group. In order that the independence of these load groups not be compromised, there are no provisions for automatically transferring ESF load group buses between standby ac power supplies.

F. DC Power System

The dc power is supplied by four independent Class 1E 125 V-dc systems, one per ESF channel. The systems are adequate to ensure a constant supply of power to vital instruments and controls. Two 125V batteries provide 125 V-dc power for the nonsafety-related electric system.

G. Essential Cooling Water System

Refer to paragraph 1.2.10.3.3.1, listing A.

H. Essential Spray Pond System

Refer to paragraph 1.2.10.3.3.2.

I. Auxiliary Feedwater System

The auxiliary feedwater system (AFS) consists of one Seismic Category I motor-driven AFS pump; one Seismic Category I steam turbine-driven AFS pump; one non-Seismic Category I motor-driven AFS pump; and associated piping, controls, and instrumentation. Refer to subsection 10.4.9 for a detailed discussion.

1.2.5 INSTRUMENTATION AND CONTROL

Automatic protection systems, control systems, and interlocks are provided, along with the administrative controls of the Applicant, to assure safe operation of the plant. Sufficient instrumentation and controls are supplied to provide manual operation as a normal backup control mode on all automatic systems.

A Plant Protection System (PPS) initiates a reactor trip if the reactor approaches prescribed safety limits, or provides an actuation signal to the Engineered Safety Features Systems when a fluid system or containment parameter approaches a prescribed limit.

Sufficient redundancy is installed to permit periodic testing of the PPS so that removal from service of any one protection system component or portion of the system will not preclude reactor trip, or other protective action when required. Additionally, no single failure can preclude the PPS providing a reactor trip or other protective action when required.

The protection system and associated instrumentation is separated from the control systems and their associated instrumentation such that failure, or removal from service, of any control system, component or instrument channel will not inhibit the functioning of the protection system (see Chapter 7.0 for details).

1.2.5.1 Protection, Control, and Instrumentation Systems

1.2.5.1.1 Reactor Protective System

The controllable reactor parameters are normally maintained within acceptable operating limits by the inherent characteristics of the reactor, the Reactor Regulating System (RRS), soluble boron concentration, and the plant operating procedures.

Four independent channels of the RPS normally monitor each of the selected plant parameters. The RPS logic is designed to initiate protective action whenever the signal of any two channels of a given parameter reach the preset limit. Should this occur, the power supplied to the Control Element Drive Mechanisms (CEDM) is interrupted, releasing the Control Element Assemblies (CEA) which drop into the core to shutdown the reactor. The two-out-of-four logic can be converted to two-out-of-three logic to allow one channel to be bypassed for testing maintenance or operation. The protection system is independent of and separate from the manual and automatic control systems except for a Control Element Withdrawal Prohibit (CWP).

1.2.5.1.2 Supplementary Protection System

The Supplementary Protection System (SPS) augments reactor protection by utilizing a separate and diverse trip logic from the Reactor Protective System for initiation of reactor trip. The added equipment of the SPS provides a simple yet diverse mechanism to increase the overall reliability of the Plant

Protection Systems. The SPS will initiate a reactor trip when pressurizer pressure exceeds a predetermined value.

The SPS is provided with sensors and circuitry which are diverse from that of the RPS. The SPS design uses a selective two-out-of-four logic to interrupt the power supplied to the CEDM's and thereby cause the CEA’s to drop into the core. The SPS is independent and separate from all control systems.

1.2.5.1.3 Engineered Safety Features Actuation System

The Engineered Safety Features Actuation System (ESFAS) operates in a manner similar to the RPS to automatically actuate the Engineered Safety Features (ESF) Systems. Again, it has a selective two-out-of-four actuation logic that can be converted to a selective two-out-of-three logic. The ESFAS is completely independent of the control systems.

1.2.5.1.4 Reactor Control Systems

The reactor control systems are used for startup and shutdown of the reactor, and for adjustment of the reactor power in response to turbine load demand. The NSSS control systems are capable of following ramp load changes between 15% and 100% of full power at a rate of 5% per minute and a step change of 10%, except as limited by Xenon. This control is normally accomplished by automatic movement of CEAs in response to a change in reactor coolant temperature, with manual control capable of overriding the automatic signal at any time. If the reactor coolant temperature is different from a programmed value, the CEAs are adjusted until the difference is within the prescribed control band. Regulation of the reactor coolant

temperature, in accordance with this program, maintains the secondary steam pressure within operating limits and matches reactor power to load demand.

The reactor is controlled by a combination of CEA motion and dissolved boric acid in the reactor coolant. Boric acid is used for reactivity changes associated with large but gradual changes in water temperature, Xenon concentration, and fuel burnup. Addition of boric acid also provides an increased shutdown margin during the initial fuel loading and subsequent refuelings. The boric acid solution is prepared and stored at a temperature sufficient to prevent precipitation.

CEA movement provides changes in reactivity for shutdown or power changes. The CEAs are moved by CEDMs mounted on the reactor vessel head. The CEDMs are designed to permit rapid insertion of the CEAs into the reactor core by gravity. CEA motion can be initiated manually or automatically.

The pressure in the Reactor Coolant System is controlled by regulating the temperature of the coolant in the pressurizer where steam and water are held in thermal equilibrium. Steam is formed by the pressurizer heaters or condensed by the pressurizer spray to reduce variations caused by expansion and contraction of the reactor coolant due to system temperature changes.

Overpressure protection is provided by safety valves connected to the pressurizer and designed in accordance with ASME Code, Section III. The discharge from the pressurizer safety valves is released underwater in the reactor drain tank, where it is cooled and condensed. Over-pressure protection for the tank is

provided by a rupture disc which relieves to the containment. A Steam Bypass Control System (SBCS) is used to dump steam in case of a large mismatch between the power being produced by the reactor and the power being used by the turbine. This allows the reactor to remain at power instead of tripping. Each steam generator’s water level is maintained by a Feedwater Control System (FWCS). A Reactor Power Cutback System (RPCS) is used to drop selected CEAs into the core to reduce reactor power rapidly during a large loss of load. This allows the SBCS and FWCS to maintain the NSSS in a stable condition, without a reactor trip, and without lifting any safety valves during loss of large load transients with condenser available.

1.2.5.1.5 Nuclear Instrumentation

The nuclear instrumentation includes ex-core and in-core neutron flux detectors. Eight channels of ex-core instrumentation monitor the power. Two channels are provided for the startup, two channels are provided for power control, and four channels are provided for the protection channels. The control channels are used to control the reactor power during power operations. The protection channels are used to provide inputs to the overpower, logarithmic power Departure from Nuclear Boiling Rate (DNBR), and Local Power Density (LPD) trips in the RPS.

The in-core instrumentation consists of self-powered detectors, distributed throughout the core, which provide information on flux distribution within the core.

1.2.5.1.6 Monitoring Systems

The Plant Monitoring System (PMS) performs general monitoring of the NSSS and balance of plant; logging, trending, and alarming of conditions are its major functions. The PMS is not necessary for successful plant operations. Part of the PMS is the Core Operating Limit Supervisory System (COLSS).

General temperature, pressure, flow and liquid level monitoring are provided as required to keep the operating personnel informed as to plant operating conditions. Protection channels will indicate the various parameters used for protective action as well as providing trip and pre-trip alarms from the RPS. The plant liquid and gaseous effluents are monitored to assure that they are maintained within applicable radioactivity limits. A complete description of the radiation instrumentation is discussed in Chapter 11.0.

Additional instrumentation and controls are discussed in detail in chapter 7.

1.2.6 ELECTRIC SYSTEM

1.2.6.1 Transmission and Generation System

The main generator is connected by an isolated phase bus to the 24 kV side of the main step-up transformer. The other side of the main transformer is connected to 525 kV lines which carry the power to the Palo Verde 525 kV switchyard that is part of the 525 kV transmission network.

1.2.7 POWER CONVERSION SYSTEM

1.2.7.1 Turbine-Generator

The turbine-generator is an 1800 r/min, tandem compound, six-flow, 43-inch last-stage bucket reheat unit with an electrohydraulic control system.

The rated NSSS power levels, turbine generator gross outputs, and nominal net output powers for the Palo Verde Units are provided in section 1.1.4.

The generator is a direct-driven, three-phase, 60 Hz, 24,000V, 1800 r/min, conductor cooled synchronous generator rated at approximately 1559 MVA at 0.90 power factor and 75 psig hydrogen pressure.

1.2.7.2 Main Steam Supply System

The main steam supply system provides steam from the steam generators for the turbine-generator, the feedwater pump turbines, the turbine gland sealing system, condensate and feed-water heating, and main turbine reheat steam as required.

1.2.7.3 Main Condenser

Steam from the low-pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings and is condensed. The condenser is a multisection, multipressure condenser, each section serving one double-flow, low-pressure turbine section. The condenser also serves as a heat sink for the turbine bypass system.

1.2.7.3.1 Condenser Air Removal System (CARS)

The condenser air removal system removes air and noncondensable gases from the main condenser and exhausts them to the atmosphere via the plant vent. The CARS consists of four two-stage mechanical vacuum pumps. Three vacuum pumps are used during startup and normal operation. One additional vacuum pump serves as backup to the three pumps in operation.

1.2.7.4 Circulating Water System

The circulating water system provides the main condenser with a continuous supply of cooling water to remove the heat rejected from the turbine thermal cycle. The circulating water system consists of three circular mechanical draft cooling towers and four vertical, motor-driven pumps. The circulating water pumps circulate the cooling water from the cooling tower basins through the main condenser and then back to the cooling towers. Makeup water to compensate for drift, blowdown, and evaporative losses is supplied from the makeup water reservoirs.

1.2.7.5 Condensate and Feedwater System

Three condensate pumps take the deaerated condensate from the hotwells of the main condenser and deliver it through the low-pressure feedwater heaters to two feedwater pumps. Drains from moisture separators and reheaters, and the high-pressure feedwater heaters, are pumped into the suction stream of the feedwater pumps by two heater drain pumps, and the drains from low-pressure heaters are cascaded back to the main condenser. The feedwater pumps discharge the total feedwater flow through the high-pressure feedwater heaters to the steam generators.

1.2.7.6 Condensate Storage and Transfer System

The condensate storage and transfer system maintains the required capacity and flow of condensate for the auxiliary feedwater systems and maintains a level in the condenser hot-well. The system consists of a condensate tank, two condensate transfer pumps, and the necessary controls and instrumentation. For a detailed description of this system, see subsection 10.4.7.

1.2.8 HEATING, VENTILATING, AND AIR CONDITIONING SYSTEMS

1.2.8.1 Control Building

The control building includes the following heating, ventilating, and air conditioning systems (HVAC):

A. Control Room

The control room HVAC system is designed to provide a suitable environment for equipment and personnel. The HVAC system is divided into two subsystems, a normal HVAC system and an essential HVAC system. The system is designed to detect, limit the introduction of, and remove foreign material from the control room environment. Refer to subsection 9.4.1 for system description. The emergency system is described in section 6.4.

B. Engineered Safety Features Switchgear Rooms

Each area has its own HVAC system that consists of the following components; prefilter, high efficiency particulate filter, cooling coil, supply fan, and duct

heater. These units are located in separate fan rooms and serve ESF switchgear trains A and B, respectively. This same system supplies ESF equipment rooms and battery rooms. See subsection 9.4.1 for additional information.

C. Cable Spreading Rooms

The upper and lower cable spreading rooms HVAC systems are designed to remove heat generated in these rooms. A smoke exhaust system is also provided. The system is a part of the control building normal HVAC system. This system receives power from the normal power distribution system. See subsection 9.4.1 for additional information.

D. Computer Room

This system is combined with the control room air conditioning system as specified in subsection 9.4.1.

1.2.8.2 Containment Building

The containment building ventilation systems consist of the normal cooling, CEDM cooling, reactor cavity cooling, tendon gallery ventilation, preaccess filter, and normal purge systems. Details of these systems are discussed in subsection 9.4.6.

1.2.8.3 Turbine Building

The turbine building ventilation system is designed to provide an environment that ensures the comfort of plant personnel and the integrity of equipment and components. Evaporative cooled

outside air is supplied to the turbine building at each floor and then is drawn through the equipment areas on the floor by the exhaust systems. Turbine building ventilation systems are discussed in detail in subsection 9.4.4.

1.2.8.4 Auxiliary Building

The auxiliary building ventilation system is designed to provide a controlled environment to ensure the comfort and safety of personnel and to maintain the integrity of equipment. Conditioned outside air is distributed throughout the building.

The design of the ventilation system is such that, during normal plant operation, air is directed from areas of lower to areas of potentially higher airborne activity. Air is exhausted from the areas of high potential radioactivity, through a filter train to the plant vent. The ESF pump rooms are provided with one cooling unit per room to supply cooling to ESF pump motors. The unit consists of a fan and cooling coil that removes heat from the pump room. For additional information, refer to subsection 9.4.2.

1.2.8.5 Radwaste Building

The radwaste building ventilation system is designed to provide an environment with controlled temperature and airflow patterns. Outside air is directed to areas of low potential radioactivity and then is exhausted from areas of high potential radioactivity. The design of the ventilation system is such that, during normal plant operation, air is directed from areas of lower to areas of potentially higher airborne activity. A filtering unit processes the air before it is

released through the plant vent. A description of the system is found in subsection 9.4.3.

1.2.8.6 Fuel Building

The fuel building ventilation system provides a controlled temperature environment to ensure personnel comfort and safety and to ensure equipment integrity. Cooled outside air is distributed by the supply fan and associated ducting to areas of the building. The design of the ventilation system is such that, during normal plant operation, air is directed from areas of lower to areas of potentially higher airborne activity. The air is exhausted continuously to the plant vent.

The fuel building normal ventilation system is isolated by the closure of automatic dampers, and the fuel building essential ventilation system is started upon sensing abnormal radiation levels. See subsection 9.4.5 for a detailed description.

1.2.8.7 Diesel Generator Building

The diesel generator rooms are heated and ventilated to provide a suitable environment for operation of the diesel and its support equipment. Each diesel generator supplies power to its own exhaust fans when operational. See subsection 9.4.7 for a detailed description.

1.2.9 FUEL HANDLING AND STORAGE

1.2.9.1 Fuel Handling

Fuel handling equipment provides for the safe handling of fuel assemblies and CEAs under all specified conditions and for the

required assembly, disassembly, and storage of reactor vessel head and internals during refueling.

The major components of the system are the refueling machine, the CEA change platform, the fuel transfer system, the spent fuel handling machine, the new fuel handling crane, the cask handling crane, the transportable storage canister, the transfer cask, vertical concrete casks, and the new fuel and CEA elevators. This equipment is provided to transfer new and spent fuel between the fuel storage facility, the containment building, the fuel shipping and receiving areas, and the independent spent fuel storage installation (ISFSI) during core loading, refueling, and storage operations. Fuel is inserted and removed from the core using the refueling machine. During normal operations, irradiated fuel and CEA's are always maintained in a water environment. During interim dry storage at the ISFSI, irradiated fuel is stored in a helium environment in dry casks.

The principal design criteria specify the following:

A. Fuel is inserted, removed, and transported in a safe manner.

B. Subcriticality is maintained in all operations.

Fuel handling is discussed in section 9.1.4.

1.2.9.2 <u>Fuel Storage</u>

New fuel is stored dry in vertical racks in the fuel handling building. Room is provided to store one third of a core. The rack and fuel assembly spacing precludes criticality. Refer to subsection 9.1.1 for details.

Either new or spent fuel may be stored underwater in the intermediate storage racks inside containment. Refer to subsection 9.1.2.4 for details.

The spent fuel pool is a reinforced Seismic Category I concrete structure, stainless steel lined, which provides storage capacity for up to five and one-third cores (with expansion).

Either new or spent fuel assemblies may be stored in vertical racks in the spent fuel pool so spaced as to preclude criticality with partial credit taken for administrative controls on storage locations, and the borated pool water. Refer to subsection 9.1.2 for details.

Cooling and purification equipment is provided for both the refueling pool and spent fuel pool water, as described in paragraph 1.2.10.3.3.6.

The Independent Spent Fuel Storage Installation (ISFSI) is a Seismic Category 1X facility for interim dry storage of fuel assemblies that meet specific selection criteria. Irradiated fuel assemblies are stored in specially designed canisters and casks which provide passive cooling and shielding. Refer to subsection 9.1.2 for details.

1.2.10 AUXILIARY SYSTEMS

1.2.10.1 Shutdown Cooling System

The shutdown cooling system is used to reduce the temperature of the reactor coolant at a controlled rate from 350°F to a refueling temperature of approximately 135°F and to maintain the proper reactor coolant temperature during refueling. This system utilizes the low-pressure safety injection pumps to

circulate the reactor coolant through two shutdown heat exchangers, returning it to the reactor coolant system through the low-pressure injection header. The component cooling water system supplies cooling water for the shutdown heat exchangers.

The shutdown cooling system is further discussed in Section 5.4.7.

1.2.10.2 Chemical and Volume Control System

The Chemical and Volume Control System (CVCS) controls the purity, volume, and boric acid content of the reactor coolant.

The coolant purity level in the Reactor Coolant System is controlled by continuous purification of a bypass stream of reactor coolant. Water removed from the Reactor Coolant System is cooled in the regenerative heat exchanger. From there, the coolant flows to the letdown heat exchanger and then through a filter and a demineralizer where corrosion and fission products are removed. It is then sprayed into the volume control tank and returned by the charging pumps to the regenerative heat exchanger where it is heated prior to return to the Reactor Coolant System.

The Chemical and Volume Control System automatically adjusts the amount of reactor coolant in order to maintain a programmed level in the pressurizer. The level program partially compensates for changes in specific volume due to coolant temperature changes and reactor coolant pump controlled seal leakage. (See Section 9.3.4.2 for details.)

The CVCS controls the boric acid concentration in the coolant by a "feed and bleed" method where the purified letdown stream

is diverted to a boron recovery section and either concentrated boric acid or demineralized water is sent to the charging pumps. The diverted coolant stream is processed by ion exchange and degasification and flows to a concentrator. The concentrator bottoms are sent to the refueling water tank for reuse as boric acid solution and the distillate is first passed through an ion exchanger and then stored for reuse as demineralized water in the reactor makeup water tank.

1.2.10.3 Other Auxiliary Systems

1.2.10.3.1 Secondary Chemistry Control System

The secondary chemistry control system is designed to continuously monitor and inject chemicals into the feedwater to minimize system corrosion in the steam generator and the feed-water. The system is described in subsection 10.4.6.

1.2.10.3.2 Nuclear Sampling System

The nuclear sampling system is designed to collect samples from the reactor coolant and auxiliary systems for analysis. It permits sampling during reactor operation and cooldown without requiring access to the containment. Remote samples can be taken from equipment located in high radiation areas without personnel entering these areas. The sample lines are sized for the proper velocities to obtain representative samples and to prevent deposition. The process sampling system is described in detail in subsection 9.3.2.

1.2.10.3.3 Cooling Water Systems

1.2.10.3.3.1 Cooling Systems for Reactor Auxiliaries.

Cooling for reactor auxiliaries is provided by two systems, the safety-related essential cooling water system (ECWS) and the nonsafety-related nuclear cooling water system (NCWS). These systems are described in detail in subsection 9.2.2. A brief description of each system is provided as follows:

A. Essential Cooling Water System

The ECWS is comprised of two redundant Seismic Category I trains. These trains supply corrosion inhibited cooling water to components that are required for normal and emergency shutdown. The system also functions as an intermediate barrier between systems and equipment containing radioactive or potentially radioactive fluids and the essential spray pond system (ESPS) described in paragraph 1.2.10.3.3.2. Following a safety injection actuation signal (SIAS), cooling is supplied to the essential headers.

B. Nuclear Cooling Water System

The nonsafety-related NCWS supplies corrosion inhibited cooling water to reactor auxiliary systems and equipment during normal plant operation. The NCWS consists of one train with redundant components and acts as an intermediate barrier between systems and equipment containing radioactive or potentially radioactive fluids and the plant cooling water system.

1.2.10.3.3.2 Essential Spray Pond System. The ESPS is a safety-related, Seismic Category I system comprised of two redundant trains. The ESPS trains supply cooling water to the ECWS trains that are required to function for normal and emergency shutdown. This system is described in detail in subsection 9.2.1.

1.2.10.3.3.3 Ultimate Heat Sink. One ultimate heat sink is provided for each generating unit. The ultimate heat sink consists of two Seismic Category I essential spray ponds. The ultimate heat sink is utilized for normal and emergency shutdown in conjunction with the ESPS and the ECWS. The ultimate heat sink has a storage capacity that enables the associated ESPS trains to operate continuously for 26 days without any makeup water supply. However, normal makeup to replace evaporative loss from the ultimate heat sink is provided from the domestic water system or makeup water reservoir. Refer to subsection 9.2.5 for a detailed description of the ultimate heat sink.

1.2.10.3.3.4 Plant Cooling Water System. During normal operation, the plant cooling water system (PCWS) is utilized to remove heat from the NCWS and the turbine cooling water system (TCWS).

The PCWS rejects heat to the circulating water system. Redundant heat exchangers and pumps are provided. The PCWS is described in detail in subsection 9.2.10.

1.2.10.3.3.5 Turbine Cooling Water System. The TCWS is a nonsafety-related cooling system that provides treated demineralized cooling water to components in the turbine plant and acts as an intermediate system between turbine plant components and the PCWS. A detailed description of the TCWS is provided in subsection 9.2.8.

1.2.10.3.3.6 Spent Fuel Pool Cooling and Cleanup System. The spent fuel pool cooling system provides forced cooling of the pool water as required under normal and emergency (loss of offsite power) operating conditions. During normal operation, the fuel pool heat exchangers are supplied with cooling water by the NCWS. In the event of loss of offsite power, cooling water is available from the ECWS. The fuel pool and the fuel pool cooling system are Seismic Category I systems. The shutdown cooling system described in UFSAR Section 1.2.10.1 can also be used to augment fuel pool cooling. See Section 9.1.3.2.1.1

The purification loop is used to maintain the purity and clarity of water in the fuel transfer canal, the spent fuel pool, and refueling pool. The loop has a filter and demineralizer for purifying the water.

These systems are described in detail in subsection 9.1.3.

1.2.10.3.3.7 Evaporation Ponds. Evaporation ponds were added incrementally as the units were brought on line. They are earth embankments, lined with an artificial liner to limit seepage. The ponds store and evaporate cooling tower blowdown water and wastewater. Pond No. 1, pond No. 2 and pond No. 3

are lined with a composite liner that is described in paragraph 2.4.8.2.3.

1.2.10.3.4 Plant Fire Protection System

The fire protection water system provides water to any plant area where fire protection may be required. Units 1, 2, and 3 share a common fire protection water system. Water is taken from its two fire water/well water reserve tanks. The system consists of one electric-driven pump, two diesel engine driven pumps, one jockey pump, and the associated piping, valves, hydrants, and hose stations.

Chemical, carbon dioxide, and Halon 1301 firefighting systems also are provided in addition to the water fire protection system.

Necessary instrumentation and controls are provided for proper operation of the fire protection system. The fire protection system is described in subsection 9.5.1

1.2.10.3.5 Communications Systems

A communication system is provided with multiple redundancy to ensure safety, ease of operation, and maintenance. The system provides onsite, intraplant, interplant, and plant-to-offsite communications. The communication system is normally ac powered with a backup dc supply. The system description is given in subsection 9.5.2.

1.2.10.3.6 Lighting System

The three lighting systems provided are described as follows:

A. Normal Lighting

The normal lighting system provides illumination for the entire plant. The lighting load is distributed between two non-Class 1E lighting transformers.

B. Essential Lighting

The essential lighting system is connected to ESF buses. In general, the essential lighting system is designed to provide sufficient illumination to allow safe personnel access/egress throughout the plant in the event of a loss of normal lighting. It is also designed to provide sufficient illumination for the local manual operation of safe shutdown equipment in the event of fire. It provides 100% lighting in the control room area and remote shutdown room.

C. Emergency Lighting

The emergency lighting system is provided in areas used during shutdown or emergency. These areas include the control room, the local control stations required to shut down and maintain the plant in a hot shutdown condition from outside the control room, and the emergency exit routes. All emergency lighting is served by either self-contained battery units or battery backed UPS systems.

The lighting systems are described in detail in subsection 9.5.3.

1.2.10.3.7 Demineralized Water System

The demineralized water system furnishes demineralized water to each unit. Water from the reverse osmosis subsystem of the domestic water system is used to supply the demineralized water makeup system. The demineralizers consist of three mixed bed demineralizer units. Any two demineralizer beds operate in series to form a makeup train. A condensate tank, a demineralized water tank, and a reactor makeup tank are used at each unit to maintain the required demineralized water storage. The system is described in subsection 9.2.3.

1.2.10.3.8 Domestic Water System

The domestic water system provides necessary potable water to each unit for the consumptive use of plant personnel and water for other general plant uses. Well water is filtered, processed, and chlorinated prior to distribution throughout the plant. The domestic water system is described in subsection 9.2.4.

1.2.10.3.9 Alternate AC Power System

The station blackout gas turbine generation system is available to provide ac power to station loads that have been identified as important to the mitigation of a station blackout in any one unit of PVNGS. Two redundant 100 percent capacity Station Blackout Generators (SBOGs) are available for providing power to one of the safety related 4.16kV busses in each unit. The system is described in Section 8.3.1.1.10.

The SBOGs are also available during modes 5 & 6 to provide emergency power for shutdown cooling operations under conditions addressed in station abnormal and emergency operating procedures.

Having the SBOGs available to support a shutdown unit in the event of a SBO, does not impact their ability to support a unit that is at full power.

1.2.11 RADIOACTIVE WASTE MANAGEMENT SYSTEMS

The radioactive waste management system is designed to safely control potentially radioactive liquid, gaseous, and solid wastes. The system includes three principal subsystems:

- Liquid radwaste system (LRS)
- Gaseous radwaste system (GRS)
- Solid radwaste system (SRS)

The LRS is designed so that during normal operation there is no offsite release of radioactive liquids of plant origin from the plant site. The design of all radwaste systems ensures that all radioactive releases are as low as is reasonably achievable (ALARA).

1.2.11.1 Liquid Radwaste System

The LRS recovers radioactive or chemical liquid wastes for solidification. The system can accommodate liquid wastes generated at maximum anticipated rates, including demineralizer resin chemical regenerants from the condensate demineralizers,

and can segregate waste on the basis of total dissolved solids (TDS) for optimal economic treatment.

Particulate and ionic impurities in low TDS waste are removed by filters and ion exchangers. High or low TDS liquid wastes are concentrated by the LRS evaporator and are solidified. Evaporator condensate flows through ion exchangers prior to being recycled as reactor makeup water or condensate makeup. See section 11.2 for a detailed description of the LRS.

1.2.11.2 Gaseous Radwaste System

The GRS has two separate process paths based on the activity and/or hydrogen content of the waste gas. High-activity, hydrogen rich gases from the reactor coolant are collected, compressed, and stored in tanks to allow for radioactive decay. Low activity, aerated gases are removed by exhaust systems and are released through the plant vent. After decay, contents of the waste gas decay tanks are discharged to the plant ventilation system for dilution and are released with the low activity gases. All waste gases are filtered and monitored prior to environmental release. See section 11.3 for a detailed description of the GRS.

1.2.11.3 Solid Radwaste System

The SRS originally designed for the station is abandoned. The waste solidification process is described in section 11.4.

1.2.12 MAJOR STRUCTURES AND EQUIPMENT ARRANGEMENTS

Major Seismic Category I structures are described in the following sections. Engineering drawings 13-C-ZVA-005 and

13-P-OOB-001 provide a plot plan and engineering drawings 13-P-OOB-002 through -011 provide the general arrangements for the PVNGS units.

1.2.12.1 Containment Building

The containment building is a prestressed concrete cylinder with a hemispherical dome. The basemat is a flat, circular slab of reinforced concrete. The interior of the structure is lined with a continuous, welded steel plate 1/4 inch thick. Approximate dimensions of the structure are:

Structure Characteristic	Dimensions (ft)
Inside diameter	146
Inside height	206.5
Vertical wall thickness	4
Dome thickness at apex	3.5
Basemat diameter	161
Basemat thickness	10.5
Net Free Volume	2.62×10^6 ft^3

The Containment building is designed for a maximum internal pressure of 60 psig and a maximum, accident condition inner surface temperature of 300 degrees F. Housed within the containment building and supported by the basemat are the reinforced concrete and structural steel internal structures that support the reactor and reactor coolant system.

Under the most severe of postulated loading conditions -- including the combined effects of permanent loads, design basis LOCA loads, and either the safe shutdown earthquake or tornado

loads -- the containment building is designed to maintain its structural and leaktight integrity. This design permits a predictable response of the containment structure to allow operation of engineered safety features equipment for mitigation of accident consequences. Together with isolation valves, penetration assemblies, and its continuous, welded-steel liner, the structure contains the released fission products and maintains a leak rate below the design leak rate levels. The containment is designed to provide long-term control of fission products following a postulated accident.

1.2.12.2 Auxiliary Building

The auxiliary building is a multistory, reinforced concrete structure approximately 139 by 194 feet. It is located adjacent to the containment building but is physically separated from it. It has a two-level basement extending approximately 60 feet below grade. The building rises to about 56 feet above grade at its highest point. The auxiliary building primarily houses the ESF and CVCS equipment, and the power block controlled access facility.

1.2.12.3 Control Building

The control building is approximately 86 by 114 feet and is a four-story reinforced concrete structure. It is located adjacent to the radwaste and auxiliary buildings but is physically separated from them. It has a full basement below grade and rises to about 80 feet above grade at its highest point. The control building primarily houses the control room, computer room, upper and lower cable spreading rooms, battery

rooms, electrical equipment rooms, and ventilation equipment rooms.

1.2.12.4 Fuel Building

The fuel building is a reinforced concrete structure approximately 88 by 124 feet, rising to about 94 feet at its highest point. It is located adjacent to the containment and auxiliary building but is physically separated from them. The fuel building primarily houses the spent fuel pool, new fuel storage area, the dry spent fuel storage system loading and transfer equipment, and the spent fuel pool cooling heat exchangers and pumps.

1.2.12.5 Essential Spray Ponds

Two identical essential spray ponds (ESPs) are provided per unit. The combined water capacity of both ESPs is sufficient for 26 days continuous operation without makeup. The ESPs are approximately 172 by 345 feet. The perimeter walls are 17.5 feet high and 2 feet thick. See subsection 9.2.5 for a detailed description of the ESP.

1.2.12.6 Diesel Generator Building

The diesel generator building is a reinforced concrete structure located adjacent to the control building but is physically separated from it. The building is approximately 80 by 60 feet and has a maximum height of approximately 48 feet above grade.

1.3 COMPARISON TABLES

1.3.1 COMPARISONS WITH SIMILAR FACILITY DESIGNS

Tables 1.3-1 and 1.3-2 present a summary of the characteristics of the Palo Verde Nuclear Generating Station for Unit 1 Cycle 1 (the reference cycle for the three PVNGS units). Table 1.3-1 presents similar reactor core and coolant system data for Pilgrim Station Unit 2 and San Onofre Units 2 and 3.
Table 1.3-2 presents similar containment system, engineered safety features, and electrical components data for Farley Units 1 and 2, Calvert Cliffs 1 and 2, and San Onofre Units 2 and 3. The values presented in these tables were valid at the time the operating licenses were issued, and are not updated.

The Pilgrim Station Unit 2 and San Onofre Units 2 and 3 designs were selected for comparison in table 1.3-1 because of the basic similarity of the reactor core and coolant systems. In addition, San Onofre was selected for comparison because this reactor is nearing completion of its operating license application review with the NRC.

1.3.2 COMPARISON OF FINAL AND PRELIMINARY INFORMATION

Table 1.3-3 contains a discussion of significant changes that have been made in plant design since submittal of the PVNGS 1, 2, and 3 PSAR and amendments 1 through 20. These changes were applicable at the time the operating licenses were issued. Any subsequent changes are not documented in Table 1.3-3.

Table 1.3-1

REACTOR CORE AND COOLANT SYSTEM PARAMETERS (Sheet 1 of 9)

Item	Palo Verde	Reference Section	Pilgrim Station Unit 2	San Onofre Units 2 and 3
Hydraulic and Thermal Design Parameters				
Rated core heat output, MWt	3800	4.4	3,456	3,390
Rated core heat output, Btu/h	$12,970 \times 10^6$	4.4	$11,800 \times 10^6$	$11,570 \times 10^6$
Heat generated in fuel, %	97.5	4.4	96.5	97.5
System pressure, nominal, psia	2250	4.4	2,250	2,250
System pressure, minimum steady state, psia	2200	4.4	2,200	2,200
Hot channel factors,				
Heat flux, Fq	2.35	1.3	2.35	2.35
Enthalpy rise, F_H (outlet enthalpy = 699)	1.56	4.4	1.55	1.55
DNB ratio at nominal conditions	1.79 (CE-1)	4.4	2.26 (W-3)	2.07 (CE-1)
Coolant flow				
Total flowrate, lb/h	164.0×10^6	5.2	148×10^6	148×10^6
Effective flowrate for heat transfer, lb/h	157.4×10^6	4.4	142.8×10^6	142.8×10^6
Effective flow area for heat transfer, ft^2	60.9	4.4	54.8	54.7
Average velocity along fuel rods, ft/s	16.4	4.4	16.5	16.3
Average mass velocity, lb/h-ft^2	2.58×10^6	4.4	2.60×10^6	2.61×10^6
Coolant temperatures, °F				
Nominal inlet	568	4.4	557.5	553.
Design inlet	564.5	4.4	560.5	556
Average rise in vessel	56	4.4	58.3	58
Average rise in core	59	4.4	60.3	60
Average in core	594	4.4	588	583

Table 1.3-1

REACTOR CORE AND COOLANT SYSTEM PARAMETERS (Sheet 2 of 9)

Item	Palo Verde	Reference Section	Pilgrim Station Unit 2	San Onofre Units 2 and 3
Hydraulic and Thermal Design Parameters (cont)				
Coolant temperatures, °F (cont)				
Average in vessel	593	4.4	587	582
Nominal outlet of hot channel	653	4.4	651.4	642
Average film coefficient, Btu/h-ft^{2}F	6300	4.4	6,200	6,200
Average film temperature difference, °F	30	4.4	30	30
Heat transfer at 100% rated power				
Active heat transfer surface area, ft^2	68,600	4.4	62,000	62,000
Average heat flux, Btu/h-ft^2	184,400	4.4	184,000	182,400
Maximum heat flux, Btu/h-ft^2	433,000	4.4	429,900	428,000
Average thermal output, kW/ft	5.40	4.4	5.39	5.34
Maximum thermal output, kW/ft	12.7	4.4	12.6	12.5
Maximum clad surface temperature at nominal pressure, °F	656	4.4	656.5	657.0
Fuel center temperature, °F	3,290	4.4	3,420	3,180
Core Mechanical Design Parameters				
Fuel assemblies				
Design	CEA	4.2	CEA	CEA
Rod pitch, in.	0.506	4.2	0.5063	0.506
Cross-section dimensions, in.	7.972 x 7.972	4.2	7.98 x 7.98	7.972 x 7.972
Fuel weight (as UO_2), lbs	257.1 x 10^3	4.2	223.9 x 10^3	223.9 x 10^3

Table 1.3-1

REACTOR CORE AND COOLANT SYSTEM PARAMETERS (Sheet 3 of 9)

Item	Palo Verde	Reference Section	Pilgrim Station Unit 2	San Onofre Units 2 and 3
Core Mechanical Design Parameters (cont)				
Fuel assemblies (cont)				
Total weight, lbs	346,076	4.2	-	314,867
Number of grids per assembly	11	4.2	12	12
Fuel rods				
Number	56,876	4.2	49,476	49,580
Outside diameter, in.	0.382	4.2	0.382	0.382
Diametral gap, in.	0.007	4.2	0.007	0.007
Clad thickness, in	0.025	4.2	0.025	0.025
Clad material	Zircaloy-4	4.2	Zircaloy-4	Zircaloy-4
Fuel pellets				
Material	UO_2 sintered	4.2	UO_2 sintered	UO_2 sintered
Diameter, in.	0.325	4.2	0.325	0.325
Length, in.	0.390	4.2	0.390	0.390
Control assemblies				
Neutron absorber	B_4C	4.2	B_4C/Ag-In-Cd	B_4C/Ag-In-Cd
Cladding material	Inconel 625	4.2	NiCrFe alloy	Inconel 625
Clad thickness	0.035	4.2	0.035	0.035
Number of assemblies, full/part-strength	76/13	4.2	81/8	83/8
Number of rods per assembly	4 or 12 (4 part-strength rods per part-strength assembly)	4.2	5/4 (4 full-strength CEAs have 4 absorber rods per CEA)	4,5/5

Table 1.3-1

REACTOR CORE AND COOLANT SYSTEM PARAMETERS (Sheet 4 of 9)

Item	Palo Verde	Reference Section	Pilgrim Station Unit 2	San Onofre Units 2 and 3
<u>Nuclear Design Data</u>				
Structural characteristics				
Core diameter, in. (equivalent)	143.6	4.2	136	136
Core height, in. (active fuel)	150	4.2	150	150
HO_2/U, unlimited assembly (hot)	4.20	4.3	4.26	4.34
Number of fuel assemblies	241	4.2	217	217
UO_2 Rods per assembly	236	4.3	236	236
Performance characteristics				
Loading technique	5-region mixed central zone	4.3	3-batch mixed central zone	3-batch mixed central zone
Fuel enrichment, wt%				
Region 1	1.92	4.3	1.9	1.87
Region 2	1.92 and 2.78	4.3	2.4	2.38
Region 3	1.92 and 2.78	4.3	3.0	2.88
Region 4	2.78 and 3.30	4.3	N/A	N/A
Region 5	2.78 and 3.30	4.3	N/A	N/A
Control characteristics effective multiplication (beginning of life)				
Cold, no power, clean	1.193	4.3	1.169	1.170
Hot, no power, clean	1.133	4.3	1.133	1.125
Hot, full power, Xe equilibrium	1.078	4.3	1.071	1.067

Table 1.3-1

REACTOR CORE AND COOLANT SYSTEM PARAMETERS (Sheet 5 of 9)

Item	Palo Verde	Reference Section	Pilgrim Station Unit 2	San Onofre Units 2 and 3
Nuclear Design Data (cont)				
Control assemblies				
Total rod worth (hot), % $\Delta\rho$	16.76	4.3	>8	11.35
Boron concentrations for criticality:				
Zero power with no rods inserted, clean, ppm				
Cold/hot	1084/1018	4.3	980/970	899/832
At power with no rods inserted, clean/ equilibrium xenon, ppm	911/657		850/620	719/452
Kinetic characteristics, range over life				
Moderator temperature coefficient, $\Delta\rho$/°F	-0.7×10^{-4} to -2.5×10^{-4}	4.3	-0.5×10^{-4} to -2.2×10^{-6}	-0.5×10^{-4} to -2.3×10^{-4}
Moderator pressure coefficient, $\Delta\rho$/psi	0.64×10^{-6}	4.3	$+0.59 \times 10^{-6}$	$+0.7 \times 10^{-6}$
Moderator void coefficient, $\Delta\rho$/% Void	-0.24×10^{-3}	4.3	-0.26×10^{-3}	-0.36×10^{-3}
Doppler coefficient, $\Delta\rho$/°F	-1.18×10^{-5} to -1.66×10^{-5}	4.3	-1.10×10^{-5} to -1.9×10^{-5}	-1.13×10^{-5} to -1.87×10^{-5}
Reactor Coolant System - Code Requirements				
Component				
Reactor vessel	ASME III, Class 1	5.2	ASME III, Class 1	ASME III, Class 1

Table 1.3-1

REACTOR CORE AND COOLANT SYSTEM PARAMETERS (Sheet 6 of 9)

Item	Palo Verde	Reference Section	Pilgrim Station Unit 2	San Onofre Units 2 and 3
Reactor Coolant System - Code Requirements (cont)				
Steam generator				
Tube side	ASME III, Class 1	5.2	ASME III, Class 1	ASME III, Class 1
Shell side	ASME III, Class 2	5.2	ASME III, Class 2	ASME III, Class 2
Pressurizer	ASME III, Class 1	5.2	ASME III, Class 1	ASME III, Class 1
Pressurizer safety valves	ASME III, Class 1	5.2	ASME III, Class 1	ASME III, Class 1
Reactor coolant piping	ASME III, Class 1	5.2	ASME III, Class 1	ASME III, Class 1
Principal Design Parameters of the Coolant System				
Operating pressure, psia	2250	5.1	2250	2250
Reactor inlet temperature, °F	564.5	5.1	558.3	553
Reactor outlet temperature, °F	621.2	5.1	616	611.2
Number of loops	2	5.1	2	2
Design pressure, psia	2500	5.1	2500	2500
Design temperature, °F	650	5.1	650	650
Total coolant volume, ft^3 (without pressurizer)	12,353	5.1	11,700	10,300

Table 1.3-1

REACTOR CORE AND COOLANT SYSTEM PARAMETERS (Sheet 7 of 9)

Item	Palo Verde	Reference Section	Pilgrim Station Unit 2	San Onofre Units 2 and 3
Principal Design Parameters of the Reactor Vessel/Closure Head				
Material: Reactor Vessel	SA-533, Grade B, Class 1 (shell); clad with austenitic SS	5.2	SA-533, Grade B Class 1 (plate); clad with Type 304 austenitic SS	SA-533, Grade B, Class 1 (shell); clad with austenitic SS
:Closure Head	SA-508 GR. 3 CL. 2 Clad with 308L or 309L Austenitic SS	5.2		
Design pressure, psia	2500	5.4	2500	2500
Design temperature, °F	650	5.1	650	650
Operating pressure, psia	2250	5.3	2250	2250
Inside diameter of shell, in.	182-1/4	5.3	172	172
Outside diameter across nozzles, in.	267-1/4	5.3	253	253
Overall height of vessel and enclosure head, ft-in. to top of CEDM nozzle	48-0	5.3	43-6-1/2	43-6-1/2
Minimum clad thickness, in.	1/8	5.3	1/8	1/8
Principal Design Parameters of the Steam Generators				
Number of units	2	5.4	2	2
Type	Vertical U-tube with integral moisture separator	5.4	Vertical U-tube with integral moisture separator	Vertical U-tube with integral moisture separator
Tube Materials	NiCrFe alloy	5.2	NiCrFe alloy	Inconel (ASME SB-163)

Table 1.3-1

REACTOR CORE AND COOLANT SYSTEM PARAMETERS (Sheet 8 of 9)

Item	Palo Verde	Reference Section	Pilgrim Station Unit 2	San Onofre Units 2 and 3
<u>Principal Design Parameters of the Steam Generators</u> (cont)				
Shell material	SA-533 Gr. B Class I and SA-516 Gr. 70	5.2	SA-533 Gr. B Class I and SA-516 Gr. 70	SA-533 Gr. B Class I and SA-516, Gr.70
Tube side design pressure, psia	2500	5.4	2500	2500
Tube side design temperature, °F	650	5.4	650	650
Tube side design flow, lb/h (each)	82.0×10^6	5.4	79.2×10^6	74×10^6
Shell side design pressure, psia	1270	5.4	1,200	1,100
Shell side design temperature, °F	575	5.4	570	560
Operating pressure, tube side, nominal, psia	2250	5.4	2250	2250
Operating pressure, shell side, maximum, psia	1070	5.4	1100	1000
Maximum moisture at outlet at full load, %	0.25	5.4	0.25	0.2
Steam pressure at full power, psia	1070	5.4	1,000	900
Steam temperature at full power, °F	552.9	5.4	544.6	532
<u>Principal Design Parameters of the Reactor Coolant Pumps</u>				
Number of units	4	5.4	4	4
Type	Vertical, single stage centrifugal with bottom suction and horizontal discharge		Vertical, single stage, centrifugal with bottom suction and horizontal discharge	Vertical, single stage, radial flow with bottom suction and horizontal discharge

Table 1.3-1

REACTOR CORE AND COOLANT SYSTEM PARAMETERS (Sheet 9 of 9)

Item	Palo Verde	Reference Section	Pilgrim Station Unit 2	San Onofre Units 2 and 3
Principal Design Parameters of the Reactor Coolant Pumps (cont)				
Design pressure, psia	2500	5.4	2500	2500
Design temperature, °F	650	5.4	650	650
Operating pressure, nominal, psia	2,250	5.4	2250	2250
Suction temperature, °F	564.5	5.4	557.5	553
Design capacity, gal/min	111,400	5.4	99,500	99,000
Design head, ft	363	5.4	305	310
Motor type	AC induction, single speed	5.4	AC induction, single speed	AC induction, single speed
Motor rating, hp	12,000	5.4	10,000	9,700
Principal Design Parameters of the Reactor Coolant Piping				
Material	SA-516, Gr. 70 with SS clad	5.2	SA-516, Gr. 70 with SS clad	SA-516, Gr. 70 with nominal 7/32 SS clad
Hot leg ID, in.	42	5.4	42	42
Cold leg ID, in.	30	5.4	30	30
Between pump and steam generator ID, in.	30	5.4	30	30

Table 1.3-2

COMPARISON OF PLANT CHARACTERISTICS (Sheet 1 of 5)

Item	Palo Verde (FSAR)	San Onofre Units 2 and 3 (FSAR)	Farley Units 1and 2 (FSAR)	Calvert Cliffs Units 1 and 2 (FSAR)	Significant Similarities	Significant Differences	References By Sections
Containment System Parameters							
Type	Steel-lined, pre-stressed post-tensioned concrete cylinder, curved dome roof.	Steel-lined, pre-stressed post-tensioned concrete cylinder, curved dome roof	Steel-lined, pre-stressed post-tensioned concrete cylinder, curved dome roof	Steel-lined, pre-stressed post-tensioned concrete cylinder, curved dome roof	Containment types are the same for all units.	None	3.8.1
Design parameters						Containment design Parameters differ because of differences in dome height or inside Diameter.	3.8.1
Inside diameter, ft	146	150	130	130			
Inside height, ft	206	172	183	182			
Nominal free volume, ft^3	2,600,000	2,335,000	2,024,900	2,000,000			
Design pressure, psig	60	60	54	50			
Concrete thickness, ft							
Vertical wall	4	4-1/3	3-3/4	3-3/4			
Dome	3-1/2	3-3/4	3-1/4	3-1/4			
Containment leak prevention and mitigation systems	Leaktight penetrations and continuous steel liner. Automatic isolation where required	Leaktight penetrations and continuous steel liner. Automatic isolation where required	Leaktight penetrations and continuous steel liner. Automatic isolation where required	Leaktight penetrations and continuous steel liner. Automatic isolation where required	Same design bases for all units.		6.2.4, 9.4.3
Gaseous effluent purge	Discharge through stack.	Discharge through stack.	Discharge through stack	Discharge through stack	All use stack discharge.		
Engineered Safety Features							
Safety injection system						Palo Verde uses 2 high head injection pumps. All other units use 3.	6.3
No. of high head pumps	2	3	3	3			
No. of low head pumps	2	2	2	2			
Post-accident filters					Palo Verde similar to San Onofre and Farley.	Calvert Cliffs has post-accident filters. The other units do not.	9.4.1
No. of units	None	None	None	3			
Ft^3/min	None	None	None	20,000			
Containment spray, No. of pumps	2	2	2	2	Palo Verde, San Onofre, Farley and Calvert Cliffs have 2 each.		6.2.2

Table 1.3-2

COMPARISON OF PLANT CHARACTERISTICS (Sheet 2 of 5)

Item	Palo Verde (FSAR)	San Onofre Units 2 and 3 (FSAR)	Farley Units land 2 (FSAR)	Calvert Cliffs Units 1 and 2 (FSAR)	Significant Similarities	Significant Differences	References By Sections
Engineered Safety Features (cont)							
Emergency power							
Diesel-generator units	6 total (2 per unit)	4 total for both units	5 total for both units	3 total for both units	Palo Verde is similar to San Onofre	Palo Verde and San Onofre utilize 2 diesel generators per unit. Farley has a total of 5 for both plants; Calvert Cliffs has 3 for both units.	8.3.1
Safety injection tanks, number	4	4	3	4	Palo Verde, San Onofre and Calvert Cliffs have similar designs utilizing 4 safety injection tanks.	Farley has a 3-safety injection tank design.	
Electrical components							
Standby power system	Total of 6 diesels; 2 supply each unit. Diesels are connected to 4160V buses. No capability for sharing between units.	Total of 4 diesels; 2 supply each unit. Diesels are connected to 4160V buses. No capability for sharing.	Total of 5 diesels; 3 are shared between Units 1 and 2. Diesels are connected to 4160V buses.	Three diesels connected to 4-kV buses and shared between Units 1 and 2.	Palo Verde is similar to San Onofre.	Palo Verde has 1 diesel permanently aligned to an ESF bus per unit. Calvert Cliffs and Farley have shared diesels only.	8.3.1
Engineered safety feature buses	Two 4160V buses/unit divided into two separate and redundant systems.	Two 4160V buses/unit divided into two separate and redundant systems.	Two 4160V buses/unit divided into two separate and redundant systems.	Two 4-kV buses/unit divided into two separate and redundant systems.	Palo Verde is similar to all	None	8.3.1
DC systems	Separate and redundant 125 V-dc systems for ESF loads. Separate 125 V-dc systems for non-ESF loads.	Separate and redundant 125 V-dc systems for ESF loads. Separate 125 V-dc and 250 V-dc systems for non-ESF loads.	Separate and redundant 125 V-dc systems for ESF loads. Separate dc systems for loads in auxiliary building, turbine building, cooling tower area, diesel generator building and switchyard.	Four batteries between 2 units divided to give two separate and redundant 125 V-dc systems. Separate dc systems for turbine building and the switchyard.	Palo Verde similar to San Onofre, Farley, and Calvert Cliffs for ESF loads.		8.3.2
Vital instrumentation systems	Four inverters arranged to give 4 separate and redundant channels.	Four inverters arranged to give 4 separate and redundant channels.	Four inverters arranged to give 4 separate and redundant channels.	Four inverters between 2 units to give 4 separate and redundant channels per unit.	Palo Verde similar to all.	None	8.3.1

Table 1.3-2

COMPARISON OF PLANT CHARACTERISTICS (Sheet 3 of 5)

Item	Palo Verde (FSAR)	San Onofre Units 2 and 3 (FSAR)	Farley Units 1 and 2 (FSAR)	Calvert Cliffs Units 1 and 2 (FSAR)	Significant Similarities	Significant Differences	References By Sections
<u>Electrical Components</u> (cont)							
Offsite power systems	One 525 kV switchyard is common to Units 1, 2 & 3. Within the switchyard each of Units 1, 2 and 3 is normally provided with 2 offsite supplies from 2 of the 3 startup transformers. ESF buses are supplied from startup transformers	One 230 kV switchyard is common to Units 2 and 3. Each unit is provided with two unit auxiliary and three startup transformers supplied from the common switchyard.	Unit 1 - 230 kV switch-yard. Unit 2 - 500 kV Switchyard. Each unit has 2 startup transformers and 2 unit auxiliary transformers with the ESF buses supplied from startup Transformers.	500 kV switchyard. Two startup transformers shared between two units.	ESF buses are supplied directly from startup transformers on Palo Verde and Farley.	The startup transformers for San Onofre units are not shared as is the case for Palo Verde and Calvert Cliffs.	8.2 and 8.3
<u>Radioactive Waste Management System</u>							
Liquid radwaste system							
Miscellaneous liquid waste system	1/unit	Shared	Shared	Shared			11.2
Discharge:							
Evaporator distillate	Reactor makeup water tank, condensate tank, and spent fuel pool	Circulating water outfall	Circulating water Outfall	Circulating water outfall		Palo Verde does not discharge offsite. It retains evaporator distillate for reuse.	
Evaporator bottoms	Solid radwaste system	Solid radwaste system	Solid radwaste system	Solid radwaste system			
Recycle capability	Yes	Yes	Yes	Yes			
Total reprocessing storage capacity (holdup tanks)	2 at 5,000 gal 2 at 30,000 gal	1 at 6,000 gal 2 and 25,000 gal	40,000 gal	8,000 gal			
Filter type	Disposable cartridge	Disposable cartridge and backflushable	Disposable cartridge	Disposable cartridge			
Evaporator capacity	30 gal/min	50 gal/min	35 gal/min	20 gal/min			

Table 1.3-2

COMPARISON OF PLANT CHARACTERISTICS (Sheet 4 of 5)

Item	Palo Verde (FSAR)	San Onofre Units 2 and 3 (FSAR)	Farley Units 1 and 2 (FSAR)	Calvert Cliffs Units 1 and 2 (FSAR)	Significant Similarities	Significant Differences	References By Sections
Radioactive Waste Management System (cont)							
Coolant and boric acid recycle system	1/unit	Shared	Shared	Shared (Reactor coolant waste processing System		Palo Verde has one recycling system per unit. Others share recycling system among units.	9.3.4
Discharge:							
Concentrator bottoms	No; recycled to refueling water tank	No; recycle to boric acid makeup and batching tanks	Liquid radwaste system	Solid radwaste system			
Concentrator condensate	No; recycled to reactor makeup water tank	No; recycled to CVCS	No; recycled to CVCS	Circulating water Discharge			
Concentrator capacity	20 gal/min	50 gal/min	30 gal/min	2 at 20 gal/min			
Concentrated boric acid storage tanks	1 at 800,000 gal (Refueling water tank)	2 at 25,000 gal each	2 at 21,000 gal each	2 at 10,000 gal each			
Radwaste receiver tanks	3/unit at 30,000 gal	2 primary at 120,000 gal each and 2 secondary at 120,000 gal each	3 at 28,000 gal each	2 waste receiver tanks at 90,000 gal each			
Waste gas system	1/unit	Shared	Shared	Shared		Palo Verde has one waste gas system per unit; others share waste processing system	11.3
Number of decay tanks	3/unit	6	8	3			
Tank size (each)	760 ft^3	500 ft^3	600 ft^3	610 ft^3			
Design pressure	380 psig	350 psig	150 psig	150 psig			
Discharge Point	Plant vent	Plant vent stack	Plant vent	Plant vent			
Holdup time available	45 days	30 days (minimum)	30 days (minimum)	60 days			
Surge tank	1/unit	1/shared	No	1/shared			
Surge tank size	760 ft^3 at 1 to 3 psig	500 ft^3 at 150 psig		610 ft^3 at 50 psig			
Compressor capacity	2 at 10 standard ft^3/min	2 at 5 standard ft^3/min	2 at 40 standard ft^3/min	2 at 4.7 standard ft^3/min			
Radwaste solidification system	1/unit	Shared	Shared	Shared		Palo Verde has one solidification system per unit; others share waste solidification system among units.	11.4
Solidification agent	Vermiculite-Portland cement	Urea formaldehyde	Vermiculite - cement				

Table 1.3-2

COMPARISON OF PLANT CHARACTERISTICS (Sheet 5 of 5)

Item	Palo Verde (FSAR)	San Onofre Units 2 and 3 (FSAR)	Farley Units 1 and 2 (FSAR)	Calvert Cliffs Units 1 and 2 (FSAR)	Significant Similarities	Significant Differences	References By Sections
Radioactive Waste Management System (cont)							
Radwaste solidification system (cont)							
On site storage:							
High level solidification	42-80 ft^3 drums or 294-55 gal drums	20-50 ft^3 drums	175-55 gal drums				
Low level solidification baling station	50-55 gal drums	25-55 gal drums	400-55 gal drums				
Shipping containers used	55-gal drums and 80 ft^3 drums	55 gal drums and 50 ft^3 drums	55 gal drums				

COMPARISON TABLES

Table 1.3-3

SIGNIFICANT DESIGN CHANGES

Items	System Described in FSAR Section	Reason for Change
Containment spray	6.1	The containment spray additive was eliminated based on analyses that demonstrate acceptable consequences following a small or large break LOCA using borated refueling water as spray. The Iodine Removal System (IRS) has been disconnected from the Containment Spray System (CCS) and abandoned in place. Hydrazine is caustic and hazardous to work with. Elimination of the IRS reduces both personnel and property hazards from leaking seals, pumps, and valves, and significantly reduces cleanup requirements in the event of an inadvertent CSS actuation. Elimination of the IRS increases CSS System reliability by removing active components subject to potential failure.
Condensate storage tank	3.8	Changed from steel tank with concrete missile barrier to concrete, Seismic Category I structure with stainless steel liner.
Refueling water tank	3.8	Changed from steel tank with concrete missile barrier to concrete, Seismic Category I structure with stainless steel liner.
Atmospheric dump valves	10.3.2	Changed to safety grade controls.

1.4 IDENTIFICATION OF AGENTS AND CONTRACTORS

1.4.1 ENGINEER

Bechtel Power Corporation (BPC) entered into separate contracts with Arizona Public Service Company (APS) for the engineering and construction of Palo Verde Nuclear Generating Station (PVNGS) in 1973.

In 1984, the construction contract was assigned to Bechtel Construction, Inc. (BCI) which is responsible for the construction of PVNGS, and in 1986, the engineering and procurement services were subcontracted to Bechtel Western Power Corporation (BWPC).

BWPC, as agent for APS, is responsible for all procurement and manages procurement contracts, including the nuclear steam supply system (NSSS), turbine-generator and other designated contracts entered into by APS.

BWPC and BCI are responsible for implementing the Bechtel quality assurance program within the scope of their respective contracts. BWPC is obligated to conduct a quality assurance program, including audits of its own work, BCI, and all of its subcontractors.

1.4.2 NUCLEAR STEAM SUPPLY SYSTEM SUPPLIER

APS has contracted with Combustion Engineering, Inc. (C-E), located in Windsor, Connecticut, to design, manufacture, and deliver an NSSS for each unit and nuclear fuel for the initial core and first reload batch of each NSSS. In addition, C-E furnishes technical direction for erection, initial fuel

loading, testing, and initial startup of each NSSS. C-E is further obligated to conduct a quality assurance program, including audits, of its own work and all its subcontractors and suppliers, in a manner which complies with 10CFR50, Appendix B.

1.4.3 TURBINE-GENERATOR SUPPLIER

The turbine-generator (TG) is manufactured by the General Electric Company (GE). Design of the TG is under the direction of the Large Steam Turbine-Generator Products Division located in Schenectady, New York. General Electric furnishes technical direction during erection testing and startup of the TG.

1.4.4 PRINCIPAL CONSULTANTS

1.4.4.1 NUS/ERTEC Western

NUS Corporation of Rockville, Maryland, along with its geotechnical consultant, ERTEC Western, Inc. (formerly FUGRO) of Long Beach, California, has performed site selection and environmental studies and has provided appropriate input to the FSAR and Environmental Report-Operating License Stage (ER-OL). NUS and ERTEC are obligated to conduct a quality assurance program, including audits of their own work and all their subcontractors and suppliers, as appropriate, in a manner which complies with 10CFR50, Appendix B.

1.4.4.2 S. M. Stoller Corporation

The S. M. Stoller Corporation, located in New York City, has acted as a general nuclear consultant, providing technical assistance as required.

1.4.5 DIVISION OF RESPONSIBILITY

1.4.5.1 Design Stage

Combustion Engineering, Inc. and Bechtel are delegated the responsibility for design of the NSSS and the balance of the plant, respectively. All parties (APS, Bechtel, C-E, and NUS/Fugro) participated in the preparation and review of design bases and philosophies for both systems and structures by reviews of the design. General Electric and C-E are responsible to review Bechtel's balance of plant design to assure proper interface with their supply.

1.4.5.2 Procurement of Safety-Related Equipment

1.4.5.2.1 Combustion Engineering, Inc. Scope of Supply

Procurement procedures are established for safety-related equipment under the C-E scope of supply. These require both APS and Bechtel to review bidders' lists and specifications. All bidders meet the quality assurance requirements described in CESSAR Section 17.0. Combustion Engineering, Inc. prepares specifications, issues requests for proposals, evaluates proposals, advises Bechtel and APS of prospective suppliers, and issues purchase orders to suppliers.

1.4.5.2.2 Bechtel Scope of Supply

Procurement procedures are established for the safety-related equipment under the Bechtel scope of supply. These require both APS and Bechtel participation. Bechtel prepares the specifications and lists of qualified bidders and transmits them to APS for review and comment. After review by APS and resolution of any comments by Bechtel, Bechtel has the responsibility for issuing specifications to the bidders for proposals in accordance with the approved bidders' list. All bidders meet the quality assurance requirements described in chapter 17. After reviewing the proposals, Bechtel prepares a technical and commercial evaluation and forwards a recommendation for purchase to APS. After review by APS, Bechtel is advised of the selected supplier. Bechtel then prepares purchase order documents for execution by APS. Bechtel then manages these purchase orders for APS.

1.4.5.3 Construction

Bechtel provides primary construction activities and overall construction management for PVNGS. Certain portions of the construction activities have been subcontracted subject to the concurrence of APS. Independent testing agencies are utilized, as necessary, to perform special tests and to provide expertise in the interpretation of test results.

1.4.5.4 Operation

APS has the responsibility for the operation of PVNGS as described in chapter 13.

1.5 REQUIREMENTS FOR FURTHER TECHNICAL INFORMATION

This section lists a number of development programs. Table 1.5-1 lists those programs and identifies where results are documented.

1.5.1 TOPICAL PROGRAM SUMMARY

References 1 through 5 present descriptions of safety related Research and Development programs which are being carried out by, or in conjunction with Combustion Engineering, Inc., and which are applicable to C-E pressurized water reactors (PWR). This type of report is updated annually.

For each program summarized in these reports, the objectives are first introduced, followed, where appropriate, by background information. This is followed by a description of each program relative to the stated objectives and a presentation of pertinent, up-to-date results. Finally, conclusions are made where appropriate and future work plans are discussed relative to past performance and findings of the program. New programs, which include existing programs which become safety related for licensing purposes will be described in future versions of this report. Descriptions of programs or parts of programs are phased out of versions of this report as they are completed and documented.

1.5.2 SYSTEM 80 - 16 x 16 ASSEMBLY TEST PROGRAM

Since fuel fabrication for System 80 reactors is not scheduled to start for some time, the development schedule is compatible with the project schedules having System 80 designs such that

definite results will be available before each plant design is complete and/or in time to consider a backup position in the program or changes in the design should the program results not verify expectations.

1.5.2.1 Components Testing

Component test programs have been conducted in support of all C-E PWR designs. The tests subject a full-scale reactor core module comprising fuel assemblies, control element assembly, control element drive mechanism, and reactor vessel internals components to the hydraulic environment of the reactor under all normal operating conditions. The program is a continuing series of tests wherein components introduced as part of a particular design are tested in C-E TF-2 hot loop test facility at Windsor, Connecticut. The Tests are designed to proof and life test the integrated fuel assembly and control element drive mechanism under a variety of simulated operating conditions to evaluate component fretting and wear characteristics, scram performance, and fuel assembly uplift and pressure drop. Information and a description of the testing is provided in Section 4.4.4.2.

1.5.2.2 Fuel Assembly Seismic Testing

The program can be divided into three areas - spacer grid tests, fuel assembly static tests and fuel assembly dynamic tests. The results are utilized in developing the seismic models of the fuel described in Section 3.7.3.14 and Section 4.2.

1.5.2.3 Reactor Flow Model Testing

A scale flow model of the C-E System 80 reactor vessel and internals has been tested. A detailed discussion of the flow model and test facility appears in Section 4.4.4.2. The purpose of these tests is to establish or verify design hydraulic parameters. In particular, core inlet flow distributions and pressure losses along the flow path segments within the reactor vessel have been measured for operating configurations.

1.5.2.4 DNB Improvement

A substantial test program has been undertaken to verify the thermal performance capability of the System 80 fuel assembly. The test program is an extension of the experimental studies conducted with rod bundles representative of the C-E 14 x 14 fuel assembly. Those studies are described in more detail in Section 4.4.4.5 and are used in System 80 analyses.

1.5.2.5 Fuel Development Programs

Combustion Engineering has in progress several company-sponsored fuel irradiation programs. In addition, several cooperative fuel development programs are being performed with Kraftwerk Union as part of a technical agreement. Also, Combustion Engineering has access to all data and results of Kraftwerk Union's company-sponsored fuel development programs.

A complete description of the programs and the results obtained is provided in Section 4.2.

1.5.3 SYSTEM 80 STEAM GENERATOR DEVELOPMENT PROGRAMS

C-E's System 80 Steam Generator is a vertical U tube component. The current Palo Verde steam generators from Ansaldo-Camozzi energy special SPA represent the next evolution of the System 80 steam generator. A complete description of the steam generator is given in Section 5.4.2. Development efforts were conducted to confirm the structural integrity of the steam generator during thermal, MSLB and FWLB transients.

REFERENCES FOR SECTION 1.5

1. CENPD-87, "Safety Related Research and Development for CE Pressurized Water Reactors Program Summaries; January, 1973", March, 1973.
2. CENPD-143, "Safety Related Research and Development for CE Pressurized Water Reactors Program Summaries; January, 1973 through February 1974", June, 1974.
3. CENPD-184, "Safety Related Research and Development for CE Pressurized Water Reactors; 1974 Program Summaries", May, 1975.
4. CENPD-229, "Safety Related Research and Development for CE Pressurized Water Reactors; 1975 Program Summaries", June 1976.
5. CENPD-258, "Safety Related Research and Development for CE Pressurized Water Reactors; 1976 Program Summaries", October 1977.

REQUIREMENTS FOR FURTHER

TECHNICAL INFORMATION

TABLE 1.5-1

SUMMARY OF DEVELOPMENT PROGRAMS TO DEMONSTRATE

SYSTEM 80 DESIGN CONSERVATISM

	PROGRAM	RESULTS DOCUMENTED IN: OR EXPECTED SUBMITTAL DATE:
1.	Components tests	CESSAR Appendix 4C
2.	Fuel Assembly Seismic Tests	CENPD 178 Rev. 1
3.	Reactor Flow Model Test	CESSAR Appendix 4B
4.	DNB Improvement and Flow Mixing Tests	CENPD-162A and CENPD-207
5.	Fuel Densification Program	Section 4.2.3.2.10 and CENPD-139
6.	LOCA Refill Program	CENPD-134
7.	Blowdown Heat Transfer Program	CENPD-132, SUPP. 1, 2, & 3
8.	Reflood Test	CENPD-213
9.	Iodine Decontamination and Iodine Spiking Tests	CENPD-180, Supp. 1
10.	Original Steam Generator Program	CESSAR Appendices 5B & 5C
11.	CPC Program	CEN-72A and CEN-73A
12.	Replacement Steam Generator Program	Appendices 5D\ & 5E[a]

[a] Information shown is for Unit 2 Replacement Steam Generators and is generally representative for Units 1 and 3 Replacement Steam Generators.

1.6 REFERENCED MATERIAL

1.6.1 GENERAL REFERENCES

General references are not considered part of the FSAR, but are intended to provide background information or additional detail that the reader may refer to in order to learn more about particular material presented in the FSAR. These may be texts, environmental studies or technical reports, as well as PVNGS controlled documents such as operating or maintenance procedures, calculation manuals, etc. References to such information may be located at specific points in the FSAR, or they may be listed at the end of FSAR chapters or in introductory sections.

The basic reference document for the PVNGS FSAR is the Combustion Engineering Standard Safety Analysis Report (CESSAR). The use of the CESSAR is described in section 1.9.

Referenced Bechtel Power Corporation (BPC) topical reports are listed in Table 1.6-1. These topical reports have been approved by the NRC as shown in Table 1.6-2. Referenced Combustion Engineering Topical Reports are listed in Table 1.6-3. The revision/supplement/addendum level indicated in these tables represents the revision/supplement/addendum that is referenced. Additional references may be included at the end of each FSAR section or chapter.

1.6.2 INCORPORATION BY REFERENCE

Information that is appropriate to include in the FSAR, that is also part of a separate PVNGS controlled document or technical

report, may be incorporated by reference. "Incorporation by reference" refers to a method by which all or part of a separate source document can be made part of the FSAR without duplicating the desired information in the FSAR.

For PVNGS information to be incorporated by reference, the information must be publicly available (i.e., it must have been submitted to the NRC) unless there exists an explicit NRC requirement to maintain the information on site. Furthermore, information incorporated by reference into the FSAR is subject to the update and reporting requirements of 10 CFR 50.71(e) and change controls of 10 CFR 50.59 unless a separate NRC change control requirement applies (e.g., 10 CFR 50.54(a)). References should be as clear as possible as to the extent of the information incorporated by reference and thus considered part of the FSAR.

A list of PVNGS documents incorporated by reference are listed in Table 1.6-4.

REFERENCE MATERIAL

Table 1.6-1

Referenced Bechtel Power Corporation (BPC) Topical Reports

Report Number	Title
BN-TOP-1 Rev. 1	Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structure for Nuclear Power Plants
BN-TOP-2 Rev. 2	Design for Pipe Break Effects
BN-TOP-4 Rev. 1	Subcompartment Pressure and Temperature Transient Analysis
BC-TOP-1 Rev. 1	Containment Building Liner Plate Design
BC-TOP-3-A Rev. 3	Tornado and Extreme Wind Design Criteria for Nuclear Power Plants
BC-TOP-4-A Rev. 3	Seismic Analysis of Structures and Equipment for Nuclear Power Plants
BC-TOP-5-A Rev. 3	Prestressed Concrete Nuclear Reactor Containment Structures
BC-TOP-7 Rev. 0	Full Scale Buttress Test for Prestressed Nuclear Containment Structures
BC-TOP-8 Rev. 0	Tendon End Anchor Reinforcement Test
BC-TOP-9-A Rev. 2	Design of Structures for Missile Impact
BP-TOP-1 Rev. 3	Seismic Analysis of Piping Systems

Table 1.6-2
BPC Topical Reports Approved by the NRC

Report Number	Date Approved By NRC	FSAR Location Referencing Topical Report	Nature of Report
BN-TOP-1	February 1973	6.2.6	Nonproprietary
BN-TOP-2	June 1974	3.6	Nonproprietary
BN-TOP-4	February 1979	6.2	Nonproprietary
BC-TOP-1	February 1974	3.8	Nonproprietary
BC-TOP-3-A	October 1974	3.3, 3.8	Nonproprietary
BC-TOP-4-A	November 1974	3.7, 3.8	Nonproprietary
BC-TOP-5-A	March 1975	3.8	Nonproprietary
BC-TOP-7	August 1973	3.8	Nonproprietary
BC-TOP-8	August 1973	3.8	Nonproprietary
BC-TOP-9-A	June 1974	3.8	Nonproprietary
BP-TOP-1	September 1976	3.7	Nonproprietary

REFERENCE MATERIAL

Table 1.6-3

Referenced Combustion Engineering and Westinghouse

Topical Reports

REPORT NO.	TITLE	DATE ISSUED
CENPD-26	Description of Loss-of-Coolant Calculational Procedures	8/20/71
Suppl. #1	Description of Loss-of-Coolant Calculational Procedures	10/14/71
Suppl. #2	Steam Venting Experiments	1/10/72
Suppl. #3	Moisture Carryover during a PWR post-LOCA Core Refill	1/10/72
CENPD-67	Combustion Engineering, Inc.	September 1973
Suppl. #1	"Iodine Decontamination	May 1974
Suppl. #2	Factors During PWR Steam	June 1974
Addendum 1	Generation and Steam Venting"	November 1974
Addendum 2		August 1975
CENPD-80	Moisture Carryover During an NSSS Steam Line Break Accident	January 1973
CENPD-98-A	COAST Code Description	4/18/75
CENPD-105	Combustion Engineering, Inc. "Fast Neutron Attenuation by the ANISN-SHADRAC Analytical Method"	June 1973
CENPD-107	Combustion Engineering, Inc. "CESEC"	August 1974
Suppl. #1		September 1974
Suppl. #3	ATWS Model Modification	August 1975
Suppl. #4	To CESEC	December 1975
Suppl. #5		June 1976
Suppl. #2	ATWS Models For Reactivity Feedback and Effects of Pressure on Fuel	September 1974
CENPD-118	Combustion Engineering, Inc. "Densification of Combustion Engineering Fuel"	June 1974

REFERENCE MATERIAL

Table 1.6-3 (Cont'd)

Referenced Combustion Engineering and Westinghouse Topical Reports

REPORT NO.	TITLE	DATE ISSUED
CENPD-133	Combustion Engineering, Inc. "CEFLASH-4A Fortran IV Digital Computer Program for Reactor Blowdown Analysis	August 1974
Suppl. #1	CEFLASH-4AS, A Computer	09/25/74
Suppl. #3	Program for Reactor Blowdown Analysis of The Small Break Loss of Coolant Accident	02/10/77
Suppl. #2	CEFLASH-4A, A FORTRAN IV Digital Computer Program for Reactor Blowdown Analysis (Modifications)	03/13/75
CENPD-134	Combustion Engineering, Inc. "COMPERC-II A Program for	August 1974
Suppl. #1	Emergency Refill - Reflood of the Core"	February 1975
CENPD-135	Combustion Engineering, Inc.	August 1974
Suppl. #2	"STRIKIN-II A Cylindrical	February 1975
Suppl. #4	Geometry Fuel Rod Heat	August 1976
Suppl. #5	Transfer Program"	April 1977
CENPD-137	Combustion Engineering, Inc. "Calculative Methods for the	August 1974
Suppl. #1	C-E Small Break LOCA Evaluation Model	January 1977
CENPD-138	PARCH - A FORTRAN IV	August 1974
Suppl. #1	Digital Computer Program to	February 1975
Suppl. #2	Evaluate Pool - Boiling Axial Rod, and Coolant Heatup	January 1977
CENPD-161-A	Combustion Engineering, Inc. "TORC Code = A Computer Code for Determining the Thermal Margin of a Reactor Core"	April 1986
CENPD-162-A	Combustion Engineering, Inc. "CHF Correlation for C-E Fuel	September 1976
Suppl. #1-A	Assemblies with Standard Spacer Grids - Part 1; Uniform Axial Power Distribution"	February 1977

REFERENCE MATERIAL

Table 1.6-3 (Cont'd)

Referenced Combustion Engineering and Westinghouse Topical Reports

REPORT NO.	TITLE	DATE ISSUED
CENPD-168-A	Combustion Engineering, Inc. "Design Basis Pipe Breaks for the Combustion Engineering Two Loop Reactor Coolant System"	June 1977
CENPD-169	Combustion Engineering, Inc. "Assessment of the Accuracy of PWR Operating Limits as Determined by Core Operating Limit Supervisory System"	July 1975
CENPD-170 Suppl. #1	Combustion Engineering, Inc. "Assessment of the Accuracy of the PWR Safety System Actuation as Performed by the Core Protection Calculators"	August 1975 November 1975
CENPD-179	Combustion Engineering, Inc. "C-E Thermo-Structural Fuel Evaluation Method"	April 1976
CENPD-180 Suppl. #1	Radioiodine Behavior in Reactor Coolant During Transient Operation	March 1976 March 1977
CENPD-182	Combustion Engineering, Inc. "Seismic Qualification of C-E Control Equipment"	November 1975
CENPD-183	Combustion Engineering, Inc. "C-E Methods for Loss of Flow Analysis"	August 1975
CENPD-187-A Suppl. #1-A	Combustion Engineering, Inc. "Method of Analyzing Creep Collapse of Oval Cladding"	March 1976 June 1977
CENPD-188	HERMITE, A Multi-Dimensional Time Kinetics Code for PWR Transients	March 1976
CENPD-190	Combustion Engineering, Inc. "C-E Method for Control Element Assembly Ejection Analysis"	January 1976
CENPD-198	Combustion Engineering, Inc. "Zircaloy Growth-In-Reactor Dimensional Changes in Zircaloy-4 Fuel Assemblies	December 1975
CENPD-201-A	Reactor Coolant Pump Performance	April 1976

Table 1.6-3 (Cont'd)

Referenced Combustion Engineering and Westinghouse Topical Reports

REPORT NO.	TITLE	DATE ISSUED
CENPD-206-A	Combustion Engineering, Inc. "TORC Code Verification and Simplified Modeling Method"	June 1981
CENPD-207-A	Combustion Engineering, Inc. "Critical Heat Flux Correlation for C-E Fuel Assemblies with Standard Spacer Grids, Part 2, Non-Uniform Axial Power Distributions"	December 1984
CENPD-210-A	Quality Assurance Program A Description of the C-E Nuclear Steam Supply System Quality Assurance Program	July 1977
CENPD-213 Suppl. #1	Combustion Engineering, Inc. "Application of FLEIGHT Reflood Heat Transfer Coefficients to Combustion Engineering 16 x 16 Fuel Bundles"	January 1976 March 1976
CENPD-225	Combustion Engineering, Inc. "Fuel and Poison Rod Boiling"	October 1976
Suppl. #1		February 1977
Suppl. #2		June 1978
Suppl. #3		July 1979
CENPD-254	"Post-LOCA Long Term Cooling Evaluation Model"	June 1977
CENPD-255	"Qualification of Combustion Engineering Class 1E Instrumentation"	July 1977
CENPD-404-P	Implementation of ZIRLO™ cladding material in CE Nuclear Power Fuel Assembly Designs.	November 2001
CENPD-282-P Volumes 1-3	"Technical Manual for the CENTS Code"	October 1991
CESSAR PSAR	Appendix 6B	
WCAP-15996-P	"Technical Description Manual for the CENTS Code"	December 2002

REFERENCE MATERIAL

Table 1.6-4

PVNGS Documents Incorporated By Reference

DOCUMENT TITLE	REPORTING REQUIREMENTS	CHANGE CONTROL REQUIREMENTS
PVNGS Equipment Qualification Program Manual Appendix A	10CFR50.49(d)(NOTE 1)	10CFR50.59

NOTES:

1. Updates are not required to be submitted under 10CFR50.71(e)

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1.7 DRAWINGS AND OTHER DETAILED INFORMATION

1.7.1 ELECTRICAL, INSTRUMENTATION, AND CONTROL DRAWINGS

Table 1.7-1 lists nonproprietary electrical, instrumentation, and control (EI&C) drawings which are necessary to evaluate the safety-related features described in chapters 7 and 8. When appropriate, reference is made to the specific sections which discuss the drawing. There are no proprietary EI&C drawings. Engineering drawings 01, 02, 03-J-ZZL-010 and 01, 02, 03-J-ZZL-012 illustrate the legend and symbols used on control logic diagrams referenced in this section.

1.7.2 PIPING AND INSTRUMENTATION DIAGRAMS

Table 1.7-2 lists piping and instrumentation diagrams (P&IDs) which have been incorporated by reference into this UFSAR. Engineering drawings 13-M-ZZP-001 through –004 illustrate the legend and symbols utilized on the listed P&IDs.

1.7.3 OTHER DETAILED INFORMATION

Other detailed information which has been provided separately to the NRC staff is itemized below.

A. PVNGS onsite hourly meteorological data have been provided on magnetic tape utilizing the recommended NRC format, for the 5-year period from August 13, 1973 to August 13, 1978.

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 1 of 72)

Drawing Number	Title	Section Reference
13-E-MAA-001	Main Single Line Diagram	Chapter 8
13-E-ZAC-001	Auxiliary Bldg Conduit and Tray Plan at El 40 ft Level D ZADC	Chapter 8
13-E-ZAC-002	Auxiliary Bldg Conduit and Tray Plan at El 40 ft Level D ZADD	Chapter 8
13-E-ZAC-003	Auxiliary Bldg Conduit and Tray Plan at El 51 ft-6 in Level C ZACC	Chapter 8
13-E-ZAC-004	Auxiliary Bldg Conduit and Tray Plan at El 51 ft-6 in Level C ZACD	Chapter 8
13-E-ZAC-005	Auxiliary Bldg Conduit and Tray Plan at El 70 ft Level D ZABA	Chapter 8
13-E-ZAC-006	Auxiliary Bldg Conduit and Tray Plan at El 70 ft Level B ZABB	Chapter 8
13-E-ZAC-007	Auxiliary Bldg Conduit and Tray Plan at El 70 ft Level B ZABC	Chapter 8
13-E-ZAC-008	Auxiliary Bldg Conduit and Tray Plan at El 70 ft Level B ZABD	Chapter 8
13-E-ZAC-010	Auxiliary Bldg Conduit and Tray Plan at El 88 ft Level A ZAAA	Chapter 8
13-E-ZAC-011	Auxiliary Bldg Conduit and Tray Plan at El 88 ft Level Z ZAAB	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 2 of 72)

Drawing Number	Title	Section Reference
13-E-ZAC-012	Auxiliary Bldg Conduit and Tray Plan at El 88 ft Level A ZAAC	Chapter 8
13-E-ZAC-013	Auxiliary Bldg Conduit and Tray Plan at El 88 ft Level A ZAAD	Chapter 8
13-E-ZAC-015	Auxiliary Bldg Conduit and Tray Plan at El 100 ft Level 1 ZA1A	Chapter 8
13-E-ZAC-016	Auxiliary Bldg Conduit and Tray Plan at El 100 ft Level 1 ZA1B	Chapter 8
13-E-ZAC-017	Auxiliary Bldg Conduit and Tray Plan at El 100 ft Level 1 ZA1C	Chapter 8
13-E-ZAC-018	Auxiliary Bldg Conduit and Tray Plan at El 100 ft Level 1 ZA1D	Chapter 8
13-E-ZAC-020	Auxiliary Bldg Conduit and Tray Plan at El 120 ft Level 2 ZA2A	Chapter 8
13-E-ZAC-021	Auxiliary Bldg Conduit and Tray Plan at El 120 ft Level 2 ZA2B	Chapter 8
13-E-ZAC-022	Auxiliary Bldg Conduit and Tray Plan at El 120 ft Level 2 ZA2C	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 3 of 72)

Drawing Number	Title	Section Reference
13-E-ZAC-023	Auxiliary Bldg Con-duit and Tray Plan at El 120 ft Level 2 ZA2D	Chapter 8
13-E-ZAC-025	Auxiliary Bldg Con-duit and Tray Plan at El 140 ft Level 3 ZA3A	Chapter 8
13-E-ZAC-026	Auxiliary Bldg Con-duit and Tray Plan at El 140 ft Level 3 ZA3B	Chapter 8
13-E-ZAC-027	Auxiliary Bldg Con-duit and Tray Plan at El 140 ft Level 3 ZA3C	Chapter 8
13-E-ZAC-028	Auxiliary Bldg Con-duit and Tray Plan at El 140 ft Level 3 ZA3D	Chapter 8
13-E-ZAC-030	Auxiliary Bldg Con-duit Plan at El 156 ft Level 4 ZA4A	Chapter 8
13-E-ZAC-031	Auxiliary Bldg Con-duit Plan at El 156 ft Level 4 ZA4B	Chapter 8
13-E-ZAC-032	Auxiliary Bldg Tray Hanger Layout Plan at El 100 ft Level 1A	Chapter 8
13-E-ZAC-033	Auxiliary Bldg Tray Hanger Layout Plan at El 100 ft Level 1B	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 4 of 72)

Drawing Number	Title	Section Reference
13-E-ZAC-034	Auxiliary Bldg Tray Hanger Layout Plan at El 120 ft Level 2A	Chapter 8
13-E-ZAC-035	Auxiliary Bldg Tray Hanger Layout Plan at El 120 ft Level 2B	Chapter 8
13-E-ZAC-036	Auxiliary Bldg Tray Hanger Layout Plan at El 100 ft Level 1C	Chapter 8
13-E-ZAC-037	Auxiliary Bldg Tray Hanger Layout Plan at El 100 ft Level 1D	Chapter 8
13-E-ZAC-038	Auxiliary Bldg Tray Hanger Layout Plan at El 120 ft Level 2C	Chapter 8
13-E-ZAC-039	Auxiliary Bldg Tray Hanger Layout Plan at El 120 ft Level 2D	Chapter 8
13-E-ZAC-040	Auxiliary Bldg Conduit and Tray Sections and Details Sheet 1	Chapter 8
13-E-ZAC-041	Auxiliary Bldg Conduit and Tray Sections and Details Sheet 2	Chapter 8
13-E-ZAC-042	Auxiliary Bldg Conduit and Tray Sections and Details Sheet 3	Chapter 8
13-E-ZAC-043	Category 1 Tray Support Details and Notes Sheet 1	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 5 of 72)

Drawing Number	Title	Section Reference
13-E-ZAC-044	Category 1 Tray Support Details and Notes Sheet 2	Chapter 8
13-E-ZAC-045	Auxiliary Bldg Tray Support Types Sheet 1	Chapter 8
13-E-ZAC-046	Auxiliary Bldg Tray Support Types Sheet 2	Chapter 8
13-E-ZAC-047	Auxiliary Bldg Tray Support Types Sheet 3	Chapter 8
13-E-ZAC-048	Auxiliary Bldg Tray Support Types Sheet 4	Chapter 8
13-E-ZAC-049	Auxiliary Bldg Conduit and Tray Sections and Details Sheet 4	Chapter 8
13-E-ZAC-051	Auxiliary Bldg Conduit and Tray Sections and Details Sheet 5	Chapter 8
13-E-ZAC-053	Category 1 Tray Support Details Notes Sheet 3	Chapter 8
13-E-ZAC-055	Category 1 Conduit Support Details Sheet 1	Chapter 8
13-E-ZAC-056	Category 1 Conduit Support Details Sheet 2	Chapter 8
13-E-ZAC-057	Category 1 Tray Support Details Sheet 4	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 6 of 72)

Drawing Number	Title	Section Reference
13-E-ZAC-058	Category 1 Conduit Support Details Sheet 3	Chapter 8
13-E-ZAC-060	Auxiliary Bldg Tray Support Types Sheet 5	Chapter 8
13-E-ZAC-061	Auxiliary Bldg Tray Support Types Sheet 6	Chapter 8
13-E-ZAC-062	Auxiliary Bldg Tray Support Types Sheet 7	Chapter 8
13-E-ZAC-063	Auxiliary Bldg Tray Support Types Sheet 8	Chapter 8
13-E-ZAC-064	Auxiliary Bldg Con-duit and Tray Partial Plan at El 129 ft	Chapter 8
13-E-ZAC-065	Auxiliary Bldg Elect Penetration Area N.W.	Chapter 8
13-E-ZAC-066	Auxiliary Bldg Elect Penetration Area N.E.	Chapter 8
13-E-ZAC-067	Auxiliary Bldg Con-duit Plan at El 156 ft Level 4 ZA4C	Chapter 8
13-E-ZAC-068	Auxiliary Bldg Con-duit Plan at El 156 ft Level 4 ZA4D	Chapter 8
13-E-ZAC-069	Auxiliary Bldg Tray Support Types Sheet 9	Chapter 8
13-E-ZAC-070	Auxiliary Bldg Exposed Conduit Plan at El 120 ft ZA2A	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 7 of 72)

Drawing Number	Title	Section Reference
13-E-ZAC-071	Auxiliary Bldg Exposed Conduit Plan at El 120 ft Level 2 ZA2B	Chapter 8
13-E-ZAC-072	Auxiliary Bldg Exposed Conduit Plan at El 120 ft Level 2 ZA2C	Chapter 8
13-E-ZAC-073	Auxiliary Bldg Exposed Conduit Plan at El 120 ft Level 2 ZA2D	Chapter 8
13-E-ZAC-074	Auxiliary Bldg Tray Support Types Sheet 10	Chapter 8
13-E-ZCC-007	Contain Bldg Conduit and Tray Plan at El 80 ft Level A ZCAA, ZCAB	Chapter 8
13-E-ZCC-008	Contain Bldg Conduit and Tray Plan at El 80 ft Level A ZCAC, ZCAD	Chapter 8
13-E-ZCC-009	Contain Bldg Conduit and Tray Plan at El 100 ft Level 1 ZC1A	Chapter 8
13-E-ZCC-010	Contain Bldg Conduit and Tray Plan at El 100 ft Level 1 ZC1B	Chapter 8
13-E-ZCC-011	Contain Bldg Conduit and Tray Plan at El 100 ft Level 1 ZC1C	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 8 of 72)

Drawing Number	Title	Section Reference
13-E-ZCC-012	Contain Bldg Conduit and Tray Plan at El 100 ft Level 1 ZC1D	Chapter 8
13-E-ZCC-013	Contain Bldg Conduit and Tray Plan at El 120 ft Level 2 ZC2A	Chapter 8
13-E-ZCC-014	Contain Bldg Conduit and Tray Plan at El 120 ft Level 2 ZC2B	Chapter 8
13-E-ZCC-015	Contain Bldg Conduit and Tray Plan at El 120 ft Level 2 ZC2C	Chapter 8
13-E-ZCC-016	Contain Bldg Conduit and Tray Plan at El 120 ft Level 2 ZC2D	Chapter 8
13-E-ZCC-017	Contain Bldg Conduit and Tray Plan at El 140 ft Level 3 ZC3A	Chapter 8
13-E-ZCC-018	Contain Bldg Conduit and Tray Plan at El 140 ft Level 3 ZC3B	Chapter 8
13-E-ZCC-019	Contain Bldg Conduit and Tray Plan at El 140 ft Level 3 ZC3C	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 9 of 72)

Drawing Number	Title	Section Reference
13-E-ZCC-020	Contain Bldg Conduit and Tray Plan at El 140 ft Level 3 ZC3D	Chapter 8
13-E-ZCC-021	Contain Bldg Conduit and Tray Plan above El 140 ft Level 4 ZC4A	Chapter 8
13-E-ZCC-025	Contain Bldg Conduit and Tray Sections and Details Sheet 1	Chapter 8
13-E-ZCC-026	Contain Bldg Conduit and Tray Sections and Details Sheet 2	Chapter 8
13-E-ZCC-027	Contain Bldg Conduit and Tray Sections and Details Sheet 3	Chapter 8
13-E-ZCC-028	Contain Bldg Conduit and Tray Sections and Details Sheet 4	Chapter 8
13-E-ZCC-029	Contain Bldg Conduit and Tray Sections and Details Sheet 5	Chapter 8
13-E-ZCC-030	Contain Bldg Conduit and Tray Sections and Details Sheet 6	Chapter 8
13-E-ZCC-031	Contain Bldg Tray Support Types Sheet 1	Chapter 8
13-E-ZCC-032	Contain Bldg Tray Support Types Sheet 2	Chapter 8
13-E-ZCC-033	Contain Bldg Tray Support Types Sheet 3	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZCC-034	Contain Bldg Tray Support Types Sheet 4	Chapter 8
13-E-ZCC-035	Contain Bldg Tray Support Types Sheet 5	Chapter 8
13-E-ZCC-036	Contain Bldg Tray Support Types Sheet 6	Chapter 8
13-E-ZCC-037	Contain Bldg Tray Support Types Sheet 7	Chapter 8
13-E-ZCC-038	Contain Bldg Tray Support Types Sheet 8	Chapter 8
13-E-ZCC-039	Contain Bldg Conduit and Tray Sections and Details Sheet 7	Chapter 8
13-E-ZCC-040	Contain Bldg Reactor Head Area CEDM Cabling Plan and Sects Sheet 1	Chapter 8
13-E-ZCC-041	Contain Bldg Elect Penetration Internal Expanded View S.E.	Chapter 8
13-E-ZCC-042	Contain Bldg Elect Penetration Internal Expanded View S.W.	Chapter 8
13-E-ZCC-045	Main Steam Support Structure Conduit and Tray Plan at El 81 ft and 100 ft ZCAE, ZC1E	Chapter 8
13-E-ZCC-046	Main Steam Support Structure Conduit and Tray Plan at El 120 ft and 140 ft ZC2E, ZC3E	Chapter 8

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZCC-047	Main Steam Support Structure Conduit and Tray Sections and Details	Chapter 8
13-E-ZCC-050	Contain Bldg Tray Hanger Layout Plan at El 100 ft Level 1 ZC1A	Chapter 8
13-E-ZCC-051	Contain Bldg Tray Hanger Layout Plan at El 100 ft Level 1 ZC1B	Chapter 8
13-E-ZCC-052	Contain Bldg Tray Hanger Layout Plan at El 100 ft Level 1 ZC1C	Chapter 8
13-E-ZCC-053	Contain Bldg Tray Hanger Layout Plan at El 100 ft Level 1 ZC1D	Chapter 8
13-E-ZCC-054	Contain Bldg Tray Hanger Layout Plan at El 120 ft Level 2 ZC2A	Chapter 8
13-E-ZCC-055	Contain Bldg Tray Hanger Layout Plan at El 120 ft Level 2 ZC2B	Chapter 8
13-E-ZCC-056	Contain Bldg Tray Hanger Layout Plan at El 120 ft Level 2 ZC2C	Chapter 8

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NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZCC-057	Contain Bldg Tray Hanger Layout Plan at El 120 ft Level 2 ZC2D	Chapter 8
13-E-ZCC-058	Contain Bldg Tray Hanger Layout Plan at El 140 ft Level 3 ZC3A	Chapter 8
13-E-ZCC-059	Contain Bldg Tray Hanger Layout Plan at El 140 ft Level 3 ZC3B	Chapter 8
13-E-ZCC-060	Contain Bldg Tray Hanger Layout Plan at El 140 ft Level 3 ZC3C	Chapter 8
13-E-ZCC-061	Contain Bldg Tray Hanger Layout Plan at El 140 ft Level 3 ZC3D	Chapter 8
13-E-ZCC-062	Contain Bldg Conduit and Tray Sections and Details Sheet 8	Chapter 8
13-E-ZCC-063	Contain Bldg Conduit and Tray Sections and Details Sheet 9	Chapter 8
13-E-ZCC-065	Contain Bldg Reactor Head Area CEDM Cabling Plan Sheet 2	Chapter 8
13-E-ZCC-066	Contain Bldg Reactor Head Area CEDM Cabling Plan Sheet 3	Chapter 8

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NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZCC-067	Contain Bldg Reactor Head Area CEDM Cabling Sections and Details Sheet 4	Chapter 8
13-E-ZCC-068	Contain Bldg Reactor Head Area CEDM Cabling Sections and Details Sheet 5	Chapter 8
13-E-ZFC-001	Fuel Handling Bldg Conduit and Tray Plan at El 100 ft Level 1 ZF1A	Chapter 8
13-E-ZFC-002	Fuel Handling Bldg Conduit and Tray Plan at El 100 ft Level 1 ZF1B	Chapter 8
13-E-ZFC-003	Fuel Handling Bldg Conduit and Tray Plan at El 120 ft Level 2 ZF2A	Chapter 8
13-E-ZFC-004	Fuel Handling Bldg Conduit and Tray Plan at El 120 ft Level 2 ZF2B	Chapter 8
13-E-ZFC-005	Fuel Handling Bldg Conduit and Tray Plan at El 140 ft Level 3 ZF3A	Chapter 8
13-E-ZFC-006	Fuel Handling Bldg Conduit and Tray Plan at El 140 ft Level 3 ZF3B	Chapter 8

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NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZFC-020	Fuel Handling Bldg Conduit and Tray Sections and Details Sheet 1	Chapter 8
13-E-ZFC-030	Fuel Handling Bldg Tray Support Types Sheet 1	Chapter 8
13-E-ZFC-031	Fuel Handling Bldg Tray Support Types Sheet 2	Chapter 8
13-E-ZGC-001	Diesel Generator Bldg Embedded Conduit Plan	Chapter 8
13-E-ZGC-002	Diesel Generator Bldg Conduit and Tray Plan Sheet 1	Chapter 8
13-E-ZGC-003	Diesel Generator Bldg Conduit Plan Sheet 2	Chapter 8
13-E-ZGC-004	Diesel Generator Bldg Conduit Plan Sheet 3	Chapter 8
13-E-ZGC-030	Diesel Generator Bldg Tray Support Types	Chapter 8
13-E-ZJC-001	Control Bldg Conduit and Tray Plan at El 74 ft Level AA ZJAA	Chapter 8
13-E-ZJC-002	Control Bldg Conduit and Tray Plan at El 74 ft Level AB ZJAB	Chapter 8

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NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZJC-003	Control Bldg Conduit and Tray Plan at El 100 ft Level 1A ZJlA	Chapter 8
13-E-ZJC-004	Control Bldg Conduit and Tray Plan at El 100 ft Level 1B ZJ1B	Chapter 8
13-E-ZJC-006	Control Bldg Conduit and Tray Plan at El 120 ft ZJ2A Lower Spreading Rm Level 2A	Chapter 8
13-E-ZJC-007	Control Bldg Conduit and Tray Plan at El 120 ft ZJ2B Lower Spreading Rm Level 2B	Chapter 8
13-E-ZJC-009	Control Bldg Conduit and Tray Plan at El 140 ft ZJ3A	Chapter 8
13-E-ZJC-012	Control Bldg Conduit and Tray Plan at El 160 ft ZJ4A Upper Spreading Rm Level 4A	Chapter 8
13-E-ZJC-013	Control Bldg Conduit and Tray Plan at El 160 ft ZJ4B Upper Spreading Rm Level 4B	Chapter 8
13-E-ZJC-014	Control Bldg Wireway Sections and Details Sheet 1	Chapter 8

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NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZJC-015	Control Bldg Wireway Sections and Details Sheet 2	Chapter 8
13-E-ZJC-016	Control Bldg Tray Sections and Details Sheet 1	Chapter 8
13-E-ZJC-017	Control Bldg Tray Sections and Details Sheet 2	Chapter 8
13-E-ZJC-018	Control Bldg Tray Section Sheet 3	Chapter 8
13-E-ZJC-019	Corridor Bldg Tray Support Types Sheet 3	Chapter 8
13-E-ZJC-020	Control Bldg Tray Support Types Sheet 1	Chapter 8
13-E-ZJC-021	Control Bldg Tray Support Types Sheet 2	Chapter 8
13-E-ZJC-022	Control Bldg Tray Support Types Sheet 3	Chapter 8
13-E-ZJC-023	Control Bldg Tray Support Types Sheet 4	Chapter 8
13-E-ZJC-024	Control Bldg Tray Support Types Sheet 5	Chapter 8
13-E-ZJC-025	Control Bldg Tray Support Types Sheet 6	Chapter 8

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NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZJC-026	Control Bldg Tray Support Types Sheet 7	Chapter 8
13-E-ZJC-027	Control Bldg Tray Support Types Sheet 8	Chapter 8
13-E-ZJC-028	Control Bldg Tray Support Types Sheet 9	Chapter 8
13-E-ZJC-030	Control Bldg Cable Riser Shafts Plan Sections and Details Sheet 1	Chapter 8
13-E-ZJC-031	Control Bldg Cable Riser Shafts Plan Sections and Details Sheet 2	Chapter 8
13-E-ZJC-033	Control Bldg Conduit Arrangement Plan at El 74 ft Level AA	Chapter 8
13-E-ZJC-034	Control Bldg Conduit Arrangement Plan at El 74 ft Level AB	Chapter 8
13-E-ZJC-037	Control Bldg Conduit Arrangement Plan at El 100 ft Level 1A	Chapter 8
13-E-ZJC-038	Control Bldg Conduit Arrangement Plan at El 100 ft Level 1B	Chapter 8

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NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZJC-039	Control Bldg Wireway and Hanger Location Plan at El 140 ft	Chapter 8
13-E-ZJC-040	Control Bldg Tray Hanger Layout Plan at El 100 ft Level 1A	Chapter 8
13-E-ZJC-041	Control Bldg Tray Hanger Layout Plan at El 100 ft Level 1B	Chapter 8
13-E-ZJC-042	Control Bldg Tray Hanger Layout Plan at El 120 ft Level 2A	Chapter 8
13-E-ZJC-043	Control Bldg Tray Hanger Layout Plan at El 120 ft Level 2B	Chapter 8
13-E-ZJC-044	Control Bldg Tray Hanger Layout Plan at El 160 ft Level 4A	Chapter 8
13-E-ZJC-045	Control Bldg Tray Hanger Layout Plan at El 160 ft Level 4B	Chapter 8
13-E-ZJC-050	Control Bldg Tray Sections Sheet 4	Chapter 8
13-E-ZJC-051	Control Bldg Tray Sections Sheet 5	Chapter 8

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NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
13-E-ZJC-052	Control Bldg Conduit and Tray Sections Sheet 1	Chapter 8
13-E-ZJC-053	Control Bldg Conduit and Tray Sections Sheet 2	Chapter 8
13-E-ZJC-054	Control Bldg Tray Sections Sheet 6	Chapter 8
13-E-ZJC-055	Control Bldg Tray Sections Sheet 7	Chapter 8
13-E-ZJL-004	Control Bldg Lighting and Communications Plan at El 140 ft Level 3	Chapter 8
13-E-ZJP-001	Battery and DC Equip Rooms Plan	Chapter 8
13-E-ZVU-005	Underground Elect Duct Layout Sections Sheet 5	Chapter 8
13-E-ZVU-006	Underground Elect Duct Layout Plot Plan Sheet 1 ZV06	Chapter 8
13-E-ZVU-007	Underground Elect Duct Layout Plot Plan Sheet 2 ZV07	Chapter 8
13-E-ZVU-008	Underground Elect Duct Layout Plot Plan Sheet 3 ZV08	Chapter 8
13-E-ZVU-009	Underground Elect Duct Layout Plot Plan Sheet 4 ZV09	Chapter 8

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Drawing Number	Title	Section Reference
13-E-ZYU-009	Diesel Storage Tank Conduit Plan and Sections	Chapter 8
13-E-ZYU-025	Essential Pipe Tunnel Conduit and Lighting Plan and Section	Chapter 8
13-E-ZYU-027	Condensate Storage Tunnel Conduit Plan Sheet 1	Chapter 8
13-E-ZYU-028	Condensate Storage Tunnel Conduit Plan Sheet 2	Chapter 8
13-E-ZYU-034	Condensate Storage Tunnels Conduit and Lighting Plans Sheet 3	Chapter 8
13-E-ZYU-035	Condensate Storage Tunnels Sections and Details Plans	Chapter 8
01-E-MAB-024 02-E-MAB-024 03-E-MAB-024	E/D Main Generation System 4.16KV Switchgear Breakers Synchronizing Unit 1	Chapter 8
01-E-MAB-027	E/D Generation System 13.8KV Bus 1-E-NAN-S05 and S06 Common Loads Billing Metering	Chapter 8
01-E-AFB-001 02-E-AFB-001 03-E-AFB-001	E/D Auxiliary Feedwater System Aux Feedwater Pump M-AFB-P01	Chapter 8

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Drawing Number	Title	Section Reference
01-E-AFB-003 02-E-AFB-003 03-E-AFB-003	E/D Auxiliary Feedwater System Aux Feedwater Regulating Valves Pump B to SG-1&2 J-AFB-HV-30 and J-AFB-HV-31	Chapter 8
01-E-AFB-004 02-E-AFB-004 03-E-AFB-004	E/D Auxiliary Feedwater System Aux Feedwater Regulating Valves J-AFA-HV-32 and J-AFC-HV-33	Chapter 8
01-E-AFB-005 02-E-AFB-005 03-E-AFB-005	E/D Auxiliary Feedwater System Valves - Aux Feedwater Iso Pump B to SG-1&2 J-AFB-UV-34 and J-AFB-UV-35	Chapter 8
01-E-AFB-006 02-E-AFB-006 03-E-AFB-006	E/D Auxiliary Feedwater - System Aux Feedwater Regulating Valve J-AFC-HV-33	Chapter 8
01-E-AFB-007 02-E-AFB-007 03-E-AFB-007	E/D Auxiliary Feedwater System Aux Feedwater Turbine Trip Throttle Valve J-AFA-HV-54	Chapter 8
01-E-AFB-008 02-E-AFB-008 03-E-AFB-008	Elem Diag Auxiliary Feedwater System Aux Activation Signal Channel C Initiation Circuit	Chapter 8

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Drawing Number	Title	Section Reference
01-E-AFB-010 02-E-AFB-010 03-E-AFB-010	Elem Diag Auxiliary Feedwater System Aux Feedwater Regulating Valve J-AFA-UV-37	Chapter 8
01-E-AFB-011 02-E-AFB-011 03-E-AFB-011	Elem Diag Auxiliary Feedwater System Aux Feedwater Regulating Valve J-AFA-UV-36	Chapter 8
01-E-CHB-011 02-E-CHB-011 03-E-CHB-011	E/D Chem and Volume Cont System RCP Controlled Bleedoff to RDT Valve J-CHA-HV-507	Chapter 8
01-E-CHB-012 02-E-CHB-012 03-E-CHB-012	E/D Chem and Volume Cont System Letdown Line to Regen Heat Exchanger Containment Iso Valve J-CHA-UV-516	Chapter 8
01-E-CHB-013 02-E-CHB-013 03-E-CHB-013	E/D Chem and Volume Cont System - Regen Heat Exchanger to Letdown Heat Exchanger Iso Valve J-CHB-UV-523	Chapter 8
01-E-CHB-014 02-E-CHB-014 03-E-CHB-014	E/D Chem and Volume Cont System RCP Controlled Bleedoff Valve to VCT Valve J-CHA-UV-506	Chapter 8
01-E-CHB-015 02-E-CHB-015 03-E-CHB-015	E/D Chem and Volume Cont System RCP Controlled Bleedoff to VCT Valve J-CHB-HV-505	Chapter 8

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Drawing Number	Title	Section Reference
01-E-CHB-017 02-E-CHB-017 03-E-CHB-017	E/D Chem and Volume Cont System Reactor Drain Tank Outlet Iso Valve J-CHB-UV-561	Chapter 8
01-E-CHB-018 02-E-CHB-018 03-E-CHB-018	E/D Chem and Volume Cont System Reactor Tank Outlet Iso Valve J-CHA-UV-560	Chapter 8
01-E-CHB-024 02-E-CHB-024 03-E-CHB-024	E/D Chem and Volume Cont System Charging Pump 1 M-CHA-PO1	Chapter 8
01-E-CHB-025 02-E-CHB-025 03-E-CHB-025	E/D Chem and Volume Cont System Charging Pump 2 M-CHB-PO1	Chapter 8
01-E-CHB-026 02-E-CHB-026 03-E-CHB-026	E/D Chem and Volume Cont System Charging Pump 3 M-CHE-PO1	Chapter 8
01-E-CHB-029 02-E-CHB-029 03-E-CHB-029	E/D Chem and Volume Cont System – RWT to Train Safety Injection System Valves J-CHB-HV-530 and J-CHA-HV-531	Chapter 8
01-E-CHB-031 02-E-CHB-031 03-E-CHB-031	E/D Chem and Volume Cont System Letdown Line to Regen Heat Exchanger Valve J-CHB-UV-515	Chapter 8

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Drawing Number	Title	Section Reference
01-E-CHB-037 02-E-CHB-037 03-E-CHB-037	E/D Chem and Volume Cont System Makeup to Reactor Drain Tank Valve J-CHA-UV-580	Chapter 8
01-E-CHB-039 02-E-CHB-039 03-E-CHB-039	E/D Chem and Volume Cont System Regenerative Heat Exchanger to Aux Spray Valve J-CHA-HV-205 and J-CHB-HV-203	Chapter 8
01-E-CPB-001 02-E-CPB-001 03-E-CPB-001	E/D Contain Purge System - Ctmt Refueling Purge Mode Iso Valves J-CPA-UV-2A and J-CPB-UV-3B	Chapter 8
01-E-CPB-002 02-E-CPB-002 03-E-CPB-002	E/D Contain Purge System - Ctmt Refueling Purge Mode Valves J-CPA-UV-2B and J-CPB-UV-3A	Chapter 8
01-E-CPB-003 02-E-CPB-003 03-E-CPB-003	E/D Contain Purge System - Ctmt Pwr-Access Purge Power Access Mode Iso Valves J-CPA-UV-4B and J-CPB-UV-5B	Chapter 8
01-E-CPB-004 02-E-CPB-004 03-E-CPB-004	E/D Contain Purge System - Ctmt Pwr-Access Purge Mode Iso Valves J-CPA-UV-4B and J-CPB-UV-5A	Chapter 8

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Drawing Number	Title	Section Reference
01-E-CTB-001 02-E-CTB-001 03-E-CTB-001	E/D Condensate Transfer and Storage System Condensate Transfer Pumps A and B MCTA-PO1 and MCTB-PO1	Chapter 8
01-E-CTB-002 02-E-CTB-002 03-E-CTB-002	E/D Condensate Transfer and Storage System – Normal AFP Suction Valves J-CTA-HV-1 and J-CTA-HV-4	Chapter 8
01-E-DGB-002 02-E-DGB-002 03-E-DGB-002	E/D Diesel Gen System Diesel Gen A and B Lube Oil Circ Pumps M-DGA-PO4 and M-DGB-PO4	Chapter 8
01-E-DGB-004 02-E-DGB-004 03-E-DGB-004	E/D Diesel Gen System Diesel Gen A and B Lube Oil Warm-up Htr M-DGA-MO2 and M-DGB-MO2	Chapter 8
01-E-DGB-005 02-E-DGB-005 03-E-DGB-005	E/D Diesel Gen System Gen A and B Jkt Wtr Circ Pump M-DGA-PO1 and M-DGB-PO1	Chapter 8
01-E-DGB-006 02-E-DGB-006 03-E-DGB-006	E/D Diesel Gen System Diesel Gen A and B M-DGA-HO1H, M-DGB-HO2H and J-DGN-BO3A, BO3B Stator and High Volt Cubicle Space Heater	Chapter 8

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Drawing Number	Title	Section Reference
01-E-DGB-007 02-E-DGB-007 03-E-DGB-007	E/D Diesel Gen System Diesel Engine Control	Chapter 8
01-E-DGB-015 02-E-DGB-015 03-E-DGB-015	E/D Diesel Gen System Diesel Gen A and B Jkt Wtr Htr M-DGA-MO1 and M-DGB-MO1	Chapter 8
01-E-ECB-001 02-E-ECB-001 03-E-ECB-001	E/D Essential Chilled Water System Essential Chillers M-ECA-EO1 and M-ECB-EO1	Chapter 8
01-E-ECB-002 02-E-ECB-002 03-E-ECB-002	E/D Essential Chilled Water System - Essential Chilled Aux Pwr Pnl and Pumpout U Term Box J-ECA-EOl, J-ECB-EO2 and ECN-EO1A, E-ECN-EO1B	Chapter 8
01-E-ECB-003 02-E-ECB-003 03-E-ECB-003	E/D Essential Chilled Water System Essential Chilled Wtr Circ Pumps M-ECA-PO1 and M-ECB-PO1	Chapter 8
01-E-ECB-004 02-E-ECB-004 03-E-ECB-004	E/D Essential Chilled Water System Chilled Water Expansion Tank Makeup Valves J-ECA-LV15 and J-ECB-LV16	Chapter 8

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NONPROPRIETARY EI&C DRAWINGS INCORPORATED
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Drawing Number	Title	Section Reference
01-E-ESB-001 02-E-ESB-001 03-E-ESB-001	Elementary Diagram Safety Equipment Status System Panels J-ESA-CO1 and J-ESB-CO1	Chapter 8
01-E-EWB-001 02-E-EWB-001 03-E-EWB-001	E/D Essential Cooling Water System Essential Cooling Water Pumps A and B M-EWA-PO1 and M-EWB-PO1	Chapter 8
01-E-EWB-002 02-E-EWB-002 03-E-EWB-002	E/D Essential Cooling Water System Essential Cooling Water Surge Tank Fill Valves J-EWA-LV-91 and J-EWB-LV-92	Chapter 8
01-E-EWB-003 02-E-EWB-003 03-E-EWB-003	E/D Essential Cooling Water System - ECW Loop A to/from NCW Cross Tie Valves J-EWA-UV-145 and 65	Chapter 8
01-E-FTB-005 02-E-FTB-005 03-E-FTB-005	E/D Steam Generator Feedwater Pump Turbine System Steam Gen Feedwater Pump Turbine A M-FTN-KO1A Trip and Reset Control Circuit	Chapter 8
01-E-FTB-006 02-E-FTB-006 03-E-FTB-006	E/D Steam Generator Feedwater Pump Turbine System Steam Gen Feedwater Pump Turbine B M-FTN-KO1B Trip and Reset Control Circuit	Chapter 8

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Drawing Number	Title	Section Reference
01-E-GAB-001 02-E-GAB-001 03-E-GAB-001	E/D Service Gases System Nitrogen Containment Isolation Valves J-GAA-UV-1 and GAA-UV-2	Chapter 8
01-E-GRB-003 02-E-GRB-003 03-E-GRB-003	E/D Gaseous Radwaste System - Radioactive Drain Tk/Gas Surge Hdr Internal Ctmt Iso Valve J-GRA-UV-1	Chapter 8
01-E-GRB-004 02-E-GRB-004 03-E-GRB-004	E/D Gaseous Rad waste System Radioactive Drain Tk/Gas Surge Hdr External Ctmt Iso Valve J-GRB-UV-2	Chapter 8
01-E-HAB-001 02-E-HAB-001 03-E-HAB-001	E/D HVAC - Aux Bldg System HPSI Pump Rms A and B Essential ACU M-HAA-ZO1 and M-HAB-ZO1	Chapter 8
01-E-HAB-002 02-E-HAB-002 03-E-HAB-002	E/D HVAC - Aux Bldg System LPSI Pump Rms A and B Essential ACU M-HAA-ZO2 and M-HAB-ZO2	Chapter 8
01-E-HAB-003 02-E-HAB-003 03-E-HAB-003	E/D HVAC - Aux Bldg System Containment Spray Pump Rms A and B Essential ACU M-HAA-ZO3 and M-HAB-ZO3	Chapter 8

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Drawing Number	Title	Section Reference
01-E-HAB-004 02-E-HAB-004 03-E-HAB-004	E/D HVAC - Aux Bldg System Essential Water Pump Rms A and B Essential ACU M-HAA-ZO5 and M-HAB-ZO5	Chapter 8
01-E-HAB-005 02-E-HAB-005 03-E-HAB-005	E/D HVAC - Aux Bldg System Elec Penet Rms A and B Essential ACU M-HAA-ZO6 and M-HAB-ZO6	Chapter 8
01-E-HAB-006 02-E-HAB-006 03-E-HAB-006	E/D HVAC – Aux Bldg System Aux Feedwater Pump Rm B Essential ACU M-HAB-ZO4	Chapter 8
01-E-HAB-016 02-E-HAB-016 03-E-HAB-016	E/D HVAC – Aux Bldg System Basement Pump Rooms Supply and Exhaust Iso Dampers M-HAA-MO1, 02, 04, 05, 06 and M-HAB-MO1, 02, 04, 05, 06	Chapter 8
01-E-HAB-017 02-E-HAB-017 03-E-HAB-017	E/D HVAC - Aux Bldg System Pump Rooms Exhaust Iso Dampers M-HAA-MO3 and M-HAB-MO3	Chapter 8
01-E-HCB-001 02-E-HCB-001 03-E-HCB-001	E/D HVAC - Containment Bldg System CEDM Norm ACU Fans A and B M-HCN-AO2A and M-HCN-AO2B	Chapter 8

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Drawing Number	Title	Section Reference
01-E-HCB-002 02-E-HCB-002 03-E-HCB-002	E/D HVAC - Containment Bldg System CEDM Norm ACU Fans C and D M-HCN-AO2C and M-HCN-AO2D	Chapter 8
01-E-HCB-004 02-E-HCB-004 03-E-HCB-004	E/D HVAC - Containment Bldg System Contain Norm ACU Fans A and D M-HCN-AO1A and M-HCN-AO1D	Chapter 8
01-E-HCB-005 02-E-HCB-005 03-E-HCB-005	E/D HVAC - Containment Bldg System Contain Norm ACU Fans B and C M-HCN-AO1B and M-HCN-AO1C	Chapter 8
01-E-HCB-009 02-E-HCB-009 03-E-HCB-009	E/D HVAC - Containment Bldg System Ctmt Atmosphere Radn Monitoring (inside) Iso Valves J-HCB-UV-44 and 47	Chapter 8
01-E-HCB-010 02-E-HCB-010 03-E-HCB-010	E/D HVAC - Containment Bldg System Ctmt Atmosphere Radn Monitoring (outside) Iso Valves J-HCA-UV-45 and 46	Chapter 8
01-E-HCB-011 02-E-HCB-011 03-E-HCB-011	E/D HVAC - Containment Bldg System Ctmt Pressure Transmitters A and B Iso Valves J-HCA-HV-74 and J-HCB-HV-75	Chapter 8

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Drawing Number	Title	Section Reference
01-E-HCB-012 02-E-HCB-012 03-E-HCB-012	E/D HVAC - Containment Bldg System Ctmt Pressure Transmitters C and D Iso Valves J-HCC-HV-76 and J-HCD-HV-77	Chapter 8
01-E-HDB-001 02-E-HDB-001 03-E-HDB-001	E/D HVAC - Diesel Gen Bldg System, Diesel Gen Rooms Essential Exhaust Fans M-HDA-JO1 and M-HDB-JO1	Chapter 8
01-E-HDB-005 02-E-HDB-005 03-E-HDB-005	E/D HVAC - Diesel Gen Bldg System, Diesel Gen Control Equip Rms Essential AHL Fans A M-HDA-AO1 and M-HDB-AO1	Chapter 8
01-E-HFB-004 02-E-HFB-004 03-E-HFB-004	E/D HVAC Fuel Bldg System, Fuel and Aux Bldg Essential Exhaust AFU Fans M-HFA-JO1 and M-HFB-JOl	Chapter 8
01-E-HFB-005 02-E-HFB-005 03-E-HFB-005	E/D HVAC Fuel Bldg System, Fuel Bldg Essential Exhaust Dampers J-HFA-MO5 and J-HFB-MO5	Chapter 8
01-E-HFB-006 02-E-HFB-006 03-E-HFB-006	E/D HVAC Fuel Bldg System, Fuel and Aux Bldg Essential Exhaust AFU Htrs M-HFA-EO1 and M-HFB-EOl	Chapter 8

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Drawing Number	Title	Section Reference
01-E-HFB-007 02-E-HFB-007 03-E-HFB-007	E/D HVAC Fuel Bldg System, Supply Fuel Bldg Iso Dampers M-HFA-MO1, MO2 and M-HFB-MO1, MO2	Chapter 8
01-E-HFB-008 02-E-HFB-008 03-E-HFB-008	E/D HVAC Fuel Bldg System - Exhaust Fuel Bldg Iso Dampers M-HFA-MO3, MO4 and M-HFB-MO3, MO4	Chapter 8
01-E-HFB-011 02-E-HFB-011 03-E-HFB-011	E/D HVAC - Fuel Bldg Sys Aux Bldg Essential Exhaust AFU Dampers M-HFA-MO6 and M-HFB-MO6	Chapter 8
01-E-HJB-002 02-E-HJB-002 03-E-HJB-002	E/D HVAC Control Bldg System Control Room Essential AHU Fan M-HJA-FO4 and M-HJB-FO4	Chapter 8
01-E-HJB-006 02-E-HJB-006 03-E-HJB-006	E/D HVAC Control Bldg System ESF Swgr Room Essential AHU A and B M-HJA-ZO3 and M-HJB-ZO3	Chapter 8
01-E-HJB-015 02-E-HJB-015 03-E-HJB-015	E/D HVAC Control Bldg System ESF Swgr Rooms Normal Supply Iso Damper M-HJA-M23	Chapter 8
01-E-HJB-016 02-E-HJB-016 03-E-HJB-016	E/D HVAC Control Bldg System ESF Rooms A and C Essential Return Iso Damper M-HJA-M34	Chapter 8

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Drawing Number	Title	Section Reference
01-E-HJB-017 02-E-HJB-017 03-E-HJB-017	E/D HVAC Control Bldg System Control Bldg Essential Isolation Dampers M-HJB-M38, 34, 54 and 31	Chapter 8
01-E-HJB-018 02-E-HJB-018 03-E-HJB-018	E/D HVAC Control Bldg System ESF Swgr Rooms Supply and Smoke Exh Isolation Dampers M-HJB-M52, 32 and 28	Chapter 8
01-E-HJB-019 02-E-HJB-019 03-E-HJB-019	E/D HVAC Control Bldg System Comm Equip Room Essential Isolation Dampers H-HJA-M58 and M59, M-HJB-M10 and M13	Chapter 8
01-E-HJB-020 02-E-HJB-020 03-E-HJB-020	E/D HVAC Control Bldg System Control Room Essential Isolation Dampers M-HJA-M56 and M57, M-HJB-M56 and M57	Chapter 8
01-E-HJB-021 02-E-HJB-021 03-E-HJB-021	E/D HVAC Control Bldg System Control Room Toilet and Kitchen Exhaust Isolation Dampers M-HJA-M15 and M16, M-HJB-M23 and M24	Chapter 8
01-E-HJB-022 02-E-HJB-022 03-E-HJB-022	E/D HVAC Control Bldg System ESF Swgr Rooms Outside Air and Exhaust Isolation Dampers M-HJA-M55, M53, M54	Chapter 8

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Drawing Number	Title	Section Reference
01-E-HJB-023 02-E-HJB-023 03-E-HJB-023	E/D HVAC Control Bldg System Control Bldg Bat Rooms Essential Exhaust Fans M-HJA-JO1A, JO1B and M-HJB-JO1A, JO1B	Chapter 8
01-E-HJB-024 02-E-HJB-024 03-E-HJB-024	E/D HVAC Control Bldg System Control Room Essential AHU OSA Intake Dampers M-HJA-MO2, M-HJA-MO3, M-HJB-MO2, M-HJB-MO3	Chapter 8
01-E-HPB-001 02-E-HPB-001 03-E-HPB-001	E/D Containment Hydrogen Control System Hydrogen Analyzer A and B Inlet and Outlet Valves J-HPA-HV-7A, 7B and J-HPB-HV-8A, 8B	Chapter 8
01-E-HPB-002 02-E-HPB-002 03-E-HPB-002	E/D Containment Hydrogen Control System Hydrogen Control Ctmt Isolation Valves J-HPA-UV-1 and J-HPB-UV-2	Chapter 8

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Drawing Number	Title	Section Reference
01-E-HPB-003 02-E-HPB-003 03-E-HPB-003	E/D Containment Hydrogen Control System Hydrogen Control Ctmt Isolation Valves J-HPA-UV-3, 5 and J-HPB-UV-4, 6	Chapter 8
01-E-IAB-002 02-E-IAB-002 03-E-IAB-002	E/D Instrument and Service Air System Containment Isolation Valve J-IAA-UV-2	Chapter 8
01-E-MAB-018 02-E-MAB-018 03-E-MAB-018	E/D Main Generation System Main Transformer and Diesel Generator Billing Meter	Chapter 8
01-E-MAB-031 02-E-MAB-031 03-E-MAB-031	E/D Main Generation System Unit Phasing Diagram	Chapter 8
01-E-NCB-002 02-E-NCB-002 03-E-NCB-002	E/D Nuclear Cooling Water System Containment Isolation Valves J-NCB-UV-401 and J-NCA-UV-402	Chapter 8
01-E-NCB-003 02-E-NCB-003 03-E-NCB-003	E/D Nuclear Cooling Water System Containment Isolation Valve J-NCB-UV-403	Chapter 8
01-E-NHB-006 02-E-NHB-006 03-E-NHB-006	E/D Non-Class 1E 480V Power System MCC E-NHN-M19, M20 Incm Fdrs	Chapter 8

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Drawing Number	Title	Section Reference
01-E-PBB-001 02-E-PBB-001 03-E-PBB-001	E/D Class 1E 4.16KV Power System Swgr E-PBA-SO3, E-PBB-SO4, 4.16KV Norm Supply Breakers	Chapter 8
01-E-PBB-002 02-E-PBB-002 03-E-PBB-002	E/D 4.16KV Class 1E Power System Swgr E-PBA-SO3, E-PBB-SO4, 4.16KV Alt Supply Breakers	Chapter 8
01-E-PBB-004 02-E-PBB-004 03-E-PBB-004	E/D 4.16KV Class 1E Power System Swgr E-PBA-SO3, E-PBB-SO4, Bus Potential Transformers	Chapter 8
01-E-PBB-005 02-E-PBB-005 03-E-PBB-005	E/D 4.16KV Class 1E Power System Swgr E-PBA-SO3, E-PBB-SO4, 4.16KV Spare Breakers	Chapter 8
01-E-PBB-006 02-E-PBB-006 03-E-PBB-006	E/D 4.16KV Class 1E and Non-Class 1E Power System ACB Breaker Internal Mechanism and Swgr Space Htrs and Blower Ckts	Chapter 8
01-E-PCB-001 02-E-PCB-001 03-E-PCB-001	E/D Fuel Pool Cooling and Cleanup System Fuel Pool Cooling Pumps M-PCA-PO1 and M-PCB-PO1	Chapter 8

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Drawing Number	Title	Section Reference
01-E-PEB-001 02-E-PEB-001 03-E-PEB-001	E/D Standby Generation System Diesel Generator E-PEA-GO1, E-PEB-GO2 4.16KV Breaker	Chapter 8
01-E-PEB-002 02-E-PEB-002 03-E-PEB-002	E/D Standby Generation System Diesel Generator Three Line Metering and Relaying	Chapter 8
01-E-PEB-003 02-E-PEB-003 03-E-PEB-003	E/D Standby Generation System Diesel Generator Tripping and Voltage Regulation	Chapter 8
01-E-PGB-001 02-E-PGB-001 03-E-PGB-001	E/D 480V Class 1E Power System LC E-PGA-L31 and E-PGB-L32 4.16 KV Supply Breakers	Chapter 8
01-E-PGB-002 02-E-PGB-002 03-E-PGB-002	E/D Class 1E 480V Power System LC E-PGA-L33 and E-PGB-L34 4.16KV Supply Breakers	Chapter 8
01-E-PGB-003 02-E-PGB-003 03-E-PGB-003	E/D 480V Class 1E Power System Load Centers E-PGA-L35 and E-PGB-L36 4.16KV Supply Breakers	Chapter 8
01-E-PGB-006 02-E-PGB-006 03-E-PGB-006	E/D 480V Class 1E Power System Load Centers E-PGA-L31 and E-PGB-L32 480V Mn Fdr Breakers	Chapter 8

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Drawing Number	Title	Section Reference
01-E-PGB-007 02-E-PGB-007 03-E-PGB-007	E/D 480V Class 1E Power System Load Centers E-PGA-L33 and E-PGB-L34 480V Mn Fdr Breakers	Chapter 8
01-E-PGB-008 02-E-PGB-008 03-E-PGB-008	E/D 480V Class 1E Power System Load Centers E-PGA-L35 and E-PGB-L36 480V Mn Fdr Breakers	Chapter 8
01-E-PGB-011 02-E-PGB-011 03-E-PGB-011	E/D 480V Class 1E Power System LCS E-PGA-L31, L33, L35 and E-PGB-L32, L34, L36 Spare Breakers for Motor Feeder	Chapter 8
01-E-PGB-012 02-E-PGB-012 03-E-PGB-012	E/D 480V Class 1E Power System LCS E-PGA-L31 and E-PGB-L34 Spare Breakers for MCC	Chapter 8
01-E-PGB-013 02-E-PGB-013 03-E-PGB-013	E/D 480V Class 1E Power System LCS E-PGB-L32 Space Compartment for Class 1E Power Motor	Chapter 8
01-E-PGB-015 02-E-PGB-015 03-E-PGB-015	E/D 480V Class 1E Power System Load Centers E-PGA-L31, L35 and E-PGB-L32, L34 Spare Breaker for Non-Class 1E Motor	Chapter 8

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Drawing Number	Title	Section Reference
01-E-PGB-021 02-E-PGB-021 03-E-PGB-021	E/D 480V Class 1E Power System 480V Load Centers ACB Internal Mech and Space Heaters	Chapter 8
01-E-PHB-001 02-E-PHB-001 03-E-PHB-001	E/D 48OV Class 1E 480V Power System MCC E-PHA-M31, -M33, -M35 Incoming Feeder	Chapter 8
01-E-PHB-002 02-E-PHB-002 03-E-PHB-002	E/D 480V Class 1E Power System MCC E-PHA-M37 Incoming Feeder	Chapter 8
01-E-PHB-003 02-E-PHB-003 03-E-PHB-003	E/D 480V Class 1E Power System MCC E-PHB-M32, -M34, -M36 Incoming Feeder	Chapter 8
01-E-PHB-004 02-E-PHB-004 03-E-PHB-004	E/D 480V Class 1E Power System MCC E-PHB-M38 Incoming Feeder	Chapter 8
01-E-PHB-005 02-E-PHB-005 03-E-PHB-005	E/D 480V Class 1E Power System Motor Space Heaters	Chapter 8
01-E-PHB-008 02-E-PHB-008 03-E-PHB-008	E/D 480V Class 1E or Power System Feeder Breakers FED from 480V MCC with Shunt Trip Coil-Typical	Chapter 8
01-E-PHB-009 02-E-PHB-009 03-E-PHB-009	E/D 480V Class 1E Power System Spare Starter with Ground Relay Typical	Chapter 8

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Drawing Number	Title	Section Reference
01-E-PHB-010 02-E-PHB-010 03-E-PHB-010	E/D 480V Class 1E Power System Spare Starter without Ground Relay Typical	Chapter 8
01-E-PHB-011 02-E-PHB-011 03-E-PHB-011	E/D 480V Class 1E Power System Feeder Breakers Fed from 480V MCC with Shunt Trip Coil-Typical	Chapter 8
01-E-PHB-012 02-E-PHB-012 03-E-PHB-012	E/D 480V Class 1E System Spare Reversing Starter Typical	Chapter 8
01-E-PHB-016 02-E-PHB-016 03-E-PHB-016	E/D 480 Class 1E and Non-Class 1E Power System Motor Control Center Space Heaters	Chapter 8
01-E-PKB-001 02-E-PKB-001 03-E-PKB-001	E/D Class 1E 125VDC Power System DC Control Centers E-PKA-M41 and E-PKB-M42 125VDC Battery Breakers	Chapter 8
01-E-PKB-002 02-E-PKB-002 03-E-PKB-002	E/D Class 1E 125VDC Power System DC Control Centers E-PKC-M43 and E-PKD-M44 125VDC Battery Breakers	Chapter 8
01-E-PKB-003 02-E-PKB-003 03-E-PKB-003	E/D 125V DC Class 1E System Spare Reversing Starter Typical	Chapter 8

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Drawing Number	Title	Section Reference
01-E-PKB-004 02-E-PKB-004 03-E-PKB-004	E/D 125V DC Class 1E Power System 480V AC Fdr for Norm and Backup Battery Charges E-PKA-H11, E-PKA-H15, E-PKC-H13, E-PKB-H12, E-PKB-H16 and E-PKD-H14	Chapter 8
01-E-PNB-001 02-E-PNB-001 03-E-PNB-001	E/D Instrument Class AC Class 1E Power System 120V AC 10 Distr Panel Voltage Regulators E-PNA-V25, E-PNC-V27, E-PNB-V26 and E-PND-V28	Chapter 8
01-E-QBB-001 02-E-QBB-001 03-E-QBB-001	E/D 480V Non-Class 1E Power System Main Essential Lighting Panels E-QBN-D90, D91 Incoming Feeders	Chapter 8
01-E-RCB-010 02-E-RCB-010 03-E-RCB-010	E/D Reactor Coolant System Pressurizer Backup Heaters M-RCE-A07 thru A12	Chapter 8
01-E-RCB-017 02-E-RCB-017 03-E-RCB-017	E/D Reactor Coolant System Pressurizer Level Control	Chapter 8
01-E-RCB-018 02-E-RCB-018 03-E-RCB-018	E/D Reactor Coolant System Pressurizer Pressure and Level Control	Chapter 8

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Drawing Number	Title	Section Reference
01-E-RDB-007 02-E-RDB-007 03-E-RDB-007	E/D Radioactive Waste Drain System Ctmt Radwaste Sumps External Isolation Valves J-RDB-UV-24	Chapter 8
01-E-RDB-008 02-E-RDB-008 03-E-RDB-008	E/D Radioactive Waste Drain System Ctmt Radwaste Sump Internal Isolation Valves J-RDA-UV-23	Chapter 8
01-E-RKB-001 02-E-RKB-001 03-E-RKB-001	E/D Plant Annunciator System Cabinets, J-RKN-CO1, CO2A, B&C	Chapter 8
01-E-SAB-001 02-E-SAB-001 03-E-SAB-001	E/D Engineered Safety Features Actuation System ESFAS NSSS Manual Actuation	Chapter 8
01-E-SAB-002 02-E-SAB-002 03-E-SAB-002	E/D Engineered Safety Features Actuation System BOP ESFAS Manual Actuation	Chapter 8
01-E-SAB-003 02-E-SAB-003 03-E-SAB-003	E/D Engineered Safety Features Actuation System ESFAS NSSS Manual Actuation	Chapter 8
01-E-SAB-015 02-E-SAB-015 03-E-SAB-015	E/D Engineered Safety Features Actuation System, Isolation Cabinets, J-SAA-CO4, J-SAB-CO4, J-SAC-CO4, J-SAD-CO4	Chapter 8

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Drawing Number	Title	Section Reference
01-E-SBB-001 02-E-SBB-001 03-E-SBB-001	E/D React. Protection System React Trip Breakers Channel A & B	Chapter 8
01-E-SBB-002 02-E-SBB-002 03-E-SBB-002	E/D React. Protection System React Trip Breakers Channel C & D	Chapter 8
01-E-SGB-001 02-E-SGB-001 03-E-SGB-001	E/D Main Steam System Steam Gen 1 to Aux Fdr Pump A Steam Supply Valve J-SGA-UV-134	Chapter 8
01-E-SGB-002 02-E-SGB-002 03-E-SGB-002	E/D Main Steam System Steam Gen 2 to Aux Fdr Pump A Steam Supply Valve J-SGA-UV-138	Chapter 8
01-E-SGB-003 02-E-SGB-003 03-E-SGB-003	E/D Main Steam System Steam Gen Blowdown Ctmt Isolation Valves J-SGA-UV-500P and J-SGB-UV-500R	Chapter 8
01-E-SGB-004 02-E-SGB-004 03-E-SGB-004	E/D Main Steam System Steam Gen Blowdown Ctmt Isolation Valves J-SGA-UV-500S and J-SGB-UV-500Q	Chapter 8
01-E-SGB-008 02-E-SGB-008 03-E-SGB-008	E/D Main Steam System Steam Gen 1 MSIV Bypass Valve J-SGE-UF-169	Chapter 8

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Drawing Number	Title	Section Reference
01-E-SGB-010 02-E-SGB-010 03-E-SGB-010	E/D Main Steam System Downcomer Feedwater Isolation Valve J-SGA-UV-172 and J-SGB-UV-130	Chapter 8
01-E-SGB-011 02-E-SGB-011 03-E-SGB-011	E/D Main Steam System Downcomer Feedwater Isolation Valve J-SGA-UV-175 and J-SGB-UV-135	Chapter 8
01-E-SGB-016 02-E-SGB-016 03-E-SGB-016	E/D Main Steam System Steam Gen 2 MSIV Bypass Valve J-SGE-UV-183	Chapter 8
01-E-SGB-018 02-E-SGB-018 03-E-SGB-018	E/D Main Steam System Steam Gen No. 1 Line No. 1 Atmospheric Dump Valve J-SGA-HV-184	Chapter 8
01-E-SGB-020 02-E-SGB-020 03-E-SGB-020	E/D Main Steam System Steam Gen No. 2 Line No. 1 Atmospheric Dump Valve J-SGB-HV-185	Chapter 8
01-E-SGB-021 02-E-SGB-021 03-E-SGB-021	E/D Main Steam System Steam Gen No. 2 Line No. 2 Atmospheric Dump Valve J-SGA-HV-179	Chapter 8
01-E-SGB-022 02-E-SGB-022 03-E-SGB-022	E/D Main Steam System Steam Gen No. 1 Line No. 2 Atmospheric Dump Valve J-SGB-HV-178	Chapter 8

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01-E-SGB-023 02-E-SGB-023 03-E-SGB-023	E/D Main Steam System Economizer Feedwater Isolation Valve J-SGA-UV-174 and J-SGB-UV-132	Chapter 8
01-E-SGB-024 02-E-SGB-024 03-E-SGB-024	E/D Main Steam System Economizer Feedwater Isolation Valve J-SGA-UV-177 and J-SGB-UV-137	Chapter 8
01-E-SGB-030 02-E-SGB-030 03-E-SGB-030	E/D Main Steam System Blowdown Sample Containment Isolation Valves J-SGA-UV-204 and J-SGB-UV-222 and 224	Chapter 8
01-E-SGB-031 02-E-SGB-031 03-E-SGB-031	E/D Main Steam System Blowdown Sample Containment Isolation Valves J-SGA-UV-219, 228,J-SGA-UV-223 and 225	Chapter 8
01-E-SGB-038 02-E-SGB-038 03-E-SGB-038	E/D Main Steam System Blowdown Sample Containment Isolation Valves J-SGA-UV-220 and J-SGB-UV-226	Chapter 8
01-E-SGB-039 02-E-SGB-039 03-E-SGB-039	E/D Main Steam System Blowdown Sample Containment Isolation Valves J-SGB-UV-221 and J-SGA-UV-227	Chapter 8

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Drawing Number	Title	Section Reference
01-E-SIB-001 02-E-SIB-001 03-E-SIB-001	E/D Safety Injection and Shutdown Cooling System HP Safety Injection Pumps M-SIA-PO2 and M-SIB-PO2	Chapter 8
01-E-SIB-002 02-E-SIB-002 03-E-SIB-002	E/D Safety Injection and Shutdown Cooling System LP Safety Injection Pumps M-SIA-PO1 and M-SIB-PO1	Chapter 8
01-E-SIB-003 02-E-SIB-003 03-E-SIB-003	E/D Safety Injection and Shutdown Cooling System Containment Spray Pumps M-SIA-PO3 and M-SIB-PO3	Chapter 8
01-E-SIB-005 02-E-SIB-005 03-E-SIB-005	E/D Safety Injection and Shutdown Cooling System Safety Injection Tank Isolation Valves J-SIA-UV-634 and 644	Chapter 8
01-E-SIB-006 02-E-SIB-006 03-E-SIB-006	E/D Safety Injection and Shutdown Cooling System Safety Injection Tank Isolation Valves J-SIB-UV-614 and 624	Chapter 8
01-E-SIB-007 02-E-SIB-007 03-E-SIB-007	E/D Safety Injection and Shutdown Cooling System LPSI Flow Cont. to Reactor Coolant Valves J-SIB-UV-615 and 625	Chapter 8

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Drawing Number	Title	Section Reference
01-E-SIB-008 02-E-SIB-008 03-E-SIB-008	E/D Safety Injection Shutdown Cooling System LPSI Flow Cont. to Reactor Coolant Valves J-SIA-UV-635 and 645	Chapter 8
01-E-SIB-009 02-E-SIB-009 03-E-SIB-009	E/D Safety Injection and Shutdown Cooling System HPSI 1 Flow Cont. to Reactor Coolant Valves J-SIA-UV-617 and 627	Chapter 8
01-E-SIB-010 02-E-SIB-010 03-E-SIB-010	E/D Safety Injection and Shutdown Cooling System HPSI 1 Flow Cont. to Reactor Coolant Valves J-SIA-UV-637 and 647	Chapter 8
01-E-SIB-011 02-E-SIB-011 03-E-SIB-011	E/D Safety Injection and Shutdown Cooling System HPSI 2 Flow Cont. to Reactor Coolant Valves J-SIB-UV-616 and 626	Chapter 8
01-E-SIB-012 02-E-SIB-012 03-E-SIB-012	E/D Safety Injection and Shutdown Cooling System HPSI 2 Flow Cont. to Reactor Coolant Valves J-SIB-UV-636 and 646	Chapter 8
01-E-SIB-013 02-E-SIB-013 03-E-SIB-013	E/D Safety Injection Shutdown Cooling System Shutdown Cooling Isolation Valves J-SIA-UV-651 and J-SIB-UV-652	Chapter 8

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Drawing Number	Title	Section Reference
01-E-SIB-014 02-E-SIB-014 03-E-SIB-014	E/D Safety Injection and Shutdown Cooling System Shutdown Cooling Isolation Valves J-SIC-UV-653 and J-SID-UV-654	Chapter 8
01-E-SIB-015 02-E-SIB-015 03-E-SIB-015	E/D Safety Injection and Shutdown Cooling System Shutdown Cooling Ctmt Isolation Valves J-SIA-UV-655 and J-SIB-UV-656	Chapter 8
01-E-SIB-016 02-E-SIB-016 03-E-SIB-016	E/D Safety Injection and Shutdown Cooling System HSPI Recirc. to Refuel Water Tank Valves J-SIA-UV-660 and J-SIC-UV-659	Chapter 8
01-E-SIB-017 02-E-SIB-017 03-E-SIB-017	E/D Safety Injection Shutdown Cooling System - Cont. Spray Pumps to RWT Isolation Valves J-SIA-UV-664 and J-SIB-UV-665	Chapter 8
01-E-SIB-018 02-E-SIB-018 03-E-SIB-018	E/D Safety Injection Shutdown Cooling System - HPSI Pumps to RWT Isolation Valves J-SIA-UV-666 and J-SIB-UV-667	Chapter 8
01-E-SIB-019 02-E-SIB-019 03-E-SIB-019	E/D Safety Injection Shutdown Cooling System - LPSI Pumps to RWT Isolation Valves J-SIA-UV-669 and J-SIB-UV-668	Chapter 8

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Drawing Number	Title	Section Reference
01-E-SIB-020 02-E-SIB-020 03-E-SIB-020	E/D Safety Injection and Shutdown Cooling System - Cont. Spray Control Valves J-SIB-UV-671 and J-SIA-UV-672	Chapter 8
01-E-SIB-021 02-E-SIB-021 03-E-SIB-021	E/D Safety Injection and Shutdown Cooling System - Cont. Sump Isolation Valves J-SIA-UV-673 and J-SIB-UV-675	Chapter 8
01-E-SIB-022 02-E-SIB-022 03-E-SIB-022	E/D Safety Injection and Shutdown Cooling System - Cont. Sump Isolation Valves J-SIA-UV-674 and J-SIB-UV-676	Chapter 8
01-E-SIB-023 02-E-SIB-023 03-E-SIB-023	E/D Safety Injection and Shutdown Cooling System - LPSI Hdr Discharge Valves J-SIA-HV-306 and J-SIB-HV-307	Chapter 8
01-E-SIB-024 02-E-SIB-024 03-E-SIB-024	E/D Safety Injection and Shutdown Cooling System - Cont. Spray Isolation Valves J-SIA-HV-687 and J-SIB-HV-695	Chapter 8
01-E-SIB-025 02-E-SIB-025 03-E-SIB-025	E/D Safety Injection and Shutdown Cooling System - Shutdown Cooling Heat Exchanger Isolation Valves J-SIA-HV-684 and J-SIB-HV-689	Chapter 8

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Drawing Number	Title	Section Reference
01-E-SIB-026 02-E-SIB-026 03-E-SIB-026	E/D Safety Injection and Shutdown Cooling System - LPSI Pump Isolation Valves J-SIA-HV-683 and J-SIB-HV-692	Chapter 8
01-E-SIB-027 02-E-SIB-027 03-E-SIB-027	E/D Safety Injection and Shutdown Cooling System - Shutdown Cooling Temperature Control Valves J-SIA-HV-657 and J-SIB-HV-658	Chapter 8
01-E-SIB-028 02-E-SIB-028 03-E-SIB-028	E/D Safety Injection and Shutdown Cooling System - Shutdown Cooling Warmup Bypass Valves J-SIA-HV-691 and J-SIB-HV-690	Chapter 8
01-E-SIB-029 02-E-SIB-029 03-E-SIB-029	E/D Safety Injection and Shutdown Cooling System Shutdown Cooling Heat Exchanger Bypass Valves J-SIA-HV-688 and J-SIB-HV-693	Chapter 8
01-E-SIB-030 02-E-SIB-030 03-E-SIB-030	E/D Safety Injection and Shutdown Cooling System LPSI Pump Cross Connect Valves J-SIA-HV-685 and J-SIB-HV-694	Chapter 8

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01-E-SIB-031 02-E-SIB-031 03-E-SIB-031	E/D Safety Injection and Shutdown Cooling System Cont. Spray Cross Connect Valves J-SIA-HV-686 and J-SIB-HV-696	Chapter 8
01-E-SIB-033 02-E-SIB-033 03-E-SIB-033	E/D Safety Injection Shutdown Cooling System Shutdown Cooling Heat Exchanger Isolation Valves J-SIA-HV-678 and J-SIB-HV-679	Chapter 8
01-E-SIB-034 02-E-SIB-034 03-E-SIB-034	E/D Safety Injection and Shutdown Cooling System Safety Injection Fill and Drain Valves J-SIB-UV-611 and J-SIB-UV-621	Chapter 8
01-E-SIB-035 02-E-SIB-035 03-E-SIB-035	E/D Safety Injection and Shutdown Cooling System Safety Injection Tk Fill & Drain Valves J-SIA-UV-631 and J-SIB-UV-641	Chapter 8
01-E-SIB-036 02-E-SIB-036 03-E-SIB-036	E/D Safety Injection and Shutdown Cooling System Spray Chemical Addition Pumps M-SIA-PO5 and M-SIB-PO5	Chapter 8
01-E-SIB-037 02-E-SIB-037 03-E-SIB-037	E/D Safety Injection and Shutdown Cooling System Hydrazine Pump to Cont. Spray Pump Valves J-SIA-UV-681 and J-SIB-UV-680	Chapter 8

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01-E-SIB-038 02-E-SIB-038 03-E-SIB-038	E/D Safety Injection & Shutdown Cooling System Spray Chemical Pumps Suction Valves J-SIA-UV-603 and J-SIB-UV-602	Chapter 8
01-E-SIB-039 02-E-SIB-039 03-E-SIB-039	E/D Safety Injection and Shutdown Cooling System HPSI Pumps A&B Discharge Valves J-SIA-HV-698 and J-SIB-HV-699	Chapter 8
01-E-SIB-040 02-E-SIB-040 03-E-SIB-040	E/D Safety Injection and Shutdown Cooling System HPSI Pump Long Term Cooling Valves J-SIA-HV-604 and J-SIB-HV-609	Chapter 8
01-E-SIB-041 02-E-SIB-041 03-E-SIB-041	E/D Safety Injection - Shutdown Cooling System HPSI Pump Long Term Cooling Valves J-SIC-HV-321 and J-SID-HV-331	Chapter 8
01-E-SIB-042 02-E-SIB-042 03-E-SIB-042	E/D Safety Injection & Shutdown Cooling System SI Tank Check Valve Leakage Line Isolation Valves J-SIB-UV-618 and 628	Chapter 8
01-E-SIB-043 02-E-SIB-043 03-E-SIB-043	E/D Safety Injection and Shutdown Cooling System SI Tank Check Valve Leakage Line Isolation Valves J-SIA-UV-638 and 648	Chapter 8

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01-E-SIB-044 02-E-SIB-044 03-E-SIB-044	E/D Safety Injection and Shutdown Cooling System SI Tank RWT Return Hdr Cont. Isolation Valve J-SIB-UV-682	Chapter 8
01-E-SIB-045 02-E-SIB-045 03-E-SIB-045	E/D Safety Injection and Shutdown Cooling System Hot Leg Injection Check Valve Leakage Isolation Valves J-SIA-UV-322 and J-SIB-UV-332	Chapter 8
01-E-SIB-046 02-E-SIB-046 03-E-SIB-046	E/D Safety Injection and Shutdown Cooling System Safety Injection Tk Nitrogen Supply Valves J-SIB-HV-612 and J-SIB-HV-622	Chapter 8
01-E-SIB-047 02-E-SIB-047 03-E-SIB-047	E/D Safety Injection and Shutdown Cooling System Safety Injection Tk Nitrogen Supply Valves J-SIB-HV-632 and J-SIB-HV-642	Chapter 8
01-E-SIB-048 02-E-SIB-048 03-E-SIB-048	E/D Safety Injection and Shutdown Cooling System Safety Injection Tk Nitrogen Supply Valves J-SIA-HV-619 and J-SIA-HV-629	Chapter 8

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01-E-SIB-049 02-E-SIB-049 03-E-SIB-049	E/D Safety Injection and Shutdown Cooling System Safety Injection Tk Nitrogen Supply Valves J-SIA-HV-639 and J-SIA-HV-649	Chapter 8
01-E-SIB-050 02-E-SIB-050 03-E-SIB-050	E/D Safety Injection and Shutdown Cooling System Shutdown Injection Tank Vent Valves J-SIA-HV-605 and J-SIA-HV-606	Chapter 8
01-E-SIB-051 02-E-SIB-051 03-E-SIB-051	E/D Safety Injection and Shutdown Cooling System Safety Injection Tank Vent Valves J-SIA-HV-607and J-SIA-HV-608	Chapter 8
01-E-SIB-052 02-E-SIB-052 03-E-SIB-052	E/D Safety Injection and Shutdown Cooling System Safety Injection Tank Vent Valves J-SIB-HV-613 and J-SIB-HV-623	Chapter 8
01-E-SIB-053 02-E-SIB-053 03-E-SIB-053	E/D Safety Injection and Shutdown Cooling System Safety Injection Tank Vent Valves J-SIB-HV-633 and J-SIB-HV-643	Chapter 8
01-E-SIB-054 02-E-SIB-054 03-E-SIB-054	E/D Safety Injection and Shutdown Cooling System Safety Injection Tank Vent Valves Power Supply Train A and B	Chapter 8

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Drawing Number	Title	Section Reference
01-E-SPB-001 02-E-SPB-001 03-E-SPB-001	E/D Essential Spray Ponds System Essential Spray Ponds Pumps A&B M-SPA-PO1 and M-SPB-PO1	Chapter 8
01-E-SSB-001 02-E-SSB-001 03-E-SSB-001	E/D Nuclear Sampling System Sample Containment Isolation Valves J-SSB-UV-200 and 201	Chapter 8
01-E-SSB-002 02-E-SSB-002 03-E-SSB-002	E/D Nuclear Sampling System Sample Containment Isolation Valve J-SSB-UV-202	Chapter 8
01-E-SSB-003 02-E-SSB-003 03-E-SSB-003	E/D Nuclear Sampling System Sample Containment Isolation Valves J-SSA-UV-203 and 204	Chapter 8
01-E-SSB-004 02-E-SSB-004 03-E-SSB-004	E/D Nuclear Sampling System Sample Containment Isolation Valve J-SSA-UV-205	Chapter 8
01-E-WCB-001 02-E-WCB-001 03-E-WCB-001	E/D Chilled Water System Normal Chiller M-WCN-EO1A	Chapter 8

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01-E-WCB-009 02-E-WCB-009 03-E-WCB-009	E/D Chilled Water System Norm. Chilled Water Rtn Cont. Isolation Valve J-WCB-UV-61	Chapter 8
01-E-WCB-010 02-E-WCB-010 03-E-WCB-010	E/D Chilled Water System Normal Chilled Water Rtn and Supply Ctmt Isolation Valves J-WCA-UV-62 and 63	Chapter 8
01-E-MAA-002 02-E-MAA-002	Unit S/L Diagram	Chapter 8
01-E-NHA-019 02-E-NHA-019 03-E-NHA-019	S/L Diagram 480V Non-Class 1E Power System MCC E-NHN-M19	Chapter 8
01-E-NHA-020 02-E-NHA-020 03-E-NHA-020	S/L Diagram 480V Non-Class 1E Power System MCC E-NHN-M20	Chapter 8
01-E-NHA-071 02-E-NHA-071 03-E-NHA-071	S/L Diagram 480V Non-Class 1E Power System MCC E-NHN-M71	Chapter 8
01-E-NHA-072 02-E-NHA-072 03-E-NHA-072	S/L Diagram 480V Non-Class 1E Power System MCC E-NHN-M72	Chapter 8
01-E-NKA-001 02-E-NKA-001 03-E-NKA-001	Main S/L Diagram 125V DC Non-Class IE Power System	Chapter 8

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01-E-NNA-001 02-E-NNA-001 03-E-NNA-001	S/L Diagram 120V AC Non-Class 1E Ungrounded Instrument and Control Panel E-NNN-D11	Chapter 8
01-E-NNA-002 02-E-NNA-002 03-E-NNA-002	S/L Diagram 120V AC Non-Class 1E Ungrounded Instrument and Control Panel E-NNN-D12	Chapter 8
01-E-NNA-003 02-E-NNA-003 03-E-NNA-003	Single Line Diagram 120V AC Non-Class 1E Grounded Instrument and Control Panel E-NNN-D15	Chapter 8
01-E-NNA-004 02-E-NNA-004 03-E-NNA-004	Single Line Diagram 120V AC Non-Class 1E Grounded Instrument and Control Panel E-NNN-D16	Chapter 8
01-E-PBA-001 02-E-PBA-001 03-E-PBA-001	S/L Diagram, 4.16KV Class 1E Power System Switchgear E-PBA-SO3	Chapter 8
01-E-PBA-002 02-E-PBA-002 03-E-PBA-002	S/L Diagram, 4.16KV Class 1E Power System Switchgear E-PBB-SO4	Chapter 8
01-E-PEA-001 02-E-PEA-001 03-E-PEA-001	S/L Class 1E Standby Generator System Diesel Generator E-PEA-GO1 and E-PEB-GO2	Chapter 8
01-E-PGA-001 02-E-PGA-001 03-E-PGA-001	S/L 480V Class 1E Power System LC E-PGA-L31	Chapter 8

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01-E-PGA-002 02-E-PGA-002 03-E-PGA-002	S/L 480V Class 1E Power System LC E-PGB-L32	Chapter 8
01-E-PGA-003 02-E-PGA-003 03-E-PGA-003	S/L Class 1E 480V Power System LC E-PGA-L33	Chapter 8
01-E-PGA-004 02-E-PGA-004 03-E-PGA-004	S/L Class 1E 480V Power System LC E-PGB-L34	Chapter 8
01-E-PGA-005 02-E-PGA-005 03-E-PGA-005	SLD 480V Class 1E Power System Load Center E-PGA-L35	Chapter 8
01-E-PGA-006 02-E-PGA-006 03-E-PGA-006	SLD 480V Class 1E Power System LC E-PGB-L36	Chapter 8
01-E-PHA-001 02-E-PHA-001 03-E-PHA-001	S/L Diagram 480V Class 1E Power System MCC E-PHA-M31	Chapter 8
01-E-PHA-002 02-E-PHA-002 03-E-PHA-002	S/L 480V Class 1E Power System MCC E-PHB-M32	Chapter 8
01-E-PHA-003 02-E-PHA-003 03-E-PHA-003	S/L Diagram 480V Class 1E Power System MCC E-PHA-M33	Chapter 8
01-E-PHA-004 02-E-PHA-004 03-E-PHA-004	S/L 480V Class 1E Power System MCC E-PHB-M34	Chapter 8
01-E-PHA-005 02-E-PHA-005 03-E-PHA-005	S/L 480V Class 1E Power System MCC E-PHA-M35	Chapter 8

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01-E-PHA-006 02-E-PHA-006 03-E-PHA-006	S/L 480V Class 1E Power System MCC E-PHB-M36	Chapter 8
01-E-PHA-007 02-E-PHA-007 03-E-PHA-007	S/L 480V Class 1E Power System MCC E-PHA-M37	Chapter 8
01-E-PHA-008 02-E-PHA-008 03-E-PHA-008	S/L 480V Class 1E Power System MCC E-PHB-M38	Chapter 8
01-E-PKA-001 02-E-PKA-001 03-E-PKA-001	Main Single Line Diagram 125V DC Class 1E and 120V AC Vital Instrument Power System	Chapter 8
01-E-PKA-002 02-E-PKA-002 03-E-PKA-002	S/L Diagram 125V DC Class 1E Power System DC Control Center E-PKA-M41	Chapter 8
01-E-PKA-003 02-E-PKA-003 03-E-PKA-003	S/L Diagram 125V DC Class 1E Power System Distr. Panel E-PKA-D21	Chapter 8
01-E-PKA-004 02-E-PKA-004 03-E-PKA-004	S/L Diagram 125V DC Class 1E Power System DC Control Center E-PKC-M43	Chapter 8
01-E-PKA-005 02-E-PKA-005 03-E-PKA-005	S/L Diagram 125V DC Class 1E Power System DC Control Center E-PKB-M42	Chapter 8
01-E-PKA-006 02-E-PKA-006 03-E-PKA-006	S/L Diagram 125V DC Class 1E Power System Distr. Panel E-PKB-D22	Chapter 8

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01-E-PKA-007 02-E-PKA-007 03-E-PKA-007	S/L Diagram 125V DC Class 1E Power System DC Control Center E-PKD-M44	Chapter 8
01-E-PNA-001 02-E-PNA-001 03-E-PNA-001	S/L Diagram 120V AC Class 1E Power System Ungrounded Vital Instrument and Control Distr. Panels E-PNA-D25 and E-PNC-D27	Chapter 8
01-E-PNA-002 02-E-PNA-002 03-E-PNA-002	S/L Diagram 120V AC Class 1E Power System Ungrounded Vital Instrument and Control Distr. Panels E-PNB-D26 and E-PND-D28	Chapter 8
01-J-AFE-051 02-J-AFE-051 03-J-AFE-051	Instrument Loop Diagram - Auxiliary Feedwater System	Chapter 7
01-J-AFE-056 02-J-AFE-056 03-J-AFE-056	Instrument Loop Diagram Auxiliary Feedwater System	Chapter 7
01-J-AFL-001 02-J-AFL-001 03-J-AFL-001	Control Logic Diagram - Auxiliary Feedwater Pump B and AFAS Maintained Logic	Chapter 7
01-J-AFL-002 02-J-AFL-002 03-J-AFL-002	Control Logic Diagram - Auxiliary Feedwater Regulating Valves	Chapter 7

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01-J-AFL-004 02-J-AFL-004 03-J-AFL-004	Control Logic Diagram Auxiliary Feedwater Pump A Turbine Trip and Throttle Valve J-AFA-HV-54	Chapter 7
01-J-CPL-001 02-J-CPL-001 03-J-CPL-001	Control Logic Diagram - Containment Purge HVAC Isol Valves	Chapter 7
01-J-CTL-001 02-J-CTL-001 03-J-CTL-001	Control Logic Diagram - Condensate Transfer Pumps and Normal AFP Suction Valves	Chapter 7
01-J-DFL-001 02-J-DFL-001 03-J-DFL-001	Control Logic Diagram - DGFO Transfer Pumps and System Alarms	Chapter 7
01-J-DGL-001 02-J-DGL-001 03-J-DGL-001	Control Logic Diagram - Diesel Generator Systems	Chapter 7
01-J-ECE-053 02-J-ECE-053 03-J-ECE-053	Instrument Loop Diagram Essential Chilled Water System	Chapter 7
01-J-ECL-001 02-J-ECL-001 03-J-ECL-001	Control Logic Diagram - Essential Chillers	Chapter 7
01-J-ECL-002 02-J-ECL-002 03-J-ECL-002	Control Logic Diagram Essential Chilled Water Pumps Exp Tank Make-Up Valve and Alarms	Chapter 7

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01-J-EWE-052 02-J-EWE-052 03-J-EWE-052	Instrument Loop Diagrams - Diesel Essential Cooling Water System	Chapter 7
01-J-EWL-001 02-J-EWL-001 03-J-EWL-001	Control Logic Diagram - Essential Cooling Water Pumps and Surge Tank Fill Valves	Chapter 7
01-J-EWL-002 02-J-EWL-002 03-J-EWL-002	Control Logic Diagram - Essential Cooling Water Loop A X-Tie Valves and System Alarms	Chapter 7
01-J-GAL-001 02-J-GAL-001 03-J-GAL-001	Control Logic Diagram - Nitrogen Containment Isolation Valves and System Alarms	Chapter 7
01-J-GRL-002 02-J-GRL-002 03-J-GRL-002	Control Logic Diagram - Gas Surge Header Containment Isolation Valves	Chapter 7
01-J-HAL-001 02-J-HAL-001 03-J-HAL-001	Control Logic Diagram - Auxiliary Bldg Pump Room ACUs	Chapter 7
01-J-HAL-002 02-J-HAL-002 03-J-HAL-002	Control Logic Diagram Auxiliary Bldg Pump Rooms Isolation Dampers	Chapter 7
01-J-HCL-001 02-J-HCL-001 03-J-HCL-001	Control Logic Diagram - Containment HVAC CEDM ACU Fans and System Dampers	Chapter 7

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01-J-HCL-002 02-J-HCL-002 03-J-HCL-002	Control Logic Diagram - Containment HVAC Normal ACU and Reactor Cavity Fans	Chapter 7
01-J-HCL-003 02-J-HCL-003 03-J-HCL-003	Control Logic Diagram - Containment HVAC ACU Heaters AFU and Gallery Fans and Isolation Valves	Chapter 7
01-J-HCL-004 02-J-HCL-004 03-J-HCL-004	Control Logic Diagram - Containment HVAC System Alarms and Pressure Sensor Isolation Valves	Chapter 7
01-J-HDL-001 02-J-HDL-001 03-J-HDL-001	Control Logic Diagram DG Rooms HVAC Essential Exhaust and AHL Fans	Chapter 7
01-J-HFE-051 02-J-HFE-051 03-J-HFE-051	Instrument Loop Diagrams - HVAC-Fuel Bldg.	Chapter 7
01-J-HFE-052 02-J-HFE-052 03-J-HFE-052	Instrument Loop Diagrams - HVAC-Fuel Bldg.	Chapter 7
01-J-HFL-001 02-J-HFL-001 03-J-HFL-001	Control Logic Diagram - Fuel and Auxiliary Bldg Essential Exhaust Fans and Heaters	Chapter 7
01-J-HFL-002 02-J-HFL-002 03-J-HFL-002	Control Logic Diagram - Fuel Bldg Normal Supply and Exhaust Fans, Dampers and Heaters	Chapter 7

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01-J-HFL-003 02-J-HFL-003 03-J-HFL-003	Control Logic Diagram - Fuel Bldg AHU Air Washer Pumps, OIC, and System Alarms	Chapter 7
01-J-HFL-004 02-J-HFL-004 03-J-HFL-004	Control Logic Diagram - Fuel and Auxiliary Bldg Essential Exhaust AFU Dampers	Chapter 7
01-J-HJE-051 02-J-HJE-051 03-J-HJE-051	Instrument Loop Diagrams - HVAC-Control Bldg	Chapter 7
01-J-HJL-004 02-J-HJL-004 03-J-HJL-004	Control Logic Diagram - CR Essential AHUs and Intake Dampers	Chapter 7
01-J-HJL-005 02-J-HJL-005 03-J-HJL-005	Control Logic Diagram - Control Bldg ESF and Battery Room Essential Fans, Essential Heaters and Alarms	Chapter 7
01-J-HJL-006 02-J-HJL-006 03-J-HJL-006	Control Logic Diagram - Control Room and Bldg Essential Isolation Dampers	Chapter 7
01-J-HJL-007 02-J-HJL-007 03-J-HJL-007	Control Logic Diagram - Control Bldg Essential Isolation Dampers	Chapter 7
01-J-HJL-008 02-J-HJL-008 03-J-HJL-008	Control Logic Diagram - Control Bldg Essential Isolation Dampers	Chapter 7

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01-J-HPE-051 02-J-HPE-051 03-J-HPE-051	Instrument Loop Diagrams - Containment Hydrogen Control	Chapter 7
01-J-HPL-001 02-J-HPL-001 03-J-HPL-001	Control Logic Diagram - Containment Post-Accident H_2 Control System	Chapter 7
01-J-IAL-001 02-J-IAL-001 03-J-IAL-001	Control Logic Diagram - Air Compressors System Valves and System Alarms	Chapter 7
01-J-NCE-053 02-J-NCE-053 03-J-NCE-053	Instrument Loop Diagrams - Nuclear Cooling Water System	Chapter 7
01-J-NCE-060 02-J-NCE-060 03-J-NCE-060	Instrument Loop Diagram Nuclear Cooling Water System	Chapter 7
01-J-NCL-002 02-J-NCL-002 03-J-NCL-002	Control Logic Diagram - Nuclear Cooling Water System Valves	Chapter 7
01-J-PCL-001 02-J-PCL-001 03-J-PCL-001	Control Logic Diagram - Fuel Pool Cooling System	Chapter 7
01-J-RDL-002 02-J-RDL-002 03-J-RDL-002	Control Logic Diagram - Containment Radwaste Sumps Containment Isolation Valves	Chapter 7
01-J-SGE-051 02-J-SGE-051 03-J-SGE-051	Instrument Loop Diagrams - Main Steam System	Chapter 7
01-J-SGE-0074 02-J-SGE-0074 03-J-SGE-0074	Instrument Loop Diagrams – Main Steam Systems	Chapter 7

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01-J-SGL-001 02-J-SGL-001 03-J-SGL-001	Control Logic Diagram - Auxiliary Feed Pump Turbine Main Steam Supply Valves	Chapter 7
01-J-SGL-002 02-J-SGL-002 03-J-SGL-002	Control Logic Diagram - Steam Generator MSIV Bypass and Blowdown Isolation Valves	Chapter 7
01-J-SGL-003 02-J-SGL-003 03-J-SGL-003	Control Logic Diagram - Steam Generator Feedwater Isolation and Main Steam Atmospheric Dump Valves	Chapter 7
01-J-SGL-006 02-J-SGL-006 03-J-SGL-006	Control Logic Diagram Steam Generator Blowdown Sample Isolation Valves	Chapter 7
01-J-SPL-001 02-J-SPL-001 03-J-SPL-001	Control Logic Diagram - Essential Spray Pond Pumps	Chapter 7
01-J-WCL-002 02-J-WCL-002 03-J-WCL-002	Control Logic Diagram - Normal Chiller and Contain-Ment Isolation Valves	Chapter 7
13-J-ZAF-001	Instrument Location Plan Auxiliary Bldg El 40 ft Level D ZADC	Chapter 7

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 67 of 72)

Drawing Number	Title	Section Reference
13-J-ZAF-002	Instrument Location Plan Auxiliary Bldg El 40 ft Level D ZADD	Chapter 7
13-J-ZAF-003	Instrument Location Plan Auxiliary Bldg El 51 ft-6 in Level C ZACC	Chapter 7
13-J-ZAF-004	Instrument Location Plan Auxiliary Bldg El 51 ft-6 in Level C ZACD	Chapter 7
13-J-ZAF-005	Auxiliary Bldg Instrument Location Plan Level B ZABA	Chapter 7
13-J-ZAF-006	Auxiliary Bldg Instrument Location Plan Level B ZABB	Chapter 7
13-J-ZAF-007	Auxiliary Bldg Instrument Location Plan El 70 ft Level B ZABC	Chapter 7
13-J-ZAF-008	Auxiliary Bldg Instrument Location Plan El 70 ft Level B ZABD	Chapter 7
13-J-ZAF-013	Auxiliary Bldg Instrument Location Plan El 100 ft Level 1 ZA1A	Chapter 7
13-J-ZAF-014	Auxiliary Bldg Instrument Location Plan El 100 ft Level 1 ZA1B	Chapter 7

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 68 of 72)

Drawing Number	Title	Section Reference
13-J-ZAF-015	Auxiliary Bldg Instrument Location Plan El 100 ft Level 1 ZA1C	Chapter 7
13-J-ZAF-016	Auxiliary Bldg Instrument Location Plan El 100 ft Level 1 ZA1D	Chapter 7
13-J-ZAF-017	Auxiliary Bldg Instrument Location Plan El 120 ft Level 1 ZA2A	Chapter 7
13-J-ZAF-019	Auxiliary Bldg Instrument Location Plan El 120 ft Level 2 ZA2C	Chapter 7
13-J-ZAF-020	Auxiliary Bldg Instrument Location Plan El 120 ft Level 2 ZA2D	Chapter 7
13-J-ZCF-002	Containment Bldg El 80 ft Level A ZCAA, ZCAB Instrument Location Plan	Chapter 7
13-J-ZCF-003	Containment Bldg Instrument Location Plan El 80 ft Level A ZCAC, ZCAD	Chapter 7
13-J-ZCF-004	Instrument Location Plan Containment Bldg El 100 ft Level 1 ZC1A	Chapter 7

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 69 of 72)

Drawing Number	Title	Section Reference
13-J-ZCF-005	Containment Bldg Instrument Location Plan El 100 ft Level 1 ZC1B	Chapter 7
13-J-ZCF-006	Containment Bldg Instrument Location Plan El 100 ft Level 1 ZC1C	Chapter 7
13-J-ZCF-007	Containment Bldg Instrument Location Plan El 100 ft Level 1 ZC1D	Chapter 7
13-J-ZCF-008	Instrument Location Plan Containment Bldg El 120 ft Level 2 ZC2A	Chapter 7
13-J-ZCF-009	Instrument Location Plan Containment Bldg El 120 ft Level 2 ZC2B	Chapter 7
13-J-ZCF-010	Containment Bldg Instrument Location Plan El 120 ft Level 2 ZC2C	Chapter 7
13-J-ZCF-011	Instrument Location Plan Containment Bldg El 120 ft Level 2 ZC2D	Chapter 7
13-J-ZCF-013	Instrument Location Plan Containment Bldg El 140 ft Level 3 ZC3B	Chapter 7

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 70 of 72)

Drawing Number	Title	Section Reference
13-J-ZCF-015	Instrument Location Plan Containment Bldg El 140 ft Level 3 ZC3D	Chapter 7
13-J-ZFF-001	Instrument Location Plan Fuel Handling Bldg El 100 ft Level 1 ZF1B	Chapter 7
13-J-ZFF-002	Instrument Location Plan Fuel Handling Bldg El 120 ft Level 2 ZF2B	Chapter 7
13-J-ZGF-001	Instrument Location Plan Diesel Generator Bldg El 100 ft Level 1 ZG1A	Chapter 7
13-J-ZJF-001	Instrument Location Plan Control Bldg El 74 ft Level AA ZJAA	Chapter 7
13-J-ZJF-002	Instrument Location Plan Control Bldg El 74 ft Level AB ZJAB	Chapter 7
13-J-ZJF-009	Instrument Location Plan Control Bldg El 140 ft Level 3A, 3B, 3C, ZJ3A	Chapter 7
13-J-ZMF-001	Main Steam Support Structure Instrument Location Plan at El 81 ft and 100 ft ZCAE, ZCIE	Chapter 7

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 71 of 72)

Drawing Number	Title	Section Reference
01-J-ZZE-003 02-J-ZZE-003 03-J-ZZE-003	Instrument Loop Diagram Cabinet and Panel Wiring	Chapter 7
01-J-ZZE-010 02-J-ZZE-010 03-J-ZZE-010	Instrument Loop Diagram Instrument Rack Power Supply Alarm and External Wiring Control Room	Chapter 7
01-J-ZZE-021 02-J-ZZE-021 03-J-ZZE-021	Instrument Loop Diagram Instrument Rack Power Distribution and Alarm Wiring	Chapter 7
01-J-ZZE-031 02-J-ZZE-031 03-J-ZZE-031	Instrument Loop Diagram Distribution Module Device Wiring Control Room Instrument Cabinet	Chapter 7
01-J-ZZE-042 02-J-ZZE-042 03-J-ZZE-042	Instrument Loop Diagram Distribution Module Device Wiring Control Room Control Board	Chapter 7
01-J-ZZE-043 02-J-ZZE-043 03-J-ZZE-043	Instrument Loop Diagram Distribution Module Device Wiring Control Room Control Board	Chapter 7
01-J-ZZE-044 02-J-ZZE-044 03-J-ZZE-044	Instrument Loop Diagram Distribution Module Device Wiring Control Room Control Board	Chapter 7

Table 1.7-1
NONPROPRIETARY EI&C DRAWINGS INCORPORATED
BY REFERENCE (Sheet 72 of 72)

Drawing Number	Title	Section Reference
01-J-ZZE-045 02-J-ZZE-045 03-J-ZZE-045	Instrument Loop Diagram Distribution Module Device Wiring Control Room Control Board	Chapter 7
01-J-ZZE-046 02-J-ZZE-046 03-J-ZZE-046	Instrument Loop Diagram Distribution Module Device Wiring Control Room Control Board	Chapter 7
01-J-ZZL-010 02-J-ZZL-010 03-J-ZZL-010	Control Logic Diagram - Legend	Chapter 7
01-J-ZZL-012 02-J-ZZL-012 03-J-ZZL-012	Control Logic Diagram - General Notes	Chapter 7
01-J-ZZL-021 02-J-ZZL-021 03-J-ZZL-021	Control Logic Diagram Reactor Trip Logic	Chapter 7
01-E-ZZI-003 02-E-ZZI-003 03-E-ZZI-003	Electrical Equipment Database	Chapter 8

Table 1.7-2
PVNGS ENGINEERING DRAWINGS INCORPORATED BY REFERENCE
(Sheet 1 of 8)

Engineering Drawing #	**Title**
01, 02, 03-C-OOA-030	Settlement Monitor Point Locations
13-E-MAA-001	Main Single Line Diagram
01, 02, 03-E-MAA-002	Unit Single Line Diagram System Connection
01, 02, 03-E-NKA-001	Main Single Line Diagram 125V DC Non-Class 1E Power System
01, 02, 03-E-PKA-001	Main Single Line Diagram 125V DC 1E and 120V AC Vital Inst. Power System
01, 02, 03-J-ZZL-010	Control Logic Diagram Legend
01, 02, 03-J-ZZL-012	Control Logic Diagram General Notes
01, 02, 03-M-AFP-001	Auxiliary Feedwater System
01, 02, 03-M-ARP-001	Condenser Air Removal System
01, 02, 03-M-ASP-001	Auxiliary Steam System
01, 02, 03-M-CDP-001, -002, -003 & -004	Condensate System
01, 02, 03-M-CHP-001, -002, -003, -004 & -005	Chemical & Volume Control System
01, 02, 03-M-CMP-001 & -002	Chemical Waste System
01, 02, 03-M-CPP-001	Containment Purge System
01, 02, 03-M-CTP-001	Condensate Storage & Transfer System
01, 02, 03-M-CWP-001	Circulating Water System
01, 02, 03-M-DFP-001	Diesel Fuel Oil & Transfer System
01, 02, 03-M-DGP-001	Diesel Generator System
01, 02, 03-M-DSP-002 (Sheet 4)	Domestic Water System
01, 02, 03-M-DWP-002 (Sheet 4)	Demineralized Water System
01, 02, 03-M-ECP-001	Essential Chilled Water System
01, 02, 03-M-EDP-001, -002, -003, -004 & -005	Feedwater Heater Extraction Steam and Drain System
01, 02, 03-M-EWP-001	Essential Cooling Water System

Table 1.7-2
PVNGS ENGINEERING DRAWINGS INCORPORATED BY REFERENCE
(Sheet 2 of 8)

Engineering Drawing #	**Title**
01, 02, 03-M-FPP-002, -003, -004, -006	Fire Protection System
01, 02, 03-M-FTP-001	Steam Generator Feedwater Pump Turbine System
01, 02, 03-M-FWP-001	Feedwater System
01, 02, 03-M-GAP-001 & -002	Service Gas System (N2 and H2 Supply)
01, 02, 03-M-GSP-001	Turbine Steam Seal & Drain System
01, 02, 03-M-HAP-001, -002, -003 & -004	HVAC Auxiliary Building
01, 02, 03-M-HCP-001	HVAC Containment Bldg.
01, 02, 03-M-HCP-002	HVAC Containment CEDM Reactor & Tendon Gallery System
01, 02, 03-M-HCP-003	Main Steam and Feedwater Penetration Cooling System
01, 02, 03-M-HDP-001	HVAC Diesel Generator Bldg.
01, 02, 03-M-HFP-001	HVAC Fuel Bldg.
01, 02, 03-M-HJP-001 & -002	Control Bldg. HVAC
01, 02, 03-M-HPP-001	Containment Hydrogen Control
01, 02, 03-M-HRP-001	HVAC Radwaste System
01, 02, 03-M-HTP-001	Turbine Bldg. HVAC
01, 02, 03-M-IAP-001 & -002	Instrument & Service Air System
01, 02, 03-M-IAP-003	Instrument & Service Air System
01, 02, 03-M-MTP-001, -002 & -003	Main Turbine System
01, 02, 03-M-NCP-001, -002 & -003	Nuclear Cooling Water System
01, 02, 03-M-OWP-001, -002 & -003	Oily Waste & Non-Radioactive Waste System
01, 02, 03-M-PCP-001	Fuel Pool Cooling Water System
01, 02, 03-M-PWP-001	Plant Cooling Water System
01, 02, 03-M-RCP-001, -002 & -003	Reactor Coolant System
01, 02, 03-M-RDP-001	Rad Waste Drain Containment Bldg.
01, 02, 03-M-RDP-002	Rad Waste Drain System
01, 02, 03-M-RDP-003	Rad Waste Drain System Auxiliary Bldg.
01, 02, 03-M-RDP-004	Rad Waste Drain System Radwaste Bldg.
01, 02, 03-M-RDP-005	Rad Waste Drain System Fuel Bldg.
01, 02, 03-M-SCP-001	Secondary Chemical Control System (Condensate Demin.)

Table 1.7-2
PVNGS ENGINEERING DRAWINGS INCORPORATED BY REFERENCE
(Sheet 3 of 8)

Engineering Drawing #	**Title**
01, 02, 03-M-SCP-002	Secondary Chemical Control System
01, 02, 03-M-SCP-003	Secondary Chemical Control System Chemical Addition
01, 02, 03-M-SCP-004	Secondary Chemical Control System Blowdown System
01, 02, 03-M-SCP-005, -006 & -007	Secondary System Control System Turbine & Aux Cold Lab Non-Nuclear Process Sampling
01, 02, 03-M-SGP-002, -001	Main Steam System
01, 02, 03-M-SIP-001, -002 & -003	Safety Injection & Shutdown Cooling System
01, 02, 03-M-SPP-001, -002	Essential Spray Pond System
01, 02, 03-M-TCP-001, -002 & -003	Turbine Cooling Water System
01, 02, 03-M-WCP-001	Normal Chilled Water System
01, 02, 03-N-GRP-001	Gaseous Radwaste System (Units 1, 2 & 3)
01, 02, 03-N-LRP-001, -002 & -003	Liquid Radwaste System (Units 1, 2 & 3)
01, 02, 03-N-SRP-001, -002 & -003	Solid Radwaste System (Units 1, 2 & 3)
01, 02, 03-N-SSP-001	Nuclear Sampling System
01, 02, 03-P-SGF-401	Turbine Bldg. Isometric Main Steam System
01-P-SGF-118	Ctmt Bldg. Isometric Main Steam System
01-P-SGF-155	MSSS Isometric Main Steam
01, 02, 03-M-GHP-0001	Generator Hydrogen and CO2 System
02, 03-N-SSP-003	Post Accident Sampling System
02-M-HJP-003	Control Bldg. HVAC
13-A-ZYD-021	Yard Area Floor Plan at 100’
13-A-ZYD-022	Ctmt. Bldg. Floor Plan at 55’
13-A-ZYD-023	Aux. Bldg. Floor Plan at 40’
13-A-ZYD-024	Aux. Bldg. Floor Plan at 120’
13-A-ZYD-026	Radwaste Bldg. Floor Plan at 100’
13-A-ZYD-029	Control Bldg. Floor Plan at 74’
13-A-ZYD-030	Fuel Bldg. Floor Plan at 100’
13-A-ZYD-031	Diesel Generator Bldg. Floor Plan at 100’ and 115’

Table 1.7-2
PVNGS ENGINEERING DRAWINGS INCORPORATED BY REFERENCE
(Sheet 4 of 8)

Engineering Drawing #	**Title**
13-C-SPS-375	Nuclear Spray Ponds Plan
13-C-ZCS-102	Ctmt Bldg. Base Mat Reinf. Plan Bottom Layers Areas CAA, CAB, CAC & CAD
13-C-ZCS-104	Ctmt Bldg. Base Mat Reinf. Sections and Details
13-C-ZCS-108	Ctmt Bldg. Inside Curtain Wall Reinf. Buttress 1-2
13-C-ZCS-111	Ctmt Bldg. Outside Curtain Wall Reinf. Buttress 1-2
13-C-ZCS-114	Ctmt Bldg. Wall Reinf. Sections & Details
13-C-ZCS-115	Ctmt Bldg. Wall Reinf. Sections & Details
13-C-ZCS-117	Ctmt Bldg. Wall Reinf. Sections & Details
13-C-ZCS-122	Ctmt Bldg. Dome Reinf
13-C-ZCS-123	Ctmt Bldg. Dome Reinf.
13-C-ZCS-175	Ctmt Bldg. Prestressing Reqmt. General Arrangement
13-C-ZCS-177	Ctmt Bldg. Prestressing Reqmt. Dome & Wall Cross Sections
13-C-ZCS-181	Ctmt Bldg. Prestressing Reqmt. Buttress, Wall & Dome Sections and Details
13-C-ZCS-200	Ctmt Bldg. Base Mat Liner Plate Floor Plan Areas CAA, CAB, CAC & CAD
13-C-ZCS-201	Ctmt Bldg. Base Mat Liner Plate Inserts Plan CAA, CAB, CAC & CAD
13-C-ZCS-205	Ctmt Bldg. Liner Plate Wall Buttress 1 & 2
13-C-ZCS-206	Ctmt Bldg. Liner Plate Wall Buttress 2 & 3
13-C-ZCS-207	Ctmt Bldg. Liner Plate Wall Buttress 3 to 1
13-C-ZCS-211	Ctmt Bldg. Wall Liner Plate Sections & Details
13-C-ZCS-212	Ctmt Bldg. Wall Liner Plate Sections & Details
13-C-ZCS-213	Ctmt Bldg. Wall Liner Plate Sections & Details
13-C-ZCS-215	Ctmt Bldg. Wall Liner Plate Sections & Details

Table 1.7-2
PVNGS ENGINEERING DRAWINGS INCORPORATED BY REFERENCE
(Sheet 5 of 8)

Engineering Drawing#	**Title**
13-C-ZCS-217	Ctmt Bldg. Wall Liner Plate Plans & Sections
13-C-ZCS-306	Ctmt Internal Partial Concrete Plan 140’ Areas
13-C-ZCS-307	Ctmt Internal Partial Concrete Plan 140’ Areas
13-C-ZCS-345	Ctmt Internal Reinf. Concrete Primary Shield
13-C-ZCS-346	Ctmt Internal Reinf. Concrete Primary Shield
13-C-ZCS-347	Ctmt Internal Reinf. Concrete Primary Shield
13-C-ZCS-348	Ctmt Internal Reinf. Concrete Primary Shield
13-C-ZCS-358	Ctmt Internal Refin. Concrete West Secondary Shield Walls
13-C-ZCS-366	Ctmt Internal Reinf. Concrete Shield Walls Section & Details
13-C-ZCS-520	Ctmt Internal Polar Crane Support Grinder Sections & Details
13-C-ZCS-600	Ctmt Internal Reactor Vessel Supports
13-C-ZCS-601	Ctmt Internal Reactor Vessel Supports
13-C-ZCS-602	Ctmt Internal Coolant Pump Supports
13-C-ZCS-603	Ctmt Internal Coolant Pump Supports
13-C-ZCS-604	Ctmt Internal PZR & SI Tank Supports
13-C-ZCS-605	Ctmt Internal SG Lower Supports Sections & Details
13-C-ZCS-606	Ctmt Internal SG Lower Supports Sections & Details
13-C-ZVA-005	Site General Arrangement
13-J-ZYF-009	Instrument Location Plan RWT Area
13-M-ZZP-001, -002, -003 & -004	Legends and Symbols Flow Diagrams and P&ID Diagrams
13-N-997-184	Process, Effluent and Area Radiation Monitoring System Block Diagram
13-N-GRF-001	Basic Flow Diagram – Gaseous Radwaste System
13-N-LRF-001 & -002	Basic Flow Diagram – Liquid Radwaste System
13-N-RAR-001	Rad Zones (Oper.) Between 40’ & 100’
13-N-RAR-002	Rad Zones (Oper.) at 100’

Table 1.7-2
PVNGS ENGINEERING DRAWINGS INCORPORATED BY REFERENCE
(Sheet 6 of 8)

Engineering Drawing #	**Title**
13-N-RAR-003	Rad Zones (Oper.) Between 120′ & 140′
13-N-RAR-004	Rad Zones (Oper.) Between 140′ & 200′
13-N-RAR-005	Rad Zones (Oper. & Refuel) at Roof El.
13-N-RAR-006	Rad Zones (Oper.) Section A-A
13-N-RAR-007	Rad Zones (Oper.) Section J-J
13-N-RAR-008	Rad Zones (Oper.) Section D, E, H
13-N-RAR-009	Rad Zones (Oper. & Refuel) Section B, C, K
13-N-RAR-010	Rad Zones (Oper. & Refuel) at Aux Bldg. 88′ and Control Bldg. 160′ and Sections F & G
13-N-RAR-011	Rad Zones (Refuel) Between 40′ & 100′
13-N-RAR-012	Rad Zones (Refuel) at 100′
13-N-RAR-013	Rad Zones (Refuel) Between 120′ & 140′
13-N-RAR-014	Rad Zones (Refuel) Between 140′ & 200′
13-N-RAR-015	Rad Zones (Refuel) Section A-A
13-N-RAR-016	Rad Zones (Refuel) Section J-J
13-N-RAR-017	Rad Zones (Refuel) Section D, E, H
13-N-RAR-018	Rad Zones LOCA w/Sump Recirc Between 40 & 100′
13-N-RAR-019	Rad Zones LOCA w/Sump Recirc at 100′
13-N-RAR-020	Rad Zones LOCA w/Sump Recirc Between 120′ & 140′
13-N-RAR-021	Rad Zones LOCA w/Sump Recirc Between 140′ & 200′
13-N-RAR-022	Rad Zones LOCA w/Sump Recirc at Roof El.
13-N-RAR-023	Rad Zones LOCA w/Sump Recirc Section A
13-N-RAR-024	Rad Zones LOCA w/Sump Recirc Section J-J
13-N-RAR-025	Rad Zones LOCA w/Sump Recirc Section D, E, H
13-N-RAR-026	Rad Zones LOCA w/Sump Recirc Section B, C, K
13-N-RAR-027	Rad Zones LOCA w/Sump Recirc Section at Aux. 88′
13-N-RAR-028	Rad Zones LOCA Outside Areas (Direct Dose)
13-N-RAR-029	Rad Zones LOCA Degraded Core Intact Primary Between 40′ and 100′

Table 1.7-2
PVNGS ENGINEERING DRAWINGS INCORPORATED BY REFERENCE
(Sheet 7 of 8)

Engineering Drawing #	**Title**
13-N-RAR-030	Rad Zones LOCA Degraded Core Intact Primary at 100’
13-N-RAR-031	Rad Zones LOCA Degraded Core Intact Primary Between 120’ & 140’
13-N-RAR-032	Rad Zones LOCA Degraded Core Intact Primary Between 140’ & 200’
13-N-RAR-033	Rad Zones LOCA Degraded Core Intact Primary at Roof El.
13-N-RAR-034	Rad Zones LOCA Degraded Core Intact Primary Section A
13-N-RAR-035	Rad Zones LOCA Degraded Core Intact Primary Section J-J
13-N-RAR-036	Rad Zones LOCA Degraded Core Intact Primary Section D, E, H
13-N-RAR-037	Rad Zones LOCA Degraded Core Intact Primary Section B, C, K
13-N-RAR-038	Rad Zones LOCA Degraded Core Intact Primary at Aux. 88’, Control 160’ & Sections F & G
13-N-RAR-039	Rad Zones (Dry Cask Transfer Operation) Floor Plans at El. 100’, 120’, 140’ and Sections
13-N-SRF-001	Basic Flow Diagram – Solid Radwaste System
13-P-OOB-001	Site General Arrangement Pwr Block Site Plan
13-P-OOB-002	General Arrangement Plans Between 40’ & 100’
13-P-OOB-003	General Arrangement Plans at 100’
13-P-OOB-004	General Arrangement Plans Between 120’ & 140’
13-P-OOB-005	General Arrangement Plans Between 140’ & 200’
13-P-OOB-006	General Arrangement Plans at Roof El.
13-P-OOB-007	General Arrangement Plans Section A-A
13-P-OOB-008	General Arrangement Plans Section J-J
13-P-OOB-009	General Arrangement Plans Sections
13-P-OOB-010	General Arrangement Plans Sections
13-P-OOB-011	General Arrangement Plans at 160’ and Sections
13-P-RCF-114	Ctmt Bldg. Isometric RCS Pzr Relief Lines
13-P-ZCG-114	Ctmt Dome Spray Header Arrangement (Primary)
13-P-ZCG-118	Ctmt Bldg. Safety Injection System
13-P-ZCG-120	Ctmt 100’ – 200’ Spray Header Arrangement (Aux)
13-P-ZGL-701	Diesel Generator Bldg. Equipment Location

Table 1.7-2
PVNGS ENGINEERING DRAWINGS INCORPORATED BY REFERENCE
(Sheet 8 of 8)

Engineering Drawing #	Title
13-P-ZGL-702	Diesel Generator Bldg. Equipment
A0-A-ZYD-187	TSC Floor Plans
A0-M-CMP-003	Chemical Waste System Water Treatment
A0-M-DSP-001 (Sheet 1-3)	Domestic Water System
A0-M-DWP-001 (Sheet 1-3)	Demineralized Water System
A0-M-FPP-001 and -005	Fire Protection System
A0-M-OWP-004	Oily Waste & Non-Radioactive Waste
A0-M-RDP-006	Rad Waste Drain System (Decon, Laundry
A0-M-STP-001	Sanitary Drainage and Treatment System
A0-M-TBP-003	“B” Blowdown System

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1.8 CONFORMANCE TO NRC REGULATORY GUIDES

This section discusses the conformance of plant design with the guidelines presented in the NRC regulatory guides. A reference to the FSAR section in which the applicable design feature is described is also provided.

Where the design deviates from the regulatory guide, or where conformance to the guide has been qualified by an interpretation of the guide, these variances are discussed in detail in this section.

This section presents the applicant's position with respect to the regulatory guides. Refer to CESSAR Section 1.8 for C-E's response to the regulatory guides in CESSAR scope. Regulatory guides that are incorporated into CESSAR will also be incorporated into PVNGS by reference in this section.

REGULATORY GUIDE 1.1: Net Positive Suction Head for ECCS and Containment Heat Removal Systems Pumps (Revision 0, November 2, 1970)

RESPONSE

Refer to section 6.3, 6.2.2.3, 5.1.4, and 5.4.7.1.

REGULATORY GUIDE 1.2: Thermal Shock to Reactor Pressure Vessels (Revision 0, November 2, 1970)

RESPONSE

Refer to 5.2.3.3.1.1, 4.2.5, and 5.1.4.

REGULATORY GUIDE 1.3: Assumptions Used for Evaluating the Potential Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors (Revision 1, June 1973)

RESPONSE

Not applicable.

REGULATORY GUIDE 1.4: Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors (Revision 2, June 1974)

RESPONSE

The position of Regulatory Guide 1.4 is accepted (refer to section 15.6). Additional references: 3.11, 5.1.4, 5.4.7.1, 6.4.4.3, 9.3.2.2.2, 9A.60, 12.2.3, 12.3.2.2.7, 15B.4, 18.II.B.2, and 18.II.B.3.

REGULATORY GUIDE 1.5: Assumptions Used for Evaluating the Potential Consequences of a Steam Line Break Accident for Boiling-Water Reactors (Revision 0, March 10, 1971)

RESPONSE

Not applicable.

REGULATORY GUIDE 1.6: Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Revision 0, March 10, 1971)

RESPONSE

The position of Regulatory Guide 1.6 is accepted (refer to section 8.3). Additional references: 7.1.2.13 and 8.1.4.3.

REGULATORY GUIDE 1.7: Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident (Revision 0, March 10, 1971)

RESPONSE

The position of Regulatory Guide 1.7 is accepted (refer to subsection 6.2.5). Additional references: 3.11, 6.2.5, 9.3.2.2.2, 12.2.3, and 18.II.B.3.

REGULATORY GUIDE 1.8: Personnel Selection and Training (Revision 1-R, May 1977).

RESPONSE

PVNGS identifies conformance to the regulatory positions of Regulatory Guide 1.8 (including any exemptions or clarifications) in the PVNGS Operations Quality Assurance Program Description.

REGULATORY GUIDE 1.9: Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units used as Class 1E Onsite Electric Power Systems at Nuclear Power Stations, (Revision 3, July 1993)

RESPONSE

The position of Regulatory Guide 1.9 is accepted with the following clarifications and exceptions:

A. Clarification: The diesel generator power supplies were originally selected in accordance with R.G. 1.9, Rev. 0.

B. Regulatory Position C. Exception is taken to regulatory endorsement of IEEE Std 387 1984. Palo Verde retains commitments to earlier editions of IEEE Std 387. The original selection and qualification testing of the diesel generator power supplies were performed in accordance with IEEE Std 387-1972. The present design and testing of the diesel generators is performed in accordance with IEEE Std 387-1977. The following table identifies the applicable portions of IEEE Std 387-1977 that are equivalent to the general sections and specific paragraphs of IEEE Std 387-1984 referenced in Regulatory Guide 1.9, Revision 3.

IEEE Std 387-1984	IEEE Std 387-1977
Section 1, Scope	Section 1, Scope
Section 2, Purpose	Section 2, Purpose
Section 3, Definitions	Section 3, Definitions
Section 4, References	Section 4, References
Section 5, Principle Design Criteria	Section 5, Principle Design Criteria
Section 6, Testing	Section 6, Requirements for Testing and Analysis (excluding section 6.3)

Section 7, Qualification Requirements	Sections 5.4 and 6.3, Note 1
Appendix A, Load Profile	Note 2
Appendix B, Aging	Note 1, 2
Section 1.2, Inclusions	Section 1.2, Inclusions
Section 3.7.1, Continuous Rating	Section 3.7.1, Continuous Rating
Section 5.5.3.1, Surveillance Systems	Section 5.6.3.1, Surveillance Systems
Section 5.5.4, Protection	Note 3
Section 5.5.4(2), Other Protective Features	Note 3
Section 7.5.2, Records and Analysis	Note 4

Note 1. The emergency diesel generator supply units were originally qualified to IEEE Std 387-1972. Environmental qualification of the emergency diesel generators is not required per 10 CFR 50.49, Regulatory Guide 1.89, NUREG-0588 and IEEE Std 323 1974.

Note 2. As noted within the IEEE Std 387-1984, the appendixes of IEEE Std 387-1984 are not part of the standard.

Note 3. The guidance provided in Section 5.5.4 with regard to EDG protection is stated in UFSAR Section 8.3.1.1.4.3.

Note 4. The EDG performance records that are described in Section 7.5.2 of IEEE Std 387-1984 are addressed by the Maintenance Rule 10 CFR 50.65, Regulatory Guide 1.160, Rev. 3 and NUMARC 93-01.

C. Regulatory Position C.1.5. Exception to EDG fast start tests being performed from "normal standby conditions" as described in regulatory position C.1. Technical Specifications and its associated bases will define which EDG starts are performed from normal standby conditions (temperature of jacket water and lube oil systems within range of keep-warm system) and from hot conditions (immediately following an engine shutdown). The other EDG test starts may be performed from jacket water and lube oil system temperatures within Operability limits.

D. Regulatory Position C.2.1. Exception to the section describing EDG reliability. A new criterion is being

added to the list of EDG reliability failure "Exceptions" on page 1.9-6. This exception is stated as follows, "A failure that occurs during a post maintenance test, prior to declaring the EDGs Operable is not a valid failure, providing the failure is directly attributable preceding maintenance activity."

E. Regulatory Position C.2.2: Exception to the regulatory guidance that "jumpers and other nonstandard configurations or arrangements should not be used subsequent to initial equipment startup testing." Non-standard configurations and arrangements such as jumpers, lifted leads and connection of data recorder test connections will be utilized and administratively control during portions of the 18-month tests specified in R.G. 1.9, Rev. 3.

F. Regulatory Position C.2.2.6. Exception to regulatory guidance that the combined LOOP and SIAS testing is performed in whatever sequence they might occur. Combined LOOP and SIAS testing will be performed concurrently.

G. Exception to Regulatory Position C.2.2.7, C.2.2.8 and C.2.2.9. EDG tests of the single largest load reject, full load reject and, endurance tests will be performed in accordance with TS 3.8.1.

H. Exception to Regulatory Positions C.2.2 and C.2.3. Diesel Generator testing frequency is in accordance with the requirements of Technical Specification 5.5.18 (Surveillance Frequency Control Program).

Additional References: 8A.8 and 14.2.7.

REGULATORY GUIDE 1.10: Mechanical (Cadweld) Splices in Reinforcing Bars of Category 1 Concrete Structures (Revision 1, January 2, 1973)

RESPONSE

The position of Regulatory Guide 1.10 is accepted with the following clarifications to Sections 2 and 4.

Section 2:

Prior to casting, some, but not all, mechanical splices are inspected. An inspector covers the work of more than one crew and periodic preparation checks are made. Each completed splice is visually inspected.

Section 4:

A. The terms "horizontal, vertical, and diagonal bars" are interpreted to apply, respectively, to the following types of splice position:

1. Horizontal, including 10° to horizontal
2. Vertical, including 10° to vertical
3. Diagonal (45° angle), including 10° to 80°B.

B. The words "splicing crew" are interpreted to refer to all members on the project that are actively engaged in preparing and assembling cadweld mechanical splices at the final splice location.

C. A sister splice may be substituted for a production splice when:

1. Cadwelding to dowels which are too short to take a production splice

2. The responsible quality control engineer, in conjunction with engineering, determines that the area of reinforcing is too congested to take a production splice.

Reference 3.8.1.2, 3.8.1.6, and 3.8.3.2.

REGULATORY GUIDE 1.11: Instrument Lines Penetrating Primary Reactor Containment (Revision 0, March 10, 1971)

RESPONSE

The position of Regulatory Guide 1.11 is accepted (refer to subsection 6.2.4). Additional references: 3.1.47 and 7.1.2.14

REGULATORY GUIDE 1.12: Nuclear Power Plant Instrumentation for Earthquakes (Revision 2, March 1997)

RESPONSE

The position of Regulatory Guide 1.12 is accepted, except as noted below:

A. Force balance accelerometers are provided at select locations in lieu of triaxial time-history accelerographs. The force balance accelerometers are located at design critical points specifically selected to display significant strain under earthquake excitation. The force balance accelerometers, recorder, and trigger makes up the time-history accelerograph as defined in the "Definitions" of Regulatory Guide 2.12, Rev. 2. The recorder and seismic trigger are separately located (at the 140' level of the Control Building, Unit 1) from the force balance accelerometers.

B. Annunciation to more than one control room at a site, per Section 7 of Regulatory Guide 1.12, Revision 2, is not constructive at PVNGS, and an exception is taken to Section 7. Triggering of the free-field or any foundation level force balance accelerometer will be annunciated to the Unit 1 control room. The control rooms of Unit 2 and 3 will be administratively notified of the triggering by the Unit 1 control room.

Refer to subsection 3.7.4 and Table 3.2-1 for a description of the PVNGS instrumentation for earthquakes.

REGULATORY GUIDE 1.13: Fuel Storage Facility Design Bases (Revision 0, March 10, 1971)

RESPONSE

The position of Regulatory Guide 1.13 is accepted (refer to Sections 3.2.2 (Table 3.2-1), 3.5, 3.8, 4.2.5, 9.1 and 9.4, and 11.5.1.2 for descriptions).

REGULATORY GUIDE 1.14: Reactor Coolant Pump Flywheel Integrity (Revision 0, October 27, 1971)

RESPONSE

Refer to 5.1.4 and 5.4.1.

REGULATORY GUIDE 1.15: Testing of Reinforcing Bars for Category I Concrete Structures (Revision 1, December 28, 1972)

RESPONSE

The position of Regulatory Guide 1.15 is accepted (refer to section 3.8).

REGULATORY GUIDE 1.16: Reporting of Operating Information (Revision 1, October 1973)

RESPONSE

The guidance in Regulatory Guide 1.16, Revision 1, for reporting operating information has been superseded by changes to NRC regulations and PVNGS Technical Specifications and Technical Requirements Manual (TRM) (the TRM contains reporting requirements that were relocated from the Technical Specifications). Therefore, reporting of operating information

will be in accordance with current NRC regulations and PVNGS Technical Specifications and TRM.

REGULATORY GUIDE 1.17: Protection of Nuclear Power Plants Against Industrial Sabotage (Revision 1, June 1973)

RESPONSE

The position of Regulatory Guide 1.17 is accepted with the following exception to ANSI N18.17-1973 regarding employee screening.

Section 4.3 of ANSI N18.17-1973 addresses employee screening. Section 4.3 has become obsolete with the promulgation of 10CFR73.56, "Personnel Access Authorization Requirements for Nuclear Power Plants." APS complies with the requirements of 10CFR73.56 as described in the PVNGS Security Plan, rather than Section 4.3 of ANSI N18.17-1973. Reference 13.6.2.

REGULATORY GUIDE 1.18: Structural Acceptance Test for Concrete Primary Reactor Containments (Revision 1, December 28, 1972)

RESPONSE

Regulatory Guide 1.18 established a systematic approach to testing wherein quantitative information is obtained concerning structural response to pressurization. The following interpretations of Regulatory Guide 1.18 are provided:

A. Position C.2

The number and distribution of measuring points for monitoring radial deflection is selected so that the as-built condition can be considered in the assessment of roundup, buttress-shell interaction, and general shell response. Measurements are made at points similar to those shown in Chapter 9 of BC-TOP-5-A. However, to obtain the most significant data, the measuring point locations may be changed to those where the as-built containment is at the limit of tolerances if such points exist. Accordingly, an arbitrary selection of measurement points is not intended.

B. Position C.5

This containment structure is not a prototype. Therefore, this paragraph is not applicable.

C. Position C.9

Structural integrity testing is scheduled for periods when extremely inclement weather is not forecast. Should, despite the forecast, snow, heavy rain, or strong wind occur during the test, the test results will be considered valid unless there is evidence to indicate otherwise.

D. Position C.10

Any test will be continued, without a restart at atmospheric pressure, unless the structural response deviates significantly from that expected.

E. Position C.12

A description of structural tests will be submitted at a time to permit suitable review. Paragraph 3.8.1.7.1 provides a general description of the planned tests. Information on previous structural testing is contained in Chapter 9 of BC-TOP-5-A.

F. Appendix A

The containment has no prototypal features. Therefore, this appendix is not applicable.

Reference 3.8.1.7.1, 3.8.1.2.3, 14.2.7, and 14A.4.

REGULATORY GUIDE 1.19: Nondestructive Examination of Primary Containment Liner Welds (Revision 1, August 11, 1972)

RESPONSE

Nondestructive examination of primary containment liner welds is conducted in accordance with the procedures described in Regulatory Guide 1.19 except as noted herein.

A. Position C.1.b

Where radiography is not feasible, the full-length of the liner seam weld is examined by the magnetic particle or

liquid penetrant method in accordance with the methods and techniques of Section V of the ASME Boiler and Pressure Vessel Code. Since surface examination by the magnetic particle method is permitted by the Regulatory Guide 1.19, the liquid penetrant method is specified as an alternative since the two methods are considered comparable by ASME Section III, Division 1, 1974 Edition and Summer 1974 Addenda.

B. Position C.2.a

All welds in penetrations, airlocks, and access openings not backed by concrete are fully examined in accordance with NE 5200 of Section III, Division 1, 1974 Edition of the ASME Boiler and Pressure Vessel Code, Summer 1974 Addenda.

C. Position C.7

Acceptance standards for radiography, magnetic particle, and liquid penetrant examination are specified in NE 5300 of Section III, Division 1, 1974 Edition of the ASME Boiler and Pressure Vessel Code, Summer 1974 Addenda.

D. Positions C.8 and C.9

These procedures are complied with except as noted in the preceding paragraphs.

Reference 3.8.1.2.3 and 3.8.1.6.7.4.

REGULATORY GUIDE 1.20: Vibration Measurements on Reactor Internals (Revision 0, December 29, 1971)

RESPONSE

Refer to 3.9.2.4, 14.2.7, and 14A.3.

REGULATORY GUIDE 1.21: Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants (Revision 1, June 1974)

RESPONSE

The position of Regulatory Guide 1.21 is accepted (refer to section 11.5). Additional references: 4.2.5, 9.3.2.1, 12.3.4, and 12.5.1.3.

REGULATORY GUIDE 1.22: Periodic Testing of Protection System Actuation Functions (Revision 0, February 17, 1972)

RESPONSE

The position of Regulatory Guide 1.22 is accepted (refer to subsections 7.1.2 and 8.3.1). Also see 7.2.1.1.9, 7.2.2.3.3, 7.3.1, 7.3.2.3.3, and 7.3.5.1.17.

REGULATORY GUIDE 1.23: Onsite Meteorological Programs (Revision 0, February 17, 1972)

RESPONSE

The position of Regulatory Guide 1.23 is accepted (refer to section 2.3). Additional references: 18.III.A.1.1.

REGULATORY GUIDE 1.24: Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water Reactor Radioactive Gas Storage Tank Failure (Revision 0, March 23, 1972)

RESPONSE

The position of Regulatory Guide 1.24 is accepted (refer to section 15.7 and 5.1.4).

REGULATORY GUIDE 1.25: Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors (Revision 0, March 23, 1972)

RESPONSE

PVNGS deviates from Regulatory Guide 1.25 to allow use of 'peak assembly average fuel pin pressure is < 1200 psig' in place of 'maximum fuel rod pressurization is 1200 psig'. This approach allows a few fuel rods to exceed the 1200 psig maximum pressurization while still maintaining the conservative iodine DF value specified by Regulatory Guide 1.25. This deviation is

acceptable due to the overall conservatisms associated with analyzing the fuel handling accident. This deviation can not be used for fuel that incorporates zirconium diboride pellet coatings (i.e., integrated fuel burnable absorber (IFBA)).

Refer to section 15.7, 1.9.2.4.5, and 9.1.4.6.

REGULATORY GUIDE 1.26: Quality Group Classification and Standards for Water, Steam and Radioactive-Waste-Containing Components of Nuclear Power Plants (Revision 1, September 1974)

RESPONSE

For operational phase activities, PVNGS identifies conformance to the regulatory positions of Regulatory Guide 1.26 (including any exceptions or clarifications) in the PVNGS Operations Quality Assurance Program Description.

REGULATORY GUIDE 1.27: Ultimate Heat Sink for Nuclear Power Plants (Revision 2, January 1976)

RESPONSE

The position of Regulatory Guide 1.27 is accepted (refer to subsections 9.2.5, 9.1.3, 9.2.1.1, and 3.1.40).

REGULATORY GUIDE 1.28: Quality Assurance Program Requirements (Design and Construction)

RESPONSE

For operational phase activities, PVNGS identifies conformance to the regulatory positions of Regulatory Guide 1.28 (including any exceptions or clarifications) in the PVNGS Operations Quality Assurance Program Description.

REGULATORY GUIDE 1.29: Seismic Design Classification

RESPONSE

For operational phase activities, PVNGS identifies conformance to the regulatory positions of Regulatory Guide 1.29 (including any exceptions or clarifications) in the PVNGS Operations Quality Assurance Program Description.

REGULATORY GUIDE 1.31: Control of Ferrite Content in Stainless Steel Weld Metal (Revision 3, April 1978)

RESPONSE

The recommendations of Regulatory Guide 1.31 are followed for non-NSSS ESF components except as noted below:

The delta-ferrite determination method specified in Part C is not met. Austenitic stainless steel welding filler materials used in the fabrication and installation of ASME Section III, Class 1, 2, and 3 components are controlled to deposit from 8 to 25% delta-ferrite except for 309 and 309L welding filler materials which are controlled to deposit from 5 to 15% delta-ferrite and are used when welding carbon or low alloy steel to austenitic stainless steel. Welding filler material 309L is

used further for the overlay deposit on the carbon or low alloy steel component nozzles or connecting pipe when postweld treatment is required. Meaningful control of delta-ferrite content is based on chemical analysis of the welding filler material to assure that there is an adequate margin above the minimum required to prevent fissuring. Delta-ferrite content of procedure qualification welds is determined by chemical analysis in accordance with ASME Code, Section III, Division 1, 1974 Edition, Paragraph NB-2433, instead of by magnetic measurement devices called for in Paragraph C.1. Since austenitic stainless steel welding materials are controlled to deposit 8 to 25% delta-ferrite based on chemistry, except for 309 and 309L welding materials, which are controlled to deposit 5 to 15% delta-ferrite based on chemistry, magnetic measurement of production welds required by Paragraph C.1 is not necessary to assure satisfactory delta-ferrite content. Reference 5.1.4, 5.1.5, 5.4.7, 5.2.3, 4.2.1, 4.2.5, 6.3.1, 6.1.1.1.4, 6.5.2.8, 9.1.4.6, 9.3.4, and 10.3.6.2.

REGULATORY GUIDE 1.32: Use of IEEE STD 308-1971, Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations (Revision 0, August 11, 1972)

RESPONSE

The position of Regulatory Guide 1.32 is accepted (refer to subsections 8.2.1.3 and 8.3.1). In addition, for a discussion of compliance with IEEE Standard 308-1974, refer to section 8.3.

REGULATORY GUIDE 1.33: Quality Assurance Program Requirements (Operation)

RESPONSE

For operational phase activities, PVNGS identifies conformance to the regulatory positions of Regulatory Guide 1.33 (including any exceptions or clarifications) in the PVNGS Operations Quality Assurance Program Description.

REGULATORY GUIDE 1.34: Control of Electroslag Weld Properties (Revision 0, December 28, 1972)

RESPONSE

Refer to 5.2.3.3.2.2. Additional references: 4.2.5, 5.1.4, and 5.4.7.1.

REGULATORY GUIDE 1.35: Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures (Revision 1, June 1974)

RESPONSE

The inservice inspection requirements and positions described in Regulatory Guide 1.35 are now covered by ASME Code Section XI, Subsection IWL, 1992 Edition with the 1992 Addenda, as modified and supplemented by 10 CFR 50.55a. The design considerations discussed in this regulatory guide shall remain applicable.

The reportable conditions are detailed in 10 CFR 50.55a do not require prompt notification as described in Regulatory Guide 1.16, Regulatory Position c.2.a. In addition to the ISI Summary Report requirements described in 10 CFR 50.55a, any reportable condition detected during surveillance testing and inservice inspections shall be reported to the NRC as described in the PVNGS Technical Requirements Manual.

REGULATORY GUIDE 1.36: Nonmetallic Thermal Insulation for Austenitic Stainless Steel (Revision 0, February 23, 1973)

RESPONSE

The position of Regulatory Guide 1.36 is accepted (refer to section 6.1). Also see 5.2.3.2.3. Additional References: 6.3.1, 6.5.2, 4.2.5, 5.1.4, 5.1.5, 5.4.7, 5.2.3.4.1.2.2, and 9.3.4.

REGULATORY GUIDE 1.37: Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants

RESPONSE

For operational phase activities, PVNGS identifies conformance to the regulatory positions of Regulatory Guide 1.37 (including any exceptions or clarifications) in the PVNGS Operations Quality Assurance Program Description.

REGULATORY GUIDE 1.40: Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants (Revision 0, March 16, 1973)

RESPONSE

Regulatory Guide 1.40 is not applicable to PVNGS as there are no safety-related, continuous-duty motors installed inside the containment. Reference 3.11.2, 7.1.2.18, 8.3.1.2.2.9, and 8.3.2.2.1.8.

REGULATORY GUIDE 1.41: Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments (Revision 0, March 16, 1973)

RESPONSE

The position of Regulatory Guide 1.41 is accepted (refer to subsection 8.3.1 and section 14.2). Additional References: 8.3.2.2.1.9 and 14A.19.

REGULATORY GUIDE 1.42: Withdrawn.

REGULATORY GUIDE 1.43: Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components (Revision 0, May 1973)

RESPONSE

For ASME Section III, Class 1, 2, and 3 components, the restrictions of Paragraph C.1.a of Regulatory Guide 1.43 are

observed. The remaining requirements of Regulatory Guide 1.43 are complied with when "high-heat-input" welding processes such as submerged-arc welding (SAW) and gas metal-arc welding (GMAW) are used by Bechtel suppliers to clad SA-508, Class 2 forgings or to plate material of equivalent composition. Regulatory Guide 1.43 is not complied with when "low-heat-input" welding processes such as shielded metal-arc welding (SMAW) and gas tungsten-arc welding (GTAW) are used in the field by Bechtel or Bechtel subcontractors to clad completed welds and adjacent SA-508, Class 2 material during installation. It is noted in Part B of Regulatory Guide 1.43 that underclad cracking has not been observed in SA-508, Class 2 material welded with the "low-heat-input" processes.

(Also see 5.2.3.3.2.1.) Additional references: 4.2.5 and 5.1.4.

REGULATORY GUIDE 1.44: Control of the Use of Sensitized Stainless Steel (Revision 0, May 1973)

RESPONSE

Refer to 5.2.3.4.1.1.1 for components within the C-E scope of supply. Additional references: 4.2.5, 5.1.4, 5.1.5, 5.4.7, 6.1.1.1.3.1, 6.3.1, 6.5.2, 9.1.4.6, 9.3.4, and 10.3.6.2.

For components within the Bechtel scope of supply, the position of Regulatory Guide 1.44 is accepted, except as indicated below:

Additional tests specified in Paragraph C.3 of Regulatory Guide 1.44 to verify the nonsensitization of the material will

not be performed for each different heat treatment practice and each material heat. All austenitic stainless steels are furnished in accordance with applicable ASME or ASTM material specifications. Testing to determine susceptibility to intergranular attack is performed when required by the ASME or ASTM material specification. Austenitic stainless steel exposed to temperatures in the range of 800 to 1500F during hot forming are solution heat-treated in accordance with the ASME or ASTM material specification after completion of hot forming. Certified materials test reports are checked upon receipt of the material to ensure that all requirements of the material specification have been met.

Intergranular corrosion testing specified in Paragraph C.6 of Regulatory Guide 1.44 is not performed on a routine basis.

Welding practices are controlled to avoid severe sensitization as follows:

A. Weld Heat Input

Weld heat input is controlled during field installation by using SMAW and GTAW processes only, and limiting the size of electrodes for each process to 5/32 inch and 1/8 inch diameter maximum, respectively.

In addition to the above two processes, suppliers and subcontractors are permitted to use automatic submerged-arc welding (ASAW) and GMAW. When ASAW or GMAW is used, or SMAW or GTAW is used with electrodes larger than those specified above, testing in

accordance with ASTM A262, Practice A or E, is required unless welding is followed by solution heat treatment.

B. Interpass Temperature

The interpass temperature is controlled to not exceed 350F.

C. Carbon Content

Susceptibility to sensitization is reduced significantly by selecting material with the lowest reported carbon content.

D. Solution Heat Treatment

Solution heat treatment in accordance with the material specification, although not required after welding, is permitted in order to avoid severe sensitization.

Severe sensitization is avoided by not permitting heat treatment in the temperature range of 800 to 1500F following welding. This requires a special technique when welding stainless safe ends (transition pieces) to carbon or low alloy steel component nozzles or piping. Specifically, a low carbon steel or Inconel weld overlay is deposited on the component and the component is postweld heat-treated. Following final postweld heat treatment of the component, the stainless steel safe end is welded to the weld overlay using welding materials to match the overlay.

Since severe sensitization is avoided, testing to determine susceptibility to intergranular attack is not performed.

REGULATORY GUIDE 1.45: Reactor Coolant Pressure Boundary Leakage Detection Systems (Revision 0, May 1973)

RESPONSE

The position of Regulatory Guide is accepted, except for the following:

A. Position C.5 states that each method of detection should have the capability of detecting leak rates of 1 gpm within 1 hour. The airborne particulate and airborne gaseous monitoring methods are capable of identifying leakage conditions, but are not used for quantifying that leakage. Procedures are available that instruct operators to perform a water inventory balance upon alarm or increasing trend of activity (refer to subsection 5.2.5). Additional references: 5.1.4, 5.1.5, 5A.3, 9A.34, 11.5.1.1.1, and 11.5.2.1.3.13.

B. Position C.4 states that the methods used to detect reactor coolant pressure boundary (RCPB) leakage to connecting systems "should include radioactivity monitoring and indicators to show abnormal water levels or flow in the affected area." As described in subsection 5.2.5.4, leakage past two shutdown cooling isolation valves in series would discharge through the Low Temperature Over-Pressure (LTOP) safety relief valves in the containment recirculation sumps. Given the capacity of the recirculation sump, this leakage would not be detected by level monitoring

instrumentation in the radwaste sumps. As an alternative to Position C.4, small leakage through this pathway would be detected by radiation monitoring and periodic RCS water inventory balance, not by level or flow indication. This is conservative because, unless such leakage could be quantified locally by containment entry, the leak rate would be applied to the unidentified leakage limit as opposed to the less restrictive identified leakage limit. In addition, a temperature indicator in the recirculation sump provides indication of large-scale leakage.

REGULATORY GUIDE 1.46: Protection Against Pipe Whip Inside Containment (Revision 0, May, 1973)

RESPONSE

Except as discussed below, protection against pipe whip inside the containment complies with Regulatory Guide 1.46. (For additional information refer to Section 3.6.2.1.1.2).

A. Position C.1.b

Intermediate break locations between terminal ends are postulated to occur at weld joints where the piping incorporates a fitting, valve, or welded attachment where the following are met (as specified in NRC Branch Technical Position MEB 3-1):

1. The stress range Sn exceeds 2.4 Sm, where Sm is the design stress intensity as defined in Section III of the ASME Code, or

2. The stress range S_n as calculated by Equation 10 of Paragraph NB-3653 exceeds 2.4 S_m and the stresses computed by Equations 12 and 13 of Paragraph NB-3653 are greater than 2.4 S_m, or

3. If fatigue analysis is performed, any intermediate location between terminal ends where the cumulative usage factor under loading associated with operational plant conditions and an operating basis earthquake (OBE) exceed 0.1 of the code allowable.

B. Position C.2.b

Intermediate break locations between terminal ends are selected where either the circumferential or longitudinal stress associated with specified seismic events and operational plant conditions exceeds 0.8 ($1.2S_h + S_A$) in accordance with NRC Branch Technical Position MEB 3-1. Also see 3.6.2.5.2.1.

C. Position C.3

1. Circumferential breaks are not postulated at locations where circumferential stress range is at least one and one-half times the axial stress range in accordance with NRC Branch Technical Position MEB 3-1.

2. Longitudinal breaks are not postulated at locations where axial stress range is at least one and one-half times the circumferential stress

range in accordance with NRC Branch Technical Position MEB 3-1.

Reference 3.8.1.2.3, 3.8.3.2.2, 4.2.5, 5.1.4, 5.4.7.1, and 6.3.1.3.

REGULATORY GUIDE 1.47: Bypassed and Inoperable Status Indication for Nuclear-Power Plant Safety Systems (Revision 0, May 1973)

RESPONSE

Refer to section 7.5 and 7.1.2.19. Additional references: 3.11.4, 5.1.4, 7.1.1.3, 7.1.2.19, 8.3.1.2.2.11, and 8.3.2.2.1.10.

REGULATORY GUIDE 1.48: Design Limits and Loading Combinations for Seismic Category I Fluid System Components (Revision 0, May 1973)

RESPONSE

The position of Regulatory Guide 1.48 is accepted with the following interpretations:

A. Load Combinations

Since neither the code (ASME Section III) nor Regulatory Guide 1.48 are explicit with regard to delineation of the actual loads to be combined under each plant operating condition, a position has been developed (refer to tables 3.9-5 and 3.9-6) which

reflects the intent of both the code and Regulatory Guide 1.48.

B. Stress Limits

ASME Section III, Code Cases 1606-1, 1607-1, 1635-1, and 1636-1, are utilized to establish stress limits for Class 2 and 3 components as an alternate to Regulatory Guide 1.48.

C. Operability

Regulatory Guide 1.48 requires that the operability of safety-related components be demonstrated without specifying how this shall be accomplished. This FSAR addresses in detail the methods used to ensure the operability of the safety-related components (refer to section 3.9). Also see CESSAR Section 1.8.

Additional references: 3.10.3, 4.2.5, 5.1.4, 5.4.7, 6.3.1.3, and 9.3.4.6.

REGULATORY GUIDE 1.49: Power Levels of Nuclear Power Plants (Revision 1, December 1973)

RESPONSE

Refer to section 1.1.4.

REGULATORY GUIDE 1.50: Control of Preheat Temperature for Welding of Low-Alloy Steel (Revision 0, May 1973)

RESPONSE

Refer to section 5.2.3.3.2.1. Additional references: 4.2.5, 5.1.4, 5.4.7.1, and 10.3.6.2.

In addition, for Bechtel and Bechtel suppliers the preheat for welding of low alloy steel is controlled in accordance with Regulatory Guide 1.50, except as described below:

A. Position C.1.a is complied with when impact testing, in accordance with ASME Boiler and Pressure Vessel Code, Section III, Subarticle 2300, is required.

   The maximum interpass temperature shall be 500F unless otherwise specified. When impact testing is not required, specification of a maximum interpass temperature in the welding procedure is not necessary in order to assure that the required mechanical properties are met. The minimum preheat temperatures of Appendix D of section III of the ASME Boiler and Pressure Vessel Code are required to be et regardless of whether impact testing is required or not.

B. Position C.1.b is not complied with since the welding procedure qualification of Section III and Section IX of the ASME Code are considered to be more than adequate.

C. Compliance with Position C.2 is not necessary for any Class 1, 2, or 3 component within the Bechtel scope of supply.

Current usage of low alloy steel in piping, pumps, and valves is minimal and is normally limited to Class 3 construction. When low alloy steel piping, pumps, and valves are used, preheat is maintained until welding is complete, but not until postweld heat treatment (PWHT) is performed, since the conditions which cause delayed cracking in the weld or heat affected zone (HAZ) are not present. Liquid penetrant or magnetic particle examination required by ASME Section III, Division 1, is capable of detecting cold cracking and this examination is required by ASME Section III, Division 1, to be performed after postweld heat treatment.

Experience has shown that delayed cracking due to hydrogen embrittlement is not a problem when the surface to be welded is dry. The preheat temperatures of Appendix D of ASME Section III, Division 1, are maintained during welding and low hydrogen electrodes are used which are packaged and stored so that the very low moisture contents are maintained until the electrodes are consumed.

D. Position C.4 is complied with when the positions stated in C above and section 5.2.3.3.2.1 are not met.

REGULATORY GUIDE 1.51: Withdrawn. Now covered by ASME Code Section XI. Refer to section 6.6.

REGULATORY GUIDE 1.52: Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants.
(Revision 2, March 1978)

RESPONSE

Regulatory Guide 1.52 applies to the control room essential ventilation system and the fuel building essential ventilation system.

Exceptions are taken to applicable portions of Regulatory Guide 1.52 in response to NRC Generic Letter 83-13, Clarification of Surveillance requirements for HEPA Filters and Charcoal Adsorber Units in Standard Technical Specifications of ESF Cleanup Systems, and NRC Generic Letter 99-02, Laboratory Testing of Nuclear-Grade Activated Charcoal (APS Letter #102-04373). Exception to applicable portions of Regulatory Guide 1.52 is taken in reference to using ANSI N509-1980 in place of ANSI N509-1976 and using ANSI N510 1980 in place of ANSI N510-1975.

Except as indicated below, including the general exception statements above, the design, testing and maintenance criteria for the above mentioned essential ventilation systems, commonly referred to as nuclear air treatment systems (NATS), comply with Regulatory Guide 1.52, Revision 2, March 1978.

A. Position C.1.b

For the control room essential ventilation system (CREVS), the postulated DBA is the design basis LOCA.

For the fuel building essential ventilation system operating in the fuel building essential ventilation actuation signal (FBEVAS) mode as the fuel building essential ventilation system (FBEVS), the postulated DBA is the design basis fuel handling accident.

For the fuel building essential ventilation system operating in the safety injection actuation signal (SIAS) mode as the pump room exhaust air cleanup system (PREACS), the postulated DBA is the design basis LOCA.

B. Position C.2.a

For the control building essential ventilation system, no mist eliminator nor electric heater is required upstream of the filters to limit relative humidity. Only approximately 4% of the total system capacity is drawn in from outside. The remaining fraction is recirculated air from the main control room, which is controlled to a relative humidity below 50% and thus the return air is below 70%.

For the fuel building essential ventilation system, demisters are not provided. Due to the low air velocity, water is not carried in the air stream.

C. Position C.2.c

The drain lines from the fuel building and auxiliary building essential air filtration units, and from the control building essential air handling units, are designated as Quality Class R and Seismic Category IX. An evaluation of these drain lines has identified that they are structurally equivalent to Seismic Category I and will maintain their structural integrity during and after a safe shutdown earthquake.

D. Position C.2.d

No significant pressure surges are foreseen for these systems during or following the postulated DBAs; thus, no special protective devices are needed.

E. Position C.2.f

The particulate filter banks of the control room nuclear air treatment system are arranged 5 wide by 6 high. A floor has been installed between the third and fourth level of the filters.

F. Position C.2.g

There are no Class 1E alarms associated with the control room and fuel building essential ventilation systems nor are there any recorders for pressure drops or flowrates.

Alarm status information is, however, logged in the plant computer. The annunciated and alarm status information is available in the main control room via the alarm display/computer log for pertinent pressure drops in these systems. The alarm is both visual and audible and no operator action is required to retrieve the alarm status from the computer.

Pertinent pressure drops are measured (ΔP indicators) across each section of the filter unit and across the entire filter unit itself. Both high- and low-pressure drop alarms are generated and provided in the main control room. A high-pressure drop alarm is indicative of high filter loading. A low-pressure drop alarm is indicative of a zero or low flow condition. Since the filter unit blower and blower motor are single speed devices, operation of the unit with no alarms present indicates delivery of rated flow to the filter unit. Pressure drop information is also indicated locally.

G. Position C.2.j

The filter unit Curie loading following a postulated DBA will consist mostly of short-lived isotopes. Credit will be taken for decay time to achieve permissible handling levels prior to workers removing components. Consequently, filter trains are not designed for intact removal. The charcoal adsorber section is designed to keep operator exposure as low as reasonably achievable during charcoal bed replacement.

The change out process involves only a few operator actions for hookup.

H. Position C.3.e

Upstream mounting of filters may be employed in some cases. Corrosion-resistant steel or carbon steel coated with inorganic nuclear grade paint will be used for construction of filter and adsorber mounting frames.

I. Position C.3.i

The activated carbon, when new, will be provided to meet the requirements of Regulatory Guide 1.52, Revision 2, March 1978, except using the physical property specifications of Table 5.1 of ANSI N509-1980 in place of Table 5.1 of ANSI N509-1976.

Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to NRC Generic Letter 99-02, APS Letter #102-04373).

J. Position C.3.k

There are no ESF filter units where the carbon bed temperature can exceed 200F following a postulated DBA as a result of loss of air flow.

K. Position C.3.o

Air straightening devices are installed only if tests indicate that uniform air flow distribution is not achieved.

L. Position C.4.a

Vacuum breakers would be of minimal assistance in opening doors to units during fan operation. The use of vacuum breakers creates potential leakage paths.

Units which operate at higher pressure than external pressures; i.e., push-through units, do not require vacuum breakers.

M. Position C.4.b

Accessibility for ease of maintenance is provided by removing opposing filters in opposite directions. The standard suggested distance of 3 feet plus length of component for removal of filters is met.

N. Position C.4.c

Piping associated with manifolding could result in plate-out of components of the sampled gas stream, leading to erroneous test results. The test probes are located in readily accessible locations with a minimum of piping, but are not manifolded.

O. Position C.4.d

Each atmosphere cleanup train will be operated per the required Surveillance Frequency listed in the Surveillance Frequency Control Program. There is not expected to be any moisture buildup on the absorbers and HEPA filters due to the low humidity at PVNGS.

P. Position C.5.a

Visual inspection of the ESF atmospheric cleanup system and all associated components will be done in accordance with Position C.5.a of Regulatory Guide 1.52, Revision 2, and using ANSI N510-1980 in place of ANSI N510-1975.

However, inspection criteria specific to each system will be developed to accommodate the uniqueness of each system.

Q. Position C.5.b

The air flow distribution test for the HEPA filter and iodine adsorbers will be tested in accordance with ANSI N510-1980 in place of ANSI Ns510-1975.

R. Position C.5.c

The in-place DOP test for HEPA filters will be done in accordance with Position C.5.c of Regulatory Guide 1.52, Revision 2, and using ANSI N510-1980 in place of ANSI N510-1975.

In-place filter testing will not be performed following painting, fire, or chemical release in a ventilation zone communicating with the system unless it has been evaluated that the event had the potential to adversely affect the integrity of the filters.

The in-place testing penetration acceptance criterion for penetration will be less than or equal to 1.0% in place of 0.05%. (Reference NRC Generic Letter 83-13).

If not removed during welding activities, the filters and adsorber section will be protected/isolated from the affects of the process.

Silicone sealant may be used to seal electrical and piping penetrations into filter housings. Use of silicone sealants will be within the manufacturer's recommended guidelines.

S. Position C.5.d

The activated carbon adsorber section will be leak-tested in accordance with Position C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and using ANSI N510-1980 in place of ANSI N510-1975.

The in-place testing penetration acceptance criterion for penetration will be less than or equal to 1.0% in place of 0.05%. (Reference NRC Generic Letter 83-13).

Airflow through the unit will not be maintained to remove the residual refrigerant gas.

In-place filter testing will not be performed following painting, fire, or chemical release in a ventilation zone communicating with the system or following the removal of adsorber carbon samples unless it has been evaluated that the event had the potential to adversely afect the integrity of the filters.

T. Position C.6.a

The laboratory testing criteria for testing a representative carbon absorber sample will be in

accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. Test acceptance criteria is derived by using the assigned activated carbon decontamination efficiency of 95% for organic iodide per Regulatory Guide 1.52, Revision 2, March 1978, Table 2, and imposing a safety factor of 2. This results in the test acceptance criteria of a methyl iodide penetration of less than or equal to 2.5%. (In response to NRC Generic Letter 99-02, APS Letter #102-04373).

New activated carbon will meet the physical property specifications given in Table 5.1 of ANSI N509-1980, in place of Table 5.1 if ANSI N509-1976.

U. Position C.6.b

The number of samplers (sample stations) is not sufficient to last throughout the expected adsorbent life. Therefore, when depleted, they will be refilled from a composite sample taken from the absorber by means of a grain-thieving device.

The design of the samplers should be in accordance with the provisions of Appendix A of ANSI N509-1980 in place of ANSI N509-1976.

A representative carbon sample of the adsorber will be obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, using Appendix A of ANSI N509-1980 in place of Appendix A of ANSI N509-1976. However, a thieving device other than

a slotted tube sampler may be used when extracting carbon from the absorber section.

Laboratory tests of representative samples will be conducted in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity (In response to NRC Generic Letter 99-02, APS Letter #102-04373). As such, the representative sample media will not experience the test gas flow in the same direction as the flow during service conditions, as it will have been homogeneously mixed and fed into the test appratus. Therefore, it will be taken out of its orginal test canister (or, thieved directly from the absorber bed) and transferred into an airtight container until at which time it is prepared for the laboratory test.

The activated carbon adsorber section should be replaced with new unused activated carbon meeting the physical property specifications of Table 5.1 of ANSI N509-1980 in place of Table 5.1 of ANSI N509-1976 if (1) laboratory test results indicate a methyl iodide penetration greater than 2.5%, or (2) no representative sample is available for testing.

V. Table 2

The laboratory testing criteria for testing a representative carbon adsorber sample will be in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. Test acceptance

criteria is derived by using the assigned activated carbon decontamination efficiency of 95% for organic iodide, per Regulatory Guide 1.52, Revision 2, March 1978, Table 2, and imposing a safety factor of 2 on such effciency. This results in the test acceptance criteria of a methyl iodide penetration of less than or equal to 2.5%. (In response to NRC Generic Letter 99-02, APS Letter #102-04373).

The activated carbon, when new, will be provided to meet the requirements of Regulatory Guide 1.52, Revision 2, March 1978, except using the physical property specifications of Table 5.1 of ANSI N509-1980 in place of Table 5.1 of ANSI N509-1976. Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to NRC Generic Letter 99-02, APS Letter #102-04373).

Testing of adsorber samples should be performed (1) initially, (2) once every refueling cycle, (3) when certain events occur and have been evaluated that it could adversely affect the ability of the carbon to perform its intended function, and (4) following a defined period of continuous essential or ESF system operation. (In response to NRC Generic Letter 99-02, APS Letter #102-04373).

References: 3.4, 3.6, 6.4, 6.5.1, 6A.6, 9.4.5.2.2.1, 9.B.3.1, Table 9.B.3-1, 12.3.3.3, 14.2.7, 14B, and 18.III.

REGULATORY GUIDE 1.53: Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems (Revision 0, June 1973)

RESPONSE

The position of Regulatory Guide 1.53 is accepted (refer to section 7.1.2). Additional references: 7.3.5.1.18, 6.3.1.3, 8.3.1.2.2.12, and 8.3.2.2.1.11.

REGULATORY GUIDE 1.54: Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

RESPONSE

PVNGS identifies conformance to the regulatory positions of Regulatory Guide 1.54 (including any exceptions or clarifications) in the PVNGS Operations Quality Assurance Program Description.

REGULATORY GUIDE 1.55: Concrete Placement in Category I Structures (Revision 0, June 1973)

RESPONSE

Except as discussed below, concrete is placed in Category I structures in accordance with Regulatory Guide 1.55.

Creep tests are normally performed on prestressed structures only. Loss of prestress through creep is not applicable to

nonprestressed structures. Reference section 3.8.1.2.3, 3.8.1.6, and 3.8.3.2.2.

REGULATORY GUIDE 1.56: Maintenance of Water Purity in Boiling Water Reactors (Revision 0, June 1973)

RESPONSE

Not applicable.

REGULATORY GUIDE 1.57: Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components (Revision 0, June 1973)

RESPONSE

Not applicable. Each PVNGS unit utilizes a prestressed concrete primary containment.

REGULATORY GUIDE 1.59: Design Basis Floods for Nuclear Power Plants (Revision 2, August 1977)

RESPONSE

The position of Regulatory Guide 1.59 is accepted (refer to subsection 2.4.2). Additional reference: 3.8.1.2.3.

REGULATORY GUIDE 1.60: Design Response Spectra for Seismic Design of Nuclear Power Plants (Revision 1, December 1973)

RESPONSE

The position of Regulatory Guide 1.60 is accepted (refer to subsection 3.7.1). Additional references: 2.5.2.6, 2A.5, 3.8.1.2.3, 3.8.3.2.2, 4.2.5, and 9.1.4.6.

REGULATORY GUIDE 1.61: Damping Values for Seismic Design of Nuclear Power Plants (Revision 0, October 1973)

RESPONSE

The position of Regulatory Guide 1.61 is accepted (refer to section 3.7) with the exception of the analysis and design of cable tray supports, and the evaluation of unrestrained piping uplift at support locations. The damping value for seismic design of cable tray supports is given in subsection 3.10.3. Increased damping values may be used, in some cases, for determining acceptability of unrestrained piping uplift at support locations (refer to paragraph 3.7.1.3). Additional references: 3.8.1.2.3, 3.8.3.2.2, 4.2.5, 5.1.4, 5.4.7.1, and 9.1.4.6.

REGULATORY GUIDE 1.62: Manual Initiation of Protective Actions (Revision 0, October 1973)

RESPONSE

The position of Regulatory Guide 1.62 is accepted (refer to subsection 7.1.2 and section 7.3). Also see section 7.1.2.21. Additional references: 7.2.1.1.1.11 and 8.3.1.2.2.13.

REGULATORY GUIDE 1.63: Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants (Revision 2, July 1978)

RESPONSE

The position of Regulatory Guide 1.63 is accepted as interpreted below:

The electric penetration assemblies conform to IEEE Standard 317-1976.

Consistent with the recommendations of Regulatory Guide 1.63, the electrical penetration assemblies are designed to withstand, without loss of mechanical integrity, the maximum fault current vs. time conditions that could occur as a result of single random failures of circuit overload devices. The following system features are provided to be consistent with this recommendation of Regulatory Guide 1.63:

A. Medium Voltage System (13.8 kV system)

For medium voltage circuits feeding loads in the containment, the circuit breaker associated with the load is backed up by the main bus feeder breaker. These breakers are provided in the normal course of auxiliary system design and are non-Class 1E. The penetration withstands the available fault current and time duration for the main bus feeder breaker. Primary protection is provided by the individual load circuit breaker. The primary and backup circuit breakers are each provided

with independent dc control power from two different non-Class 1E batteries so that the failure of either battery will not violate the single failure criteria.

B. 480V Load Center Systems

For 480V load center power circuits feeding loads in the containment, redundant protection is provided by a combination of a breaker and a fuse or two breakers. The individual load circuit breaker provides primary protection. The load center bus feeder breaker is not used for backup because of its high, long time current rating. Breaker trip units are direct acting.

C. 480V Motor Control Center Systems

For 480V motor control center circuits feeding loads in the containment, a second breaker in series with the primary breaker of each load is used. Credit is not taken for the motor control center main bus feeder breaker because its large rating relative to the individual load breaker ratings may not provide adequate protection against individual faults.

As in the case of the load center feeds, separate battery sources are not provided. Molded case circuit breakers have direct-acting trips.

D. Low Voltage Control Systems

For low voltage protection circuits connected in the containment, redundant protection is provided by a combination of two fuses, a combination of a breaker and a fuse, or two breakers in series where the circuit resistance does not limit the fault current to a level that does not damage the penetration.

E. Instrument Systems

The energy levels in the instrument systems are sufficiently low so that no damage can occur to the containment penetration.

The circuit overload protection system for electric penetration assemblies meets the single failure criterion set forth in IEEE Standard 279-1971.

The overload protection systems do not conform to the online testability, bypassing, or manual initiation criteria of IEEE 279-1971, since these criteria do not apply to these systems.

Reference 3.8.1.2.3, 3.11.2, 7.1.2.22, 8.3.1.2.2.14, and 8A.11.

REGULATORY GUIDE 1.65: Materials and Inspections for Reactor Vessel Closure Studs (Revision 0, October 1973)

RESPONSE

Refer to Section 5.3.1.7. Additional references: 4.2.5, 5.1.4, 5.3.1.3, and 9.1.4.

REGULATORY GUIDE 1.66: Withdrawn.

REGULATORY GUIDE 1.67: Installation of Overpressure Protection Devices (Revision 0, October 1973)

RESPONSE

Except as discussed below and in section 5.2.2, the installation of overpressure protection devices complies with Regulatory Guide 1.67. Additional reference: 5.1.4.

A. The specifications are applicable to open discharge, simple configurations of stack, nonwater seal and nonslug flow, relief or safety valves.

B. Position C.1 of Regulatory Guide 1.67 requires that the magnitude of the reaction force, the anticipated transient behavior, and the basis for their determination should be included in the design specification for the valve. Since all of the above are characteristic to each valve manufacturer, it is not current practice to stipulate these data. Rather, the manufacturer supplies that information after selection of the valve, orifice size, inlet and outlet OD, etc., to accommodate the flowrates required by the design specification. This manufacturer supplied information is then used in the design of the relief/safety valve, as discussed in paragraph 3.9.3.3.

REGULATORY GUIDE 1.68: Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors (Revision 0, November 1973)

RESPONSE

The positions and guidelines of Regulatory Guide 1.68 are accepted with the following exceptions and clarifications:

A. Power ascension tests will be conducted using power plateaus of 20%, 50%, 80%, and 100% instead of 25%, 50%, 75%, and 100% as recommended in Paragraph D.4 of Appendix A to Regulatory Guide 1.68.

B. Procedures will be available either 60 days prior to fuel load or 60 days prior to their scheduled use as recommended in Appendix B of Regulatory Guide 1.68 (Revision 2, August 1978, which is used in lieu of the Revision 0, November 1973). See subsection 14.2.11 for a further clarification of procedure availability.

C. Implementation of Regulatory Guide 1.68 is discussed in section 14.2. See 14.2.7 for additional exceptions and clarifications to Regulatory Guide 1.68.

REGULATORY GUIDE 1.68.2: Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants (Revision 1, July 1978)

RESPONSE

The position of Regulatory Guide 1.68.2 is accepted, except as follows:

Paragraph C indicates licensee should develop and conduct a test program for each unit. As the PVNGS units will be identical, testing on all units is unrealistic with the objectives of the test which are:

A. Verification that the plant can be shut down from outside the control room

B. Verification that the plant can be maintained in hot shutdown

C. Verification of cooldown capability.

Remote shutdown testing on the first unit will demonstrate the above objectives. Component and preoperational testing of following units and plant systems to be used in the remote shutdown panel will verify that they will function in the same manner as would be experienced on the first unit tested (see section 14.2).

REGULATORY GUIDE 1.68.3: Preoperational Testing of Instrument and Control Air Systems (Revision 0, April 1982)

RESPONSE

The position of Regulatory Guide 1.68.3 is accepted where applicable to the safety-related atmospheric dump valve nitrogen pressurization system. The PVNGS instrument air (IA)

system is not required for safe shutdown. There is no control air system. The design of the IA system is such that a malfunction cannot lead to failure of loads that are important to safety. The PVNGS design also precludes the inadvertent connection of poor quality air systems to loads that are important to safety since PVNGS has only one air system that supplies filtered, dry, oil-free compressed air for operation of pneumatic instruments and pneumatic actuators. The independent and separate service/breathing air system supplies oil-free compressed air to outlets throughout the plant for the operation of pneumatic tools and other service air requirements.* Reference 14.2.7.

(*) The IA system design has been modified per DMWO 3449152 to allow a cross-connection to the service air system, which contains poorer quality air. Local filters and an air dryer are provided for the cross-connection to ensure the necessary instrument air quality. The system no longer performs the function of providing breathing air.

REGULATORY GUIDE 1.69: Concrete Radiation Shields for Nuclear Power Plants (Revision 0, December 1973)

RESPONSE

The position of Regulatory Guide 1.69 is accepted (refer to section 12.3). Additional references: 3.8.1.2.3 and 3.8.3.2.2.

REGULATORY GUIDE 1.70: Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants – LWR Edition (Revision 3, November 1978)

RESPONSE

The original PVNGS FSAR content and format was specified by 10 CFR 50.34(b) and the position of Regulatory Guide 1.70 was accepted in that the required content was provided except as identified below. The recommended format also is followed, except when deviations were originally necessary to be consistent with CESSAR. These deviations followed the recommended format of Regulatory Guide 1.70, Revision 2.

Specific drawing revision numbers and dates were not identified in Tables 1.7-1 and 1.7-2, but were provided upon request. However, if the drawing is included in the UFSAR, they can be found on the drawing itself.

The requirement of Paragraph 13.1.1.3 of Regulatory Guide 1.70 to provide resumes of individuals already employed by the applicant to fulfill responsibilities identified in Item 3 of Section 13.1.1.1 was met by making these resumes available to the NRC by separate letter rather than including them in the FSAR.

The requirements of Sections 13.3 and 13.3.2 to consult Regulatory Guide 1.101, “Emergency Planning for Nuclear Power Plants,” were met by consulting NUREG-0654/FEMA-REP-1, Revision 1, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in

Support of Nuclear Power Plants.” This document superseded Regulatory Guide 1.101.

The requirements of Sections 3.10 and 3.11 of the Regulatory Guide to provide a list of equipment required to be environmentally and seismically qualified have been met by providing this information by separate letters to the NRC rather than including the information in the FSAR. The current list of equipment required to be environmentally and seismically qualified is controlled and maintained by the Equipment Qualification Program.

Regulatory Guide 1.181 is used to maintain the content of the UFSAR in accordance with 10 CFR 50.71(e). The references to RG 1.70 are being maintained for historical value.

References: 2.1.3.6, 2.2.2.2.4, 2.2.3.1.4, 2A.10, 4A.4, 12A.9, 12A.11, 12A.16, 14A.5, 15.0.1.1, and 17.1B.

<u>REGULATORY GUIDE 1.71</u>: Welder Qualification for Areas of Limited Accessibility (Revision 0, December 1973)

<u>RESPONSE</u>

The position of Regulatory Guide 1.71 is accepted with the following interpretations:

A. Position C.1.

For welds made under conditions of limited access as defined in Regulatory Position C.1 of Regulatory Guide 1.71, performance qualification to the applicable

requirements of ASME Sections III and IX are maintained with the additional requirement for selection and utilization of the more highly skilled welders for these applications as determined by responsible site supervisory personnel. Nondestructive examination requirements are determined by applicable codes, standards, specifications, and regulatory guides and any waiver or relaxation of either examination method or acceptance criteria for reasons of limited access is not permitted.

B. Position C.2.a

Requalification is required when any of the essential variables of ASME Section IX are changed or at any time the authorized inspector questions the ability of the welder to satisfactorily perform to the requirements of ASME Sections III or IX.

C. Position C.3

Production welding is monitored and welding qualifications are certified for the conditions described in the interpretations to Regulatory Positions C.1 and C.2.a.

Reference: 5.2.3.3.2.3. Additional references: 4.2.5, 5.1.4, and 10.3.6.2.

REGULATORY GUIDE 1.72: Spray Pond Plastic Piping (Revision 0, December 1973).

RESPONSE

Not applicable to PVNGS.

REGULATORY GUIDE 1.73: Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants (Revision 0, January 1974)

RESPONSE

The position of Regulatory Guide 1.73 is accepted (refer to section 3.11 and 7.1.2.22). Additional references: 5.1.4, 5.4.7.1, 6.2.4.2.2, 7.1.2.24, and 8.3.1.2.2.15.

REGULATORY GUIDE 1.75: Physical Independence of Electric Systems (Revision 1, January 1975

RESPONSE

The requirements of Regulatory Guide 1.75 are met, with the following clarifications and/or exceptions:

A. Isolation of non-Class 1E power circuits supplied by a Class 1E source is provided by a circuit interrupting device (circuit breaker) actuated by a safety injection actuation signal (SIAS), except for the circuits feeding the essential lighting system in the control room and remote shutdown panel, the backup supplies for the non-Class 1E instrument buses (E-NNN-D11, E-NNN-D12,

E-NNN-D15 and E-NNN-D16), and non-Class 1E valves XJ-CHN-UV501 and XJ-CHN-UV536. Class 1E regulating transformers with circuit limiting characteristics are provided as isolation devices to feed these non-Class 1E circuits of essential lighting. Two Class 1E interrupting devices connected in series with proper coordination are provided as isolation devices for the non-Class 1E valves. The two non-Class 1E instrument buses (E-NNN-D11 and E-NNN-D12) utilize Class 1E regulating transformers (E-NNA-V13 and E-NNB-V14) with current limiting characteristics to provide isolation of the devices. The non-Class 1E instrument buses (E-NNN-D15) and (2E-NNN-D16 and 3E-NNN-D16) utilize a non-Class 1E regulating transformer (E-NNN-V17, 2E-NNN-V18 and 3E-NNN-V18 respectively) with current limiting characteristics. These instrument buses however, are tripped on an SIAS signal and can be re-established manually after the sequential loading of the diesel generator. The non-Class 1E instrument bus (3E-NNN-D16) utilizes a non-Class 1E regulating transformer (3E-NNN-V18) with current limiting characteristics and two Class 1E interrupting devices connected in series with proper coordination to provide isolation of the instrument bus.

B. Isolation of control circuits is provided by photo isolators, relays, or operational amplifiers. The applied isolators provide isolation and separation between the Class 1E and nonsafety-related systems,

preventing degradation of the Class 1E system by any occurrence within the nonsafety system. Isolation of the diesel generators' nonsafety-related protective relay circuits from the Class 1E potential transformer circuits is provided with a single isolation fuse.

C. Associated power, control, and instrumentation cables which terminate on isolation devices are treated as Class1E through the isolation device to its outgoing terminals. Beyond this point, the cables lose their Class 1E preferential treatment. This precludes termination of associated circuits from redundant trains on a common device. Some associated circuit cables without isolation devices are uniquely identified as associated, per Regulatory Guide 1.75, and the identification scheme is in accordance with paragraph 7.1.3.16. In addition, some associated circuits are provided with two (redundant) isolation devices: i.e., fuses and/or circuit breakers. The identification of these cables is given in section 8.3.1.3.

The Safety Equipment Status System (SESS) described in section 7.5.2.6 provides by-passed and inoperable status indication of safety related equipment. The cables for this system are treated as described in section 8.3.1.3 and are color-coded as described in section 7.1.3.16. The channels of this system do not have isolation devices between them and the channels of the Class 1E equipment with which they are respectively

associated because, in accordance with IEEE 384-1974 as endorsed by Regulatory Guide 1.75, there exist within the SESS key subcomponents (which may include redundant fuses and/or circuit breakers) that prevent credible failures within the SESS from reducing the availability of the Class 1E equipment. These key subcomponents are maintained as Quality Class Q, although they are not safety-related and are not isolation devices as would be required by IEEE 384-1974.

D. Where the term "circuit" appears, it is construed to mean power, control, and instrumentation cables.

E. CEDM RSPT Type I and RSPT Type II circuits at the reactor head are run in flexible stainless steel conduits. Due to the configuration and proximity of control element assemblies, minimum separation requirement of 1 inch cannot be maintained.

F. A 1-inch separation exists between raceways and/or exposed cables of different separation groups prior to encircling a separation group raceway(s) and/or cable(s) with damage limiting barrier materials within areas deviating from standard Reg Guide 1.75 separation distances.

G. In instances where spatial constraints prevent non-Class 1E cables in totally enclosed raceways from maintaining a 1-inch minimum separation distance from Class 1E cables in totally enclosed raceways, analyses are performed demonstrating that failure of the non-

Class 1E cables will not prevent the proper functioning of the adjacent 1E circuits.

Further discussion pertaining to Regulatory Guide 1.75 is given in subsection 8.3.1.

For implementation of Regulatory Guide 1.75, refer to paragraphs 8.3.1.1.7 and 8.3.1.4. Additional references: 7.1.2, 7.1.4.19, 7.3.5.1.16, 8.1.4.2, 8.3.2.2.1.12, 8.3.6, 9A.84, and Table 9B.3-1.

REGULATORY GUIDE 1.76: Design Basis Tornado for Nuclear Power Plants (Revision 0, April 1974)

RESPONSE

The position of Regulatory Guide 1.76 is accepted (refer to paragraph 3.3.2.1) with the following exception:

A. Essential Spray Pond nozzles

Tornado missile protection is not provided for the essential spray pond nozzles because the loss of the unlimate heat sink safety function has been demonstrated by probabilistic risk assessment to be less than a median value of 10^-7 per reactor year or a mean value of 10^-6 per reactor year without missile protection (Ref. 5, Section 3.5.5).

Additional references: 2.3.1.2.2 and 3.8.1.2.3.

REGULATORY GUIDE 1.77: Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors (Revision 0, May 1974)

RESPONSE

The position of Regulatory Guide 1.77 is accepted with the following exceptions:

A. Position C, Item 3

The offsite dose consequences for the CEA ejection event are limited to 100% of 10 CFR Part 100 exposure guideline values.

B. Appendix A, Item 14

The number of failed fuel rods equals the number of rods that experience Departure from Nucleate Boiling (DNB), as calculated with a statistical convolution technique. The statistical convolution technique involves the summation, over the reactor core, of the number of fuel rods with a specific Departure from Nucleate Boiling Ratio (DNBR) value, multiplied by the probability of DNB at that DNBR value.

Additional references: 15.3.4.3.2, 15.4.8, and 15.6.5.2.3.

REGULATORY GUIDE 1.78: Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release (Revision 0, June 1974)

RESPONSE

The position of Regulatory Guide 1.78 is accepted (refer to section 6.4). Additional references: 2.2.2.2.2 and 2.2.3.1.3.

REGULATORY GUIDE 1.79: Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors (Revision 0, June 1974)

RESPONSE

The position of Regulatory Guide 1.79 is accepted with the exception that a hydraulic scale model test of the containment recirculation sump is performed in lieu of taking direct suction from this sump during recirculation tests (refer to subsection 6.2.2 and section 6.3). Also see Section 14.2.7. Additional references: 5.1.4, 5.4.7.1, and 6A.51.

REGULATORY GUIDE 1.80: Preoperational Testing of Instrument Air Systems (Revision 0, June 1974)

RESPONSE

Regulatory Guide 1.80 has been withdrawn and has been replaced by Regulatory Guide 1.68.3, "Preoperational Testing of Instrument and Control Air Systems (Revision 0, April 1982)."

REGULATORY GUIDE 1.81: Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants (Revision 1, January 1975)

RESPONSE

The position of Regulatory Guide 1.81 is accepted (refer to subsections 8.3.1 and 8.3.2.2.1.13).

REGULATORY GUIDE 1.82: Sumps for Emergency Core Cooling and Containment Spray Systems (Revision 0, June 1974)

RESPONSE

The position of Regulatory Guide 1.82 is accepted with exception to the guidance of approximate coolant velocity of 6 cm/sec (0.2 ft/sec), partial blockage of one-half of the inner screen surface area, and credit for horizontal surfaces in determining the available screen surface area (refer to subsection 6.2.2). Additional references: 6.3.1, 6.5.2, 6A.47, and 6A.58.

REGULATORY GUIDE 1.83: Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes (Revision 0, June 1974)

RESPONSE

The position of Regulatory Guide 1.83 is accepted (refer to subsection 5.2.4) except that for compliance with Position c.3.a, the inspection shall be performed prior to the field hydrostatic test. Additional references: 5.1.4.

REGULATORY GUIDE 1.84: Design and Fabrication Code Case Acceptability ASME Section III Division 1

RESPONSE

The position of Regulatory Guide 1.84 is accepted (refer to table 5.2-3). Additional references: 5.2.1.2, 5.2.2, 3.7.1.3, 4.2.5, 5.1.4, and 5.4.7.1.

REGULATORY GUIDE 1.85: Materials Code Case Acceptability ASME Section III Division 1

RESPONSE

The position of Regulatory Guide 1.85 is accepted (refer to table 5.2-4). Additional references: 5.2.2, 5.2.1.2, 5.1.4, 5.4.7.1, 4.2.5, and 10.3.6.2.

REGULATORY GUIDE 1.86: Termination of Operating Licenses for Nuclear Reactors (Revision 0, June 1974)

RESPONSE

The position of Regulatory Guide 1.86 is accepted.

REGULATORY GUIDE 1.87: Construction Criteria for Class 1 Components in Elevated Temperature Reactors (Revision 0, June 1974)

RESPONSE

Not applicable.

REGULATORY GUIDE 1.89: Environmental Qualification of Certain Electronic Equipment Important to Safety for Nuclear Power Plants (Revision 1, June 1984)

RESPONSE

Class 1E equipment is qualified in accordance with IEEE 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations. However, clarifications to the guidelines presented in that document are necessary.

A. For equipment that has been seismically qualified by the testing procedures referenced in section 3.10, prior to qualification testing to IEEE 323-1974, the seismic qualification of IEEE 323-1974 of the aged equipment is by analysis using the testing outlined in section 3.10 and, if necessary, appropriate supplemental tests as a basis for the analysis. This combined qualification is in accordance with Sections 5.3 and 5.4 of IEEE 323-1974. Justification for qualification of equipment in this manner will be provided on an individual basis in qualification reports.

B. Objectives and methods described for aging are difficult to apply much of the equipment. The use of thermal and vibrational techniques to simulate aging may be valid for some components (cable or motor insulation), but is not valid or practical for many items. Any variation in aging methods or procedures

will be identified and justified on an individual basis in qualification reports.

C. Section 2.1 of Appendix D to this Regulatory Guide describes methods and assumptions used by the staff for calculating the radiation qualification dose in PWR dry containments. As part of this effort to eliminate the Iodine Removal (IR) System, the containment radiation qualification doses were calculated using the methodologies and guidance provided in Revision 2 of the Standard Review Plan. Some of these methodologies and assumptions differ from those presented in Revision 1 of Regulatory Guide 1.89. The differences, other than those plant specific characteristics such as containment volume, spray flow, etc., are summarized in the table below.

D. The following exception to Section 6.3.1.5.(7) of IEEE 323-1974 is taken:

For environmental qualification of equipment within the Palo Verde Equipment Qualification Program, the initial transient and the dwell at peak temperature need only be applied once during testing.

A description of the seismic qualification criteria of Class 1E equipment is provided in section 3.10. A description of the environmental qualification criteria of electrical equipment important to safety is provided in Section 3.11.

Additional references: 7.1.2.27, 8.3.1.2.2, 8.3.2.2.1.14, 18.II.F-1, and Table 18.II.F.2-3.

E. Regulatory Guide 1.89 Revision 1 does not specifically address qualification of equipment located outside the containment to beta radiation. PVNGS qualifies equipment located outside the containment to gamma radiation only.

Qualification Dose Analysis Characters/Parameter	Regulatory Guide 1.89, Revision 1	IR System Removal Analysis[3] (SRP, Rev. 2 Section 6.5.2)
% of core iodine activity instantly released to the containment atmosphere	50	50 (50)
% of iodine instantaneously plated out on cold surfaces	0	50 (50)
Hydrazine injection to spray	Yes	No (No)
pH of sump water during recirculation phase	8.5	7.0 (7.0)
Equilibrium iodine partition coefficent during injection phase	5000[1]	250[2] (250[2])
Spray removal constant for elemental iodine (hr^{-1})	27.2	19.6 (main spray region) 6.05 (auxiliary spray region) 0.0 (unsprayed region)
Overall plate out constant for elemental iodine (hr^{-1})	1.23	2.14 (main spray region) 14.4 (auxiliary spray region) 14.4 (unsprayed region)
Spray removal constant for particulate iodine (hr^{-1})	0.43	0.32 (main spray region) 0.09 (auxiliary spray region) 0.0 (unsprayed region)
Decontamination factor for elemental iodine	200	6.51 (main & aux. spray regions) 100 (time dependent plate out) Total=100[3]

1 Applicable to a sodium hydroxide system with pH > 8.0
2 Applicable for borated water with pH < 7.0
3 Combination of reduction in source term due to instantaneous plateout and time dependent plate out result in a total decontamination factor of 200.

REGULATORY GUIDE 1.90: Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons (Revision 0, November 1974)

RESPONSE

Not applicable. PVNGS tendons are ungrouted.

REGULATORY GUIDE 1.91: Evaluation of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plant Sites (Revision 1, February 1978)

RESPONSE

There are no transportation routes or explosive quantities reflected in Regulatory Guide 1.91 which would impact PVNGS design (refer to section 2.2).

REGULATORY GUIDE 1.92: Combining Modal Responses and Spatial Components in Seismic Response Analysis (Revision 1, February 1976)

RESPONSE

Information contained in Regulatory Guide 1.92 is utilized as discussed in sections 3.7, 3.9, and 3A.9.

REGULATORY GUIDE 1.93: Availability of Electric Power Sources (Revision 0, December 1974)

RESPONSE

The position of Regulatory Guide 1.93 is accepted, as described in the Technical Specifications Bases.

Reference 8.3.1.2.2.19 and 8.3.2.2.1.15.

REGULATORY GUIDE 1.94: Quality Assurance Requirements for Installation, Inspection and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants

RESPONSE

For operations phase activities, PVNGS identifies conformance to the regulatory positions of Regulatory Guide 1.94 (including any exceptions or clarifications) in the PVNGS Operations Quality Assurance Program Description.

REGULATORY GUIDE 1.95: Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release (Revision 0, February 1975)

RESPONSE

Regulatory Guide 1.95 is not applicable to PVNGS as there is no gaseous chlorine stored onsite and the nearest railroad route for possible chlorine transportation is several miles away.

REGULATORY GUIDE 1.97: Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident

RESPONSE

PVNGS compliance with the recommendations of Revision 2 to Regulatory Guide 1.97 is addressed in table 1.8-1. Reference 2.3.3.1, 3.2.2 (Table 3.2-1), 6.2.5, 6A.14, 7.1.2.29, 7.5.2.5, 9.3.2.2, 9A.60, 11.5, 12.1.2, 12.3.2.1, and 18.

The NRC letter and Safety Evaluation for PVNGS license Amendment 136 dated September 28, 2001 states, in part: "The issuance of plant specific amendments to adopt this change, which would remove PASS and related administrative controls from TS, supersede the PASS specific requirements imposed by post-TMI confirmatory orders." Additionally, the operating license condition pertaining to Supplement No. 1 to NUREG-0737 was deleted from the operating licenses in NRC correspondence dated September 29, 2000.

REGULATORY GUIDE 1.99: Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials (Revision 2, May 1988)

RESPONSE

This guide is not applicable to balance of plant design. For the CE supplied (NSSS) portion of the plant, the following response is applicable:

This Guide presents general procedures for predicting radiation-induced changes in the toughness properties of low alloy steels used in the fabrication of reactor pressure vessels. These procedures serve to meet certain requirements

of 10CFR50 Appendices G and H, which in turn implement 10CFR50 Appendix A, Criterion 31. The three principal positions of the Regulatory Guide are as follows:

C.1 Methods are presented to predict adjustment of the reference temperature and upper shelf impact energy based on neutron fluence and residual element content when credible surveillance data from the specific reactor vessel are not available.

C.2 Methods are presented to predict adjustment of the reference temperature and upper shelf impact energy by extrapolation or interpolation of credible surveillance data.

C.3 A 200°F limit is placed on the predicted adjusted reference temperature at the 1/4T position in the vessel wall at end-of-life for new plants.

POSITION:

Palo Verde reactor vessels, fabricated from SA 533 Grade B Class 1 material, are designed to maintain system integrity during their operating lifetime. Specifications for the toughness properties and residual chemistry of the vessel beltline materials are established to provide an ample margin against non-ductile failure during normal operation or under postulated accident conditions. The reactor vessel pressure-temperature operational limits are adjusted to account for the effects of neutron radiation on the toughness properties of the vessel beltline materials.

The methods used to predict adjustment of the reference temperature for Palo Verde reactor vessel beltline materials comply with the methods prescribed in Regulatory Guide 1.99, Revision 2. The Palo Verde surveillance program is designed to yield credible surveillance data for the verification or adjustment of plant operating parameters. Finally, the specifications for Palo Verde vessel beltline materials are designed to limit the adjusted reference temperature to 200°F at the inside surface of the reactor vessel wall at end-of-life.

Therefore, the prediction of neutron radiation effects in Palo Verde reactor pressure vessel materials is consistent with the procedures subsequently presented in Regulatory Guide 1.99, Revision 2.

REGULATORY GUIDE 1.100: Seismic Qualification of Electric Equipment for Nuclear Power Plants (Revision 0, March 1976)

RESPONSE

The position of Regulatory Guide 1.100 is accepted (refer to section 3.10). Additional references: Sections 7.1.2.30, 18.II.F.1, and Table 18.II.F.2-3.

REGULATORY GUIDE 1.101: Emergency Planning for Nuclear Power Plants (Revision 1, March 1977)

RESPONSE

Regulatory Guide 1.101 Revision 1 has been superseded by NUREG-0654/ FEMA-REP-1, Revision 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." The guidance of NUREG-0654 was utilized in developing the PVNGS emergency plan.

Emergency action levels contained in the plan are based upon the guidance of NUMARC/NESP-007 and NEI-99-01 as endorsed by Regulatory Guide 1.101 Revisions 3 and 4 respectively.

Reference appendix 9B.3.1 (Table 9B.3-1).

REGULATORY GUIDE 1.102: Flood Protection for Nuclear Power Plants (Revision 1, September 1976)

RESPONSE

The position of Regulatory Guide 1.102 is accepted for a dry site (refer to subsection 2.4.10 and section 3.4).

REGULATORY GUIDE 1.105: Instrument Setpoints (Revision 1, November 1976)

RESPONSE

For instruments within the Bechtel scope of supply, the position of Regulatory Guide 1.105 is accepted, except that securing devices are not used since seismic and/or plant vibration tests have demonstrated that drift specifications are met without their use. Reference 7.1.2.31.

REGULATORY GUIDE 1.108: Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants **(Withdrawn 8/5/93)**

All references to Regulatory Guide 1.108 are historical. The commitment to Regulatory Guide 1.108 has been changed to Regulatory Guide 1.9.

REGULATORY GUIDE 1.109: Calculation of annual doses to man from routine releases of reactor effluents for the purpose of evaluating compliance with 10 CFR Part 50, Appendix I, (Revision 1, October 1977)

RESPONSE

The position of Regulatory Guide 1.109 is accepted

Reference 15.4.8.

REGULATORY GUIDE 1.111: Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors (Revision 1, July 1977)

RESPONSE

Information contained in Regulatory Guide 1.111 is utilized as discussed in section 2.3

REGULATORY GUIDE 1.112: Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light-Water-Cooled Power Reactors (Revision 0-R, May 1977)

Table 1.8-1
PVNGS COMPLIANCE WITH REGULATORY GUIDE 1.97 (REVISION 2) REQUIREMENTS
(Sheet 1 of 37)

Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
1) Pressurizer Level Pressurizer Level (Hot Cal), Ch X Pressurizer Level (Hot Cal), Ch Y (see also row 52)	A-1 (f)	Fully	J-RCA-LT-0110X J-RCB-LT-0110Y	0 to 100 % Level	EQ	I	Q	At 3.7% and 93.7% volume points (q)	1E	CR, TSC, EOF. LT-110X recorded on JRCALR0110X	
2) RCS Cold Leg Temperature RC Cold Leg 1A Temperature (WR) RC Cold Leg 1B Temperature (WR) RC Cold Leg 2A Temperature (WR) RC Cold Leg 2B Temperature (WR) (see also rows 14 and 16)	A-1 (f)	Fully	J-RCA-TT-0112C1 J-RCB-TT-0112C2 J-RCA-TT-0122C1 J-RCB-TT-0122C2	50 to 750 °F	EQ (sensor) EM (xmtr)	I	Q	At Reactor Vessel Inlet Piping	1E	CR, TSC, EOF QSPDS-B serves as CR indicator for TT112C2 and TT122C2 TT-112C1 is recorded on JRCATR0112. TT-122C1 is recorded on JRCATR0122.	
3) RCS Hot Leg Temperature RC Hot Leg 1Temperature (WR) Ch A RC Hot Leg 1Temperature (WR) Ch B RC Hot Leg 2Temperature (WR) Ch A RC Hot Leg 2Temperature (WR) Ch B (see also row 15)	A-1 (f)	Fully	J-RCA-TT-0112H1 J-RCB-TT-0112H2 J-RCA-TT-0122H1 J-RCB-TT-0122H2	50 to 750 °F	EQ (sensor) EM (xmtr)	I	Q	At Reactor Vessel Outlet Piping	1E	CR, TSC, EOF QSPDS-B serves as CR indicator for TT112H2 and TT122H2 TT-112H1 is recorded on JRCATR0112. TT-122H1 is recorded on JRCATR0122.	
4) Containment Pressure Containment Pressure (X WR), Ch. A Containment Pressure (X WR), Ch. B (see also rows 24, 26, 31 and 38)	A-1 (f)	Fully	J-HCA-PT-0353A J-HCB-PT-0353B	-5 to 180 psig	EM EQ	I	Q	In Cnmnt, 93' level	1E	CR, TSC, EOF. PT-353A is recorded on JHCAPR0353A	Sensor readings relayed to ERFDADS via datalink from qualified QSPDS.

Table 1.8-1

PVNGS COMPLIANCE WITH REGULATORY GUIDE 1.97 (REVISION 2) REQUIREMENTS

(Sheet 2 of 37)

Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
5) Steam Generator Level Steam Generator 1 Level (WR), Ch A Steam Generator 1 Level (WR), Ch B Steam Generator 1 Level (WR), Ch C Steam Generator 1 Level (WR), Ch D Steam Generator 2 Level (WR), Ch A Steam Generator 2 Level (WR), Ch B Steam Generator 2 Level (WR), Ch C Steam Generator 2 Level (WR), Ch D (see also row 57)	A-1 (f)	See footnote (g)	J-SGA-LT-1113A J-SGB-LT-1113B J-SGC-LT-1113C J-SGD-LT-1113D J-SGA-LT-1123A J-SGB-LT-1123B J-SGC-LT-1123C J-SGD-LT-1123D	0 to 100 % Level (g)	EQ	I	Q	(g)	1E	CR, TSC, EOF Train A (WR) values are recorded on JSGALR1113A	
6) Steam Generator Pressure Steam Generator 1 Pressure, Ch A Steam Generator 1 Pressure, Ch B Steam Generator 1 Pressure, Ch C Steam Generator 1 Pressure, Ch D Steam Generator 2 Pressure, Ch A Steam Generator 2 Pressure, Ch B Steam Generator 2 Pressure, Ch C Steam Generator 2 Pressure, Ch D (see also row 58)	A-1 (f)	Fully	J-SGA-PT-1013A J-SGB-PT-1013B J-SGC-PT-1013C J-SGD-PT-1013D J-SGA-PT-1023A J-SGB-PT-1023B J-SGC-PT-1023C J-SGD-PT-1023D	0 to 1524 psia (y)	EQ	I	Q	On Steam Generator dome.	1E	CR, TSC, EOF. Train A values are recorded on JSGAPR1013A	
7) RCS Pressure RCS Pressure (X WR), Ch. A RCS Pressure (X WR), Ch. B (see also rows 17, 21, 30 and 36)	A-1 (f)	Fully	J-RCA-PT-0190A J-RCB-PT-0190B	0 to 4000 psig	EQ	I	Q	see Comments	1E	CR, TSC, EOF QSPDS-B serves as CR indicator for PT190B PT-190A recorded on JRCAPR0102A	at RCP1A Discharge at RCP2B Discharge

Table 1.8-1
PVNGS COMPLIANCE WITH REGULATORY GUIDE 1.97 (REVISION 2) REQUIREMENTS
(Sheet 3 of 37)

Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
8) Degrees of Subcooling Saturation Margin, RCS, Ch. A Saturation Margin, RCS, Ch. B ——— Saturation Margin, CET, Ch. A Saturation Margin, CET, Ch. B (see also row 20)	A-1 (f)	Fully	J-SHA-C01, pt RCTS1 J-SHB-C01, pt RCTS2 (h) ——— J-SHA-C01, pt RITS1 J-SHB-C01, pt RITS2 (i)	663°F subcooled to 2268°F superheated	EQ (sensor) EM (CPU)	I	Q	see Comments	1E	CR,TSC,EOF On qualified CR displays JSHAUI02 and JSHBUI02. Train A values are recorded on JSHATR03 (RCS) and JSHATR04 (CET). (Recorder range differs from QSPDS range)	Calculated by QSPDS-A from pressure PT-102A and Max. hot leg temp TT-112H1 / 122H1. Calculated by QSPDS-B from pressure PT-102B and max. hot leg temp TT-112H2 / 122H2. ——— Calculated by QSPDS-A from pressure PT-102A and rep. CET RITM1. Calculated by QSPDS-B from pressure PT-102B and rep. CET RITM2.
9) Containment H2 Concentration Containment Hydrogen Conc., Ch. A Containment Hydrogen Conc., Ch. B (see also rows 37)	A-1 (f)	See footnote (j)	J-HPA-AIT-0009 J-HPB-AIT-0010	0 to 10 % by volume	EQ (cell and xmtr) EM (bal. of loop)	I	Q	taps off recombiner suction lines (see comments)	1E	CR, TSC, EOF. Train A value recorded on JHPAUR0009	Samples analyzed by in-line catalytic reactor/thermal conductivity cell.
10) HPSI System Flow HPSI Flow to Cold Leg 2A HPSI Flow to Cold leg 2B HPSI Flow to Cold Leg 1A HPSI Flow to Cold Leg 1B ------- HPSI Flow to Hot Leg 1 HPSI Flow to Hot Leg 2	A-1 (OO)	Fully	J-SIB-FT-0311 J-SIB-FT-0321 J-SIA-FT-0331 J-SIA-FT-0341 -------- J-SIA-FT-0390 J-SIB-FT-0391	0 to 750 gpm (cc)	EQ	I	Q	at each injection nozzle	1E	CR, TSC, EOF. HPSI flows are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS. ——— Recorded for trending on non-qualified ERFDADS.	Sensors are on separate trains. NOTE: readings are inaccurate below 75 gpm.
11) Neutron Flux Reactor Power (Log Range), Ch A Reactor Power (Log Range), Ch B)	B-1	Fully	J-SEA-NE-0001A (*) J-SEB-NE-0001B (*) (*) Log range uses center chamber	2 X 10-^{7} to 200 % Power Level	EQ (sensor & pre-amp) EM (bal. of loop) (see note)	I	Q	Excore, vertical tri-section(*) fission chambers	1E	CR, TSC, EOF. Log A and B recorded on non-qualified recorder JSENJR1A	Log ranges A and B also displayed on qualified QSPDS. NOTE: A and B channels are qualified for 200 days.

Table 1.8-1
PVNGS COMPLIANCE WITH REGULATORY GUIDE 1.97 (REVISION 2) REQUIREMENTS
(Sheet 4 of 37)

Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
12) <u>Control Rod Full-in Position</u> CEA 1 Fully Inserted thru CEA 89 Fully Inserted	B-3	Fully	J-SFX-ZT-0001A/B (*) thru J-SFX-ZT-0089A/B (*) (x refers to train A, B, C, or D; the "A" and "B" contacts are in different trains). (*) EQID for RSPT, integral bottom contact does not have separate EQID.	N-In In	EX (see note)	I	Q (see note)	bottom contacts(*) on dual element reed switch pos. xmtrs.	Non 1E (1E bkp)	CR display on core mimic JSFNZI0001. mimic display avail on ERFDADS in CR, TSC, EOF.	Redundant sensors. A & B sensors at each reed switch position transmitter elevation, but one contact closure is displayed. NOTE: RSPTs are Q but instrument loop is QAG. NOTE : Qualification not required under RG 1.97, classed as EX for reasons other than post-accident monitoring.
13) Deleted											
14) <u>RCS Cold Leg Temperature</u> (see row 2)	B-3	Fully									
15) <u>RCS Hot Leg Temperature</u> (see row 3)	B-1	Fully									
16) <u>RCS Cold Leg Temperature</u> (see row 2)	B-1	Fully									
17) <u>RCS Pressure</u> (see row 7)	B-1	Fully									

Table 1.8-1
PVNGS COMPLIANCE WITH REGULATORY GUIDE 1.97 (REVISION 2) REQUIREMENTS
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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
18) <u>Core Exit Temperature</u> Representative Core Exit Temp, Ch A Representative Core Exit Temp, Ch B Core Exit Thermocouple 1 Temp. through Core Exit Thermocouple 61 Temp. (see also row 27)	B-3	Fully	J-SHA-C01, pt RITM1 J-SHB-C01, pt RITM2 J-RIX-TE-0001 thru J-RIX-TE-0061 (x refers to train A, B, C, or D)	32 to 2300°F (i)	EQ (CETs) EM (CPU)	I	Q	61 CETs at top of core	1E	CR,TSC,EOF On qualified CR displays JSHAUI02 and JSHBUI02. RITM1 is recorded on JSHATR0004.	“Highest” selected from 15 (*) CET measurements per quadrant. “Representative” is formed from distribution weighted average of 30 (31) (*) CETs. —— (*) one quadrant contains 16 CET measurements
19) <u>Coolant Level in Reactor</u> Reactor Vessel Level - Head, Ch A Reactor Vessel Level - Head, Ch B Level 1 Heated TC Temp., Ch, A Level 1 Unheated TC Temp, Ch A Level 1 Heated TC Temp., Ch, B Level 1 Unheated TC Temp, Ch B Level 2 Heated TC Temp., Ch, A Level 2 Unheated TC Temp, Ch A Level 2 Heated TC Temp., Ch, B Level 2 Unheated TC Temp, Ch B Level 3 Heated TC Temp., Ch, A Level 3 Unheated TC Temp, Ch A Level 3 Heated TC Temp., Ch, B Level 3 Unheated TC Temp, Ch B Level 4 Heated TC Temp., Ch, A Level 4 Unheated TC Temp, Ch A Level 4 Heated TC Temp., Ch, B Level 4 Unheated TC Temp, Ch B	B-1	See footnotes (l) & (m)	J-SHA-C01, RCXL1A J-SHB-C01, RCXL1B J-RIA-LE-0001A " J-RIB-LE-0001B " J-RIA-LE-0002A " J-RIB-LE-0002B " J-RIA-LE-0003A " J-RIB-LE-0003B " J-RIA-LE-0004A " J-RIB-LE-0004B "	0 to 100 % (l) 32 to 2300 °F	EQ (HJTC) EM (CPU)	I	Q	Vertical quad-section HJTC in vessel head region	1E	CR,TSC,EOF On qualified CR displays JSHAUI02 and JSHBUI02. RCXL1A and RCXL2A are recorded on JSHATR0005.	“Level” is inferred from HJTC temperature differences. U3 NOTE: heated and unheated junctions within same sensor.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
19) Coolant Level in Reactor (Continued) Reactor Vessel Level - Plenum, Ch A Reactor Vessel Level - Plenum, Ch B Level 5 Heated TC Temp., Ch, A Level 5 Unheated TC Temp, Ch A Level 5 Heated TC Temp., Ch, B Level 5 Unheated TC Temp, Ch B Level 6 Heated TC Temp., Ch, A Level 6 Unheated TC Temp, Ch A Level 6 Heated TC Temp., Ch, B Level 6 Unheated TC Temp, Ch B Level 7 Heated TC Temp., Ch, A Level 7 Unheated TC Temp, Ch A Level 7 Heated TC Temp., Ch, B Level 7 Unheated TC Temp, Ch B Level 8 Heated TC Temp., Ch, A Level 8 Unheated TC Temp, Ch A Level 8 Heated TC Temp., Ch, B Level 8 Unheated TC Temp, Ch B	B-1	See footnotes (l) & (m)	J-SHA-C01, RCXL2A J-SHB-C01, RCXL2B J-RIA-LE-0005A " J-RIB-LE-0005B " J-RIA-LE-0006A " J-RIB-LE-0006B " J-RIA-LE-0007A " J-RIB-LE-0007B " J-RIA-LE-0008A " J-RIB-LE-0008B "	0 to 100 % (m) 32 to 2300 °F	EQ (HJTC) EM (CPU)	I	Q	Vertical quad-section HJTC in vessel outlet plenum (see note)	1E		
20) Degrees of Subcooling (see row 8)	B-2	Fully									
21) RCS Pressure (see row 7)	B-1	Fully									
22) Containment Sump Level) Containment RW Sump Level, East Containment RW Sump Level, West (see also row 32)	B-2	See footnote (MM)	J-RDE-LT-0410 J-RDE-LT-0411	0 - 75 inches	EX (sensor) EM (xmtr) (MM)	II	Q (xmtr only) QAG (sensor and balance of loop)	Float probe in sump	1E DG backup	CR, TSC, EOF. LT-410 & 411 are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Instrument range covers from 6.5" above bottom of sump to 6.5" above the top of the sump. Transmitter provides separation between class 1E power and non-1E loop components.
23) Containment Level Containment Level at Recirc. -A Containment Level at Recirc. -B (see also row 33)	B-1	See footnote (n)	J-SIA-LT-0706 J-SIB-LT-0707	6 to 150 inches Containment Level (n)	EQ (sensor) EM (xmtr)	I	Q	float probe on wall above each recirc. suction point	1E	CR, TSC, EOF. LT-706 is recorded on JHPAUR009	NOTE: sensor readings relayed to ERFDADS via datalink from qualified QSPDS.

Table 1.8-1
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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
24) Containment Pressure (see row 4)	B-1	Fully									
25) Containment Isolation Valve Status (see Comments)	B-1	Fully		N-clsd Clsd		I	Q	internal actuator switches on each damper (*)	1E	CR,TSC,EOF "Not in safe operating position" status displayed on CR SESS Component Level Panels JESAUA2E and JESBUA2F. Also, status lights at each CR hand switch location. Piping mimic display of status on non-qualified ERFDADS NOTE: Cnmnt. Isolation portion of SESS panels marked with RG 1.97 designation strip : Separate sensors for SESS and ERFDADS	Includes those valves closed by a Containment Isolation Actuation (CIAS).
Cnmnt. Refuel. Purge Supply, Outside			J-CPA-UV-0002A (*)		EP						
Cnmnt. Refuel. Purge Exh., Inside			J-CPA-UV-0002B (*)		"						
Cnmnt. Refuel. Purge Supply, Inside			J-CPB-UV-0003A (*)		"						
Cnmnt. Refuel. Purge Exh., Outside			J-CPB-UV-0003B (*)		"						
Cnmnt. Pwr Acc. Purge Supply, Outside			J-CPA-ZSL-0004A		EQ			limit switch on each valve operator.			
Cnmnt. Pwr Acc. Purge Exh., Inside			J-CPA-ZSL-0004B		"						
Cnmnt. Pwr Acc. Purge Supply, Inside			J-CPB-ZSL-0005A		"						
Cnmnt. Pwr Acc. Purge Exh., Outside			J-CPB-ZSL-0005B		"						
Letdown to Regen. Heat Exch.			J-CHA-ZSL-0516		"			"			
Regen. Heat Exch. Outlet			J-CHB-ZSL-0523		"			"			
Reactor Drain Tank Outlet			J-CHA-ZSL-0560		"			"			
Reactor Drain Tank Outlet			J-CHB-ZSL-0561		"			"			
Make-up Supply to RDT			J-CHA-ZSL-0580		"			"			
Sample Return to RDT			J-CHA-UV-0715 (*)(TT)		EP			"			
Letdown Line Sample			J-CHB-UV-0924 (*)(SS)		"			"			
HP Nitrogen to Safety Injection Tanks			J-GAA-UV-0001 (*)		"			"			
LP Nitrogen to Containment			J-GAA-UV-0002 (*)		"			"			
Waste Gas Header Inside Cnmnt.			J-GRA-UV-0001 (*)		"			"			
Waste Gas Header Outside Cnmnt.			J-GRB-UV-0002 (*)		"			"			
To Mon. RU-1 Inside Cnmnt.			J-HCB-UV-0044		EQ			"			
To Mon. RU-1 Outside Cnmnt.			J-HCA-UV-0045		"			"			
From Mon. RU-1 Outside Cnmnt.			J-HCA-UV-0046		"			"			
From Mon. RU-1 Inside Cnmnt.			J-HCB-UV-0047		"			"			
			(*) EQID for valve, integral limit switch does not have separate EQID								

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location	Comments
Containment Isolation Valve Status **Con't**											
Cnmt Control System A Supply			J-HPA-UV-0001 (*)		EP			limit switches on each valve			
Cnmt Control System B Supply			J-HPB-UV-0002 (*)		"						
Cnmt Control Sys A to Recombiner			J-HPA-UV-0003 (*)		"						
Cnmt Control Sys B to Recombiner			J-HPB-UV-0004 (*)		"						
Cnmt Control Sys A from Recombiner			J-HPA-UV-0005 (*)		"						
Cnmt Control Sys B from Recombiner			J-HPB-UV-0006 (*)		"						
Cnmt.Hydrogen Monitor Return			J-HPA-UV-0023 (*)(TT)		"						
Cnmt.Hydrogen Monitor			J-HPA-UV-0024 (*)(TT)		"						
Cnmnt.Sumps Inside Containment			J-RDA-UV-0023 (*)		"						
Cnmnt.Sumps Outside Containment			J-RDB-UV-0024 (*)		"						
SG 1 Chemical Injection			J-SGB-HV-0200 (*)		"						
SG 2 Chemical Injection			J-SGB-HV-0201 (*)		"						
Cnmt.. Isolation Valve, downstream functions removed			J-SIA-UV-0708 (*)(SS)		"						
Hot Leg Sample, Outside			J-SSB-UV-0200 (*)		"						
Surge Line Sample, Outside			J-SSB-UV-0201		EQ						
Pzr. Steam Space Sample, Outside			J-SSB-UV-0202 (*)		EP						
Hot Leg Sample, Inside			J-SSA-UV-0203		EQ						
Surge Line Sample, Inside			J-SSA-UV-0204		"						
Pzr. Steam Space Sample, Inside			J-SSA-UV-0205		"						
WC Return Header Inside Cnmnt.			J-WCB-UV-0061 (*)		EP						
WC Return Header Outside Cnmnt.			J-WCA-UV-0062 (*)		"						
WC Supply Header Outside Cnmnt.			J-WCB-UV-0063 (*)		"						
			(*) EQID for valve, integral limit switch does not have separate EQID								
26) Containment Pressure (see row 4)	B-1	Fully									
27) Core Exit Temperature (see row 18)	C-1	Fully									

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
28) Primary Coolant Radiation Level Primary Coolant Activity, Ch A Primary Coolant Activity, Ch B	C-1	See footnote (o)	J-SQA-RU-0150 J-SQB-RU-0151	1.0×10^0 to 1.0×10^5 R/hr (o) Sensitivity: 1 R/hr Accuracy: ± 20%	EQ (sensor) EM (micro)	I	Q	ion chambers above cold leg at RCP 2B	1E	CR, TSC, EOF. Displayed on qualified QSPDS. Also, displayed on non-qualified RMS terminal in CR & avail. on non-qualified ERFDADS. RU-150 & 151 are recorded on both RMS & ERFDADS for trending.	Redundant sensors and redundant displays. Micros are parallel-connected to QSPDS and RMS. (Also, ERFDADS values received from both QSPDS and RMS).
29) Primary Coolant Gamma Spectrum Primary Coolant Specific Activity (liquid) Grab Sample: (see also row 102)	C-3	See footnote (PP)									
30) RCS Pressure (see row 7)	C-1	Fully									
31) Containment Pressure (see row 4)	C-1	Fully									
32) Containment Sump Level (NR) (see row 22)	C-2	See footnote (MM)									
33) Containment Sump Level (WR) (see row 23)	C-1	See footnote (n)									

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PVNGS COMPLIANCE WITH REGULATORY GUIDE 1.97 (REVISION 2) REQUIREMENTS
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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
34) Containment Area Radiation, High Range In-Cnmnt. Area Monitor, Ch A In-Cnmnt. Area Monitor, Ch B (see also row 76)	C-3	Fully	J-SQA-RU-0148 J-SQB-RU-0149	1.0×10^{0} to 1.0×10^{7} R/hr Sensitivity: 1 R/hr Accuracy: ± 20% @ 100KEV ± 35% @ 60KEV (p)	EQ (sensors) EM (micro)	I	Q	ion chambers, 'A' above refuel. area, 'B' east of access door	1E	CR, TSC, EOF. Displayed on qualified QSPDS. Also, displayed on non-qualified RMS terminal in CR and avail. on non-qualified ERFDADS. RU-148 & 149 are recorded on both RMS & ERFDADS for trending.	Redundant sensors and redundant displays. Micros are parallel-connected to QSPDS and RMS. (Also, ERFDADS values received from both QSPDS and RMS).
35) Effluent Radioactivity from Condenser Air Removal Exhaust (see also row 81)	C-3	N/A	NONE (not needed, effluent discharges through common plant vent, see row 38)								
36) RCS Pressure (see row 7)	C-1	Fully									
37) Containment H2 Concentration (see row 9)	C-1	See footnote (j)									
38) Containment Pressure (see row 4)	C-1	Fully									
39) Effluent Activity, Common Plant Vent (see note) Plant Vent Exhaust, Gas, Low Range Plant Vent Exhaust, Gas, High Range (see also row 83)	C-2	Fully	J-SQN-RU-0143, Ch 1 J-SQN-RU-0144	1.0×10^{-6} to 1.0×10^{-1} µCi/cc 3.0×10^{-2} to 1.0×10^{5} µCi/cc Accuracy: 25% (CC)	EM (sensors) EM (micro)	II	QAG	low range beta scintillator and mid and high range GM tubes in plant vent 176' Turb. Bldg., West	1E	CR, TSC, EOF Display on non-qualified RMS terminal in CR. Also avail. on non-qualified ERFDADS. RU-143 and RU-144 are recorded on both RMS and ERFDADS for trending.	Overlapping range sensors are not redundant, normal configuration with RU-144 in standby. Displays are not redundant since ERFDADS receives values from RMS via datalink. NOTE: includes Containment effluent and Condenser Air Removal exhaust.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
40) Radiation Exposure Area Monitors, In-Plant Penetration, MSSS-A, 88' Penetration, MSSS-B, 88' Penetration, Aux. Bldg, West 70 Penetration, Aux. Bldg, East 88' Penetration, Aux. Bldg, West 100' Penetration, Aux. Bldg, East 100' Penetration, MSSS-A, 100' Penetration, MSSS-B, 100' Penetration, Aux. Bldg, West 120' Penetration, Aux. Bldg, East 120' Penetration, Aux. Bldg, West 140' Penetration, Aux. Bldg, East 140' Penetration, Aux. Bldg, Hot Lab 140' (see also row 77)	C-2	Fully	J-SQN-RE-0155A J-SQN-RE-0155B J-SQN-RE-0155C J-SQN-RE-0156A J-SQN-RE-0156B J-SQN-RE-0156C J-SQN-RE-0157A J-SQN-RE-0157B J-SQN-RE-0157C J-SQN-RE-0158A J-SQN-RE-0158B J-SQN-RE-0158C J-SQN-RE-0158D	$1.0 \times 10^{+2}$ to 1.0×10^{7} mR/hr Sensitivity: 10 mR/hr Accuracy: ± 20%	EX (micro) EX (ww) EQ " " " " " " " " " " " "	II	QAG	ion chambers at primary penetration	1E	CR, TSC, EOF Display on non-qualified RMS terminal in CR. Also avail. on non-qualified ERFDADS. RU-155 thru RU-158 are recorded on both RMS and ERFDADS for trending.	Sensors are not redundant. Displays are not redundant since ERFDADS receives values from RMS via datalink.
41) Effluent Activity, Identified Release Point Fuel Bldg. Exhaust, Gas, Low Range Fuel Bldg. Exhaust, Gas, High Range (see also row 88)	C-2	Fully	J-SQB-RU-0145 J-SQB-RU-0146	1.0×10^{-6} to 1.0×10^{-1} µCi/cc 3.0×10^{-2} to 1.0×10^{5} µCi/cc Accuracy: ± 25% (CC)	EM (sensors) EM (micro)	I	Q	low range beta scintillator and mid and high range GM tubes in exh. vent 176' Fuel Bldg, West	1E	CR, TSC, EOF Display on non-qualified RMS terminal in CR. Also avail. on non-qualified ERFDADS. RU-145 and RU-146 are recorded on both RMS and ERFDADS for trending.	Overlapping range sensors are not redundant, normal configuration with RU-146 in standby. Displays are not redundant since ERFDADS receives values from RMS via datalink.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
42) LPSI - RHR System Flow LPSI - S/D Cooling. Flow, Train A LPSI - S/D Cooling. Flow, Train B (see also row 48)	D-2	Fully	J-SIA-FT-0306 J-SIB-FT-0307	0 to 10000 gpm (bb)	EQ	I	Q	at low pressure injection headers A & B	1E	CR, TSC, EOF. FT-306 and FT-307 are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Sensors are on redundant trains. NOTE: readings are inaccurate below 500 gpm.
43) RHR Heat Exchanger Outlet Temp. S/D Clg. HX Outlet Temp., Train A S/D Clg. HX Outlet Temp., Train B	D-2	See footnote (r)	J-SIA-TT-0303X J-SIB-TT-0303Y	40 to 400 °F (r)	EQ (sensor) EM (xmtr)	I	Q	at heat exchangers A & B outlets	1E	CR, TSC, EOF. TT-303X and TT-303Y are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Sensors are on redundant trains.
44) Accumulator Tank Level Safety Injection Tank 2A Level (WR) Safety Injection Tank 2B Level (WR) Safety Injection Tank 1A Level (WR) Safety Injection Tank 1B Level (WR)	D-3	See Footnote (EE)	J-SIB-LT-0311 J-SIB-LT-0321 J-SIA-LT-0331 J-SIA-LT-0341	0 to 100 % Level	EX (EE)	I	Q	at 9.6% and 90.4% volume points on each tank (q)	1E	CR, TSC, EOF. LT-311 thru LT-341 are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Sensors are not redundant; located on separate tanks.
45) Accumulator Tank Pressure Safety Inject. Tank 2A Pressure (WR) Safety Inject. Tank 2B Pressure (WR) Safety Inject. Tank 1A Pressure (WR) Safety Inject. Tank 1B Pressure (WR)	D-3	See Footnote (EE)	J-SIB-PT-0311 J-SIB-PT-0321 J-SIA-PT-0331 J-SIA-PT-0341	0 to 750 psig	EX (EE)	I	Q	sensing line on each tank	1E	CR, TSC, EOF. PT-311 thru PT-341 are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Sensors are not redundant; located on separate tanks.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
46) <u>Accumulator Isolation Valve Status</u> SI Tank 2A Isolation Valve Status SI Tank 2B Isolation Valve Status SI Tank 1A Isolation Valve Status SI Tank 1B Isolation Valve Status	D-2	Fully	J-SIB-ZSL/H-0614 J-SIB-ZSL/H-0624 J-SIA-ZSL/H-0634 J-SIA-ZSL/H-0644 ----- J-SIB-UV-0614 (*) J-SIB-UV-0624 (*) J-SIA-UV-0634 (*) (*) EQID for valve, integral limit switch does not have separate EQID.	N-clsd Clsd	EQ ____ EP	I	Q	limit switch on each valve ____ limit switch on each vlv. operator (*)	1E	Status lights at each CR hand switch location. ____ Redundant Status lights at each CR hand switch location. Plus “not in safe operating position” status displayed on CR SESS Component Level Panels JESAUA2E and JESBUA2F. Also piping mimic display of status on non-qualified ERFDADS in CR, TSC and EOF	Redundant information displays and redundant sensors.
47) <u>Boric Acid Charging Flow</u> Primary System Charging Flow (see also row 67)	D-2	Fully	J-CHB-FT-0212	0 to 150 gpm (tt)	EQ	I	Q	at Chrg. Pmps discharger header to Regen HX	1E	CR, TSC, EOF. FT-212 is assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Redundant information displays but not redundant sensor.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
48) LPSI - RHR System Flow (see row 42)	D-2	Fully									
49) Refueling Water Storage Tank Level Refuel. Water Storage Tank Level, A Refuel. Water Storage Tank Level, B	D-2	Fully	J-CHA-LT-0203A J-CHB-LT-0203B	0 to 100 %	EM	I	Q	at 6.1% and 93.3% volume points (q)	1E	CR, TSC, EOF. LT-203A/D are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	
50) Reactor Coolant Pump Motor Current RCP 1A Motor Current RCP 1B Motor Current RCP 2A Motor Current RCP 2B Motor Current	D-3	Fully	E-NAN-S01M (*) E-NAN-S02L (*) E-NAN-S01L (*) E-NAN-S02M (*) (*) EQID for breaker, current xfmr does not have separate EQID.	0 to 600 A (see note)	N	IX	QAG	current xfmr at each pump motor supply (*)	Self	Current meter at each CR hand switch. Also: display avail on non-qualified ERFDADS in CR, TSC, EOF.	NOTE: normally used for RUN vs. N-RUN indication only. NOTE : each analog signal recorded for trending on ERFDADS
51) Primary System Relief Valve Flow Flow Percent Thru Pzr. PSV-200 Flow Percent Thru Pzr. PSV-201 Flow Percent Thru Pzr. PSV-202 Flow Percent Thru Pzr. PSV-203	D-2	Fully	J-RCN-ZIT-0726 J-RCN-ZIT-0727 J-RCN-ZIT-0728 J-RCN-ZIT-0729	0 to 100% flow (See Note)	EQ (sensor & preamp) EM (xmtr)	IX	QAG	acoustic accelero-meters on each PSV tail pipe	Non 1E (1E. bkp)	Analog signal converted to tri-level CR display. Also, analog signal recorded for trending on non-qualified ERFDADS in CR, TSC & EOF	Redundant information displays but not redundant sensors. NOTE: tri-level display shows 0-9-100% flow
52) Pressurizer Level (see row 1)	D-1	Fully									
53) Pressurizer Heater Current Pzr. Heater Current, Train B, 1E Pzr. Heater Current, Train A, 1E	D-2	Fully	E-PGB-L32E1 (*) E-PGA-L33D1 (*) (*) EQID for breaker, current xfmr does not have separate EQID.	0 to 300 A " ON/OFF	EP "	I "	Q "	current xfmr at each heater supply (*)	Self	Ammeter at CR hand switches. Also: display avail on non-qualified ERFDADS in CR, TSC, EOF.	Each analog signal recorded for trending on ERFDADS

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Plant Variable	Type – Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
54) Quench Tank Level Reactor Drain Tank Level	D-3	Fully	J-CHN-LT-0268	0 to 100 %	N	III	QAG	At 7.8% and 92.2% volume points on horizontal tank (q)	Non 1E	CR, TSC, EOF. LT-268 is assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	
55) Quench Tank Temperature Reactor Drain Tank Temperature	D-3	Fully	J-CHN-TT-0268	0 to 750 °F	EX (T/C) EM (xmtr) (see note)	III	QAG	mid-point on horizontal tank	Non 1E	CR, TSC, EOF. TT-268 is assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	NOTE: Environ. Qualification not required under RG 1.97, classed as EX for reasons other than post-accident monitoring.
56) Quench Tank Pressure Reactor Drain Tank Pressure	D-3	Fully	J-CHA-PT-0268	0 to 150 psig	EX (see note)	I	Q	in tank vapor space	1E	CR, TSC, EOF. PT-268 is assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	NOTE: Environ. Qualification not required under RG 1.97, classed as EX for reasons other than post-accident monitoring.
57) Steam Generator Level (see row 5)	D-1	See footnote (g)									
58) Steam Generator Pressure (see row 6)	D-2	Fully									

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Plant Variable	Type – Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
59) Main Steam Relief Valve Flow Flow Percent Thru SG 1 PSV-692 Flow Percent Thru SG 1 PSV-575 Flow Percent Thru SG 1 PSV-574 Flow Percent Thru SG 1 PSV-573 Flow Percent Thru SG 1 PSV-691 Flow Percent Thru SG 1 PSV-576 Flow Percent Thru SG 1 PSV-577 Flow Percent Thru SG 1 PSV-578 Flow Percent Thru SG 1 PSV-579 Flow Percent Thru SG 1 PSV-572 Flow Percent Thru SG 2 PSV-695 Flow Percent Thru SG 2 PSV-557 Flow Percent Thru SG 2 PSV-556 Flow Percent Thru SG 2 PSV-555 Flow Percent Thru SG 2 PSV-554 Flow Percent Thru SG 2 PSV-694 Flow Percent Thru SG 2 PSV-558 Flow Percent Thru SG 2 PSV-559 Flow Percent Thru SG 2 PSV-560 Flow Percent Thru SG 2 PSV-561 (see also row 87)	D-2	See footnote (AA)	J-SGN-ZIT-0715 J-SGN-ZIT-0711 J-SGN-ZIT-0710 J-SGN-ZIT-0702 J-SGN-ZIT-0714 J-SGN-ZIT-0712 J-SGN-ZIT-0713 J-SGN-ZIT-0703 J-SGN-ZIT-0699 J-SGN-ZIT-0698 J-SGN-ZIT-0709 J-SGN-ZIT-0705 J-SGN-ZIT-0704 J-SGN-ZIT-0700 J-SGN-ZIT-0696 J-SGN-ZIT-0708 J-SGN-ZIT-0706 J-SGN-ZIT-0707 J-SGN-ZIT-0701 J-SGN-ZIT-0697	0 to 100% flow	EX (sensor & preamp) EM (xmtr) (AA)	IX	QAG	acoustic accelero-meters on each PSV tail pipe	Non 1E (1E. bkp)	CR, TSC, EOF Analog signal converted to tri-level CR display. Also, analog signal recorded for trending on non-qualified ERFDADS.	Redundant information displays but not redundant sensors. NOTE: tri-level display shows 0-9-100% flow
60) Main Feedwater Flows Main Feedwater Flow to SG 1 Main Feedwater Flow to SG 2 -------- Downcomer Feedflow to SG 1 Downcomer Feedflow to SG 2	D-3	Fully	J-SGN-FT-1112X J-SGN-FT-1122X -------- J-SGN-FT-1113X J-SGN-FT-1123X	0 to 1 X 10^7 lb/hr (dd) -------- 0 to 1.5 X10^6 lb/hr (ee)	N	III	QAG -----	on SG-1 common FW header on SG-2 common FW header ----- on SG-1 downcomer line. on SG-2 downcomer line.	Non 1E	CR, TSC, EOF. FT-1112X, FT-1113X, FT-1122X, and FT-1123X are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Redundant information displays but not redundant sensors.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
61) Auxiliary Feedwater Flows Auxiliary Feed Flow to SG 1, Ch A Auxiliary Feed Flow to SG 1, Ch B Auxiliary Feed Flow to SG 2, Ch A Auxiliary Feed Flow to SG 2, Ch B	D-2,	Fully	J-AFA-FT-0040A J-AFB-FT-0041A J-AFA-FT-0040B J-AFB-FT-0041B	0 to 2000 gpm (ff)	EM EQ EM EQ	I	Q	at Aux FW header to SG-1 at Aux FW header to SG-2 (see comment)	1E	CR, TSC, EOF. FT-40A/41A and FT-40B/41B are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Redundant transmitters on shared sensors, one for each AF train. NOTE: excludes Aux. feed from non-Class pump AFN-P01 (accounted for by JSGNFT1113 and JSGNFT1123)
62) Condensate Storage Tank Level Condensate Storage Tk Level, Ch A Condensate Storage Tk Level, Ch B	D-1	See footnote (QQ)	J-CTA-LT-0035 J-CTB-LT-0036	3 to 50 ft.	EM	I	Q	at 5.7% and 94.3% volume points (q)	1E	CR,TSC,EOF LT-35 is recorded on JCTALR35	Redundant sensors. NOTE: sensor readings relayed to ERFDADS via datalink from qualified QSPDS.
63) Containment Spray Flow Cnmnt. Spray Pump A Disch. Flow Cnmnt. Spray Pump B Disch. Flow	D-2	Fully	J-SIA-FT-0338 J-SIB-FT-0348	0 to 5000 gpm (gg)	EQ	I	Q	at disch. of each pump (see note)	1E	CR, TSC, EOF. FT-338 and FT-348 are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Redundant information displays but not redundant sensors. NOTE: transmitters indicate flow leaving CS pumps; indication of flow entering Containment CS header depending on valve alignment.
64) Cnmnt. Re-Circ. Fans Status (FF) Cnmt Normal ACU Fan A Brkr Status Cnmt Normal ACU Fan B Brkr Status Cnmt Normal ACU Fan C Brkr Status Cnmt Normal ACU Fan D Brkr Status ----- CEDM Norm. ACU Fan A Brkr Status CEDM Norm. ACU Fan B Brkr Status CEDM Norm. ACU Fan C Brkr Status CEDM Norm. ACU Fan D Brkr Status	D-2	Fully	E-PGA-L31E2 (86-1) E-PGB-L36D3 (86-1) E-PGA-L33D2 (86-1) E-PGB-L34D2 (86-1) ----- E-PGA-L31E3 (86-1) E-PGB-L32E2 (86-1) E-PGA-L33D3 (86-1) E-PGB-L34D3 (86-1)	N-trip Trip	EM	III	QAG	relay contact at each breaker	1E	Status lights at each CR hand switch location. Also HVAC mimic display of status on non-Class ERFDADS in CR, TSC and EOF	NOTE: CEDM Status at CR hand switch only. "

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
65) Containment Atmosphere Temp. Containment Temp 104'West Wall (WR) Containment Temp, 122' East Wall(WR) Containment Temp, 125' NE Wall (WR) Containment Temp, 127', SE Wall (WR) Containment Temp, Pzr. Area (WR)	D-2	See footnote (HH)	J-HCN-TE-0042A1 J-HCN-TE-0042B1 J-HCN-TE-0042C1 J-HCN-TE-0042D1 J-HCN-TE-0042E1	40 to 400°F	EQ (T/Cs) EM (bal. of loop) (HH)	II (T/Cs) III (bal. of loop)	QAG (T/C's) QAG (bal. of loop) (HH)	redundant thermo-couples at locations indicated; one set connected to ERFDADS the other connected to CR recorder and plant computer	Non 1E (1E bkp)	CR, TSC, EOF. CR indication on ERFDADS. QAG T/C's TE-42A1 thru TE-42E1 are recorded for trending on non-qualified ERFDADS.	Reference junction for TE-42A1 thru TE-42E1 is part of ERFDADS circuit.
66) Containment Sump Water Temp. Cnmt. Recirc. Sump A Water Temp. Cnmt. Recirc. Sump B Water Temp.	D-2	Fully	J-SIN-TT-0712 J-SIN-TT-0713	50 to 250 °F	EQ (sensor) EM (xmtr)	IX	QAG	thermo-couples in each sump	Non 1E (1E. bkp)	CR, TSC, EOF. TT-712 and TT-713 are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Not redundant sensors; located in separate sumps
67) Boric Acid Charging Flow (see row 47)	D-2	Fully									
68) Letdown Flow Primary System Letdown Flow	D-2	Fully	J-CHN-FT-0202	0 to 200 gpm (hh)	EX (ww)	IX	QAG	at disch. of purification filter	Non 1E (1E. bkp)	CR, TSC, EOF. FT-202 is assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
69) Volume Control Tank Level Volume Control Tank Level, Ch X Volume Control Tank Level, Ch Y	D-2	See footnote (xx)	J-CHN-LT-0226 J-CHN-LT-0227	0 to 100 % Level	EX (xx)	IX	QAG	at 9.7% and 90.3% volume points (q)	Non 1E (1E. bkp)	CR, TSC, EOF. LT-226 and LT-227 are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	
70) Cooling Water Temp. to ESF Components ECWS Train A Discharge Temp. ECWS Train B Discharge Temp.	D-2	Fully	J-EWN-TT-0083 J-EWN-TT-0084	0 to 200 °F	EQ (T/C) EM (T/C) EM (xmtr)	III	Q (T W) QAG (bal. of loop)	at disch. of each ECWS pump	Non 1E (1E. bkp)	CR, TSC, EOF. TT-83 and TT-84 are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Not redundant sensors; located on separate pumps
71) Cooling Water Flow. to ESF Components ECWS Train A Discharge Flow ECWS Train B Discharge Flow	D-2	Fully	J-EWA-FT-0013 J-EWB-FT-0014	0 to 20000 gpm (ii)	EQ	1	Q (xmtr) QAG (bal. of loop)	at disch. of each ECWS pump	Non 1E (1E. bkp)	CR, TSC, EOF. FT-13 and FT-14 are assignable to CR recorders via non-qualified plant computer. Also, recorded for trending on non-qualified ERFDADS.	Not redundant sensors; located on separate pumps.
72) Radioactive Liquid Tank Level High TDS Holdup Tank T01A Level High TDS Holdup Tank T01B Level Low TDS Holdup Tank T01C Level	D-3	Fully	J-LRN-LT-0004 J-LRN-LT-0005 J-LRN-LT-0006	0 to 32000 gal (jj)	N	III	QAG	bottom to top of tanks	Non 1E	CR, TSC, EOF CR indication on ERFDADS. Signals are recorded for trending on non-qualified ERFDADS.	Not redundant sensors; located on separate tanks.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
73) Radioactive Gas Holdup Tank Pressure Gas Decay Holdup Tank X02A Press. Gas Decay Holdup Tank X02B Press. Gas Decay Holdup Tank X02C Press.	D-3	See footnote (t)	J-GRN-PIT-0023 J-GRN-PIT-0024 J-GRN-PIT-0025	0 to 400 psig (t)	N	II	QAG	on each tank	Non 1E	CR, TSC, EOF CR indication on ERFDADS. Signals are recorded for trending on non-qualified ERFDADS.	Not redundant sensors; located on separate tanks.
74) Emer. Ventilation Damper Status Cnmt. Refuel. Purge Supply, Outside Cnmt. Refuel. Purge Exh., Inside Cnmt. Refuel. Purge Supply, Inside Cnmt. Refuel. Purge Exh., Outside -------- Cnmt. Pwr Acc. Purge Supply, Otside Cnmt. Pwr Acc. Purge Exh., Inside Cnmt. Pwr Acc. Purge Supply, Inside Cnmt. Pwr Acc. Purge Exh., Outside -------- Aux. Bldg, Pump Rms.Supply Isol,A1 Aux. Bldg, Pump Rms.Supply Isol,B1 Aux. Bldg, Pump Rms.Exh. Isol,A2 Aux. Bldg, Pump Rms.Exh. Isol,B2 Aux. Bldg, Pump Rms.Exh. Isol,A3 Aux. Bldg, Pump Rms.Exh. Isol,B3 Aux. Bldg, Pump Rms.Supply Isol,A4 Aux. Bldg, Pump Rms.Supply Isol,B4 Aux. Bldg, Pump Rms.Supply Isol,A5 Aux. Bldg, Pump Rms.Supply Isol,B5 Aux. Bldg, Pump Rms.Exh. Isol,A6 Aux. Bldg, Pump Rms.Exh. Isol,B6 -------- Fuel Bldg. Normal Supply Isol., A1 Fuel Bldg. Normal Supply Isol., B1 Fuel Bldg. Normal Supply Isol., A2 Fuel Bldg. Normal Supply Isol., B2 Fuel Bldg. Normal Supply Isol., A3 Fuel Bldg. Normal Supply Isol., B3 Fuel Bldg. Normal Supply Isol., A4 Fuel Bldg. Normal Supply Isol., B4 Fuel Bldg.AFU -A Ess. Exhaust Isol Fuel Bldg.AFU -B Ess. Exhaust Isol Fuel Bldg.AFU -A Ess. Exh. X-conn. Fuel Bldg.AFU -B Ess. Exh. X-conn.	D-2	See footnote (zz)	J-CPA-UV-0002A (*) J-CPA-UV-0002B (*) J-CPB-UV-0003A (*) J-CPB-UV-0003B (*) ----- J-CPA-ZSL-0004A J-CPA-ZSL-0004B J-CPB-ZSL-0005A J-CPB-ZSL-0005B ----- J-HAA-ZSH-0001 J-HAB-ZSH-0001 J-HAA-ZSH-0002 J-HAB-ZSH-0002 J-HAA-ZSH-0003 J-HAB-ZSH-0003 J-HAA-ZSH-0004 J-HAB-ZSH-0004 J-HAA-ZSH-0005 J-HAB-ZSH-0005 J-HAA-ZSH-0006 J-HAB-ZSH-0006 ----- J-HFA-ZSL-0001 J-HFB-ZSL-0001 J-HFA-ZSL-0002 J-HFB-ZSL-0002 J-HFA-ZSL-0003 J-HFB-ZSL-0003 J-HFA-ZSL-0004 J-HFB-ZSL-0004 J-HFA-ZSH-0005 J-HFB-ZSH-0005 J-HFA-ZSH-0006 J-HFB-ZSH-0006 (*) EQID for damper, integral limit switch does not have separate EQID.	N-clsd Clsd	EP ----- EQ ----- EQ EQ EQ EQ EX (**) EX (**) EX (**) EX (**) EX (**) EX (**) EQ EQ ----- EM (**) see footnote (zz)	I	Q	internal actuator switches on each damper (*) ---- limit switch on each damper ---- limit switch on each damper ----- limit switch on each damper	1E	Status lights at each CR hand switch location. Plus "not in safe operating position" status displayed on CR SESS Component Level Panels JESAUA2E and JESBUA2F. Also HVAC mimic display of status on non-Class ERFDADS in CR, TSC and EOF	Separate sensors for SESS and ERFDADS NOTE: UV-2A/B, UV-3A/B, UV-4A/B and UV-5A/B are also in Cnmnt. Isol. set.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location	Comments
<u>Emer. Ventilation Damper Status (Con't)</u>											Same sensors for SESS and ERFDADS
<u>Control Room Isolation:</u>											
Control Room Normal AHU Isol, A			J-HJA-ZSL/H-0001		EM			limit switch on each damper			
Control Room Normal AHU Isol, B			J-HJB-ZSL/H-0001		"						
Control Room Ess AHU A intake, A			M-HJA-M002 (*)		"						
Control Room Ess AHU A intake, B			M-HJB-M002 (*)	(*) EQID for damper, integral limit switch does not have separate EQID.	"			"			
Control Room Ess AHU B intake, A			M-HJA-M003 (*)		"			"			
Control Room Ess AHU B intake, B			M-HJB-M003 (*)		"			"			
CR Comm. Equip Room Isolation, B			J-HJB-ZSL/H-0010		"			"			
CR Comm. Equip Room Isolation, B			J-HJB-ZSL/H-0013		"			"			
CR Kitchen / Toilet Exh. Isol, A			J-HJA-ZSL/H-0015		"			"			
CR Kitchen / Toilet Exh. Isol, A			J-HJA-ZSL/H-0016		"			"			
CR Kitchen / Toilet Exh. Isol, B			J-HJB-ZSL/H-0023		"			"			
CR Kitchen / Toilet Exh. Isol, B			J-HJB-ZSL/H-0024		"			"			
Control Room Normal AHU Isol, A			J-HJA-ZSL/H-0052		"			"			
Control Room Normal AHU Isol, B			J-HJB-ZSL/H-0055		"			"			
Control Room Smoke Rem. Isol., A			J-HJA-ZSL/H-0056		"			"			
Control Room Smoke Rem. Isol., B			J-HJB-ZSL/H-0056		"			"			
Control Room Smoke Rem. Isol., A			J-HJA-ZSL/H-0057		"			"			
Control Room Smoke Rem. Isol., B			J-HJB-ZSL/H-0057		"			"			
CR Comm. Equip Room Isolation, A			J-HJA-ZSL/H-0058		"			"			
CR Comm. Equip Room Isolation, A			J-HJA-ZSL/H-0059		"			"			
					"						
<u>Control Building Isolation:</u>					"						
ESF Swgr Rooms Normal Supply Isol			J-HJA-ZSL/H-0023		"			"			
ESF Rms. B&D Normal Supply Isol, A			J-HJA-ZSL/H-0025		"			"			
ESF Rms. B&D Normal Return Isol, A			J-HJA-ZSL-0028		"			"			
ESF Rooms B&D Smoke Exh. Isol.,B			J-HJB-ZSL-0028		"			"			
Ess. AHU B Supply Isolation			J-HJB-ZSL/H-0031		"			"			
ESF Rooms Smoke Exhaust Isol.			J-HJB-ZSL/H-0032		"			"			
ESF Equip. Rms Smoke Exhaust Isol.			J-HJA-ZSL/H-0034		"			"			
ESF Rms. B&D Normal Supply Isol, B			J-HJB-ZSH-0034		"			"			
Upper Rooms Normal Return Isol.			J-HJA-ZSL/H-0036		"			"			
ESF Rms. B&D Normal Return Isol, B			J-HJB-ZSL/H-0038		"			"			
Control Bldg. Normal AHU Inlet Isol.			J-HJA-ZSL/H-0051		"			"			
ESF Swgr Rooms S.M. Supply Isol.			J-HJB-ZSL/H-0052		"			"			
ESF Rooms Smoke OSA Intake Isol.			J-HJA-ZSL/H-0053		"			"			
ESF Swgr. Smoke OSA Intake Isol.			J-HJA-ZSL/H-0054	(**) see note	"			"			
ESF Rooms B&D Smoke Exh. Isol.,A			J-HJA-ZSL/H-0055		"			"			
ESF Rms. A&C Normal Supply Isol, A			J-HJA-ZSL/H-0066		"			"			
ESF Rms. A&C Normal Supply Isol, B			J-HJB-ZSL/H-0066		"			"			-----
ESF Rms. B&D Ess. AHU Disch. Isol			J-HJB-ZSL/H-0058 (**)					"			NOTE: not yet connected to ERFDADS
ESF Rms. A&C Ess. AHU Disch. Isol			J-HJA-ZSL/H-0062 (**)					"			

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Plant Variable	Type – Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location	Comments (RR)
75) Standby Power Status Indications	D-2	Fully			EM	I	Q		Self		NOTE: Elec. one-line mimic display of status on non-qualified ERFDADS in CR, TSC and EOF
4.16 KV Bus S03 Voltage			E-PBA-ET-S03	0 to 5250 V				transducer at each bus.		control board meter	
4.16 KV Bus S04 Voltage			E-PBB-ET-S04	"							
S03 Bus Standby Supply Current			E-PBA-II-S03K	0 to 1200 A							
S03 Bus Normal Supply Current			E-PBA-II-S03L	"						------	
S04 Bus Normal Supply Current			E-PBB-II-S04K	"						Status lights at each CR hand switch location.	Signals are recorded for trending on non-qualified ERFDADS in CR, TSC and EOF
S04 Bus Standby Supply Current			E-PBB-II-S04L	"							
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S03 Bus Normal Supply. Breaker Status			E-PBA-S03L-(786)	N-trip Trip				relay contact at each breaker			
S03 Bus Standby Supply Breaker Status			E-PBA-S03K-(786)							--------	
S04 Bus Normal Supply. Breaker Status			E-PBB-S04K-(786)							control board meter	
S04 Bus Standby Supply Breaker Status			E-PBB-S04L-(786)								
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480V Load Center L-31 Voltage			E-PGA-L031-(V)	0 to 600 V				transducer at each bus.			
480V Load Center L-32 Voltage			E-PGB-L032-(V)								
480V Load Center L-33 Voltage			E-PGA-L033-(V)								
480V Load Center L-34 Voltage			E-PGB-L034-(V)							--------	
480V Load Center L-35 Voltage			E-PGA-L035-(V)							Status lights on control boards	
480V Load Center L-36 Voltage			E-PGB-L036-(V)								
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480 V MCC M31 Feeder Breaker			E-PGA-L31C2-(86)	N-trip Trip				relay contact at each breaker			
480 V MCC M32/M38 Feeder Breaker			E-PGB-L32C2/C3-(86)								
480 V MCC M33/M37 Feeder Breaker			E-PGA-L33C2/C3-(86)								
480 V MCC M34 Feeder Breaker			E-PGB-L34C2-(86)								
480 V MCC M35 Feeder Breaker			E-PGA-L35C2-(86)								
480 V MCC M36 Feeder Breaker			E-PGB-L36C3-(86)								
LC L-31 480V Supply Breaker Status			E-PGA-L31B2-(86-1)								
LC L-32 480V Supply Breaker Status			E-PGB-L32B2-(86-1)								
LC L-33 480V Supply Breaker Status			E-PGA-L33B2-(86-1)								
LC L-34 480V Supply Breaker Status			E-PGB-L34B2-(86-1)								
LC L-35 480V Supply Breaker Status			E-PGA-L35B2-(86-1)								
LC L-36 480V Supply Breaker Status			E-PGB-L36B2-(86-1)								
LC L-31 4.16KV Feeder Breaker Status			E-PBA-S03H-(786)								
LC L-32 4.16KV Feeder Breaker Status			E-PBB-S04J-(786)								
LC L-33 4.16KV Feeder Breaker Status			E-PBA-S03J-(786)								
LC L-34 4.16KV Feeder Breaker Status			E-PBB-S04H-(786)								
LC L-35 4.16KV Feeder Breaker Status			E-PBA-S03N-(786)								
LC L-36 4.16KV Feeder Breaker Status			E-PBB-S04N-(786)								

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Standby Power Status Indications (Con't)											NOTE: Elec. one-line mimic display of status on non-qualified ERFDADS in CR, TSC and EOF
125V DC Dist. Pnl. D21 Voltage			E-PKA-D21	0 to 150 V				transducer at each bus.		control board meter	Signals are recorded for trending on non-qualified ERFDADS in CR, TSC and EOF
125V DC Dist. Pnl. D22 Voltage			E-PKB-D22								
125V DC Dist. Pnl. D23 Voltage			E-PKC-D23								
125V DC Dist. Pnl. D24 Voltage			E-PKD-D24								
125V DC MCC M41 Voltage			E-PKA-EI-M41								
125V DC MCC M42 Voltage			E-PKB-EI-M42								
125V DC MCC M43 Voltage			E-PKC-EI-M43								
125V DC MCC M44 Voltage			E-PKD-EI-M44								
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Battery Charger-A Status			E-PKA-H11	Norm Trbl				relay contact at each charger		Status lights on control boards	
Battery Charger-B Status			E-PKB-H12								
Battery Charger-C Status			E-PKC-H13								
Battery Charger-D Status			E-PKD-H14								
Battery Charger-AC Status			E-PKA-H15								
Battery Charger-BD Status			E-PKB-H16	--------				------		--------	
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120V Vital AC Dist. Panel D25 Status			E-PNA-D25	Norm Trbl				relay contact at each breaker		Status lights on control boards	
120V Vital AC Dist. Panel D26 Status			E-PNB-D26								
120V Vital AC Dist. Panel D27 Status			E-PNC-D27								
120V Vital AC Dist. Panel D28 Status			E-PND-D28								
120V AC Stdby. Supply to D25 Status			E-PNA-V25								
120V AC Stdby. Supply to D26 Status			E-PNB-V26								
120V AC Stdby. Supply to D27 Status			E-PNC-V27								
120V AC Stdby. Supply to D28 Status			E-PND-V28								

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location	Comments (RR)
<u>Standby Power Status Indications</u> **(Con't)** MSIV UV-170 Accum-1 Pressure MSIV UV-170 Accum-2 Pressure MSIV UV-180 Accum-1 Pressure MSIV UV-180 Accum-2 Pressure MSIV UV-171 Accum-1 Pressure MSIV UV-171 Accum-2 Pressure MSIV UV-181 Accum-1 Pressure MSIV UV-181 Accum-2 Pressure ---------- FWIV UV-174 Accum-A Pressure FWIV UV-174 Accum-B Pressure FWIV UV-177 Accum-A Pressure FWIV UV-177 Accum-B Pressure FWIV UV-132 Accum-A Pressure FWIV UV-132 Accum-B Pressure FWIV UV-137 Accum-A Pressure FWIV UV-137 Accum-B Pressure ---------- ADV HV-178 Accum. Pressure ADV HV-179 Accum. Pressure ADV HV-184 Accum. Pressure ADV HV-185 Accum. Pressure			J-SGA-PT-0229 J-SGB-PT-0230 J-SGA-PT-0231 J-SGB-PT-0232 J-SGA-PT-0233 J-SGB-PT-0234 J-SGA-PT-0235 J-SGB-PT-0236 -------- J-SGA-PT-0237A J-SGA-PT-0237B J-SGA-PT-0238A J-SGA-PT-0238B J-SGB-PT-0239A J-SGB-PT-0239B J-SGB-PT-0240A J-SGB-PT-0240B -------- J-SGB-PT-0301 J-SGA-PT-0308 J-SGA-PT-0315 J-SGB-PT-0321	0 to 6000 psig -------- 500 to 700 psig	EX ----- (BB) ...... EX (ww) EQ EX (ww) EQ	I	Q ------ Q (xmtr) QAG (bal. of loop)	transducer at each accumulator	1E .... Non 1E (1E bkp)	control board meter ---------- CR indication on ERFDADS (vv)	Signals are recorded for trending on non-qualified ERFDADS in CR, TSC and EOF.
76) <u>Containment Area Radiation, High Range</u> (see row 34)	E-1	Fully							(for PT-0301, -0308, -0315,-0321)		
77) <u>Radiation Exposure Area Monitors, In-Plant</u> Person Access, Aux Bldg. West, 70' Person Access, Aux Bldg. East, 70' Person Access, Aux Bldg. South, 40' Person Access, Aux Bldg. North, 40 Person Access, Aux Bldg. West, 100' Person Access, Aux Bldg. East, 100' Person Access, Aux Bldg. Rec Area Person Access, Aux Bldg. West, 120' Person Access, Aux Bldg. East, 120' Person Access, Aux Bldg. South 140' (see also row 40)	E-2	Fully	J-SQN-RE-0152A J-SQN-RE-0152B J-SQN-RE-0152C J-SQN-RE-0152D J-SQN-RE-0153A J-SQN-RE-0153B J-SQN-RE-0153C J-SQN-RE-0154A J-SQN-RE-0154B J-SQN-RE-0154C	$1.0 \times 10^{+2}$ to 1.0×10^{7} mR/hr Sensitivity 10 mR/hr Accuracy ± 20%	EX (micro) EQ " " " " " " " "	II	QAG	ion chambers at access locations	1E	CR, TSC, EOF Display on non-qualified RMS terminal in CR. Also avail. on non-qualified ERFDADS. RU-152 thru RU-154 are recorded on both RMS and ERFDADS for trending Monitors also have local visual and audible alarms	Sensors are not redundant Displays are not redundant since ERFDADS receives values from RMS via datalink

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
78) Containment or Purge Effluent	E-2	N/A	NONE (not needed, effluent discharges through common plant vent) (See row 38)								
79) Reactor Shield Bldg. Annulus Effluent	E-2	N/A	NONE (not in PVNG design)								
80) Effluent from Auxiliary Building (including any bldg. containing primary system gases)	E-2	N/A	NONE (not needed, effluent discharges through common plant vent)								NOTE: waste gas decay tank is located in Radwaste Bldg. Its discharge header is monitored by JSQNRU12, available on RMS & ERFDADS.
81) Effluent Radioactivity from Condenser Air Removal Exhaust (see row 35)	E-2	N/A	NONE (not needed, effluent discharges through common plant vent, see row 38)								
82) Condenser Air Removal Exhaust Flowrate	E-2	N/A	NONE (not needed, effluent discharges through common plant vent, see row 84))								NOTE: air removal rate is measured at exhaust point by JARNFT38, available on ERFDADS
83) Effluent Activity, Common Plant Vent (see also row 39)	E-2	Fully									
84) Common Plant Vent Discharge Flow Plant Vent Stack Exhaust Flow (see also row 92)	E-2	Fully	J-CPN-FT-0042	0 to 165000 scfm (z)	EM	III	QAG	in plant vent stack	Non 1E (1E. bkp)	CR, TSC, EOF CR indication on ERFDADS. Signals recorded for trending on non-qualified ERFDADS	NOTE: includes condenser air removal exhaust.
85) Radiation at S/G relief /dump paths SG 1, Line 1 Effluent Monitor SG 1, Line 2 Effluent Monitor SG 2, Line 1 Effluent Monitor SG 2, Line 2 Effluent Monitor	E-2	Fully	 J-SQN-RU-0139A J-SQN-RU-0139B J-SQN-RU-0140A J-SQN-RU-0140B	1.5×10^{0} to 1.0×10^{7} mR/hr (kk) Sensitivity: 1.5 mR/hr Accuracy: $\pm$ 20%	EQ (sensor) EM (micro)	II	QAG	ion chambers on each steam line upstream of atmos. dump valves and main steam reliefs.	1E DG bkp	CR, TSC, EOF Display on non-qualified RMS terminal in CR. Also avail. on non-qualified ERFDADS. RU-139A/B & 140A/B are recorded on RMS & ERFDADS for trending.	One sensor located on each steam line. Displays are not redundant since ERFDADS receives values from RMS via datalink.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
86) Flowrate from Atmospheric Dump Paths (Calculated from analog valve position) SG 1, Line 2 Atm. Dump Vlv Pos. SG 2, Line 2 Atm. Dump Vlv Pos. SG 1, Line 1 Atm. Dump Vlv Pos. SG 2, Line 1 Atm. Dump Vlv Pos.	E-2	See footnote (GG)	J-SGB-ZT-0178 J-SGA-ZT-0179 J-SGA-ZT-0184 J-SGB-ZT-0185	0 to 100% open	EQ (sensors) EM (xmtr) EQ (xmtr) EM (xmtr) EQ (xmtr)	I	Q	LVDTs on each vlv positnr.	1E	CR,TSC,EOF Analog position on CR meter. Also, analog signals recorded for trending on non-qualified ERFDADS. (GG)	NOTE : ADVs are the preferred path to atm., under accident conditions.
87) Main Steam Relief Valve Flow (see row 59)	E-2	See footnote (AA)									
88) Effluent Activity, Identified Release Point Fuel Bldg. Exhaust Gas (see row 41)	E-2	Fully									
89) Identified Release Point, Discharge Flow Fuel Bldg. Vent Stack Exhaust Flow (see also row 94)	E-2	Fully	J-HFB-FT-0093	0 to 63800 scfm (aa)	EM	I	Q (xmtr) QAG (bal. of loop)	in fuel bldg. vent stack	1E	CR, TSC, EOF CR indication on ERFDADS. Signals are recorded for trending on non-qualified ERFDADS.	

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
90) Plant Vent Exhaust, Particulate Activity Low Level, continuous monitoring:	E-3	Fully	J-SQN-RU-0143, Ch 2	1.0 X 10^{-9} to 1.0 X 10^{-4} µCI/cc Accuracy ± 25%	EM (sensors) EM (micro)	II	QAG	beta scintillator in plant vent.	Non 1E	CR, TSC, EOF Display on non-qualified RMS terminal in CR. Also avail. on non-qualified ERFDADS. RU-143P is recorded on both RMS and ERFDADS for trending.	Displays are not redundant since ERFDADS receives values from RMS via datalink.
------			------	------	------	----	----	----	-----	-----	-------
High Level, continuous and grab sample collection w/ lab measurement:			Sampling at RU-144 skid, Multi-channel Analyzer, and hand calculation.	Particulate identification from samples: 10 mCi/ml to 1.4 mCi/ml (with dilution capability to 10 Ci/ml) Sensitivity: 10 µCi/ml Accuracy: factor of 2	EM (skid) None (for Hot Lab equip)	II (skid) None (for H`ot Lab equip)	QAG (skid) None (for Hot Lab equip)	sample collectors at RMS skid	Non 1E	Analysis results relayed to CR, TSC, EOF via fax	Samples are locally trapped in continuous collection or grab sample chambers located at the RMS skid. Determination of particulates is performed on Multichannel Analyzer. Activity Equivalent is calculated from results. NOTE: Sample collection may be access limited. NOTE: Hot lab equip. backed-up by labs in unaffected units.

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
91) Plant Vent Exhaust, Halogen Activity	E-3	Fully									
Low Level, continuous monitoring:			J-SQN-RU-0143, Ch 3	$1.0 X 10^{-9}$ to $1.0 X 10^{-4}$ µCI/cc Accuracy ± 25%	EM (sensors) EM (micro)	II	QAG	gamma scintillator in plant vent.	Non 1E	CR, TSC, EOF Display on non-qualified RMS terminal in CR. Also avail. on non-qualified ERFDADS. RU-143I is recorded on both RMS and ERFDADS for trending.	Displays are not redundant since ERFDADS receives values from RMS via datalink.
------ High Level, continuous and grab sample collection w/ lab measurement:			------ Sampling at RU-144 skid, Multi-channel Analyzer, and hand calculation.	------ Particulate identification from samples: 10 µCi/ml to 1.4 mCi/ml (with dilution capability to 10 Ci/ml) Sensitivity: 10 µCi/ml Accuracy: factor of 2	----- EM (skid) None (for Hot Lab equip)	----- II (skid) None (for Hot Lab equip)	----- QAG (skid) None (for Hot Lab equip)	---- sample collectors at RMS skid	----- Non 1E	------ Analysis results relayed to CR, TSC, EOF via fax.	------- Samples are locally trapped in continuous collection or grab sample chambers located at the RMS skid. Determination of radioisotopes is performed on Multichannel Analyzer. Activity Equivalent is calculated from results. NOTE: Sample collection may be access limited. NOTE: Hot lab equip. backed-up by labs in unaffected units.
92) Common Plant Vent Discharge Flow (see row 84)	E-3	Fully									

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location	Comments
93) Fuel Bldg. Exhaust, Particulate and Halogen Activity Continuous and grab sample collection with lab measurement	E-3	Fully	Sampling at RU-146 skid, Multi-channel Analyzer, and hand calculation.	Particulate and radioisotope identification from samples: 10 µCi/ml to 1.4 mCi/ml (with dilution capability to 10 Ci/ml) Sensitivity: 10 µCi/ml Accuracy: factor of 2	EM (skid) None (for Hot Lab equip)	II (skid) None (for Hot Lab equip)	QAG (skid) None (for Hot Lab equip)	sample collectors at RMS skid	non 1E	Analysis results relayed to CR, TSC, EOF via fax.	Samples are locally trapped in continuous collection or grab sample chambers located at the RMS skid. Determination of particulates and radioisotopes is performed on Multichannel Analyzer. Activity Equivalent is calculated from results. NOTE: Sample collection may be access limited. NOTE: Hot lab equip. backed-up by labs in unaffected units.
94) Fuel Bldg., Discharge Flow (see row 89)	E-3	Fully									
95) Radiation Exposure Area Monitors, Off-Plant Radiological Environmental Monitoring Exposure Meters (at fixed locations)	E-3	Fully	Panasonic 812 TLDs at fixed locations ranging from 1 to 45 miles from PVNGS; read on TLD Re'dr in Dosimetry Lab. (uu)	5 mRem to 6000 R	None	None	None	TLDs located as listed in Table 6-4 of the ODCM	N/A	Results relayed to CR, TSC, EOF via fax.	Each location has 2 or more dosimeters for measuring dose rate continuously.
96) Deleted											

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
97) Portable Area Radiation Monitors Portable 1 Portable 2 Portable 3 Portable 4 Portable 5 Portable 6 Portable 7 Portable 8 Portable 9	E-3	Fully	A-J-SQN-RU-0061 A-J-SQN-RU-0062 A-J-SQN-RU-0063 A-J-SQN-RU-0064 A-J-SQN-RU-0065 A-J-SQN-RU-0066 A-J-SQN-RU-0067 A-J-SQN-RU-0068 A-J-SQN-RU-0069	1.0 X 10^{-1} to 1.0 X 10^{4} mR/hr (with shield capability to 10^{4} R/hr)	N	II	NQR	portable GM devices (see note)	N/A	CR, TSC, EOF Display on non-qualified RMS terminal in CR. Also avail. on non-qualified ERFDADS. RU-61 thru 69 are recorded on both RMS and ERFDADS for trending.	Moveable monitors may be connected to RMS bus at portable connection boxes located throughout the PVNGS power block. NOTE: normally not connected to RMS bus.
98) Portable Multichannel Spectrometer Portable Multichannel Analyzer	E-3	Fully	Canberra Series 35+ Portable Multichannel Analyzer	determined by detector and counting conditions	None	None	None	portable	N/A	Analysis results relayed to CR, TSC, EOF via fax. or radio.	NOTE: there are two portable MCAs for three unit site.
99) Wind Direction Site Wind Direction at 35 ft., Instan. Site Wind Direction at nominal 200 ft., Instan.	E-3	Fully	A-J-RGN-ZT-0035P/R A-J-RGN-ZT-0195P/R	0 to 360° (from North)	N	III	NQR (loop) QAG (calibra-tion)	wind vanes at 35 ft and 200 ft on common site tower	Non 1E	CR, TSC, EOF CR indication on ERFDADS. Recorded at tower on JRGNUR1P/R. (see note). Data relayed for trending and display to ERFDADS.	"R" sensor is used for validity check against "P" sensor, only one analog value is reported at each elevation by MDTS computer. NOTE: "P" and "R" are separate recorders
100) Wind Speed Site Wind Speed at 35 ft Instantaneous Site Wind Speed at nominal 200 ft. Instantaneous	E-3	See footnote (u)	A-J-RGN-ST-0035P/R A-J-RGN-ST-0195P/R	0.5 to 50 mph (u)	N	III	NQR (loop) QAG (calibra-tion)	anemometers at 35 ft and 200 ft on common site tower	Non 1E	CR, TSC, EOF CR indication on ERFDADS. Recorded at tower on JRGNUR1P/R. (see note). Data relayed for trending and display to ERFDADS.	"R" sensor is used for validity check against "P" sensor, only one analog value is reported at each elevation by MDTS computer. NOTE: "P" and "R" are separate recorders

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location (RR)	Comments
101) Estimation of Atmospheric Stability (Calculated from) Met Tower Delta-Temp, Instantaneous (160 ft. interval)	E-3	See footnote (v)	A-J-RGN-C01 pt RGTD1	-6 to +6 °F (v)lo	N	III	NQR (loop) QAG (calibra-tion)	see Comment	Non 1E	CR, TSC, EOF CR indication on ERFDADS. Temp. difference recorded at tower JRGNUR1P/R. (see note) Temperature difference and Stability Class are avail. for trending and display on ERFDADS.	Temperature difference calculated by MDTS computer at tower, relayed via non-qualified datalink to ERFDADS. ERFDADS calculates Atmospheric Stability Class. NOTE: "P" and "R" are separate recorders
102) Primary Coolant Gamma Spectrum Primary Coolant Specific Activity (liquid and gas) Grab Sample:	E-3	See footnote (PP)									
103) Sump Specific Activity Grab Sample: Containment Recirculation Sump	E-3	see footnote (NN) and (PP)									

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location	Comments
104) Primary Coolant Boron Concentration Grab Sample:	E-3	See footnote (PP)									
105) Sump Boron Concentration Grab Sample: Containment Recirculation Sump	E-3	See footnote (PP) and (NN)									
106) Primary Coolant Chloride Content Grab Sample:	E-3	See footnote (PP)									
107) Sump Chloride Content Grab Sample: Containment Recirculation Sump	E-3	See footnote (PP) and (NN)									
108) Primary Coolant Total Dissolved Gases Grab Sample:	E-3	See footnote (PP)									
109) Primary Coolant Dissolved Hydrogen Grab Sample:	E-3	See footnote (PP)									
110) Primary Coolant Dissolved Oxygen Grab Sample: (JJ)	E-3	See footnotes (JJ) and (NN) and (PP)									
111) Primary Coolant pH Grab Sample:	E-3	See footnote (NN) and (PP)									
112) Sump pH Grab Sample: Containment Recirculation Sump (KK)	E-3	See footnote (KK) and (NN) and (PP)									
113) Containment Air Hydrogen Conc. Grab Sample: (LL) (see also Row 9)	E-3	See footnote (LL) and (PP)									
114) Containment Air Oxygen Conc. Grab Sample:	E-3	See footnote (PP)									

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Plant Variable	Type - Categ.	Comply	Monitoring Instrumentation (a)	Instrument Range (a)	Env. Qual. (b)	Seismic Class (c)	Quality Class (d)	Sensing Location	Power Supply (e)	Display Location	Comments
115) Containment Air Gamma Activity Grab Sample:	E-3	Fully See Footnote (PP)	(Sampling provided at RMS monitor RU-1 Grab Sampler). Multichannel Analyzer, and hand calculation.	Radionuclide isotopic identification from samples: 10 µCi/ml to 1.4 mCi/ml (with dilution capability to 10 Ci/ml) Sensitivity: 10 mCi/ml Accuracy: factor of 2	None (for Hot Lab equip)	None (for Hot Lab equip)	None (for Hot Lab equip)	Sample at RU-1 Skid at Cnmnt. 100' East Pene. Rm.	Non 1E (1E bkp)	Analysis results relayed to CR, TSC, EOF via fax.	Determination of radio-nuclides is performed on Multichannel Analyzer. I-131 Dose Equivalent is calculated from results. NOTE: Hot lab equip. backed-up by labs in unaffected units. NOTE: No heat tracing on sample lines. Plateout factor used for RU-1 cartridge samples. Samples are locally obtained in P&I grab sample chamber located at the RU-1 skid. Alternate sample collection may be access limited.

Footnotes:

(a) The identified instrumentation is usually the transmitter, although it is understood that the post-accident monitoring instrumentation loop extends from the sensing elements through to and including the control room display. In some cases the PVNGS instrumentation range is not literally that specified in RG 1.97. Some of these differences have been cited in letters to the NRC requesting an exception, other are cited in these footnotes; the differences cited in footnotes are not considered significant enough to render the "RG 1.97 compliance" of the instrumentation as questionable.

(b) Equipment Qualification Category Codes
- EQ = Component which is important to safety and qualified for harsh environment
- EM = Component performs safety-related function in a mild environment
- EP = Qualified as part of a larger component that has its own equip. ID tag.
- EX = Component which is important to safety but is exempt from qualification requirements based on an evaluation and/or NRC submittal.
- N = No equipment qualification requirements
- None = Item is not an Installed-Plant Component and has no assigned EQ Category.

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(c) Seismic Category Codes
- I = Applies to components that must remain functional in the event of a Safe Shutdown Earthquake, including those items that perform a safety-related function
- II = Applies to components, not included in I or IX, which are essential to power generation or whose failure could cause a safety hazard to station personnel.
- III = Applies to components not included in I, II or IX categories.
- IX = Applies to components, not included in I, whose structural failure or collapse could reduce the functioning of any safety-related feature to an unacceptable level.
- None = Item is not an Installed-Plant Component and has no assigned Seismic Category.

(d) Quality Assurance Classification Codes
- Q = Applies to those components that perform a safety-related function
- QAG = Applies to those components that are not included in Q class, but on which PVNGS has made a regulatory or FSAR commitment to be included within the scope of the QA Program. QAG components have a quality class code conveying the basis for their classification; these codes are defined in an administratively controlled procedure.
- NQR = Applies to those components not included in Q or QAG classes. [NOTE: QAG is sub-divided by reference code conveying the basis for its classification]
- None = Item is not an Installed-Plant Component and has no assigned QA Classification.

[Note: The quality class code associated with the (bal of loop) notation represents the minimum classification level to meet RG 1.97 Type/Category requirements. Individual components within the loop may have a higher classification code for other reasons.]

(e) Power Supply Codes
- 1E = The sensing device up to and including any isolation device is powered from a Class 1E source which meets the “standby power with battery backup” requirement.
- 1E - DG bkp = The sensing device up to and including any isolation device is powered from a Class 1E source which receives backup from emergency diesel generators (but not batteries) [some tolerable interruption of indication occurs]
- Non-1E = The instrument loop is powered from a non-Class 1E source (no designed backup)
- Non 1E (1E bkp) = The instrument loop is normally powered from a non-Class 1E source; diesel-backed 1E power available through manual or automatic transfer [some tolerable interruption of indication may occur]
- Self = The instrument loop is powered from the same source it is monitoring
- N/A = Not applicable

(f) Type A variable per APS letter #ANPP-31334 (12/5/84)

(g) Note: Wide range level indication is provided for both steam generators. RG 1.97, Rev. 2, required range is from the tube sheet to separators, but due to the economizer design of the steam generators, measuring level down to the tubesheet is not practical. The indication range extends from approximately 167-inches above the tube sheet to approximately 57-inches above the separator deck for the steam generators. Plant operations procedures are based on the as-built tap locations.

(h) Note: Normal practice is for STA to calculate margin from lowest pressurizer pressure and highest T-hot; QSPDS value is used as backup.

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(i) Note: CET readings are invalid above 25% reactor power.

(j) Note: Non-qualified heat trace on sample lines necessary for analyzer operability. Analyzer normally not in service; accurate readings after 30 minutes.

(k) Note: Footnote Deleted.

(l) Note: Zero point is top of vessel outlet plenum. RG 1.97, Rev. 2, required range is to the bottom of the core. This is accomplished indirectly by the use of the CETs.

(m) Note: Zero point is 4 inches above fuel alignment plate. Plenum level readings are unreliable when reactor coolant pumps are running.

(n) Note: Narrow Range overlaps the Wide Range by 0.5". Zero point on Wide Range is 6 inches above containment floor at approx. 40,000 gal. point. Upper limit is at approx. 960,000 gal. level equivalent.

(o) Note: Complies with R.G. 1.97 (Rev. 2) with the exception of the instrument range which does not meet the required range of ½ to 100 times Technical Specification limit in r/hr. The instruments cover the range from 10 to 100 times Technical Specification limit.

(p) Note: During extreme temperature ramps, radiation indication may exceed RG 1.97, Rev. 2 accuracy requirements for a short duration [less than 30 minutes].

(q) Note: Effectively top to bottom of vessel for operational use.

(r) Note: Lower range is 40°F instead of 32°F, exception approved in NRC letter Knighton to Van Brunt (6/18/85)

(s) Footnote deleted.

(t) Note: Upper range is equivalent to 105% design pressure, exception approved NRC letter Knighton to Van Brunt (6/18/85)

(u) Note: Upper range is 50 mph, exception approved NRC letter Knighton to Van Brunt (6/18/85)

(v) Note: Lower range is -6°F and upper range is +6°F (this has no effect on calculated Atmospheric Stability Class), see NRC letter Knighton to Van Brunt (6/18/85)

(w) Footnote deleted.

(x) Footnote deleted.

(y) Upper range is equivalent to approx. 20% above lowest safety valve setting.

(z) Upper range is equivalent to approx. 134% of vent design flow.

(aa) Upper range is equivalent to approx. 139% of vent design flow at rated pressure.

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(bb) Upper range is equivalent to approx. 200% of maximum one-pump flow. Nominal one-pump flow is 4437 gpm while nominal two-pump flow is 7519 gpm, which is design flow in accordance with RG 1.97, Rev. 2, thus the upper range is equivalent to 133% of this flow.

(cc) Upper range is equivalent to approx. 184% of design flow at rated pressure.

(dd) Upper range is equivalent to approx. 116% of S/G design or rated flow at rated pressure.

(ee) Upper range is equivalent to approx. 136% of downcomer design flow or 17% of steam generator rated flow. Downcomer flow is the normal post trip flow path if main feedwater, main condensate or when the “N” auxiliary feedwater pump (AFN-P01) is being used.

(ff) Upper range is equivalent to approx. 198% of design flow at rated pressure.

(gg) Upper range is equivalent to approx. 128% of design flow at rated pressure.

(hh) Upper range is equivalent to approx. 148% of design flow at rated pressure.

(ii) Upper range is equivalent to approx. 126% of design flow at rated pressure.

(jj) Upper range is equivalent to approx. 102% of design tank capacity.

(kk) Lower range is equivalent to approx. 8×10^{-2} μCi/cc to 16 mCi/cc depending on time since reactor shutdown, and upper range is equivalent to approx. 8×10^{5} μCi/cc to 16×10^{7} μCi/cc depending on time since reactor shutdown.

(ll) deleted

(mm) Footnote deleted.

(oo) Footnote deleted.

(pp) Footnote deleted.

(qq) Footnote deleted.

(rr) Footnote deleted.

(ss) Footnote deleted.

(tt) Upper range is equivalent to approx. 113% of design flow.

(uu) Note: TLDs are part of normal environmental sampling program, specific dosimeters may be read during post-accident situations at the discretion of the emergency response team.

(vv) Footnote deleted.

(ww) Note: Coded “EX” on the basis that local conditions are “mild” although the EQ Zone for the transmitter is identified as “harsh”.

(xx) Note: Coded “EX’ on the basis of Not Needed for mitigation exclusion.

(yy) Note: footnote deleted.

(zz) Note: Coded “EX” on the basis of Not Needed for Mitigation exclusion.

(AA) Note: Coded “EX” on the basis of Limited Period of need exclusion.

(BB) Footnote deleted.

(CC) Note: Post-accident monitor correction factors are tabulated in a design calculation.

(DD) Note: Footnote deleted.

Table 1.8-1
PVNGS COMPLIANCE WITH REGULATORY GUIDE 1.97 (REVISION 2) REQUIREMENTS
(Sheet 37 of 37)

(EE) Note:	APS letter #102-02800-WFC/RAB/SAB (1/21/94) states PVNGS' acceptance of NRC relaxation of qualification requirements from Category 2 to Category 3
(FF) Note:	Containment Spray is primary post accident heat removal method; re-circulation fans used only when termination of containment spray criteria are met.
(GG) Note:	Calculation of flowrate currently done manually (no longer performed by CRACS) assuming full open position.
(HH) Note:	Redundant thermocouples at five separate locations; one set (TE-42A1 thru TE-42E1) is connected to ERFDADS, while the other set (TE-42A thru TE-42E) is connected to CR recorder (J-RMN-TJR1) and the plant computer. A single failure can eliminate five readings within a set, but not both sets. The calibration of set TE-42A1 thru TE-42E1 is quality-related although the equipment beyond the thermocouples is classed as NQR. Set TE-42A thru TE-42E is not environmentally qualified and is classified as NQR throughout. The maximum temperature displayable on recorder JRMNTJR1 and plant computer is 200 F.
(JJ) Note:	APS replaced direct measurement with indirect measurement using temperature and pressure of Containment and borated water storage tank, as recommended in CEN-415 and accepted by NRC in letter J.E. Richardson to CEOG, dated 4/12/93.
(KK) Note:	APS deleted sampling capability and relies on the passive pH control agent in the containment recirculation sump, as recommended in CEN-415 and accepted by NRC in letter J.E. Richardson to CEOG, dated 4/12/93.
(LL) Note:	APS deleted sampling capability and relies on the safety-grade hydrogen monitors, as recommended in CEN-415 and accepted by NRC in letter J.E. Richardson to CEOG, dated 4/12/93.
(MM) Note:	Coded "EX" on the basis of "not needed for mitigation exclusion."
(NN) Note:	Note: APS has eliminated all Containment Radwaste Sump Samples and Auxiliary Building Sump Grab Samples. The Containment Re circulation Sump Sample requirements are satisfied utilizing the Emergency Plan and RCS Sampling Procedures. The pH requirement is satisfied using passive pH control. All; of the above exceptions are recommended per CEN-415 and documented in Modification of Post Accident Sampling System commitments file: 94-009-545. (APS letter number 102-02938 dated April 29, 1994).
(OO) Note:	These instruments are required for manual balancing of HPSI flow during initiation of post LOCA Long Term Cooling, and are therefore defined as Regulatory Guide 1.97 Type A-1 variables. These components were not classified as Regulatory Guide 1.97 Type A-1 variables during the initial PAMI determination (see footnote f) since this balancing function was automatic at the time.
(PP) Note:	APS no longer must meet the licensing requirements for a dedicated Post Accident Sampling System (PASS) as described in NRC approved PVNGS License Amendment 136 dated September 28, 2001. Remaining post accident sampling requirements are met through the Emergency Plan and associated procedures. This change is supported by CE-NPSD-1157, as accepted by the NRC in Safety Evaluation Report, dated May 16, 2000, for CEOG Topical Report CE-1157 Revision 1 (WESTINGHOUSE CEOG-00-215).
(QQ) Note:	The two transmitters share a common sensing line; this is acceptable since no credible failure mechanism will affect this line.
(RR) Note:	EOF display of plant variable data is provided through modified ERFDADS data via a Wide Area Network (WAN). WAN provides data not directly connected to the plant ERFDADS System. Various plant variables would be available as needed. In addition, three screens have been configured to replicate the ERFDADS monitor displays.
(SS) Note:	In units where DMWO 2778159 has been implemented, applicable valve(s) have been removed.
(TT) Note:	In Units where DMWO 2529758 has been implemented, valve CHA-UV-715 is removed and valves HPA-UV-0023 & HPA-UV-0024 are de-terminated with upstream piping cut and capped as the new containment boundary.

RESPONSE

Information contained in Regulatory Guide 1.112 is utilized as discussed in section 11.3.

REGULATORY GUIDE 1.114: Guidance on Being Operator at the Controls of a Nuclear Power Plant (Revision 1, November 1976

RESPONSE

The position of Regulatory Guide 1.114 is accepted. Reference 13.1.3.1.

REGULATORY GUIDE 1.115: Protection Against Low-Trajectory Turbine Missiles (Revision 1, July 1977)

RESPONSE

The position of Regulatory Guide 1.115 is accepted as described in section 3.5.

REGULATORY GUIDE 1.117: Tornado Design Classification (Revision 1, April 1978)

RESPONSE

The position of Regulatory Guide 1.117 is accepted to the extent described in sections 3.3 and 3.5, and subsection 9.2.5.4. Also see Regulatory Guide 1.76.

REGULATORY GUIDE 1.118: Periodic Testing of Electric Power and Protection Systems (Revision 1, November 1977)

RESPONSE

The position of Regulatory Guide 1.118 is accepted as described in sections 7.1 and 8.3. Additional references 14.2.7 and Table 18.II.F.2-3.

REGULATORY GUIDE 1.121: Bases for Plugging Degraded PWR Steam Generator Tubes (Revision 0, August 1976)

RESPONSE

The position of Regulatory Guide 1.121 is accepted. Reference the Technical Specifications.

REGULATORY GUIDE 1.124: Service Limits and Loading Combinations for Class 1 Linear-Type Component Supports (Revision 1, January 1978)

RESPONSE

The position of Regulatory Guide 1.124 is accepted for the BOP Bechtel scope (see 3.9.3). The following response is applicable to the CE supplied (NSSS) scope:

The Regulatory Guide addresses service limits and loading combinations for Class I linear type component supports. The Regulatory Guide is more restrictive in terms of allowable

stresses than the previous revision and attempts to take into account the non-linear behavior encountered in bolted connections and shear stresses.

POSITION:

The RCS component supports as presently designed meet this latest revision of the regulatory guide.

The materials used in the design of the Reactor Coolant System components supports have been designed without using extremely high strength materials. This maintains an ultimate to yield strength ratio which is greater than 1.2 and as a result the allowable stresses used in the present design of the supports are the same as the allowable stresses in the latest revision of the regulatory guide. The regulatory guide addresses the fact that failure in shear may be a non-linear phenomenon. To compensate for this, the allowable stress in shear for Level "D" (faulted) is limited to 1.5 times the level of A & B allowable stresses in the latest revision of the regulatory guide. The RCS supports as presently designed meet this latest revision of the regulatory guide.

REGULATORY GUIDE 1.127: Inspection of Water-Control Structures Associated with Nuclear Power Plants (Revision 1, March 1978)

RESPONSE

The position of Regulatory Guide 1.127 does not apply to PVNGS.

REGULATORY GUIDE 1.129: Maintenance, Testing and Replacement of Large Lead Storage Batteries for Nuclear Power Plants (Revision 2, February 2007)

RESPONSE

The position of Regulatory Guide 1.129 Revision 2 is accepted with the following exceptions:

1. Battery temperature correction may be performed before or after conducting discharge tests.
2. RG 1.129 Regulatory Position 1 subsection 2, “References” is not applicable to the PVNGS Battery Monitoring and Maintenance program.
3. In lieu of RG 1.129, Regulatory Position 2, subsection 5.2, “Inspections” the following shall be used:

   “Where reference is made to the pilot cell, pilot cell selection shall be based on the lowest voltage cell in the battery.”

4. In Regulatory Guide 1.129, Regulatory Position 3, subsection 5.4.1,”State of Charge Indicator,” the following statements in paragraph (d) may be omitted:

   “When it has been recorded that the charging current has stabilized at the charging voltage for three consecutive hourly measurements, the battery is near full charge. These measurements shall be made after the initially high charging current decreases sharply and the battery voltage rises to approach the charger output voltage.”

5. In lieu of RG 1.129 Regulatory Position 7, Subsections 7.6, "Restoration" the following may be used.

   "Following the test, record the float voltage of each cell of the string."

   References 8.3.2.1.2.1 and 8.3.2.2.1.21.

REGULATORY GUIDE 1.130: Design Limits and Loading Combinations for Class 1 Plate-and-Shell Type Component Supports (Revision 0/1, July 1977/October 1978)

RESPONSE

There are no Class 1 plate-and-shell type component supports in the BOP Bechtel scope.

The following response is applicable to the CE supplied (NSSS) scope:

The Regulatory Guide addresses design limits and loading combinations for Class 1 plate and shell type component supports.

POSITION

Most Class 1 supports designed by C-E are of the linear type and, therefore, are not affected by this guide. The only exception is the steam generator sliding base support which is subjected to biaxial stress fields. The design for the steam generators conforms to revision 1 of Regulatory Guide 1.130.

REGULATORY GUIDE 1.133: Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors (Revision 1, May 1981)

RESPONSE

The LPMS has been evaluated to determine conformance to the guidelines of Regulatory Guide 1.133, Revision 1. The evaluation is shown on table 1.8-2. Reference sections 4A.4, 7.7.1.1.8, and Table 3.2-1.

Table 1.8-2
LOOSE PARTS MONITORING SYSTEM CONFORMANCE EVALUATION
(Sheet 1 of 2)

Regulatory Guide 1.133, Rev. 1 Regulatory Positions	PVNGS Conformance to the Regulatory Positions
1. System characteristics	
a. Sensor locations	No exception
b. System sensitivity	No exception
c. Channel separation	No exception
d. Data acquisition system	A digital recording system is provided. Signals from all channels are continually sampled. Power is supplied from a 120 V-ac normal (non-seismically qualified) instrument bus, which has a Class 1E backup source. No exception
e. Alert level	No exception
f. Capability for sensor channel functionality test	
g. Functionality for seismic and environmental conditions	The LPMS components will be qualified to meet the normal environmental parameters of the areas in which they are installed.

Table 1.8-2
LOOSE PARTS MONITORING SYSTEM CONFORMANCE EVALUATION
(Sheet 2 of 2)

Regulatory Guide 1.133, Rev. 1 Regulatory Positions	PVNGS Conformance to the Regulatory Positions
h. Quality of system	No exception
i. System repair	No exception
2. Establishing the alert Level	No exception
3. Using the data acquisition Modes	APS takes exception to RG 1.133 regulatory position C.3.a(2)(e) to submit changes to the alert level and alert logic.
4. Content of safety analysis Reports	No exception to this section or section 7.7
5. Technical specification for the loose parts detection system	The guidance in Regulatory Position C.5, "Technical Specification for the Loose-Part Detection System," is implemented in the Technical Requirements Manual instead of the Technical Specifications.
6. Notification of a loose part	APS takes exception to RG 1.133 regulatory position C.6. This regulatory position has been superceded by 10 CFR 50.72 and 10 CFR 50.73.

REGULATORY GUIDE 1.134: Medical Evaluation of Licensed Personnel for Nuclear Power Plants (Revision 2, April 1987)

RESPONSE

The position of Regulatory Guide 1.134 is accepted.

REGULATORY GUIDE 1.137: Position C.2: Fuel Oil Systems for Standby Diesel Generators (Revision 1, October 1979)

RESPONSE

Position C.2 of Regulatory Guide 1.137 is accepted with the following exceptions to the Guide and the referenced standard (ANSI N195-1976):

A. ASTM D2276, Particulate Contaminant in Aviation Turbine Fuels, will replace ASTM D2274-70, Oxidation Stability of Distillate Fuel Oil (Accelerated Method), as outlined in Appendix B of ANSI N195-1976. The specification for particulate contamination will be 10 mg/l, maximum.

B. Fuel oil sampling will be in accordance with ASTM D4057-81, Manual Sampling of Petroleum and Petroleum Products. This replaces ASTM D270-1975, Standard Method of Sampling Petroleum and Petroleum Products, which has been deleted as an ASTM standard.

C. A high level alarm is not provided on the underground storage tanks. These tanks serve only the diesel

generators and are refilled only to replace fuel used during periodic testing. Safety grade level indication is provided in the main control room so that the refueling may be monitored.

D. Internal corrosion protection is not provided. Periodic (every 92 days) checks of fuel quality combined with low humidity and low rainfall at the site (see section 2.3) will preclude water accumulation and subsequent corrosion.

E. The fuel sampling connection is located within the vault above the tank. This connection can also be used as a stick gauge connection. The vault is approximately 6 feet high, which allows adequate access and use of a hinged stick gauge. This location precludes missile damage to a connection aboveground.

F. Analysis performed to determine if the "remaining applicable specifications" and "other properties" of new fuel and stored fuel, described in Position C.2.a and C.2.b, should be completed within 31 days of obtaining the sample.

G. Clarification: Fuel oil contained in the supply tank not meeting the "remaining applicable specifications" described in Position C.2.a (specifications other than viscosity or water and sediment) should, in a short period of time (about a week from identification), be replaced or returned to specification via processing.

H. Diesel fuel oil will meet the specifications of ASTM D975, Table 1, and analysis will be performed using the methods described in ASTM D975 per the ASTM standard revision referenced in the Technical Specification Bases 3.8.3 in lieu of ASTM D975-77 as described in Position C.2.a. For parameters not required by Technical Specifications, the analytical methods can be based on more current approved ASTM methods.

Reference 9.5.4.1.3, 9.5.4.2, 9A.9, and 9A.11.

REGULATORY GUIDE 1.140: Design, Testing and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants (Revision 1, October 1979)

RESPONSE

Exceptions are taken to applicable portions of Regulatory Guide 1.140 as referenced in NRC Generic Letter 83-13, Clarification of Surveillance requirements for HEPA Filters and Charcoal Adsorber Units in Standard Technical Specifications on ESF Cleanup Systems, and NRC Generic Letter 99-02, Laboratory Testing of Nuclear-Grade Activated Charcoal (APS Letter #102-04373). Exception to Regulatory Guide 1.140 is taken in reference to using ANSI N509-1980 in place of ANSI N509-1976 and using ANSI N510-1980 in place of ANSI N510-1975.

Information contained in Regulatory Guide 1.140 is utilized as discussed in sections 9.4 and 11.3, and in table 1.8-3.

Additional references: 9A.38 and 14.2.8.

REGULATORY GUIDE 1.141: Containment Isolation Provisions for Fluid Systems (Revision 0, April 1978)

RESPONSE

The position of Regulatory Guide 1.141 is accepted (refer to subsection 6.2.4) except for the following. An exception is taken to Regulatory Guide 1.141 for the CVCS charging line containment isolation valve CHA-HV-524. This valve does not meet the guidance of Section 4.2.2 of ANSI N271-1976 which requires all power-operated isolation valves to be capable of remote manual actuation from the control room. The power supply for this valve is removed by locking open its breaker at MCC PHA-M3520. The restoration of the power supply requires local operator action at the MCC. This exception to lock open valve CHA-HV-524 ensures that a flow path is available for charging or auxiliary spray flow by preventing inadvertent operation of the valve.

REGULATORY GUIDE 1.143: Design Guidance for Radioactive Waste Management Systems Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants (Revision 0, July 1978)

RESPONSE

PVNGS accepts the position of Regulatory Guide 1.143 including implementation of quality assurance requirements for the radwaste management systems (refer to sections 9.3, 11.2, 11.3, 11.4, and the PVNGS Operations Quality Assurance Program Description. Additional references: 3.2.2 (Table 3.2-1), 6.2.4.2.2, 11.5.4.2, and 11A.1) with the following exceptions:

A. Position B, (Discussion) - For the purpose of this guide the radwaste systems do not include instrumentation and sampling systems beyond the first root valve.

B. Position B - The instrument and controls of the gaseous radioactive waste processing system satisfy the requirements of Section 7.2 of ANSI/ANS-55.4-1979 referenced by Regulatory Guide 1.143, Rev. 1, with the following exception:

   The system gas analyzer, as specified in Table 6, will not record the H_2% by volume. It is assumed that the gaseous radwaste system will contain > 4% H_2 by volume whenever the system is in service. Monitoring the potentially explosive mixture will be based upon this assumption and the measured O_2 concentration by the gas analyzers.

C. Position C, Paragraph 1.1.3

   The turbine building, which houses most of the steam generator blowdown system, is a Seismic Category II braced steel and concrete structure with a design that

has been shown not to collapse under SSE loads. The turbine building has no means of containing the maximum liquid inventory contained in the potentially radioactive portions of the steam generator blowdown system. This potential for liquid/gaseous release is less than that resulting from failure of the refueling water tank analyzed in subsection 15.7.3 where the radiological consequences have been determined to be less than 1% of the 10CFR100 limits.

D. Position C, Paragraph 1.2.1

High level alarms on tanks in the radwaste building alarm in the radwaste control room instead of the main control room. A common radwaste alarm sounds in the main control room for any alarm that exists in the radwaste control room. No tank has a local alarm as the tank overflows are hardpiped to sumps avoiding local uncontrolled spillage.

E. Position C, Paragraph 1.2.3

The blowdown flashtank, (SCN-X01) in the turbine building, does not have an elevated threshold to catch potential leakage. However, because this tank operates at an elevated temperature and pressure, any leakage would be initially visible as steam. Liquid leaks would be collected by the turbine building drain system, which can be routed to the liquid radwaste system.

F. Position C, Paragraph 4.3

Pressure testing (hydrostatic or equivalent pneumatic) is conducted using the applicable ASME or ANSI code, but in no case less than one and one-half times the line design pressure for hydrostatic testing and no less than 1.2 times design pressure for pneumatic testing of the GRS for a minimum of 10 minutes as required by the above codes.

G. Position C, Paragraphs 5.1.2 and 5.2.4

The reinforced concrete design of these structures is in accordance with American Concrete Standard ACI 318 in lieu of ACI 349-76. Structures containing radwaste systems are analytically verified to withstand SSE loads without collapse.

H. Position C, Paragraph 1.1.2

"Materials for pressure retaining components" will be met for Chemical Waste (CM) system, except that ferritic ductile cast iron that meets the requirement of ASTM A-395 may be substituted for low carbon steel components where the maximum service temperature is 200°F and the maximum service pressure is 200 psig. Welding shall not be permitted on any ductile iron component.

Table 1.8-3
COMPARISON BETWEEN DESIGN FEATURES AND REGULATORY GUIDE 1.140 POSITIONS
(Sheet 1 of 9)

Radioactivity Removal Normal Ventilation Systems Regulatory Guide 1.140 Positions	Containment Power Access Purge	Auxiliary Building	Radwaste Building	Turbine Building Vacuum Pump Exhaust	Containment Preaccess (Air Cleanup Recirculation)
C.1.b	System is not located in an area of high radiation during normal plant operation.	System is not located in an area of high radiation during normal plant operation.	System is not located in an area of high radiation during normal plant operation.	System is not located in an area of high radiation during normal plant operation.	Adequate shielding is provided.
C.2.a	HEPA filters have been included after the adsorber.	A prefilter is used, also a HEPA filter is included after the adsorber. No heater or cooling coils are used.	No adsorber has been included in this system. System is to remove particulate materials only. No heater or cooling coils are used.	No exception taken.	No exception taken.
C.2.b	No exception taken.	All three filter banks, one prefilter and two HEPA, are arranged 5 wide by 6 high. A floor has been placed between the third and fourth level of filters.	Both filter banks, prefilter and HEPA, are arranged 4 wide by 6 high. A floor has been placed between the third and fourth level of filters.	No exception taken.	No exception taken.
C.2.c	Local pressure drop indication provided. Refer to section 9.4 for location. All alarms are automatic, visual, and audible.	High and low pressure drop alarms in control room.	High pressure drop alarms locally.	High pressure drop alarm in control room.	High pressure drop alarm in control room.
C.2.e	No outdoor air is brought through the system.	Outdoor air is not brought through the system.	Outdoor air is not brought through the system.	Outdoor air is not brought through the system.	Outdoor air is not brought through the system.

Table 1.8-3
COMPARISON BETWEEN DESIGN FEATURES AND REGULATORY GUIDE 1.140 POSITIONS
(Sheet 2 of 9)

Radioactivity Removal Normal Ventilation Systems Regulatory Guide 1.140 Positions	Containment Power Access Purge	Auxiliary Building	Radwaste Building	Turbine Building Vacuum Pump Exhaust	Containment Preaccess (Air Cleanup Recirculation)
C.3.a	No exception taken.	The auxiliary building normal supply system has been designed to insure that the exhaust atmosphere will have a relative humidity of less than 70%. The supply unit contains cooling coils to remove moisture from the air. Both supply and exhaust units are in continuous operation, precluding relative humidity buildup from within the building. As a result, neither heaters or cooling coils have been included in the normal ventilation system exhaust unit.	No adsorber has been included in this system. System is to remove particulate materials only. No heater or cooling coils are used.	No exception taken.	Maximum relative humidity will be less than 70% at the inlet to the unit at all times during normal plant operation. Consequently, a heater is not required for the unit to control the inlet RH to the charcoal filter. (In response to NRC Generic Letter 99-02).
C.3.c	Upstream mounting of filters may be employed in some cases.	Upstream mounting of filters may be employed in some cases.	Upstream mounting of filters may be employed in some cases.	Upstream mounting of filters may be employed in some cases.	Upstream mounting of filters may be employed in some cases.
C.3.g	The activated carbon, when new, will be provided to meet the physical property specifications of Table 5.1 of ANSI N509-1980 Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to NRC Generic Letter 99-02).	The activated carbon, when new, will be provided to meet the physical property specifications of Table 5.1 of ANSI N509-1980 Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to NRC Generic Letter 99-02).	No charcoal adsorber has been included into the design of this system. It is designed to remove particulates only	The activated carbon, when new, will be provided to meet the physical property specifications of Table 5.1 of ANSI N509-1980 Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to NRC Generic Letter 99-02).	The activated carbon, when new, will be provided to meet the physical property specifications of Table 5.1 of ANSI N509-1980 Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to NRC Generic Letter 99-02).
C.3.h	No exception taken.	No exception taken.	Position does not apply since no charcoal absorber has been provided in the system.	No exception taken.	No exception taken.

Table 1.8-3
COMPARISON BETWEEN DESIGN FEATURES AND REGULATORY GUIDE 1.140 POSITIONS
(Sheet 3 of 9)

Radioactivity Removal Normal Ventilation Systems Regulatory Guide 1.140 Positions	Containment Power Access Purge	Auxiliary Building	Radwaste Building	Turbine Building Vacuum Pump Exhaust	Containment Preaccess (Air Cleanup Recirculation)
C.3.m	No exception taken.	No exception taken.	No exception taken.	No prefilter included in this system.	No exception taken.
C.4.b	No exception taken.	Accessibility for ease of maintenance is provided by removing opposing filters in opposite directions. This fulfills the suggested standard distance of 3 feet plus length of component for filter.	Accessibility for ease of maintenance is provided by removing opposing filters in opposite directions. This fulfills the suggested standard distance of 3 feet plus length of component for filter.	No exception taken.	No exception taken.
C.5.c	In-place dictylphthalate (DOP) penetration and bypass leakage test of HEPA filter banks will confirm a penetration of less than 1%.	In-place dictylphthalate (DOP) penetration and bypass leakage test of HEPA filter banks will confirm a penetration of less than 1%.	In-place dictylphthalate (DOP) penetration and bypass leakage test of HEPA filter banks will confirm a penetration of less than 1%.	In-place dictylphthalate (DOP) penetration and bypass leakage test of HEPA filter banks will confirm a penetration of less than 1%.	In-place leak testing will not be performed. Visual inspection will be performed periodically and at acceptance. Also, testing will be performed in accordance with ANSI N510, 1980, Table 1, Note 5. Silicone sealants are acceptable for sealing filtration housing electrical and piping penetration.

Table 1.8-3
COMPARISON BETWEEN DESIGN FEATURES AND REGULATORY GUIDE 1.140 POSITIONS
(Sheet 4 of 9)

Radioactivity Removal Normal Ventilation Systems / Regulatory Guide 1.140 Positions	Containment Power Access Purge	Auxiliary Building	Radwaste Building	Turbine Building Vacuum Pump Exhaust	Containment Preaccess (Air Cleanup Recirculation)
C.5.c	The in-place testing penetration acceptance criterion for penetration will be less than or equal to 1.0% in place of 0.05%. (In response to NRC Generic Letter 83-13). If not removed during welding activities, the filters and adsorber section will be protected/isolated from the affects of the process. Silicone sealant may be used to seal electrical and piping penetrations into the filter housing. Use of silicone sealants will be within manufacturer's recommended guidelines.	The in-place testing penetration acceptance criterion for penetration will be less than or equal to 1.0% in place of 0.05%. (In response to NRC Generic Letter 83-13). If not removed during welding activities, the filters and adsorber section will be protected/isolated from the affects of the process. Silicone sealant may be used to seal electrical and piping penetrations into the filter housing. Use of silicone sealants will be within manufacturer's recommended guidelines.	The in-place testing penetration acceptance criterion for penetration will be less than or equal to 1.0% in place of 0.05%. (In response to NRC Generic Letter 83-13). If not removed during welding activities, the filters and adsorber section will be protected/isolated from the affects of the process. Silicone sealant may be used to seal electrical and piping penetrations into the filter housing. Use of silicone sealants will be within manufacturer's recommended guidelines.	The in-place testing penetration acceptance criterion for penetration will be less than or equal to 1.0% in place of 0.05%. (In response to NRC Generic Letter 83-13). If not removed during welding activities, the filters and adsorber section will be protected/isolated from the affects of the process. Silicone sealant may be used to seal electrical and piping penetrations into the filter housing. Use of silicone sealants will be within manufacturer's recommended guidelines.	An in-place leak test will not be performed since these are recirculating systems within the reactor containment building. (Reference ANSI N510-1980, Table 1, Footnote (5). If not removed during welding activities, the filters and adsorber section will be protected/isolated from the affects of the process. Silicone sealant may be used to seal electrical and piping penetrations into the filter housing. Use of silicone sealants will be within manufacturer's recommended guidelines.
C.5.d	The in-place testing penetration acceptance criterion for penetration will be less than or equal to 1.0% in place of 0.05%. (In response to NRC Generic Letter 83-13). Airflow through the unit will not be maintained to remove the residual refrigerant gas.	The in-place testing penetration acceptance criterion for penetration will be less than or equal to 1.0% in place of 0.05%. (In response to NRC Generic Letter 83-13). Airflow through the unit will not be maintained to remove the residual refrigerant gas.	Position does not apply. No charcoal adsorber has been included into the design of this system. It is designed to remove particulates only.	The in-place testing penetration acceptance criterion for penetration will be less than or equal to 1.0% in place of 0.05%. (In response to NRC Generic Letter 83-13). Airflow through the unit will not be maintained to remove the residual refrigerant gas.	An in-place leak test will not be performed since these are recirculating systems within the reactor containment building. (Reference ANSI N510-1980, Table 1, Footnote(5).

Table 1.8-3
COMPARISON BETWEEN DESIGN FEATURES AND REGULATORY GUIDE 1.140 POSITIONS
(Sheet 5 of 9)

Radioactivity Removal Normal Ventilation Systems	Containment Power Access Purge	Auxiliary Building	Radwaste Building	Turbine Building Vacuum Pump Exhaust	Containment Preaccess (Air Cleanup Recirculation)
C.6.a	The activated carbon, when new, will be provided to meet the physical property specifications of Table 5.1 of ANSI N509-1980. Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to Generic Letter 99-02). The laboratory testing criteria for testing a representative carbon adsorber sample will be in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. Test acceptance criteria is derived by using the assigned activated carbon decontamination efficiency of 70% for organic iodide per Regulatory Guide 1.140, Revision 1, October 1979, Table 2, and imposing a safety factor of 2. This results in the test acceptance criteria of a methyl iodide penetration of less than or equal to 15%. (In response to Generic Letter 99-02).	The activated carbon, when new, will be provided to meet the physical property specifications of Table 5.1 of ANSI N509-1980. Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to Generic Letter 99-02). The laboratory testing criteria for testing a representative carbon adsorber sample will be in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. Test acceptance criteria is derived by using the assigned activated carbon decontamination efficiency of 70% for organic iodide per Regulatory Guide 1.140, Revision 1, October 1979, Table 2, and imposing a safety factor of 2. This results in the test acceptance criteria of a methyl iodide penetration of less than or equal to 15%. (In response to Generic Letter 99-02).	Position does not apply. No charcoal adsorber has been included into the design of this system. It is designed to remove particulates only.	The activated carbon, when new, will be provided to meet the physical property specifications of Table 5.1 of ANSI N509-1980. Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to Generic Letter 99-02). The laboratory testing criteria for testing a representative carbon adsorber sample will be in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. Test acceptance criteria is derived by using the assigned activated carbon decontamination efficiency of 70% for organic iodide per Regulatory Guide 1.140, Revision 1, October 1979, Table 2, and imposing a safety factor of 2. This results in the test acceptance criteria of a methyl iodide penetration of less than or equal to 15%. (In response to Generic Letter 99-02).	The activated carbon, when new, will be provided to meet the physical property specifications of Table 5.1 of ANSI N509-1980. Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to Generic Letter 99-02) The laboratory testing criteria for testing a representative carbon adsorber sample will be in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. (In response to Generic Letter 99-02). These units are recirculating systems (not exhaust systems) and are used for general atmosphere cleanup purposes. Additionally, ASTM D3803-1989 is a more stringent test than that described in Section 4.5.4 of RDT M16-1T (reference Regulatory Guide 1.140, Revision 1, October 1979, Table 2). Therefore, exception is taken to Table 2 criteria and an acceptance criteria of a methyl iodide penetration of less than or equal to 15% will be established.

Table 1.8-3
COMPARISON BETWEEN DESIGN FEATURES AND REGULATORY GUIDE 1.140 POSITIONS
(Sheet 6 of 9) continued

Radioactivity Removal Normal Ventilation Systems	Containment Power Access Purge	Auxiliary Building	Radwaste Building	Turbine Building Vacuum Pump Exhaust	Containment Preaccess (Air Cleanup Recirculation)
C.6.b	The number of samplers (sample stations) is not sufficient to last throughout the expected adsorbent life. Therefore, when depleted, they will be refilled from a composite sample taken from the adsorber by means of a grain-thieving device. The design of the samplers should be in accordance with the provisions of Appendix A of ANSI N509-1980 in place of ANSI N509-1976. A representative carbon sample of the adsorber will be obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.140, Revision 1, October 1979, using Appendix A of ANSI N509-1980 in place of Appendix A of ANSI N509-1976. However, a thieving device other than a slotted tube sampler may be used when extracting carbon from the adsorber section. Laboratory tests of representative samples will be conducted in accordance with ASTM D3803-1989, using a	The number of samplers (sample stations) is not sufficient to last throughout the expected adsorbent life. Therefore, when depleted, they will be refilled from a composite sample taken from the adsorber by means of a grain-thieving device. The design of the samplers should be in accordance with the provisions of Appendix A of ANSI N509-1980 in place of ANSI N509-1976. A representative carbon sample of the adsorber will be obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.140, Revision 1, October 1979, using Appendix A of ANSI N509-1980 in place of Appendix A of ANSI N509-1976. However, a thieving device other than a slotted tube sampler may be used when extracting carbon from the adsorber section. Laboratory tests of representative samples will be conducted in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity(In response to Generic Letter 99-02).	Position does not apply. No charcoal adsorber has been included into the design of this system. It is designed to remove particulates only.	The number of samplers (sample stations) is not sufficient to last throughout the expected adsorbent life. Therefore, when depleted, they will be refilled from a composite sample taken from the adsorber by means of a grain-thieving device. The design of the samplers should be in accordance with the provisions of Appendix A of ANSI N509-1980 in place of ANSI N509-1976. A representative carbon sample of the adsorber will be obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.140, Revision 1, October 1979, using Appendix A of ANSI N509-1980 in place of Appendix A of ANSI N509-1976. However, a thieving device other than a slotted tube sampler may be used when extracting carbon from the adsorber section. Laboratory tests of representative samples will be conducted in accordance with ASTM D3803-1989, using a	The number of samplers (sample stations) is not sufficient to last throughout the expected adsorbent life. Therefore, when depleted, they will be refilled from a composite sample taken from the adsorber by means of a grain-thieving device. The design of the samplers should be in accordance with the provisions of Appendix A of ANSI N509-1980 in place of ANSI N509-1976. A representative carbon sample of the adsorber will be obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.140, Revision 1, October 1979, using Appendix A of ANSI N509-1980 in place of Appendix A of ANSI N509-1976. However, a thieving device other than a slotted tube sampler may be used when extracting carbon from the adsorber section. Laboratory tests of representative samples will be conducted in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity

Table 1.8-3
COMPARISON BETWEEN DESIGN FEATURES AND REGULATORY GUIDE 1.140 POSITIONS
(Sheet 7 of 9)

Radioactivity Removal Normal Ventilation Systems Regulatory Guide 1.140 Positions	Containment Power Access Purge	Auxiliary Building	Radwaste Building	Turbine Building Vacuum Pump Exhaust	Containment Preaccess (Air Cleanup Recirculation)
	temperature of 30°C and 70% relative humidity (In response to Generic Letter 99-02). As such, the representative sample media will not experience the test gas flow in the same direction as the flow during service conditions, as it will have been homogeneously mixed and fed into the test apparatus. Therefore, it will be taken out of its original test canister (or, thieved directly from the adsorber bed) and transferred into an airtight container until at which time it is prepared for the laboratory test. The activated carbon adsorber section should be replaced with new unused activated carbon meeting the physical property specifications of Table 5.1 of ANSI N509-1980 in place of Table 5.1 of ANSI N509-1976 if (1) laboratory test results indicate a methyl iodide penetration greater than 15%, or (2) no representative sample is available for testing.	As such, the representative sample media will not experience the test gas flow in the same direction as the flow during service conditions, as it will have been homogeneously mixed and fed into the test apparatus. Therefore, it will be taken out of its original test canister (or, thieved directly from the adsorber bed) and transferred into an airtight container until at which time it is prepared for the laboratory test. The activated carbon adsorber section should be replaced with new unused activated carbon meeting the physical property specifications of Table 5.1 of ANSI N509-1980 in place of Table 5.1 of ANSI N509-1976 if (1) laboratory test results indicate a methyl iodide penetration greater than 15%, or (2) no representative sample is available for testing.		temperature of 30°C and 70% relative humidity(In response to Generic Letter 99-02). As such, the representative sample media will not experience the test gas flow in the same direction as the flow during service conditions, as it will have been homogeneously mixed and fed into the test apparatus. Therefore, it will be taken out of its original test canister (or, thieved directly from the adsorber bed) and transferred into an airtight container until at which time it is prepared for the laboratory test. The activated carbon adsorber section should be replaced with new unused activated carbon meeting the physical property specifications of Table 5.1 of ANSI N509-1980 in place of Table 5.1 of ANSI N509-1976 if (1) laboratory test results indicate a methyl iodide penetration greater than 15%, or (2) no representative sample is available for testing.	(In response to Generic Letter 99-02). As such, the representative sample media will not experience the test gas flow in the same direction as the flow during service conditions, as it will have been homogeneously mixed and fed into the test apparatus. Therefore, it will be taken out of its original test canister (or, thieved directly from the adsorber bed) and transferred into an airtight container until at which time it is prepared for the laboratory test. The activated carbon adsorber section should be replaced with new unused activated carbon meeting the physical property specifications of Table 5.1 of ANSI N509-1980 in place of Table 5.1 of ANSI N509-1976 if (1) laboratory test results indicate a methyl iodide penetration greater than 15%, or (2) no representative sample is available for testing.

Table 1.8-3

COMPARISON BETWEEN DESIGN FEATURES AND REGULATORY GUIDE 1.140 POSITIONS

(Sheet 8 of 9)

Radioactivity Removal Normal Ventilation Systems Regulatory Guide 1.140 Positions	Containment Power Access Purge	Auxiliary Building	Radwaste Building	Turbine Building Vacuum Pump Exhaust	Containment Preaccess (Air Cleanup Recirculation)
Table 1	Charcoal will be provided to meet the requirements of ANSI N509-1980, Table 5-1	Charcoal will be provided to meet the requirements of ANSI N509-1980, Table 5-1.	No charcoal absorber has been designed in the system.	Charcoal will be provided to meet the requirements of ANSI N509-1980, Table 5-1.	Charcoal will be provided to meet the requirements of ANSI N509-1980, Table 5-1.
Table 2.	The laboratory testing criteria for testing a representative carbon adsorber sample will be in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. Test acceptance criteria is derived by using the assigned activated carbon decontamination efficiency of 70% for organic iodide, per	The laboratory testing criteria for testing a representative carbon adsorber sample will be in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. Test acceptance criteria is derived by using the assigned activated carbon decontamination efficiency of 70% for organic iodide, per	Position does not apply. No charcoal adsorber has been included into the design of this system. It is designed to remove particulates only.	The laboratory testing criteria for testing a representative carbon adsorber sample will be in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. Test acceptance criteria is derived by using the assigned activated carbon decontamination efficiency of 70% for organic iodide, per	The laboratory testing criteria for testing a representative carbon adsorber sample will be in accordance with ASTM D3803-1989, using a temperature of 30°C and 70% relative humidity. (In response to Generic Letter 99-02). These units are recirculating systems (not exhaust systems) and are used for

Table 1.8-3
COMPARISON BETWEEN DESIGN FEATURES AND REGULATORY GUIDE 1.140 POSITIONS
(Sheet 9 of 9)

Radioactivity Removal Normal Ventilation Systems Regulatory Guide 1.140 Positions	Containment Power Access Purge	Auxiliary Building	Radwaste Building	Turbine Building Vacuum Pump Exhaust	Containment Preaccess (Air Cleanup Recirculation)
	Regulatory Guide 1.140, Revision 1, October 1979, Table 2, and imposing a safety factor of 2 on such efficiency. This results in the test acceptance criteria of a methyl iodide penetration of less than or equal to 15%. (In response to Generic Letter 99-02). The activated carbon, when new, will be provided using the physical property specifications of Table 5.1 of ANSI N509-1980. Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to Generic Letter 99-02).	Regulatory Guide 1.140, Revision 1, October 1979, Table 2, and imposing a safety factor of 2 on such efficiency. This results in the test acceptance criteria of a methyl iodide penetration of less than or equal to 15%. (In response to Generic Letter 99-02). The activated carbon, when new, will be provided using the physical property specifications of Table 5.1 of ANSI N509-1980. Additionally for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to Generic Letter 99-02).		Regulatory Guide 1.140, Revision 1, October 1979, Table 2, and imposing a safety factor of 2 on such efficiency. This results in the test acceptance criteria of methyl iodide penetration of less than or equal to 15%. (In response to Generic Letter 99-02). The activated carbon, when new, will be provided using the physical property specifications of Table 5.1 of ANSI N509-1980. Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to Generic Letter 99-02).	general atmosphere cleanup purposes. Additionally, ASTM D3803-1989 is a more stringent test than that described in Section 4.5.4 of RDT M16-1T (reference Regulatory Guide 1.140, Revision 1, October 1979, Table 2). Therefore, exception is taken to Table 2 criteria and an acceptance criteria of a methyl iodide penetration of less than or equal to 15% will be established. The activated carbon, when new, will be provided using the physical property specifications of Table 5.1 of ANSI N509-1980. Additionally, for optimum service life, the new carbon should exhibit a penetration less than 1.0% when tested in accordance with ASTM D3803-1989. (In response to Generic Letter 99-02).

REGULATORY GUIDE 1.145: Atmospheric Dispersion Models for Potential Accident Consequence Assessment at Nuclear Power Plants (November 1982)

RESPONSE

Information contained in Regulatory Guide 1.145 is utilized as discussed in section 2.3.

REGULATORY GUIDE 1.147: Inservice Inspection Code Case Acceptability ASME Section XI Division 1

RESPONSE

The position of Regulatory Guide 1.147 is accepted. Code Cases that are actually used will be identified in the applicable Inservice Inspection Programs. Reference 5.2.1.2.

REGULATORY GUIDE 1.155: Station Blackout Revision 0, August 1988

The position of Regulatory Guide 1.155 is accepted as described in Table 1.8-4. The compliance of PVNGS to Regulatory Guide 1.155 is based on the following significant issues:

a. A minimum emergency diesel generator (EDG) reliability target of 0.95 per demand for each EDG has been selected and a reliability program is in place to monitor and maintain this reliability level.

1. Regulatory Guide 1.155 section 1.1.1 (NUMARC 87-00 sections 3.2.3, 3.2.4) - Exception is taken to monitoring failures based on 20, 50, and 100 demands. Since the Maintenance Rule has been accepted and utilized for system reliability monitoring, Maintenance Rule EDG Performance Criteria (PC) for Reliability has been set to meet the overall goal of EDG targeted reliability of 0.95.

2. Section 1.1.2 – Exception is taken to averaging a nuclear unit’s failures based on 20, 50, and 100 demands. Per the Maintenance Rule, monitoring and tracking of failures is performed per train to avoid masking a poor performing EDG. Also 20, 50, and 100 demands are not used per the Maintenance Rule PC.

3. Section 1.1.3 – Comparison on average nuclear unit EDG reliability is not performed per 20, 50, and 100 demands, but per the Maintenance Rule PC.

4. Section 1.2 (various NUMARC 87-00 App. D sections) – Exceptions are taken to:

   a. NUMARC various App. D sections – General exception is taken to counting 20, 50, and 100 demands. Per Maintenance Rule PC, overall target meets Regulatory Guide 1.155 and NUMARC 87-00 target of 0.95.

   b. NUMARC 87-00 section D 2.2 – Exception is taken to counting start demands and load-run demands separately. All engine starts are counted as

demands (no separating start demands and load-run demands).

c. NUMARC 87-00 sections D 2.2.2, 2.2.3, 2.3.4, 2.3.5, 2.4.2, 2.4.3 – Exception is taken to monitoring failures to 50 and 100 demands per the Maintenance Rule PC. In addition, the Corrective Action Program performs monitoring of failures and maintenance performance under these NUMARC sections.

d. NUMARC D 2.4.4 – Exception is taken to requirements for a problem diesel and accelerated testing based on the Maintenance Rule and Corrective Action Program providing monitoring of failures and maintenance performance.

e. NUMARC D 2.4.5 – Exception is taken to requirements from exceeding failure trigger values. The Maintenance Rule and Corrective Action Program provide monitoring of failures and maintenance performance.

f. NUMARC D 2.4.6 – Exception is taken to requirements to retain demands and failures, corrective actions etc. for 50 and 100 demands. Since the Maintenance Rule PC and Corrective Action Program is used to track and monitor EDG performance, 50 and 100 demands are not specifically tracked.

g. NUMARC D 2.4.7 – Exception is taken to reporting to the NRC all failures/demands per 20, 50, and 100 demands. Exception is taken to the 20, 50, and 100 demand trigger values.

b. The minimum acceptable station blackout (SBO) coping duration was determined to be 16 hours. Studies and analyses have been performed to demonstrate the capability of withstanding and recovering from a station blackout event of 16 hour duration.

c. An onsite Alternate AC (AAC) power system has been installed to provide power to plant loads that have been determined to be important to the mitigation of a station blackout event. This system is manually started and can be connected to the affected nuclear unit within one hour of the onset of a SBO. The AAC power system is inspected and tested periodically to demonstrate its availability and reliability. Further discussion of the AAC power system is provided in Section 8.3.1.1.10.

d. A minimum reliability target of 0.95 per demand for the AAC power system has been selected and a reliability program is in place to monitor and maintain this reliability level.

e. Procedures and training have been established for operator actions necessary to cope with a station blackout event.

f. Quality assurance activities have been implemented as applicable for the non-safety related systems and

equipment installed and dedicated for the operation of the AAC power source. Further discussion of the quality assurance program for SBO is provided in the PVNGS Operations Quality Assurance Program Description.

Table 1.8-4
PVNGS Position to Regulatory Guide 1.155 – Station Blackout Revision 0, August 1988
(Sheet 1 of 4)

Regulatory Position	RG 1.155 Applicable Sections	PVNGS Position
ONSITE EMERGENCY AC POWER SOURCES	1.0	
Emergency Diesel Generator Target Reliability Levels	1.1	No exception taken
Reliability Program	1.2	No exception taken
Procedures for restoring Emergency AC Power	1.3	No exception taken
OFFSITE POWER	2.0	No exception taken
ABILITY TO COPE WITH A SBO	3.0	
Minimum Acceptable SBO Duration Capability.	3.1	Exception taken, 16 hour coping time is based on a voluntary license condition rather than an evaluation of the factors discussed in section 3.1.
Evaluation of Plant-Specific SBO Capability	3.2	
The evaluation should be performed assuming that the SBO event occurs while the reactor is operating at 100% rated thermal power and has been at this power level for at least 100 days.	3.2.1	Exception taken, The NSSS, secondary performance, and condensate volume are calculated using the decay heat used for the 16 hour analyses based on the ANSI/ANS-5.1 1979 decay heat curve, plus a 2 sigma uncertainty at equilibrium.
The capability of all systems and components necessary to provide core cooling and decay heat removal following a SBO should be determined, including station battery capacity, condensate storage tank capacity, compressed air capacity, and instrumentation and control requirements.	3.2.2	No exception taken
The ability to maintain adequate reactor coolant system inventory to ensure that the core is cooled should be evaluated, taking into consideration shrinkage, leakage from pump seals, and inventory loss from letdown or other normally open lines dependent on ac power for isolation.	3.2.3	No exception taken – Methodology used is different than NUMARC 87-00.
The design adequacy and capability of equipment needed to cope with a SBO for the required duration and recovery period should be addressed and evaluated as appropriate for the associated environmental conditions.	3.2.4	No exception taken – Methodology used is different than NUMARC 87-00.

Table 1.8-4
PVNGS Position to Regulatory Guide 1.155 – Station Blackout Revision 0, August 1988
(Sheet 2 of 4)

Regulatory Position	RG 1.155 Applicable Sections	PVNGS Position
Consideration should be given to using available non-safety-related equipment, as well as safety-related equipment to cope with a SBO provided such equipment meets the recommendations of Regulatory Positions 3.3.3 and 3.3.4. Onsite or nearby AAC power sources that are independent and diverse from the normal Class 1E emergency ac power sources (e.g., gas turbine, separate diesel engine, steam supplies) will constitute an acceptable SBO copying capability provided an analysis is performed that demonstrates the plant has this capability from the onset of SBO until the AAC power source or sources are started and lined up to operate all equipment necessary to cope with SBO for the required duration.	3.2.5	No exception taken – It has been demonstrated that in onset of SBO event, the station can cope for duration of 1 hour without any AC sources until the AAC power sources are started and lined up to operate all equipment necessary to cope with SBO for the 16 hour required duration. Based on regulatory guidelines, it is assumed that only one of three units at the Palo Verde site would experience SBO.
Consideration should be given to timely operator actions inside or outside the control room that would increase the length of time that the plant can cope with a SBO provided it can be demonstrated that these actions can be carried out in a timely fashion.	3.2.6	No exception taken
The ability to maintain appropriate containment integrity should be addressed. “Appropriate containment integrity” for SBO means that adequate containment integrity is ensured by providing the capability, independent of the preferred and blackout unit’s onsite emergency ac power supplies, for valve position indication and closure for containment isolation valves that may be in the open position at the onset of a SBO.	3.2.7	No exception taken
Modifications To Cope with SBO.	3.3	
If, after considering load shedding to extend the time until battery depletion, battery capacity must be extended further to meet the SBO duration recommended in Regulatory Position 3.1, it is considered acceptable either to add batteries or to add a charging system for the existing batteries that is independent of both the offsite and the blacked-out unit’s onsite emergency ac power systems, such as a dedicated diesel generator.	3.3.1	No exception taken. Batteries have the capacity to serve the required loads for one hour, without additional equipment or load shedding, until charging is restored from the AAC source.

Table 1.8-4
PVNGS Position to Regulatory Guide 1.155 - Station Blackout Revision 0, August 1988
(Sheet 3 of 4)

Regulatory Position	RG 1.155 Applicable Sections	PVNGS Position
If the capacity of the condensate storage tank is not sufficient to remove decay heat for the SBO duration recommended in Regulatory Position 3.1, a system meeting the requirements of Regulatory Position 3.5 to resupply the tank from an alternative water source is an acceptable means to increase its capacity provided any power source necessary to provide additional water is independent of both the offsite and the blacked-out unit's onsite emergency ac power systems.	3.3.2	No exception taken. Plant CST has sufficient volume.
If the compressed air capacity is not sufficient to remove decay heat and to maintain appropriate containment integrity for the SBO duration recommended in Regulatory Position 3.1, a system to provide sufficient capacity from an alternative source that meets Regulatory Position 3.5 is an acceptable means to increase the air capacity provided any power source necessary to provide additional air is independent of both the offsite and the blacked-out unit's onsite emergency ac power systems.	3.3.3	No exception taken. The longer duration event was originally supported by addition of a supplementary nitrogen system. This supplementary nitrogen system is no longer necessary and is now functionally retired because the ADV accumulator tanks capacity have been increased. Currently the long duration event is supported via design capacity of the ADV accumulator tanks.
A system is required for primary coolant charging and makeup, reactor coolant pump seal cooling or injection, decay heat removal, or maintaining appropriate containment integrity specifically to meet the SBO duration recommended in Regulatory Position 3.1, the following criteria should be met: 1. The system should be capable of being actuated and controlled from the control room, or if other means of control are required, it should be demonstrated that these steps can be carried out in a timely fashion, and 2. If the system must operate at 10 minutes of a loss of all ac power, it should be capable of being actuated from the control room.	3.3.4	No exception taken.

Table 1.8-4
PVNGS Position to Regulatory Guide 1.155 – Station Blackout Revision 0, August 1988
(Sheet 4 of 4)

Regulatory Position	RG 1.155 Applicable Sections	PVNGS Position
If an AAC power source is selected specifically for satisfying the requirements for SBO, the design should meet the following criteria: 1. The AAC power source should not normally be directly connected to the preferred or the blacked-out unit's onsite emergency ac power system. 2. There should be a minimum potential for common –cause failure with the preferred or the blacked-out unit's onsite emergency ac power sources. No single-point vulnerability should exist whereby a weather-related event or single active failure could disable any portion of the blacked-out unit's onsite emergency ac power sources or the preferred power sources and simultaneously fail the AAC power. 3. The AAC power source should be available in a timely manner after the onset of SBO and have provisions to be manually connected to one or all of the redundant safety buses as required. The time required for making this equipment available should not be more than 1 hour as demonstrated by test. If the AAC power source can be demonstrated by test to be available to power the shutdown buses at 10 minutes of the onset of SBO, no coping analysis is required. 4. The AAC power source should have sufficient capacity to operate the systems necessary for coping with a SBO for the time required to bring and maintain the plant in safe shutdown. 5. The AAC power system should be inspected, maintained, and tested periodically to demonstrate operability and reliability. The reliability of the AAC power system should meet or exceed 95 percent as determined in accordance with NSAC-108 or equivalent methodology.	3.3.5	No exception taken.
If a system or component is added specifically to meet the recommendations on SBO duration in Regulatory Position 3.1 system walkdowns and initial tests of new or modified systems or critical components should be performed to verify that the modifications were performed properly. Failures of added components that may be vulnerable to internal or external hazards within the design basis (e.g., seismic events) should not affect the operation of systems required for the design basis accident.	3.3.6	No exception taken
A system or component added specifically to meet the recommendations on SBO duration in Regulatory Position 3.1 should be inspected, maintained, and tested periodically to demonstrate equipment operability and reliability.	3.3.7	No exception taken
Procedures and Training to Cope with SBO. Procedures and training should include all operator actions necessary to cope with a SBO for at least the duration determined according to Regulatory Position 3.1.	3.4	No exception taken – Methodology used different than NUMARC 87-00.
Quality Assurance and Specification Guidance for SBO Equipment That is Not Safety-Related.	3.5	No exception taken

REGULATORY GUIDE 1.160: Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (Revision 3, May 2012)

RESPONSE

APS accepts the position of Regulatory Guide 1.160.

REGULATORY GUIDE 1.163 Performance – Based Containment Leak-Test Program (Revision 0, September, 1995)

RESPONSE

The positions of Regulatory Guide 1.163 are accepted except as provided below.

In Regulatory Guide 1.163, Regulatory Position C.3 specifies containment visual examination requirements. However, visual examinations of containment concrete surfaces and the steel liner plate are performed in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, Subsections IWL and IWE respectively, as described by Technical Specification 5.5.16.

REGULATORY GUIDE 1.181: Content of the Updated Final Safety Analysis Report in accordance with 10 CFR 50.71(e). (Revision 0, September 1999)

RESPONSE

The positions of Regulatory Guide 1.181 are accepted except as provided below.

With respect to NEI 98-03, Revision 1, Section A5, any NRC commitments incorporated into the UFSAR become part of the UFSAR, and are no longer part of the commitment management program. Therefore, implementing and reporting any changes to commitments incorporated in the UFSAR (including removals) are done under the appropriate change process (e.g., 10 CFR 50.59, 10 CFR 50.54, and 10 CFR 50.71(e), etc.), and are outside of the scope of the commitment management or corrective action programs.

With respect to NEI 98-03, Revision 1, Section A6, the reporting requirements of 10 CFR 50.71(e) and 10 CFR 50.59 provide adequate and complete information to the NRC regarding relevant deletions of information from the UFSAR. The additional reporting identified in Section A6 is not required.

REGULATORY GUIDE 1.187 Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments (Revision 0, November 2000)

RESPONSE

The position of Regulatory Guide 1.187 is accepted, except as provided below.

NEI 96-07, Revision 1, “Guidelines for 10 CFR 50.59 Implementation”, Section 5.0, Documentation and Reporting, restates the requirements of 10 CFR 50.59(d). In addition, this section states that “A summary of 10 CFR 50.59 evaluations for activities *implemented* under 10 CFR 50.59 must be provided to NRC… The 10 CFR 50.59 reporting requirement (every 24 months) is identical to that for UFSAR updates such that licensees may provide these reports to NRC on the same schedule.” (emphasis added).

10 CFR 50.59 evaluation summary reports will include a summary of all 10 CFR 50.59 evaluations that were performed for the stated time period, regardless of the implementation status for the change, test, or experiment that was evaluated.

REGULATORY GUIDE 1.190 Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence (March 2001)

RESPONSE

The position of Regulatory Guide 1.190 is accepted for Generic Letter (GL) 96-03 implementation as provided below.

NRC GL 96-03, "Relocation of Pressure-Temperature Limit Curves and Low Temperature Overpressure Protection System Limits", January 1996, specifies that licensees use acceptable methods for reactor vessel neutron calculations (PTLR Criterion 1). PVNGS provided the fluence methodology details and provisions used to develop its Pressure-Temperature Limits Report (PTLR) in Westinghouse Electric Company, LLC, "Palo Verde Nuclear Generating Stations Units 1, 2, and 3: Basis for RCS Pressure and Temperature Limits Report", WCAP-16835-NP, Revision 0. In the Safety Evaluation for Operating License Amendment No. 178 for PVNGS Unit 1, 2, and 3, the NRC staff evaluated that information to establish that it adheres to the guidance contained in RG 1.190 and is thereby acceptable for GL 96-03 implementation.

REGULATORY GUIDE 3.72 Guidance for Implementation of 10 CFR 72.48, Changes, Tests, and Experiments (Revision 0, March 2001)

RESPONSE

The position of Regulatory Guide 3.72 is accepted, except as provided below.

NEI 96-07, Appendix B, "Guidelines for 10 CFR 72.48 Implementation", Section B5, Documentation and Reporting, restates the requirements of 10 CFR 72.48(d). In addition, this

section states that “A summary of 10 CFR 72.48 evaluations for activities *implemented* under 10 CFR 72.48 must be provided to NRC… The 10 CFR 72.48 reporting requirement (every 24 months) is identical to that for UFSAR updates such that licensees and CoC holders may provide these reports to NRC on the same schedule.” (emphasis added).

10 CFR 72.48 evaluation summary reports will include a summary of all 10 CFR 72.48 evaluations that were performed for the stated time period, regardless of the implementation status for the change, test, or experiment that was evaluated.

REGULATORY GUIDE 4.1: Programs for Monitoring Radioactivity in the Environs of Nuclear Power Plants (Revision 1, April 1975)

RESPONSE

The position of Regulatory Guide 4.1 is accepted.

REGULATORY GUIDE 8.2: Guide for Administrative Practices in Radiation Monitoring (Revision 0, February 2, 1973)

RESPONSE

The position of Regulatory Guide 8.2 is accepted (refer to subsections 12.1.1, 12.3.4, 11.5.1.1.3, and sections 12.5 and 13.2).

REGULATORY GUIDE 8.4: Personnel Monitoring Device – Direct-Reading Pocket Dosimeters (Revision 1, June 2011)

RESPONSE

The position of Regulatory Guide 8.4 is accepted; although PVNGS no longer uses direct-reading pocket dosimeters, PVNGS would conform to Regulatory Guide 8.4 if direct-reading dosimeters were to be used in the future.

REGULATORY GUIDE 8.7: Occupational Radiation Exposure Records Systems (Revision 0, May 1973)

RESPONSE

The position of Regulatory Guide 8.7 is accepted (refer to section 12.5.2.2.7).

REGULATORY GUIDE 8.8: Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable (Revision 3, June 1978)

RESPONSE

The position of Regulatory Guide 8.8 is accepted (refer to subsections 5.4.7 and 12.3.4 and sections 11.3, 12.1, 12.5, and 13.1.2.2.1.5). Additional references: 11.4.1, 11.5.1, 12.2.1, and 12.3.

REGULATORY GUIDE 8.9: Acceptable Concepts, Models, Equations, and Assumptions for a Bioassay Program (Revision 1, July 1993)

RESPONSE

The position of Regulatory Guide 8.9 is accepted (refer to section 12.5).

REGULATORY GUIDE 8.10: Operating Philosophy for Maintaining Occupational Radiation Exposures As Low As Is Reasonably Achievable (Revision 1-R, May 1977)

RESPONSE

The position of Regulatory Guide 8.10 is accepted (refer to subsection 12.1.3 and sections 12.5 and 13.2).

REGULATORY GUIDE 8.12: Criticality Accident Alarm Systems (Revision 0, December 1974)

RESPONSE

The position of Regulatory Guide 8.12 is accepted as clarified in section 11.5, and 12.3.4.

REGULATORY GUIDE 8.13: Instruction Concerning Prenatal Radiation Exposure

RESPONSE

The guidance of Regulatory Guide 8.13 is utilized in developing lesson plans. Reference section 12.5.3.8.

REGULATORY GUIDE 8.14: Personnel Neutron Dosimeters (Revision 1, August 1977)

RESPONSE

Regulatory Guide 8.14 has been withdrawn by the NRC, as described in the February 26, 2001. Federal Register (66 FR 11611). RG 8.14 guidance was superseded by 10 CFR 20.1501 (Refer to paragraph 12.5.3.6).

REGULATORY GUIDE 8.19: Occupational Radiation Dose Assessment in Light-Water Reactor Power Plants Design Stage Man-Rem Estimates (Revision 1, June 1979)

RESPONSE

The dose assessments noted in section 12.4 have been provided to demonstrate that occupational exposures will be ALARA by design and by operation. The assessments have considered operational experience and plant specific shielding, access control, and maintainability. The specific data requested by Regulatory Guide 8.19 was not provided as the Regulatory Guide 8.19 was issued subsequent to the construction permit.

To satisfy the intent and concerns of Regulatory Guide 8.19, as well as Regulatory Guide 8.8, PVNGS conducted extensive ALARA reviews as described in paragraph 12.1.1.1 and appendix 12B.

These reviews, in conjunction with the radiation zones in the plant, the shielding design criteria, and the operating policies for ALARA will ensure that occupational man-rem will be ALARA.

REGULATORY GUIDE 8.26: Applications of Bioassay for Fission and Activation Products (Revision 0, September 1980)

RESPONSE

The position of Regulatory Guide 8.26 is accepted. (Refer to paragraph 12.5.3.6.)

1.9 STANDARD DESIGNS

The CESSAR design scope has been incorporated in each PVNGS unit and described in the UFSAR to the maximum extent practical. Subsection 1.9.1 describes the specific procedures that are used to incorporate CESSAR in the PVNGS FSAR. Subsection 1.9.2 describes the exceptions and/or deviations from the CESSAR design. Both Subsection 1.9.1 and 1.9.2 describe the methods used, at the time the operating licenses were issued. If a CESSAR subsection is referenced by the applicable UFSAR Section, then the methods described in UFSAR subsections 1.9.1 and 1.9.2 remain applicable.

1.9.1 REFERENCES TO CESSAR

Refer to the CESSAR introductory statement for the format and content used in CESSAR. Where applicable, the PVNGS NSSS design information required by Regulatory Guide 1.70, Revision 3, is incorporated in the PVNGS FSAR by reference to the appropriate CESSAR chapter, section, table, or figure. For example, the phrase "refer to CESSAR Section 9.3.5" is used to incorporate the identified CESSAR section into the PVNGS FSAR. Any other chapter, section, table, or figure referenced in the FSAR refers to a chapter, section, table, or figure of this FSAR.

Each reference to a CESSAR section also incorporates all figures, tables, and appendices referred to in such incorporated CESSAR section. All topical reports referred to in such CESSAR section and listed in CESSAR Section 1.6 are also incorporated in the PVNGS FSAR. Where the CESSAR section incorporated in this FSAR refers to another CESSAR section, the

latter section is not incorporated herein unless it is also incorporated by specific reference in the corresponding section of this FSAR. However, reference to CESSAR Section 1.8 incorporates those positions of CESSAR sections referenced in CESSAR Section 1.8 which respond to the Regulatory Guides.

Where the PVNGS FSAR refers to CESSAR sections relating to systems not in the C-E scope of responsibility (table 1.9-1), the reference means that the CESSAR section is applicable to and descriptive of the non-C-E system.

1.9.1.1 PVNGS Scope of Supply

Table 1.9-1 sets forth the PVNGS scope of responsibility for the NSSS, safety-related components, and other auxiliary systems. CESSAR systems comprising the C-E System 80 are delineated in UFSAR Table 1.2-1.

1.9.1.2 Interfaces with CESSAR Systems

The method of addressing CESSAR interface information in the PVNGS FSAR is described in CESSAR Section 1.1.3.

Interface sections in CESSAR have been identified in CESSAR Table 1.2-2. The CESSAR sections containing interface requirements that are addressed herein and sections of the PVNGS FSAR that evaluate how the applicable CESSAR interface requirements are satisfied are itemized in table 1.9-2.

Each applicable balance of plant interface requirement is repeated in the appropriate section of the PVNGS FSAR under the heading "CESSAR Interface Requirements". Information in sections titled “CESSAR Interface Requirements” has been

reproduced verbatim from the CESSAR for incorporation into the UFSAR and, therefore, should not be altered or revised. If information in any of these sections is different from actual plant design, that should be addressed in the “CESSAR Interface Evaluation” section. A discussion regarding compliance of the PVNGS system design with the applicable interface requirements is provided under the heading "CESSAR Interface Evaluation".

STANDARD DESIGNS

Table 1.9-1
SUMMARY OF SYSTEMS (Sheet 1 of 2)

System or Component	Scope of Responsibility
Reactor and reactor coolant system	
Reactor vessel assembly	C-E
Reactor vessel support structure	C-E
Reactor vessel internals	C-E
Control element assemblies and drives	C-E
Fuel	C-E
Steam Generators	Westinghouse
Pressurizer	C-E
Reactor coolant pumps	C-E
Reactor coolant piping (loop piping only)	C-E
Reactor coolant instrumentation	C-E
Engineered safety features systems	
Auxiliary feedwater system	Bechtel
Containment spray system	C-E
Containment isolation system	C-E/Bechtel
Containment hydrogen recombiner system	Bechtel
Main steam isolation system	Bechtel
Safety injection system	C-E
Fuel building essential ventilation system	Bechtel
Containment building purge isolation system	Bechtel
Control building essential ventilation system	Bechtel

STANDARD DESIGNS

Table 1.9-1
SUMMARY OF SYSTEMS (Sheet 2 of 2)

System or Component	Scope of Responsibility
Protection, control and instrumentation systems	
Reactor protective system	C-E
Engineered safety features actuation systems	C-E/Bechtel
NSSS control system	C-E
Fuel handling and storage systems	
New and spent fuel storage	C-E/Bechtel
Pool cooling and purification system	Bechtel
Fuel transfer	C-E
Fuel handling (reactor and fuel pool area)	C-E
Cooling water and other auxiliary systems	
Essential cooling water system	Bechtel
Nuclear cooling water system	Bechtel
Shutdown cooling system	C-E
Process sampling system	C-E
Chemical volume and control system	C-E
Secondary chemical control system	C-E/Bechtel
Waste management system	
Liquid radwaste system	Bechtel
Gaseous radwaste system	Bechtel
Solid radwaste system	Bechtel

1.9.2 EXCEPTIONS TO CESSAR

Any CESSAR exception that meets the definition of a system deviation given in paragraph 1.9.2.4 is discussed in that paragraph. Differences which are within the definitions of either envelope deviations, terminology deviations, or analysis deviations set forth in paragraphs 1.9.2.1, 1.9.2.2, and 1.9.2.3, respectively, are not interpreted to be CESSAR exceptions. Changes to the CESSAR design that do not modify interface requirements are indicated in the applicable FSAR sections.

1.9.2.1 Envelope Deviations

Site-related characteristics, such as meteorology, hydrology, site boundaries, and cooling water sources are within CESSAR envelopes. There are no envelope deviations.

1.9.2.2 Terminology Deviations

Differences in PVNGS system nomenclature from nomenclature used in CESSAR are defined as terminology deviations.

Table 1.9-3 provides a cross-reference of terminology used. Valve and instrument numbers contained in those CESSAR sections incorporated by reference are illustrative only and do not represent the PVNGS system component nomenclature.

STANDARD DESIGNS

Table 1.9-2
INTERFACE EVALUATIONS CROSS-REFERENCES (Sheet 1 of 2)

R.G. 1.70 Rev. 3	CESSAR Section	PVNGS Section	Section Title
3.4.3	(a)	(a)	Water Level (Flood) Design
3.5.4	3.5.3.1	3.5.4.2	Missile Protection
3.6.3	5.1.4	5.1.5	Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping
3.7.5	5.1.4	5.1.5	Seismic Design
3.8.6	(a)	(a)	Design of Category I Structures
3.9.7	(a)	(a)	Mechanical Systems and Components
3.10.5	(a)	(a)	Seismic Qualification of Seismic Category I Instrumentation and Electrical Equipment
3.11.6	(a)	(a)	Environmental Design of Electrical Equipment
5.2.6	5.1.4	5.1.5	Integrity of Reactor Coolant Pressure Boundary
5.4.7.5	5.4.7.1.3	5.4.7.2	Residual Heat Removal System
5.4.11	(a)	(a)	Pressurizer Relief Discharge System
6.2.4.5	7.3.3	7.3.4	Containment Isolation System
6.3.6	6.3.1.3	6.3.1.4	Emergency Core Cooling System

a. No CESSAR interface requirements.

Table 1.9-2
INTERFACE EVALUATIONS CROSS REFERENCES (Sheet 2 of 2)

R.G. 1.70 Rev. 3	CESSAR Section	PVNGS Section	Section Title
6.4.7	(a)	(a)	Habitability Systems
6.6.9	(a)	(a)	Inservice Inspection of Class 2 and 3 Components
7.2.3	7.1.3	7.1.4	Reactor Trip System
7.8	7.2.3	7.2.4	Instruments and Controls
8.2.3	8.1.1	8.3.5	Offsite Power Systems
8.3.1.5	8.3.1	8.3.5	AC Power System
8.3.2.3	8.1.1	8.3.5	DC Power System
9.1.1.4	4.2.5 9.1.4.6	4.2.6 9.1.4.7	New Fuel Storage
9.1.2.4	4.2.5 9.1.4.6	4.2.6 9.1.4.7	Spent Fuel Storage
9.1.4.6	9.1.4.6	9.1.4.7	Fuel Handling System
9.3.4.6	9.3.4.6	9.3.4.2	Chemical and Volume Control System
9.5.1.6	(a)	(a)	Fire Protection System
10.4.4.X	(a)	(a)	Turbine Bypass System
13.6.3	(a)	(a)	Industrial Security
15.X.X.X	(a)	(a)	Event Evaluation

1.9.2.3 Analysis Deviations

Differences in methods of analysis, calculational techniques, and models used by C-E and Bechtel are defined as analysis deviations. These differences achieve similar results by alternative means and are not, therefore, considered analysis deviations.

1.9.2.4 System Deviations

Each of the systems that are within the C-E scope of responsibility, as defined in table 1.9-1, have interface sections. System interfaces which do not conform to those described in CESSAR are categorized as system deviations.

In this situation, an alternative method of providing the functional requirement specified by the CESSAR interface has been adopted for PVNGS. A description of each of these system interface deviations is given in the following sections.

1.9.2.4.1 Containment Spray System (CESSAR Appendix 6A, Section 7.14/FSAR paragraph 6.5.2.8 (RA) 7.1.4)

Containment spray system (CSS) actuation and flow delivery occurs on a preestablished schedule given in Section 6.3 of CESSAR Appendix 6A. This schedule determines flow conditions in various analyses that take credit for a train of the CSS functioning to mitigate the consequences of postulated transients. The maximum time to establish rated flow given in CESSAR Appendix 6A, Section 7.1.4, is 58 seconds after receipt of CSAS. For PVNGS, CSS rated flow will be delivered in greater than 58 seconds (table 6.2.1-7). The exception to the

Table 1.9-3
PVNGS SYSTEM TERMINOLOGY COMPARISON

PVNGS System or Component	CESSAR System or Component
Essential cooling water system (ECWS)	Component cooling water system (CCWS)
Nuclear cooling water system (NCWS)	Component cooling water system (CCWS)
Essential spray pond system (ESPS)	Station service water system
Fuel pool cooling and cleanup system	Pool cooling and purification system
Liquid radwaste system (LRS)	Liquid waste management system
Gaseous radwaste system (GRS)	Gaseous waste management system
Solid radwaste system (SRS)	Solid waste management system
Demineralized water system	Demineralized water makeup system
Auxiliary feedwater system	Emergency feedwater system/auxiliary feedwater system
Auxiliary feedwater actuation signal (AFAS)	Emergency feedwater actuation signal (EFAS)
Load Group 1	Train A
Load Group 2	Train B
Diesel generator	Emergency generator

CESSAR interface requirement for the CSS flow delivery time is only significant in the determination of the in-containment equipment qualification temperature parameters. However, under the worst case temperature conditions (i.e., main steam line 7.16 square feet slot break at 102% power, loss of one containment spray train, and no loss of offsite power), the calculated temperature transient of paragraph 6.2.1.8 is bounded by the equipment qualification environment of Appendix A of the Equipment Qualification Program Manual. Combustion Engineering has also committed to qualify safety-related equipment within their scope to the same environment. By this analysis, the delay in delivery of rated flow to the CSS has been shown to have no adverse consequences under postulated transients.

1.9.2.4.2 Containment Spray System (CESSAR Appendix 6A, Section 7.13.14/FSAR paragraph 6.5.2.8 (RA) 7.13.14)

The head loss requirements of CESSAR Appendix 6A are not applicable to the PVNGS design due to the addition of the auxiliary spray headers. The analyses of both train A and train B of the containment spray system have shown that either train of the system will operate satisfactorily and meet the design flow requirements independent of the other train during all modes of operation. The design flow includes the additional flow for auxiliary spray headers.

1.9.2.4.3 DELETED

1.9.2.4.4 Engineered Safety Features Monitoring (CESSAR Section 7.5.1.1.3/FSAR paragraph 7.5.1.1.3)

The PVNGS design has two Class 1E wide range refueling water tank (RWT) level indicator channels with Class 1E indicators on the remote shutdown panel and one Class 1E indicator channel in the control room. The second channel in the control room is Class 1E with the exception of the isolated non Class 1E indicator and indicator power supply. This arrangement is acceptable in that both Class 1E channels are displayed on the remote shutdown panel and there are four narrow range Class 1E level indicator channels in the control room which are redundant for the volume of the RWT required to mitigate the consequences of a LOCA.

1.9.2.4.5 Spent Fuel Pool (CESSAR Section 9.1.4.6/FSAR paragraph 9.1.4.7)

CESSAR Section 9.1.4.6 requires 23 feet of water cover for a fuel rod assembly lying horizontally on top of the fuel racks.

In the evaluation of a fuel handling accident, Regulatory Guide 1.25 permits an overall iodine decontamination factor of 100 for pool depths of 23 feet or greater above the broken fuel pins. At PVNGS, there is a minimum of 22 feet 6 inches of water over the damaged fuel pins at the pool low level alarm point. As iodine decontamination by 22 feet 6 inches of covering water is considered virtually the same as the decontamination provided by 23 feet 0 inch of covering water, this 6-inch difference has a negligible impact on the radiological effects of a fuel handling accident.

1.9.2.4.6 Refueling Water Tank (CESSAR Section 9.3.4.6/FSAR paragraph 9.3.4.2)

CESSAR Section 9.3.4.6 requires that the vent piping of the refueling water tank be maintained at a minimum temperature of 40F. As noted in response to related NRC concerns (see Question 6A.55), the water within the RWT will be kept above 60F at all times. The vent is located in the uppermost portion of the tank. The vent pipes are routed without piping pockets that could cause the accumulation of moisture. As the design winter ambient temperature at PVNGS is 25F for 24 hours, plugging of the RWT vent line is considered very improbable.

CESSAR Section 9.3.4.6 requires that redundant CVCS equipment loads shall be supplied by separate buses or motor control centers to minimize the effect of power outages. The two RWT heaters are powered through separate circuit breakers in a single motor control center fed from a single 480V load center. The tank contents are normally above 60F and redundant low temperature annunciation in the main control room is provided. The thick concrete wall tank construction, relatively mild Palo Verde climate, and large tank inventory combine to allow only very slow tank content temperature changes. Adequate time is available to restore heater power following distribution equipment malfunction without concern for precipitation of tank contents.

1.9.2.4.7 Safety Injection System (CESSAR Section 6.3.1.3.M.8/ FSAR paragraph 6.3.1.4, listing M.8)

Section 6.3.1.3.M.8.b requires that the volume in each safety injection (SI) line between the RCS and the first SI valve to

be less than 30 cubic feet. This requirement ensures that the time taken to inject borated water from the SI system into the RCS is minimized. The PVNGS design satisfies this requirement for each of the four, 12-inch diameter, cold leg injection SI lines. These four cold leg injection paths are used for boration of the RCS.

The ‘A’ train SI long term recirculation line conforms to, but, the ‘B’ train line exceeds the maximum water volume requirement of Section 6.3.1.3.M.8.b. The PVNGS design for the ‘A’ train lines has less than 16 cubic feet of unborated water volume between the RCS and the first SI valve. The PVNGS design for the ‘B’ train lines has less than 44 cubic feet of unborated water volume between the RCS and the first SI valve. The excess 14 cubic feet of unborated water volume is acceptable since these lines are not required for boration of the RCS. The long term recirculation lines are used to prevent boron precipitation in the core following a LOCA.

1.9.2.4.8 Containment Spray System (CESSAR Appendix 6A, Section 7.13.7.B/FSAR paragraph 6.5.2.8, listing A (RA)7.13.7.B)

CESSAR Appendix 6A, Section 7.13.7.B, discusses delay time for spray of borated water. This interface requirement uses the term "borated water" because the containment spray pump suction is from the RWT which is borated. The total volume of water in both spray headers inside containment when filled to the 113-foot indicated elevation (110-foot actual) is less than 700 gallons, and filling this volume with fresh instead of borated water will have no impact on the performance of the

containment spray system in removing containment heat or iodine, and negligible potential for boron dilution following sump recirculation after a loss-of-coolant accident. The intent of the CESSAR interface requirement is met as described in paragraph 6.5.2.8, listing A (RA)7.13.7.B by filling the spray headers inside containment to the 113-foot indicated elevation (110-foot actual) with fresh water.

1.9.2.4.9 Preoperational Test Descriptions for HPSI, LPSI, and SIT Subsystem Tests (CESSAR Sections 14.2.12.1.22, 14.2.12.1.23, and 14.2.12.1.24)

CESSAR Sections 14.2.12.1.22 (HPSI), 14.2.12.1.23 (LPSI), and 14.2.12.1.24 (SIT) each include as a prerequisite:

> "2.4 The reactor vessel head and internals have been removed."

These tests will be accomplished, in part, on PVNGS Unit 1, with the reactor vessel head and internals in place.

For CESSAR Sections 14.2.12.1.22 (HPSI), and 14.2.12.1.23 (LPSI), for PVNGS Unit 1 only, replace the existing Item 2.4 with:

> 2.4 Four pressurizer safety valves removed to provide a pressure vent path.

For CESSAR Section 14.2.12.1.23 (LPSI), for PVNGS Unit 1 only, replace the first two lines of existing Item 3.4 with:

> 3.4 Start each LPSI pump using an SIAS signal and collect initial pump operating data. For this

portion of the test, the pump under test will....................

For CESSAR Section 14.2.12.1.24 (SIT), for PVNGS Unit 1 only, replace the existing Item 2.4 with:

2.4 Test method Item 3.6 (discharge of safety injection tanks into RCS) will be accomplished with the reactor vessel head and internals removed. Test method Items 3.1 through 3.5 may be accomplished with the reactor vessel head and internals installed or removed.

The CESSAR prerequisite 2.4 that the reactor vessel head and internals be removed ensures an adequate pressure vent path to allow operation of tested components at near runout conditions to confirm system design in case of RCS rupture, and to prevent flow-induced movement of unrestrained reactor vessel internals. By draining the RCS to the mid-point of the cold legs prior to the test and by providing a pressure vent path through the removed pressurizer safety valves, and additionally, in the case of the LPSI test, aligning the LPSI pump not under test to take a suction from the RCS and discharge to the RWT, sufficient room exists in the RCS to obtain the required test data. By ensuring a test backpressure less than or equal to the head of water at a level equal to the reactor vessel flange, as indicated by the refueling level indicator, the intent of the original test prerequisite is maintained. If insufficient test data can be obtained because of some unforeseen reason with the reactor vessel head and internals installed, portions of the test will be repeated with the

reactor vessel head and internals removed, as needed to meet the acceptance criteria of the CESSAR test descriptions.

1.9.2.4.10 Main and Auxiliary Feedwater System (CESSAR Sections 5.1.4.G.6.a, 5.1.4.G.7, 5.1.4.I.9.a, 8.3.1.3.d/FSAR subsection 5.1.5, listing G.6, G.7, and I.9.a, and paragraph 8.3.1.1.4.6)

The PVNGS design takes exception to four CESSAR interface requirements with respect to the main and auxiliary feedwater systems. These exceptions are:

A. An increase in the feedwater isolation valve closure time (in both the downcomer and economizer lines) from 4.6 to 9.6 seconds (CESSAR Section 5.1.4.I.9.a),

B. A reduction in the auxiliary feedwater flowrate from 875 to 650 gal/min per pump (CESSAR Section 5.1.4.G.7),

C. An increase in the auxiliary feedwater pump start times when normal ac is available from 10 seconds to 22 and 45 seconds for the motor and turbine-driven pumps, respectively (CESSAR Section 5.1.4.G.6.a), and

D. An increase in the time delay from 15 to 23 seconds in which interrupted auxiliary feedwater flow must be fully reestablished to the steam generators (CESSAR Section 8.3.1.3.d).

Table 1.9-4 provides a matrix which describes how these exceptions impact the chapter 15 safety and chapter 6 containment analyses. This table demonstrates that the consequences of all of these analyses remain acceptable.

Table 1.9-4
IMPACT OF MAIN AND AUXILIARY FEEDWATER DEVIATIONS FROM THE CESSAR INTERFACE REQUIREMENTS AND REDUCTION OF LPSI AND HPSI FLOW (Sheet 1 of 6)

FSAR Section (a)	Event	FWIV Increased Closure Time After MSIS	AFW Flow Reduction 875 to 650 gal/min	AFW Flow Delay with Normal ac	AFW Increase in Reestablish Delay When ac is Lost	LPSI Flow Reduction	HPSI Flow Reduction	Overall Impact
15.1.1	Decrease in feedwater temperature	See event 15.1.3 below						
15.1.2	Increase in feedwater flow	See event 15.1.3 below						
15.1.3	Increased main steam flow	Event reanalyzed, see Section 15.1.3						
15.1.4	Inadvertent opening ADV	Event reanalyzed, see Section 15.1.4						None[b]
15.1.5	Steam line break	Event reanalyzed, see Sections 15.1.5 and 15.1.6						Acceptable[m]
15.2.1	Loss of external load	See event 15.2.3 below						
15.2.2	Turbine trip	See event 15.2.3 below						
15.2.3	Loss of condenser vacuum	Signal not encountered	No impact		(c)	System not actuated	No impact [d]	None [d]
15.2.4	MSIV closure	See event 15.2.3 above						
15.2.5	Steam pressure regulator failure	Not applicable						
15.2.6	Loss of ac power	See event 15.3.1 below						
15.2.7	Loss of normal feed flow	See event 15.2.3 above						

Table 1.9-4

IMPACT OF MAIN AND AUXILIARY FEEDWATER DEVIATIONS FROM THE CESSAR INTERFACE REQUIREMENTS AND REDUCTION OF LPSI AND HPSI FLOW (Sheet 2 of 6)

FSAR Section (a)	Event	FWIV Increased Closure Time After MSIS	AFW Flow Reduction 875 to 650 gal/min	AFW Flow Delay with Normal ac	AFW Increase in Reestablish Delay When ac is Lost	LPSI Flow Reduction	HPSI Flow Reduction	Overall Impact
15.2.8	Feedwater line break	Event reanalyzed, see section 15.2.8[e]				System not actuated[u]		Acceptable [u]
15.3.1	Loss of reactor coolant flow	Signal not encountered	System not actuated			System not actuated		None
15.3.2	Flow controller malfunction	Not applicable						
15.3.3	Single reactor coolant pump seizure	Signal not encountered	No impact [r]	Loss of ac assumed -- no impact		System not actuated		None [f]
15.3.4	RCP shaft break	See event 15.3.3 above						
15.4.1	Low power CEA withdrawal	Signal not encountered	System not actuated			System not actuated		None
15.4.2	Full power CEA withdrawal	Signal not encountered	System not actuated			System not actuated		None
15.4.3	CEA assembly drop	Signal not encountered	System not actuated			System not actuated		None
15.4.4	Startup inactive RCP	Signal not encountered	System not actuated			System not actuated		None
15.4.5	Flow controller malfunction	Not applicable						
15.4.6	Inadvertent deboration	Signal not encountered	System not actuated			System not actuated		None
15.4.7	Inadvertent fuel loading	Signal not encountered	System not actuated			System not actuated		None

Table 1.9-4
IMPACT OF MAIN AND AUXILIARY FEEDWATER DEVIATIONS FROM THE CESSAR INTERFACE REQUIREMENTS AND REDUCTION OF LPSI AND HPSI FLOW (Sheet 3 of 6)

FSAR Section (a)	Event	FWIV Increased Closure Time After MSIS	AFW Flow Reduction 875 to 650 gal/min	AFW Flow Delay with Normal ac	AFW Increase in Reestablish Delay When ac is Lost	LPSI Flow Reduction	HPSI Flow Reduction	Overall Impact
15.4.8	CEA ejection	Signal not encountered	System not actuated			System not actuated	No impact[n]	None[n]
15.5.1	Inadvertent ECCS operation	Signal not encountered	System not actuated			No impact [o]		None [o]
15.5.2	CVCS malfunction	Signal not encountered	System not actuated			System not actuated		None
15.6.1	Inadvertent opening PSV	See event 15.6.5 below						
15.6.2	Letdown line break	Signal not encountered	System not actuated			System not actuated		None
15.6.3	System generator tube rupture	Signal not encountered	No impact[g]	Loss of ac assumed[h] -- No impact		System not actuated	No impact[p]	None[q]
15.6.4	Outside containment main steam failure (BWR)	Not applicable						
15.6.5	Loss of coolant accident		No impact[i]	Loss of ac assumed – No impact		Limiting Event Reanalyzed[r]		None[r]
(j)	SGTR with fully stuck ADV	Event reanalyzed[j]				System not actuated	No impact[p]	Acceptable[p]
6.2.1	Containment analysis, peak pressure	Acceptable[k]	No Impact[l]			No impact[s]		Acceptable[s]
6.2.1.8	Containment analysis, peak temperature	Event reanalyzed in section 6.2.1.8				No impact[t]		Acceptable[t]

Table 1.9-4

IMPACT OF MAIN AND AUXILIARY FEEDWATER DEVIATIONS FROM THE CESSAR INTERFACE REQUIREMENTS AND REDUCTION OF LPSI AND HPSI FLOW (Sheet 4 of 6)

a. This column identifies the PVNGS FSAR sections that reference the CESSAR safety analyses.

b. For the inadvertent opening of an ADV transient, an increase in the feedwater isolation valve closure time from 4.6 to 9.6 seconds does not alter the minimum DNBR or the maximum RCS pressure of the event. Therefore, with respect to the Standard Review Plan (SRP) criteria, there is no impact on the consequences of the event.

c. The interface requirement for auxiliary feedwater delivery when ac power is not available is 45 seconds following the generation of an AFAS signal, and when ac power is available, 22 seconds for the motor driven pump. Therefore, if flow reestablishment following the loss of ac occurs in less than the difference between these two times. i.e., 23 seconds, then it is assured that the total delay is less than the 45 seconds assumed in the chapter 15 safety analysis.

d. For the loss of condenser vacuum transient, the maximum reactor coolant system (RCS) pressure occurs before the delivery of auxiliary feedwater or safety injection. Therefore, with respect to SRP criteria, there will be no impact on the consequences of the event.

e. The maximum RCS pressure of the feedwater line break transient is unaffected by the reduction in auxiliary feedwater flow because the pressure occurs before auxiliary feedwater delivery. However, this transient was reanalyzed in subsection 15.2.8 in order to demonstrate that 650 gal/min is adequate for long term RCS heat removal.

f. For the locked rotor and sheared shaft transients, the minimum departure from nucleate boiling ratio (DNBR) occurs before auxiliary feedwater delivery, and is not changed. In addition, the integrated atmospheric steam releases and therefore the radiological consequences of the event remain unchanged by the reduction in auxiliary feedwater flow. Therefore, with respect to the SRP criteria, there is no impact on the consequences of the event.

g. The steam generator tube rupture (SGTR) transient presented in CESSAR Section 15.6.3 is not impacted by the reduction in auxiliary feedwater because the integrated atmospheric steam releases, and therefore the radiological consequences of the event, remain unchanged. However, the SGTR transient with a fully stuck open atmospheric dump valve (ADV) is sensitive to this reduction in auxiliary feedwater flow. This transient was reanalyzed using the PVNGS specific auxiliary feedwater system in response to NRC questions (see note j).

h. For the steam generator tube rupture with ac available, the auxiliary feedwater system is not actuated. Therefore, these changes do not impact the transient's results and the tube rupture discussion is limited to the case with the loss of ac power.

i. The minimum auxiliary feedwater flowrate of 650 gal/min does not alter the reported results of the emergency core cooling system (ECCS) performance analysis referenced in subsection 15.6.5. Therefore, conformance to the 10CFR50.46 ECCS acceptance criteria is preserved.

   The large break loss-of-coolant accident (LOCA) and long-term cooling evaluations in the CESSAR Sections 6.3.3.2 and 6.3.3.4 are unaffected by the reduced minimum auxiliary feed flowrate. The energy removal capability of large breaks overwhelms steam generator heat transfer and auxiliary feed flowrate considerations. Post-LOCA RCS heat removal in the long term cooling mode (after 1 hour) requires a much lower auxiliary feedwater flowrate to remove the diminished decay heat values which occur at this later time.

   The small break LOCA evaluation in CESSAR Section 6.3.3.3 is sensitive to steam generator heat removal and hence auxiliary feedwater flowrate. However, an evaluation of the auxiliary feedwater flowrate of 650 gal/min shows that this flowrate is sufficient to preserve the RCS depressurization, core liquid inventory and hence, the peak cladding temperature results presented in CESSAR.

   With respect to the feedwater isolation valve closure time change, the LOCA analyses conservatively assumed that main feedwater flow is terminated in less than 1 second after the reactor trip.

Table 1.9-4
IMPACT OF MAIN AND AUXILIARY FEEDWATER DEVIATIONS FROM THE CESSAR
INTERFACE REQUIREMENTS AND REDUCTION OF LPSI AND HPSI FLOW (Sheet 5 of 6)

j. This reanalysis was provided in response to NRC questions on the steam generator tube rupture transient via letter ANPP-30572 from E. E. Van Brunt, Jr. to G. W. Knighton dated September 19, 1984. The questions and responses are presented in appendix 15A as Questions 15A.56 through 15A.62.

k. The peak containment pressure of a steam line break transient will be increased (4.5 psi) as a result of an increase in the feedwater isolation valve closure time from 4.6 to 9.6 seconds. The peak containment pressure of a steam line break will still be bounded by the loss of coolant accident, which is unaffected by the change.

l. These changes to the interface requirements tend to reduce the quantity of auxiliary feed flow to the generators. As a result, the containment response to the transient will improve as the mass and energy releases will be reduced.

m. In no case does the SI flow effect the offsite dose. Therefore, the SLB consequences with respect to SRP criteria are not affected by the reduced SI flow.

n. Maximum RCS pressure and minimum DNBR occur before SI flow delivery. Calculated radiological dose is not dependent on SI flow. Therefore, with respect to SRP criteria, there is no impact on the event. LOCA considerations are bounded by subsection 15.6.5.

o. Reduced SI flow reduces the severity of this event.

p. For the SGTR with loss of offsite power event, the reduced HPSI flow curve will result in a slightly lower primary pressure at 30 minutes, which is the time at which the CESEC analysis was terminated. However, this difference will have no significance on the radiological consequences of the event during the subsequent cooldown. The cooldown for this case was performed by a hand calculation which did not include the feedback effects of the primary and secondary responses.

   For the SGTR with loss of offsite power with a stuck open ADV event, changes in HPSI now will have minimal impact. A decrease in HPSI flow will result in a slight decrease in offsite dose which is confirmed by an analysis which assumed maximum (higher) HPSI flow which resulted in a slightly higher dose (1% increase). For this event the feedback effects of the primary and secondary system responses are dynamically modeled for the 8 hour transient. Operator actions are simulated as per the CE emergency procedure guidelines in bringing the plant to hot shutdown. As a result, the operator is assumed to throttle the HPSI as necessary to maintain the safety functions as specified by the guidelines.

q. Since the reduced auxiliary feedwater and HPSI flows do not significantly impact the integrated atmospheric steam releases, no overall impact in the radiological consequences of the event would occur.

Table 1.9-4

IMPACT OF MAIN AND AUXILIARY FEEDWATER DEVIATIONS FROM THE CESSAR INTERFACE REQUIREMENTS AND REDUCTION OF LPSI AND HPSI FLOW (Sheet 6 of 6)

r. The reduction in SI flow was evaluated for its impact on both large and small break LOCA. The evaluation also considered the additional effects, if any, caused by the AFW flow reduction. The evaluation confirmed that the large break LOCA results in CESSAR Section 6.3.3.2 are unaffected, but the small break LOCA results were affected. Consequently, the worst case small break LOCA was reanalyzed to consider the HPSI, LPSI, and AFW pump flowrate reductions. Section 6.3.3.3 was revised accordingly.

The large break LOCA spectrum is unaffected by the combined effects of the HPSI, LPSI, and AFW flowrate reductions because:

(1) The energy release through the break overwhelms the amount of SG heat transfer.

(2) There is no credit taken for SI pump flow until the SIT is empty, at which time the reflood has already begun and the downcomer is full of water.

(3) Once credit is taken for the SI flow, the total flow reduction of concern is much less than the amount of calculated spillage to the containment. Therefore, the amount of injection water flowing into the reactor vessel and core remains unchanged.

The small break LOCA spectrum is affected by the SI pump flow reduction. Although the smallest sizes (0.05 square foot and less) are sensitive to SG heat removal, the AFW flow reduction of concern was found insufficient to change their response. To assess the combined influence of the HPSI, LPSI, and AFW pump flow reduction, the worst small break (0.05 square foot cold leg break) was reanalyzed. The combined effect caused a peak cladding temperature increase from 1557F to 1630F. The increased temperature remains more than 500F lower than the limiting large break LOCA. Other small break sizes are influenced to a lesser amount. Breaks greater than 0.05 square foot are not sensitive to AFW flow and inventory recovery is provided by the SITs. Breaks smaller than 0.05 square foot lead to little or no uncovering of the core and, hence, significantly lower peak cladding temperatures. The 0.05 square foot, therefore, remains the worst case small LOCA and yields a peak cladding temperature more than 500F higher than other small break sizes.

s. The combined influence of reduced AFW flow and SI flow results in lower mass/energy releases to the containment for the LOCA. The LOCA event results in the calculated peak pressure.

t. Safety injection flow has no impact on secondary mass/energy releases during an SLB.

u. For RCS pressure consideration only. For cooldown consideration, the MSLB is limiting (see subsection 15.1.5).

1.9.2.4.11 DELETED

1.9.2.4.12 Containment Sump Isolation Valves Actuation Time Acceptance Criteria (CESSAR Section 6.2.4/ FSAR subsection 6.2.4)

CESSAR Table 6.2.4-1 indicates a closure time of 20 seconds for the following valves which are actuated by a recirculation actuation signal (RAS): SIA-UV673, SIA-UV674, SIB-UV675, and SIB-UV676. Though the CESSAR Table specifies a closure time for these valves, the recirculation sump suction is an essential system penetrating containment and is not functionally isolated by a CIAS. These valves are normally closed and the automatic actuation stroke position for these valves is open. The recirculation sump suction is critical to ensure the capability to mitigate consequences of accidents, and the valves are designed to open at a RAS. An increased actuation (open) time of 35 seconds was reviewed against the safety analysis requirements for these valves and found to be acceptable. These valves are required to open upon receipt of a RAS, which is generated by a low RWT level signal. These valves are required to open before the RWT level reaches the level of the SI pump suction line to ensure an uninterrupted source of water for the SI pumps. Sufficient margin is available in the low RWT setpoint to allow for a 15-second increase in the valve open time. The increased actuation time limit will not affect these valves' operability or durability. This deviation from these valves' original specification is acceptable. Any mechanical failure of a valve or its operator

which would not cause the valves' actuation time to exceed 35 seconds would not jeopardize the function of the valve.

1.9.2.4.13 Chemical and Volume Control System (CVCS) (CESSAR Section 9.3.4.4/FSAR subsection 9.3.4)

CESSAR Section 9.3.4.4, Testing and Inspection Requirements, states in part: "All sections of the CVCS will be operated and tested initially with respect to flow paths, flow capacity, and mechanical operability. Pumps will be tested to demonstrate head and capacity."

The gas stripper pumps were supplied as an integral part of the gas stripper which is comprised of a stripper column, heat exchange equipment, piping subassemblies, pumps, valves, structural hardware, and instrumentation; as such, the pumps were not provided with provisions for measuring suction and discharge pressures. This lack of test connections precludes the ability to satisfy the aforementioned requirement.

Combustion Engineering has determined that the requirement to prove head and capacity does not apply to the gas stripper pumps and may be exempted for the following reasons:

A. Operation of the gas stripper is not required during or after an accident. Therefore, pump performance and operability is not a criteria for plant safety.

B. The gas stripper was tested and qualified by the vendor. As long as the proper interface requirements (i.e., inlet pressure, backpressures, flows, temperatures) to the gas stripper are maintained, the

stripper will operate as required during normal plant operation.

1.9.2.4.14 Historical information moved to Appendix 1A

1.9.2.4.15 Historical information moved to Appendix 1A

1.9.2.4.16 Historical information moved to Appendix 1A

1.9.2.4.17 Historical information moved to Appendix 1A

1.9.2.4.18 Historical information moved to Appendix 1A

1.9.2.4.19 Fuel Handling System (CESSAR Section 9.1.4.2.2.11/ FSAR subsection 9.1.4) Refueling Equipment Test (CESSAR Section 14.2.12.1.36)

CESSAR Section 9.1.4.2.2.11 describes a dry sipping system to be utilized in the detection of fuel cladding failures during refueling operations. This system is currently not utilized at PVNGS; instead, as a minimum, a visual surveillance program for discharged fuel assemblies will be instituted as stated in the response to NRC Question 490.3 (FSAR Question 4A.3).

Since the dry sipping system is currently not being utilized at PVNGS, exception is being taken to Paragraph 3.3 of the refueling equipment test description, CESSAR Section 14.2.12.1.36, of the preoperational test program.

NOTE

Equipment for the purpose of detecting fuel cladding failure will be preoperationally tested prior to its use.

1.9.2.4.20 Historical information moved to Appendix 1A

1.9.2.4.21 Historical information moved to Appendix 1A

1.9.2.4.22 Historical information moved to Appendix 1A

1.9.2.4.23 Demineralized Water System (CESSAR Table 9.2-1, FSAR paragraph 9.2.3.1.2, listing D)

CESSAR Table 9.2-1 imposes certain water quality requirements on the demineralized water system at PVNGS. As discussed in paragraph 9.2.3.1.2, listing D, PVNGS does not fully meet these CESSAR requirements. However, this condition is acceptable since the water quality specifications for the ultimate uses of demineralized water (such as the reactor coolant system, the feedwater system, and the steam generators) are in accordance with the CESSAR.

1.9.2.4.24 Use of Inhibited (with Hydrazine) Water for Cleaning, Flushing, and Pressure Testing (CESSAR Sections 4.5.1.5 and 5.2.3.4.1.2)

To prevent halide-induced intergranular corrosion in the RCS, CESSAR Sections 4.5.1.5 and 5.2.3.4.1.2 require the water for cleaning, flushing, and pressure testing to be inhibited with hydrazine. Welding electrodes are coated with fluorine-containing material and small amounts of the coatings can be left behind from the field welds of the piping, etc. Hydrazine will prevent SCC scavenging any oxygen that may be dissolved in the water. Because of the numerous personnel precautions needed for hydrazine, a closer look was taken at the use of

inhibited water. It was found that the use of inhibited water is not needed for cleaning, flushing, or pressure testing as long as water does not remain in the RCS for a long (weeks) period of time. A review of the literature showed that it takes about a week to produce fluorine-induced stress corrosion cracking (SCC) in sensitizing weldments. Hence, if the length of time a component is wet is limited to a day or two and weldments are not sensitized, the possibility of SCC is precluded. Therefore, Sections 4.5.1.5 and 5.2.3.4.1.2 have been changed to make the use of inhibited water mandatory only if the water will remain in the component or RCS for a long period of time; i.e., wet layup.

1.9.2.4.25 Historical information moved to Appendix 1A

1.9.2.4.26 Inadvertent Loading of a Fuel Assembly Into the Improper Position (CESSAR Section 15.4.7.2)

CESSAR 15.4.7.2 indicates that a licensed operator will be present in the area where fuel assemblies are being handled to ensure that the assemblies are moved to their correct location. PVNGS takes exception to this in that all core alterations shall be observed and directly supervised by either a licensed senior reactor operator or a senior reactor operator limited to fuel handling who has no other concurrent responsibilities during this operation.

In addition, PVNGS takes exception to CESSAR 15.4.7.2 with respect to "periodic" independent inventories of components in the reactor core, spent fuel, and new fuel storage areas to ensure that the tag board is correct. PVNGS does perform

annual inventories of the spent fuel and new fuel storage areas in addition to post refueling reactor core mapping. These inventories are then used as the basis for setting up the tag board for use during fuel movement.

1.9.2.4.27 Increase in Feedwater Flow (CESSAR Section 15.1.2)

CESSAR 15.1.2 assumes a maximum increase to feedwater flow at full power to be 110% of the nominal feedwater flow. After testing, the feedwater system has been found to be capable of supplying 125% of the nominal flow at full power. To assure conservatism, a re-evaluation of the increase in feedwater flow event was made. The results of this re-evaluation showed that the most limiting event in UFSAR Section 15.1 is the increase in main steam flow event due to the quick opening of 8 steam bypass valves (Section 15.1.3). Therefore, the assumed feedwater flow value should be 125% of the nominal flow instead of 110%.

1.9.2.4.28 Reactor Vessel Closure Head Handling/Containment Polar Crane (CESSAR Sections 9.1.4.3.5 and 9.1.4.6.I.1/FSAR sections 9.1.4.1.3., 9.1.4.2.2.18, 9.1.4.3.3, and 9.1.4.7.I.1)

CESSAR Section 9.1.4.6.I.1 states that the reactor vessel closure head assembly shall not be raised to a height greater than 17 feet while above the reactor vessel flange. This maximum drop limit will be exceeded due to the height of the reactor closure head alignment pins being at 16'-8" and the polar crane limit switch tolerance of $\pm$ 6".

CESSAR Section 9.1.4.3.5 made the analysis and conclusion that the reactor core is maintained in a coolable configuration, and the reactor vessel support system, the fuel assembly, and the shutdown cooling supply flow paths will remain functional in the unlikely event of a free fall of the reactor head assembly from 18 feet above the reactor vessel flange.

References to the reactor vessel closure head assembly raised height of 18 feet in CESSAR Interface Evaluation section 9.1.4.7 are no longer applicable to PVNGS. Refer to section 9.1.4.3.5 for closure head lift height evaluation.

1.9.2.4.29 Initial Test Program (CESSAR Section 14.2.12.2.14)

Based upon the satisfactory results of the feedwater water hammer tests in Unit 1 and Unit 3, the visual inspection of the feedwater sparger in Unit 2 will not be performed.

1.9.2.4.30 Safety Injection System (CESSAR Section 6.3.2.2.5.b)

See Section 6.3.2.2.5.b.

1.9.2.4.31 Section 5.4.7.2.P.2, Cooling Water System Requirements, describes the interface deviations of the PVNGS Essential Cooling Water (EW) system from the CESSAR interface requirement for the Shutdown Cooling Heat Exchangers described in Section 5.4.7.1.P.2. These deviations are acceptable as noted in Section 5.4.7.2.P.2.b.

1.9.2.4.32 Containment Spray System (CESSAR 6A)

The containment spray system (CSS) was originally intended to interface with the iodine removal system (IRS). The IRS would inject hydrazine into the CSS to remove iodine from the containment atmosphere. PVNGS will no longer use the IRS and will not inject hydrazine into the CSS for the purpose of removing iodine from the containment atmosphere. For a discussion on the methodology for removing iodine from the containment atmosphere, see subsection 6.5.2.

1.9.2.4.33 Power Sources for Containment Spray (CESSAR Appendix 6A Section 7.1.1/FSAR Section 6.5.2.8.A.7.1.1)

CESSAR Appendix 6A section 7.1.1 states that the plant turbine generator, plant startup power source, and the emergency generators are available to power the containment spray pumps, valves, and associated instrumentation. PVNGS is not designed to power any class equipment via the onsite turbine generator.

Aligning the onsite turbine generator would place both (redundant) trains of safety related equipment tied to a single power source (the main generator) and would not comply with 10 CFR 50 GDC 17 requirements relating to single failure criteria. The trip of the generator would cause a loss of power to both safety trains. Therefore, no in-plant interconnection to/from the plant main generator to the Class 1E power system has ever existed at PVNGS. This is consistent with the as licensed configuration documented in UFSAR Chapter 8 and related design drawings.

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1.10 EXEMPTIONS TO 10 CFR PART 50 REQUIREMENTS

Table 1.10-1, 10 CFR Part 50 Approved Exemptions, lists PVNGS exemptions which have been approved by the NRC in accordance with 10 CFR 50.12 and are currently effective. 10 CFR 50.12, Specific Exemptions, provides a means by which the "Commission may, upon application by any interested person or upon its own initiative, grant exemptions from the requirements of the regulations of this part [10 CFR 50], which are authorized by law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security."

Table 1.10-1

10 CFR PART 50 APPROVED EXEMPTIONS (Sheet 1 of 2)

Unit	**Expiration Date**	**Description of Exemption**	**Date Granted**	**Reference**
1, 2, & 3	none	Exemption from certain requirements of 10 CFR 50.71(e)(4) to allow submittal of UFSAR revisions; changes to the QA program (10 CFR 50.54(a)(3)); and reports of changes, test, and experiments made in accordance with 10 CFR 50.59 (10 CFR 50.59(b)(2)) on a 24-month periodicity not tied to a particular unit's refueling outage schedule. (Note: The revised 10 CFR 50.59(d)(2), effective March 13, 2001, changed the reporting interval such that these reports are to be submitted at intervals not to exceed 24 months.)	July 8, 1999	NRC Letter dated July 8, 1999, "Palo Verde Nuclear Generating Station, Unit Nos. 1, 2, and 3 – Issuance of Exemption from Certain Requirements of 10 CFR 50.71(e)(4)"
1, 2, & 3	none	Exemption from 10 CFR Part 50, Appendix J, Paragraph III.D.2(b)(ii) "Air locks opened during periods when containment integrity is not required by the plant's Technical Specifications shall be tested at the end of such periods at not less than Pa." This exemption allows the substitution of the seal leakage test of Paragraph III.D.2(b)(iii) when no maintenance has been performed on an air lock.	Dec. 1984	SSER Supplement 7, Section 6.2.6 Operating Licenses, Section 2.D.
1	End of Cycle 17	Exemption from specific requirements of 10 CFR 50.46 and 10 CFR 50 Appendix K to allow use of up to eight lead fuel assemblies manufactured by AREVA NP consisting of fuel rods with M5 cladding material.	Oct. 14, 2008	NRC letter dated, October 14, 2008 "Palo Verde Nuclear Generating Station, Unit 1 – Temporary Exemption from the Requirements of 10 CFR Part 50, Section 50.46 and Appendix K for Lead Fuel Assemblies (TAC NO. MD8330)"
3	End of Cycle 18	Exemption from certain requirements of 10 CFR 50 Section 50.46, and Appendix K to allow use of eight lead fuel assemblies that contain Optimized Zirlo cladding material.	August 26, 2010	NRC Letter dated, August 26, 2010, "Palo Verde Nuclear Generating Station, Unit 3- Temporary Exemption from the Requirements of 10 CFR Part 50, Section 50.46 and Appendix K (TAC NO. ME2590)"

Table 1.10-1

10 CFR PART 50 APPROVED EXEMPTIONS (Sheet 2 of 2)

Unit	**Expiration Date**	**Description of Exemption**	**Date Granted**	**Reference**
1, 2, & 3	None	Exemption from specific requirements of 10 CFR 50 Appendix G, “Fracture Toughness Requirements,” to allow the application of the methodology in Combustion Engineering Topical Report NPSD-683-A, Revision 6, “Development of a RCS Pressure and Temperature Limits Report for the Removal of P-T Limits and LTOP requirements from the Technical Specifications,” for the calculation of stress intensity factors due to internal pressure loadings.	February 24, 2010	NRC Letter dated February 24, 2010 “Palo Verde Nuclear Generating Station, Units 1, 2, and 3 - Exemption from the Requirements of Appendix G to 10 CFR Part 50”

1.11 BEYOND DESIGN BASIS EXTERNAL EVENTS – DIVERSE AND FLEXIBLE COPING STRATEGIES (FLEX)

As a result of the NRC's evaluation of the lessons learned from the accident at Fukushima Dai-ichi in March 2011, the NRC required additional defense-in-depth measures to address uncertainties associated with protection from beyond-design-basis external events. The NRC issued Orders EA-12-049 (Mitigating Strategies) and EA-12-051 (Reliable Spent Fuel Pool Instrumentation) to direct nuclear power plant licensees and construction permit holders to take certain actions. To support the industry's completion of these actions, the Nuclear Energy Institute (NEI) prepared NEI 12-06 (Diverse and Flexible Coping Strategies (FLEX) Implementation Guide) which was subsequently endorsed by the NRC.

Modified plant systems include, but are not limited to: Chemical and Volume Control System, Emergency Core Cooling(Safety Injection), Main Steam, Auxiliary Feedwater, Condensate Storage, and Emergency Diesel Fuel Oil and Transfer. Electrical systems have been modified to support alternate power source connections.

The Spent Fuel Pool (SFP) Cooling system has been modified to address the following: SFP level monitoring, make-up, sloshing barriers, and gate seal gas backup.

APPENDIX 1A
HISTORICAL INFORMATION
FROM CHAPTER 1

CONTENTS

HISTORICAL

1.9.2.4.14 Preoperational Test Description for the Boric Acid Batching Tank Subsystem Test (CESSAR Section 14.2.12.1.12/FSAR subsection 14.2.12)

CESSAR Section 14.2.12.1.12 has the following required test method:

3.3 Refill the boric acid batching tank, dissolve boric acid crystals, and start the batch tank mixer. Take samples as the tank is drained to the equipment drain tank and determine the boric acid concentration.

The requirement to drain the tank to the equipment drain tank cannot be achieved at PVNGS since the as-built configuration does not include a drain path to the equipment drain tank. Drainage from this tank is routed to the non-ESF sump.

To satisfy the requirement to obtain boric acid concentration data the samples will be taken while transferring the contents of the boric acid batching tank to the refueling water tank or when draining the contents to the non-ESF sump.

HISTORICAL

1.9.2.4.15 Power Ascension Testing for Incore Detectors, Variable T_{avg}, Control Systems Checkout Test, and Turbine Test (CESSAR Sections 14.2.12.5.2, 14.2.12.5.20, and Table 14.2-2/FSAR subsection 14.2.12)

For Units 2 and 3, the variable T_{avg} test method (item 3.0) and data required (item 4.0) is modified as shown below (CESSAR

Section 14.2.12.5.2). This CESSAR exception modifies the test method, but the purpose and results of the test remain the same.

3.0 Test Method

3.1 The ITC is measured as follows:

3.1.1 Changes are made to core average temperature and power is maintained essentially constant using CEA movement or adjustment to the RCS boron concentration.

3.2 The power coefficient is measured using one of the following methods:

3.2.1 Changes are made to core power using CEA motion and core average temperature is maintained essentially constant.

3.2.2 Changes are made to core power and balanced by allowing core average temperature to change to a new value.

4.0 Data Required

4.1 Conditions of the measurement

4.1.1 Power

4.1.2 CEA configuration

4.1.3 Core burnup

4.2 Time dependent data

4.2.1 Power

4.2.2 RCS temperatures

4.2.3 CEA positions

4.2.4 Boron concentration

For Units 2 and 3, the incore detector test deviates from CESSAR Section 14.2.12.5.20. Items 1.2, 3.2, and 5.2 in CESSAR Section 14.2.12.5.20 are deleted for Units 2 and 3. In deleting these steps, only the movable incore data will be affected. Since the units are identical, this part of the testing is redundant. This portion of incore detector testing is not required by Regulatory Guide 1.68. The movable incore detectors are not required for the operation of the plant.

Replace CESSAR Table 14.2-2 with FSAR table 1.9-5. The modified power ascension percent loads for the following tests are acceptable as described below:

A. The control systems checkout testing is not being reduced in scope; it is only being changed from 80% to 100%. The main reason for the change is that reactor regulating system testing requires rod insertion resulting in axial perturbations. There are no other tests at 80% on Units 2 and 3 which will require rod insertion. Therefore, it is actually safer to do the testing at 100% and eliminate the possibility of axial perturbations.

STANDARD DESIGNS

HISTORICAL

Table 1.9-5

POWER ASCENSION TEST (Sheet 1 of 2)

Test Title	Unit 1	Units 2 and 3[(a)]
Natural Circulation Test	≥ 80%[(b)]	N/A
Variable T_{avg} (Isothermal Temperature Coefficient and Power Coefficient) Test	20, 50, 80, 100%[(c)]	50[(d)] and 100%[(c)]
Unit Load Transient Test	50, 100%	50, 100%
Control Systems Checkout Test	20, 50, 80, 100%	50, 100%
RCS and Secondary Chemistry and Radio chemistry Test	20, 50, 80, 100%	20, 50, 80, 100%
Turbine Trip Test	100%	N/A
Unit Load Rejection Test	100%	100%

a. Reduced testing is contingent upon the demonstration that Units 2 and 3 behave in an identical manner as Unit 1 through conformance with the acceptance criteria given in Table 14.2-7 of CESSAR.

b. Initial power level.

c. The temperature and power coefficient measurements are done as close as possible to 100% power at a level where CEA motion is practical accounting for margin considerations.

d. Unit 3 will perform a reduced scope test at the 50% power plateau.

e. This test will not be performed on Unit 3.

f. This test will not be performed at either 20% or 80% power on Unit 3.

HISTORICAL

Table 1.9-5

POWER ASCENSION TEST (Sheet 2 of 2)

Test Title	Unit 1	Units 2 and 3[(a)]
Shutdown from Outside the Control Room Test	≥ 10%	≥ 10%
Loss of Offsite Power Test	≥ 10%	≥ 10%[(e)]
Biological Shield Survey Test	20, 50, 80, 100%	20, 50, 80, 100%
Xenon Oscillation Control Test	≥ 50%	N/A
Dropped CEA Test	Post 80%	N/A
"Ejected" CEA Test	Post 80%	N/A
Steady-State Core Performance Test	20, 50, 80, 100%	20, 50, 80, 100%
Intercomparison of PPS, CPC and Process Computer Inputs	20, 50, 80, 100%	20, 50, 80, 100%
Verification of CPC Power Distribution Related Constants	20, 50%	20,50%
Main and Emergency Feedwater	≥ 10%[(b)]	≥ 10%[(b)]
CPC Verification	20, 50, 80, 100%	20, 50, 80, 100%[(f)]
Steam Dump and Bypass Valve Capacity Test	≥ 15%	≥ 15%
Incore Detector Test	20, 50, 80, 100%	20, 50, 80, 100%
COLSS Verification	20, 50, 80, 100%	20, 50, 80, 100%[(f)]

B. Since the units are identical and the turbine will be tripped during unit load rejection testing, there is no need to perform the turbine trip test for Units 2 and 3 as was done on Unit 1.

HISTORICAL

1.9.2.4.16 Post-Core Hot Functional Testing of CEDM Performance (CESSAR Section 14.2.12.3.4/FSAR subsection 14.2.12)

The objective of the post-core hot functional testing of CEDM performance for PVNGS is to demonstrate the proper operation of the CEDMs and CEAs. This demonstration will be performed under hot shutdown (Unit 1 only) and hot, zero power conditions (Units 1, 2, and 3). The withdrawal and insertion of each CEA to verify proper operation of the CEDM under hot shutdown conditions will be performed for Unit 1 only.

Testing at hot shutdown conditions for Units 2 and 3 is eliminated because criticality will not be reached until hot, zero power conditions. All Units 2 and 3 CEDM performance testing can be done at hot, zero power conditions, and as required at cold shutdown conditions.

HISTORICAL

1.9.2.4.17 Low Power Physics Testing of Shutdown CEA Group Worth (CESSAR Section 14.2.12.4.4 and CESSAR Table 14.2-1/FSAR subsection 14.2.12)

For Units 2 and 3 only, FSAR paragraph 1.9.2.4.17.1 and table 1.9-6 replace CESSAR Section 14.2.12.4.4 and CESSAR

Table 14.2-1. Due to these changes, the shutdown margin will not be explicitly measured; however, it is verified by analysis.

Since the core design for PVNGS Units 1, 2, and 3 is essentially identical, the nuclear characteristics and performance of all three units are expected to be equivalent. Unit 1 underwent extensive testing. The test program for Unit 2 will be a subset of the testing performed on Unit 1, but more stringent acceptance criteria will be applied. The test program for Unit 3 will include the same type of measurements as the Unit 2 program; however, the CEA exchange method, in accordance with Technical Specifications, may be used in place of the boration/dilution technique to measure control rod worths. If the CEA exchange method is used, all regulating and shutdown CEA group worths will be measured and the CEA symmetry test will be deleted as shown in table 1.9-6. If similarity of Units 2 and 3 to Unit 1 cannot be adequately demonstrated, additional testing will be performed.

HISTORICAL

1.9.2.4.17.1 Shutdown and Regulating CEA Group Worth Test for Units 2 and 3.

1.0 Objective

To determine regulating and shutdown CEA group worths necessary to demonstrate shutdown margin (i.e., worth of all CEAs less the highest worth CEA), see item 3.1.2 below for the requirements to measure shutdown group worths and net shutdown

margin. (For Unit 3, section 3.2 below, in accordance with Technical Specifications, may be performed in place of section 3.1.)

2.0 Prerequisites

2.1 The reactor is critical.

2.2 The reactivity computer is operating.

3.0 Test Method

3.1 Boration/Dilution Technique

STANDARD DESIGNS

HISTORICAL

Table 1.9-6

LOW POWER PHYSICS TESTS

Test Title	Unit 1	Unit 2 and 3[a][c]	CEA Exch. Method
Low Power Biological Shield Survey Test	320F/565F	565F	565F
CEA Symmetry Test	565F	565F	N/A
Isothermal Temperature Coefficient Test	320F-565F	565F	565F
Regulating CEA Group Worth Test	320F and 565F	565F	565F
Shutdown CEA Group Worth Test	320F	N/A[b]	565F
Differential Boron Worth Test	320F and 565F	565F	565F
Critical Boron Concentration Test	320F-565F	565F	565F
Pseudo Dropped and Ejected CEA Worth Test	565F	N/A	N/A

a. Reduced testing is contingent upon the demonstration that Units 2 and 3 behave in an identical manner as Unit 1 through conformance with the acceptance criteria given in CESSAR Table 14.2-7.

b. Deletion of this measurement on Units 2 and 3 is contingent upon the regulating CEA worths satisfying acceptance criteria of CESSAR Table 14.2-7. If this is not the case and the measurement is required, it will be performed at an RCS temperature of 565F.

c. Unit 3, in accordance with Technical Specifications, may utilize the CEA exchange method. The acceptance criteria for CEA group worth is as specified in CEN-319, "Control Rod Group Exchange Technique", November 1985.

3.1.1 The CEA group worths will be measured by dilution/boration of the RCS at hot zero power.

3.1.2 Shutdown group worths and net shutdown margin will be measured at hot zero power if the total regulating CEA worth does not fall within a ±10% tolerance of the predicted worth.

3.1.3 Where dilution/boration is not feasible, worths may be determined by CEA drop and/or by use of alternate CEA configurations.

3.2 CEA Exchange Technique

3.2.1 The referenced CEA group worth(s) will be measured by dilution/boration of the RCS at hot zero power.

3.2.2 CEA groups are individually fully inserted while the reference CEA group is withdrawn. Final CEA group positions are recorded.

3.2.3 The individual CEA group worths are determined from the final positions of the reference CEA group.

4.0 Data Required

4.1 Conditions of the Measurement

4.1.1 RCS temperature

4.1.2 Pressurizer pressure

4.1.3 CEA configuration

4.1.4 Boron concentration

4.2 Time dependant information

4.2.1 Reactivity variation (strip chart)

4.2.2 CEA positions

5.0 Acceptance Criteria

5.1 The measured CEA group worths agree with predictions within the acceptance criteria specified in table 1.9-6.

HISTORICAL

1.9.2.4.18 Initial Criticality (CESSAR Section 14.2.10.2/FSAR paragraph 14.2.10.2)

For Units 2 and 3, the final approach to initial criticality may be made by either withdrawal of the last regulating group or by RCS boric acid concentration reduction. In either case, the last regulating group will be used to control the chain reaction after achieving criticality.

HISTORICAL

1.9.2.4.20 Chemical and Volume Control System (CESSAR Section 9.3.4.4/FSAR subsection 9.3.4)

CESSAR Section 9.3.4.4, Testing and Inspection Requirements, states in part: "All sections of the CVCS will be operated and tested initially with respect to flowpaths, flow capacity, and mechanical operability. Pumps will be tested to demonstrate head and capacity."

The testing requirements regarding the head and capacity of the boric acid concentrator (BAC) pumps may be deleted without impacting plant safety. The BAC package is a nonsafety-related system which is not required for accident mitigation or safe shutdown of the reactor.

The performance of the BAC pumps has been demonstrated as follows:

- The pump head and capacity were tested on a component basis by the manufacturer.
- The BAC package unit was tested and qualified by C-E.
- The proper function of the BAC pumps is assured by demonstrating, during preoperational testing, the BAC's processing of the holdup tank contents at a rate of 20 gallons per minute (refer to CESSAR Section 14.2.12.1.16).

HISTORICAL

1.9.2.4.21 Unit Load Rejection Test (CESSAR Section 14.2.12.5.7)

CESSAR Section 14.2.12.5.7, Test Method, states that "a breaker(s) is tripped so as to subject the turbine to the maximum credible overspeed condition." For Units 2 and 3, PVNGS takes exception to that part of the test method. Instead of the method described in 3.1 of that test description, the method used will be to trip the breaker(s) in order to initiate the load rejection. Maximum overspeed condition will not be achieved.

The alternate test method still meets the objective of the test and the acceptance criteria still applies. This alternate method allows PVNGS to test the fast bus transfer during the unit load rejection test.

Since all three units have the same circuitry to arrest turbine acceleration and Units 2 and 3 have circuitry that has been functionally tested, performing the unit load rejection test with the same method for all three units is not necessary. PVNGS will gather more useful information by taking this exception to CESSAR for Units 2 and 3.

HISTORICAL

1.9.2.4.22 Precore Reactor Coolant System Heat Loss (CESSAR Section 14.2.12.2.9)

CESSAR Section 14.2.12.2.9 requires that a precore hot functional test be performed to measure RCS heat loss and pressurizer heat loss under hot, zero power conditions. The

RCS heat loss is measured to determine a value for use in the RCS thermal performance program COLSS, and pressurizer heat loss is measured to satisfy the requirements of Regulatory Guide 1.68.

A more accurate determination of the RCS heat loss value for the COLSS program in Unit 3 is to be achieved utilizing test data obtained from the Unit 3 containment HVAC systems. The objective of CESSAR Section 14.2.12.2.9 is still met if the containment HVAC test method replaces the steam-down test method that is specified within Section 14.2.12.2.9 to measure RCS heat loss.

HISTORICAL

1.9.2.4.25 Preoperational Test Description for the Holdup Subsystem Test (CESSAR Section 14.2.12.1.15)

CESSAR Section 14.2.12.1.15 specifies the following as a test method for the holdup subsystem preoperational test:

3.1 Fill the holdup tank and observe level indications and alarms.

3.2 Simulate holdup tank temperature and observe indications and alarms.

3.3 Using each holdup pump, drain the holdup tank to the boric acid concentrator. Observe holdup tank level indications, alarms, and interlocks and holdup pump discharge pressure.

3.4 Refill and isolate the holdup tank. Open the holdup tank recirculation valves and start each holdup pump. Observe tank level. Line up the holdup pumps to the reactor drain tank filter and observe holdup tank level.

This CESSAR-specified test method precludes the capability to adjust for plant conditions at the time of testing, and also does not address the site-specific need to conserve treated water at PVNGS. Therefore, the following modification to the CESSAR test description is utilized:

2.5 There is a sufficient inventory of water contained in the holdup tank to conduct testing in accordance with section 3.0.

3.0 Test Method

3.1 Observe level indication, alarms, and interlocks in response to actual or simulated holdup tank levels.

3.2 Simulate holdup tank temperature and observe indications and alarms.

3.3 Using each holdup pump, transfer holdup tank contents to the boric acid concentrator. Observe holdup tank level indication, alarms, and interlocks and holdup pump discharge pressure.

3.4 Refill and isolate the holdup tank. Open the holdup tank recirculation valves and start each holdup pump. Observe tank level. Line up the holdup pumps to the reactor drain tank filter and observe holdup tank level.

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APPENDIX 1B

HISTORICAL REGULATORY GUIDE INFORMATION

FROM CHAPTER 1

APPENDIX 1B

HISTORICAL

REGULATORY GUIDE 1.28: Quality Assurance Program Requirements (Design and Construction) (Revision 0, June 7, 1972)

RESPONSE

For construction phase activities and prerequisite and phase I startup testing, the position of Regulatory Guide 1.28 is accepted. Also see 17.1 and 17.2. For operations phase activities including phase II through phase IV startup testing, the regulatory position found in Regulatory Guide 1.28 will be replaced by the regulatory position found in Regulatory Guide 1.33 as modified and interpreted by APS in Section 1.8. Additional References: 4.2.5, 5.4.7.1, 6.3.1.3, 9.1.4.6, and 18.II.F.2-3.

HISTORICAL

REGULATORY GUIDE 1.30: Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electronic Equipment (Revision 0, August 11, 1972)

RESPONSE

The requirements of the referenced standard (ANSI N45.2.4-1972) will be applied to the Bechtel quality program for construction of safety-related items as interpreted in the regulatory position as modified and interpreted below:

A. Section 2.1, Planning. The required planning is frequently performed on a generic basis for application to many installations on one or more projects. This results

in standard procedures or plans for installation and inspection and testing which meet the requirements of the standard. Individual plans for each item or system are not normally prepared unless the work operations are unique; however, standard procedures or plans are reviewed for applicability in each case. Installation plans or procedures are also limited in scope to those actions or activities which are essential to maintain or achieve required quality.

B. Section 3, Preconstruction Verification. The requirements of this section are applied to items which are received and stored prior to installation. They are combined with receiving inspection activities in accordance with ANSI N45.2.2 requirements for items which are installed immediately after receiving inspection.

For operations phase activities that are comparable to activities occurring during the construction phase, the following interpretations apply to the position of Regulatory Guide 1.30:

A. Section 5.2:

The various tests are performed “as appropriate” as determined by PVNGS Engineering Department based upon the significance of the change or modification.

B. Section 6.2.1:

PVNGS utilizes a computer information management system to maintain plant equipment calibration status including the date of calibration and identity of the person that

performed the calibration. The computer information management system provides a more reliable and accessible method of documenting plant equipment calibration status than the use of tags or labels affixed to equipment.

C. Section 6.2.2:

The requirement that systems tests be made to verify that all parts of a system properly coordinate with each other is interpreted as not requiring that an entire system be retested after modification of only a portion of that system. The testing requirements of the Technical Specifications are met for inoperable equipment.

Reference 3.11.2, 7.1.2.6, 7.1.2.17, 8.3.1.2.2.7, 8.3.2.2.1.6, 14.2.7, 17.1, 17.2, and Table 18.II.F.2-3.

HISTORICAL

REGULATORY GUIDE 1.33: Quality Assurance Program Requirements (Operation) (Revision 2, February 1978)

RESPONSE

The position of Regulatory Guide 1.33 is accepted with the following exceptions to Regulatory Positions C.2 and C.4:

For Regulatory Position C.2, the APS commitment refers to regulatory guides, and revisions thereof, specifically identified in this FSAR.

For Regulatory Position C.4, the specific audits at C.4.a, C.4.b, and C.4.c shall be performed at a frequency of at least once per 24 months. In addition, a grace period of 90 days

beyond the specified frequency shall be permitted for completion of internal audits. When the grace period is utilized, subsequent scheduling for the audit shall be based upon the original due date. This grace period shall not be applied to those audits that have a frequency specifically defined by regulation.

In addition, the following clarification is made in APS' position regarding Regulatory Guide 1.33:

> Compliance to ANSI standards referenced throughout ANSI N18.7-1976/ANS-3.2 are addressed separately in APS' response to conformance with the regulatory guides listed in section C.2 of Regulatory Guide 1.33.

The following exceptions are taken to ANSI N18.7:

A. Section 3.4.2

> The APS commitment on the qualification of personnel who are performing preoperational and startup test functions is found in paragraph 14.2.2.12.

B. Section 5.2.13.1

> When purchasing commercial-grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Alternative requirements described in UFSAR Section 1.8 for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1971.

In addition, the following interpretations of ANSI N18.7 are made:

A. Section 5.2.2

The requirements of this section are accepted with the following interpretations:

Temporary changes to procedures may be made provided the change is approved by two members of the plant management staff, at least one of whom holds a senior reactor operator license on the unit affected.

Procedural steps traditionally identified as immediate actions are incorporated into standard post-trip actions. Following a manual or automatic reactor trip, standard post-trip actions will be performed. The reactor operators are expected to know the standard post-trip actions and begin to take action.

The control room supervisor shall perform the standard post-trip actions in the order written and go over each step with the control room staff.

B. Section 5.2.13.1

The requirement that changes made to procurement documents be subject to the same degree of control as was used in the preparation of the original documents is applied consistent with the requirements of ANSI N45.2.11, Paragraph 7.2. Minor changes to documents, such as inconsequential editorial corrections or changes to commercial terms and conditions, may not require that the

revised document receive the same review and approval as the original documents.

C. Section 5.2.17

The requirements of this section are accepted with the following interpretation:

The requirement that deviations, their cause, and any corrective action completed or planned shall be documented shall apply to significant deviations. Other identified deviations will be documented and corrected. This interpretation is consistent with Appendix B to 10CFR50, Criterion XVI, Corrective Action.

D. Section 5.2.19.1

Preoperational testing (phase I startup testing) addressed in ANSI N18.7, Paragraph 5.2.19.1, will be conducted in accordance with Regulatory Guide 1.68, Revision 0.

E. Section 5.3.9.1

The requirements of this section are accepted with the following interpretation:

Actions identified as immediate operator actions have been standardized in the form of safety function status checks. Safety functions are maintained for all transients when the emergency procedure is implemented. This ensures proper operator response independent of event diagnosis. This approach is consistent with CEN-152, CE Emergency Procedure Guidelines.

Actions identified as subsequent operator action are addressed as a recovery procedure, implemented after event

diagnosis. This approach is consistent with CEN-152, CE Emergency Procedure Guidelines.

The specific procedure format and content have been identified in the Emergency Procedure Generation Package and submitted to the NRC for review. This is consistent with NUREG-0899.

F. Section 5.2.15

The requirements of this section are accepted with the following interpretation(s):

The requirement for periodic review of routine plant procedures no less frequently than every two years may be exceeded for routine plant procedures which are used infrequently, when alternative means are provided to ensure review of these procedures prior to use.

Periodic review of plant procedures no less frequently than every two years is not required for routine, frequently-used plant procedures. Periodic audits to satisfy regulatory requirements and commitments include an assessment of a representative sample of related procedures to validate that the procedures are acceptable for use and that the procedure review and revision process is being effectively implemented.

The exceptions to periodic review requirements stated above do not apply to non-routine procedures (such as abnormal operating procedures, emergency operating procedures, alarm response procedures, procedures which implement the Emergency Plan, or procedures which implement the Security Plan). The periodic review

requirement for these procedures may be satisfied by the use or review of the procedure during plant operation, training exercise, drill, or by other such review activity which validates acceptability of the procedure, provided the procedure use or review activity is documented.

G. Section 5.2.7

The requirements of this section are accepted with the following interpretations:

Activities occurring during the operational phase that are comparable in nature and extent to related activities occurring during initial plant design and construction shall be interpreted to mean those activities of such a scale and type that the following conditions are met:

A. The work is to be performed by an outside contractor or owner’s service organization not part of the plant organization.

B. The system or area of the plant affected by the work is released to the contractor or service organization during the activity, and, except for radiological protection purposes, effectively ceases to be part of an operating nuclear power plant.

C. The contractor or service organization has been directed in advance of the work that conformance to Regulatory Guide 1.33, ANSI N18.7, and Applicable standards referenced in ANSI N18.7 will be required, consistent with the PVNGS UFSAR position on these standards.

The implementation of the positions of Regulatory Guide 1.33 are described in chapters 13 and 17 and the Technical Specifications.

HISTORICAL

REGULATORY GUIDE 1.37: Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (Revision 0, March 16, 1973)

RESPONSE

The requirements of the referenced standard (ANSI N45.2.1-1973) as modified in the regulatory position are applied to cleaning activities specified or applied by Bechtel to safety-related items as modified and interpreted below:

A. Section 2.1, Planning. The required planning is frequently performed on a generic basis for application to many installations on one or more projects. This results in standard procedures or plans for installation and inspection and testing which meet the requirements of the standard. Individual plans for each item or system are not normally prepared unless the work operations are unique; however, standard procedures or plans are reviewed for applicability in each case. Installation plans or procedures are also limited in scope to those actions or activities which are essential to maintain or achieve required quality. This is consistent with Section II, Paragraphs 2 and 3, of ANSI N45.2-1971 which provide for examination, measurement, or testing to assure quality or

indirect control by monitoring of processing methods. However, final cleaning or flushing activities are performed in accordance with procedures specific to the system.

Also see 5.2.3.4.1.2.1. Additional References: 4.2.5, 4.5.1.5, 5.1.5, 5.2.3, 5.4.2.4, 5.3.3.5, 5.4.7, 6.1.1.1.3.2, 6.3.1.4, 6.5.2.8, (RA) 7.12.5, 9.3.4, 10.3.6.2, 14.2.7, 17.1, and 17.2.

For operations phase activities that are comparable to activities occurring during the construction phase, the referenced standard (ANSI N45.2.1-1973) as modified by Regulatory Guide 1.37 is accepted as modified below.

A. Section 2.1, Planning. The required planning is frequently performed on a generic basis for application to many systems and component installations. This results in standard procedures for cleaning, inspection, and testing which meet the requirements of the standard.

B. Individual plans for each item or system are not normally prepared unless the work operations are unique; however, standard procedures are reviewed for applicability in each case. Cleaning procedures are limited in scope to those actions or activities which are essential to maintain or achieve required quality. This is consistent with Section 5.2.17, Paragraph 5, of ANSI N18.7-1976 which provides for examination, measurement, or testing to assure quality or indirect control by monitoring of processing methods.

HISTORICAL

REGULATORY GUIDE 1.38: Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Revision 0, March 16, 1973)

RESPONSE

The requirements of the referenced standard (ANSI N45.2.2-1972) as modified and interpreted in the regulatory position are applied to the Bechtel quality program for construction of safety-related items, except as modified and interpreted below:

A. Section 2.4, Personnel Qualification. Personnel performing offsite audits shall be qualified to ANSI N45.2.23. Personnel performing offsite material inspection shall be qualified to ANSI N45.2.6. Personnel performing offsite monitoring activities shall be qualified to ANSI N45.2.23 or ANSI N45.2.6.

B. Section 2.7, Classification of Items. The four-level classification system may not be used explicitly. However, the specific requirements for each classification as specified in the standard are applied to the items suggested in each classification and for similar items.

C. Section 3.9, Marking. Identification of items after the outside of the container has been removed, is accomplished in accordance with ANSI N18.7, Section 5.2.13.3.

D. Section 6.2, Storage Areas. Paragraph 6.2.1 requires control and limited access to storage areas. In lieu of and to amplify this paragraph, the following is applied:

"Access to storage areas for levels A, B, and C is controlled by the individual(s) responsible for material storage." Level D items are stored in a site area which has access control consistent with zone IV of ANSI N45.2.3-1973. While the areas may be posted to limit access, other positive controls (other than that for the overall site area) or guards may not be provided.

E. Sections 3.9 and 5.6, and Section A3.9 of Appendix A, Marking. These ANSI N45.2.2 sections control direct marking of austenitic stainless steel and nickel based alloys. Marking is in compliance with the requirements of these sections except that markings may be directly applied using inks controlled so as not to contain more than 200 ppm of inorganic halogens.

Reference 4.2.5, 5.1.4, 5.2.3.4.1.2.2, 6.3.1.3, 9.1.4.6, 17.1A.2, 17.1B, 17.2B, and Table 18.II.F.2-3.

HISTORICAL

REGULATORY GUIDE 1.39: Housekeeping Requirements for Water-Cooled Nuclear Power Plants (Revision 2, September 1977) [Historical]

RESPONSE

The requirements of the referenced standard (ANSI N45.2.3-1973) are applied to the Bechtel quality program for construction of safety-related items except as modified and interpreted below:

A. Section 2.1, Planning. The required planning is frequently performed on a generic basis for application to many installations on one or more projects. This results in standard procedures or plans for installation and inspection and testing which meet the requirements of the standard. Individual plans for each item or system are not normally prepared unless the work operations are unique; however, standard procedures or plans are reviewed for applicability in each case. Installation plans or procedures are also limited in scope to those actions or activities which are essential to maintain or achieve required quality.

B. Alternative equivalent zone designations and requirements may be utilized to cover those situations not included in the subject standard. For example, situations in which shoe covers and/or coveralls are required but material accountability is not.

   For operations phase activities that are comparable to activities occurring during the construction phase, the position of Regulatory Guide 1.39 is accepted with the following exception:

   Alternative equivalent zone designations and requirements may be utilized to cover those situations not included in the subject standard. For example, situations in which

shoe covers and/or coveralls are required but material accountability is not.

Reference 5.3.3.5, 9A.33, 12.5.3.4, 17.1B, 17.1A.2, and 17.2B.

HISTORICAL

REGULATORY GUIDE 1.58: Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel (Revision 1, September 1980) [Historical]

RESPONSE

The position of Regulatory Guide 1.58 is accepted with the following exceptions:

A. Position C.1

The qualification of personnel who approve preoperational and startup test procedures and test results, and those who direct or supervise the conduct of individual preoperational and startup tests is discussed in paragraph 14.2.2.12. The qualification of other personnel discussed in Position C.1 follows the guidelines of Regulatory Guide 1.8 as discussed in sections 13.1 and 13.2.

B. Position C.6

The specified education and experience recommendation of ANSI N45.2.6-1978 for various levels of inspectors shall not be treated as absolute when other factors provide reasonable assurance that a person can competently perform

a particular task. These factors will be documented, with justification by management (on an individual basis), demonstrating that the individual does have equivalent competence to that which would be gained from having the required education and experience.

In addition, the following exceptions are taken to the referenced standard ANSI N45.2.6-1978 are made:

A. The first sentence of Paragraph 3.4 states that a Level III qualified person shall have all the capabilities of a Level II qualified person for the inspection, examination or test category or class in question. APS will qualify Level III persons without the actual hands on experience and capability to perform specific inspections, examinations or tests required of a Level I or II qualified person, and utilize these persons for administrative and supervisory functions including certifying persons at the same or lower level.

B. Paragraph 3.3 states that a Level II qualified person shall have demonstrated experience in certifying lower level qualified persons. APS does not use Level II qualified persons to certify lower level qualified persons, and does not require Level II qualified persons to demonstrate this capability.

The following interpretation is also made to Regulatory Guide 1.58:

A. Position C.1

For qualification of personnel, (1) who perform or approve operational test procedures and test results, and (2) who

direct or supervise the conduct of individual operational tests, the guidelines contained in Regulatory Guide 1.8, Revision 1-R, "Personnel Selection and Training" with the criteria for selection and training contained in ANSI/ANS 3.1-1978, substituted for ANSI N18.1-1971, will be followed.

See also conformance to Regulatory Guide 1.8:

Personnel Selection and Training (Revision 1-R, May 1977)

Reference sections 17.1A.2, 17.1B, 17.2B, and Table 18.II.F.2-3.

HISTORICAL

REGULATORY GUIDE 1.64: Quality Assurance Requirements for the Design of Nuclear Power Plants (Revision 0, October 1973) [Historical]

RESPONSE

Regulatory Guide 1.64 endorses a superseded draft issue of ANSI N45.2.11. For C-E's program, refer to Section 17.1C. The Bechtel program complies with ANSI N45.2.11-1974 as interpreted herein.

A. Section 3.1

This section implies that all necessary design input (as listed in section 3.2) should be available prior to the start of a design activity. In practice, certain design activities are initiated before the firm input requirements are available. (For example, foundation

designs prepared based on preliminary information or equipment sizes and mounting and embedded conduit run based on preliminary estimates of circuit requirements.) The design phase QA program is structured to assure that all necessary design input is available before completion of final design of the work affected by the input and that final design input is available for use in verification of the final design.

B. Section 4.1, Design Process General

Paragraph 3 implies traceability back from final design to the source of design input. In practice, a literal interpretation of this is not always possible. For example, final design drawings do not identify the related calculations. This paragraph is interpreted to mean that it shall be possible to relate the criteria used and analyses performed to the final design documents and that record files will permit location of analyses supporting specific design output documents.

Additional References: 3.8.1.2.3, 4.2.5, 5.1.4, 5.4.7.1, 6.3.1.3, 9.1.4.6, 9.3.4.6, 17, and Table 18.II.F.2-3.

HISTORICAL

REGULATORY GUIDE 1.64: Quality Assurance Requirements for the Design of Nuclear Power Plants (Revision 2, June 1976)

RESPONSE

For operations phase activities that are comparable to activities occurring during the construction phase, the

position of Regulatory Guide 1.64 is accepted with the following exception to Position C.2:

Supervisory personnel may perform design verification under exceptional circumstances as documented and approved by the next level of supervision, if:

1. The justification (for design verification by a designer's immediate supervisor) is individually documented and approved in advance, and

2. Quality assurance audits cover frequency and effectiveness of use of supervisors as design verifiers to guard against abuse.

APS interprets ANSI N45.2.11-1974, Sections 3.1 and 4.1, as follows:

A. Section 3.1

   This section implies that all necessary design input (as listed in section 3.2) should be available prior to the start of a design activity. In practice, certain design activities are initiated before the firm input requirements are available. (For example, foundation designs prepared based on preliminary information or equipment sizes and mounting and embedded conduit run based on preliminary estimates of circuit requirements).

   The design phase QA program is structured to assure that all necessary design input is available before completion of final design of the work affected by the input and that final design input is available for use in verification of the final design.

B. Section 4.1, Design Process General

Paragraph 3 implies traceability back from final design to the source of design input. In practice, a literal interpretation of this is not always possible. For example, final design drawings do not identify the related calculations. This paragraph is interpreted to mean that it shall be possible to relate the criteria used and analyses performed to the final design documents and that record files will permit location of analyses supporting specific design output documents.

References: 3.8.1.2.3, 4.2.5, 5.1.4, 5.4.7.1, 6.3.1.3, 9.1.4.6, 9.3.4.6, 17, and Table 18.II.F.2-3.

HISTORICAL

REGULATORY GUIDE 1.74: Quality Assurance Terms and Definitions (Revision 0, February 1974)

RESPONSE

The position of Regulatory Guide 1.74 is accepted (refer to section 17.2 and 17.16). Additional references: 4.2.5, 5.1.4, 5.4.7.1, 9.1.4.6, 17.1A, 17.1B, and Table 18.II.F.2-3.

HISTORICAL

REGULATORY GUIDE 1.88: Collection, Storage and Maintenance of Nuclear Power Plant Quality Assurance Records (Revision 2, October 1976) [Historical]

RESPONSE

The position of Regulatory Guide 1.88 is accepted with the following exceptions to Section 5.6 of ANSI N45.2.9-1974:

A. Doors, structures and frames, and hardware shall be designed to comply with the requirements of a minimum 2-hour fire rating. (Section 4.4.1 (c) of Supplement 17S-1 of NQA-1 requires 2-hour rated doors and dampers, and the latest version of Regulatory Guide 1.28 provides no additional guidance in this area.)

B. Vinyl tile is used on the floor in lieu of a surface sealant.

C. A roof drainage line penetrating the structure has been plugged to avoid any potential flooding due to rain. There is a floor drain with a vent line located in the center of the room. The vent line to the roof is exclusively for the drain and it does not carry liquids, therefore it does not present any potential flooding problems to the storage room.

D. PVNGS also provides the following clarification with regard to application of ANSI N45.2.9-1974: PVNGS adheres to the guidance of the Standard for classification and retention periods of quality assurance records, unless other more stringent requirements apply or a graded approach as defined in Section 17.2 has been applied to determine the relative value of the record or group of records. When the graded approach is utilized, the extent to which the record maintenance and storage requirements of the Standard apply may be modified.

For quality assurance records to which the graded approach is not applied, the records shall be maintained and stored consistent with applicable regulatory requirements and the pertinent requirements of R.G. 1.88 and ANSI N45.2.9-1974, with exceptions as noted in A through C above.

Reference: 17.1, 17.2, and Table 18.II.F.2-3.

HISTORICAL

REGULATORY GUIDE 1.116: Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems (Revision 0-R, May 1977) [Historical]

RESPONSE

For operations phase activities, the position of Regulatory Guide 1.116 is accepted with the following interpretations of ANSI N45.2.8:

A. Section 2.3

Test reports attached to or referenced in data sheets may meet the evaluation requirements of the last paragraph.

B. Sections 2.2 and 2.3; 5.2 and 5.4

For application of the provisions of these sections to preoperational and startup testing, the APS position on the applicable revision of Regulatory Guide 1.68, “Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors,” shall take precedence where there is a conflict or difference.

C. Item 2.9e (6)

This item shall be interpreted to mean that any work performed without an approved design change shall not be considered complete and acceptable for its intended use until the change is approved, and that the intent of this item will be satisfied provided that such work is performed only with approved procedures and that the activities and the results are documented. Evidence of design change approval shall be required prior to placing the affected item in service.

D. Section 5

For purposes of functional tests addressed by this standard, APS defines completed systems as any system, or portion or component thereof, on which construction is sufficiently complete to allow the required testing, and on which further or adjacent construction will not render the results of such testing invalid or indeterminate.

E. Item 5.1.g

Traceability as used in this item is considered to be the same as discussed in Section 5.2.13.3 of ANSI N18.7.

Reference sections 14.2.7, 17.1A.2, 17.1B, and 17.2B.

HISTORICAL

REGULATORY GUIDE 1.123: Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants (Revision 1, July 1977) [Historical]

RESPONSE

For operations phase activities, the position of Regulatory Guide 1.123 is accepted with the following modifications to ANSI N45.2.13-1976:

A. Section 7.5, Personnel Qualifications

Personnel performing offsite audits shall be qualified to ANSI N45.2.23. Personnel performing offsite material inspection shall be qualified to ANSI N45.2.6. Personnel performing offsite monitoring activities shall be qualified to ANSI N45.2.23 or ANSI N45.2.6.

B. Section 3.2.3

The requirements of this section are accepted with the following exception:

When purchasing commercial grade calibration services from calibration laboratories accredited by a nationally recognized accrediting body, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Nationally-recognized accrediting bodies include the National Voluntary Laboratory Accreditation Program (NVLAP) administered by the National Institute of Standards and Technology (NIST) and other accrediting bodies recognized by NVLAP via a Mutual Recognition Agreement (MRA). In such cases, accreditation may be accepted in lieu of the Purchaser imposing a QA program consistent with ANSI N45.2-1971, provided all the following are met:

1. The accreditation is to ANSI/ISO/IEC 17025.

2. The accrediting body is either NVLAP or the American Association for Laboratory Accreditation (A2LA) based upon A2LA continued NVLAP recognition through the International Laboratory Accreditation Corporation (ILAC) Mutual Recognition Agreement.

3. The published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.

4. The purchase documents impose additional technical and administrative requirements, as necessary, to satisfy APS QA Program and technical requirements. The purchase documents shall specifically require that the calibration certificate or report will include identification of the equipment and/or standards used.

5. The purchase documents require reporting as-found calibration data when calibrated items are found to be out-of-tolerance.

HISTORICAL

REGULATORY GUIDE 1.144: Auditing of Quality Assurance Program for Nuclear Power Plants (Revision 1, September 1980) [Historical]

RESPONSE

The requirements of the referenced standard (ANSI N45.2.12-1977) as modified and interpreted in the position of Regulatory Guide 1.144 are applied to the APS

quality assurance program for operations phase activities, with the following exceptions:

A. Section 4.3.1 requires that a brief preaudit conference may be conducted with cognizant organization management. A formal preaudit conference may not be required for some routine internal audits where informal preaudit communication is determined to be adequate. The manager of the auditing organization will monitor the performance of audits, through review of audit reports, to ensure that informal preaudit communication is utilized only in cases where such informal communication is adequate.

B. Section 4.5.1 states that any “adverse findings” shall be reviewed and investigated to determine and schedule appropriate corrective action including action to prevent recurrence. Consistent with the PVNGS position established in Section 1.8 for Regulatory Guide 1.33, PVNGS requires determination of root cause and actions to prevent recurrence for significant conditions adverse to quality that are identified during audits. This interpretation is consistent with Appendix B to 10CFR50, Criterion XVI, Corrective Action.

C. A grace period of 90 days beyond the specified frequency shall be permitted for completion of supplier annual evaluations and supplier audits. When the grace period is utilized, subsequent scheduling for the evaluation or audit shall be based upon the original due date. This grace period shall not be applied to evaluations or audits that have a frequency specifically defined by regulation.

Reference: 17.1, 17.2, and Table 18.II.F.2-3.

D. Regulatory Guide 1.144, Section C.3.b (2)

The requirements of this section are accepted with the following interpretation:

When purchasing commercial grade calibration services from calibration laboratories accredited by a nationally-recognized accrediting body, the accreditation process and accrediting body may be credited with carrying out a portion of the Purchaser's duties of verifying acceptability and effective implementation of the calibration service supplier's quality assurance program. Nationally-recognized accrediting bodies include the National Voluntary Laboratory Accreditation Program (NVLAP) administered by the National Institute of Standards and Technology (NIST) and other accrediting bodies recognized by NVLAP via a Mutual Recognition Arrangement (MRA).

In lieu of performing an audit, accepting an audit by another licensee, or performing a commercial-grade supplier survey, a documented review of the supplier's accreditation shall be performed by the Purchaser. This review shall include, at a minimum, all of the following:

1. The accreditation is to ANSI/ISO/IEC 17025.
2. The accrediting body is either NVLAP or the American Association for Laboratory Accreditation (A2LA) based upon A2LA continued NVLAP recognition through the International Laboratory Accreditation Cooperation (ILAC) Mutual Recognition Arrangement.

3. The published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.

HISTORICAL

REGULATORY GUIDE 1.146: Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants (Revision 0, August 1980) [Historical]

RESPONSE

The requirements of the referenced standard (ANSI N45.2.23-1978) as modified and interpreted in the position of Regulatory Guide 1.146 are applied to the quality assurance program with the following modifications:

A. At paragraph 2.2.1 of ANSI N45.2.23: Orientation of auditors is provided to produce a working knowledge and understanding of ANSI N18.7, ANSI N45.2.12, this standard, and the auditing organization’s procedures for implementing audits and reporting results.

B. At paragraph 2.3.4 of ANSI N45.2.23: Prospective lead auditors shall demonstrate their ability to effectively implement the audit process and lead an audit team. They shall have participated in at least one audit within the year preceding the individual’s effective date of qualification. Upon successful demonstration of the ability to effectively lead audits, licensee management may designate a prospective lead auditor as a “lead auditor”.

   Reference 17.1 and 17.2.

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CHAPTER 2

SITE CHARACTERISTICS

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2. SITE CHARACTERISTICS

2.1 GEOGRAPHY AND DEMOGRAPHY

2.1.1 SITE LOCATION AND DESCRIPTION

2.1.1.1 Specification of Location

The PVNGS site is located in Maricopa County in southwestern Arizona, 16 miles west of the city of Buckeye and 34 miles west of the nearest boundary of the city of Phoenix. Figure 2.1-1 identifies the general location of the plant site with respect to roads and highways, communities, and cities in the vicinity. The site area is flat with small, scattered hills.

To the west and northwest of the site are the Palo Verde Hills, sharply rising to 2172 feet above mean sea level.[1] To the south is Centennial Wash, an intermittent stream backed by gently rising uplands with scattered, isolated, steeply sloped hills and buttes. Buckeye Valley, bisected by the Gila River, lies to the east and southeast. To the north and northeast, the terrain is a relatively flat desert traversed by numerous intermittent streams that are typical of the region (refer to engineering drawings 13-C-ZVA-005, 13-P-OOB-001, and UFSAR figures 2.1-2 and 2.1-3).

The location of the centerline of each containment building is given in table 2.1-1.

2.1.1.2 Site Area Maps

Engineering drawings 13-C-ZVA-005 and 13-P-OOB-001 illustrate the plant site, including topographical features and the location and orientation of principal plant structures.

The total area of the plant property is approximately 4250 acres. The plant property line coincides with the plant site boundary. Units 1, 2, and 3 and their supporting facilities are located in the northern half of the site. The site

Table 2.1-1

CONTAINMENT BUILDING CENTERLINES[2]

PVNGS Unit	Geodetic Coordinates	Universal Transverse Mercator Zone 12S
1	Latitude 33°23'23.269"	N 3,695,857.885
	Longitude 112°51'43.375"	E 326,808.124
2	Latitude 33°23'14.152"	N 3,695,581.206
	Longitude 112°51'52.327"	E 326,571.769
3	Latitude 33°23'3.016"	N 3,695,240.368
	Longitude 112°51'57.022"	E 326,444.304

is bounded on the south by Ward Road (Elliot Road) and on the west by Wintersburg Road. No public roads or railroads cross the site. Site elevations range from 890 feet above mean sea level at the southern boundary to 1030 feet above mean sea level at the northern boundary.

Figure 2.1-4 defines the boundaries of the plant exclusion area. The exclusion area boundary coincides with the plant site boundary, except in the southern portion of the property. Minimum distances from each unit to the site boundary and exclusion boundary are provided in tables 2.1-2 and 2.1-3, respectively.

2.1.1.3 Boundaries for Establishing Effluent Release Limits

The boundary for establishing effluent release limits coincides with the plant site boundary (refer to figure 2.1-4). For purposes of radiation protection and general safety, the area Table 2.1-2 within the site boundary will be under the control of the applicant. The areas around the main buildings of the plant site are fenced and patrolled. One guard house is provided. Distances from plant effluent release points to the site boundary are given in table 2.1-2.

MINIMUM DISTANCES TO SITE BOUNDARY FROM CONTAINMENT EDGE[a]

Exposure Direction	Site Boundary Distance (Meters)		
	Unit 1	Unit 2	Unit 3
N	1,037	1,318	1,661
NNE	1,057	1,342	1,693
NE	2,006	2,544	2,755
ENE	1,967	2,206	2,336
E	1.927	2,163	2,290
ESE	1,967	2,067	2,023
SE	2,049	2,101	2,256
SSE	2,729	3,025	2,785
S[b]	3,005	2,698	2,345
SSW	2,258	1,836	1,607
SW	1,487	1,208	1,057
WSW	1,251	1,014	889
W	1,225	993	871
WNW	1,244	1,010	885
NW	1,254	1,191	1,045
NNW	1,059	1,342	1,561

a. Based on 22.5° sectors.

b. For the purpose of this table, the site boundary corresponds to the EAB.

Table 2.1-3

MINIMUM DISTANCES TO EXCLUSION BOUNDARY FROM CONTAINMENT EDGE[a]

Exposure Direction	Exclusion Boundary Distance (Meters)		
	Unit 1	Unit 2	Unit 3
N	1,037	1,318	1,661
NNE	1,037	1,318	1,661
NE	2,000	1,426	1,790
ENE	1,927	2,163	2,290
E	1.927	2,163	2,223
ESE	1,927	2,067	2,023
SE	2,049	2,067	2,023
SSE	2,171	2,450	2,345
S	2,974	2,695	2,345
SSW	1,757	1,431	1,266
SW	1,333	1,083	953
WSW	1,225	993	871
W	1,225	993	871
WNW	1,225	993	871
NW	1,124	1,074	943
NNW	1,037	1,318	1,288

a. Based on 45° sectors.

2.1.2 EXCLUSION AREA AUTHORITY AND CONTROL

2.1.2.1 Authority

The applicant owns all land within the site boundary; therefore, the applicant also owns all land within the exclusion area. The applicant has complete authority to regulate any and all access and activity within the exclusion area. There will be no unauthorized public access or activity allowed within the exclusion area. The site boundary will be posted and fenced with light gauge wire such as that used to contain cattle. This will prevent inadvertent public access.

The applicant has examined the titles of each parcel of land owned within the PVNGS exclusion area and site boundary. Based on such title examination, it is clear that the applicant owns or controls all minerals, including oil and gas, within the PVNGS exclusion area and site boundary.

In respect to the following described parcels:

Parcel B

The Southeast quarter (SE-1/4) of Section Twenty-Eight (28), Township One North (TSlN), Range Six West (R6W) of the Gila and Salt River Base and Meridian.

Parcel C

The West quarter (W-1/4) of Section Two (2), Township One South (TSlS), Range Six West (R6W) of the Gila and Salt River Base and Meridian.

There are outstanding reservations for a 50% interest in respect to parcel B and a 1/16% interest in respect to parcel C in any oil, gas, or other minerals therein. In neither case,

however, does the owner of the reservation have the right of ingress or egress to or from property for any purpose, including the prospecting for or removal of any oil or gas therein.

2.1.2.2 Control of Activities Unrelated to Plant Operation

Activities unrelated to operation of the reactor may be permitted within the plant site exclusion area under appropriate limitations, provided that no significant hazards to public health and safety will result and senior management has concurred with the unrelated activity.

2.1.2.3 Arrangements for Traffic Control

No public roads, railways, or waterways traverse the plant site exclusion area.

2.1.2.4 Abandonment or Relocation of Roads

No public roads presently traverse the plant site exclusion area; hence, none will have to be abandoned or relocated.

2.1.3 POPULATION DISTRIBUTION

Population centers within a 50-mile radius of the plant are shown in figure 2.1-3. Of these population centers, those that are larger than 500 persons as of July 1, 1978 are listed in table 2.1-4 by distance and direction from the plant and actual size. The remaining population centers, i.e., those smaller than 500 persons and for which no statistics are available, are listed in table 2.1-5 by distance and direction

from the plant. Figure 2.1-2 shows the location of population centers within a 10-mile radius of the plant.

2.1.3.1 Population Within 10 Miles

Figure 2.1-5 illustrates the 1978 estimated residential population located within a 10-mile radius of the plant site. Data are displayed at 1-, 2-, 3-, 4-, 5-, and 10-mile distances from the centerline of the Unit 2 containment building for 16 compass sectors. Population data for the 0- to 5- and 5- to 10-mile areas were tabulated from primary and secondary data sources, respectively. An aerial house count backed by ground verification was performed in October 1978 for the first 5-mile radii. Population figures were obtained by multiplying the number of dwelling units times a factor of 3.44; i.e., the 1970 Buckeye Census Enumeration District statistic on dwelling unit occupancy.[5] The 1978 population distributions for the 5- to 10-mile radii were based on 1970 U.S. Bureau of the Census data. Population centroids, that is, the locations of population within 1970 census enumeration districts, were assigned by the Census Bureau. Population totals per segment were calculated based on the location of the centroids relative to PVNGS.

Table 2.1-4

JULY 1, 1978, POPULATION ESTIMATE FOR CITIES WITH 500 OR MORE PERSONS WITHIN A 50-MILE RADIUS OF PVNGS[3]

City	1978 Population Estimate	Distance and Direction[a] From PVNGS (Miles)
Buckeye	2,900	16 E
Gila Bend	2,400	31SSE
Avondale	7,130	30 E
Litchfield Park	3,195	30 ENE
Goodyear	2,745	30 E
Cashion	4,420	33 E
Luke Air Force Base	7,630	31 ENE
Phoenix	725,000	34 E
Surprise	3,400	35 ENE
El Mirage	3,800	35 ENE
Youngtown	2,000	35 ENE
Tolleson	3,890	35 E
Sun City	45,125	36 ENE
Peoria	13,000	39 ENE
Glendale	80,000	40 ENE
Wickenburg	3,295	41 N

a. Measurements taken from centerline of Unit 2 containment building.

Table 2.1-5

POPULATION CENTERS WITH LESS THAN 500 PERSONS AS OF JULY 1, 1978 WITHIN A 50-MILE RADIUS OF PVNGS[3],[4] (Sheet 1 of 2)

Center	Distance and Direction[a] From PVNGS (Miles)
Wintersburg	2.5 N
Dixie	6.5 ESE
Crag	6.5 SSW
Arlington	7.5 SE
Hassayampa	8.5 ESE
Tonopah	9.0 NNW
Gillespie	11.0 SW
Palo Verde	11.5 ESE
Harqua	13.0 SW
Harquahala	17.5 NW
Saddle	20.0 SW
Liberty	22.0 E
Perryville	24.0 E
Cotton Center	24.0 SSE
Norton	25.5 E
Sundad	26.0 WSW
Fennemore	28.0 ENE
Sil Murk	29.0 SSE
Montezuma	29.5 SW
Waddell	30.0 ENE
Smurr	32.0 S
Bumstead	32.5 ENE
Theba	32.5 S
Wittman	33.5 NE

a. Measurements taken from centerline of Unit 2 containment building.

Table 2.1-5

POPULATION CENTERS WITH LESS THAN 500 PERSONS AS OF JULY 1, 1978 WITHIN A 50-MILE RADIUS OF PVNGS[(3),(4)] (Sheet 2 of 2)

Center	Distance and Direction[(a)] From PVNGS (Miles)
Camel	34.0 SW
Beardsley	34.0 ENE
Circle City	34.0 NNE
Piedra	34.0 SSW
Bosque	34.0 SSW
Morristown	35.5 NNE
West End	36.5 E
Estrella	37.5 SE
Hyder	38.0 SW
Agua Caliente	38.5 SW
Fowler	39.0 E
Laveen	41.0 E
Komatke	41.0 E
Gila Crossing	41.5 ESE
Centinel	41.5 S
Santa Cruz	42.0 ESE
Mobile	42.0 SE
Aguila	43.0 NNW
Gladden	44.0 NNW
Enid	44.5 ESE
Big Horn	46.0 SE
Love	48.0 NW
Heaton	48.0 ESE
Horn	48.5 SW
Wenden	50.0 NW
Freeman	50.0 SE

Figures 2.1-6 through 2.1-14 illustrate the estimated residential population located within a 10-mile radius of the plant site for the years 1980, 1982, 1984, 1986, 1990, 2000, 2010, 2020, and 2030. Data are displayed at 1-, 2-, 3-, 4-, 5- and 10-mile distances from the centerline of the Unit 2 containment building for 16 compass sectors. Maricopa County population estimates provided by the Arizona State Department of Economic Security(6) for the years 1980, 1982, 1984, 1986, 1990, and 2000 were used for all six radii calculations. Maricopa County population projections for the years 2010, 2020, and 2030 were derived from the assumption that decennial growth rates from 2000 to 2030 would be held constant to the same rate of growth as experienced between 1990 and 2000. Population projections were calculated according to the methodology described above for the 1978 estimated 5- to 10-mile radii population.

2.1.3.2 Population Between 10 and 50 Miles

Figure 2.1-5 illustrates the 1978 estimated residential population located between 10 and 50 miles of the plant site. Figures 2.1-6 through 2.1-14 show the estimated residential population located between 10 and 50 miles of the plant site for the years 1980, 1982, 1984, 1986, 1990, 2000, 2010, 2020, and 2030. Data are displayed at 10-, 20-, 30-, 40-, and 50-mile distances from the centerline of the Unit 2 containment building for 16 compass sectors. Population input data for Maricopa, Pinal, Yavapai, and Yuma Counties were supplied by the Arizona State Department of Economic Security(6) and calculated according to the methodology described in paragraph 2.1.3.1.

2.1.3.3 Transient Population

Transient population within a 10-mile radius of the centerline of the Unit 2 containment building for 1978 is estimated to be approximately 150 persons.[(7),(8),(9),(10),(11)] This is a conservative estimate based upon the consideration that 100 people included in the total represent migrant farm workers -- a figure that can be considered excessively high.[(7)] The remaining 50 persons are employed at the Hassayampa Cotton Gin, the Ruth Fisher and Arlington School Districts, and the Gila Compressor Station. Table 2.1-6 lists employment centers within a 10-mile radius of the PVNGS according to distance and direction from the plant site, number of employees, seasonality of employment, and combined residential and transient population totals per sector.

Table 2.1-6

1978 TRANSIENT POPULATION WITHIN A 10-MILE RADIUS OF PVNGS[(7),(8),(9),(10),(11)]

Employment Center	Distance and Direction From PVNGS[(a)]	Number of Employees	Seasonality of Employment	Combined 1978 Residential and Transient Population Total, Per Sector
Farms	3 to 10 miles N, NNE, ENE, E, ESE, SE, SSE, S, SSW, SW, WSW, WNW, NW, NNW	100 (Migrant)	High in spring and fall; low in summer and winter	3,032
Hassaympa Cotton Gin	6.0 miles SE	10	November to March	10
Ruth Fisher School District	7.5 miles N	6	September to June	6
Arlington School District	8.0 miles SE	10	September to June	10
Gila Compressor Station	10.0 miles SSE	25	Year-round	25

a. Measurements taken from centerline of Unit 2 containment building.

2.1.3.4 Low Population Zone

The PVNGS low population zone (LPZ) has been defined as a 6400-meter (4-mile) radius area, based on the centerline of the Unit 2 containment building. The LPZ has been conservatively selected on the basis of providing effective emergency planning for the residents in the LPZ, as well as limiting radiation doses to below 10CFR100 limits to those residents outside the LPZ under the most conservative assumptions for a design basis accident.

As indicated in figures 2.1-6 through 2.1-14, the population density of the LPZ is low and is expected to remain as such throughout the plant life, thereby enabling effective emergency planning. Figure 2.1-15 illustrates the LPZ in terms of topographic features and transportation for evacuation purposes. There are no hospitals, prisons, or parks located within either the LPZ or a 5-mile radius.

There is one school located within the LPZ, Arlington Elementary at 3.3 miles to the south east. Winters Well Elementary school is located north of the plant site at approximately 4.4 miles.

2.1.3.5 Population Center

Currently, the nearest population center as defined in 10CFR100 is Sun City, which had a 1977 estimated residential population of 43,500 persons.(1) Its nearest city limit boundary, as represented on a 1979 Maricopa Country road map,(12) in relation to the plant site and the LPZ is approximately 36 miles and 32 miles, respectively, east-northeast. Sun City transient population has not been included in the 1977 population estimate. In assuming for Sun City a growth rate identical to

Maricopa County, by the year 2030 Sun City is expected to sustain a residential population of 170,988 persons. By that same time, the sector in which Sun City is located is expected to sustain 283,107 persons, for a population density of 2060 persons per square mile.

It is projected that by 1995, the cities of Avondale and Goodyear will have qualified as the nearest population centers as defined in 10CFR100 with estimated residential populations of 28,600 and 26,800 persons, respectively.(13) Their nearest city limit boundaries, as represented on a 1979 Maricopa County road map,(12) in relation to the plant site and the LPZ are 29 miles and 25 miles east for both adjacent cities. Avondale and Goodyear transient population has not been included in the 1995 population estimate. In assuming for Avondale and Goodyear growth rates identical to Maricopa County, by the year 2030 Avondale and Goodyear are expected to sustain residential populations of 76,127 persons and 75,288 persons, respectively. By that same time, the sector in which Avondale and Goodyear are located is expected to sustain 145,581 persons, for a population density of 1059 persons per square mile.

2.1.3.6 Population Density

Figures 2.1-7 through 2.1-9 show the estimated residential population located within a 50-mile radius of the site for the years of initial unit operation; i.e., 1982, 1984, and 1986. Within a 30-mile radius of the site, the following residential population projections are estimated:

1982 32,187 persons

1984 33,701 persons

1986 35,415 persons

Table 2.1-7 lists the cumulative residential population density within a 30-mile radius of the site by annulus for the three unit startup dates. As can be seen from table 2.1-7, the PVNGS site falls well below the uniform population density standard of 500 persons per square mile as expressed in Regulatory Guide 1.70, Revision 3.

Table 2.1-7

CUMULATIVE RESIDENTIAL POPULATION DENSITY WITHIN A 30-MILE RADIUS OF THE PVNGS PLANT SITE DURING YEARS OF INITIAL PLANT STARTUP (PERSONS PER SQUARE MILE)

Miles From Plant	1982	1984	1986
0-1	0	0	0
0-2	1	1	1
0-3	20	21	22
0-4	22	23	24
0-5	16	17	18
0-10	12	13	14
0-20	13	13	14
0-30	11	12	13

Figure 2.1-14 shows the estimated residential population located within a 50-mile radius of the site for the end of the decade of plant life end; i.e., 2030. Within a 30-mile radius

of the site, the 2030 residential population projection is estimated to be 106,914 persons.

Table 2.1-8 lists the cumulative residential population density within a 30-mile radius of the site by annulus for the end of the decade of plant life end.

As can be seen from table 2.1-8, the PVNGS site falls well below the uniform population density standard of 1000 persons per square mile as expressed in Regulatory Guide 1.70, Revision 3

Table 2.1-8

CUMULATIVE RESIDENTIAL POPULATION
DENSITY WITHIN A 30-MILE RADIUS
OF THE PVNGS PLANT SITE
FOR THE END OF THE DECADE OF PLANT LIFE END
(PERSONS PER SQUARE MILE)

Miles From Plant	2030
0-1	0
0-2	3
0-3	73
0-4	81
0-5	60
0-10	43
0-20	42
0-30	38

2.1.4 REFERENCES

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2.2 NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES

2.2.1 LOCATIONS AND ROUTES

This section contains initial licensing information and is not expected to be routinely updated. Significant changes that could potentially affect the content of this section should be evaluated for inclusion as discussed in NEI 98-03, Guidelines for updating Final Safety Analysis Reports, Section A3.

2.2.1.1 Industrial Facilities

Figure 2.2-1 shows the location of the nearest industrial facilities. The closest industrial facility to PVNGS is the Mesquite natural gas fired combined cycle power generation station owned and operated by SEMPRA. The station is located approximately 2.6 miles south of unit 3. Two other electric generating stations in the immediate area are the Redhawk station owned and operated by Pinnacle West Capital Corporation and the Arlington Valley station owned and operated by Duke Energy Company.

There are no chemical plants, refineries, oil storage facilities, oil drilling operations and wells, underground gas storage facilities, or mining and quarrying operations located within a 10-mile radius of the PVNGS plant site.

2.2.1.2 Transportation Facilities

2.2.1.2.1 Roads

Figure 2.2-1 shows the location of two major roads (i.e., Interstate 10 and Buckeye-Salome Road) and a number of lesser

used roads within a 10-mile radius of the plant site. At its closest point to the PVNGS site, Interstate 10 (I-10) is located approximately 6.5 miles northeast of the centerline of the Unit 2 containment building. Buckeye-Salome Road is closest to the PVNGS site at a point 2 miles north-northeast of the centerline of the Unit 2 containment building.

2.2.1.2.2 Railroads

Figure 2.2-1 shows the location of the only railroad within a 10-mile radius of the plant site. It is owned by the Union Pacific Railroad. At its closest point to the PVNGS site, the railroad is located approximately 4.5 miles south-southeast of the centerline of the Unit 2 containment building. A railroad spur extends from this line to the site.

2.2.1.2.3 Airways

Figure 2.2-2 shows the location of both high- and low-level altitude airways within the jurisdiction of the U.S. Federal Aviation Administration (FAA) Air Route Traffic Control Centers in Albuquerque, New Mexico and Los Angeles, California. In the airspace west of the Phoenix Sky Harbor International Airport, Victor Airways 16 (V-16) and 461 (V-461) and Jet Routes 4 (J-4) and 65 (J-65) are routed within a 10-mile radius of the plant site.

2.2.1.2.3.1 <u>Victor 16 Airway</u>. Victor 16 is a low-altitude airway that extends from Los Angeles through Ontario, Palm Springs, and Blythe, California, and Phoenix and Tucson,

Arizona, to points as far east as Lynchburg, Virginia. The centerline of V-16 passes directly over the Buckeye VORTAC[a], and at its closest point is located approximately 4 nautical miles north of the centerline of the Unit 2 containment building. The total width of the band over which the airway extends is 8 nautical miles, that is, 4 nautical miles on either side of the centerline. Hence, aircraft using V-16 could pass directly over PVNGS.

Along this airway, aircraft flying by visual flight rules (VFRs) and instrument flight rules (IFRs) may not exceed a maximum altitude of 17,000 and 30,000 feet above mean sea level, respectively.[1] Minimal enroute altitude for IFR aircraft is 5600 feet above mean sea level.

2.2.1.2.3.2 Victor 461 Airway. Victor 461 is a low-altitude airway that extends from the Buckeye VORTAC to the Gila Bend VORTAC. At its closest point, the centerline of V-461 is located approximately 3 nautical miles east of the centerline of the Unit 2 containment building. The total width of the band over which the airway extends is 8 nautical miles, that is, 4 nautical miles on either side of the centerline. Hence, aircraft using V-461 could pass directly over PVNGS. Minimal enroute altitude for aircraft flying by IFR is 4000 feet above mean sea level.

a. VORTAC refers to a very high frequency omnidirectional range station (VOR) and ultrahigh frequency tactical air navigation aid (TACAN).

2.2.1.2.3.3 Jet Route 4. Jet Route 4 is a high-altitude airway that extends from Twenty-Nine Palms, California, through Casa Grande and San Simon, Arizona, to points as far east as Wilmington, Delaware. At its closest point, the centerline of J-4 is located approximately 3 nautical miles southwest of the centerline of the Unit 2 containment building. The total width of the band over which the airway extends is 8 nautical miles. Hence, aircraft using J-4 could pass directly over PVNGS. As a high-altitude airway, aircraft operating along J-4 may not pass below a minimum altitude of 18,000 feet above mean sea level.

2.2.1.2.3.4 Jet Route 65. Jet Route 65 is a high-altitude airway that extends from Red Bluff, California, through Sacramento, Fresno, Bakersfield, Palmdale, and Blythe, California; Phoenix, Arizona, and Truth or Consequences, New Mexico, to points as far east as Abilene, Texas. Jet Route 65 passes directly over the Buckeye VORTAC and parallels the V-16 airway from there to the Phoenix Sky Harbor International Airport. At its closest point, J-65 is located approximately 4 nautical miles north-northeast of the centerline of the Unit 2 containment building. The total width of the band over which the airway extends is 8 nautical miles. Hence, aircraft using J-65 could pass directly over PVNGS. As a high-altitude airway, aircraft operating along J-65 may not pass below a minimum altitude of 18,000 feet above mean sea level.

2.2.1.2.4 Airports

Figure 2.2-1 shows two airports located in the PVNGS environs: the Buckeye Municipal and Pierce Airports. Buckeye Municipal and Pierce Airports are located outside a 10-mile radius of the plant site at approximately 11 miles east-northeast and 15.5 miles east of the centerline of the Unit 2 containment building, respectively. Not shown on figure 2.2-1 is the Arizona Public Service (APS) company private helipad. The helipad is located on the PVNGS plant site as shown in figure 2.2-4.

2.2.1.2.5 Natural Gas and Petroleum Pipelines

Figure 2.2-1 shows two operating pipelines to be within a 10-mile radius of the plant site. One is owned by Southern Pacific Pipelines, Inc. (SPPL); the other is owned by El Paso Natural Gas Company (EPNG). At its closest point to the PVNGS site, the SPPL pipeline is approximately 4.5 miles south-southeast of the centerline of the Unit 2 containment building. The EPNG pipeline is approximately 6 miles southwest of the Unit 2 containment building at its closest point to the PVNGS site. In addition there are three smaller pipelines connecting the gas fired electric plants discussed in section 2.2.1.1 to the EPNG pipeline.

2.2.1.3 Military Facilities

2.2.1.3.1 Luke Air Force Base

Figure 2.2-2 shows Luke Air Force Base (LAFB) to be approximately 33 miles east-northeast of the plant site. Alert area A-231 and restricted areas R-2301, R-2304, and R-2305 used by the base in its training missions are located well outside a 10-mile radius of the plant site. The closest Air Force training area, A-231, is located approximately 10 miles north-northeast of the Unit 2 containment building. It should be noted that the LAFB corridor used to traverse V-16 enroute to and from LAFB restricted areas is located approximately 15 miles east of the PVNGS site.

2.2.2 DESCRIPTIONS

2.2.2.1 Industrial Facilities

The closest industrial facility to PVNGS is the Mesquite natural gas fired combined cycle power generation station owned and operated by SEMPRA. The station is located approximately 2.6 miles south of unit 3. Two other electric generating stations in the area are the Redhawk station owned and operated by Pinnacle West Capital Corporation and the Arlington Valley station owned and operated by Duke Energy Company.

NEARBY INDUSTRIAL, TRANSPORTATION,

AND MILITARY FACILITIES

Table 2.2-1

AVERAGE DAILY TRAFFIC (ADT) IN THE VICINITY OF THE

PALO VERDE NUCLEAR GENERATING STATION JUNE 1978[4]

Traffic Count Location	ADT (Actual)
Buckeye-Salome Road between Wintersburg Road and 339th Avenue	4,859
Buckeye-Salome Road between 339th Avenue and Baseline Road	4,375
Buckeye-Salome Road between Wintersburg Road and 411th Avenue	794
Wintersburg Road between Buckeye-Salome Road and plant site entrance	3,814
Wintersburg Road between Buckeye-Salome Road and Buckeye Road	296

2.2.2.2 Transportation Facilities

2.2.2.2.1 Roads

The road system in the vicinity of the plant site is essentially a rectangular grid oriented on north-south and east-west axes, following township and sectional lines. The plant site is bounded on two sides by Wintersburg Road and Ward (Elliot) Road. A June 1978 traffic count of the area has revealed average daily traffic (ADT) listed in table 2.2-1.[3] June 1978 ADT counts are well below design levels.[4] As of early 1979, Wintersburg Road and Buckeye-Salome Road are the major asphalt roads in the area. Given the amount of traffic

in the area, several projects are either planned or underway to improve roadway conditions.[4] If hazardous materials were shipped in the area, the most probable route taken is expected to be I-10, rather than over the county road system.[5]

2.2.2.2.2 Railroads

The Union Pacific Railroad operates over the Arlington-Wellton line, which is the segment that runs past PVNGS at an approximate distance of 4.5 miles from the south-southeast of the centerline of the Unit 2 containment building.

Short term exposure limits for hazardous materials like those carried over the Arlington-Wellton line can be found in OSHA 29 CFR part 1910-1000 Subpart Z, or in Reg. Guide 1.78. Ammonia, sulfur dioxide and chlorine are classified as poison gases, class 2.3. The DOT hazard classes are as follows:

Hazard Class	Description
2.1	Flammable Compressed Gas
2.2	Non-Flammable Compressed Gas
2.3	Poison Gas
3	Flammable Liquids
4	Flammable Solids
5.1	Oxidizers
6.1	Poison Liquids
8	Corrosive Liquids
9	Hazardous Substances
	Combustible Liquids
	Etiologic Agents
	Hazardous Waste

2.2.2.2.3 Airways

2.2.2.2.3.1 Victor 16 Airway. The V-16 airway is used by commercial, general aviation, and military aircraft that range in size from single-engine, propeller-driven airplanes to four-engine, wide-body jets. Typical peak-day IFR air traffic statistics are given in table 2.2-2. For the same reporting period, a total of 250 aircraft are estimated to be flying by VFR in both directions. No estimates are available on the level of future growth.[(1)]

2.2.2.2.3.2 Victor 461 Airway. The V-461 airway can be used by commercial, general aviation, and military aircraft that range in size from single-engine, propeller-driven airplanes to four-engine, wide-body jets. It is estimated that current aircraft operations flying by VFR and IFR number approximately 100 movements annually.[(9)]

2.2.2.2.3.3 Jet Routes 4 and 65. Jet Routes 4 and 65 are used by commercial, general aviation, and military aircraft capable of performing at high altitudes. Typical peak-day IFR air traffic using routes J-4 and J-65, or flying parallel to them above 24,000 feet above mean sea level within range of the Buckeye VORTAC, is estimated to be 204 flights in 1979. This is a 13% increase in Phoenix area air traffic over 1978 estimates. It is expected that this growth rate will apply in future years.[(9)]

NEARBY INDUSTRIAL, TRANSPORTATION,

AND MILITARY FACILITIES

Table 2.2-2

TYPICAL PEAK-DAY IFR AIR TRAFFIC ALONG VICTOR-16 BETWEEN VICKO INTERSECTION AND THE PHOENIX SKY HARBOR AIRPORT[a][(1)]

Type of aircraft	Flights	Type of Equipment
	Direction Number	
Commercial air carrier	Westbound 39	NA[b]
	Eastbound 37	
General aviation	Westbound 19	17 twin-engine
		1 four-engine
		1 single-engine
	Eastbound 25	21 twin-engine
		3 single-engine
		1 four-engine
Military	Westbound 9	6 twin-engine
		2 single-engine
		1 four-engine
	Eastbound 5	3 twin-engine
		2 four-engine

a. Count taken by the Federal Aviation Administration, Los Angeles, California, on January 12, 1979.

b. Not available.

2.2.2.2.4 Airports

2.2.2.2.4.1 Buckeye Municipal Airport. Buckeye Municipal Airport, once called Luke Air Force Base Auxiliary Field No. 5, is located 6 miles northwest of the city of Buckeye. It is classified as a Class 2 Fixed-Base Operator. The elevation of the airport is 1024 feet above mean sea level. The airport is open during daylight hours. Services offered there include fuel sales, storage, and major airframe and power plant repairs. The Slurry Bomber Company is based there. The airport consists of three runways oriented north-south, northeast-southwest, and southeast-northwest, forming a triangle. Each leg is 3820 feet long. One runway is paved, the other two are turf. The traffic pattern altitude above ground level is 800 feet or 1800 feet above mean sea level.(10)

Buckeye Municipal Airport is used primarily as a base for local general aviation activities and student training. It has been estimated that approximately 90% of the planes using Buckeye Municipal Airport are single-engine aircraft; the rest are twin-engine airplanes. The largest type of aircraft served is a four-engine, propeller-driven DC-7.(11) The local estimate of the number of annual aircraft operations for 1978 is 6000 movements.(12) In accordance with Regulatory Guide 1.70 criteria, given the low number of annual movements, it is not necessary to report aircraft accident statistics.

The Maricopa Association of Governments Regional Aviation System Plan calls for the expansion of the Buckeye Municipal Airport. Construction of a runway parallel to the most

frequently used one and the dismantling of the other two cross-wind runways is planned.[13]

2.2.2.2.4.2 Pierce Airport. Pierce Airport is a privately-owned facility of Pierce Aviation, which is considered by the FAA not to be a Fixed-Base Operator because, even though fuel is sold, business is not actively solicited. Pierce Airport is located 2 miles west of the city of Buckeye, east of U.S. Highway 85, and 0.75 miles north of Hozen Road. The elevation of the airport is 860 feet above mean sea level. The airport is open during daylight hours, Monday through Saturday. Services offered include storage and minor airframe and power-plant repairs. The airport consists of one turf runway 2990 feet long with an east-west orientation. The traffic pattern altitude above ground is 800 feet or 1700 feet above mean sea level.[10]

Pierce Airport is used primarily as a base for crop dusting activities, although some farmers within a 40-mile area use it to station their planes. Pierce Aviation conducts roughly 15 to 21% of its crop dusting business from Pierce Airport. The remainder takes place at satellite duster strips located throughout Western Maricopa County.[14]

Approximately 30 airplanes are hangered at Pierce Airport, 10 of which are owned by Pierce Aviation. Of these 30 air-planes, two are privately-owned, twin-engine aircraft. The rest are single-engine aircraft.[14]

Peak aircraft operations occur during the months of July through September when there is a lot of crop dusting. It has been estimated that the daily peak traffic during this season is approximately 108, based on 72 takeoffs and landings in the mornings and half that number in the afternoons.[14]

It is estimated that during the period from October through June, there are 25 airplanes, each making one takeoff and landing daily, that use the facility. Based on this information, the annual number of operations are set at approximately 24,000 movements.[14] According to Regulatory Guide 1.70 criteria, given the number of annual movements at Pierce Airport, it is not necessary to report aircraft accident statistics.

Pierce Aviation aircraft direct their flights to either the north or the south of the PVNGS plant site; hence, no over-flights are conducted.[14]

Future plans for expansion of Pierce Airport include the possibility of increasing its facilities to accommodate a maximum of 50 aircraft.[14]

2.2.2.2.4.3 Arizona Public Service Company PVNGS Helipad. The Arizona Public Service (APS) Company has built a private helipad located on the PVNGS plant site as shown in figure 2.2-4. APS will operate a helicopter to and from the site for approximately 1000 helicopter operations annually. The approach and departure path(s) are kept away from the plant safety-related structures to the maximum extent possible.

Since there are no planned instrument approaches,[17] the helicopter operations will only be conducted under VFR conditions.

2.2.2.2.5 Pipelines

2.2.2.2.5.1 Southern Pacific Pipelines. Southern Pacific Pipelines owns and operates a 12-inch, high-pressure refined petroleum-products pipeline located within a Southern Pacific Transportation Company operating right-of-way. The pipeline was constructed in 1955 and buried approximately 5 feet deep. Pipeline gate valves are installed generally at 20-mile intervals. The unmanned Palo Verde Booster Station is located approximately 11 miles east-southeast of the centerline of the Unit 2 containment building at the intersection of Palo Verde Road and the pipeline right-of-way. Maximum operating pressure in the line is at the booster station, where the discharge pressure is calculated at 1160 psig.[18]

Southern Pacific Pipe Lines is currently studying the feasibility of installing a second pipeline parallel to the existing line for transport of refined petroleum products.[18]

2.2.2.2.5.2 El Paso Natural Gas Company. El Paso Natural Gas Company (EPNG) owns and operates one 26-inch (line number 1100) and three 30-inch (line numbers 1103, 1110, and 1600), high-pressure, natural-gas pipelines within its right-of-way. Line 1100 was constructed in 1948 and buried 3 feet deep. Plug valves, manually operated at an American National Standards Institute (ANSI) 400 rating, are located at the Gila Compressor

Station, which is approximately 10 miles south-southeast of the centerline of the Unit 2 containment building. The line is maintained at a maximum operating pressure of 837 psig. Line 1103 was constructed in 1951 and buried 3 feet deep. Plug valves, manually operated at an ANSI 400 rating, are located at the Gila Compressor Station and at approximately 8 and 17 miles west of it. The line is maintained at a maximum operating pressure of 837 psig. Line 1110 was constructed in 1957 and buried 3 feet deep. Plug valves, manually operated at an ANSI 400 rating, are located at the Gila Compressor Station and at approximately 8 and 17 miles west of it. The line is maintained at a maximum operating pressure of 837 psig. Pipeline 1600 was constructed in 1970 and buried 3 feet deep. Ball valves, manually operated at an ANSI 600 rating, are located at the Gila Compressor Station; and gate valves, manually operated at an ANSI 600 rating, are located approximately 17 miles west of the Gila Compressor Station. Pipeline 1600 is maintained at a maximum operating pressure of 1080 psig. The Gila Compressor Station employs approximately 25 persons. A company-owned airstrip is located at the facility. It is used seldom, if at all.[19]

El Paso Natural Gas Company has no plans to use any of the four pipelines for gas storage at higher than normal pressure.[19]

2.2.2.3 Military Facilities

2.2.2.3.1 Luke Air Force Base

The primary mission of Luke Air Force Base (LAFB) is F-4, F-5, F-15, and F-104 combat-fighter, air-crew training. Other significant functions include the following:

- F-104 Starfighter training
- The provision of air defense coverage for the south-western United States by the 26th North American Air Defense region air division
- Support for the 2.7-million acre LAFB Gunnery Range complex and the Gila Bend Auxiliary Air Field located 65 miles south of Phoenix.[20]

Other aircraft stationed at LAFB include T-33s, used for targets or in providing cross-country proficiency training; CH-3s, used in special operations such as search and rescue missions by the 302nd Special Operations Squadron; and UH-1 helicopters used in mission support.[20]

Luke Air Force Base maintains two parallel 11,000-foot runways, oriented to 030-210 magnetic. Landing facilities include an instrument landing system (ILS), precision approach radar, ultrahigh frequency tactical air navigation aid (TACAN), and other nonprecision approach equipment for both runways. All approaches are conventional except those that use ILS and TACAN from the north in accordance with a published deviation used to avoid Sun City overflights.[20]

Runways are capable of withstanding aircraft landings and take-offs for planes up to 200,000 pounds gross weight. Luke Air Force Base facilities can provide service to transient aircraft of all services, including military air cargo airplanes and normal transient transport aircraft such as C-141s and C-9s. Emergency support can be provided to all types of aircraft; however, because LAFB is in a high-density traffic area, prior clearance is required before landing except in emergency situations.[20]

Luke Air Force Base operates approximately 180 to 210 sorties daily, usually five days per week. For each of the four major aircraft types operating out of LAFB, the average is 40 to 50 daily sorties. The number of annual LAFB aircraft operations is estimated to be approximately 100,000 movements. In accordance with Regulatory Guide 1.70 criteria, given the low number of annual movements, it is not necessary to report aircraft accident statistics.

Luke Air Force Base aviation routes for normal cross-country flights follow conventional airways established by the FAA.

Low-level training flights follow two military training routes. All routes are published in government and privately-printed aeronautical charts.[20]

Luke Air Force Base flight operations to restricted areas R-2301, R-2304, and R-2305 follow an outbound route which, at its closest point, comes to within 11 nautical miles of the centerline of the Unit 2 containment building. Inbound flights returning from the restricted areas to LAFB follow a route

which, at its closest point, comes to within 17 nautical miles of the centerline of the Unit 2 containment building. Luke Air Force Base flight operations to areas northwest of the base follow a route which, at its closest point, comes to within 13 nautical miles of the centerline of the Unit 2 containment building.

There are no VFR low-altitude training or other flight routes below 3000 feet above ground level (AGL) over the PVNGS site nor are any planned for the future. The closest to the planned PVNGS site that some of these routes are located is in the restricted area R-2305 complex underlying the SELLS airspace.[20]

There are no plans to establish any training routes or flight paths below 3000 feet AGL within 5 nautical miles of PVNGS.[20]

2.2.2.3.2 Other Low-Altitude Military Training Routes

The El Toro Marine Corps Air Station, California, conducts some of its low-altitude pilot training in the vicinity of the PVNGS plant site. At its closest point, the centerline of military training route IR-218 is located approximately 11 nautical miles west of the centerline of the Unit 2 containment building. The total width of the band over which the training route extends is 10 nautical miles, that is, 5 nautical miles on either side of the centerline. Hence, the closest to PVNGS that an aircraft using IR-218 could pass is 6 nautical miles. Nevertheless, most operations are expected to be routed close

to the centerline of IR-218. Training operations generally take place between 3500 and 4000 feet above mean sea level.

The route is flown by fighter and attack bomber types of aircraft. There are approximately 180 operations annually scheduled over this route.[23]

2.2.2.4 Projections of Industrial Growth

Future development in the vicinity of the PVNGS site is expected to be limited and scattered.[24]

2.2.3 EVALUATION OF POTENTIAL ACCIDENTS

As indicated in the previous sections, there are no significant industrial or military facilities near PVNGS. The industrial facilities south of unit 3 and the nearby transportation routes were evaluated for the determination of potential design basis events.

2.2.3.1 Determination of Design Basis Events

2.2.3.1.1 Industrial Facilities

The closest industrial facility to PVNGS is the Mesquite natural gas fired combined cycle power generation station owned and operated by SEMPRA. The station is located approximately 2.6 miles south of unit 3. Two other electric generating stations in the area are the Redhawk station owned and operated by Pinnacle West Capital Corporation and the Arlington Valley station owned and operated by Duke Energy Company.

The chemicals used at the plants have been evaluated per Reg. Guide 1.78 “Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release.”

2.2.3.1.2 Highway Transportation

Since Interstate 10 is over 5 miles from the plant, no credible accident could have any effect on safety-related structures. Flammable or toxic vapor clouds from maximum truck load quantities of materials or credible missiles cannot reach PVNGS. Hazardous materials that are carried by other transportation routes near PVNGS to the closest industrial facilities have been evaluated per Reg. Guide 1.78 “Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release.”

2.2.3.1.3 Rail Transportation

As indicated, the Union Pacific Railroad Arlington-Wellton line passes approximately 4.5 miles south-southeast of the plant. At this distance, only compressed liquified gases could be a potential hazard. Materials that are liquids at normal temperatures and pressure will not vaporize fast enough to present either a flammable cloud or toxic cloud hazard. For compressed liquified gases, a gross tank car failure could lead to a large "puff" type release which, under adverse weather conditions, could travel significant distances.

The flammable compressed gas category includes mostly liquefied hydrocarbons such as LPG, propane, butane and a few other materials such as methyl chloride and vinyl chloride. Flammable liquids, corrosive liquids and other hazardous substances are not hazards at this distance because only compressed gases could cause an uninhabitable condition in the control room. The non-flammable compressed gas class contains mostly chloro fluorocarbons and inert gasses which would not create a toxic hazard due to either a very high toxicity limit, or being non-toxic. The chemicals in each hazard class can be found in reference 47.

From the above discussion, studies of hazardous material storage and transport (25), (26), (27), (28) and from a review of 1973 to 1977 records of spills reported to the Office of Hazardous Materials, Department of Transportation, the chemicals listed in table 2.2-3 were identified as potentially shipped past PVNGS and a potential toxic chemical hazard for further investigation. This list includes materials shipped as compressed liquified gases and involved in two or more rail accidents that led to a spill during the 5 year period 1973 to 1977. It should be noted that of these materials, only LPG (propane or butane) and anhydrous ammonia were involved in spills in the five-state region: Arizona, New Mexico, Utah, Nevada, and California. Most of the cars of flammable compressed gasses shipped past the plant were LPG since this is by far the largest commodity in this category. From a review of the U.S. DOT Hazardous Material Information System for 1991-1995 (48), there were no spills along the line past PVNGS. The

Regulatory Guide 1.78 allowable weight of the commodities in table 2.2-3 was determined conservatively for a type C control room but with an air exchange rate of 0.45 h^{-1}, type G dispersion and a 4.2-mile distance to the nearest safety-related structure. The hazardous chemicals were analyzed utilizing the basic puff dispersion model assumptions of Reg. Guide 1.78 and the following control room model:

$$V_{cr}\frac{dC_{cr}}{dt} = x(t)F\,Q_{in} - C_{cr}Q_{out}$$

where:

C_{cr} = concentration in the control room
V_{cr} = volume of control room = 161,000 cubic feet
$x(t)$ = concentration outside the building
F = nonfiltered coefficient = 1.0
Q_{in} = flow coming into the control room = 1200 cfm
Q_{out} = flow going out of the control room = Q_{in}

Dispersion parameters utilized were from site data analyzed to obtain a direction dependent 0.5 percentile χ/Q. Values for σ_y were determined from the standard Pasquill-Gifford (P-G) curves with no credit allowed due to meander. Vertical dispersion parameters, σ_z, are based on curves developed for use in dispersion modelling in desert regimes and reflect the decreased vertical dispersion encountered in a desert climate.(29) The cloud and control room concentration time-histories are provided in figures 2.2-3a and 2.2-3b respectively. While the maximum concentration is greater than the toxic limit, there is more than 2 minutes between the odor

threshold of 17 ppm [30] and the toxic limit. This meets the Regulatory Guide 1.78 criteria for donning self-contained breathing apparatus.

Analysis of the potential effect of an LPG spill has been made by considering a vapor cloud made up of an instantaneous puff of the isenthalpic flash fraction. The cloud undergoes gravity-induced spreading analyzed by the Van Ulden Model[31] followed by normal Gaussian dispersion utilizing the same dispersion coefficients discussed above. With this model, the resulting vapor cloud would be a potential hazard at the plant only for the G stability class. For class F stability, the gas concentration decreased below the flammable limit prior to reaching the point where an explosion could damage the plant. Statistics[28],[32],[33] show that 48% of spills of flammable vapor are ignited at the accident site and are no hazard at 4.2 miles. The remaining 52% would form vapor clouds which could be blown toward the plant. Section 2.3 provides the probability of winds blowing toward the plant with G stability. Utilizing a 20% energy equivalent TNT yield, overpressure data from TM-5-1300[34] a nationwide loss of lading accident rate of 0.152×10^{-6} per mile[28] results in a probability of a peak incident overpressure in excess of 1 psi at the plant of 1.3×10^{-7}. This result is conservative since it assumes all 185 shipments of the flammable compressible gas to be LPG, a very limited vertical dispersion, no ignition until the cloud reaches its closest approach to the plant, the cloud ignites at this point with all ignitions leading to a 20% energy equivalent TNT detonation involving all vapor in the cloud. A

Table 2.2-3

TOXICITY LIMITS

Chemical	Toxic Limit[a] ppm	Remarks
Anhydrous ammonia	300[b]	
Propane	Simple asphyxiant[c]	No toxicity hazard
Butane	Simple asphyxiant[c]	No toxicity hazard
Butadiene	2000[b]	
Carbon dioxide	40,000[b]	
Hydrogen sulfide	100[b]	
Vinyl chloride	1000	
Chlorine	10[b]	
Sulfur Dioxide	100[b]	

a. From Regulatory Guide 1.78 unless otherwise indicated.

b. NUREG/CR-6624, Recommendations for Revision of Regulatory Guide 1.78.

c. TLV-STEL from "Threshold Limit Valves for Chemical Substances in Work Room Air Adopted by ACGIH for 1978."

realistic evaluation would lead to a significantly lower probability.

The frequency of a release that leads to a hazardous condition must be less than 10^{-6} times per reactor year to be probabilistically insignificant. This is consistent with NUREG-0800 and Reg Guide 1.91. The allowable number of shipments by rail for the probability to remain below 1.0 x 10^{-6} is significantly above the number of actual shipments.

2.2.3.1.4 Air Traffic

2.2.3.1.4.1 Airports. Airports in the vicinity of PVNGS are described in paragraph 2.2.1.2.4 and 2.2.2.2.4. As indicated, there are no major airports near the plant. Two small facilities occur at 11 and 16-mile distances from the plant. In addition, the APS private helipad is located on the plant site. The number of operations from these facilities and those from LAFB are compared with the Regulatory Guide 1.70 airport criteria in table 2.2-4. Annual operations at each facility are seen to be much less than the Regulatory Guide 1.70 criteria.

As indicated in paragraph 2.2.2.2.4.2, long-range regional government plans include expansion of operations at Buckeye Airport. This is a new plan and actual implementation is not certain. Buckeye Airport is not included in the Federal Aviation Administrations satellite airport development program.[35] Most growth is expected in local operations

NEARBY INDUSTRIAL, TRANSPORTATION,

AND MILITARY FACILITIES

Table 2.2-4

ANNUAL OPERATIONS AT NEARBY AIRPORTS

Airport	Closest Distance and Orientation between the Airport and PVNGS (mi)	1978 Estimated No. of Annual Operations	Regulatory Guide 1.70 Allowable Number of Operations[a]
Buckeye Municipal Airport	10.8	6,000	116,640
Pierce Airport	15.5 E	23,586	240,250
LAFB	32.8 ENE	100,000	1,075,840
APS Helipad	Onsite	1,000[b]	na

a. 500 d^2 for airports located between 5 and 10 miles.
1000 d^2 for airports located more than 10 miles.
d is distance from plant in miles

b. Estimated annual activity after PVNGS becomes operational.

(flights within 5 miles of the airport) which will not affect PVNGS.

2.2.3.1.4.2 Airways. The federal civil airways which pass within 2 miles of PVNGS and the closest military routes from LAFB are given in table 2.2-5. A study of the probability of potentially unacceptable impact from operations on these airways on the PVNGS units has been performed. This study is an update of the study[36] referenced in the PVNGS PSAR. The basic methodology has been retained with various parameters updated to reflect current conditions.

In general, the probability of impact is given by:[37]

$$P = \sum_{i=I}^{I} \sum_{j=I}^{J} N_{ij} C_i A_i f_{ij}(x)$$

where:

P = Annual probability of unacceptable impact per year

N_{ij} = Annual operation of aircraft of type i along airway or from airport j per year

C_i = Crash rate for aircraft of type i per mile

A_i = Effective impact area for each unit for aircraft of type i, square mile

$f_{ij}(x)$ = Aircraft lateral crash density at plant site for aircraft of type i operating along airway or from airport j per mile

The values of various parameters used in the analysis are included in table 2.2-5 and the basis of their determination are discussed in the following paragraphs. As indicated above, the methodology is as described in reference 36.

The annual number of operations is taken from information in paragraph 2.2.2.2.3.

The crash rates used are based on National Transportation Safety Board (NTSB) crash data and FAA flight data. Accident rates which might cause significant damage are based on historical records of crashes which resulted in fatalities. Non-fatal accidents are not considered severe enough to cause significant damage to the plant structures. In-flight or enroute fatal crash rates are used since the plant is more than 5 miles from the nearest airport.

For all general aviation operations, the NTSB[(38)] reported a fatal crash rate of 1.82×10^{-5} per hour. Of these, approximately 67% were enroute. Using an average speed estimated from FAA data,[(39)] the resulting fatal in-flight crash rate is 9.8×10^{-8} crashes/flight mile.

For U.S. certified route and supplemental air carriers, there were eight fatal in-flight crashes in the years 1972-1977.[(40),(41)] During this time, 15.28×10^{9} miles were flown by these air carriers.[(41)] The resultant crash rate is 5.9×10^{-10} crashes/flight mile. Crash statistics on military aircraft are difficult to obtain, and they would not be directly useful since total domestic miles flown do not even appear to be tabulated. It is expected that military experience should fall

Table 2.2-5

AIRCRAFT IMPACT EVALUATION

Airway	Distance to Nearest Safety Related Structure (mi)	Type of Operation	Number of Flights per year	Crash Rate (mi^{-1})	Effective Impact Area (mi^2)	Lateral Crash Density (mi^{-1})	Impact Probability (10^{-7}/yr)
V-16	4.5	AC[a]	27,740	5.9 X 10^{-10}	0.05	6 x 10^{-4}	0.005
		Mil[b]	5,110	1.2 x 10^{-8}	0.04	5.6 x 10^{-3}	0.14
		GA[c]	107,300	9.8 x 10^{-8}	0.01	1.2 x 10^{-4}	0.13
V-461	3.2	GA	100	9.8 x 10^{-8}	0.01	1.7 x 10^{-3}	0.002
J-65	4.5	AC	37,230	5.9 x 10^{-10}	0.05	6.0 x 10^{-4}	0.007
J-4	2.9	AC	37,230	5.9 x 10^{-10}	0.05	7.7 x 10^{-3}	0.085
Luke Departure	12.5	Mil	54,800	1.2 x 10^{-8}	0.04	1.9 x 10^{-6}	<0.001
IR218	12.6	Mil	180	1.2 x 10^{-8}	0.04	1.7 x 10^{-6}	<0.001
IR272	12.4	Mil	500	1.2 x 10^{-8}	0.04	2.1 x 10^{-6}	<0.001
PVNGS Approach/ Departure	0.13[f]	Privately owned heli-copter	1,000	4.9 x 10^{-7} [d]	----	7.5 x 10^{-5} [e]	0.37[f]
TOTAL							0.74

a. AC is air carrier

b. Mil is military

c. GA is general aviation

d. Crash rate per takeoff or landing operation.

e. Conditional probability of impacting any safety-related structure

f. The helipad was relocated in 2013 (see Figure 2.2-4 for new location). These values correspond to the original location of the helipad – southwest of the switchyard. The distance to the nearest safety related structure now exceeds 0.13 miles.

somewhere between the commercial crash rate and the 200 times higher general aviation total crash rate. Most general aviation crashes are caused by pilot error. Military pilots and commercial pilots have similar training which suggests a military crash rate close to the commercial experience. On the other hand, military crashes occur mainly in training, acrobatics, or low-level photographic missions. None of these activities occur on the departure route from LAFB. While they may be training flights, actual training operations occur in restricted air space or the military operations areas. Flights departing from LAFB are under IFR and their movements controlled by FAA air route traffic control center. Flights along V-16 are also IFR and mainly involve itinerant aircraft and not local-based training. For purposes of this analysis, we have, therefore, chosen the military crash rate to be 20 times the commercial crash rate or 1.2×10^{-8} crashes per flight mile.

Flights on low-level training routes IR-218 and IR-272 are quite infrequent and are not a significant contributor to overall impact probability.

The effective impact area is defined as that horizontal area which, if impacted by an aircraft, could lead to consequences in excess of the guidelines of 10CFR100. The area consists of the actual plan area of the target, a shadow area considering target height, and a skid area considering potential sliding into the target. For the updated study, the effective impact area is based on a single unit and considers self shielding by

other plant structures and by local site features such as railroad embankments. For air carrier and military operations, all plant safety-related structures were included. For general aviation operations, the containment was excluded since it would withstand the impact of the relatively light and slow general aviation aircraft.

The lateral crash density was calculated as in reference 36.

The parameters used to calculate impact probability are summarized in table 2.2-5, along with resultant probabilities. The total probability of potentially unacceptable impact is 7.4×10^{-8}.

2.2.3.1.5 Pipeline Transportation

Southern Pacific Pipeline operates a 12-inch pipeline that passes through the vicinity of PVNGS. The closest point lies 4.2 miles SSE from the nearest safety-related structure (see figure 2.2-1). The pipeline is at a lower elevation than the plant.

Based on the data supplied from the Office of General Superintendent of Operations of Southern Pacific Pipe, the products shipped via this pipeline are exclusively refined petroleum products such as gasoline, diesel fuel, and jet fuel. No flammable liquified compressed gases such as LNG or LPG are carried in this line section. Considering the distance involved, there is no credible explosive, flammable cloud, toxic gas, fire, or liquid spill hazards that would originate from this pipeline.

The El Paso Natural Gas Company pipelines are over 6 miles from the plant. At this distance, there is no flammable cloud hazard to the plant.

2.2.3.2 Effects of Design Basis Events

As discussed in the previous section, the nearby industrial, military, and transportation facilities present no hazard to the operation of PVNGS, and there are no site-related design basis events due to accidents at these facilities.

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2.3 METEOROLOGY

This section provides a description of the meteorology and climatology of the Palo Verde Nuclear Generating Station (PVNGS) and surrounding area. The PVNGS site is located in southwestern Arizona, approximately 50 miles WSW of Phoenix (Sky Harbor International Airport). This section contains initial licensing information and is not expected to be routinely updated. Significant changes that could potentially affect the content of this section should be evaluated for inclusion as discussed in NEI 98-03, Guidelines for updating Final Safety Analysis Reports, Section A3.

2.3.1 REGIONAL CLIMATOLOGY

2.3.1.1 General Climate

PVNGS is located in southwest Arizona, a region characterized by a desert-type climate. This area, which is in the Inter-mountain Plateau Climatic zone, is in the driest region of the United States.(1) Typical characteristics of this large, arid region include abundant sunshine, infrequent precipitation, low relative humidities, large diurnal temperature ranges, moderate wind speeds, and an occasional intense summer thunderstorm.(2) The summers are hot and the winters are mild.

Table 2.3-1 presents the normals, means, and extremes of climatological data for the National Weather Service (NWS) station at Phoenix, Arizona - Sky Harbor International Airport, the most consistent record of offsite meteorological data representative of the PVNGS region.

Table 2.3-1

NORMALS, MEANS, AND EXTREMES, PHOENIX, ARIZONA

[1977 local climatological data, taken from reference 2.]

Month	Temperature (°F) Normal: Daily maximum	Normal: Daily minimum	Normal: Monthly	Extremes: Record highest	Year	Record lowest	Year	Normal heating degree days (Base 65°)
(a)	(b)	(b)	(b)	13		13		(b)
J	64.8	37.6	51.2	88	1971	19	1971	428
F	69.3	40.8	55.1	89	1963	26	1964	292
M	74.5	44.8	59.7	95	1972+	25	1966	185
A	83.6	51.8	67.7	101	1962	37	1968	60
M	92.9	59.6	76.3	108	1970+	40	1967+	0
J	101.5	67.7	84.6	116	1970	51	1969	0
J	104.8	77.5	91.2	115	1973+	67	1968+	0
A	102.2	76.0	89.1	116	1972	61	1968+	0
S	98.4	69.1	83.8	110	1971	47	1965	0
O	87.6	56.8	72.2	103	1972	34	1971	17
N	74.7	44.8	59.8	92	1967	31	1968	182
D	66.4	38.5	52.5	82	1965	24	1968	388
YR	85.1	55.4	70.3	116	AUG. 1972+	19	JAN. 1971	1552

Month	Precipitation Totals (Inches): Normal total	Maximum monthly	Year	Minimum monthly	Year	Maximum in 24 hrs.	Year	Snow, Ice pellets: Mean total	Maximum monthly	Year	Maximum in 24 hrs.	Year
(a)	(b)	36		36		36		36	36		36	
J	0.71	2.41	1955	0.00	1972+	1.31	1951	T	T	1962+	T	1962+
F	0.60	2.23	1944	0.00	1967	1.07	1944	T	0.6	1939	0.6	1939
M	0.76	4.16	1941	0.00	1959+	1.32	1941	0.0	0.0		0.0	
A	0.32	2.10	1941	0.00	1962+	1.38	1941	T	T	1949	T	1949
M	0.14	0.94	1944	0.00	1952+	0.94	1944	0.0	0.0		0.0	
J	0.12	1.70	1972	0.00	1971+	1.64	1972	0.0	0.0		0.0	
J	0.75	4.19	1955	T	1947	1.97	1955	0.0	0.0		0.0	
A	1.22	5.36	1951	T	1973	3.07	1943	0.0	0.0		0.0	
S	0.69	4.23	1939	0.00	1973+	2.43	1970	0.0	0.0		0.0	
O	0.46	4.40	1972	0.00	1973+	2.27	1972	0.0	0.0		0.0	
N	0.46	3.04	1952	0.00	1956+	1.07	1952	0.0	0.0		0.0	
D	0.82	3.98	1967	0.00	1973+	1.89	1967	T	T	1968+	T	1968+
YR	7.05	5.36	AUG. 1951	0.00	DEC. 1973+	3.07	AUG. 1943	T	0.6	FEB. 1939	0.6	FEB. 1939

Month	Relative humidity (%): Hour 05 (Local time)	Hour 11	Hour 17	Hour 23	Wind &: Mean speed	Prevailing direction	PEAK GUST ∅: Speed	Direction	Year	† Pct. of possible sunshine	$ Mean sky cover sunrise to sunset
(a)	13	13	13	13	28	18	36	36		78	28
J	67	44	30	56	5.0	E	49	WNW	1965	78	4.7
F	60	38	26	49	5.6	E	49	SSE	1959	80	4.4
M	58	33	23	44	6.3	E	50	WNW	1956	83	4.3
A	44	23	16	29	6.7	E	45	NW	1957+	89	3.4
M	36	18	13	22	6.7	E	59	SSE	1954	93	2.7
J	36	18	13	23	6.7	E	59	S	1972	94	1.9
J	46	28	20	33	6.9	W	71	N	1959	85	3.7
A	55	35	24	41	6.4	E	60	SSW	1953	85	3.4
S	53	32	23	41	6.1	E	75	SW	1950	89	2.1
O	53	29	21	42	5.6	E	48	SSW	1956	88	2.6
N	61	38	29	53	5.1	E	45	WSW	1963+	83	3.6
D	69	48	35	60	4.9	E	68	W	1953	77	4.0
YR	53	32	23	41	6.0	E	75	SW	SEP. 1950	86	3.4

Month	Mean number of days: Sunrise to sunset: Clear	Partly cloudy	Cloudy	Precipitation .01 inch or more	Snow, Ice pellets 1.0 inch or more	Thunderstorms	Heavy fog	Temperatures Max.: 90° and above	Max.: 32° and below	Min.: 32° and below	Min.: 0° and below	** Average daily solar radiation - langleys
(a)	36	36	36	34	36	34	36	13	13	13	13	
J	14	7	10	4	0	*	1	0	0	7	0	
F	13	6	9	4	0	1	*	0	0	3	0	
M	15	7	9	3	0	1	*	2	0	1	0	
A	17	7	6	2	0	1	0	7	0	0	0	
M	21	6	4	1	0	1	0	22	0	0	0	
J	23	5	2	1	0	1	0	29	0	0	0	
J	17	10	4	4	0	6	0	31	0	0	0	
A	17	10	4	5	0	8	0	31	0	0	0	
S	22	5	3	3	0	3	0	27	0	0	0	
O	21	6	4	3	0	1	*	14	0	0	0	
N	17	7	6	2	0	1	*	*	0	*	0	
D	15	6	10	4	0	1	1	0	0	3	0	
YR	212	82	71	34	0	23	2	163	0	14	0	

∅ Peak Gust observed during Airway observational program from January 1938 through October 1953; from recorder charts thereafter.
† Combined record from Post Office, August 1895 through October 1953, and from Sky Harbor Airport, November 1953 to date.
$ Broken record: 1940, 1941, and 1948 to date.
Means and extremes above are from existing and comparable exposures. Annual extremes have been exceeded at other sites in the locality as follows:
Highest temperature 118 in July 1958+; lowest temperature 16 in January 1913; maximum monthly precipitation 6.47 in July 1911; maximum precipitation in 24 hours 4.98 in July 1911; maximum monthly snowfall 1.0 in January 1937 and earlier; maximum snowfall in 24 hours 1.0 in January 1937 and earlier.

(a) Length of record, years, based on January data. Other months may be for more or fewer years if there have been breaks in the record.
(b) Climatological normals (1941-1970).
* Less than one half.
\+ Also on earlier dates, months, or years.
T Trace, an amount too small to measure.
\- Below zero temperatures are preceded by a minus sign.
‡ ≥ 70° at Alaskan stations.

The prevailing direction for wind in the Normals, Means, and Extremes table is from records through 1963.

Unless otherwise indicated, dimensional units used in this bulletin are: temperature in degrees F.; precipitation, including snowfall, in inches; wind movement in miles per hour; and relative humidity in percent. Heating degree day totals are the sums of negative departures of average daily temperatures from 65° F. Cooling degree day totals are the sums of positive departures of average daily temperatures from 65° F. Sleet was included in snowfall totals beginning with July 1948. The term "ice pellets" includes solid grains of ice (sleet) and particles consisting of snow pellets encased in a thin layer of ice. Heavy fog reduces visibility to 1/4 mile or less.

Sky cover is expressed in a range of 0 for no clouds or obscuring phenomena to 10 for complete sky cover. The number of clear days is based on average cloudiness 0-3, partly cloudy days 4-7, and cloudy days 8-10 tenths.

Solar radiation data are the averages of direct and diffuse radiation on a horizontal surface. The langley denotes one gram calorie per square centimeter.

& Figures instead of letters in a direction column indicate direction in tens of degrees from true North; i.e., 09 - East, 18 - South, 27 - West, 36 - North, and 00 - Calm. Resultant wind is the vector sum of wind directions and speeds divided by the number of observations. If figures appear in the direction column under "Fastest mile" the corresponding speeds are fastest observed 1-minute values.

** The National Weather Service considers the accuracy of solar radiation data questionable; therefore, publication is suspended pending determination of corrected values.

2.3.1.1.1 Types of Air Masses

The air masses that dominate the Arizona region are mostly continental in nature. Although the Rocky Mountains to the north normally prevent cold Canadian air masses from penetrating into Arizona in the winter, occasionally these air masses can influence the weather in the entire state. However, the cold air is somewhat modified if it reaches the central-southwest Arizona area. Air masses approaching from the Pacific Ocean are moist and mild initially on the west coast, but are substantially drier when they reach Arizona because of orographic effects when encountering the Sierra Nevada mountain ranges west of Arizona.[3] Moist, tropical air can penetrate into Arizona from the Gulf of Mexico southeast of the state, and more rarely from the southwest off the west coast of Mexico, providing the moisture sources for summer thundershowers and the heaviest precipitation episodes.[4]

2.3.1.1.2 Regional Synoptic Features

The primary synoptic features that influence the region are associated with the seasonal position and intensity of a semi-permanent ridge of high-pressure off the Pacific West Coast and a semi-permanent high-pressure cell protruding into the central part of the United States from the Atlantic Ocean in the summer season. Large-scale synoptic storms typically follow a path around the north side of the Pacific high-pressure ridge, entering the continent in northern Oregon and Washington and producing only partly cloudy and increased wind conditions in Arizona. Displacement of the ridge of Pacific high-pressure can cause the storm systems to move southward along the west

coast, often as far south as San Francisco before turning inland, rather than passing eastward through Oregon and Washington and bring precipitation to the Arizona region. Certain low-pressure systems have a tendency to stagnate and intensify off the California coast for several days before moving inland. These storms are fully developed by the time they reach Arizona and can bring intense precipitation.(3) On occasion, tropical air associated with dying tropical storms and hurricanes that originated off the west coast of Mexico penetrate the state from the Gulf of California and the Pacific Ocean. Once every 4 or 5 years, a tropical storm may cross into Arizona, accompanied by gale-force winds and flood-producing rains.(3)

2.3.1.1.3 General Airflow Patterns

Prevailing winds in the state are strongly influenced by the orientation of the mountain ranges and the local topography. Ordinarily, if no large-scale weather disturbances are present and the winds in the free atmosphere are light, local and mesoscale wind circulation patterns will dominate. In this situation, the surface wind will blow upslope or upvalley during the daytime, when the air overlying the slope is heated more rapidly than that at the same elevation over the valley. At night, rapid radiational cooling of the air overlying the mountain slopes compared to the slow cooling of the free atmosphere air over the valleys induces downslope or downvalley winds.

The primary station for data comparison with the PVNGS site, Phoenix, is located near the center of the Salt River Valley, a

broad, relatively flat plain. The valley, in general, is characterized by light winds. Annually, predominant winds are from the east; however, during the spring months, prevailing winds are from the southwest and west associated with the passage of low-pressure systems. Throughout the year, there are periods, often several days in length, in which winds remain under 10 miles per hour. The annual mean wind speed at Phoenix-Sky Harbor International Airport is 6 mi/h. The prevailing direction is from the east.(2)

2.3.1.1.4 Temperature and Humidity

Average temperatures throughout the state are dependent on the elevation and latitude. Great extremes occur between day and night temperatures throughout Arizona. The daily range between maximum and minimum temperatures sometimes runs as high as 50F to 60F during drier portions of the year.(4) The warmest weather in Arizona usually occurs during the last week of June and the first 2 weeks in July.(3) The site area normally experiences temperatures above 100F in the mid-afternoon in the summer and experiences relatively mild winter temperatures. Harsher winter temperatures characterize the northern, more mountainous, portion of the state.

Based on the period 1941 to 1970, the normal maximum and minimum temperatures at Phoenix are 64.8F and 37.6F in January (the coldest month) and 104.8F and 77.5F in July (the warmest month). The annual mean temperature is 70.3F. The mean number of days per year with maximum temperatures of 90F and above is 165. The mean annual number of days with a minimum temperature

of 32F and below is 12. There has never been a below zero reading recorded in Phoenix.[2]

Seasonally, the highest relative humidity values in Arizona are observed in winter and the lowest values in summer, but when unusually moist tropical air enters the state from the Gulf of Mexico, high relative humidities can occur during July and August.[3] During the period late spring to fall, relative humidities of 10% or lower are recorded in the mid-afternoon in the southwestern desert regions.

At Phoenix, the lowest relative humidities are found in the afternoon hours, corresponding to the maximum daily temperature readings during that time. The highest relative humidities at Phoenix occur shortly before sunrise, corresponding with minimum temperature readings. The mean annual average humidity value at Phoenix is 36%, based on four observations per day.[2]

2.3.1.1.5 Precipitation

The state of Arizona normally experiences two "wet" seasons. The summer wet season occurs during July and August, which are the wettest months in all parts of Arizona. The winter wet season extends from November or December through the middle of March. The severity of a drought is difficult to assess in southwest Arizona because of already existing extreme dry conditions. May and June are the driest months, especially in the desert-type climate of the site region. The heavier summer precipitation is associated with thundershower activity induced primarily by a flow of moist tropical air from the Gulf of Mexico. Record precipitation amounts in the state have

occurred in August and September from tropical flows of moist air from the Gulf of California and Pacific Ocean associated with tropical depressions and hurricanes off the west coast of Mexico. Winter precipitation is generally widespread over the state and is normally of light or moderate intensity. Greater amounts occur in the higher latitudes, on exposed southwest slopes, and at higher elevations. Winter precipitation is heaviest when the middle latitude storm track is unusually far south, so that storms enter Arizona directly from the west or southwest after picking up considerable moisture from the Pacific Ocean. The mean number of days of precipitation of 0.01 inch or more at Phoenix is 34, based on 38 years of data. The normal annual rainfall at Phoenix is 7.05 inches.(2) Snow rarely falls on the desert floor in the site region, but when it does, the snow usually melts almost as soon as it contacts the ground. At Phoenix, trace amounts have been recorded in December to April, with 0.6 inch of snow the maximum monthly recorded amount.(2)

2.3.1.1.6 Relationships Between Synoptic and Local Meteorological Conditions

The topography of the region strongly influences the meteorological conditions and climate at specific locations within the state of Arizona. The general orientation of topographic features such as mountains with respect to the site of interest and the elevation and exposure of the site itself can result in local wind flows, precipitation amounts, and temperature patterns differing substantially from large synoptic-scale conditions. The effects of topography on

climatological conditions have been discussed in the preceding sections.

2.3.1.2 Regional Meteorological Conditions for Design and Operating Bases

2.3.1.2.1 Hurricanes

Most of the record summer rains in the past century in Arizona have been associated with tropical storms moving into the state from the Gulf of California or the Pacific Ocean.

These storms, which occur most frequently in late August and September, usually originate as hurricanes off the west coast of Mexico. As they move northward, they weaken considerably, sometimes to the point of dissipating completely; however, once every 4 or 5 years, a tropical storm may affect Arizona with gale-force winds and flood-producing rains.[3]

2.3.1.2.2 Tornadoes

In the period January 1950 through December 1977, a total of 23 tornadoes was reported and characterized by the National Severe Storms Forecast Center within a 50-nautical-mile radius of the PVNGS site. This is an average of 0.82 tornadoes per year within this radius.[5]

To derive an average tornado path area for tornadoes within a 50-nautical-mile radius of the site, all reported tornado path lengths and path widths were respectively ranked and the median path length and median path width were selected from the two groupings. Because of the sparsity of data, this approach was followed to include unpaired tornado path lengths and path

widths in the analysis. Multiplying the median path length (13 data points) and width (12 data points) results in a median tornado path area of 0.014 square nautical mile.

Based on methods outlined by Thom,[6] the probability of a tornado hitting a particular point within 50 nautical miles of the PVNGS site is 1.46×10^{-6} per year, or a recurrence interval of 6.85×10^{5} years. Analyses of tornado occurrences in the PVNGS site region indicate that the average individual path area of a tornado provided by Thom, 2.82 square miles, is not representative and is overly conservative for the site area. Therefore, the site-specific tornado path length and width data were used for the calculation of tornado occurrence probabilities.

Table 2.3-2

DESIGN BASIS TORNADO CHARACTERISTICS FOR THE PVNGS SITE

Region II Characteristics	Value
Maximum windspeed (mi/h)	300
Rotational speed (mi/h)	240
Maximum translational speed (mi/h)	60
Minimum translational speed (mi/h)	5
Radius of maximum rotational speed (feet)	150
Pressure drop (psi)	2.25
Rate of pressure drop (psi/s)	1.2

Of the total of 23 tornadoes reported within 50 nautical miles of the site, 18 occurred to the east (in the Phoenix area), while the remaining five occurred to the south and south-southwest of the site. No tornadoes were reported within 50 nautical miles northwest of the site region from 1950 to 1977. The spatial differences in the frequency of tornado sightings may possibly be attributed to the higher population density east of the site and sparsity of population elsewhere. The closest tornado touched down on October 18, 1971, 1340 MST, 12 nautical miles south-southwest of the PVNGS site. The tornado had a path length of 0.5 mile and a path width of 150 feet. No deaths or injuries were reported, and the tornado had a damage class designation of 4 ($5000 to $50,000). The tornado had a Fujita-Pearson scale estimate of 1, which indicates winds of 73-112 mi/h. The average Fujita-Pearson scale estimate of force for the tornado was also 1. The design basis tornado (DBT) for PVNGS is as provided in USNRC Regulatory Guide 1.76, Design Basis Tornadoes for Nuclear Power Plants, for Region II. The DBT characteristics are provided in table 2.3-2.

2.3.1.2.3 Extreme Winds

The extreme mile wind speed is defined as the 1-mile passage of wind with the highest speed for the day and includes all meteorological phenomena (extra tropical cyclones, thunderstorms, and tropical cyclones including hurricanes) except tornadoes. The highest such extreme wind speed predicted to occur at the PVNGS site once in 100 years has been calculated based on the statistical methodology of Brooks and Carruthers.[7] In this procedure, the reported annual fastest

mile wind speeds for Phoenix for the period January 1949 to December 1977 are corrected to a standard design level of 30 feet with the assumption that the vertical distribution of velocity is defined by the 1/7 power law.[8] The following relationship was then applied to the wind speed data:

$$u_n = \bar{u} + \frac{(u_k - \bar{u})\log_{10} n}{\log_{10} k} \qquad (1)$$

where:

u_n = extreme fastest mile wind speed, miles per hour

$\bar{u}$ = mean annual fastest mile wind speed, miles per hour

u_k = absolute maximum wind speed, miles per hour

n = recurrence interval of interest, year

k = data record length, year

The operating basis wind speed (100-year recurrence fastest mile wind) for the site region is calculated to be 105 miles per hour. Based on a gustiness factor of 1.3,[9],[10] the highest instantaneous gust expected once in 100 years is 138 miles per hour.

The fastest mile wind speed recorded at Phoenix during the 29-year period of record from January 1949 through December 1977 was 86 miles per hour (unadjusted for height) which occurred during a thunderstorm in July 1976.

2.3.1.2.4 Thunderstorms and Lightning

Widespread thundershower occurrence in Arizona is most frequent in the months of July to September. These thundershowers are most common and most intense over the mountainous sections of the state, where the combined effects of thermal heating and orographic uplift, as well as convergence of air on the windward side of mountain ranges, favor the formation of strong vertical air currents.(4) The mean annual number of days with thunderstorms is 23 for Phoenix, based on a 38-year period of record. The seasonal distribution of the mean number of thunderstorm days at Phoenix is shown in table 2.3-3.

Table 2.3-3 also provides estimates of seasonal and annual frequencies of cloud-to-ground lightning calculated based on the mean number of thunderstorm days at Phoenix.(2),(11) The site area averages three predicted strikes per square kilometer per year. A structure with the approximate dimensions of a PVNGS containment building will average approximately one strike every 6 years.

2.3.1.2.5 Hail, Freezing Rain, and Ice Pellets

Hail occurs in the site region primarily during the warmer half of the year, although its occurrence in winter is not unusual, particularly in southern Arizona.(3) One estimate of the annual mean number of days with hail in the region ranges between 2 and 4.(1) The most destructive hailstorm ever reported in Arizona hit the Phoenix area in the early afternoon of September 18, 1950. Within a period of less than 25 minutes, this storm, accompanied by heavy rain and winds,

caused almost 1.75 million dollars worth of damage ($680,000 by hail, $554,000 by wind, and $510,000 by rain). From the period of 1950 to 1972, property and crop losses due to hail have amounted to more than 4 million dollars.(3) During the period of January 1973 to September 1978, one instance of golf ball size hail was reported during a severe thunderstorm about 15 miles south of Sky Harbor International Airport on July 26, 1978. This storm was also responsible for the record highest wind speed (86 mi/h) at the airport. An additional storm, occurring near Stanton (25 miles north of the PVNGS site) on September 2, 1965, had hailstones with diameters up to 1-1/2 inches.(12)

Table 2.3-3

SEASONAL AND ANNUAL FREQUENCIES OF THUNDERSTORM DAYS
AND PREDICTED CLOUD-TO-GROUND LIGHTNING FLASHES
IN THE VICINITY OF THE PVNGS SITE

Season	Thunderstorm Days	Predicted Number of Cloud-to-Ground Lightning Flashes Per Square Kilometer
Winter (December to February)	2	<1
Spring (March to May)	3	<1
Summer (June to August)	14	2
Fall (September to November)	4	<1
Annual	23	3

The mean annual number of days with glaze (freezing rain) and ice pellets in the region is less than one.[1]

2.3.1.2.6 Dust and Sand Storms

Historical dust storm data for the PVNGS site area were determined from long-term records at Phoenix (1956 to 1978).[13] Characteristic of these storms are high winds, reduced visibilities, and increased particulate loading. Dust storms are generally associated with the decaying stages of thunderstorms. The blowing dust is due primarily to wind direction shifts and high wind speeds generated by cold air downdrafts from the thunderstorms. The NWS differentiates between a dust storm, associated with poor visibility (generally less than 1/2 mile) arising from a high concentration of airborne dust, and blowing dust, which has less severe visibility reductions. Phoenix averaged nearly four dust storms and over three blowing dust events per year during the 1956 to 1978 period. The storms occurred primarily in the summer months, with 79% occurring during July and August -- the peak months of the thunderstorm season in the Phoenix area. The average duration of dust storms was 48 minutes with a maximum duration of 4 hours.[13]

In order to more explicitly characterize dust storms in the immediate PVNGS site area, a monitoring program was conducted at the site. The program was designed to measure total suspended particulate concentration and its size distribution during dust storms. Measurements were made at 10, 40, and 75

feet above ground level. The major conclusions of the study were:

A. Dust storms are short duration events characterized by extremely high particulate concentrations. Short term particulate concentrations in excess of 100 milligrams per cubic meter can occur. No apparent variation of mass loading with height was observed.

B. The size distribution of dust storm particulates is greatly biased towards the 20- to 100-micron range. Approximately 60% of the total particulate concentration was in the 20- to 53-micron range and approximately 22% in the 53- to 106-micron range.

C. The mass loading during nondust storm conditions was very low in comparison to dust storm events. A geometric mean of 61.3 micrograms per cubic meter was observed during the season of study (June 9 to September 8, 1978). Because higher particulate concentrations are normally measured during summer conditions, a lower annual geometric mean would be expected. A decrease in small-sized particulates concentration with height was also observed for nondust storm days.

A more detailed discussion of the program, its results, and general dust storm characteristics based on long-term data from Phoenix is provided in reference 13. A more recent study was conducted to update dust concentration for Palo Verde. This study, 13-MS-A44, titled "Dust Concentration Evaluation for Palo Verde Nuclear Generating Station Units 1, 2, and 3," is

based on a comprehensive data base comprised of 41 years of dust storm weather data, and complements the earlier study in reference 13. For Palo Verde, an average design loading of 1.78 mg/m^3 is used, which is based on an average maximum dust concentration for a 30 day period. This value is derived from the aforementioned data base and is described in detail in reference 29. Refer to sections 6.4 and 9.4 for a discussion of dust loading on HVAC filter systems.

2.3.1.2.7 Snowload

Because of the lack of measurable snowfall in this section of the state, the extreme winter precipitation load (snowload) considered in the design of safety-related plant structures is only 10 pounds per square foot. The normal winter precipitation load used for design (100 year return snowpack) is 5 pounds per square foot.[(10),(14)]

2.3.1.2.8 High Air Pollution Potential

The frequency of low-level inversions is an important consideration in determining the dispersion capability of the atmosphere. The occurrence of low-level inversions or isothermal layers based at or below a 500-foot elevation in the site region is approximately 45% of the total hours on an annual basis. Seasonally, the greatest frequency of inversions, based on percent of total hours, occur during the winter and is approximately 57%. The summer has the lowest inversion frequency, occurring approximately 35% of the time. The majority of these inversions are nocturnal in nature.[(15)]

The mixing height, defined as "the height above the surface through which relatively vigorous vertical mixing occurs,"[16] is also a consideration in determining the potential for the atmosphere to disperse pollutants. The average seasonal and annual mixing heights (based on morning and afternoon measurements) for the site region are as follows:

Mean Annual and Seasonal Mixing Heights for the PVNGS Site Area[16]

	Mixing Height (ft)
Winter	2625
Spring	4760
Summer	5740
Fall	3855
Annual	4245

2.3.1.2.9 Ultimate Heat Sink

The meteorological discussion concerning the ultimate heat sink performance evaluation is provided in subsection 9.2.5.

2.3.2 LOCAL METEOROLOGY

2.3.2.1 Normal and Extreme Values of Meteorological Parameters

Local meteorological data are based on offsite data from Phoenix, Luke Air Force Base, Gila Bend, Buckeye, and Litchfield Park, Arizona and data collected from the onsite meteorological measurements program (see subsection 2.3.3). Onsite data are available for the 5-year period August 13, 1973

through August 13, 1978. All references to onsite meteorological data are for this data period unless indicated otherwise. Offsite data are provided for a long-term period (5 years or greater) and, where appropriate, concurrent with onsite data. Analysis of the data summaries in this section provides a determination of the representativeness of the onsite meteorological data for the 5-year period with respect to long-term conditions and local meteorological conditions (including atmospheric diffusion) expected at and in the vicinity of the PVNGS site.

Figure 2.3-1 indicates the location of the PVNGS site and the meteorological data collection stations used to assess the local meteorology. Table 2.3-4 more specifically provides the locations and a brief topographical description of the offsite meteorological stations.

2.3.2.1.1 Wind Direction and Speed

Onsite monthly and annual wind roses for the 35-foot and 200-foot levels are presented in figures 2.3-2 through 2.3-6 for the 5-year period August 13, 1973 to August 13, 1978. Wind roses are provided monthly for the 5 years combined, as well as annually for each individual year and the 5-year summary. Wind direction distributions are similar for both levels on the tower and for all 5 years of data collection. Prevailing winds are from the southwesterly sectors on an annual basis and during the spring and summer months. During the fall and winter months, however, prevailing winds are from the east and northeast sectors.

Table 2.3-4

OFFSITE METEOROLOGICAL DATA COLLECTION STATIONS

USED TO ASSESS THE LOCAL METEOROLOGY

Station	Distance From Site (Miles)	Direction	Local Topography
Phoenix (Sky Harbor International Airport)	50	ENE	Flat; east-west valley
Luke Air Force Base	33	ENE	Flat; mountains immediately to the west
Gila Bend Airport	34	SSE	Flat; scattered hills in the area
Buckeye	18	E	Flat
Litchfield Park	32	ENE	Flat

Shown in figures 2.3-7 through 2.3-9 are monthly and annual wind roses for Phoenix for the same 5-year period as the onsite data. For comparison to the 5-year period of site data, annual 5-year wind roses for Phoenix (1960 to 1964), Gila Bend (1948 to 1953), and Luke AFB (1960 to 1964) are presented in figure 2.3-10.

Comparison of the wind roses for the various time periods and locations shows the topographic influences on predominant wind flows and the inherent differences in wind distributions between the recording stations. Prevailing winds at Phoenix are east and west along the axis of the valley in which the airport and city are situated. The effect of the north-south oriented White Tank Mountains, immediately to the west of Luke AFB, are evident with the north-south prevailing winds at that site. Gila Bend shows less topographic influences than the other offsite locations with prevailing southwest winds due to the predominant synoptic wind flows in the area. A secondary maximum at Gila Bend of winds from the southeast may be due to the mountain ranges to the south.

The 5 years of onsite wind data appear to provide representative wind direction data for long-term considerations for the site area. There are small deviations in predominant directional frequencies from year to year at both PVNGS and Phoenix for the 5-year period. Comparisons of the two 5-year periods at Phoenix (1960 to 1964 and August 1973 to August 1978) show little difference in the distributions.

Comparisons of onsite and Phoenix monthly and annual average wind speeds are presented in table 2.3-5. The average wind

Table 2.3-5

MONTHLY AND ANNUAL AVERAGE WINDSPEEDS (MILES PER HOUR) FOR PVNGS AND PHOENIX

(AUGUST 13, 1973, TO AUGUST 13, 1978) (Sheet 1 of 4)

Month	Phoenix[a] (18-Foot Level)				
	8/13/83 to 8/13/74	8/13/74 to 8/13/75	8/13/75 to 8/13/76	8/13/76 to 8/13/77	8/13/77 to 8/13/78
August	7.4	7.7	7.8	8.8	9.2
September	6.3	7.7	8.7	8.3	7.8
October	5.9	7.3	8.0	8.0	7.0
November	5.6	5.5	7.5	7.1	6.8
December	5.8	6.2	6.5	6.6	6.0
January	6.0	6.6	6.7	5.9	6.1
February	7.0	6.8	8.3	7.1	7.3
March	6.9	8.1	9.0	9.0	7.8
April	8.5	8.5	8.8	8.7	8.4
May	8.2	8.5	8.6	9.2	8.4
June	8.7	8.1	8.7	9.1	8.4
July	8.5	8.7	9.6	9.0	8.5
Annual	7.1	7.5	8.2	8.1	7.6

a. Observations made every 3 hours.

Table 2.3-5

MONTHLY AND ANNUAL AVERAGE WINDSPEEDS (MILES PER HOUR) FOR

PVNGS AND PHOENIX

(AUGUST 13, 1973, TO AUGUST 13, 1978) (Sheet 2 of 4)

Month	PVNGS (35-Foot Level)				
	8/13/83 to 8/13/74	8/13/74 to 8/13/75	8/13/75 to 8/13/76	8/13/76 to 8/13/77	8/13/77 to 8/13/78
August	6.3	7.0	7.2	7.9	7.4
September	6.3	7.1	7.7	6.7	6.0
October	3.7	6.0	6.2	5.9	4.9
November	4.3	4.2	5.8	5.1	5.0
December	4.8	4.8	3.7	4.6	4.2
January	4.7	5.2	3.9	4.2	4.5
February	5.8	5.7	6.1	5.3	5.2
March	5.4	7.7	7.3	8.0	6.2
April	6.8	7.7	7.6	7.4	6.7
May	7.0	7.6	7.4	7.7	7.4
June	6.9	7.9	7.3	7.7	7.7
July	7.4	8.4	8.4	8.1	7.7
Annual	5.5	6.6	6.5	6.6	6.2

Table 2.3-5

MONTHLY AND ANNUAL AVERAGE WINDSPEEDS (MILES PER HOUR) FOR PVNGS AND PHOENIX

(AUGUST 13, 1973, TO AUGUST 13, 1978) (Sheet 3 of 4)

Month	PVNGS (200-Foot Level)				
	8/13/83 to 8/13/74	8/13/74 to 8/13/75	8/13/75 to 8/13/76	8/13/76 to 8/13/77	8/13/77 to 8/13/78
August	9.5	9.3	9.1	10.2	9.9
September	5.0	9.7	10.8	8.7	8.1
October	5.4	8.7	8.4	8.2	6.7
November	6.5	5.0	8.1	7.3	6.6
December	6.7	6.4	6.5	6.6	4.9
January	7.0	6.8	6.9	5.5	5.9
February	8.4	7.6	8.9	7.0	7.2
March	8.0	10.3	10.0	10.8	8.5
April	9.4	10.3	10.1	9.7	9.1
May	9.8	10.1	9.8	9.7	10.0
June	9.4	10.6	9.5	10.5	10.2
July	9.6	10.9	10.7	10.4	11.8
Annual	7.4	8.9	9.0	8.8	8.3

Table 2.3-5

MONTHLY AND ANNUAL AVERAGE WINDSPEEDS (MILES PER HOUR) FOR PVNGS AND PHOENIX

(AUGUST 13, 1973, TO AUGUST 13, 1978) (Sheet 4 of 4)

Month	8/13/73 to 8/13/78		
		PVNGS	
	Phoenix[a]	(35-Foot Level)	(200-Foot Level)
August	8.2	7.2	9.8
September	7.8	6.2	8.5
October	7.2	5.4	7.6
November	6.5	5.0	6.9
December	6.2	4.6	6.3
January	6.3	4.6	6.5
February	7.3	5.8	8.0
March	8.2	7.0	9.6
April	8.6	7.4	9.8
May	8.6	7.5	10.0
June	8.6	7.6	10.1
July	8.9	8.1	10.8
Annual	7.7	6.4	8.7

speed at the 35-foot level for PVNGS was 6.4 miles per hour for the 5 years. The 200-foot level average wind speed was higher, as expected, 8.7 mi/h. The Phoenix concurrent 5-year average wind speeds are consistently higher than both the onsite 35-foot level wind speeds and the 29-year climatological average see table 2.3-1). Average wind speeds for Gila Bend, Phoenix, and Luke AFB for the 5-year periods presented in figure 2.3-10 are 7.7, 6.8, and 6.8 miles per hour, respectively. Data from all locations show the relatively low average windspeeds indicative of wind conditions in the Salt River Valley.

The frequency of calm winds is reported in the wind rose figures 2.3-2 through 2.3-10. The 5-year composite for PVNGS indicates 0.16% and 0.07% calms at 35 feet and 200 feet, respectively. All offsite data collection station summaries indicate a higher frequency of calms than the onsite data.

Luke AFB has an unrealistically high frequency of calms when compared with all the other meteorological stations. The difference in frequency of calms between PVNGS and the offsite stations is attributed primarily to differences in wind speed sensor thresholds and exposure (see subsection 2.3.3 regarding instrumentation specifications).

Wind direction persistence is defined as the number of consecutive hours of air flow within a 22-1/2 degree sector. Wind direction persistence summaries for the 5 years of onsite data are presented in table 2.3-6 for the 35-foot level and in table 2.3-7 for the 200-foot level. Concurrent data for Phoenix are not provided since persistence summaries are not

Table 2.3-6

PVNGS WIND DIRECTION PERSISTENCE (CUMULATIVE DISTRIBUTION), 35-FOOT LEVEL

(AUGUST 13, 1973, TO AUGUST 13, 1978) [a]

Persistence[b]	Wind Direction																	
	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	Calm	All
1	2,616	2,941	2,190	1,879	3,336	2,824	2,165	1,988	2,837	3,312	5,196	3,515	2,341	1,636	1,693	1,961	171	42,601
2	628	715	343	328	1,061	628	362	297	529	946	2,345	1,118	583	471	386	385	27	11,152
3	154	191	85	96	515	186	71	55	101	370	1,302	480	181	217	160	151	9	4,324
4	38	53	24	39	285	56	13	11	23	158	758	233	55	114	75	76	5	2,016
5	11	23	10	17	174	18	2	1	11	84	443	120	21	67	32	46	4	1,084
6	3	13	4	8	116	5	1	0	6	51	271	60	8	41	14	29	3	633
7	0	8	1	4	76	1	0	0	3	34	169	27	5	28	5	20	2	383
8	0	5	0	1	50	0	0	0	2	23	105	15	2	18	2	14	1	238
9	0	3	0	0	34	0	0	0	1	15	58	9	1	12	0	12	0	145
10	0	2	0	0	21	0	0	0	0	11	34	6	0	7	0	10	0	91
11	0	1	0	0	11	0	0	0	0	8	18	4	0	3	0	9	0	54
12	0	0	0	0	5	0	0	0	0	5	11	3	0	1	0	8	0	33
13	0	0	0	0	3	0	0	0	0	2	7	2	0	0	0	7	0	21
14	0	0	0	0	2	0	0	0	0	1	4	1	0	0	0	6	0	14
15	0	0	0	0	1	0	0	0	0	0	2	0	0	0	0	5	0	8
16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	4
17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	3
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	2
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

a. Number of observations = 42,601.

b. Equal to or greater than hours indicated.

Table 2.3-7

PVNGS WIND DIRECTION PERSISTENCE (CUMULATIVE DISTRIBUTION), 200-FOOT LEVEL

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Persistence[b]	Wind Direction																
	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	Calm	All
1	1,476	2,342	2,897	2,626	3,716	2,507	2,005	1,826	2,493	3,605	5,880	3,518	2,336	1,651	1,621	1,401	78	41,978
2	394	684	892	730	1,486	621	353	346	547	1,274	3,005	1,274	727	555	527	372	18	13,805
3	130	258	334	279	764	178	79	84	140	575	1,777	584	262	278	236	150	6	6,114
4	47	115	146	124	433	42	22	17	46	304	1,112	293	112	155	109	67	3	3,147
5	14	59	71	59	257	12	4	3	16	174	715	150	43	92	57	37	1	1,764
6	5	36	36	30	159	5	0	0	5	105	473	73	15	58	34	24	0	1,058
7	1	21	17	13	100	1	0	0	2	67	309	30	5	37	19	15	0	637
8	0	14	10	4	63	0	0	0	1	42	205	13	1	22	11	12	0	398
9	0	10	5	0	42	0	0	0	0	29	126	6	0	15	8	9	0	250
10	0	7	1	0	30	0	0	0	0	20	81	2	0	10	5	7	0	163
11	0	4	0	0	21	0	0	0	0	15	50	0	0	8	3	6	0	107
12	0	2	0	0	13	0	0	0	0	11	32	0	0	7	1	5	0	71
13	0	1	0	0	9	0	0	0	0	7	21	0	0	6	0	4	0	48
14	0	0	0	0	6	0	0	0	0	5	12	0	0	5	0	3	0	31
15	0	0	0	0	4	0	0	0	0	3	6	0	0	4	0	2	0	19
16	0	0	0	0	2	0	0	0	0	2	4	0	0	3	0	1	0	12
17	0	0	0	0	1	0	0	0	0	1	2	0	0	2	0	0	0	6
18	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

a. Number of observations = 41,978.

b. Equal to or greater than hours indicated.

meaningful unless consecutive, hourly data are used. Since 1965, only three-hourly (eight observations per day) observations from NWS data collection stations are achieved on magnetic tape. Because of the 5-year data period, the onsite summaries should be representative of expected long-term conditions at the site. Probability distributions of persistence periods for offsite data from Phoenix, Luke AFB, and Gila Bend for data periods prior to 1965 are provided in figure 2.3-11.

Wind direction persistence occurrences at the site of greater than 5 hours are mostly associated with winds from the east and southwest. The maximum wind direction persistence event at the 35-foot level for PVNGS during the period of record was 19 hours for a wind from the north-northwest. The maximum 200-foot wind persistence event was 18 hours for a wind from the west-northwest direction. The maximum event for offsite data was 16 hours from the east at Phoenix (1960 to 1964 data period).

The majority of persistence occurrences of calms at the 35-foot level at PVNGS has been limited to 3 hours or less in duration during the 5-year period.

2.3.2.1.2 Ambient and Dewpoint Temperature

Monthly means of temperature and dewpoint for PVNGS and Phoenix for each year of the August 13, 1973 through August 13, 1978 period are presented in table 2.3-8. Measurements made at Phoenix tend to average higher than the site for both dewpoint and ambient temperature, indicative of the effects of urbanization. Each of the 5 years at Phoenix had higher

average ambient temperatures than the climatological normal, 70F (30-year period, 1941 to 1970). Table 2.3-9 shows the monthly and annual means and extremes of temperature for the entire 5-year period at both PVNGS and Phoenix. Table 2.3-9 indicates a fairly good comparison between the two locations with some large differences in absolute minimum temperatures, which are expected due to differences in instrument exposure. The highest monthly mean temperature at PVNGS occurred in July (91F). The lowest monthly mean temperature at PVNGS occurred in January (52F). Tables 2.3-1 and 2.3-10 through 2.3-12[(2),(17),(18),(19)] present normals, means, and extremes of ambient temperature and other meteorological parameters at the offsite locations of Phoenix, Gila Bend, Buckeye, and Litchfield Park, Arizona. There is consistent agreement between the long-term data provided in these tables and the 5-year period of site and Phoenix data provided in table 2.3-9.

Monthly and annual summaries of dewpoint temperatures for the PVNGS site and Phoenix are provided in table 2.3-13 for the 5-year period of onsite data. The table shows that relatively low dewpoint temperatures occur at both sites which, when combined with the relatively high ambient temperatures shown in the preceding tables, is indicative of the low relative humidities associated with the general climate of the site area.

The annual diurnal pattern of ambient and dewpoint temperature at PVNGS for the 5 years is provided in table 2.3-14. It indicates that the warmest part of the day usually occurs between 3 p.m. and 6 p.m. MST; the coolest, just before sunrise, at about 6 a.m. to 7 a.m. MST.

Table 2.3-8

PVNGS AND PHOENIX MONTHLY MEAN AMBIENT AND DEWPOINT TEMPERATURES (°F)

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Month	Data Year 1973-1974		Data Year 1974-1975		Data Year 1975-1976		Data Year 1976-1977		Date Year 1977-1978	
	Temperature	Dewpoint	Temperature	Dewpoint	Temperature	Dewpoint	Temperature	Dewpoint	Temperature	Dewpoiont
	PVNGS									
August	89	52	92	47	91	44	91	52	89	60
September	83	37	86	57	86	46	81	52	84	49
October	73	30	73	49	72	31	70	41	74	49
November	58	32	58	37	60	22	57	32	62	32
December	53	25	48	30	52	31	50	25	56	31
January	51	38	50	23	53	22	50	34	53	43
February	55	22	54	25	59	33	57	23	55	42
March	64	42	59	27	61	22	57	19	63	46
April	70	27	61	27	68	28	70	30	67	36
May	79	36	76	26	80	34	73	32	78	29
June	93	39	85	31	89	30	90	37	90	31
July	90	56	92	57	92	56	91	54	93	51
Annual	72	37	69	36	72	33	70	36	72	42
PHOENIX										
August	93	53	94	49	90	49	93	56	92	61
September	85	41	87	55	86	51	83	55	87	53
October	74	34	76	51	73	39	74	42	78	48
November	61	34	62	40	61	27	64	34	65	33
December	55	27	51	31	55	36	56	26	59	30
January	54	34	52	26	55	26	54	36	56	42
February	57	18	54	30	61	33	62	26	58	41
March	65	35	59	31	62	25	61	22	65	45
April	71	23	63	29	69	30	74	29	69	36
May	80	31	77	29	81	36	76	33	79	32
June	92	38	87	33	88	33	91	39	91	36
July	92	57	94	58	92	55	95	59	95	54
Annual	73	35	71	39	73	37	74	38	75	42

a. Climatological normal temperature for Phoenix is 70F.

Table 2.3-9

PVNGS AND PHOENIX MONTHLY AND ANNUAL MEANS AND EXTREMES OF TEMPERATURE [a]

(AUGUST 13, 1973, TO AUGUST 1978)

Month	PVNGS					PHOENIX				
		Maximum		Minimum			Maximum		Minimum	
	Mean	Mean [b]	Extreme	Mean [b]	Extreme	Mean	Mean [b]	Extreme	Mean [b]	Extreme
August	90	101	112	78	63	92	105	116	80	69
September	84	95	107	72	59	86	98	110	73	61
October	72	85	99	59	39	75	88	103	61	43
November	59	73	90	46	30	63	76	93	49	33
December	52	64	79	40	25	55	68	81	43	26
January	51	64	81	40	21	54	67	83	42	26
February	56	69	84	43	30	59	72	88	45	31
March	61	72	89	48	34	62	75	91	49	35
April	67	79	97	53	29	69	83	99	54	40
May	77	89	106	62	43	78	93	110	63	45
June	89	101	114	73	60	90	105	116	74	64
July	91	101	111	80	63	94	105	115	82	70
Annual	71	83	114	58	21	73	86	116	60	26

a. Based on hourly observations for both Phoenix and the PVNGS site.

b. Mean daily maximum and minimum temperatures.

Table 2.3-10

CLIMATOLOGICAL MEANS AND EXTREMES, GILA BEND, ARIZONA

LATITUDE: 32° 57'
LONGITUDE: 112° 43'
ELEV. (GROUND): 737 feet

CLIMATOLOGICAL SUMMARY

STATION: GILA BEND

STATION NO: 02-3393-6

MEANS AND EXTREMES FOR PERIOD 1893 - 1957

Month	Temperature (°F) Means Daily maximum	Temperature (°F) Means Daily minimum	Temperature (°F) Means Monthly	Temperature (°F) Extremes Record highest	Temperature (°F) Extremes Year	Temperature (°F) Extremes Record lowest	Temperature (°F) Extremes Year	Estimated mean degree days**	Precipitation Totals (inches) Mean	Precipitation Totals (inches) Greatest daily	Precipitation Totals (inches) Year	Precipitation Totals (inches) Snow, Sleet, Hail Mean	Precipitation Totals (inches) Snow, Sleet, Hail Maximum monthly	Precipitation Totals (inches) Snow, Sleet, Hail Year	Estimated mean relative humidity (percent) 0600 MST	Estimated mean relative humidity (percent) 1800 MST	Mean number Of days Precip. .10 Inch or more	Mean number Of days Temperatures Max. 90° and above	Mean number Of days Temperatures Max. 32° and below	Mean number Of days Temperatures Min. 32° and below	Mean number Of days Temperatures Min. 0° and below	Month
(a)	48	47	47	48	48	47	47		55	55	55	56	56	56			55	45	45	42	42	
J	68.5	37.4	53.0	90	1956	11	1913	372	0.60	1.30	1905	T	2.0	1937	59	32	2	*	0	7	0	J
F	73.6	40.3	56.9	95	1921	23	1953#	244	0.47	0.90	1913#	0.0	0.0		59	28	1	*	0	3	0	F
M	80.4	44.4	62.4	101	1896	27	1955	143	0.62	1.15	1930	0.0	0.0		51	19	1	4	0	1	0	M
A	88.3	50.3	69.4	108	1924#	28	1896	42	0.22	1.38	1941	0.0	0.0		45	15	1	14	0	*	0	A
M	96.4	57.5	77.0	116	1951#	39	1915	0	0.11	1.25	1930	0.0	0.0		38	11	*	26	0	0	0	M
J	106.1	66.4	86.3	121	1936#	42	1934	0	0.07	0.70	1918#	0.0	0.0		34	11	*	30	0	0	0	J
J	108.7	76.9	92.8	121	1958#	47	1941	0	0.82	1.50	1955	0.0	0.0		48	20	2	31	0	0	0	J
A	107.3	75.0	91.2	119	1911	55	1909	0	0.91	2.61	1951	0.0	0.0		58	24	2	31	0	0	0	A
S	103.8	68.5	86.2	120	1950	49	1934#	0	0.47	2.52	1946	0.0	0.0		53	22	1	29	0	0	0	S
O	92.7	55.5	74.2	109	1934#	35	1935#	0	0.36	1.32	1914	0.0	0.0		51	26	1	22	0	0	0	O
N	78.9	43.4	61.2	99	1924	22	1916	279	0.45	2.00	1923	0.0	0.0		52	27	1	3	0	2	0	N
D	69.4	37.5	53.5	90	1940	15	1911	357	0.59	2.03	1915	0.0	0.0		64	36	1	0	0	8	0	D
Year	89.5	54.4	72.0	121	June 1936#	11	Jan. 1913	1437	5.69	2.61	Aug. 1951	T	2.0	Jan. 1937	51	23	13	190	0	21	0	Year

(a) Average length of record, years.

T Trace, an amount too small to measure.

** Base 65°F

Also on earlier dates, months, or years.

* Less than one half

Table 2.3-11

CLIMATOLOGICAL MEANS AND EXTREMES, BUCKEYE, ARIZONA

LATITUDE: 33° 22'
LONGITUDE: 112° 35'
ELEV. (GROUND): 870 feet

CLIMATOLOGICAL SUMMARY

STATION: BUCKEYE
STATION NO: 02-1026-6

MEANS AND EXTREMES FOR PERIOD 1893 - 1957

Month	Temperature (°F)							Estimated mean degree days**	Precipitation Totals (Inches)						Estimated mean relative humidity (percent)		Mean number Of days					Month
	Means			Extremes								Snow, Sleet, Hail					Precip. .10 inch or more	Temperatures				
																		Max.		Min.		
	Daily maximum	Daily minimum	Monthly	Record highest	Year	Record lowest	Year		Mean	Greatest daily	Year	Mean	Maximum monthly	Year	0600 MST	1800 MST		90° and above	32° and below	32° and below	0° and below	
(a)	61	61	60	61	61	66	61		62	62	62	62	62	62			62	55	55	55	55	
J	67.7	33.3	50.5	86	1896	11	1913	450	0.89	2.04	1905	T	T	1933#	65	29	2	0	0	15	0	J
F	72.1	37.2	54.7	92	1896	18	1933#	297	0.74	1.80	1931	T	T	1939#	65	26	2	*	0	8	0	F
M	78.3	41.1	59.7	101	1934	24	1906	208	0.70	1.31	1930	T	T	1954#	58	17	2	3	0	3	0	M
A	85.8	47.2	66.6	105	1936	29	1929	72	0.31	1.80	1905	T	T	1941#	48	13	1	11	0	*	0	A
M	94.0	54.2	74.2	114	1934	32	1899	9	0.10	0.56	1930	T	T	1940	42	8	*	24	0	*	0	M
J	102.9	62.3	82.7	120	1929#	42	1908	0	0.08	0.86	1918	T	T	1931	36	9	*	29	0	0	0	J
J	105.9	73.3	89.6	121	1905	49	1944	0	1.01	2.86	1907	T	T	1946#	51	19	2	31	0	0	0	J
A	104.4	72.8	88.6	120	1936	48	1930	0	1.14	2.60	1951	0.0	0.0		58	23	3	31	0	0	0	A
S	100.6	64.4	82.4	119	1950	41	1906#	0	0.63	3.29	1916	T	T	1937#	55	21	1	28	0	0	0	S
O	89.5	50.5	70.0	107	1929	28	1935	31	0.45	1.28	1940	T	T	1932	58	25	1	17	0	*	0	O
N	76.7	39.7	58.3	96	1934	20	1931	231	0.62	1.93	1923	T	T	1919	58	28	1	1	0	4	0	N
D	67.9	34.0	51.0	87	1949	13	1911	434	0.85	1.85	1915	T	T	1923#	68	35	2	0	0	14	0	D
Year	87.2	50.8	69.0	121	July 1905	11	Jan. 1913	1732	7.52	3.29	Sep. 1916	T	T	Mar. 1954#	55	21	17	175	0	44	0	Year

(a) Average length of record, years.

T Trace, an amount too small to measure.

** Base 65°F

Also on earlier dates, months, or years.

* Less than one half

Table 2.3-12

CLIMATOLOGICAL MEANS AND EXTREMES, LITCHFIELD PARK, ARIZONA

LATITUDE: 33° 30'
LONGITUDE: 112° 22'
ELEV. (GROUND): 1030 feet

CLIMATOLOGICAL SUMMARY

STATION: LITCHFIELD PARK
STATION NO: 02-4977-6

MEANS AND EXTREMES FOR PERIOD 1918 - 1957

Month	Temperature (°F) Means: Daily maximum	Daily minimum	Monthly	Temperature (°F) Extremes: Record highest	Year	Record lowest	Year	Estimated mean degree days**	Precipitation Totals (Inches): Mean	Greatest daily	Year	Snow, Sleet, Hail: Mean	Maximum monthly	Year	Estimated mean relative humidity (percent): 0600 MST	1800 MST	Mean number Of days: Precip. .10 Inch or more	Temperatures Max.: 90° and above	32° and below	Temperatures Min.: 32° and below	0° and below	Month
(a)	39	38	37	39	39	38	38		40	40	40	40	40	40			40	23	23	22	22	
J	66.1	34.9	50.5	87	1923	16	1950	450	0.93	1.79	1954	T	T	1954#	66	32	2	0	0	12	0	J
F	71.1	38.6	54.9	93	1930	22	1948#	283	0.83	1.21	1931	T	T	1945#	66	28	2	*	0	6	0	F
M	76.9	42.6	59.7	97	1955	28	1956#	205	0.72	1.56	1941	T	T	1951#	59	19	2	1	0	2	0	M
A	85.7	49.1	67.4	105	1936	27	1938	66	0.35	1.00	1926	T	T	1944	48	14	1	11	0	*	0	A
M	94.4	56.8	75.7	113	1951#	38	1921	0	0.15	1.24	1930	T	T	1930	41	9	*	24	0	0	0	M
J	103.1	65.2	84.3	117	1940	49	1955#	0	0.11	0.67	1925	0.0	0.0		36	10	*	29	0	0	0	J
J	105.9	75.2	90.6	118	19	57	1943	0	0.76	1.73	1919	0.0	0.0		53	20	2	31	0	0	0	J
A	103.2	73.2	88.4	116	1918	57	1957#	0	1.40	2.36	1951	0.0	0.0		59	24	2	31	0	0	0	A
S	100.0	66.3	83.2	115	1950#	44	1920	0	0.75	2.71	1925	0.0	0.0		55	22	1	29	0	0	0	S
O	88.5	52.8	70.7	106	1955	33	1928	25	0.38	1.08	1957	T	T	1949	58	27	1	15	0	0	0	O
N	76.1	40.6	58.4	98	1921	23	1931	228	0.63	2.65	1923	T	T	1919	60	31	1	1	0	3	0	N
D	67.8	36.2	52.0	89	1950	20	1930	403	1.00	1.74	1940	T	T	1949#	67	37	2	0	0	10	0	D
Year	86.6	52.6	69.6	118	July 1943	16	Jan. 1950	1660	8.01	2.71	Sep. 1925	T	T	Jan. 1954#	56	23	16	172	0	33	0	Year

(a) Average length of record, years.

T Trace, an amount too small to measure.

** Base 65°F

Also on earlier dates, months, or years.

* Less than one half

2.3.2.1.3 Atmospheric Water Vapor

Monthly and annual means of relative humidity for PVNGS and Phoenix are presented in table 2.3-15 for each of the 5 years of onsite data. The PVNGS data are similar to the Phoenix summaries. Minimum relative humidities occur consistently in the summer months with maximums occurring in the winter.

The annual average diurnal variation of relative and absolute humidity at PVNGS is presented in table 2.3-16 for the 5 years. It indicates that the highest relative humidities occurred between 5 a.m. and 8 a.m. MST during the cool part of the day, and that the lowest relative humidities occurred generally during the warm part of the day.

Tables 2.3-1 and 2.3-10 through 2.3-12 provide long-term monthly means and diurnal variations of relative humidity for Phoenix, Gila Bend, Buckeye, and Litchfield Park, Arizona. These long-term means are similar to the 5-year values.

2.3.2.1.4 Precipitation

Monthly and annual extreme precipitation by time interval are presented in table 2.3-17 for PVNGS for the 5 years of onsite data. It indicates that, for the 5 years, the extreme 1-hour precipitation was 0.89 inch and occurred in August 1978. The extreme 24-hour precipitation was 1.95 inches and occurred in September 1974. During the 5-year period, there was only one hourly occurrence of precipitation when the ambient temperature was less than or equal to 32F. Additional information on rainfall rate distributions for PVNGS is presented on an annual basis in table 2.3-18.

In table 2.3-19, the extreme 24-hour precipitation for PVNGS is compared to Phoenix for the 5 years of onsite data collection. In table 2.3-20, the monthly and annual average total precipitation for the 5 years for PVNGS and Phoenix are compared. The PVNGS monthly precipitation patterns are generally consistent with Phoenix with the largest differences occurring during the summer months.

The long-term total precipitation values for offsite locations are presented in tables 2.3-1 and 2.3-10 through 2.3-12. Comparison with these tables shows that the first 4 years of site data were at or below normal for total precipitation while the 1977 to 1978 period was well above normal.

Monthly and annual precipitation wind roses for PVNGS (35-foot winds) are presented in figures 2.3-12 through 2.3-14 for the 5 years combined. These show the average speed by direction of winds during precipitation events and the percentage of total hours that precipitation occurs with each wind direction. Seasonal variations are apparent. On an annual basis, precipitation frequencies are greatest for winds from the easterly and southwesterly sectors and are least frequent for winds out of the west and northwesterly sectors. Concurrent precipitation wind roses from Phoenix are not provided since these data summaries, based on every third hour, would not be meaningful, especially in a desert climate where precipitation is very infrequent. The 5 years of onsite data should provide a representative data set.

Table 2.3-13

MONTHLY AND ANNUAL DEWPOINT SUMMARIES

FOR PVNGS AND PHOENIX

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Month	Temperature (°F)	
	PVNGS	Phoenix
August	51	54
September	48	51
October	40	43
November	31	34
December	27	30
January	31	33
February	28	30
March	30	32
April	29	30
May	32	32
June	34	36
July	55	57
Annual	36	38

Table 2.3-14

ANNUAL DIURNAL VARIATIONS OF AMBIENT AND

DEWPOINT TEMPERATURE AT THE PVNGS SITE (°F)

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Hour (Local Standard Time)	Ambient Temperature (°F)	Dewpoint Temperature (°F)
01:00	65	36
02:00	64	36
03:00	62	37
04:00	61	37
05:00	60	36
06:00	58	36
07:00	59	37
08:00	62	38
09:00	66	38
10:00	70	39
11:00	74	38
12:00	76	38
13:00	79	37
14:00	80	36
15:00	81	35
16:00	82	35
17:00	82	35
18:00	81	35
19:00	78	35
20:00	76	35
21:00	74	35
22:00	71	36
23:00	69	36
24:00	67	36

Table 2.3-15

MONTHLY AND ANNUAL AVERAGE RELATIVE HUMIDITY FOR PVNGS AND PHOENIX (PERCENT)

(AUGUST 13, 1973, TO AUGUST 1978)

Month	1973 to 1974		1974 to 1975		1975 to 1976		1976 to 1977		1977 to 1978		1973 to 1978	
	PVNGS	Phoenix	PVNGS	Phoenix	PVNGS	Phoenix	PVNGS	Phoenix	PVNGS	Phoenix	PVNGS	Phoenix
August	34	28	26	29	25	27	31	27	41	36	31	29
September	23	22	40	36	31	34	37	42	34	35	33	34
October	24	25	48	48	27	32	41	37	45	38	37	36
November	42	43	50	51	29	33	41	36	35	34	40	39
December	35	39	55	54	49	55	39	36	46	40	45	45
January	60	52	38	42	32	36	57	57	74	64	52	50
February	30	26	38	46	45	43	29	30	67	57	42	40
March	47	38	37	41	30	30	27	26	60	54	40	38
April	26	18	34	34	29	28	29	22	39	35	32	27
May	25	17	22	19	28	25	31	24	25	22	26	21
June	22	16	21	16	20	15	22	17	20	16	21	16
July	36	33	35	33	35	33	33	32	31	28	34	32
Annual	34	30	37	37	32	33	35	32	43	38	36	34

Table 2.3-16

ANNUAL AVERAGE DIURNAL VARIATIONS OF RELATIVE AND ABSOLUTE HUMIDITY AT PVNGS (AUGUST 13, 1973, TO AUGUST 13, 1978)

Hour (Local Standard Time)	Relative Humidity (%)	Absolute Humidity (g/m^3)
01:00	40	6
02:00	42	6
03:00	44	6
04:00	45	6
05:00	47	6
06:00	49	6
07:00	49	6
08:00	47	6
09:00	42	6
10:00	38	6
11:00	34	6
12:00	31	6
13:00	28	6
14:00	27	6
15:00	26	5
16:00	26	5
17:00	26	5
18:00	27	5
19:00	28	5
20:00	30	5
21:00	32	6
22:00	34	6
23:00	36	6
24:00	38	6

2.3.2.1.5 Natural Fog

On the average, there is a low frequency of natural fog in the PVNGS site region. Phoenix averages only 2 days per year with heavy fog.[(2)] Because of the low number of occurrences, expected frequencies and durations are not discussed.

2.3.2.1.6 Atmospheric Stability

Site atmospheric stability is classified by the vertical temperature gradient, ΔT (200 feet - 35 feet), in accordance with the position in Regulatory Guide 1.23. The onsite monthly and annual distributions of atmospheric stability classes for PVNGS are presented in table 2.3-21 for the combined 5 years. Table 2.3-22 presents the annual distributions for each of the 5 years.

The data show that extremely stable conditions are generally the most frequent at PVNGS. There were 29.18% occurrences of the "G" category during the first year, 24.45% during the second year, 28.12% during the third year, 24.12% during the fourth data year, and 25.27% during the fifth data year. The average frequency for the 5 years combined is 26.29%. This unusually high frequency of "G" atmospheric stability is most prevalent in the fall and winter months and consistently occurs in each of the 5 years. Examination of hourly and summarized wind and ΔT data show that these conditions occur primarily with winds from the NNW clockwise through NE (the directions toward the higher terrain) with wind speeds at the 35-foot level less than 5 miles per hour.

Table 2.3-17

PVNGS MONTHLY AND ANNUAL EXTREME PRECIPITATION (INCHES)
BY TIME INTERVAL
(AUGUST 13, 1973, TO AUGUST 13, 1978)

Month	Time Interval (Hours)				
	1	6	12	18	24
August	0.89	0.92	0.92	0.97	1.03
September	0.52	1.92	1.95	1.95	1.95
October	0.52	0.68	0.68	0.68	0.68
November	0.19	0.43	0.57	0.65	0.65
December	0.10	0.39	0.59	0.65	0.65
January	0.35	0.69	0.71	0.78	0.78
February	0.28	0.60	0.60	0.60	0.66
March	0.35	0.60	0.83	0.83	0.83
April	0.17	0.22	0.22	0.22	0.22
May	0.24	0.24	0.24	0.24	0.24
June	0.07	0.14	0.14	0.14	0.14
July	0.27	0.53	0.89	1.16	1.30
Annual	0.89	1.92	1.95	1.95	1.95

Table 2.3-18

ANNUAL PRECIPITATION INTENSITY/DURATION FOR PVNGS

(NUMBER OF OCCURRENCES)

(AUGUST 13, 1973, TO AUGUST 13, 1978) (Sheet 1 of 2)

Amount [a] (Inches)	Duration (Hours)				
	1	6	12	18	24
0.01	614	1793	2868	3814	4689[b]
0.02	428	1441	2415	3276	4082
0.03	324	1247	2143	2955	3717
0.04	255	1115	1941	2671	3376
0.05	191	984	1757	2430	3083
0.07	131	784	1452	2075	2666
0.10	83	598	1155	1694	2222
0.15	44	430	836	1230	1613
0.20	24	286	630	961	1285
0.25	12	171	413	654	898
0.30	9	123	301	495	688
0.35	7	88	222	360	508
0.40	5	69	171	292	421
0.45	5	52	144	242	349
0.50	5	47	123	203	297
0.60	1	23	82	143	208
0.70	1	13	44	83	119
0.80	1	12	33	57	85

a. Equal to or greater than value listed.

b. Example--out of a possible 43,778 24-hour periods in 5 years, 4689 had a total precipitation amount of equal to or greater than 0.01 inch.

c. There were no occurrences of precipitation totals greater than 2 inches for time periods less than or equal to 24 hours.

Table 2.3-18

ANNUAL PRECIPITATION INTENSITY/DURATION FOR PVNGS

(NUMBER OF OCCURRENCES)

(AUGUST 13, 1973, TO AUGUST 13, 1978) (Sheet 2 of 2)

Amount [a] (Inches)	Duration (Hours)				
	1	6	12	18	24
0.90	0	12	24	48	66
1.00	0	6	12	29	44
1.10	0	6	12	21	38
1.20	0	5	11	17	29
1.30	0	4	10	16	24
1.40	0	4	10	16	22
1.50	0	4	10	16	22
1.60	0	4	10	16	22
1.70	0	4	10	16	22
1.80	0	2	9	15	21
1.90	0	2	8	14	20
2.00[c]	0	0	0	0	0

Table 2.3-19

PVNGS AND PHOENIX MAXIMUM 24-HOUR

PRECIPITATION TOTALS (INCHES)

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Month	PVNGS	Phoenix
August	0.92	1.13
September	1.95	1.00
October	0.68	0.99
November	0.47	0.58
December	0.65	0.80
January	0.78	0.80
February	0.60	1.22
March	0.83	0.88
April	0.22	0.38
May	0.24	0.96
June	0.14	0.10
July	1.28	1.03
Annual	1.95	1.22

Table 2.3-20

TOTAL MONTHLY PRECIPITATION (INCHES) FOR PVNGS AND PHOENIX

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Month	PVGNS					Phoenix				
	Data Year 1973 to 1974	Data Year 1974 to 1975	Data Year 1975 to 1976	Data Year 1976 to 1977	Data Year 1977 to 1978	Data Year 1973 to 1974	Data Year 1974 to 1975	Data Year 1975 to 1976	Data Year 1976 to 1977	Data Year 1977 to 1978
August	0.33	0.21	0.02	0.60	1.27	1.15	Trace	0.03	0.25	0.57
September	0.00	2.34	0.29	1.88	0.55	0.00	1.07	0.82	1.69	0.53
October	0.00	2.50	0.26	0.25	0.99	0.00	2.12	0.23	0.70	0.61
November	0.58	0.14	0.18	0.76	1.21	1.36	0.44	0.55	0.43	Trace
December	0.01	0.61	0.26	0.72	0.17	0.00	0.59	1.12	0.85	0.54
January	0.69	0.09	0.00	0.27	1.83	0.57	0.02	Trace	0.35	2.33
February	0.00	0.24	0.44	0.04	2.23	0.02	0.33	0.47	0.06	2.21
March	0.70	0.45	0.20	0.23	1.75	1.37	0.63	0.40	0.27	2.14
April	0.00	0.58	0.15	0.01	0.30	0.01	0.43	0.67	0.06	0.20
May	0.24	0.36	0.21	0.34	0.10	0.00	Trace	1.06	0.16	Trace
June	0.00	0.36	0.00	0.00	0.01	0.00	Trace	0.09	0.10	0.01
July	0.12	0.20	0.36	0.34	2.15	0.84	0.38	1.48	0.30	1.44
Annual [(a)]	2.67	8.08	2.37	5.44	12.56	5.32	6.01	6.92	5.22	10.58

a. Climatological normal precipitation (in inches) for Phoenix is 7.05.

Table 2.3-23 presents the diurnal distribution of atmospheric stability classes for PVNGS. The stable classes (E, F, and G) occur primarily during the nighttime hours, and the unstable classes (A, B, and C) occur during the daytime hours.
Table 2.3-24 presents, for each stability class, the number of occurrences of persistence for a specific hourly persistence period. The longest persistence period for extremely stable conditions (Class G) was 18 hours. The longest persistence period for stable (inversion) conditions (Classes E, F, and G) was 40 hours.

Seasonal frequencies of stability indices for Phoenix are given in table 2.3-25 for the 5-year periods August 13, 1973 to August 13, 1978 and January 1960 to December 1964. These stability data were classified according to the Pasquill-Turner[20] method. This method is an empirical approach and involves utilization of factors such as cloud cover, insolation, time of day, and wind speed to determine stability from data that are generally available at NWS observation stations.

Appendices 2B and 2C provide annual joint frequency distributions of wind speed and wind direction by atmospheric stability class for the 35-foot and 200-foot winds, respectively. Monthly joint frequency distributions are not provided since hourly data on magnetic tape are being provided.

Table 2.3-21

MONTHLY AND ANNUAL FREQUENCY DISTRIBUTIONS OF ATMOSPHERIC STABILITY CLASSES BASED ON ΔT (200 AND 35 FEET) FOR THE PVNGS SITE (PERCENT)

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Month	Stability Category						
	A	B	C	D	E	F	G
August	11.46	6.86	6.75	24.37	21.17	17.21	12.18
September	6.40	6.49	5.83	26.58	17.81	17.27	19.64
October	4.40	5.90	5.96	20.88	13.39	14.62	34.84
November	2.48	3.39	4.15	21.06	11.23	11.68	46.02
December	1.94	4.30	4.88	18.44	11.99	13.93	44.52
January	2.35	3.16	4.50	22.23	14.75	15.36	37.65
February	3.63	5.02	7.35	20.89	13.33	15.02	34.76
March	5.70	7.09	8.29	22.26	18.34	14.62	23.68
April	9.37	9.98	9.06	18.60	16.47	15.58	20.93
May	13.43	9.50	8.92	18.26	17.60	15.57	16.72
June	12.95	9.55	9.14	18.30	14.52	17.47	18.07
July	14.62	8.21	8.66	25.25	24.03	12.62	6.60
Annual	7.39	6.64	6.97	21.39	16.21	15.11	26.29

Table 2.3-22

ANNUAL PERCENT FREQUENCY DISTRIBUTIONS OF ATMOSPHERIC STABILITY CLASSES BASED ON ΔT (200 AND 35 FEET) FOR THE PVNGS SITE

(AUGUST 13, 1973, TO AUGUST 13, 1978)

	Stability Category						
	A	B	C	D	E	F	G
August 13, 1973, to August 13, 1974 (percent)	3.90	5.17	6.53	25.31	15.29	14.64	29.18
August 13, 1974, to August 13, 1975 (percent)	2.74	6.56	3.74	16.31	31.41	14.51	24.45
August 13, 1975, to August 13, 1976 (percent)	14.27	10.42	5.55	11.94	14.35	15.35	28.12
August 13, 1976, to August 13, 1977 (percent)	8.86	7.05	8.78	21.01	16.29	13.89	24.12
August 13, 1977, to August 13, 1978 (percent)	4.20	4.96	7.59	24.14	17.65	16.18	25.27

2.3.2.2 Potential Influence of the Plant and Its Facilities on Local Meteorology

2.3.2.2.1 Cooling Tower Operation

The impacts on the local meteorology, which can result from the operation of the round mechanical draft cooling towers, include the formation of ground level fog, increased ground level temperature, increased ground level relative humidity, and elevated visible plumes. A computer analysis was performed to determine these expected atmospheric effects due to the operation of the cooling towers.[21]

The effect of an evaporative heat dissipation system on the formation of fogging conditions is determined by the quantity and location of added moisture, and on the existing ambient air conditions. The major factors of significance in determining the enhancement of fogging occurrences are the characteristics and quantity of effluent air, the height of the effluent plume rise, and the downwind dispersion of the effluent plume.

The fogging results were calculated based on a visibility criterion that a liquid water content of 1.2×10^{-5} pounds of liquid water per pound of dry air (0.015 gm H_2O/m^3 of dry air) would produce a visibility of 5/8 mile or less[22]. The predicted results show that the occurrence of reduced ground level visibility to less than 5/8 mile within 0.25 mile of the tower would occur for not more than 3 hours per year for any given direction. These predictions of insignificant fogging occurrences may be attributed to the arid climate of the site. Additionally, these predictions are consistent with the

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Table 2.3-23

DIURNAL DISTRIBUTION OF ATMOSPHERIC STABILITY CLASS

BASED ON ΔT (200 AND 35 FEET) FOR PVNGS

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Hour of Day	Stability Index									
	A	B	C	D	E	F	G	Total	FG	EFG
1	6	2	10	85	229	261	1,141	1,734	1,402	1,631
2	9	2	7	66	206	257	1,191	1,738	1,448	1,654
3	9	6	3	69	177	257	1,211	1,732	1,468	1,645
4	6	7	8	63	156	232	1,257	1,729	1,489	1,645
5	7	5	8	48	156	198	1,296	1,718	1,494	1,650
6	10	2	10	55	142	178	1,321	1,718	1,499	1,641
7	47	23	20	89	178	204	1,157	1,718	1,361	1,539
8	403	82	58	193	176	139	659	1,710	798	974
9	848	89	63	176	126	140	265	1,707	405	531
10	1,197	91	74	164	84	33	23	1,666	56	140
11	1,448	73	45	68	6	7	10	1,657	17	23
12	1,571	41	23	22	7	4	4	1,672	8	15
13	1,603	33	12	20	6	4	2	1,680	6	12
14	1,610	30	24	20	3	1	3	1,691	4	7
15	1,596	37	34	22	4	2	2	1,697	4	8
16	1,519	69	60	46	6	5	1	1,706	6	12
17	1,170	117	94	240	85	10	2	1,718	12	97
18	735	92	85	263	307	182	69	1,733	251	558
19	191	56	63	375	391	278	381	1,735	659	1,050
20	37	17	20	155	390	436	686	1,741	1,122	1,512
21	16	13	13	125	259	362	953	1,741	1,315	1,574
22	13	12	11	106	240	330	1,028	1,740	1,358	1,598
23	5	12	13	98	223	324	1,069	1,744	1,393	1,616
24	8	10	11	91	220	286	1,118	1,744	1,404	1,624
All	14,064	921	769	2,659	3,777	4,130	14,849	41,169	18,979	22,756

Table 2.3-24

ATMOSPHERIC STABILITY CLASS (BASED ON ΔT)

PERSISTENCE PERIODS FOR PVNGS (CUMULATIVE DISTRIBUTION)

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Persistence [(a)]	Stability Index								
	A	B	C	D	E	F	G	FG	EFG
2	54,272	134	121	1,581	2,960	2,404	69,057	103,857	140,937
3	42,207	31	31	843	1,538	972	56,518	87,063	120,224
4	31,939	10	12	498	814	379	45,784	72,159	101,408
5	23,340	3	6	304	436	127	36,582	58,979	84,405
6	16,335	1	3	184	237	37	28,729	47,407	69,149
7	10,832	0	1	110	129	8	22,081	37,346	55,584
8	6,731	0	0	67	73	1	16,507	28,699	43,668
9	3,829	0	0	43	43	0	11,906	21,373	33,354
10	1,930	0	0	30	25	0	8,195	15,288	24,595
11	818	0	0	21	16	0	5,295	10,382	17,360
12	283	0	0	15	10	0	3,144	6,593	11,604
13	95	0	0	10	6	0	1,657	3,850	7,276
14	37	0	0	6	3	0	725	2,024	4,276
15	15	0	0	3	1	0	231	889	2,303
16	6	0	0	1	0	0	43	304	1,136
17	3	0	0	0	0	0	6	89	549
18	1	0	0	0	0	0	1	45	340
19	0	0	0	0	0	0	0	30	279
20	0	0	0	0	0	0	0	20	246
25	0	0	0	0	0	0	0	0	136
30	0	0	0	0	0	0	0	0	66
35	0	0	0	0	0	0	0	0	21
40	0	0	0	0	0	0	0	0	1
45	0	0	0	0	0	0	0	0	0
50	0	0	0	0	0	0	0	0	0
55	0	0	0	0	0	0	0	0	0
60	0	0	0	0	0	0	0	0	0
Greater than 60	0	0	0	0	0	0	0	0	0

a. Equal to or greater than hours indicated.

Table 2.3-25

SEASONAL AND ANNUAL FREQUENCY OF STABILITY CATEGORIES FOR PHOENIX (PERCENT)

(AUGUST 13, 1973, TO AUGUST 13, 1978, AND JANUARY 1, 1960, TO JANUARY 1, 1964)

Season	Pasquill Stability Category						
	A	B	C	D	E	F	G
Spring:							
1973 to 1978	2.39	12.98	17.45	29.47	16.64	16.70	4.38
1960 to 1964	4.37	15.79	16.66	22.13	11.13	19.43	10.49
Summer:							
1973 to 1978	4.32	15.32	19.69	27.88	14.80	14.49	3.50
1960 to 1964	7.42	18.05	17.58	20.93	11.14	16.27	8.61
Fall:							
1973 to 1978	0.29	12.24	17.52	25.53	15.62	20.11	8.67
1960 to 1964	0.86	14.50	17.09	19.34	12.24	22.03	13.94
Winter:							
1973 to 1978	0.17	6.93	15.42	32.74	15.74	20.28	8.73
1960 to 1964	0.19	8.78	16.30	24.67	12.95	23.88	13.24
Annual:							
1973 to 1978	1.90	11.93	17.55	29.03	15.71	17.73	6.14
1960 to 1964	3.23	14.30	16.91	21.76	11.86	20.38	11.56

experience of APS with operating cooling towers in the Phoenix area.

Potential horizontal and vertical icing conditions were not considered for the cooling towers at the PVNGS site. A day or more of subfreezing temperatures is necessary for any ice to accumulate to significant thicknesses. Therefore, since the maximum daily temperature in the site vicinity has never been reported below 32F[(2),(17),(18),(19)], no quantitative estimates were made of potential icing conditions.

The round mechanical draft towers for PVNGS are predicted to have a negligible effect on increased ground level temperature and relative humidity. The predicted maximum increased ground level temperature and relative humidity were less than 0.2F and 1%, respectively.

The maximum occurrence of elevated visible plumes within one-half mile of the towers is approximately 530 h/yr. Generally, visible plumes will dissipate rapidly as they are emitted from the towers due to the arid climate.

The initial momentum and buoyancy of the effluent from the cooling towers are expected to raise the vapor plume to a height of approximately 920 feet during the average winter morning. Neutral buoyancy height is about 630 feet. No major difference in plume rise was predicted between winter mornings and winter evenings. For all wind directions, a saturated plume extending through the maximum height of penetration was predicted.

During the average summer morning, a plume can penetrate through a height of approximately 1900 feet. Plume buoyancy

becomes neutral at a height of 1210 feet. No saturated plume was predicted for the average summertime condition.

The visible plume length is estimated to be 870 feet during the average winter morning and 784 feet during the average winter evening.

Under typical wind speeds, the plume height from the cooling tower system can be expected to exceed 410 feet for all seasons. The lowest plume rise is predicted under strong ground based inversion conditions during summer mornings.

The effect of wind speed on plume rise is pronounced. Very strong wind (on the order of 30 to 40 miles per hour at tower height) could limit the plume rise to less than 310 feet from the tower top.

In general, the effects on local meteorology due to the operation of the evaporative cooling systems at the PVNGS site are expected to be minimal.

2.3.2.2.2 Topographic Effects

The terrain in the region of the site is generally flat with an approximate elevation of 950 feet above mean sea level (msl). The Palo Verde Hills, a range of hills with a maximum elevation of 2172 feet above msl, are located approximately 5 miles to the west and north of the site. Scattered hills are in the area (approximately 2 miles from the site) with peak elevations of 1100 feet above msl. One effect on site meteorology results from the mountains to the north and the north-to-south downward sloping terrain. At night, when stable atmospheric conditions are prevalent at the site, drainage wind flows from the north

can occur. Figure 2.3-15 is a topographic map of the site area within a 5-mile radius and figure 2.3-1 is a topographic map of the site area within a 50-mile radius. Figures 2.3-16 through 2.3-23 are the topographic cross-sections of the site area, to distances of 10 miles. A more detailed site area map with buildings, site boundary, and meteorological tower location is provided in engineering drawings 13-C-ZVA-005 and 13-P-OOB-001.

2.3.2.3 Local Meteorological Conditions for Design and Operating Bases

Design bases meteorological parameters are discussed in chapter 3.

2.3.3 ONSITE METEOROLOGICAL MEASUREMENTS PROGRAMS

2.3.3.1 Meteorological Facility Operations

The onsite meteorological measurements program at PVNGS began on August 13, 1973. The system consists of the existing 200 foot tower with two trains of sensors, designated as Primary and Redundant. Additionally, housed in a climate controlled shelter adjacent to the base of the tower, are the related signal conditioning, digital processing, power, and communication systems. The meteorological measuring sensors and support hardware are located on the northwest portion of the site (Engineering drawings 13-C-ZVA-005 and 13-P-OOB-001).

Wind and temperature data are collected at the 35 foot and 200 foot levels of the tower. Precipitation data are obtained from a rain gauge near the base of the tower. Dewpoint data are collected at the 35 foot level.

Offsite PVNGS data summaries were obtained from the NWS station at Phoenix. All measurements reported for Phoenix were made at Sky Harbor International Airport. Temperature and humidity measurements at Phoenix were made at 5 feet above ground level (AGL). Precipitation measurements were at 3 feed AGL. Wind measurements were at 41 feet AGL until December 12, 1960, then 18 feed AGL until September 19, 1975, and at 36 feet (10 meters) through the present. The wind instrumentation consists of anemometers with starting threshold speed of approximately 1.1 miles per hour, higher than the instrumentation at the PVNGS site. The instrumentation at the NWS station at Phoenix is the standard instrumentation in use at most NWS stations throughout the United States. Similar wind instrumentation was in use at Luke AFB and Gila Bend.

Real time validation of digital meteorological data will identify suspect data so that backup data will be used based on data reasonability. This validation is carried out initially by computer software designed to extract and compare data and final validation is determined by the site meteorologist. Data Acquisition of the two independent meteorological system signals (primary and redundant) may be accomplished for projected dose calculations, visual displays, and remote data can achieve a high degree of reliability.

As of December, 1995, the primary data collection method makes use of four digital data processors. These devices store 15 minute averages of preconditioned meteorological data obtained from sensors mounted on the tower. In its original configurations, the digital system, which consisted of a single computer, was backed up with analog strip chart recorders.

With the quadruple digital processors and the ability to display data in chart format, the electromechanical chart recorders have been made obsolete and are no longer included in the design. The first year of data collection was reduced from the electromechanical strip chart recorders.

The environmental parameters monitored by the tower system permit highly accurate and reliable meteorological data necessary to cover all data for the Pasquill stability classes and transport projections needed for the PVNGS site. Analog sensor information for the tower system is converted to digital data and transmitted by two separate serial links to the Meteorological Data Transmission Station (MDTS) translator/server (DataLink). It is converted here to a form recognizable to the Emergency Response Facility Data Acquisition Display System (ERFDADS) server and is reduced to 15 minute and hourly averaged meteorological parameters. This data is in turn displayed on all ERFDADS terminals and made available for time-history displays in the control room, emergency response facilities, and at external locations.

Wind and temperature data are collected at the 35 foot and 200 foot levels of the tower. Precipitation data are obtained from a rain gauge near the base of the tower. Dewpoint data are collected at the 35 foot level.

The design includes four separate reliable digital processor systems, two that process and provide data directly to the Emergency Radiological Facility Data Acquisition System (ERFDADS) and two that are accessed by telephone. Each of the four digital processing systems receives the stores conditioned

data from a common bus and this data can be extracted manually at any time, providing multiple backup in the case of a single mode failure. Accumulated data is displayed and organized by means of personal computer supplied with commonly available data display software. This data is accessed either by telephone link, by ERFDADS display, or manually by control panel at the shelter.

The specifications of the equipment for the meteorological system, which complies with the intent of the position in Regulatory Guide 1.23 (Proposed) and Safety Guide 23, are provided in the technical manuals supplied with the sensing and data processing hardware. The PVNGS meteorological system satisfies requirements set forth in Regulatory Guide 1.97, Revision 2, and NUREGs-0654, 0696, 0737, and SECY-82-111.

Using the data supplied by the equipment manufacturers, the overall system accuracy from the sensors through the signal conditioners and digital processors may be calculated. Accuracy for instantaneous recorded values is calculated using the root sum squares of the accuracy of each component. Time averaged accuracy is computed by dividing the instantaneous accuracy by the square root of the number of samples taken per hour. Sampling rates for the digital system are one per 5 seconds for wind direction, wind speed, temperature, and dewpoint. These calculations indicate that the accuracy for time averaged values exceed the recommendations in Regulatory Guide 1.23.

The primary data collection method makes use of a digital data processor subsystem. This subsystem consists of four data

loggers, all ties to a common data bus where processed analog data is supplied by the tower signal processors. Two of these data loggers are configured to be accessed remotely via dialup modem, and the remaining two are directly connected via shorthaul modem to ERFDADS. In addition to data collection, the digital processing subsystem is designed to reduce the basic data.

Table 2.3-26

OVERALL SYSTEM ACCURACY

Parameter	Full Scale Accuracy (Instantaneous)	Full Scale Accuracy (Time Averaged)
Wind Direction, degrees (Full scale 0-540 degrees)	± 3.24	±.12
Windspeed, miles per hour (35 feet) (Full scale .70-50 MPH)	±.53	±.02
Windspeed, miles per hour (nominal 195 feet) (Full scale .70-100 MPH)	±.015 or ± 1%, whichever is greater	±.04
Temperature, degrees Fahrenheit (Full scale 0-120 Degrees F.)	±.24	±.01
Temperature, difference (first Delta T range only) degrees Fahrenheit	±.24	±.01
Dewpoint, degrees Fahrenheit (Full Scale −22 -+122 degrees F.)	±1.38	±.05

Datalogger-resident software to direct data acquisition and processing events is virtually the same in all four dataloggers. All four dataloggers may also be accessed by direct connection to a laptop or similar personal computer or

by use of a manual keypad. The system is configured in such a way that any one of either the dialup or ERFDADS may be off line for maintenance and the remaining dataloggers will be available to provide quasi-real-time or averaged data on demand.

The ERFDADS dedicated dataloggers supply data to a personal computer based translator/server located in the Technical Support Center computer room. This server makes simple decisions to provide the most reliable and seemingly accurate data prior to sending it to ERFDADS. For protection, the computer is housed in a standard nineteen inch equipment cabined located in the Technical Support Center computer room.

The dose projection models used for providing the estimates of offsite exposure are described in the PVNGS Emergency Plan.

2.3.3.2 Meteorological Data Reduction

The meteorological data acquisition system consists of a computerized data processing system which collects and reduces data on a real-time basis. The average wind direction, wind speed, temperature differential, ambient temperature and dewpoint are determined for four fifteen minute samples each hour by ERFDADS. The sampling rate for each parameter for each level is once per five seconds. These data and total precipitation are available for direct access and display from the digital processing sub-system via dialup link as fifteen minute averages, as well as quasi real-time in engineering units or a graphical display.

2.3.3.3 Quality Assurance Procedures

The meteorological data collection program at PVNGS is subject to detailed APS quality assurance and quality control procedures.

The procedures involve daily examinations by a meteorologist of the digitally reduced data, redundant data storage to mitigate data losses, detailed records keeping (data corrections, calculations, etc.), site specific work plans, and internal audits.

Calibrations of the meteorological system are subject to the APS quality assurance program.

2.3.3.4 Meteorological Data Recovery

The meteorological data recovery rates for the PVNGS meteorological program (August 13, 1973 to August 13, 1978) are listed in table 2.3-27.

The data recovery for wind data at the 10 meter level and 60 meter level was 97% and 94%, respectively, for the report period.

Data recovery of the Dewpoint temperature was 94%. The data recovery for Delta temperatures was 94%. Since the initial fuel load in Unit one, data recovery rates have exceeded 90%. In contrast, since the replacement of the digital data processing subsystem in December, 1995, the data recovery rate for all parameters has been 100%.

Most of the data losses on the system are due to sensor malfunctions and calibrations. Other than sensor problems,

periods of data loss on the digital system were due primarily to data transmission and computer malfunctions. Losses due to recorder malfunctions were rare with the analog system, but became significant as the system aged. The analog strip chart recorders are no longer part of the design, having been replaced with a redundant digital system.

Calibration and maintenance of the PVNGS meteorological system are conducted at scheduled intervals according to written procedures. Maintenance trips are made as required. Equipment surveillance and routine maintenance are being performed according to established checklist and procedures by PVNGS technical personnel in order to maintain maximum data recovery.

2.3.4 SHORT-TERM (ACCIDENT) DIFFUSION ESTIMATES

2.3.4.1 Objective

Onsite data for the period 1986 through 1991 have been used to evaluate the accident meteorology for the site. Accidents are postulated to characterize upper limit concentrations and dosages that might occur in the event of plant releases. Among the basic inputs to the accident analysis are the meteorological conditions, which determine the atmospheric transport and dispersion of radioactive plumes.

2.3.4.2 Calculations

Dilution factors (χ/Q) were determined using the methodology presented in Regulatory Guide 1.145[23] using dispersion coefficients for desert regime[24] and computer code AZAP[28].

Table 2.3-27

METEOROLOGICAL DATA RECOVERY AT PVNGS (PERCENT)

(AUGUST 13, 1973, TO AUGUST 13, 1978)

Month	200-Foot Wind Data	35-Foot Wind Data	ΔT 200-35 Data	Joint Recovery 35-Foot Wind and ΔT 200-25 Data	35-Foot Dew Point	35-Foot Temperature
August	79	93	93	92	93	93
September	92	94	93	92	91	93
October	98	98	90	90	95	95
November	96	96	94	92	93	94
December	98	97	90	89	93	90
January	93	98	97	96	97	97
February	97	99	98	98	98	98
March	97	99	99	98	96	97
April	97	97	97	97	94	96
May	94	99	98	98	95	96
June	93	95	96	94	92	92
July	95	96	84	83	95	92
Annual	94	97	94	93	94	94

χ/Q values were calculated at the exclusion area boundary (EAB) and at the outer boundary of the low population zone (LPZ). Table 2.3-30 presents the minimum distances to the EAB and LPZ for each sector (conservatively measured as the shortest distance between the outer edge of the reactor containment building and the boundary within a 45° direction sector centered on the direction of interest[23]. The χ/Q values applicable for release duration less than or equal to 2 hours were calculated at the EAB distances using the joint frequency distributions of wind speed and wind direction by atmospheric stability class. Winds were determined at the 35-foot level and the stability class was based on the vertical temperature gradient between the 35- and 200-foot levels, Delta-T (200 – 35 feet), based on the position in Regulatory Guide 1.23.

The short term χ/Q is defined as the site boundary χ/Q that will not be exceeded more than 5% of the time. The following equations are utilized to develop the probability distribution for each sector:

$$\frac{\overline{\chi}}{Q}(x, i, j) = \left\{u_i\left[\pi\sigma_{yj}(x)\sigma_{zj}(x) + CA\right]\right\}^{-1} \tag{1}$$

and

$$\frac{\overline{\chi}}{Q}(x, i, j) = \left\{3u_i\pi\sigma_{yj}(x)\sigma_{zj}(x)\right\}^{-1} \tag{2}$$

Table 2.3-30

MINIMUM DISTANCES TO THE EXCLUSION AREA BOUNDARY AND THE OUTER BOUNDARY OF THE LOW POPULATION ZONE[a]

Exposure Direction	Distance to EAB (Meters)	Distance to LPZ (Meters)
N	1,037	6,029
NNE	1,037	6,013
NE	1,426	6,013
ENE	1,927	6,014
E	1,927	6.051
ESE	1,927	6,136
SE	2,023	6,103
SSE	2,171	6,032
S	2,345	6,013
SSW	1,266	6,013
SW	953	6,013
WSW	871	6,044
W	871	6,125
WNW	871	6,242
NW	943	6,201
NNW	1,037	6,094

a. Distances used for X/Q calculation are minimum distances from the surface of the three containment buildings within 45° sectors centered on each compass direction.

where:

$\chi/Q\ (x,i,j)$ = average effluent concentration normalized by source strength at distance x for i-th wind-speed category and j-th stability category (second/cubic meter).

X = shortest distance to the site boundary in a 45° sector (meters)

u_1 = the upper limit of the i-th wind-speed class (meters/second)

σ_{yj} = the lateral plume spread for stability class j at distance x (meters).

σ_{zj} = the Vertical plume spread for stability class j at distance x (meters).

A = minimum cross-sectional area of the building used to describe dilution due to the building wake (square meters).

C = mixing volume coefficient (shape factor) in the building-wake term.

The larger of the two values is selected for each combination of wind speed and stability class. Regulatory Guide 1.145 has a third equation incorporating a meander factor to account for the movement of the plume within the sector. Because desert χ/Q's are based on long term measurements, meander is already accounted for and, therefore, only the two equations above are used.

The χ/Q at the EAB, which is used to determine accident consequences during the first two hours of an accident, is the five percentile χ/Q, i.e., the χ/Q that will not be exceeded more than 5% of the time. To determine the 5% χ/Q, each direction sector is investigated separately. The χ/Q for each combination of stability and wind speed class is calculated, and arranged in descending order. A cumulative probability distribution for each sector is created by summing the frequencies of ordered χ/Q. The 5% χ/Q is identified by drawing a curve through the probability distribution. In addition, as discussed in Regulatory Guide 1.145, an overall 5th percentile χ/Q value was calculated at the EAB. The computation consists of determining the χ/Q values for each of the sectors and distance of interest and ordering these values without regard to the sector. The 5th percentile value (based on total observations) was then selected and was shown not to exceed the highest sector χ/Q value. The two hour χ/Q is the largest sector 5% χ/Q.

The χ/Q for time periods longer than two hours are based on values at the outer boundary of the LPZ. First, the two-hour value for each sector is determined as described above. Then the annual average χ/Q is determined for the sector using the methodology in Reg Guide 1.111. The χ/Q for any time is then determined by logarithmic interpolation between the two hour and one year (8760 hour) χ/Q. The sector with the largest value is selected to represent the site.

The calculation of χ/Q involves the determination of horizontal and vertical dispersion parameters (σ_y and σ_z). PVNGS is

committed to using the desert sigmas that characterizes arid regimes as developed in Reference 24 and 25.

Table 2.3-31 presents χ/Q values at the EAB and LPZ distances for the periods of interest for the period 1986 through 1991.

2.3.5 LONG-TERM DIFFUSION ESTIMATES

2.3.5.1 Objective

Onsite emteorological data for the period 1986 to 1991 were used to determine the long-term diffusion estimates for the area. The atmospheric dilution factors (χ/Q) were determined for the site boundary and for distances out to 50 miles from the containment structures. A set of distances by sector direction from the containment was developed for the analysis by determining the shortest distance to the site boundary from the closest edge of the containment in each sector. These distances are presented in table 2.3-32.

2.3.5.2 Calculations

Long term atmospheric dispersion factors or annual dispersion factors are used in determation of offsite dose design calculation due to long-term annual releases of radionuclides in gaseous effluents. PVNGS's annual average χ/Q values are determined following guidance given in SRP 2.3.5 to NUREG-75/087 and Regulatory Guide 1.111. Regulatory Guide 1.111 indicates that the χ/Q values must be related to measured meteorological parameters and extend from the site boundary to a radius of 50 miles from the plant for the 16 radial direction sectors. Site topography or unusual meteorological conditions

Table 2.3-31

SHORT-TERM (ACCIDENT) DILUTION FACTORS AT THE EXCLUSION AREA BOUNDARY AND THE OUTER BOUNDARY OF THE LOW POPULATION ZONE

(1986 - 1991)

Location	Time Period	χ/Q
	hours	Sec/M^3
EAB	0 to 2	2.3E-4
LPZ	0 to 8 hours	6.4E-5
LPZ	8 to 24 hours	4.8E-5
LPZ	1 to 4 days	2.6E-5
LPZ	4 to 30 days	1.1E-5

Table 2.3-32

LONG-TERM DIFFUSION ESTIMATES AT THE PVNGS

SITE BOUNDARY

(1986 - 1991)

Exposure Direction	Distance (m)[a]	χ/Q (s/m^3)
N	1,037	2.1(-6)
NNE	1,057	3.3(-6)
NE	2,206	2.2(-6)
ENE	1,967	2.2(-6)
E	1,927	2.7(-6)
ESE	1,967	3.4(-6)
SE	2,049	5.3(-6)
SSE	2,729	5.8(-6)
S	2,345[b]	8.1(-6)
SSW	1,607	9.6(-6)
SW	1,057	6.7(-6)
WSW	889	3.7(-6)
W	871	2.4(-6)
WNW	885	1.7(-6)
NW	1,045	1.8(-6)
NNW	1,059	1.7(-6)

a. Based on 22-1/2° sectors.

b. Distance is based on Exclusion Area Boundary (EAB).

which could influence the effluent trajectories are to be accounted for. Site topography influences are addressed in the analysis via the use of terrain correction factors (Reference 27). Terrain correction factors are presented in Table 2.3-33 Influences on long-term meteorology around the PVNGS site due to the desert regime are addressed with the use of desert sigmas for lateral and vertical dispersion coefficients in the equations used to calculate χ/Q.

Site Boundary Distances for Long Term χ/Q Determination

The site boundary distances used in long-term χ/Q determination within each of the 16 direction sectors are the minimum distances between the nearest point on the outer surface of the containment building under consideration and the closest point on the site boundary within a 22.5° sector, centered on the compass direction of interest. Direction sectors are defined using the center point of the containment under consideration as the origin. Overall minimum site boundary sector dependent distances are the smallest of the minimum sector distances determined for the 3 PVNGS units.

Equation Used for Long Term χ/Q Determination

The Regulatory Guide 1.111 equations are used to determine long-term χ/Q values (the constant mean wind direction model). χ/Q values are determined for a continuous ground level release assumed to be distributed over a 22.5°sector. Following equations are used:

$$\frac{\overline{\chi}}{Q}(x, k) = \frac{2.032}{x} RF(x, k) \sum_{i,j}^{N,7} \frac{DEPL_{ij}(x, k) \times DEC_i(x) \times f_{ij}(k)}{\overline{U}_i \sqrt{\left(\sigma_{zj}^2(x) + cD_z^2 / \pi\right)}} \qquad (3)$$

$$\frac{\overline{\chi}}{Q}(x, k) = \frac{2.032}{x} RF(x, k) \sum_{i,j}^{N,7} \frac{DEPL_{ij}(x, k) \times DEC_i(x) \times f_{ij}(k)}{\sqrt{3}\,\overline{U}_i \sigma_{zj}(x)} \qquad (4)$$

where:

χ/Q (x, k) = average effluent concentration (sec/m3) normalized by source strength at distance x in wind directional sector k.

x = downwind distance (meters)

i = The i(th) wind speed class

j = The j(th) atmospheric stability class, grouped into seven classes according to Regulatory Guide 1.23

k = k(th) wind direction sector

U_i = mid point value of the i(th) wind-speed class (meter/second)

σ_{zj} = the vertical plume spread for stability class j at distance x (meter)

$DEPL_{ij}$ (x, K) = plume depletion reduction factor at distance x for the i(th) wind speed class, the j(th) stability class, and k(th) wind direction sector.

DEC_i(x) = radiodecay reduction factor at distance x for the i(th) wind speed class. Radiodecay is based on a half-life of 2.26 days per Regulatory Guide 1.111.

RF (x, k) = Terrain Adjustment Factor at downwind distance x and k(th) wind direction sector.

F_{ij} (k) = joint probability of occurrence of the i(th) wind speed class, j(th) stability class, and K(th) wind direction sector.

c = mixing volume coefficient (shape factor) in the building-wake term

D_z = building height (meters) used to compute additional atmospheric dispersion due to the building wake. For the PVNGS analysis

Dz = 58 meters (the containment building height).

Equation (4) represents the maximum additional atmospheric dispersion due to the building wake. The results of both equations are compared and the largest (most conservative) value is used. In this analysis credit is not taken for depletion, gravitational settling or dry deposition.

Table 2.3-33

PVNGS TERRAIN ADJUSTMENT FACTORS

Distance (meters)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
402	1.0	1.1	1.1	1.1	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0
805	1.0	1.1	1.2	1.1	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.3	1.2
1,207	1.2	1.2	1.3	1.2	1.3	1.4	1.2	1.2	1.1	1.2	1.2	1.3	1.2	1.2	1.4	1.4
1,609	1.4	1.4	1.4	1.3	1.4	1.5	1.4	1.3	1.1	1.2	1.4	1.7	1.6	1.4	1.5	1.7
2,414	1.6	1.6	1.5	1.3	1.4	1.4	1.4	1.3	1.1	1.2	1.6	1.7	1.6	1.5	1.7	1.7
3,219	1.8	1.6	1.5	1.4	1.4	1.4	1.4	1.3	1.2	1.3	1.7	1.7	1.8	1.6	1.8	1.9
4,023	1.8	1.6	1.5	1.3	1.4	1.4	1.3	1.3	1.3	1.3	1.6	1.9	1.8	1.5	1.9	2.0
4,828	1.7	1.6	1.5	1.2	1.3	1.3	1.2	1.3	1.4	1.5	1.6	1.9	1.5	1.6	2.0	2.1
5,633	1.8	1.6	1.5	1.2	1.2	1.2	1.2	1.3	1.5	1.5	1.8	1.9	1.5	1.6	2.0	2.2
6,437	1.8	1.5	1.5	1.1	1.0	1.2	1.2	1.3	1.5	1.5	1.8	2.0	1.5	1.6	2.0	2.1
7,242	1.6	1.5	1.4	1.0	1.0	1.0	1.1	1.3	1.6	1.6	1.7	2.0	1.5	1.6	1.9	2.0
8,047	1.6	1.4	1.4	1.0	1.0	1.0	1.0	1.2	1.5	1.6	1.7	1.8	1.5	1.5	2.0	2.0
12,070	1.3	1.2	1.2	1.0	1.0	1.0	1.0	1.1	1.3	1.3	1.4	1.4	1.3	1.3	1.5	1.5
16,093	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
24,140	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
32,187	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
40,234	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
48,280	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
56,327	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
64,374	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
72,421	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
80,467	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Source: Taken from Appendix I, Analysis, reference 27.

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2.4 HYDROLOGIC ENGINEERING

This section contains initial licensing information and is not expected to be routinely updated. Significant changes that could potentially affect the content of this section should be evaluated for inclusion as discussed in NEI 98-03, Guidelines for updating Final Safety Analysis Report, Section A3.

2.4.1 HYDROLOGIC DESCRIPTION

2.4.1.1 Site and Facilities

The site is located west of Phoenix in a dry, desert region adjacent to the Palo Verde Hills. The terrain has very little topographic relief and slopes gently southward. Hydrologic features of significance to the site are indicated in figure 2.4-1. Proposed changes to natural drainage features and site facilities of hydrologic significance are indicated in figure 2.4-2.

Permanent access to the site is from the existing Buckeye-Salome Road which passes within 2 miles of the northern site boundary. Access among the units is by means of onsite roads and railroad spurs. Access into Seismic Category I structures is located above grade so that safety-related facilities are protected from any possibility of flooding.

Major structures and site facilities are protected from off-site floods by their locations, as shown in figure 2.4-2. A minor existing drainage course (East Wash) has been realigned to a new drainage ditch along the east side of the site. Flood calculations performed in this study for the East Wash are based upon the realigned channel.

2.4.1.2 Hydrosphere

The site is on a desert valley plain near a ridge separating the drainage basins of the Hassayampa River and Centennial Wash. Both are ephemeral desert streams which flow only with rainfall runoff. These streams are tributaries of the Gila River, which drains most of the southern half of Arizona. Other local water courses include Winters Wash and a wash draining a narrow strip extending a few miles north of the plant site, which is named East Wash for convenience. These water courses are also ephemeral. Figure 2.4-1 shows the locations of rivers and washes relative to the site.

There are no dams on East Wash, Winters Wash, or the Hassayampa River. There are several small detention dams on Centennial Wash, the largest being a low earthfill dam about 45 miles upstream from the site, which has a capacity of about 100 acre-feet. There are several large water-storage dams on the Gila River system upstream from the site. The locations of these dams are shown in figure 2.4-3. Data on these dams are presented in table 2.4-1 and paragraph 2.4.4.1.

Other dams on the Gila River system are the following:[(1),(2),(3)]

A. Sonoita Creek Dam on Sonoita Creek, a tributary of the Santa Cruz River, stores less than 10,000 acre-feet of water and is more than 200 miles upstream from the plant site.

B. Granite Reef Dam on the Salt River at the eastern end of the Salt River Valley is approximately 63 miles from the site and is a diversion dam with no storage capacity.

C. Ashurst-Hayden Dam on the Gila River, at the eastern end of the Gila River Valley, is a diversion dam with no storage capacity.

D. Sacaton Dam on the Gila River, near the town of Sacaton on the Gila River Indian Reservation, is a diversion dam no longer useful because the river has been mostly dry for many years

E. Gillespie Dam on the Gila River is about 4.5 miles downstream from the point on the river nearest the site, and is a diversion dam now filled with stream sediment.

F. Painted Rock Dam is a flood control dam on the Gila River about 40 miles downstream from Gillespie Dam. When the Painted Rock Reservoir is full, the tail water would not reach the foot of the Gillespie Dam.

   The Painted Rock Dam is earth filled to a height of 181 feet and crest length of 4780 feet, forming a reservoir with a capacity of 2,493,000 acre-feet, including 200,000 acre-feet for sedimentation.

Surface water diversion downstream from the site occurs at Gillespie Dam, where water from irrigation is diverted into the Enterprise Canal and Gila Bend Canal. Because of the poor quality of water in the canals, there is little direct diversion of canal water for irrigation.

A review of the files of the Arizona State Land Department, Water Rights Division, indicates that there are four diverters of surface water from the Gila River located south of the confluence with Centennial Wash.

This page has been redacted.

These rights are located on the Gila River between Gillespie Dam (sec. 28, T.2 S, R.5 W.) and Painted Rock Dam (sec. 18 and 19, T.4 S, R.7 W.).

Application No. A-1920, Permit 1227, Certificate 1824, was issued to A. E. Pettit for 5 million gallons per year for stock watering and for 2400 acre-feet per year for irrigation (on the basis of 3.75 acre-feet per year for 640 acres). The place of use is E1/2 sec. 23, NE1/4 and E1/2NW1/4 sec. 26, and W1/2NW1/4 sec. 25, all in T.4 S., R.8 W. The priority date is June 17, 1938.

Application No. A-2608, Permit 1866, was issued to S. L. and Alice Narramore and W. 0. and Eliza Narramore for 3729 acre-feet/per year for irrigation (on the basis of 6 acre-feet per year for 620 acres). The place of use is N1/2NW NE and NW and S1/2NW sec. 3; W1/2NW sec. 4; N1/2 sec. 5; and S1/2NE sec. 12, all in T.5 S., R.6 W. The priority date is March 16, 1943.

Application No. A-4940 was made by Floyd R., Roy D., and Russell L. Pierpont for 618,950 gallons per year for domestic use; for 2,519,500 gallons per year for stock watering; and for 18,700 acre-feet per year for irrigation (on the basis of 10 acre-feet per year for 1870 acres). Place of use is in numerous locations in T.4 S., R.4 W., and T.5 S., R.4 W. This application is presently under protest by S. L. Narramore and others.

Application No. A-5008, Permit 3288, was issued to Minnesota Title Co., as trustee for Litchfield Park Development Co., for 6300 acre-feet per year for irrigation (on the basis of 5 acre-feet per year for 1260 acres). The place of use is in various

locations in secs. 1, 2, 11, 12, and 18, T.3 S., R.5 W. The priority date of this permit is December 18, 1972.

The list includes those surface water users who have applied for permits since June 12, 1919. Prior to this date, no permit was required for withdrawal of surface water from rivers in Arizona. On August 9, 1974, the State of Arizona passed legislation requiring all diverters of surface water in Arizona to apply for a permit within 3 years of passage of the law. There are no other recorded users of surface water from the Gila River, from the confluence of Centennial Wash south to Painted Rock Dam.

Although these water users have been listed, PVNGS will not affect any of them adversely. There will be no routine liquid releases to contaminate the surface water and the analysis discussed in paragraph 2.4.13.3 shows that there will be no contamination of the groundwater offsite due to an accidental release (refer to paragraph 2.4.13.2 for information on groundwater users in the vicinity of the site).

2.4.2 FLOODS

2.4.2.1 Flood History

The U.S. Geological Survey (USGS) operates a water-stage recorder on Centennial Wash that gauges the runoff from 1810 square miles, and a flood hydrographic recorder on Winters Wash that gauges the runoff from 47.8 square miles. The Centennial Wash gauge is located at latitude 33°16'12", longitude 112°47'50", in sec. 7, T.2 S., R.5 W., Maricopa County, on the upstream side of the ford on former U.S. Highway 80, 3 miles upstream from Gillespie Dam and 4.4 miles

southwest of Arlington. The gauge datum is 773.22 feet above msl (Arizona Highway Department bench mark), obtained by use of a water-stage recorder. The base discharge is 1000 cubic feet per second, with the flow regulated by several small detention dams.

The Winters Wash gauge is located at latitude 33°29'22", longitude 112°55'05", in SW1/4NW1/4 sec. 3.0, T.2 N., R.6 W, Maricopa County, on the right bank 0.3 mile downstream from Airline Road and 1 mile east of Tonopah. The altitude of the gauge, a flood-hydrograph recorder, is 1080 feet. The base discharge is 100 cubic feet per second, with neither storage nor diversion above the station.

For the period of record (water years 1961 to 1977), maximum recorded discharge in Centennial Wash was 14,500 cubic feet per second on July 23, 1961. Maximum recorded discharge in Winters Wash for the period of record (water years 1962 to 1977) was 3640 cubic feet per second on September 25, 1976. Tables 2.4-2 and 2.4-3 give the peak discharges recorded for Centennial Wash and Winters Wash, respectively.(1),(2)

Maximum recorded discharge of the Hassayampa River, as recorded by a crest-stage recorder located near Morristown, Arizona (which gauges the runoff from 774 square miles), was 47,500 cubic feet per second on September 5, 1970. The period of record for the gauge near Morristown includes the water years 1939 to 1947, 1954, 1956, and 1964 to 1977. Table 2.4-4 gives the peak discharges recorded for the Hassayampa River at Morristown.(1),(2)

The crest-stage recorder for the Hassayampa River is located at latitude 33°53'06", longitude 112°39'41", in SW1/4SE1/4 sec. 3, T. 6N, R. 4W.; Maricopa County, on left bank 600 feet downstream from San Domingo Wash, 3 miles northwest of Morristown, and 7 miles southeast of Wickenburg. The datum of the gauge is 1831.16 feet above msl. From October 1938 to June 1947, data is from the water-stage recorder; from June 1947 to November 1963, there is miscellaneous data only. The base discharge is 1100 cubic feet per second. There are annual peaks for 1947 and 1964 through 1965 only.

Maximum observed discharge of the Gila River, at the USGS gauging station below Gillespie Dam (which gauges the runoff from 49,650 square miles), was 85,000 cubic feet per second on December 28, 1923. The period of record for the Gillespie Dam gauge includes the water years 1921 to 1977. (A maximum discharge of 250,000 cubic feet per second was estimated to have occurred in February 1891 at the Gillespie damsite.) A provisional value of 12,000 cubic feet per second has been established for the maximum discharge observed on December 20, 1978.(4) Table 2.4-5 shows the peak discharges recorded for the Gila River below Gillespie Dam.(1),(2) The gauge, a water-stage recorder since July 28, 1924, is located at latitude 33°13'45", longitude 112°46'00", in SE1/2NE1/4 sec. 28, T.2 S., R.5 W., Maricopa County, Hydrologic Unit 15070101, at the left end of the Gillespie Dam, 8 miles (13 km) downstream from the Hassayampa River. The datum of the gauge is 9.95 feet below the average elevation of the crest of the dam, which is 753.46 feet above msl. Prior to November 11, 1924, the depth of water was read on the crest at the left end of the

Table 2.4-2

CENTENNIAL WASH NEAR ARLINGTON, ARIZONA[(1),(2)]

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1961[(a)]	July 23, 1961	4.70	14,500
	July 29, 1961	3.71	3,870
1962	Sept. 6, 1962	3.09	1,110
1963	-	-	No flow
1964	July 31, 1964	3.74	2,890
1965	Feb. 7, 1965	3.27	1,040
1966	Sept. 13, 1966	4.13	5,500
1967	Sept. 5, 1967	3.27	1,040
1968	Dec. 19, 1967	4.11	5,330
1969	Aug. 29, 1969	3.25	990
1970	Sept. 5, 1970	4.71	11,900
1971	Aug. 20, 1971	3.91	2,040
1972	-	-	No flow
1973	Oct. 7, 1972	4.52	9,340
1974	Aug. 4, 1974	2.93	105
1975	Oct. 28, 1974	3.55	755
1976	Sept. 26, 1976	4.38	7,800
1977	-	-	No flow

a. Partial water year - started January 1961.

Table 2.4-3

WINTERS WASH NEAR TONOPAH, ARIZONA[(1),(2)]
(Sheet 1 of 2)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1962	Sept. 5, 1962	6.16[(a)]	776[(b)]
1963	Sept. 3, 1963	-	100[(b)]
1964	Aug. 1, 1964	5.67	680
	Aug. 1964	6.00	850
	Aug. 1964	5.89	790
	Aug. 1964	4.56	250
1965	Feb. 7, 1965	5.91	800
	Aug. 14, 1965	5.20	470
1966	Dec. 10, 1965	4.96	390
1966	Sept. 13, 1966	4.91	380
1967	Sept. 3, 1967	6.11	900
1968	Dec. 19, 1967	6.86	1,350
1969	Nov. 15, 1968	6.2	960
	Aug. 29, 1969	5.68	700
	Sept. 13, 1969	4.37	180
1970	Mar. 2, 1970	4.28	150
	Sept. 5, 1970	5.15	480

a. From floodmarks.
b. Annual peak prior to installation of gauge.
c. Estimated.

Table 2.4-3

WINTERS WASH NEAR TONOPAH, ARIZONA[1],[2]
(Sheet 2 of 2)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1971	Aug. 20, 1971	5.10	1,000
1972	Aug. 12, 1972	4.70	795
1973	Oct. 6, 1972	5.80	2,100
1974	Mar. 20, 1974	4.0	900
1975	Oct. 28, 1974	4.2	560
1976	Sept. 25, 1976	10.1	3,640
1977	Aug. 16, 1977	-	60[c]

dam. From November 11, 1924, to July 22, 1932, the datum of gauge was at the average elevation of the dam crest. From July 23, 1932 to April 27, 1955, the datum of the gauge was 5 feet below the average elevation of the crest of the dam. Since April 2, 1974, the supplementary water-stage recorder and concrete control 70 feet downstream from the crest of the dam at datum 5.64 feet lower than datum of base gauge. The base discharge was 2000 cubic feet per second from 1925 to 1938; 1000 cubic feet per second from 1939 to the current year. The flood record shown is that for uncontrolled areas below the major dams. The records include flow over the crest and through the sluice gates of the Gillespie Dam, but do not include flow in the Gila Bend and Enterprise Canals, which divert from the river immediately above the dam. There are other large diversions above the station for irrigation, municipal, and industrial use. The flow of the Gila River and its tributaries above this station is regulated by the San Carlos Reservoir on the Gila River (capacity 1,206,000 acre-feet); by a series of reservoirs on Salt River (capacity 1,755,000 acre-feet); by the Bartlett and Horseshoe Reservoirs on Verde River (capacity 317,700 acre-feet); and by Lake Pleasant on Agua Fria River (capacity 157,600 acre-feet).

Table 2.4-5 shows only the annual peaks prior to 1925. Prior to 1939, published as "at Gillespie Dam."

Table 2.4-4

HASSAYAMPA RIVER NEAR
MORRISTOWN, ARIZONA(1),(2) (Sheet 1 of 3)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1939	Dec. 20, 1938	7.30	2,700
	Sept. 4, 1939	6.6	1,240
	Sept. 6, 1939	8.7	6,200
	Sept. 12, 1939	6.55	1,600
1940	Feb. 1, 1940	5.9	160
1941	Oct. 5, 1940	7.18	2,460
	Dec. 24, 1940	7.30	3,350
	Feb. 25, 1941	6.96	2,600
	Mar. 2, 1941	8.36	6,100
	Mar. 5, 1941	6.66	2,040
	Mar. 14, 1941	7.90	4,060
	Apr. 11, 1941	7.57	3,020
	Apr. 15, 1941	7.05	1,320
	July 24, 1941	7.50	2,110
	Aug. 9, 1941	7.73	3,460
	Aug. 29, 1941	7.27	2,050
1942	Aug. 5, 1942	5.7	100

a. From high water marks in well.

b. From floodmarks.

Table 2.4-4

HASSAYAMPA RIVER NEAR
MORRISTOWN, ARIZONA[(1),(2)] (Sheet 2 of 3)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1943	Aug. 3, 1943	9.9	7,700
	Aug. 14, 1943	8.52	3,800
	Sept. 26, 1943	6.80	1,200
1944	Oct. 18, 1943	7.68	2,420
	Feb. 24, 1944	7.22	1,510
	Aug. 9, 1944	8.10	3,520
1945	Aug. 2, 1945	7.55	2,200
	Aug. 10, 1945	6.98	1,110
1946	July 22, 1946	7.38	1,510
	Aug. 11, 1946	7.50	2,090
	Sept. 17, 1946	7.60	2,310
Only miscellaneous record June 1947 to Nov. 1963			
1947	Aug. 8, 1947	8.95[(a)]	6,000
1954	-	10.50[(a)]	-
1956	-	10.15[(a)]	-
1964	July 1964	10.1[(b)]	4,000
1965	Sept. 2, 1965	11.6[(b)]	9,280
1966	Dec. 10, 1965	9.77	2,700
	Dec. 30, 1965	9.41	2,000
	Sept. 13, 1966	10.03	3,210

Table 2.4-4

HASSAYAMPA RIVER NEAR
MORRISTOWN, ARIZONA[(1),(2)] (Sheet 3 of 3)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1967	Sept. 1967	8.75	1,150
1968	Dec. 19, 1967	10.61	4,800
1969	Sept. 13, 1969	8.15	650
1970	Mar. 2, 1970	9.05	1,500
	Sept. 5, 1970	19.05	47,500
1971	Aug. 18, 1971	9.07	2,000
1972	Aug. 27, 1972	6.67	700
1973	Oct. 7, 1972	7.81	2,000
1974	July 20, 1974	7.30	650
1975	July 29, 1975	7.27	50
1976	Feb. 9, 1976	8.34	800
1977	Aug. 15, 1977	8.08	1,600

Table 2.4-5
GILA RIVER BELOW
GILLESPIE DAM, ARIZONA[(2)] (Sheet 1 of 5)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1891	Feb. 1891	-	250,000
No record 1891	to 1921		
1921	Aug. 22, 1921	3.25	26,800
1922	Jan. 4, 1922	3.67	32,700
1923	Sept. 20, 1923	2.00	13,100
1924	Dec. 28, 1923	6.00	85,000
Datum change			
1925	Sept. 2, 1925	0.68	2,500
	Sept. 6, 1925	1.73	9,570
	Sept. 20, 1925	2.23	15,200
1926	Oct. 6, 1925	1.28	6,160
	Dec. 4, 1925	0.72	2,700
	Mar. 31, 1926	0.88	4,060
	Apr. 8, 1926	3.15	26,700
	Apr. 21, 1926	1.02	4,760
	July 27, 1926	0.87	3,520
	Sept. 9, 1926	1.05	4,620
	Sept. 30, 1926	3.95	38,300
1927	Dec. 8, 1926	1.84	10,600
	Dec. 15, 1926	0.68	2,500
	Feb. 18, 1927	5.45	67,300
	Mar. 12, 1927	1.04	4,560
	Mar. 17, 1927	0.81	3,160
	Sept. 13, 1927	3.71	34,900

a. Gauge height affected by drawdown due to open sluice gates.
b. Approximate discharge with sluice gates open.

Table 2.4-5

GILA RIVER BELOW
GILLESPIE DAM, ARIZONA(2) (Sheet 2 of 5)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1928	Feb. 6, 1928	1.70	9,220
	Aug. 3, 1928	1.26	5,600
	Aug. 29, 1928	0.70	2,350
1929	Apr. 6, 1929	2.74	20,700
	Aug. 19, 1929	0.60	2,050
	Sept. 5, 1929	0.88	3,680
	Sept. 26, 1929	1.15	5,210
1930	Mar. 19, 1930	0.82	3,160
	Aug. 10, 1930	2.19	13,900
1931	Feb. 16, 1931	2.50	17,500
	Aug. 6, 1931	1.20	5,470
	Aug. 12, 1931	1.45	7,530
	Aug. 31, 1931	1.41	6,930
1932	Oct. 3, 1931	0.73	2,360
	Dec. 11, 1931	1.00	3,690
	Feb. 11, 1932	4.47	44,500
	Feb. 20, 1932	1.78	9,670
	Mar. 3, 1932	1.65	8,260
	Mar. 12, 1932	0.67	2,090
	Mar. 22, 1932	0.92	3,270
Datum change			
1933	Oct. 9, 1932	5.70	2,180
1934	Aug. 30, 1934	5.88	3,100
1935	Feb. 10, 1935	6.60	7,470
	Feb. 17, 1935	5.73	2,240
	Mar. 17, 1935	6.06	3,890
	Aug. 25, 1935	5.84	2,380
	Sept. 1, 1935	5.71	2,140

Table 2.4-5

GILA RIVER BELOW
GILLESPIE DAM, ARIZONA[2] (Sheet 3 of 5)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1936	July 29, 1936	5.90	3,240
1937	Feb. 9, 1937	8.43	45,800
	Feb. 17, 1937	7.67	18,400
	Mar. 16, 1937	6.00	4,520
	Mar. 19, 1937	7.77	21,300
1938	Mar. 5, 1938	9.95	60,000
1939	Aug. 10, 1939	5.70	2,200
	Sept. 5, 1939	2.43	2,500
	Sept. 13, 1939	5.97	3,240
1940	Aug. 19, 1940	5.87	2,620
1941	Jan. 4, 1941	6.16	5,850
	Feb. 10, 1941	5.68	1,910
	Feb. 16, 1941	5.44	1,040
	Feb. 19, 1941	5.65	1,800
	Feb. 24, 1941	6.57	7,180
	Feb. 28, 1941	6.70	7,250
	Mar. 5, 1941	7.07	10,800
	Mar. 16, 1941	9.45	45,800
	Apr. 5, 1941	5.95	3,060
	Apr. 18, 1941	8.08	25,300
	May 5, 1941	7.05	10,600
	Aug. 12, 1941	5.43	1,010
1942	Dec. 13, 1941	5.30	580
1943	Aug. 5, 1943	5.75	2,200
1944	Feb. 25, 1944	5.29	580
1945	Aug. 14, 1945	5.53	1,350
1946	Sept. 19, 1946	5.85	4,290
	Sept. 24, 1946	5.92	2,880

Table 2.4-5

GILA RIVER BELOW
GILLESPIE DAM, ARIZONA(2) (Sheet 4 of 5)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
1947	Aug. 9, 1947	5.63	4,390
1948	Aug. 9, 1948	5.23	330
1949	Aug. 7, 1949	5.42	976
1950	Oct. 19, 1949	5.56	1,460
1951	July 28, 1951	-	2,340
	Aug. 4, 1951	5.96	2,880
	Aug. 28, 1951	7.55	16.600
1952	Jan. 22, 1952	5.23	430
1953	Nov. 20, 1952	5.10	115
1954	Aug. 12, 1954	5.64	1,760
Datum change			
1955	July 25, 1955	10.56	1,870
	Aug. 8, 1955	10.78	2,240
	Aug. 14, 1955	11.05	3,420
	Aug. 28, 1955	10.82	3,660
1956	-	-	No flow
1957	Jan. 29, 1957	10.14	205
1958	Sept. 13, 1958	10.48	976
1959	Aug. 17, 1959	10.22	480
1960	Jan. 19, 1960	10.31	640
1961	July 23, 1961	10.21	380
1962	-	-	No flow
1963	Oct. 4, 1962	10.09	100
1964	Aug. 14, 1964	10.15	230
1965	Sept. 4, 1965	10.07	230
1966	Dec. 30, 1965	10.52	1,600
	Jan. 2, 1966	16.1	64,200

Table 2.4-5

GILA RIVER BELOW
GILLESPIE DAM, ARIZONA[2] (Sheet 5 of 5)

Water Year	Date	Gauge Height (ft)	Discharge (ft^3/s)
	Jan. 8, 1966	12.27	12,200
	Feb. 16, 1966	10.48	1,720
	Sept. 15, 1966	10.40	1,340
1967	Sept. 6, 1967	10.41	1,390
1968	Dec. 12, 1967	11.09	5,710
	Dec. 26, 1967	11.01	5,240
	Feb. 19, 1968	10.47	1,720
	Mar. 2, 1968	10.50	2,130
	Mar. 15, 1968	10.43	1,480
1969	Aug. 30, 1969	10.04	214
1970	Sept. 6, 1970	11.26	6,180
1971	Aug. 27, 1971	10.34	1,090
1972	-	-	No flow
1973	Oct. 7, 1972	10.60	2,340
	Oct. 22, 1972	10.48	1,720
	Jan. 2, 1973	10.55	2,080
	Mar. 1, 1973	10.40	1,340
	Apr. 3, 1973	12.20[a]	18,000[b]
	Apr. 18, 1973	11.37[a]	13,000[b]
	May 3, 1973	10.65[a]	6,000[b]
	May 10, 1973	11.20[a]	10,000[b]
	May 14, 1973	10.42[a]	5,000[b]
1974	Apr. 3, 1974	1.62	59
1975	Oct. 29, 1975	1.79	80
1976	Sept. 27, 1976	10.51	1,920
1977	Apr. 5, 1977	10.04	100

As stated above, the maximum observed discharge was 85,000 cubic feet per second on December 28, 1923 (gauge height, 16 feet, present datum; maximum gauge height, 16.1 feet on January 2, 1966; probably no flow at times; period of no flow unknown due to not publishing leakage of less than 5 cubic feet per second (0.14 cubic meter per second).

Figure 2.4-3 shows the locations of the gauging stations. No historical flood data are available for East Wash.

2.4.2.2 Flood Design Considerations

Flood design considerations for safety-related components and structures of the plant include the following:

A. Flood effects resulting from the probable maximum flood, along with a coincident wind-wave activity

B. Flood effects resulting from seismically induced upstream dam failures, along with a coincident standard project flood

Regulatory Guide 1.59, Design Basis Floods for Nuclear Power Plants, Revision 2, August 1977, has been used as the general basis for flood determination and evaluation.

The occurrence of surge, seiche, tsunami, or ice flooding is not considered to be a probable event.

2.4.2.2.1 Offsite Flood Design Considerations

The plant site is not susceptible to flooding by the Gila River, the Hassayampa River, or the Centennial Wash. The nearest approach of the Gila River to the site is 6 miles to the southeast; the probable maximum flood stage of elevation

776 is 175 feet below the lowest plant grade of 951 at Unit 3. The Hassayampa River is 5 miles to the east, with a high-water level of elevation 942. A topographic ridge between the plant site and the Hassayampa River (minimum elevation 975) provides a natural barrier against site flooding from the Hassayampa River. Centennial Wash is approximately 5 miles south of Unit 3, with a probable maximum flood level of elevation 888. The only drainage affecting plant design is from nearby offsite sources and from onsite sources.

Potential offsite flooding sources are East Wash and Winters Wash (figure 2.4-1). Since these washes have no reservoirs upstream from the plant site, flooding could occur only from precipitation. The probable maximum water levels at selected cross sections on East Wash and Winters Wash are presented in paragraph 2.4.3.5. Protection of safety-related facilities from inundation by offsite flood sources is achieved by the location of the facilities beyond the extent of flooding. East Wash has been realigned to flow past plant facilities along the east boundary of the site. Grade elevations and drainage features important to external flooding protection are shown in figure 2.4-4.

2.4.2.2.2 Onsite Flood Design Considerations

Safety-related structures and equipment are protected from the effects of onsite flood due to probable maximum thunderstorm precipitation (PMP), wind-driven water, yard pondage, and uncontrolled release of water from onsite water impoundments. The onsite drainage system is designed to minimize water pondage in the yard adjacent to plant facilities. Surface

runoff from the power block area will be collected in drainage ditches and discharged into the realigned East Wash in a lower portion of the site. The drainage system and grading plan is designed with sufficient capacity to prevent flooding of Seismic Category I structures and loss of access to these facilities due to PMP.

There are no onsite water impoundments susceptible to uncontrolled releases which could endanger Seismic Category I structures. The maximum water surface elevation in the reservoirs will be 952.5 feet. The lowest unit (Unit 3) will not be flooded even though the maximum water surface in the storage reservoirs can temporarily be at elevation 952.5 due to a 6-hour PMP, since 6 inches of additional water will be dispersed and follow the ground slopes in a southerly direction.

Plant grades for Units 1, 2, and 3 are all 951 feet or above.

The reservoirs will be protected with berms to divert surface runoff and to provide freeboard to protect against waves and runup. The essential spray ponds are designed to prevent loss of function as described in subsection 2.4.8.

2.4.2.3 Effects of Local Intense Precipitation

The onsite drainage system is designed so that runoff due to PMP will not inundate the safety-related structures, equipment, and access to these facilities. The point value PMP intensity for critically arranged time increments as presented in table 2.4-6 is based on reference 5.

Areas adjacent to the power block are sloped away at 0.5 to 1%. This results in a minimum drop of 5 to 7 feet at the peripheral drainage system, as compared to the grade elevation at each unit. The power block areas are divided into smaller tributary areas for purposes of drainage calculations. Runoff from each tributary area is collected in drainage ditches and conveyed to the peripheral drainage system. The peripheral drainage system consists of drainage ditches and culverts along the peripheral access road as shown in figure 2.4-4. The collector ditches and culverts are designed for the 50-year storm and checked for pondage effects due to a probable maximum flood. The volume of water in the vicinity of the power block area consequent to a 6-hour PMP is based on zero infiltration losses and a complete blockage of the drainage culverts for the storm duration. These assumptions are conservative for calculation of pondage around the power block area. The volume of ponded storm water around the power block area is calculated by using the formula:

$$V = \frac{i}{12} \times A \qquad (1)$$

where:

V = volume of ponded storm water in acre-feet

i = PMP-6 hour rainfall in inches = 15.53 inches

A = drainage area in acres

Table 2.4-6

LOCAL INTENSE PROBABLE MAXIMUM THUNDERSTORM PRECIPITATION[5]

Time (h)	PMP Total (in.)	PMP Incremental (in.)	Critically Arranged Thunderstorm (in.)
0.25	8.0	8.0	0.03
0.50	10.0	2.0	0.05
0.75	11.0	1.0	0.05
1.00	11.8	0.8	0.05
1.25	12.4	0.6	0.05
1.50	12.9	0.5	0.1
1.75	13.3	0.4	0.2
2.00	13.7	0.4	0.2
2.25	14.0	0.3	0.4
2.50	14.2	0.2	0.4
2.75	14.4	0.2	0.5
3.00	14.6	0.2	0.6
3.25	14.8	0.2	8.0
3.50	15.0	0.2	2.0
3.75	15.1	0.1	1.0
4.00	15.15	0.05	0.8
4.25	15.2	0.05	0.3
4.50	15.25	0.05	0.2
4.75	15.3	0.05	0.2
5.00	15.35	0.05	0.2
5.25	15.4	0.05	0.05
5.50	15.45	0.05	0.05
5.75	15.5	0.05	0.05
6.00	15.53	0.03	0.05

For each tributary area around the power block area, an elevation-volume curve is developed. The maximum water surface elevation within each tributary area is determined from the elevation-volume curve assuming no overflow across roads surrounding the tributary area. The calculated maximum water surface elevations due to local PMP storm are 955.5, 952.5, and 949.5 at Units 1, 2, and 3, respectively. These maximum flood elevations are 2.0 feet below the floor elevations at the respective units. Downslope road elevations surrounding each tributary area are conservatively established at least 0.5 feet below the maximum water elevation to ensure drainage away from the area such that the maximum water levels cannot be exceeded. To the western side of each power block area, some of the PMP runoff overflows the peripheral access road. This does not endanger the power block area because the peripheral road elevations are 2 feet below the power block grade elevations. The area surrounding the cooling towers is graded away from the power block area at 0.5 to 1% to the ditch, so the PMP runoff over the peripheral road will flow toward the ditch system. Although PMP runoff over roads located between units may cause failure from erosion, this conservative situation in no way endangers the safety-related structures because the power block grade elevations are 2 feet above the downslope road elevations.

The roofs of safety-related structures are designed for a live load of 30 pounds per square foot which approximates 6 inches of water accumulation. The roof drainage structures (roof drains and scuppers) are designed for a 50-year storm with a minimum time of concentration of 5 minutes. In addition, the

roof drainage structures are designed to limit ponding due to a 6-hour thunderstorm PMP to 6 inches. Runoff from the plant roof drains will be conveyed away from the critical areas either through ditches or buried pipes.

The occurrence of snow and ice accumulation coincident with PMP is not considered to be a probable event.

2.4.3 PROBABLE MAXIMUM FLOOD ON STREAMS AND RIVERS

The probable maximum flood (PMF) peak discharge was calculated for each of the streams in the site vicinity. The maximum water surface elevation of peak discharge was then computed for each of the streams. Figure 2.4-1 shows the locations of the cross-sections at which the PMF was calculated.

The PMF of the Gila River, as computed by the U.S. Army Corps of Engineers at Gillespie Dam, is 730,000 cubic feet per second.[3] Gillespie Dam is approximately 4.5 miles downstream from the closest point of approach of the Gila River to the plant site. To be conservative, the PMF computed at Gillespie Dam was used to compute water surface elevations of the point in the Gila River closest to the plant site. The PMF water surface elevation was computed to be 776, which is 175 feet below the lowest plant elevation of 951 for Unit 3. The PMF on the Gila River will not flood the plant site.

The PMF on Centennial Wash was computed to be 291,500 cubic feet per second. The water surface elevation of this peak discharge is 888, which is 63 feet below the lowest plant grade of 951 feet at Unit 3. The capacity of Centennial Wash to

accommodate this discharge without flooding the plant site is further discussed in paragraph 2.4.3.5.

The computed PMF on the Hassayampa River is 228,000 cubic feet per second. The water surface elevation of this peak discharge is 942 which is well below the crest of a ridge (elevation 975) located between the river and the plant site. The site is safe from inundation by the PMF on the Hassayampa River.

The unit hydrograph method of drainage basins greater than 10 square miles in area(6) was used to compute the PMF on Winters Wash. The computed PMF using this method is 172,400 cubic feet per second measured at cross-section D. This peak discharge was applied at the cross sections shown in figure 2.4-2. Water level determination at these cross-sections indicates that the water surface elevation of the PMF ranges from 929.5 feet at cross-section D to 956.4 feet at cross-section AA. The site facilities will not be inundated by the PMF in Winters Wash.

The unit hydrograph method for drainage basins less than 10 square miles was used to compute the PMF on the realigned East Wash.(6) To be conservative, the PMF was determined for cross-section E (see figure 2.4-2) to be 17,640 cubic feet per second and was used to determine the maximum water levels. With the realigned East Wash as shown in figure 2.4-2, the computed water surface elevation is from 926.6 feet at cross-section F to 978.8 feet at cross-section G_2. All Category I facilities are safe from inundation by the PMF on East Wash.

The PMF analysis for the Hassayampa River and Centennial Wash was based upon a computed ratio between the 100-year flood and

the computed PMF for area drainage basins. For the Gila River at McDowell Damsite and Painted Rock Damsite, the U.S. Army Corps of Engineers (COE) computed the following 100-year flood and PMF:[3]

	McDowell Damsite	Painted Rock Damsite
100-year flood peak, cubic feet per second	240,000	261,000
PMF, cubic feet per second	600,000	690,000
Ratio PMF to 100-year	2.50	2.64

The 100-year flood flows for Winters Wash and East Wash were computed using the method presented in reference 7. Table 2.4-7 presents the input data used to compute the 100-year flood and PMF for Winters Wash and East Wash.

	Winters Wash	East Wash
100-year flood peak, cubic feet per second	29,200	2,200
PMF, cubic feet per second	172,400	16,600
Ratio PMF to 100-year flood	5.90	7.55

To determine the PMF to 100-year flood ratio for the Hassayampa River and Centennial Wash, a log-log plot of cubic feet per second per square mile versus drainage area was plotted for the 100-year floods and PMF for McDowell Damsite, Painted Rock Damsite, Winters Wash, and East Wash. From figure 2.4-5 it is shown that using a 5 to 1 ratio of PMF to 100-year flood for the Hassayampa River and Centennial Wash results in a conservative estimate of the PMF for those water courses. Table 2.4-8 lists the data used to develop figure 2.4-5.

Table 2.4-7

PARAMETERS USED TO CALCULATE PMF AND 100-YEAR FLOOD ON WINTERS WASH AND EAST WASH (Sheet 1 of 2)

Parameter		Winters Wash	East Wash
Drainage area, mi^2	A	250	6.8
Length of drainage area, ft	L_1	55,000	
	L_2	100,000	45,000
Elevation, ft[a]			
Top of drainage area	E_1	2,800	
	E_2	1,600	
	E_1	1,600	1,172
At cross-section	E_2	935	949
Drainage area slope, %	S_1	2.18	0.5
	S_2	0.67	
Drainage width, ft		---	5,300
Width factor, W_f		---	0.89
Vegetative cover type	T_1	Desert brush	
	T_2	Herbaceous	Desert brush
Vegetative Cover density, %	D_1	10	10
	D_2	10	

a. Above mean sea level.

Table 2.4-7

PARAMETERS USED TO CALCULATE PMF AND 100-YEAR FLOOD ON WINTERS WASH AND EAST WASH (Sheet 2 of 2)

Parameter		Winters Wash	East Wash
Soil group	G_1	C	
	G_2	D	C
100-year			
1-hour point			
Precipitation, in.		---	2.49
100-year			
6-hour point			
Precipitation, in.		3.35	---
PMP		14.60	15.53
ΔD, h		1.15	0.32
Curve number, CN	CN_1	89	89
	CN_2	92	
Time of concentration, h	T_c1	2.48	2.4
	T_c2	6.18	
Time of peak, h	T_p	5.77	2.14
PMF, ft^3/s	Q_p	172,400	16,600

2.4.3.1 Probable Maximum Precipitation

To calculate the PMF, an estimate of the probable maximum precipitation (PMP) must first be made. A design PMP was selected for the Winters Wash drainage basin and East Wash drainage basin such that the resulting PMF would represent the most severe case. To accomplish this, a comparison was made between the PMF obtained from a 24-hour PMP and that obtained from a 6-hour thunderstorm PMP. The comparison showed that the 24-hour PMP produced the most severe PMF for Winters Wash, while the 6-hour thunderstorm PMP produced the most severe PMF for East Wash. The procedure used to develop the PMP for the respective drainage basins is given below.

2.4.3.1.1 Probable Maximum Precipitation for Winters Wash

The method used to estimate PMP for Winters Wash was developed by Hershfield(8) and is based on the statistics of extreme events. However, the method is not a probability approach to frequency analysis such as a Gumbel or Log-Pearson extreme value curve. Hershfield's method for estimating PMP develops the necessary statistics from envelope curves which encompass all the maximum measured precipitation data. It shows that no systematic geographic pattern for this statistic exists. Regionalization of PMP is accomplished by incorporating mean and standard deviation statistics of local precipitation records. This method provides a conservative upper limit for the PMP that does not rely on a combination of theoretical and empirical methods. The data are obtained from worldwide official observations of maximum rainfall. Since the method is based upon curves which are greater than maximum observed

values, there is no confidence interval associated with the PMP estimates. This is considerably more conservative than an upper 95% confidence interval which may be used with other statistical methods.

The method is not a frequency model and, therefore, there is no probability associated with the PMP estimates. The method yields a PMP value which is greater than any maximum observed value. The PMP estimate using this method can, therefore, be construed to be analogous to the PMP values developed by other methods.

Table 2.4-9 compares the values obtained from various methods. The table indicates that the Hershfield method results in greater precipitation values than other methods compared, except those obtained from Technical Paper 38 which is presently being revised for the southwest. Previous revisions of Technical Paper 38[9] for other areas in the west have shown that the PMP estimates from this reference are unrealistically over-estimated in some cases. The U.S. Soil Conservation Service (SCS), in the evaluation of design criteria for Queen Creek Flood Dam and Reservoir,[10] a 255-square-mile watershed located southeast of Phoenix, Arizona, obtained PMP estimates in table 2.4-9 directly from the National Oceanic and Atmospheric Association (NOAA).

The Hershfield method for estimating PMP results in a PMP value which exceeds the estimates obtained from thunderstorm precipitation and the estimates obtained by the SCS for Queen Creek.

Table 2.4-8

FLOOD DATA USED TO COMPUTE PMF TO 100-YEAR FLOOD RATIO

	McDowell[a] Damsite	Paitned Rock[a] Damsite	Winters[b] Wash	East[c] Wash	Centennial[d] Wash	Hassayampa[d] River
Drainage Area (square miles)	12,900	50,910	250	6.8	1,421	912
PMF (ft^3/s)[e]	600,000	690,000	172,400	16,600	291,500	228,000
$ft^3/(s\text{-}mi^2)$ for PMF	46.5	13.6	689.6	2,441	205	250
100-Yr flood (ft^3/s)	240,000	261,000	29,200	2,200	58,300	45,600
$ft^3/(s\text{-}mi^2)$ for 100-yr flood	18.6	5.1	116.8	324	41	50

a. Computed by the COE.[3]

b. Computed by the SCS method.[6]

c. Computed by the SCS method, as modified by the Arizona Highway Department.[7]

d. Computed by the USGS method.[16]

e. Computed using 5:1 ratio of PMF to 100-year flood.

Table 2.4-9

COMPARISON OF PMP ESTIMATES FOR WINTERS WASH (INCHES)

	Storm Duration	
	(6 h)	(24 h)
Hershfield[8] - precipitation, in.	9.1	14.6
Technical Paper 38[9] - precipitation, in.	15.1	19.6
Queen Creek PMP[10] - precipitation, in.	7.0	10.9
Thunderstorm PMP[5] - precipitation, in.	7.6	--

The computed PMP for the Winters Wash drainage basin after reduction for basin size is 14.6 inches. This value was computed using the 6- and 24-hour precipitation amounts[7] as input to Hershfield's method for estimating PMP. The resulting 6- and 24-hour PMP values were reduced by areal reduction percentages.[9]

The areal reduction percentages for a drainage basin of 250 square miles are shown below:

	Duration (h)	
	6	24
Areal reduction percentage	84	89
Precipitation, in.	9.1	14.6

A depth-duration relationship was then developed from a log-log plot of the reduced 6- and 24-hour PMP values. Figure 2.4-6 shows the resulting depth-duration relationship.

Rainfall increments were then read from the depth-duration relationship using ΔD time intervals:[6]

$$\Delta D = 0.133\ T_c \qquad (2)$$

where:

ΔD = Duration of unit excess rainfall in hours

T_c = Time of concentration in hours

The sequence of the rainfall increments is then arranged according to the unit hydrograph so that the maximum peak discharge of the flood hydrograph is obtained. That is, the largest increment is paired with the maximum discharge of the unit hydrograph, the second largest increment is paired with the second highest discharge of the unit hydrograph, and so forth. The resulting maximized time distribution of the 24-hour precipitation for the Winters Wash drainage basin is listed in table 2.4-10.

2.4.3.1.2 PMP for East Wash

The design PMP for the East Wash drainage basin was obtained using extreme summer thunderstorm rainfall for the southwest.[5] This rainfall represents PMP over an area of 1 square mile. An analysis of 6:1 hour ratio was used to extend the 1-hour PMP to the 6-hour PMP.

The 1-hour, 1-square mile PMP for the East Wash drainage basin is 11.5 inches. The 6:1 ratio for the site vicinity is given as 135% of the 1-hour PMP, or 15.53 inches.[5] To break down the 6-hour PMP into smaller time intervals, the 1-hour

precipitation amount is multiplied by percentages applicable to an area with a 6:1-hour ratio of 1.35.

Duration (h)	1/4	1/2	1	2	3	4	5	6
6:1-hour ratio	68.5	86	100	116	123.5	128.5	132.5	135

The values obtained are multiplied by areal reduction percentages which reduce the precipitation amounts in relation to basin size. The areal reduction percentages for East Wash are as follows:

Duration (h)	1/4	1/2	1	2	3	4	5	6
Areal reduction percentages	79	82	87	88	90	91	92	93

Figure 2.4-7 shows the graph from which these percentages are taken.

The incremental values of the hourly PMP values are found by subtracting each hourly value from the following hourly value. These hourly increments are then arranged according to a critical time sequence.[5]

Increment	Sequence Position
Largest hourly amount	Third
2nd largest	Fourth
3rd largest	Second
4th largest	Fifth
5th largest	First
Least	Last

Figure 2.4-8 shows the resulting PMP depth-duration curve for the East Wash drainage basin.

Table 2.4-10

MAXIMIZED STORM PRECIPITATION DISTRIBUTION
WINTERS WASH

Time (h)	Precipitation Increments (in.)
0	0
1.15	0.40
2.30	0.40
3.45	0.60
4.60	1.35
5.75	5.20
6.90	0.95
8.05	0.80
9.20	0.60
10.35	0.50
11.50	0.40
12.65	0.40
13.80	0.40
14.95	0.40
16.10	0.35
17.25	0.30
18.40	0.30
19.55	0.25
20.70	0.25
21.85	0.25
23.00	0.25
24.15	0.25

Rainfall increments were then read from the depth-duration curve using ΔD increments and then maximized according to the unit hydrograph for East Wash. The resulting maximized time distribution of the 6-hour precipitation for the East Wash drainage basin is listed in table 2.4-11.

2.4.3.2 Precipitation Losses

The method to determine precipitation losses was developed by the U.S. Soil Conservation Service[6] from studies of many small watersheds. This method was used to calculate the precipitation losses in the Winters Wash and East Wash drainage basins. The method involves the determination of a hydrologic soil cover complex number from the following parameters: hydrologic cover types, hydrologic cover density, and hydrologic soil groups.

Hydrologic soil cover complexes most commonly encountered in Arizona are shown in figure 2.4-9, together with the associated curve number (CN). These curve numbers are used to determine the volume of direct runoff (Q) from the design rainfall.[7]

2.4.3.2.1 Hydrologic Cover Types

Vegetative types that basically affect the runoff process in the southwest desert areas can be divided into five groups:

A. Desert brush includes such plants as mesquite, creosote bush, black bush, catclaw, cactus; desert brush is typical of lower elevations and low annual rainfall.

Table 2.4-11

MAXIMIZED STORM PRECIPITATION DISTRIBUTION
EAST WASH

Time (h)	Precipitation Increments (in.)
0	0
0.32	0.04
0.64	0.19
0.96	0.30
1.28	0.35
1.60	0.63
1.92	2.12
2.23	6.65
2.55	1.18
2.87	0.62
3.19	0.45
3.51	0.33
3.83	0.31
4.15	0.23
4.47	0.22
4.79	0.21
5.11	0.18
5.43	0.18
5.75	0.15
6.06	0.10

B. Herbaceous includes short desert grasses with some brush; herbaceous is typical of intermediate elevations and higher annual rainfall than desert areas.

C. Mountain brush includes mixtures of oak, aspen, mountain mahogany, manzanita, bitter brush, maple; mountain brush is typical of intermediate elevations and generally higher annual rainfall than herbaceous areas.

D. Juniper-grass includes juniper areas mixed with varying grass cover that is generally heavier than desert grasses, due to higher annual precipitation -- typical of higher elevations.

E. Ponderosa pine forests typical of high elevations and high annual precipitation are found along the Mogollon Rim, the Kaibab Plateau, and the White Mountains.

The Winters Wash basin is divided into two hydrologic sub-areas with the upper area having a hydrologic cover type of desert brush and the lower having herbaceous as the cover type. The hydrologic cover type for the East Wash drainage basin is desert brush. These cover types were determined from field inspection of the respective drainage basins.

2.4.3.2.2 Hydrologic Cover Density

Hydrologic cover density is defined as the percentage of the ground surface covered by the crown canopy of live plants and litter. Three broad ranges of vegetative cover density have been established by the SCS:

Poor 0 - 20% vegetative cover

Fair	20 - 40% vegetative cover
Good	40% + vegetative cover

From aerial photographs, topographic maps, and field inspection of the study area, the hydrologic cover density for the two sub-areas of the Winters Wash basin was determined to be 10%.

The hydrologic cover density for East Wash was considered to be 10%. Both basins fall into the range of poor vegetative cover.

2.4.3.2.3 Hydrologic Soil Groups

Surface soils which materially affect the rate of runoff have been classified into four major groups according to the infiltration rate of each soil. The distribution of these soils in Arizona is shown in figure 2.4-10. These soil groups are defined as follows:[7]

A. Low runoff potential soils having high infiltration rates even when thoroughly soaked and consisting chiefly of deep, well to excessively well-drained sands or gravels. These soils have a high rate of water transmission.

B. Soils having moderate infiltration rates when thoroughly soaked, consisting chiefly of moderately deep to deep, moderately well to well-drained soils with moderately fine to moderately coarse textures. These soils have a moderate rate of water transmission.

C. Soils having slow infiltration rates when thoroughly soaked, consisting chiefly of soils with a layer that impedes the downward movement of water, or soils with

moderately fine to fine texture and a slow infiltration rate. These soils have a slow rate of water transmission.

D. High runoff potential soils having very slow infiltration rates when thoroughly soaked, consisting chiefly of clay soils with a high swelling potential; soils with claypan or clay layer at or near the surface; and shallow soils over nearly impervious materials. These soils have a very slow rate of water transmission.

The upper sub-area of the Winters Wash basin falls within soil Group C, while the lower sub-area falls within soil Group D. The whole of the East Wash drainage basin contains soil Group C. This determination was made from field inspection and from the hydrologic soil map, figure 2.4-10.

2.4.3.2.4 Curve Numbers

The curve number associated with the upper sub-area of Winters Wash is 89, while the lower sub-area curve number is 92, and the East Wash basin curve number is 89. These curve numbers were determined from figure 2.4-9, using the appropriate hydrologic soil group, vegetative type, and vegetative cover density for the respective drainage basins.(7)

2.4.3.3 Runoff and Stream Course Models

The methods employed in computing the runoff properties of the Winters Wash drainage basin and the East Wash drainage basin were developed by the U.S. Soil Conservation Service(6) and

Arizona Highway Department.[7] These methods are applicable to small watersheds with limited hydrologic data and are the result of extensive studies on small watersheds throughout the United States.

Flood hydrographs for each hydrologic area were developed by applying the maximized runoff sequence (paragraph 2.4.3.1) to unit hydrographs for each drainage area. These unit hydrographs are based on the dimensionless unit hydrograph.[6] The procedures developed by the U.S. Soil Conservation Service apply both to small drainage areas (less than 10 square miles) and, with some modification, to drainage areas larger than 10 square miles.

The drainage area of Winters Wash is 250 square miles. The peak discharge (Q_p) and time to peak (T_p) used for developing the unit hydrograph for Winters Wash are calculated by the following equations.[6]

$$Q_p = \frac{484A}{\frac{\Delta D}{2} + 0.6T_c} \tag{3}$$

$$T_p = \frac{T_c + \Delta D}{1.7} \tag{4}$$

where:

$$T_c = \frac{L^{1.15}}{7700H^{0.38}}$$

A = drainage area in square miles

Q_p = peak discharge in cubic feet per second

T_c = time of concentration in hours

L = length of drainage area in feet

H = difference in elevation in feet

ΔD = duration of unit excess rainfall in hours

T_p = time to peak in hours

The duration of unit excess rainfall, ΔD, for the unit hydrograph is determined by equation 2.

The peak discharge (Q_p) and time to peak (T_p) used for developing the unit hydrograph for East Wash are calculated by the following equations:[7]

$$Q_p = \frac{484A}{T_p} \qquad (5)$$

$$T_p = (T_c) \times (\text{Width Factor}) \qquad (6)$$

where

Q_p = peak rate of discharge in cubic feet per second

A = contributing drainage area in square miles

T_p = time to peak in hours

T_c = time of concentration in hours

For drainage basins less than 10 square miles, T_c is determined from a graph of drainage area in square miles versus water-course slope in percent, developed by the Arizona Highway Department Bridge Division.[7] The resulting unit hydrographs of the Winters Wash drainage basin and the East Wash drainage

basin are shown in figures 2.4-11 and 2.4-12. Table 2.4-7 presents the parameters used in the above equations and the solutions for the respective drainage basins.

2.4.3.3.1 Verification of the Unit Hydrograph Model

To choose a model for calculating storm runoff, a method was purposely chosen that is in common use in Arizona. The SCS method as modified (not significantly) by the Arizona Highway Department (1968) is a good choice of models because it is in current use for a variety of design problems. The model was tested by simulating measured runoff events from the Walnut Gulch Experimental Watersheds(11) near Tombstone, Arizona. These watersheds were chosen because the soils and land use are similar to the area above the proposed plant, but more importantly, these experimental watersheds have a dense network of continuously recording instruments. The 53-square-mile area has 78 rain gauges. Accurate definition of the rainfall input becomes very important when verifying a model. This is especially important in the Southwest where small area thunderstorm rainfall dominates the runoff producing events.

Verification was accomplished by calculating a synthetic unit hydrograph for the 57.66- and 5.98-square-mile research watersheds. The measured storm rainfall of September 4, 1965, was used as input to the model, and the calculated hydrograph compared to the measured hydrograph. The results for the two areas are summarized in the table below:

Area (mi^2)	Average Precipitation (in.)	Measured Peak Flow (ft^3/s)	Calculated Peak Flow (ft^3/s)
57.66	0.92	744	2780
5.98	1.28	838	1050

The results illustrate that the model chosen for analysis is very conservative and overestimates the flow for both the large and small watersheds.

These areas were chosen as representative of the two areas in question: Winters Wash and East Wash. The test area (57.66 square miles) is smaller than Winters Wash (250 square miles) but this should in no way negate the conclusions of the verification. Both areas are complex watersheds. A good definition of rainfall input far outweighs any advantages that a test of a larger watershed might offer.

2.4.3.3.2 Nonlinearity

Unit hydrograph theory depends on two basic assumptions: time invariance and linearity. Time invariance refers to an assumption that the watershed has not changed (either in morphology or in seasonal influences) with time. This assumption may be questionable in certain areas where derived hydrographs may become invalid through urban development in the watershed. However, this should not pose a problem when using synthetic unit hydrographs for evaluating a PMF in an ungauged area. On the other hand, the assumption of linearity may be seriously violated when using unit hydrographs to predict a PMF from extraordinarily large rainfall amounts and intensities.

Unit hydrographs have been a successful tool for hydrologists for many years. Their success is, to a certain degree, due to the highly damped response (the hydrograph) of watersheds to their input (rainfall). This high degree of damping enables the hydrologist to successfully use a linear model for a highly nonlinear system. For many cases, the results are acceptable. This is at least in part due to the fact that the concept is used for generally the same conditions (rainfall rates) as those for which it was derived and not for events greatly larger. Thus, it is only when the unit hydrograph is used for conditions far different than those from which it was derived that the assumption of linearity becomes inadequate.

Unit hydrograph linearity has been the subject of several recent technical articles and studies.[(12),(13)] These studies have diagnosed the problem but have offered little in the way of solutions. A study by Givler[(13)] based on mathematical model results proposes relationships for adjusting the peak flow and time to peak according to rainfall intensity as follows:

$$q_p \propto (i)^{1.40}$$

$$t_p \propto (i)^{-0.38}$$

where:

q_p = peak flow, cubic feet per second

t_p = time to peak, hour

i = rainfall intensity, inches per hour

When considering the use of such relationships in applied hydrology, the conditions for which they were derived should be

taken into account. Givler's mathematical model consisted of a uniform flow plane and a wide channel. To the extent that this geometry represents a natural watershed, the results could be considered reasonable. However, Givler warns that hydraulically narrow channels would reduce the effect on non-linearity predicted by these relationships. Natural watersheds seldom resemble a series of uniform flow planes connected by hydraulically wide channels. Overland flow generally concentrates in narrow rills or hydraulically narrow channels. Natural channels would act as narrow channels, especially as a PMF event flows onto the flood plain, which, by nature of its increased roughness, acts as a narrow channel. What this means is that in natural watersheds with well-defined channel systems, the effects of nonlinearity between very high rainfall rates and runoff will be less dominant than in small watersheds dominated by an overland runoff regime.

In analyzing the PMF for the PVNGS site, a very conservative runoff model was used to calculate the peak discharge. Because the model is very conservative, it was felt that further adjustment for non-linearity would not be necessary. The conservative nature of the procedure used here is probably analogous to how hydrologists have historically adjusted a unit hydrograph to reflect the magnitude of the storm. Linsley, et al[14] state that hydrologists frequently increase peak flows from 5 to 15% when making estimates of very extreme floods. The Corps of Engineers[15] recommends increasing the peaks of unit hydrographs by 25 to 50% when making estimates of extreme floods. Using a very conservative synthetic unit hydrograph

procedure is equivalent to historical procedures used by hydrologists for estimating extreme floods.

2.4.3.4 Probable Maximum Flood Flow

The peak discharge of the PMF on the Gila River has been determined by the U.S. Army Corps of Engineers at Gillespie Damsite, located approximately 4.5 miles downstream from the closest point of approach of the Gila River to the plant site.[3] The figure of 730,000 cubic feet per second was applied at the nearest approach of the river to the plant site as a conservative estimate to the PMF.

The peak discharge of the PMF on Centennial Wash was estimated by computing the 100-year flood for a drainage area of 1421 square miles based on the U.S. Geological Survey method,[16] and then multiplying this flood flow by a factor of 5 as discussed in subsection 2.4.3.

Centennial Wash carries infrequent runoff. The drainage basin is divisible into three distinct parts. The uppermost part is McMullen Valley, which ends at the bedrock narrows south of Salome. Most of the runoff generated in McMullen Valley sinks into the coarse valleyfill sediments along the axis of the valley. The central part is the largest and is called Harquahala Valley. The valleyfill sediments along the axis of this valley also are extremely coarse. Runoff sinks readily into the ground. The lowest part of Centennial Wash meanders eastward and southeastward through low hills, from Harquahala Valley to the Gila River near Gillespie Dam.

The map of Arizona showing hydrologic areas from Water-Supply Paper 1683(16) shows cross-hatching in the Centennial Wash area, identified in the map legend with the words "Flood-frequency relations not defined." The nearest hydrologic area for which flood-frequency relations were defined was used to determine flood conditions of Centennial Wash.

The USGS gives the mean annual flood in the hydrologic area nearest the site for which flood frequencies are defined as about 11,000 cubic feet per second for an area of 1421 square miles. The 100-year flood for the region in which the drainage basin is located is 5.3 times greater than the mean annual flood. Therefore, using this method, the 100-year flood on Centennial Wash near the site was approximated to be 58,300 cubic feet per second. Using the conservative ratio of 5:1 for the relationship of the PMF to the 100-year flood, as discussed in subsection 2.4.3, the PMF on Centennial Wash was estimated at 291,500 cubic feet per second. The point on Centennial Wash for which the contributing drainage area of 1421 square miles was measured is at the cross-section shown in figure 2.4-1. The center of the Wash on this cross-section is approximately 6 miles southwest of the site.

The peak discharge of the PMF on the Hassayampa River is based upon the USGS method used to calculate the PMF on Centennial Wash.(16) The mean annual flood for an area of 912 square miles as determined by the USGS was found to be approximately 8600 cubic feet per second. The 100-year flood for the region in which the drainage basin lies was again 5.3 times greater than the mean annual flood. Therefore, using this method, the 100-year flood on the Hassayampa River at the selected point

was approximated at 45,600 cubic feet per second. Using the multiplying factor of 5, the PMF on the Hassayampa River was estimated at 228,000 cubic feet per second. The point on the Hassayampa River for which the contributing drainage area of 912 square miles was measured is at the cross-section shown in figure 2.4-1.

The PMF for Winters Wash and East Wash was calculated using the SCS method.[6] Runoff increments were computed from the sequence of rainfall increments shown in tables 2.4-10 and 2.4-11 for Winters Wash and East Wash, respectively, using the equation:

$$Q = \frac{(P-0.2S)^2}{(P+0.8S)} \tag{7}$$

where:

Q = runoff in inches

P = precipitation amount in inches

$$S = \frac{1000}{CN} - 10$$

CN = curve number.

The sequence of runoff increments was then combined with the respective unit hydrographs to determine the probable inflow flood hydrographs. Figures 2.4-13 and 2.4-14 represent the hydrographs of the probable maximum flow near the site of Winters Wash and East Wash, respectively.

The peak discharge of Winters Wash PMF is 172,400 cubic feet per second which was used to estimate the water level along the wash. The point on Winters Wash for which the contributing

drainage area of 250 square miles was measured is at cross section D as shown in figure 2.4-1.

The peak discharge of East Wash PMF is 16,600 cubic feet per second. The point on East Wash for which the contributing drainage area of 6.8 square miles was measured is at the north line of Sec. 34 (Arlington Quadrangle) extended eastward.

Since both Winters Wash and East Wash are ephemeral desert streams with infrequent flow near the plant site, no consideration was given to increasing the flood hydrographs with the addition of base flow.

2.4.3.5 Water Level Determinations

Water levels for PMF peak discharges were computed for each of the streams in the site vicinity. The location of each cross-section used to determine the extent of flooding is shown in figure 2.4-1. The detailed profile of each cross-section is shown in figure 2.4-15. The calculations showing the channel capacities at the selected cross-sections for each stream in the site vicinity and the associated water surface levels are shown in the tables and figures referring to each stream. Cross-section elevations for the Gila River, Centennial Wash, and the Hassayampa River were taken from the 15-minute USGA Arlington Quadrangle with 20-foot contours. The Winters Wash cross-sections at A, B, C, and D were specially prepared from the same topographic control as the contours shown in figures 2.4-2. Cross-sections AA, A_1, A_2, B_1, B_2, and C_1 were linearly interpolated from the detailed elevations prepared for cross-sections A, B, C, and D. All East Wash cross-sections

were taken directly from a 2-foot contour map prepared specifically for the site area.

Table 2.4-12 gives the cross-sectional data for the Gila River and channel capacities at elevations 775 and 776, respectively. From these computations it was found that the capacity of the Gila River channel at flow elevation 775 is 690,000 cubic feet per second and at flow elevation 776 of 785,000 cubic feet per second. A PMF at a peak discharge of 730,000 cubic feet per second would reach a peak water surface level of elevation 776, which is 175 feet below the plant grade for Unit 3. The slope area calculated for high water level during PMF was made by drawing on the Arlington 15-minute quadrangle from a point at the peak of the Buckeye Hills in sec. 10, T.2 S., R.5 W., extending northwestward to the center of sec. 34, T.1 N., R.6 W. (southwest corner of plant site).

The capacity of Centennial Wash to carry floodwaters at high water level of elevation 888 was computed and found to be 307,000 cubic feet per second which is greater than the computed PMF of 291,500 cubic feet per second. Calculations to determine the high water surface during the PMF peak discharge are shown in table 2.4-13. The PMF water surface elevation is at least 63 feet below the plant grade of Unit 3. To perform the slope area calculation for the high water level during PMF, a line was drawn on the Arlington 15-minute quadrangle extending northeastward across Centennial Wash. The southwest end of the line was SW cor. sec. 35, T.1 S., R.7 W. The northeast end of the line was SW cor. NE sec. 34, T.1 N., R.6 W (plant site). Zero distance was taken at the point where the 960-foot contour line crosses the line of the section and

Table 2.4-12

HYDROLOGIC CHARACTERISTICS OF THE GILA RIVER[a]
(Sheet 1 of 3)

Slope Area Calculation For High Water Level During Probable Maximum Flood					
Station[b]	Elevation[c]	Remarks	Station	Elevation	Remarks
0	920		26,000	840	
260	880		28,780	860	
930	840		32,370	880	
1,040	800		36,480	900	
1,170	810		39,130	920	
1,220	800		52,390	944 est	Cen Sec. 34
1,300	760	Wash			
6,500	760				
6,580	755	Gila River			
6,630	760				
16,820	780				
18,330	790	Wash			
18,640	800				
19,010	802	Est			
19,370	800				
23,530	820				

a. Gradient of river at section: 5 feet in mile, $5 \div 5{,}280 = 0.00095$ ft/ft

b. Use 0.001 ft/ft. Station distances are given in a northwestward direction from the zero point at elevation 920 feet.

c. Feet above mean sea level (1958).

Table 2.4-12

HYDROLOGIC CHARACTERISTICS OF THE GILA RIVER
(Sheet 2 of 3)

Channel Capacity With Water Surface at 775 Feet Elevation					
Station (ft)	Elevation (ft)	Mean Depth (ft)	Depth (ft)	Width (ft)	Area (ft^2)
1,270	775	0	7.5	30	225
1,300	760	15	15.0	5,200	78,000
6,500	760	15	17.5	80	1,400
6,580	755	20	17.5	50	875
6,630	760	15	7.5	7,640	57,300
14,270	775	0		13,000	137,800
-1,270					
13,000					

Wetted perimeter: Use 13,000 ft

Hydraulic radius: 137,800 13,000 = 10.52 ft, use 10.5 ft.

Velocity: $V = \frac{1.486}{n} R^{2/3} S^{1/2}$: 5.00 ft/s

Capacity of channel: 137,800 sq ft x 5.00 ft/s
= 689,000 ft^3/s
Use 690,000 ft^3/s

Manning's n = 0.045

Table 2.4-12

HYDROLOGIC CHARACTERISTICS OF THE GILA RIVER
(Sheet 3 of 3)

Channel Capacity With Water Surface at 776 Feet Elevation					
Station (ft)	Elevation (ft)	Depth (ft)	Mean Depth (ft)	Width (ft)	Area (ft^2)
1,270	776	0	8.0	30	240
1,300	760	16	16.0	5,200	83,200
6,500	760	16	18.5	80	1,480
6,580	755	21	18.5	50	925
6,630	760	16	8.0	8,150	62,200
14,780	776	0		13,510	151,045
-1,270					
13,510					

Wetted perimeter: Use 13,600 ft

Hydraulic radius: 151,045 13,600 = 11.11 ft, use 11.1 ft.

Gradient: 0.001 ft/ft

Velocity: $V = \frac{1.486}{n} R^{2/3} \quad S^{1/2}$: 5.00 ft/s

Capacity of channel: 151,045 sq ft x 5.00 ft/s
= 755,225 ft^3/s
Use 785,000 ft^3/s

Manning's n = 0.045

increasing distances were along the line of the section in a northwestward direction.

The capacity of the Hassayampa River to carry floodwaters at a high water level of elevation 942 was computed and found to be 230,000 cubic feet per second which is greater than the computed PMF of 228,000 cubic feet per second. The difference in elevation between the high water level and the crest of the ridge located between the plant site and the Hassayampa River is 33 feet (ridge elevation is 975). Calculations to determine the high water surface during the PMF peak discharge are shown in table 2.4-14. The slope area calculation for the high water level during PMF was made by drawing a line on topographic maps extending across the Hassayampa River through the point above which a calculation was made for peak discharge during a mean annual flood. The eastern end of the line was the 960-foot contour line on the Buckeye NW sheet in SW sec. 23, T.1 N., R.5 W. The line extended westward and ended about 500 feet south of NW cor. sec. 34, T.1 N., R.6 W., about 1/2 mile west of the west boundary of NE sec. 34 (plant site).

Streambed profiles for realigned East Wash and Winters Wash are provided in figures 2.4-16 and 2.4-17. The Manning's "n" value of 0.045, which is considered applicable to Winters Wash and East Wash, was determined from references which recommended values ranging from 0.035 to 0.050.[(17),(18),(19)] This value (0.045) is considered conservative for calculating flood flows in ephemeral desert streams in the site area.

Table 2.4-13

HYDROLOGIC CHARACTERISTICS OF CENTENNIAL WASH
(Sheet 1 of 3)

Slope Area Calculation For High Water Level During Probable Maximum Flood					
Station	Elevation[a]	Remarks	Station	Ele-vation	Remarks
0	960		29,900	905	Est
2,600	940		30,420	901	Est, wash
5,980	920		34,290	920	
6,080	910	Est	41,340	939	SW cor. Sec. 34
6,450	920		41,400	940	
9,880	900		43,680	944	Est, SW cor. NE 1/4 Sec. 34
12,870	880				
13,730	878	Est, Cen-tennial Wash			
13,780	800				
15,340	875	Inter-polated			
17,160	880				
11,880	899	Inter-polated			
28,730	895	Est, wash			
29,380	900				

a. All elevations in feet above mean sea level (1958).

Table 2.4-13

HYDROLOGIC CHARACTERISTICS OF CENTENNIAL WASH
(Sheet 2 of 3)

Interpolation of Elevations Between Contour Line		
Station	Elevation	Remarks
9,880	900	
11,380	890	Interpolated
11,520	889	Interpolated
11,670	888	Interpolated
11,820	887	Interpolated
11,980	886	Interpolated
12,120	885	Interpolated
12,270	884	Interpolated
12,420	883	Interpolated
12,570	882	Interpolated
12,720	881	Interpolated
12,870	880	
17,160	880	
17,460	881	Interpolated
17,760	882	Interpolated
18,060	883	Interpolated
18,360	884	Interpolated
18,660	885	Interpolated
18,970	886	Interpolated
19,270	887	Interpolated
19,570	888	Interpolated
19,870	889	Interpolated
20,170	890	Interpolated
22,880	899	

Table 2.4-13

HYDROLOGIC CHARACTERISTICS OF CENTENNIAL WASH
(Sheet 3 of 3)

Channel Capacity with Water Surface at 888 Feet Elevation					
Station (ft)	Elevation (ft)	Depth (ft)	Mean Depth (ft)	Width (ft)	Area (ft^2)
11,670	888	0	4.0	1,200	4,800
12,870	880	8	9.0	860	7,740
13,730	878	10	9.0	50	450
13,870	880	8	10.5	1,560	16,380
15,340	875	13	10.5	1,820	19,110
17,160	880	8	4.0	2,410	9.640
19,570	880	0	4.0	7,900	58,120

Wetted perimeter: 7,910 ft

Hydraulic radius: 58,120 7,910 = 7.35 ft

Gradient: 0.0018 ft/ft

Manning's coefficient "n" = Use 0.045

Velocity: $V = \frac{1.486}{n} R^{2/3} \quad S^{1/2}$: 5.00 ft/s

Capacity of channel: 58,120 sq ft x 5.00 ft/s
= 290,600 ft^3/s
Use 307,000 ft^3/s

Table 2.4-14

HYDROLOGIC CHARACTERISTICS OF THE HASSAYAMPA RIVER
(Sheet 1 of 3)

Slope Area Calculation for High Water Level During Probable Maximum Flood		
Station[a]	Elevation[b]	Remarks
0	960	
150	950	
450	940	
2,950	930	River channel
4,510	940	
6,070	960	
6,980	965	Interpolated
8,670	959	Interpolated, wash
10,230	960	
10,620	962	Est
11,010	960	
11,660	959	Interpolated
12,310	960	
14,260	975	Interpolated
16,210	960	
33,630	939	NE cor. Sec. 34 (Plant Site)

a. Station distances are given in a westward direction (in feet) from the zero point at elevation 960 feet.

b. All elevations in feet above mean sea level (1958).

Table 2.4-14

HYDROLOGIC CHARACTERISTICS OF THE HASSAYAMPA RIVER
(Sheet 2 of 3)

Interpolation of Elevations Between Contour Lines		
Station[a]	Elevation[b]	Remarks
150	950	
180	949	Interpolated
210	948	Interpolated
240	947	Interpolated
270	946	Interpolated
300	945	Interpolated
330	944	Interpolated
360	943	Interpolated
390	942	Interpolated
420	941	Interpolated
450	940	
4,510	940	
4,590	941	Interpolated
4,670	942	Interpolated
4,760	943	Interpolated
4,820	944	Interpolated
4,900	945	Interpolated
4,980	946	Interpolated
5,060	947	Interpolated
5,130	948	Interpolated
5,210	949	Interpolated
5,290	950	Interpolated
6,070	960	

Table 2.4-14

HYDROLOGIC CHARACTERISTICS OF THE HASSAYAMPA RIVER
(Sheet 3 of 3)

Channel Capacity with Water Surface at 942 Feet Elevation					
Station (ft)	Elevation (ft)	Depth (ft)	Mean Depth (ft)	Width (ft)	Area (ft^2)
390	942	0	1.0	60	60
450	940	2	7.0	2,500	17,500
2,950	930	12	7.0	1,560	10,920
4,510	940	2	1.0	160	160
4,670	942	0		4,280	28,640

Wetted perimeter: Use 4,290 ft

Hydraulic radius: 28,640 ÷ 4,290 = 6.68 ft

Gradient: 0.0048 ft/ft

Manning's coefficient "n": = Use 0.045

Velocity: $V = \frac{1.486}{n} R^{2/3} S^{1/2}$: 8.07 ft/s

Capacity of channel: 28,640 sq ft x 8.07 ft/s
= 231,125 ft^3/s
Use 230,000 ft^3/s

In Winters Wash, the standard step method[20] was used to calculate a backwater profile from section D, a potential constriction of the channel. Data of the cross-sections used to determine the high water surface during the PMF peak discharge are shown in table 2.4-15. The computed water elevations due to the PMF flood of 172,400 cubic feet per second are shown in table 2.4-16. It can be seen that the high water elevation near Unit 3 is 944.7 feet, which is 6.3 feet lower than the grade level of Unit 3.

Since the drainage basin of East Wash at the north line of section 34 extended eastward is only 6.8 square miles and the area from the point to cross-section F is 1.2 square miles, the added area contributes a significant amount of additional drainage to East Wash at cross-section F. A PMF was, therefore, computed at cross-section F and found to be 18,700 cubic feet per second. Due to the constricted East Wash channel at cross-section E, a PMF of 17,640 cubic feet per second was calculated at cross-section E by interpolating between the PMF at the north line of section 34 (Arlington Quadrangle) extended eastward (16,600 cubic feet per second) and the PMF at cross-section F (18,700 cubic feet per second). The drainage basin of East Wash measured at cross-section E is 7.4 square miles. The assumption was made that the 3:1 slope of the riprapped embankment shown in figure 2.4-18 was in place and of sufficient height to prevent overtopping. Data of the cross-sections used to determine the high water surface during the PMF peak discharge are shown in tables 2.4-17 and 2.4-18. The standard step method[20] was used to calculate the backwater profile from cross-section F to determine the water surface

elevation at various cross-sections. A PMF of 17,640 cubic feet per second was applied at cross-section F by assuming the normal depth at this cross-section. The computed results are summarized in table 2.4-16. It is shown that the proposed embankment on the site is not inundated by the PMF in East Wash. A construction access road crosses realigned East Wash between sections G and H of figure 2.4-2. The road crossing was not originally designed to pass the PMF for East Wash; however, the East Wash embankment was raised, from the road crossing to the hill near section G of figure 2.4-2, and the road profile was modified to maintain an adequate cross-sectional flow area to pass the PMF with 2 feet of freeboard on the East Wash embankment.

2.4.3.6 Coincident Wind Wave Activity

As discussed in paragraph 2.4.3.5, the plant site is protected by high ground from the PMF on the Gila River, Hassayampa River, and Centennial Wash. Determination of wind waves and runup were made for Winters and East Wash since the PMF on these streams presents a potential flood hazard to the plant site.

In order to examine the effect of severe wind waves and associated runup occurring coincidentally with the maximum water level during a PMF, a severe wind condition was assumed at the site. A westerly wind with a sustained overland speed of 40 miles per hour was applied to the Winters Wash PMF and both an easterly wind and northerly wind with a sustained overland speed of 40 miles per hour was applied to the East Wash PMF. Tables 2.4-19, 2.4-20, and 2.4-21 present the data

Table 2.4-15

WINTERS WASH CROSS-SECTIONAL DATA (Sheet 1 of 5)[a]

AA N 873,800		A N 873,000		A1 N 872,150		A2 N 871,300		B N 870,250	
Station	Elevation[b]	Station	Elevation	Station	Elevation	Station	Elevation	Station	Elevation
1375	960	925	974	1275	964	1275	966	1130	975
1550	960	980	968	1350	926	1325	964	1160	974
2000	958	1040	966	1425	960	1375	962	1220	972
2300	956	1220	962	1550	958	1425	960	1520	954
3600	956	1500	960	1725	956	1475	958	1760	952
3950	956	1760	958	1925	954	1575	956	2050	948
4250	954	1970	956	2150	952	1725	954	2330	946
4425	952	2220	954	4350	950	1875	952	2580	946
4700	952	2930	952.8	4625	948	2100	950	3350	946
5000	952	3680	954	4925	946	2450	948	3900	947
5175	954	3830	954.5	5025	946	4650	946	4520	946
5650	954	4380	952	5100	948	4800	944	4850	940
6025	954	4500	950	5200	950	5075	944	4930	943.2
6250	956	4730	950	6150	952	5150	946	5030	937.5
6400	958	4930	945.8	6500	954	5225	948	5180	946
7100	958	5080	953.7	7150	952	6000	950	5930	948
7800	956	5460	953.4	7500	950	7050	950	6200	949.5

a. Distances measured from west to east. Station 0 is located on E 195,500, Arizona Grid System.

b. All elevations in feet above mean sea level (1958).

Table 2.4-15

WINTERS WASH CROSS-SECTIONAL DATA (Sheet 2 of 5)[a]

AA N 873,800		A N 873,000		A1 N 872,150		A2 N 871,300		B N 870,250	
Station	Elevation[b]	Station	Elevation	Station	Elevation	Station	Elevation	Station	Elevation
8150	954	5620	951.1	7850	948	7300	948	6530	948
8925	952	5700	952	8400	946	7550	946	6700	946
9500	950	5950	952	10400	944	7850	944	7070	948
9900	950	6240	954	11720	942	8750	942	7220	946
10000	949.7	6370	957	11940	944	11730	940	7400	944
10250	948.9	6730	956.4	12530	946	12180	942	7610	942
10500	948.6	6920	957.5	12820	946	12500	942	7940	940
10750	948.8	7020	956	13120	948	12820	944	8660	938
11000	948	7210	954	13800	950	13050	946	9000	940
11275	948	7830	952	13900	950.5	13130	946.3	9450	940
11700	950	8250	950					9650	936.3
12175	952	9390	948					9725	938
12850	954	10520	946					9800	940
13000	956	11450	946					10370	940
13375	956	11900	948					10900	938
13800	956	12400	950					11800	938
13950	958	12750	950					11970	940
14175	960	12960	952					12500	940
		13100	954					12780	942

Table 2.4-15

WINTERS WASH CROSS-SECTIONAL DATA (Sheet 3 of 5)[a]

AA N 873,800		A N 873,000		A1 N 872,150		A2 N 871,300		B N 870,250	
Station	Elevation[b]	Station	Elevation	Station	Elevation	Station	Elevation	Station	Elevation
		13600	952					13350	944
		13800	954					13800	946
		14070	956					14200	948
		14410	960					14600	950
B1 N 869,650		**B2 N 868,800**		**C N 868,000**		**C1 N 867,100**		**D N 866,250**	
Station	Elevation[b]	Station	Elevation	Station	Elevation	Station	Elevation	Station	Elevation
1260	966	1260	962	1030	978	6810	942	6780	950
1300	964	1290	960	1480	942	6850	940	6920	927
1325	962	1325	958	1670	940	6875	938	7030	924
1350	960	1350	956	1850	940	6900	936	7250	924
1390	958	1380	954	2000	942	6950	932	7430	922
1425	956	1415	952	2200	944	6990	930	7870	924
1450	954	1450	950	2360	942	7275	928	8050	928
1485	952	1475	948	2570	935	7840	928	8300	928
1575	950	1525	946	3370	936	7950	930	8470	924

Table 2.4-15

WINTERS WASH CROSS-SECTIONAL DATA (Sheet 4 of 5)[a]

B1 N 869,650		B2 N 868,800		C N 868,000		C1 N 867,100		D N 866,250	
Station	Elevation[b]	Station	Elevation	Station	Elevation	Station	Elevation	Station	Elevation
1700	948	1675	944	3900	936	8120	932	8700	928
2075	946	2375	942	4100	938	8400	932	9100	920
2350	944	2475	940	4370	939.8	8810	930	9280	924
2675	942	3350	940	4460	932	8975	928	9430	920
2900	942	3490	942	4670	936	9175	926	9910	920
3325	944	4000	940	4740	934	9475	924	9950	921
3385	946	4450	938	4920	934	9600	924	10500	921
3450	948	5100	938	4980	936	10600	926	10870	926
3550	948	5350	940	5070	936	11050	928	10950	924.5
3625	946	5500	942	5350	934.2	11502	930	11030	926
3725	944	6550	942	5380	936	11625	932	11190	928
4425	942	6825	940	5430	940	11750	934	11470	930
4650	940	6990	938	6470	940	12000	936	11570	932
5100	940	7400	936	6790	938			11620	934
5215	942	7990	936	6930	934			11670	936
5450	944	8150	938	7500	932			11780	938
6100	946	8510	938	7600	931			12000	940
6300	946	8740	936	7750	931				

Table 2.4-15

WINTERS WASH CROSS-SECTIONAL DATA (Sheet 5 of 5)[a]

B1 N 869,650		B2 N 868,800		C N 868,000		C1 N 867,100		D N 866,250	
Station	Elevation[b]	Station	Elevation	Station	Elevation	Station	Elevation	Station	Elevation
6700	944	9100	934	7950	934				
7100	942	9375	932	8110	936				
7400	940	11500	932	8220	938				
7650	938	11970	932	8270	940				
9300	936	12260	934	8400	940				
11850	936	12250	936	8480	938				
12290	936	12580	936.2	8680	936				
12600	938			8950	933				
12740	939			9100	935.3				
				9230	928.5				
				9750	928				
				10300	930				
				11050	930				
				11080	928				
				11720	930				
				12030	932				
				12320	936				
				12700	938				
				13100	940				

Table 2.4-16

BACKWATER ELEVATIONS (Sheet 1 of 2)

Winters Wash		East Wash	
Cross-Section	Elevation (ft)	Cross-Section	Elevation (ft)
AA	956.4	G2	978.8
A	953.3	G1	976.1
A_1	949.9	G	969.8
A_2	947.2	H	966.7
B	944.7	H1	965.0
B_1	941.9	A1	962.8
B_2	939.2	A2	959.0
C	936.8	B	954.7
C_1	933.2	E	951.3
D	929.5	C	944.0
		F	926.6

	Wind Setup	
Winters Wash	East Wash North Facing Embankment	East Wash East Facing Embankment
0.8 ft	0.2 ft	0.1 ft

	Runup	
Winters Wash	East Wash North Facing Embankment	East Wash East Facing Embankment
4.8 ft	3.8 ft	1.7 ft

Table 2.4-16

BACKWATER ELEVATIONS (Sheet 2 of 2)

Maximum Water Levels at Site			
Winters Wash		East Wash	
Cross-Section	Elevation (ft)	Cross-Section	Elevation (ft)
AA	962.0	G2	982.8
A	958.9	G1	980.1
A_1	955.5	G	971.6
A_2	952.8	H	968.5
B	950.3	H1	966.8
B_1	947.5	A1	964.6
B_2	944.8	A2	960.8
C	942.4	B	956.5
C_1	938.8	E	953.1
D	935.1	C	945.8
		F	928.4

Table 2.4-17

EAST WASH CROSS-SECTIONAL DATA

G2[a]		G1[b]		G[c]		H[d]		H1[e]		A1[f]	
Station	Elevation (feet)	Station	Elevation (feet)	Station	Elevation (feet)	Station	Elevation (feet)	Station	Elevation (feet)	Station	Elevation (feet)
100	980	100	990	100	980	70.0	968.7[g]	70.0	967[g]	100	988.3[g]
230	983[g]	160	980	160	970	100	959[h]	100	957[h]	200	955[h]
275	988[h]	180	976	180	968	220	960	200	958	280	956
340	968	240	974	190	966	600	962	620	960	510	958
400	970	320	973	230	964	960	964	860	962	940	960
490	972	460	973	330	964	1020	963	1220	964	1240	962
600	974	680	974	800	966	1060	964	1460	966	1320	964
760	978	1200	976	1230	968	1250	966	1720	968	1700	966
820	978	1490	978	1690	970	1600	968	1850	968	1800	966
840	974	1700	990	2060	972	1930	970	2100	970	1900	968
880	972			2280	974	2050	970	2370	972	1980	970
930	972			3000	980	2240	972	2520	974	2100	972
970	974					2440	974			2460	974
1050	974					2740	976				
1080	972										
1130	972										
1250	974										
1520	976										
1720	978										
2000	980										

a. Station 200 is located at approximately N 876,140, E 213,120; Arizona Grid System Cross-Section runs northeasterly from this point.

b. Station 100 is located at approximately N 875,800, E 215,000; Arizona Grid System Cross-Section runs north from this point.

c. Station 100 is located at approximately N 875,400, E 215,720; Arizona Grid System Cross-Section runs northeasterly from this point.

d. Station 100 is located at approximately N 874,000, E 216,160; Arizona Grid System Cross-Section runs northeasterly from this point.

e. Station 100 is located at approximately N 873,000, E 216,450; Arizona Grid System Cross-Section runs northeasterly from this point.

f. Station 100 is located at approximately N 872,050, E 216,670; Arizona Grid System Cross-Section runs northeasterly from this point.

g. Elevation at top of embankment riprap.

h. Elevation at toe of embankment.

Table 2.4-18

EAST WASH CROSS-SECTIONAL DATA (Sheet 1 of 2)

A2 N871,300[a]		B N870,250[a]		E N869,060[a]		C N868,000[b]		F N865,500[a]	
Station[b]	Elevation (feet)	Station[c]	Elevation (feet)	Station[d]	Elevation (feet)	Station[e]	Elevation (feet)	Station[f]	Elevation (feet)
100	986.3[g]	100	981[g]	100	976.9[g]	100	971.8[g]	360	938
200	953[h]	200	947.7[h]	200	943.6[h]	200	938[h]	480	936
460	954	240	948	300	944	450	940	580	936
610	956	600	950	500	946	570	942	1000	934
900	958	920	952	600	946	770	944	1240	932
1050	960	1240	954	770	948	830	946	1500	930
1140	962	1500	956	920	950	910	948	1800	928
1340	964	1820	958	1090	952	1030	946	2240	926
1450	965.8	2030	960	1370	952	1070	946	2800	925
2050	964	2670	962	1520	954	1270	948	3340	925
2570	966			1700	956	1390	950	3600	926
2880	968			1790	958	1470	952	3880	928

a. The section was drawn from west to east along the indicated grid line Arizona Grid System.

b. Station 200 is located at approximately N871,300, E216,850, Arizona Grid System.

c. Station 200 is located at approximately N870,250, E216,860, Arizona Grid System.

d. Station 200 is located at approximately N869,060, E216,730, Arizona Grid System.

e. Station 200 is located at approximately N868,000, E216,630, Arizona Grid System.

f. Station D is located at approximately N865,500, E210,000, Arizona Grid System.

g. Elevation at top of embankment.

h. Elevation at toe of embankment.

Table 2.4-18

EAST WASH CROSS-SECTIONAL DATA (Sheet 2 of 2)

A2 N871,300[(a)]		B N870,250[(a)]		E N869,060[(a)]		C N868,000[(b)]		F N865,500[(a)]	
Station[(b)]	Elevation (feet)	Station[(c)]	Elevation (feet)	Station[(d)]	Elevation (feet)	Station[(e)]	Elevation (feet)	Station[(f)]	Elevation (feet)
				1910	958	1800	954	3950	928
				2150	960	1880	954	4240	926
						2440	956	4620	924
								5000	922
								5040	922
								5380	924
								5700	926
								5960	928
								5980	930
								6050	928
								6150	930
								6180	932
								6220	934
								6250	936
								6400	936
								6460	938

and results of the wind wave and runup calculations for Winters Wash and East Wash.[(21),(22)] Streambed profiles for East Wash and Winters Wash are shown on figures 2.4-15 and 2.4-16. These calculations are based on the assumption that the embankment shown in figure 2.4-2 has 1 on 3 (rise on run) slope with stone riprap facing East Wash. Fetch diagrams for East Wash and Winters Wash are shown on figures 2.4-19 and 2.4-20, respectively.

The maximum water surface elevation was obtained at each cross-section by summing the PMF elevation, the maximum wave height, and runup on the embankment and are tabulated in table 2.4-16.

2.4.4 POTENTIAL DAM FAILURES (SEISMICALLY INDUCED)

As discussed in paragraph 2.4.1.2, there are currently eight water storage reservoirs on the Gila River system upstream from the plant site. The primary functions of these dams are:

- Generation of hydroelectric power
- Regulation of river flows for flood control
- Storage of irrigation
- Storage for industrial and municipal water supplies
- Control of water levels of natural lakes for recreation and fish and wildlife conservation.

There are also several diversion dams with no water storage capacity. Figure 2.4-3 shows the locations of the dams. Seismically induced failure of these dams was assumed. The effect of the worst permutation of dam failures on the site was evaluated. This worst case was assumed when sequential, total

failure of major dams on the Gila River and its tributaries would occur with simultaneous arrival of the peak discharge at the point in the Gila River nearest the plant site. In this manner a maximum discharge into the Gila River and its flood plain would result.

The assumption was made that Roosevelt Dam on the Salt River, Horseshoe Dam on the Verde River, Coolidge Dam on the Gila River, and Waddell Dam on the Agua Fria River fail instantaneously and completely from seismic shock. The resulting flood waves would demolish Horse Mesa, Mormon Flat, and Stewart Mountain Dams on the Salt River and Bartlett Dam on the Verde River. The flood waves generated by the dam failures on the four rivers would flow down the canyons of the respective rivers to the valleys downstream, would flow through and spread into these valleys, and would reach the point in the Gila River nearest the plant site at the same time. Reservoirs were assumed full at the time of failure.

In addition, a standard project flood (SPF) was assumed to be in progress at the time of the dam failures, with the peak discharge arriving at the point in the Gila River nearest the plant site at the same instant as the maximum peak caused by the dam failures. For this extremely conservative approach, the results indicate the maximum water surface elevation at the point in the Gila River nearest the plant site would be 900, which is 51 feet below the plant grade for Unit 3.

Table 2.4-19

COINCIDENT WIND WAVE ACTIVITY
WINTERS WASH

Effective Fetch			
α	Cos α	x_i (ft)	$x_i \bullet$ Cos α
42	0.743	6,200	4,551
36	0.809	9,300	7,524
30	0.866	10,100	8,747
24	0.914	12,700	11,608
18	0.951	17,000	16,167
12	0.978	15,800	15,452
6	0.995	16,400	16,318
0	1.000	16,400	16,400
6	0.995	13,600	13,532
12	0.978	13,200	12,910
18	0.951	12,400	11,792
24	0.914	10,300	9,414
30	0.866	10,700	9,266
36	0.809	8,500	6,877
42	0.743	8,500	6,316
Total	13.512		116,874

$$F_{eff} = \frac{\Sigma\ X_i \bullet \text{Cos}\ \alpha}{\Sigma\ \text{Cos}\ \alpha} = 12{,}350\ \text{ft}$$

Wind direction	From NW	Significant wave height	
Fetch	12,350 ft		1.99 ft
Depth	5 ft	Maximum wave height	3.32 ft
Wind speed over land	40 mi/h	Wave period	3.5 s
Wind speed over water	48.8 mi/h	Runup	4.8 ft
		Wind set-up	0.8 ft

Table 2.4-20

COINCIDENT WIND WAVE ACTIVITY ON EAST FACING EMBANKMENT
EAST WASH

Effective Fetch			
α	Cos α	x_i (ft)	$x_i \bullet$ Cos α
42	0.743	2,680	1,991
36	0.809	5,280	4,272
30	0.866	5,280	4,573
24	0.914	2,420	2,212
18	0.951	2,260	2,149
12	0.978	2,120	2,073
6	0.995	1,920	1,950
0	1.000	1,740	1,740
6	0.995	1,620	1,612
12	0.978	1,560	1,526
18	0.951	1,540	1,465
24	0.914	1,540	1,408
30	0.866	1,500	1,299
36	0.809	1,510	1,222
42	0.743	1,580	1,174
Total	13.512		30,666

$$F_{eff} = \frac{\Sigma X_i \bullet \text{Cos}\,\alpha}{\Sigma \text{Cos}\,\alpha} = 2,270\,\text{ft}$$

Wind direction	From NNE	Significant wave height	
Fetch	2,270 ft		1.5 ft
Depth	8 ft	Maximum wave height	2.51 ft
Wind speed over land	40 mi/h	Wave period	4.0 s
Wind speed over water		Runup	1.7 ft
	43.2 mi/h	Wind set-up	0.1 ft

Table 2.4-21

COINCIDENT WIND WAVE ACTIVITY ON NORTH FACING EMBANKMENT
EAST WASH

Effective Fetch			
α	Cos α	x_i (ft)	$x_i \bullet$ Cos α
42	0.743	2,200	1,635
36	0.809	6,000	4,854
30	0.866	2,340	2,026
24	0.914	2,250	2,057
18	0.951	2,040	1,940
12	0.978	21,120	20,655
6	0.995	21,120	21,014
0	1.000	21,120	21,120
6	0.995	2,180	2,169
12	0.978	2,180	2,132
18	0.951	21,120	20,085
24	0.914	3,400	3,108
30	0.866	2,200	1,905
36	0.809	1,880	1,521
42	0.743	1,720	1,278
Total	13.512		107,499

$$F_{eff} = \frac{\Sigma X_i \bullet \text{Cos}\,\alpha}{\Sigma \text{Cos}\,\alpha} = 7{,}956\,\text{ft}$$

Wind direction	From N	Significant wave height	
Fetch	7,956 ft		2.5 ft
Depth	10 ft	Maximum wave height	4.2 ft
Wind speed over land	40 mi/h	Wave period	4.3 s
Wind speed over water		Runup	3.8 ft
	46.8 mi/h	Wind set-up	0.2 ft

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2.4.4.2 Unsteady Flow Analysis of Potential Dam Failures

The dam failure hydrographs developed in the preceding section were used as the input hydrographs to the valley topographic relief encountered in the Gila River and its tributaries.

Domino-type failure of all dams was studied with timing such that the peak discharges from each of the four rivers arrive at

the point in the Gila River nearest the plant site simultaneously.

Data developed by the U.S. Army Corps of Engineers for the Gila and Salt Rivers were used to calculate diminution of peak discharge from the dam failure flood waves during the time of travel. The Corps of Engineers synthesized a PMF for the Gila and Salt River systems. Routing the PMF hydrograph downstream caused a diminution in peak discharge from approximately 5 to 10%.(3)

Diminution of peak discharge during time of travel of the dam failure waves through the valleys would be greater than during a PMF. This conservative approach assumed the percentage diminution of flow would be the same as developed by the Corps of Engineers for a PMF in the Salt River. Diminution of peak discharge between McDowell Damsite (proposed dam) and the mouth of the Salt River during a PMF would be 10% of discharge at McDowell Damsite. From the mouth of the Salt River to Gillespie Dam, the diminution of peak discharge during a PMF was computed as 5.2% of peak discharge at the mouth of the Salt River.(3) Applying these figures to the peak discharge remaining in the Salt River from multiple dam failures indicates a peak discharge at the point in the Gila River nearest the plant site would be on the order of 3.0 million cubic feet per second.

Diminution of peak discharge in the Gila River from assumed failure of Coolidge Dam was computed on a mileage basis from the Army Corps of Engineers figures for the Salt River. The Salt River data indicated a diminution of peak discharge

amounting to 0.21% of peak at the entrance to the valley for each mile of river channel in the valley. Flow in the Gila River Valley travels 90 miles from the entrance to the valley to the point opposite the plant site. At 0.21% per mile, total diminution of peak discharge would be 19% of the 2 million cubic feet per second entering the valley. Computed peak discharge reaching the point nearest the plant site was approximately 1.6 million cubic feet per second.

Diminution of peak discharge of the flood wave arising on the Agua Fria River was calculated at 10% of peak discharge entering the valley using 0.21% per mile loss for the 49 miles of valley through which the flood wave travels. Accordingly, of 1,460,000 cubic feet per second hydrograph peak entering the valley, a peak of approximately 1,300,000 cubic feet per second would reach the point in the Gila River nearest the plant site. A less conservative approach would be to utilize the "Inundation Studies" by the Bureau of Reclamation, U.S. Department of the Interior,(39) which estimates approximately 2,660,000 cubic feet per second would reach the point in the Gila River nearest the plant site.

Diminution of peak discharge of overspill from the Salt River entering Gila River Valley would be extremely high, since it would spread out approximately 15 miles while flowing overland. The amount of diminution of peak discharge is likely to be 50%, but a more conservative approach would be to use a figure of 25%. Of the 400,000 cubic feet per second of overspill, peak discharge in the Gila River arriving at the point nearest the plant site was calculated as 300,000 cubic feet per second. The SPF as determined by the Army Corps of Engineers on the

Gila River below the mouth of the Agua Fria River is 370,000 cubic feet per second, and at Gillespie Dam, 350,000 cubic feet per second.[3] For the river point nearest the plant site, a figure of 360,000 cubic feet per second was considered reasonable for peak discharge of the SPF.

Source of Peak	Peak Discharge (10^6 ft^3/s)
Agua Fria flood wave	2.66
Salt/Verde flood wave	3.00
Gila (Coolidge Dam) flood wave	1.60
Gila River SPF	0.36
Total	7.62

Thus, with simultaneous arrival of the peak discharges from multiple dam failures on the four rivers during a SPF at the point in the Gila River nearest the site, the total cumulative peak discharge is approximately 7.6 million cubic feet per second.

2.4.4.3 Water Level at the Site

Using the cross-section data and inundation maps[39][40] of the Salt, Verde and Agua Fria river systems, a slope-area computation indicates that a floodwater surface elevation of 900 would accommodate a peak discharge of 7.6 million cubic feet per second at the selected point in the Gila River, 51 feet lower than the plant grade for Unit 3. Accordingly, a peak discharge of 7.6 million cubic feet per second resulting from domino-type failure of dams in the Gila River system

upstream from the site with timing such that the peaks from each river arrive simultaneously at the point in the Gila River nearest to the plant site during a SPF, will in no way endanger the plant.

Wind waves superimposed upon these water surface elevations will not affect the site.

2.4.5 PROBABLE MAXIMUM SURGE AND SEICHE FLOODING

The plant site is near no large bodies of water for which surge or seiche flooding would apply. The potential for flooding surge or seiche does not exist in this area.

2.4.6 PROBABLE MAXIMUM TSUNAMI FLOODING

The site is near no large bodies of water for which tsunami flooding would apply. The potential for flooding by tsunami does not exist in this area.

2.4.7 ICE EFFECTS

There are no historical data to indicate the possibility of site flooding due to ice jams. Ephemeral desert streams in the site area are not subject to ice formation, due to the infrequency of flow and the desert climate.

Climatological data for Phoenix for a 13-year period indicate that the maximum daily temperature has exceeded 32F on every day of the 13-year period of record. For the same period of record, the maximum number of days per year that the daily minimum temperature was 32F and below was 14 days.(26) Outdoor safety-related facilities are protected from sub-freezing

temperatures. Pipes are installed underground. The mass of water in the essential spray ponds and safety-related tanks will not freeze because subfreezing temperatures have too short a duration. Holes are provided in selected risers in the spray piping of each spray pond to drain standing water, in the exposed piping, to preclude freezing.

2.4.8 COOLING WATER CANALS AND RESERVOIRS

2.4.8.1 Canals

No cooling water canals are utilized on this project.

2.4.8.2 Reservoirs

2.4.8.2.1 Essential Service Spray Ponds

The only reservoirs used to impound safety-related plant cooling water are the essential spray ponds. Two rectangular ponds are provided for each unit (subsection 9.2.1).

The maximum water surface and adjacent grade elevations for the ponds are shown in figure 2.4-4. The ponds are designed as Seismic Category I structures to remain functional following the safe shutdown earthquake (SSE).

2.4.8.2.2 Station Makeup Reservoirs

Makeup water is stored onsite in two independent below-grade impoundments east of the power block area as shown in figure 2.4-2. They are of approximately 85-acres and 45-acres in surface areas.

85-Acre Reservoir: Total surface area corresponding to normal operating evaluation is 85 acres with an active storage capacity of approximately 2191 acre-feet.

Total reservoir capacity is the capacity from the bottom of each reservoir (elevation 909.0 feet for 45-acre and elevation 910.5 for 85-acre) to the maximum water level (elevation 952.5 feet.) Operational capacity for each reservoir is the capacity from elevation 922.5 feet to elevation 952.5 feet. Operational capacity is calculated from elevation 922.5 feet because this is the minimum water level necessary to operate the pumps in the intake structure of each reservoir. During normal operating conditions, each reservoir operates at or below the normal operating capacity. During plant outages or in emergencies, the reservoirs may operate at the maximum operating capacities. The normal operating capacity for each reservoir is from elevation 922.5 feet to elevation 951.0 feet. The maximum operating capacity for each reservoir is from elevation 922.5 feet to elevation 952.5 feet. The total (both reservoirs combined) normal and maximum operating capacities for the 45-acre and 85-acre reservoirs were calculated and elevation-area-capacity (EAC) curves were developed (see Figure 2.4-22a, 2.4-22b, and 2.4-22c).

At normal operating water surface elevation of 951 feet, the average water depth in the reservoir is 29.5 feet. The area capacity curve for the 85-acre reservoir is shown in figure 2.4-22a. An additional 1.5 feet of depth is provided to contain the 6-hour PMP and to accommodate occasional excess flow from the reclamation plant during outages or in emergencies. A minimum 2.5-foot freeboard is provided to

accommodate waves and runup. Operation during outages or emergencies with levels between the normal and maximum operating levels (elevations 951.0 to 952.5 feet) is acceptable since there remains sufficient volume in the impoundment to accommodate the PMP. In the unlikely event of the reservoir being overtopped, flow would be directed south towards the Gila River, away from the PVNGS power block, due to site topography. Design details for the reservoir are given in figure 2.4-23.

The reservoirs are connected with a siphon line and, if necessary, the reservoirs may be used concurrently (water drawn from both reservoirs). The combined area capacity curves for the 45-acre and 85-acre reservoirs are shown at figure 2.4-22c.

45-acre Reservoir: Total surface area corresponding to normal operating elevation is 43 acres with active minimum storage capacity of 1,823 acre-feet. (The surface area at the crest elevation of 955 feet is 45.11 acres, the surface area at the maximum operating water elevation of 952.5 feet is 43.79 acres, and the surface area at the normal operating water elevation of 951 feet is 43 acres). The area capacity curve for the reservoir is shown in figure 2.4-22b for the 45 acre reservoir. An additional 1.5 feet of depth is provided to contain the 6-hour PMP and to accommodate occasional excess flow from the reclamation plant during outages or in emergencies. A minimum 2.5 foot freeboard is provided to accommodate waves and runup. Operation during outages or emergencies with levels between the normal and maximum operating levels (elevations 951.0 to 952.5 feet) is acceptable since there remains sufficient volume in the impoundment to accommodate the PMP. In the unlikely event of the reservoir being overtopped, flow would be directed south

towards the Gila River, away from the PVNGS power block, due to site topography. Design details for the 45-acre reservoir are given in figure 2.4-23.

Evaporation rates for the site area were developed using the published data listed in references 27, 28, 29 and 30. The average lake evaporation rate is 72.4 inches per year as shown in table 2.4-22. Average precipitation for the site vicinity is 7.4 inches per year as given in table 2.4-23. Based on the above, a net evaporation rate of 65 inches per year is used in the reservoir designs.

2.4.8.2.3 Evaporation Ponds

The circulating water system blowdown and waste water from other miscellaneous station sources are discharged into the evaporation ponds at an average annual flow rate of 2,530 gallons per minute with all three units operating 100% of the year. The cooling tower water chemistry is controlled at the reclamation plant process operating parameters. However, prior to being discharged into the evaporation ponds, all potentially radioactive inputs will be tested for radioactivity.

Table 2.4-22

AVERAGE MONTHLY LAKE EVAPORATION RATE NEAR SITE VICINITY

Month	Inches	Month	Inches
January	2.2	July	9.9
February	3.1	August	9.0
March	5.0	September	6.9
April	6.6	October	5.3
May	9.0	November	3.3
June	9.9	December	2.2
Total 72.4			

Those wastes exceeding the release limits stated in the Offsite Dose Calculation Manual (ODCM) will be sent to the liquid radwaste system for processing before being discharged.

Total dissolved solid content of the influent ranges from 7,000 to 30,000 mg/l. The influent carries approximately 150 tons of solids (dry weight) per day per unit into the ponds.

The evaporation ponds are designed to retain residual solids. The net lake evaporation rate for fresh water in the site area is 65 inches per year (as described in paragraph 2.4.8.2.2). Due to the continuous evaporation process from the pond, a consequent buildup of solids results in a progressive decrease in the evaporation rate. This decreased rate is provided for in the design of the evaporation ponds.

Analyses indicate that approximately 1000 acres of pond is sufficient for three units over the plant life, assuming no blowdown treatment or sludge removal.

The evaporation ponds are developed in stages as required. Approximately 250 acres of pond was constructed initially; this provided sufficient capacity for approximately 4 years from the startup of Unit 1. Then the second pond of approximately 235 surface acres was constructed in 1988 along the east side of Pond No. 1. The pond was built with a leak collection system. In 2009, rehabilitation activities started on Pond No. 2 to remove the original HDPE liner, add a composite liner, add a Leachate Collection and Removal System (LCRS), and to rework all of the embankments for construction of two internal embankments. The internal embankments divide the pond into three segments: Pond 2A (117 acres), Pond 2B (87 acres) and Pond 2C (30 acres). Pond No. 2 shares the east embankment of Pond No. 1 to the west. Pond No. 3 is an approximate 180-acre earth embankment structure constructed in late 2009. Pond No. 3 was designed with an internal divider embankment to provide operational flexibility. The divider is aligned north and south and splits the pond into two near-equal halves, Pond 3A and Pond 3B. Pond No. 3 shares the south embankment of Pond No. 1 to the north. The internal embankments divided Pond 1 into 3 segments: Pond 1A (131 acres), Pond 1B (77.5 acres) and Pond 1C (52.5 acres) during the rehabilitation.

A composite liner system in Ponds 1, 2 and 3 consists of:

- Native soil
- Compacted embankment and subgrade
- Soil cement sideslope armoring
- Continually monitored leachate collection and removal system (LCRS)

- Geosynthetic Clay Liner (GCL)
- Secondary 60-mil HDPE geomembrane
- Geonet drainage layer and
- Primary 60-mil HDPE geomembrane

Subject to the results of continuing studies of blowdown treatment methods and pond sludge removal alternatives, additional ponds may subsequently be constructed in a similar manner. The site contains sufficient area to accommodate the ultimate pond size should this be required. The locations of the evaporation ponds are shown in figure 2.4-2.

Interior pond side slopes are four horizontal to one vertical for Pond 1 and four horizontal to one vertical for Ponds 2 and 3. Design details for the evaporation ponds are given in figure 2.4-25 and 2.4-25a.

A reserve storage capacity of 1.50 feet of pond depth is provided to contain a 6-hour thunderstorm PMP and occasional plant waste water discharge during startup. In addition, a minimum of 5 feet of freeboard is provided to accommodate waves and runup based on the Bureau of Reclamation minimum criteria.

Since the ponds are designed to retain the waste water, including PMP, over the plant life, no spillway or outlet structures are provided.

2.4.9 CHANNEL DIVERSIONS

The source of cooling water for PVNGS, including a source of makeup for the essential spray ponds, is treated sewage effluent primarily from the city of Phoenix 91st Avenue treatment facility with effluent input capability and also from

other smaller facilities enroute. The effluent is conveyed to the site through approximately 35 miles of pipeline, and treated in the onsite water reclamation facility to meet plant water quality requirements. Onsite storage reservoirs provide for a continuous water supply in the event of scheduled or unscheduled interruptions or reductions in the normal water source.

Since the conveyance line, water reclamation plant, and reservoirs are not specifically designed against failure under extreme environmental conditions, the normal water source is subject to possible interruption. However, the essential spray ponds are designed to provide storage of safety-related water necessary for safe shutdown, and the ponds will not be subject to loss of function due to any interruptions in the water source.

Table 2.4-23

PRECIPITATION RATE (IN INCHES) NEAR SITE VICINITY

Station	Record (years)	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Mesa Arizona	65	0.80	0.82	0.65	0.33	0.13	0.09	0.83	1.20	0.72	0.51	0.51	0.94	7.53
Phoenix Weather Bureau AP Arizona	25	0.73	0.85	0.66	0.32	0.13	0.09	0.77	1.12	0.63	0.46	0.49	0.85	7.1
Phoenix PO Arizona	65	0.76	0.84	0.68	0.36	0.10	0.07	0.89	0.16	0.81	0.52	0.47	0.76	7.42
Tempe Arizona	35	0.85	0.80	0.74	0.32	0.17	0.09	0.78	1.24	0.63	0.52	0.51	0.93	7.58
Average Precipitation		0.79	0.83	0.33	0.13	0.13	0.09	1.82	1.18	0.70	0.50	0.50	0.87	7.42

2.4.10 FLOODING PROTECTION REQUIREMENTS

The site is subject to potential flooding from East Wash and Winters Wash as discussed in subsection 2.4.3. Flood protection will be achieved by site grading such that all Seismic Category I facilities will be located beyond the extent of PMF.

The ground elevation along the west side of the site will be raised, as indicated on figure 2.4-4, to limit the extent of PMF on the site. A maximum of about 10 feet of compacted fill will be placed in the cooling tower areas, such that ground between the peripheral road and the power block areas will be above the PMF levels. A drainage channel designed to carry 50-year flood flows will convey flood waters from the northern portion of the site, west of the peripheral road to a discharge point south of the power block area.

East Wash has been realigned along the eastern edge of the site to maximize use of the site for other facilities and to limit the extent of the PMF. The normal channel of East Wash has been blocked by an embankment between the two hills on the northern edge of the site. This embankment forces flood flows around the small hill in the northeast corner of the site and cuts off any flow through the old channel. An additional embankment has been constructed along the eastern edge of the site to prevent flooding of the site proper. This change in drainage is illustrated in figure 2.4-2. Both embankments will be constructed to elevations sufficient to prevent any overtopping by a PMF and associated wave runup and wind setup. The East Wash embankments have been constructed of material

excavated from the reservoir and power blocks. The elevation of the north-facing embankment is approximately 983 feet msl, and the elevation of the east-facing embankment starts at about elevation 972 and gradually drops to approximately 935 feet msl to meet existing contours at the southern end.

The embankments are designed to withstand static and dynamic effects of floods corresponding to the PMF. The outer faces of the embankments are protected from erosion by providing a riprap zone. The maximum water velocity during the PMF is estimated to be 6 feet per second. A Manning's "n" value of 0.030 is used in computing the maximum water velocity for erosion design only. The maximum water elevations during the PMF, including wind wave and runup, at selected cross-sections along Winters Wash and East Wash are discussed in paragraph 2.4.3.6.

The design of erosion protection for East Wash was based on references 31, 32, and 33. Side slopes of three horizontal to one vertical, estimated angle of repose of riprap material of 40 degrees with the specific weight estimated at 155 pounds per cubic foot were used for analyses. The computed values of design shear and local boundary shear are 3.6 and 3.1 pounds per square foot, respectively. Using a velocity of 6 feet per second, 10 feet maximum water depth, and an average stone diameter of 12 inches, the value of local boundary shear is 0.8 pounds per square foot, which is less than the design local boundary shear. The dumped riprap shall be 1.5 feet thick and provided with a filter blanket.

Details of riprap placement, riprap toes, depth of flow at PMF, and filter blanket are shown in figure 2.4-18. The erosion protection is provided to 2 feet above the PMF elevation, including the effects of wind and wave runup.

Rip-rap for the east side of evaporation pond No. 2 was designed in accordance with Bureau of Reclamation criteria.

2.4.11 LOW WATER CONSIDERATIONS

Plant water demands for the nonsafety-related cooling water system are normally met using effluent primarily from the city of Phoenix 91st Avenue Sewage Treatment Plant with effluent input capability also from other smaller plants enroute. The effluent is conveyed to the site by means of a pipeline and pumping facilities and is treated in the onsite water reclamation plant to meet plant water quality requirements. Onsite makeup reservoirs provide for a continuous water supply in the event of temporary interruptions in the normal water source. Groundwater from onsite wells is used for other plant water uses as discussed in paragraph 2.4.13.2.

The safety-related ultimate heat sink consists of two essential spray ponds (ESPs). The combined water inventory in the ESP is sufficient to provide a 26-day cooling capacity without water makeup. However, makeup water is provided by either the domestic water system (onsite wells) or the water storage reservoirs.

2.4.11.1 Low Flow in Streams

Low flow in streams will have no effect on safety- or non-safety-related systems.

2.4.11.2 Low Water Resulting from Surges, Seiches, or Tsunamis

This section does not apply.

2.4.11.3 Historical Low Water

This section does not apply.

2.4.11.4 Future Control

This section does not apply.

2.4.11.5 Plant Requirements

The safety-related ultimate heat sink consists of two ESPs which have a combined water inventory sufficient to provide a 26-day cooling capacity without water makeup. The ESPs will not be subject to loss of function due to any interruptions in the water source. Refer to paragraph 9.2.5.2.

2.4.11.6 Heat Sink Dependability Requirements

Each generating unit has two Seismic Category I essential spray ponds that provide the ultimate heat sink for cooling auxiliary systems required for safe reactor shutdown. The essential spray pond system is described in subsection 9.2.5. The spray ponds operate in an emergency situation and in conjunction with a normal reactor shutdown. During normal operation, the spray

ponds are operated in support of several auxiliary systems including emergency diesel generators, shutdown cooling, essential chillers, fuel pool cooling, and nuclear cooling water priority loads, as well as for chemistry control, and testing.

Separate makeup water lines are provided to each spray pond from two independent water supply sources; i.e., the station makeup water reservoirs and the domestic water system. None of the makeup water sources are safety-related since the two spray ponds for each unit contain sufficient water in storage to permit safe shutdown and cooldown of the unit and to maintain it in a safe shutdown condition for 26 days. The independent makeup water sources described above ensure a continued capability after 26 days in the safe shutdown condition.

Plant firewater requirements and sources are described in subsection 9.5.1. Firewater is not drawn from the ultimate heat sink.

2.4.12 DISPERSION, DILUTION, AND TRAVEL TIME OF ACCIDENTAL RELEASES OF LIQUID EFFLUENTS IN SURFACE WATERS

The circulating water system blowdown and waste water from other miscellaneous station sources are discharged through piping systems into the onsite evaporation ponds. Since the ponds are designed to retain the waste water, including water from a PMP, over the plant life, accidental releases of liquid effluents in surface waters are not expected to occur.

2.4.13 GROUNDWATER

2.4.13.1 Description and Onsite Use

2.4.13.1.1 Geologic Setting

The site area (5-mile radius) is in the Lower Hassayampa-Centennial groundwater basin. This basin lies within the townships T.2N, T.1N, T.1S, and the northern half of T.2S, in Ranges R.3W through R.7W (figure 2.4-26) encompassing an area of about 400 square miles.

The hydrogeologic profile of the site area is defined by three major sedimentary units, each having distinctly different lithologic and hydrologic characteristics. These units, found in most Central Arizona water basins (U.S. Bureau of Reclamation, 1977)[34], are identified herein as:

- Upper Alluvial Unit
- Middle Fine-Grained Unit
- Lower Coarse-Grained Unit

The generalized hydrogeologic profile of the site area is depicted in figure 2.4-27. A description of the sediments as they relate to the groundwater regime of the site is presented in the following paragraphs. A detailed description of the site geology is presented in paragraph 2.5.1.2.

2.4.13.1.1.1 Upper Alluvial Unit. This unit consists of primarily silty and gravelly sands of varying proportions with interlayered, discontinuous lenses of clays and silty clays. This unit, equivalent to lithozone 5 (see paragraph 2.5.1.2.3), extends to a depth of about 30 feet to 60 feet beneath the

site. Individual layers are about 3 to 10 feet thick and are characteristically moderate to poorly bedded. The stratification is typical of sediments deposited in a high-energy fluvial environment. Primary sedimentary structures identified during the detailed geologic mapping of power block excavations (appendix 2D) consist of channel cut and fill features.

The permeability of the upper alluvial unit soils was determined by inflow and outflow (pumping) type field tests. The typical horizontal permeability of these deposits is about 10 gallons per day per square foot ($5x10^{-4}$ centimeters per second). Because of the extensive stratification, the vertical permeability (not measured) can be expected to be significantly lower than the horizontal permeability.

2.4.13.1.1.2 Middle Fine-Grained Unit. This unit consists of massive, continuous layers of clays and silty clays, interbedded with thinner layers and scattered lenses of clayey silt, clayey sand, and silty sand. The thickness of the unit is about 250 feet. The upper contact of the middle fine-grained unit is equivalent to a well-defined boundary between two distinctive depositional environments and can be clearly identified across the site. Locally, the contact is transitional where a few scattered lenses of silt and fine sand are encountered. A structure contour map of the top of the middle fine-grained unit is presented in figure 2.4-28. The middle fine-grained unit corresponds to lithozones 3 and 4 of the geologic model (see paragraph 2.5.1.2.3). The distinction between the two zones in the middle fine-grained unit is based

on subtle but definite differences in geotechnical and hydrologic properties. Silty clays of medium plasticity predominate in the upper zone (lithozone 4), while clays of somewhat higher plasticity predominate in the lower zone (lithozone 3 -- the Palo Verde clay). The two zones are separated by a relatively continuous coarse-grained soil layer.

The permeability characteristics of soils in the upper portion of the unit were evaluated by both laboratory and field tests (appendix 2G). The vertical permeability, determined by laboratory tests, is on the order of 0.001 gallons per day per square foot ($5x10^{-8}$ centimeters per second). The horizontal permeability, determined by field tests, is approximately one order of magnitude higher. The permeability characteristics of the Palo Verde clay were evaluated only by laboratory tests. Measured permeabilities in the vertical and horizontal directions are on the order of 0.0005 gallons per day per square foot ($2.5x10^{-8}$ centimeters per second) and 0.01 gallons per day per square foot ($5x10^{-7}$ centimeters per second), respectively.

2.4.13.1.1.3 Lower Coarse-Grained Unit. In general, the lower coarse-grained unit is described as a "variably cemented conglomerate which lies directly on the undifferentiated basement complex".[(34)] In the site area, the lower coarse-grained unit consists of a tilted interbedded sequence of volcanic flows and flow breccias, tuffs, tuffaceous sandstones, and coarse-grained arkosic sandstone. The flow breccias (which may be interpreted as the "variably cemented conglomerate") are common throughout the sequence (lithozone 0). Locally mantling

this volcanic/sedimentary section are deposits of moderately-to well-lithified fanglomerates (lithozone 1). The entire sequence is overlain by an unlithified to poorly-cemented silty sand, sand, and gravelly sand (lithozone 2) (refer to figure 2.4-27).

The permeability of the regional aquifer was assessed by reviewing irrigation well pumping records (see paragraph 2.4.13.2) and performing an aquifer pumping test (appendix 2G). Yields from irrigation wells which tap the regional aquifer range from 400 to 2800 gallons per minute. The average specific capacity is 35 gallons per minute per foot of drawdown. The aquifer pumping test, performed on an existing irrigation well (B-1-6 - 34abb) resulted in a calculated transmissivity of 100,000 gallons per day per foot and a storage coefficient of 0.005. The pumping rate during the test was 2360 gallons per minute.

2.4.13.1.2 Groundwater Conditions

In the site area, the groundwater reservoir consists of an extensive regional aquifer and a local perched water zone.

2.4.13.1.2.1 Regional Aquifer. In the site area, the lower coarse-grained unit, described in the preceding section, comprises the regional aquifer that extends to over 400 square miles. The regional aquifer is bounded by the mountain masses that encompass the Lower Hassayampa Centennial area (figure 2.4-26).

The primary recharge source to the regional aquifer in the site area is underflow from upper Hassayampa Valley, north of the

site area. The general flow direction is north to south. Reversal of flow direction occurs locally where the groundwater levels are depressed due to pumping for irrigation purposes. Infiltration of precipitation, surface runoff, and return flow from irrigation in the vicinity of the site comprise a small portion of the total recharge of the regional aquifer.

Discharge from the regional groundwater reservoir occurs as underflow to Arlington Valley (to the south of the site) and pumpage from irrigation wells. A detailed discussion of water use in the vicinity of the site is provided in paragraph 2.4.13.2.

Piezometric levels in the vicinity of the site are at depths ranging from 100 to 250 feet below the ground surface. A water level contour map of the regional aquifer in the lower Hassayampa-Centennial area was constructed by the U.S. Geological Survey[35] and is reproduced in figure 2.4-29. The most conspicuous hydrological features indicated by the water level contours are the large cone of depression beneath the site, and a broader but shallower cone of depression south of the site. A smaller cone of depression also occurs immediately north of the Palo Verde Hills. The cones of depression have been formed by long-term pumpage from irrigation wells in the area (see paragraph 2.4.13.2). Artesian conditions prevail within the aquifer in the site area. Confinement is generally provided by the middle fine-grained layer.

2.4.13.1.2.2 Perched Water Zone. The Palo Verde site is situated in an area that was under cultivation from about 1950 to late 1975. Water for crop irrigation was pumped from the

regional aquifer. Most of the water was consumed by the crops (primarily cotton) through evapo-transpiration. The remainder of the water percolated through the upper alluvial sediments and perched on top of the underlying aquitard (middle fine-grained unit). The shape of the perched mound is consistent with the shape of the irrigated area within the site (see figure 2.4-30). Water table conditions prevail within the perched water zone.

During the 25-year period of agricultural activity at the site, the prime source of recharge of the perched water zone was excess irrigation water that percolated through the upper sediments. Since 1975, when agricultural activity stopped within the site, the only source of recharge has been precipitation and surface runoff. However, as evidenced by the sharp decline in perched water levels since 1975 (3 feet per year average -- refer to paragraph 2.4.13.2) local natural recharge is insufficient to maintain the perched mound. The decay of the perched water mound is caused mainly by radial flow outward from the center of the mound and some downward leakage through the aquitard.

2.4.13.1.3 Onsite Use

A detailed discussion of present and projected groundwater use, as well as its effect on groundwater levels, is presented in paragraph 2.4.13.2.

2.4.13.2 Sources

2.4.13.2.1 Regional Water Use

Water for irrigation is the major use of groundwater in the lower Hassayampa-Centennial area. An average of 78,000 acre-feet per year was pumped during the period 1966 through 1972. The water for municipal and domestic use, also obtained from the groundwater reservoir, is very small. Annual pumpage for municipalities, livestock, or industrial purposes is less than 1% of the total.

The production history of wells in the lower Hassayampa-Centennial area is compiled in table 2.4-24. The table lists well locations for known active wells and the annual pumpage rate for each well for the years 1966 through 1972. The location of these wells is shown in figure 2.4-31. A steady decline of the water levels in the area began about 1950 due to the increase in pumping of groundwater for agriculture. The water level has declined by as much as 100 feet near the centers of cones of depression during the past 25 years (see figure 2.4-32). The water level decline is attributed to pumping of wells and the resultant spread of the cones of depression and consequent interference effects between wells.

2.4.13.2.2 Onsite Water Use

During the 25-year period (1950-1975) of agricultural activity at the site, water was pumped heavily from the regional aquifer, resulting in the localized depression of water levels depicted in figure 2.4-29. The locations of irrigation wells in the site area and its vicinity are shown in figure 2.4-33.

In 1972, four existing irrigation wells within the PVNGS property yielded a total of 7542 acre-feet of water. The site wells yielded a total average of 6000 acre-feet per year from 1966 through 1972. Most of the water (83%) was pumped from wells (B-1-6)34abb and 34acc.

Irrigation stopped in late 1975, a few months prior to the start of construction. Well No. (B-1-6)34abb has been used since as the primary well for construction water supply with (B-1-6)27ddc as the backup well. During the period 1976 through 1978, the combined pumping rate of these two wells has been about 350 acre-feet per year (see table 2.4-25). This quantity corresponds to approximately one-twentieth of the annual groundwater withdrawal from onsite wells during the last few years of irrigation.

The impact of groundwater withdrawal on regional aquifer water levels is demonstrated in the hydrographs of onsite wells (figure 2.4-32). Water levels declined steadily during the 25-year period (1950-1975) of agricultural activity. During this period, water level declines in the wells ranged from 50 to 100 feet. Since 1975, water levels have risen in response to the cessation of agricultural pumpage. The significant reduction (from 6000 to 350 acre-feet per year) in annual groundwater withdrawal rates has resulted in water level rises of about 20 feet in 3 years.

Table 2.4-24
PUMPAGE RECORDS OF WELLS IN THE LOWER
HASSAYAMPA-CENTENNIAL AREA[a] (Sheet 1 of 2)

WELL NO.		ANNUAL PUMPAGE (IN ACRE-FEET)						
		1966	1967	1968	1969	1970	1971	1972
(B-1-5)	$6ddb_2$						80	
	7aab						80	
	10bbc				1		2	5
	10ccc				1	5		
	$15bbb_2$				2	2		
	16bbb	556	654	470	663	0		
	16bca	558	550	372	448	0		
	17acd	105	117	92	96	212	328	140
	21bbb	249	284	34	14	0		
	21ddb	82	75	58	81	30	36	
	27bbc	101	48	54	49	41	55	48
	$28aaa_2$	83	74	61	81		15	56
(B-1-6)	7bdd	258	240	249	309	290	302	154
	8abb	398	1,959	799	852	435	758	715
	10aab	592	812	763	709	492	661	813
	11bca	40	35	97	33	18	103	161
	20dab	57	76	42	76			
	20dbb	25	43	129	486	478	1,155	849
	27cbc[b]	63	106	315	97	22	24	44
	27ddc[b]	723	957	790	916	655	779	1,277
	34abb[b]	2,099	2,684	2,373	2,176	2,157	2,105	2,583
	34acc[b]	2,079	2,960	2,319	2,914	2,247	2,343	3,638
	34adc[b]				166	31	45	0
(B-1-7)	1bbb	1,725	1,820	2,690	2,800	3,064	2,991	3,815
(B-2-6)	5daa				1,374	1,363	1,277	1,707
	6daa				1.827	1,659	1,997	2,087
	8aaa				1,580	1,372	2,193	2,303
	9bba				1,334	979	1,995	1,896
	16caa				561	414	448	647
	17aaa				1,925	2,200	2,193	2,412
	17daa				1,022	1,479	1,463	1,565
	19bbb						20	
	19daa				89	207	680	998
	20bba				841	806	981	890
	20daa	758	762	827	661	545	802	604
	21bba				386	662	466	670
	23aab	364	1,140	1,205	706	807	805	705
	24cba						100	
	28bab	1,184	1,494	1,829	984	1,340	1,661	1,767
	31daa	1,557	2,325	2,581	2,394	2,365	2,258	2,505
	32db							
	33caa	658	1,341	994	962	1,134	1,069	2,038
(B-2-7)	12cbb						20	
	14cbb				1,241	1,489	1,461	1,866
	22bbb							
	22cbb	549	670	355	353	144	246	
	23ccb	773	1,399	1,454	1,453	1,685	1,631	1,562
	25bca	15	35	475	386	588	1,058	946
	26aac	1.9	2.1	3	4	4		
	26abb	619	884	682	724	759	713	697

a. Data compiled from files of Water Resources Division, U.S. Geological Survey, Phoenix,Arizona.
b. Wells located within the PVNGS Site.

Table 2.4-24
PUMPAGE RECORDS OF WELLS IN THE LOWER
HASSAYAMPA-CENTENNIAL AREA[(a)] (Sheet 2 of 2)

WELL NO.	ANNUAL PUMPAGE (IN ACRE-FEET)						
	1966	1967	1968	1969	1970	1971	1972
(B-2-7) 26acb	1,286	1,588	1,305	1,216	1,340	1,467	1,479
26bab	318	516	674	802	1,106	970	823
27aab	358	491	607	594	598		
28bab	1,020	1,067	909	919	667	1,283	1,390
28bbb	528	564	442	394	410	466	559
34bba	653	822	393	80			
36abb	1,324	1,996	2,012	2,041	3,198	3,407	3,414
36bba	477	952	895	845	776	720	606
36cbb	503	1,110	1,121	1,056	887	986	832
(C-1-5) 1cdd						500	
3baa$_2$				422	300	502	106
4aaa$_2$				26	21	44	46
13aab				2,429	2,028	1,633	2,193
13aad				1,624	1,310	790	1,018
13bad				917	1,578	1,431	1,255
13bba				1,076	1,647	787	1,049
13cdd				910	1,616	1,245	1,167
21cdd	501	736	382	476	678	1,330	556
22ccc	614	1,541	531	858	1,328	1,875	1,060
23ccc				2,513	2,545	3,614	1,496
23dca				951	747	1,071	360
24ccb				574	861	1,302	502
36abb				1,838	2,352	4,336	2,380
27ddd$_2$	1,117	1,201	1,763	1,751	1,212	1,704	1,536
28aab	343	490	405	356	583	621	608
29adc	571	820	471	910	588	1,490	614
32baa	1,395	1,988	1,600	2,578	2,000(a)	2,547	1,475
32ccb	713	526		1,113	1,250	1,944	986
34adc	301	548	862	755	660	890	677
34dbd	36		0	308	359	255	63
(C-1-6) 13cab	397	545	513	544			
14dbb	1,150	2,019	1,935	1,538	1,270	1,763	1,892
17abb	1,738	673	1,269	1,242	1,231	1,310	2,260
18bbb	1,196	1,005	752	1,496	728	1,750	1,300
19abb	79	867	772	1,388	66		
21cbb$_2$	153	816	870	1,016			
23adb	1,026	1,500	1,219	1,131	1,120	974	1,468
23bab	410	260	396	374	234	478	488
23caa		965	901	772	878	1,016	1,345
26aba	711	956	926	830	561	604	539
26dad	1,510	1,714	1,672	1,939	1,685	2,066	2,130
27bbc	2,391	2,560	2,239	2,454	2,046	1,955	894
28acc$_2$	1,560	2,610	1,996	1,992	1,792	1,384	985
(C-1-7) 14bbb	141	78	135		114		
(C-2-5) 3aaa				928	752	999	764
5bcb		913	718	959	1,126	1,595	745
5ccb	617	1,022	511	518	588	999	333
8abb		1,281	906	1,160	1,130	1,064	1,317
8ccc	2,237	2,726	1,541	2,135	1,770	2,546	3,254
9cbb		2,865	2,189	2,726	2,238	1,145	907
16abb	0		1,450	1,106	1,197	1,265	840
16daa	1,111	1,060	1,342	530	530	1,490	1,641

Table 2.4-25

WELL PUMPING RATES DURING CONSTRUCTION

Well No.	Annual Pumpage in Acre Feet		
	1976	1977	1978
(B-1-6)34abb	287	283	314
(B-1-6)27ddc	48	68	58
Total	335	351	372

As noted in paragraph 2.4.13.1, agricultural activity also created a perched water mound above the aquitard beneath the site. Perched water levels have been monitored since late 1973. Hydrographs for perched water level monitoring wells are presented in figures 2.4-34 through 2.4-38. The locations of these wells are shown in figures 2.4-30 and 2.4-39. During the last 2 years of irrigation (1974 and 1975), perched water levels remained essentially constant (except for seasonal fluctuations), indicating that approximately steady-state conditions had been reached. A steady decline in perched water levels has been observed since 1975 when agricultural activities ceased in the site area. The average rate of perched water level decline since 1975 has been about 3 feet per year. Most hydrographs show a decrease in the rate of water level decline with time.

2.4.13.2.3 Projected Groundwater Use and its Impact on Water Levels

During plant operation, groundwater from the regional aquifer will be used only for the domestic water supply. The domestic water requirement for three units is estimated to be about

1000 gallons per minute (1600 acre-feet per year). This rate of groundwater withdrawal is about one-fourth the withdrawal rate during the last few years of irrigation.

The effects of onsite pumping for the domestic water supply on regional aquifer water levels were evaluated by an analysis presented in the PVNGS 1, 2, and 3 PSAR. The analysis was based on values of transmissivity (100,000 gallons per day per foot) and storage coefficient (0.005) determined by a pump test conducted on the production well (B-1-6-34abb). For the projected pumping rate of 1600 acre-feet per year, the predicted drawdown in the production well after 35 years of operation is 30 feet. By the same analysis, the predicted drawdown at distances of 0.5, 1, 2, 5, and 10 miles is 10.6, 9.1, 7.5, 5.3, and 3.7 feet, respectively.

These predictions are very conservative because they do not incorporate the compensating effects of cessation of irrigation in the site area. As noted in paragraph 2.4.13.2.2, a significant rise in water levels has been observed since 1975 due to the reduction of onsite pumping rates from about 6000 acre-feet per year (related to agricultural activity) to 350 acre-feet per year during construction. Because of this reduced pumping rate, regional aquifer water levels are expected to continue to rise during construction. When all three units are in operation, and the pumping rate is increased to 1600 acre-feet per year, water levels can be expected to decline, but at a rate slower than that observed during irrigation (prior to 1975). The net impact of pumping for plant operations is, therefore, expected to be even smaller than that predicted by the analysis presented in the PSAR.

2.4.13.2.4 Recharge From Local Sources

To analyze the long-term seepage effect on the movement of the perched-water table, a digital simulation was performed. Figure 2.4-42 shows the general configuration of the water storage reservoir and evaporation pond used in this analysis. The time-dependent, two-dimensional flow of groundwater in a nonhomogeneous and isotropic aquifer is governed by the following equation:

$$\frac{\partial}{\partial x}\left(T\frac{\partial h}{\partial x}\right)+\frac{\partial}{\partial y}\left(T\frac{\partial h}{\partial y}\right)=S\frac{\partial h}{\partial t}+Q \qquad (9)$$

Terms in this relationship, along with others used in the text, are defined as follows:

x,y = Cartesian coordinates

T = aquifer transmissivity = $k_h h$

h = thickness of horizontal flow zone

S = aquifer storage coefficient

t = time

Q = net groundwater loss rate per unit area

$K_{(h)}$ = horizontal permeability (hydraulic conductivity)

There is no general solution to the above equation; however, numerical solutions can be obtained. Prickett and Lonnquist[36] have developed a digital computer simulation code through a finite difference approach at the Illinois State Water Survey. Many different types of groundwater simulation conditions were presented in their report. The Water Table Condition Code,

which was designed to simulate groundwater mound decay and recharge, was used in this study.

A. Assumptions Used in Simulation

Water was assumed to seep from the bottom of the 80-acre water storage reservoir at the rate of 75 feet per year and be immediately transported down to the aquitard surface. Seepage from the storage reservoir continued in the simulation at the rate of 75 feet per year until the perched-groundwater mound rose to the bottom of the reservoir, at which time the seepage decreased linearly to zero as the groundwater mound surface approached the maximum reservoir water level. The simulation was insensitive to the initial seepage rate because the perched mound rose to the reservoir bottom in a matter of months. From then on the seepage rate declined, being controlled by other site parameters.

Inflow to the evaporation pond was assumed to be 954 gallons per minute per unit as the respective units start up in May 1983, May 1984, and May 1986. When the groundwater mound was below the bottom of the evaporation pond (elevation 920 feet above msl), the incoming blowdown was assumed to seep into the ground. When the groundwater mound rose above the bottom of the evaporation pond, an annual evaporation rate of 72 inches was assumed.[37] Evaporation was only considered when water was standing in the evaporation

pond. Seepage was decreased linearly in the same manner as in the storage reservoir.

Leakage through the fine-grained aquitard was allowed to occur in the simulation in the downward direction only. The complication of some actual horizontal movement within the aquitard was avoided by considering only vertical permeabilities and gradients. Leakage through the aquitard was simulated using the following equation:

$$Q_n = \left(K_v / m'\right) \Delta h A_s \qquad (10)$$

where:

Q_n = infiltration rate through the aquitard

K_v = vertical permeability of the aquitard

m' = thickness of the aquitard

Δh = head difference across the aquitard

A_s = area of a grid square

K_v and m' are obtained from field data.

B. Summary of Simulation Conditions and Assumptions

- Time zero was October 1976.
- Each time step represented 30 days.
- Grid points were 1000 feet apart in the north-south and east-west directions.
- Both the storage reservoir and evaporation pond were assumed to be unlined.

- Storage reservoir was assumed to be full at Unit 1 startup in May 1983.
- Each grid point in the storage reservoir was initially assumed to seep 75 feet per year multiplied by the area in square feet of that grid square within the reservoir and above the aquitard until the groundwater mound rose to the reservoir bottom. At that point, seepage began to decrease linearly to zero as the groundwater mound approached the maximum water surface elevation of the reservoir.
- The bottom of the storage reservoir was taken as 921 feet above msl with a water surface of 950 feet msl.
- The evaporation pond was assumed to receive 954 gallons per minute per unit as the respective units start up in May 1983, May 1984, and May 1986.
- When the groundwater mound was below the bottom of the evaporation pond (elevation 920 feet msl), all of the incoming blowdown was assumed to seep into the ground. When the groundwater mound rose above the bottom of the evaporation pond, an annual evaporation rate of 72 inches was assumed.[37]
- K_h of the upper coarse-grained material was represented by 10 gallons per day per square foot.
- K_v of the aquitard was represented by 0.001 gallons per day per square foot.

- The storage coefficient S of the upper coarse-grained material was assumed to be 0.2.
- Aquitard surface contours, figure 2.4-28.
- Aquitard thickness contours, figure 2.4-39.

C. Site Parameters

In the seepage model, the horizontal permeability (hydraulic conductivity) of the upper coarse-grained soil layer was represented by a value of 10 gallons per day per square foot (5 x 10^{-4} centimeters per second). Similarly, the vertical permeability of the fine-grained soil layer (aquitard) was represented by a value of 0.001 gallons per day per square foot (5 x 10^{-8} centimeters per second). These values were selected after a thorough evaluation of field and laboratory permeability test data developed at the site for this purpose. The selection process is described in detail in PVNGS 4 and 5 PSAR, Appendix 2Y. Permeability test data are presented in appendix 2G.

D. Groundwater Level Prediction

Predicted groundwater levels, as shown in figure 2.4-40, from the digital simulation are 915, 909, and 909 feet for Units 1, 2, and 3, respectively. The design groundwater levels of the units are 927, 924, and 921 feet for Units 1, 2, and 3, respectively. Throughout the operating life, therefore, water levels under each unit are predicted to stay below design groundwater levels.

The analysis of long-term seepage effects was based on an evaporation pond location as indicated in figure 2.4-42. If eventual construction of some or all of the evaporation pond was further south than shown on figure 2.4-42 or at a bottom elevation less than 920 feet msl, water levels under the units would be lower than those predicted here. This conclusion is based on the following facts:

- The distance from the evaporation pond to the units would be increased by moving the ponds southward
- The aquitard surface slopes to the south
- Lowering the pond bottom elevation would lead to a decreased head difference between the water level in the pond and the design structural integrity levels under the units.

2.4.13.3 Accident Effects

Contaminated water, if accidentally spilled during plant operation, may seep through the ground surface. For this postulated occurrence, the contaminated water will infiltrate downward through the unsaturated soil and reach the perched water table about 40 feet below the land surface. It will then disperse into the perched groundwater. Further downward movement of water from the base of perched water zone is restricted due to the presence of the Palo Verde clay layer about 200 feet below the ground surface. For the conservative analysis used in this study it is assumed that seepage could occur through the Palo Verde clay layer. Consequently, two

systems are analyzed for the possible effect of a contaminated water spill; the perched water zone and the underlying regional aquifer. The impact of such postulated accidental see pages on the groundwater system, and, in particular, on the existing wells located in the 5-mile zone around the site area, is analytically predicted and its consequences are assessed.

2.4.13.3.1 Inventory of Existing Wells in the Site Vicinity

There are 18 groundwater wells located within 2 miles and another 69 wells located between 2 and 5 miles of the plant site. Among them, 17 of the wells have depths less than 200 feet and draw their water from the perched water zone, while the remaining 70 wells draw their water from the regional confined aquifer below the Palo Verde clay layer.

2.4.13.3.2 Accidents Leading to Liquid Spills

The PVNGS is designed for zero release (releases less than the LLD values shown in the Offsite Dose Calculation Manual (ODCM)) of radioactive liquids of plant origin at or beyond the site boundary during normal operation. None of the defined accidents will be likely to result in any liquid release to the groundwater in the site area. However, to be conservative, it is assumed that the 808,850-gallon refueling water tank (RWT) (volume represents the maximum free space within the RWT tank source terms in table 2.4-26) and its surrounding walls fail, and the contents are instantaneously released to the groundwater. The computations were performed to determine the contaminants concentration at the nearest exclusion boundary on the downgradient groundwater flow direction of the perched

water and regional aquifers. Another possible point of discharge to ground water is the evaporation pond. Computations were performed for liquid releases due to pond liner failure. This calculation determined that effluent concentrations would be less than those associated with the RWT failure.

2.4.13.3.3 Analytical Approach to the Contaminant Movement

Water from a failure of the refueling tank (RWT) on the ground is assumed to percolate through the unsaturated soil before mixing with perched water. When the contaminated liquid reaches the perched water surface, dispersion takes place.

This methodolgy calculates radionuclide concentrations in a potable water supply well due to a catastrophic rupture and liquid spill from the Refueling Water Tank (RWT). The well draws its water from the perched water aquifer at the nearest exclusion area boundary (EAB) in the direction groundwater flow.

Radionuclide Concentration at EAB Perched Water Zone

A vertically averaged groundwater dispersion model with a horizontal area source is used as it is defined in reference 38. This model is for calculating the concentration in the aquifer at some point gradient of a release (e.g., water supply well), and it is the solution for the limiting case of unidirectional saturated convective transport with three dimensional dispersion in an isotropic aquifer:

Table 2.4-26

RADIONUCLIDES AND ACTIVITIES IN REFUELING WATER TANK

(Sheet 1 of 2)

Nuclide	Half-Life	RWT Inventory (Ci)[a]
Sr-89	50.8 days	1.39E-03
Sr-90	28.9 years	6.74E-04
Y-90	64 hours	6.74E-04
Sr-91	9.67 hours	6.39E-08
Y-91	58.8 hour	2.46E-04
Mo-99	66.6 hours	4.55E-04
Ru-103	39.8 days	4.93E-05
Ru-106	368 days	1.92E-04
Te-129	34.1 days	2.18E-05
I-129	1.6 E+7 years	6.64E-08
I-131	8.065 days	2.00E-02
Te-132	26.89 years	4.46E-04
I-132	2.84 hours	4.58E-04
I-133	20.8 hours	1.66E-04
I-134	52.3 minute	5.44E-09
Cs-134	2.06 years	2.00E+01
I-135	6.7 hours	5.19E-06
Cs-136	13.0 days	4.98E-02
Cs-137	30.2 years	3.90E+01
Ba-140	12.8 days	1.64E-04
La-140	40.0 hours	1.86E-04
Pr-143	13.58 days	3.64E-05
Ce-144	284.4 days	9.74E-04
Co-60	5.26 years	1.31E-01
Fe-55	2.6 years	2.68E-01

Table 2.4-26

RADIONUCLIDES AND ACTIVITIES IN REFUELING WATER TANK

(Sheet 2 of 2)

Nuclide	Half-Life	RWT Inventory (Ci)[a]
Fe-59	45 days	6.62E-03
Co-58	71.4 days	1.85E-01
Mn-54	313 days	2.39E-01
Cr-51	2.78 days	3.40E-02
Zr-95	65.5 days	2.84E-04

a. Based on 60 Ci total RWT inventory excluding tritium.

$$\frac{\partial c}{\partial t} + \frac{U\partial c}{R_d\partial x} = \frac{D_x\partial^2 c}{R_{d\partial x}{}^2} + \frac{D_y\partial^2 c}{R_{d\partial y}{}^2} + \frac{D_z\partial^2 c}{R_{d\partial z}{}^2} - \lambda c \qquad (11)$$

where:

c is the concentration in the liquid phase (Ci/cm^3),

D_x, D_y, D_z are the dispersion coefficients in x, y, z directions (cm^2/s), is the decay coefficient (1/s),

U is the seepage velocity in x direction (cm/s),

R_d is the retardation factor (dimensionless).

Solution to this equation can be found in terms of Green's functions as follows:

$$c_i = \frac{1}{neR_d} X(x)Y(y)Z(z) \qquad (12)$$

where:

Ci is the concentration at any point in space for instantaneous one curie release, and n_e is effective porosity;

where, for a horizontal area source of length l and width w centered at (0, 0, 0) in an aquifer of constant depth b:

$$X = \frac{1}{2l}\left\{\mathrm{erf}\,\frac{\left(x+\frac{1}{2}\right)-\frac{Ut}{R_d}}{\sqrt{4\frac{D_x}{R_d}t}} - \mathrm{erf}\,\frac{\left(x-\frac{1}{2}\right)-\frac{Ut}{R_d}}{\sqrt{4\frac{D_x}{R_d}t}}\right\}\exp(-\lambda t) \qquad (13)$$

$$Y = \frac{1}{2w}\left\{\operatorname{erf}\frac{\left(\frac{w}{2}+y\right)}{\sqrt{4\frac{D_y}{R_d}t}} + \operatorname{erf}\frac{\left(\frac{w}{2}-y\right)}{\sqrt{4\frac{D_y}{R_d}t}}\right\} \tag{14}$$

$$Z = \frac{1}{b} \tag{15}$$

Seepage velocity is defined as (U_i):

$$U_i = \frac{V_x}{n_e} \tag{16}$$

where V_x is the flux that can be approximated by:

$$V_x = -K\frac{dH}{dx} \approx -K\frac{\Delta H}{\Delta x} \tag{17}$$

where $\frac{\Delta H}{\Delta x}$ is the hydraulic gradient in the direction of flow that represents elevation head through distance in the x direction (dimensionless). K is respectively permeability (cm/s).

Retardation factor is defined as (R_d):

$$R_d \approx 1 + \frac{\rho}{n}K_d \tag{18}$$

where n is the total porosity, ρ is the bulk density (gm/cm^3) and K_d is the distribution coefficient (ml/g). Retardation coefficients of unity has been used for this analysis (i.e., no retardation).

Dispersion coefficient is defined as (D_i):

$$D_x = \alpha_L U_x \text{ and } D_y = \alpha_T U \tag{19}$$

Where α_L and α_T are the longitudinal and transverse dispersivities respectively.

Radionuclide Concentration in Regional Aquifer

The liquid from Refueling Water Tank (RWT) which migrates to the perched ground water zone, could percolate vertically downward through the several soil layers and reach the regional aquifer approximately 150 ft. below ground surface. The Middle Fine Grained Unit lies between the perched water zone and the regional aquifer. It is divided into the Upper Middle Fine Grained Unit and Lower Middle Grained Unit. The Upper Middle Fine Grained Unit is divided into 3 layers each 40 ft. thick for the purpose of this evaluation. The Lower Middle Fine Grained Unit is the Palo Verde Clay layer. The transport time through each vertical layer is determined based on the layer's thickness, its permeability, and the vertical hydraulic gradient

$$\tau = \left(\sum_{i}^{N,3} \left(\Delta h_i \right) / U_i \right) \qquad (20)$$

Where:

τ is the total transport time through vertical layers (day), Δhi is the thickness of each layer (ft.), U_i is seepage velocity each layer (ft./ day) as defined below;

$$U_i = K_i \times \left(\left(\frac{\Delta H}{\Delta x} \right) / \left(n_e \right) \right) \qquad (21)$$

Where;

K_v is the vertical permeability (ft./day), $\frac{\Delta H}{\Delta x}$ is the vertical hydraulic gradient (dimensionless) and n_e is the effective porosity (dimensionless).

2.4.13.3.4 The Results of Analysis

2.4.13.3.4.1 Unsaturated Flow. There are more than 40 feet of unsaturated soil above the perched water zone. Percolating this unsaturated soil, the spill will be dispersed and diluted. However, to be conservative, no credit has been given to the dilution capability or percolation through the unsaturated soil in the following calculation.

2.4.13.3.4.2 Perched Water Zone. It is conservatively assumed that the spill will not be diluted or dispersed before it reaches the perched water zone. In the event of either a slow leak or a tank and wall failure, the liquid would spread to some negligible depth over the ground surface. For a conservative analysis, a depth of 6 inches is assumed which will occupy a 500-square foot area. The horizontal conductivity or permeability of the upper coarse grained soil layer was determined to be 10 gallons per day per square foot (489 feet per year or 5×10^{-4} cm/s) and the effective porosity was determined to be 0.37.

The maximum possible groundwater gradient was chosen by assuming that groundwater was at the design water elevation of 921 feet at Unit 3 power block and that groundwater was at the aquitard surface at the site boundary elevation of 905 ft. On a line 270° from Unit 3, the gradient over the 2930 feet to the

site boundary was 0.0055 foot per foot. This yields a down-gradient flow velocity of 7.64 feet per year.

The long half-life radionuclides, Cs-137, Co-60, Sr-90 and H-3 are the only isotopes that may reach the perch water zone, the results are summarized as follows:

It can be seen that any spill in the perched zone that reaches the exclusion boundary will be below any maximum permissible concentration in water (MPCw) listed in 10CFR20, Appendix B, Table II[41].

Radionuclide	Half life	RWT Inventory	Time to reach Max Concentration	Maximum Concentration at EAB potable water source	Criteria[a]
	Years	μCi	Year	μCi/ml	μCi/ml
H-3	12.3	2.00E+09	180	8.9E-09	3.0E-05
Sr-90	28.9	6.74E+02	240	2.4E-12	3.0E-09
Cs-137	30.2	3.9E+07	245	1.8E-07	2.0E-07
Co-60	5.3	1.31E+05	125	7.3E-18	3.0E-07

a. One percent of the 10CFR20 appendix B. Table II. Column 2, 1981.

2.4.13.3.4.3 Regional Water Aquifer. It is assumed that the perched water percolates through the Palo Verde clay layer into the regional aquifer. The regional aquifer is located below the perched water zone. It is approximately 150 ft. below the perched water zone; see figure 2.4-27 for details. Vertical permeability for upper middle fine and middle fine and bottom layers are estimated to be 5.67E-3, 2.83E-4 and 5.67E-3 ft./day respectively. The Palo Verde clay layer permeability is 1.843E-5 ft./day. The effective porosity is estimated at 0.37.

A conservative and average hydraulic gradient of 0.0055 feet per feet was determined from the regional water level contours of figure 2.4-29.

The contaminated liquid will be greatly decayed before it proceeds to the Palo Verde clay layer about 200 feet below ground surface. The maximum concentration along the top of the Palo Verde layer without radioactive decay can be obtained from equation 20 and 21 in the vertical direction.

Taking into account the time required to reach this maximum value at the top of clay layer. Concentration of radio isotopes at the regional aquifer would be much less than the perched water zone and well within the one percent limit of 10CFR20 Table II, MPCs.

These calculations present a conservative study, since the dilution capability of the unsaturated soil and the ion exchange process with soil have been neglected. Thus, the accidental spill would result in minimal effect on the environment.

2.4.13.4 Monitoring or Safeguard Requirements

Effects of plant operation on the groundwater system are expected to be minor. The groundwater level and groundwater quality will be monitored to detect the effects, if any, of plant operation.

2.4.13.4.1 Groundwater Level Monitoring

The groundwater levels of both shallow perched zone and deeper regional aquifer will be monitored as described in permits as required by Arizona Statues and Administrative Codes.

2.4.13.4.2 Groundwater Quality Monitoring

The groundwater quality monitoring program is described in permits as required by Arizona Statues and administrative codes.

2.4.13.5 Design Bases for Subsurface Hydrostatic Loadings

The following design groundwater elevations are used as the basis for calculating groundwater-induced hydrostatic loadings on subsurface portions of safety-related structures:

Structure	Design Groundwater Elevation (ft)	Plant Grade at Structures (ft)
Unit 1	927	957
Unit 2	924	954
Unit 3	921	951

The groundwater level beneath each unit is predicted to remain well below its respective design groundwater elevation during the 40-year plant life (paragraph 2.4.13.1.2).

2.4.14 TECHNICAL SPECIFICATION AND EMERGENCY OPERATION REQUIREMENTS

No technical specification and/or emergency operation requirements are necessary.

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2.5 GEOLOGY, SEISMOLOGY, AND GEOTECHNICAL ENGINEERING

Summary of Geotechnical Methodology

This section presents the geologic, seismic, and foundation engineering data developed for PVNGS. The location of the site is shown on figure 1.2-1.

The purpose of this program was to thoroughly investigate the regional and site geology, seismology, and foundation conditions in accordance with the criteria outlined in Appendix A, Seismic and Geologic Siting Criteria for Nuclear Power Plants, of 10CFR Part 100, and to demonstrate that a nuclear facility can be safely constructed at the site.

The investigation of the site consisted of the following:

- Research of pertinent published and unpublished geologic, seismologic, and hydrologic literature of Arizona and adjacent areas (see also appendix 2A, Question 2A.4)

- Consultation with numerous local geologists from the universities and various public agencies who are familiar with particular areas

- Review of existing and specially prepared aerial photography and other remote sensing imagery

- Reconnaissance and detailed geologic mapping of the site and vicinity at scales of 1 mile, 2000 feet, 1000 feet, and 500 feet to the inch

- As-graded geologic mapping of excavations for Category I structures, at scales of 10 feet, 5 feet, and 1 foot

- to the inch, and inspection of non-Category I excavations

- Subsurface investigations which include:

  - Drilling of approximately 630 borings to depths ranging from 25 to 720 feet for geologic and engineering data

  - Logging of selected borings with high resolution, downhole geophysics

  - Seven detailed cross-hole seismic surveys in and adjacent to the power block areas to define the in-situ engineering characteristics of the site soils

  - Excavation of 32 backhoe trenches totaling about 1800 linear feet

  - Twenty-one seismic refraction geophysical profiles (hammer energy source) totaling about 32,500 feet; three refraction profiles (explosive energy source) totaling about 49,600 feet

  - Reconnaissance and detailed gravity and magnetic geophysical surveys covering a 10-mile radius of the site

  - Installation and monitoring of perched and regional groundwater observation wells on and adjacent to the site

- Six multiposition extensometers and 18 mechanical rebound anchors to monitor pre- and post-construction related heave and settlement
- One large tank percolation test, three pumping tests in the perched water zone, one regional aquifer pump test, and approximately 25 in-situ injection permeameter tests to determine aquifer characteristics
- Excavation of three large-diameter (6 feet) borings to depths of about 40 feet to obtain bulk undisturbed samples for engineering testing

- Geologic sample analyses which include:
  - Lithologic analysis of thin-section samples of bedrock
  - Potassium-argon age dating of volcanic rock samples
  - Analysis of approximately 550 samples of basin sediments for paleomagnetic polarity
  - Palynology studies of 20 samples of basin sediments
  - X-ray crystallography of selected clay samples
- Engineering testing of foundation materials for static and dynamic properties. Types of tests include:
  - Moisture content and dry density
  - Atterberg limits for selected samples

- Consolidation
- Triaxial shear (dynamic and static)
- Standard penetration (for granular materials within zones of possible liquefaction)
- Relative density
- Direct shear
- Unconfined compression
- Expansion or swell

Soil sampling was initiated in the plant area in April 1973 and continued periodically through December 1978.

Of the more than 630 borings drilled during the site investigations, approximately 575 have been drilled within the site property and at site-specific power block areas. The remainder have been drilled around the site property at spacings ranging from 750 feet to 1 mile and extending up to 5 miles from the plant location.

The investigation of PVNGS conforms to accepted standard practice within the geology/engineering professions and to NRC acceptance criteria defined at the time of the investigations. Sampling of undisturbed soils and soft sediments, for geologic and engineering requirements, was performed with a 12-inch drive sampler; a standard 18-inch, split-spoon drive sampler; a 30-inch pitcher tube; a 12-inch diameter plastic cylinder for hand-excavated samples; and an NX core barrel. The soil samples were taken continuously or at intervals of 5 feet down to a depth of 100 feet, intervals of 10 feet down to a depth of

200 feet, and intervals of 20 feet down to a depth where material suitable for coring was encountered, or to specific completion depth determined by geologic or engineering considerations. The sampling procedures were dependent on expected loading conditions related to building geometry. Samples taken for the general suite of engineering tests of static and dynamic properties were taken from pitcher tube, 2.5-inch (inner diameter) drive sampler, and large-diameter, hand-excavated samples. Standard penetration tests onforming to American Society for Testing Materials (ASTM) specifications were done with an 18-inch, split-spoon sampler.

Trenches were oriented to intersect photo lineations or suspicious linear relationships found during the field investigation. Trenches were usually excavated to depths within the capabilities of the excavating equipment. The walls of the trenches were inspected for geologic evidence of faulting or other potentially hazardous geologic conditions. Scales of the trench logs ranged from 5 feet to the inch to 2 feet to the inch.

In order to monitor the effects of construction excavation activity on the site soils and their response to structural loading following construction, a soil heave and settlement monitoring program has been established at PVNGS. The instrumentation installed prior to construction consists of 18 mechanical rebound (MR) anchors (six in each unit) and six electrical read-out multiple position extensometers (MPEs) (three in Unit 1, one in Unit 2, and two in Unit 3). The MPEs are used to supplement the MRs during the rebound phase but

their primary function is to monitor construction and post-construction settlement recompressions. Based on the data obtained to date, heave/settlements are much less than predicted, on the order of one-third. Heave monitoring results verify that the heave/settlement analyses and the settlement design criteria based on these analyses are very conservative. The subsidence monitoring network consists of survey monuments located within the site boundary on soil. The survey monuments are surveyed relative to benchmarks established on bedrock north and southwest of the site. Data through March 1978 indicate no subsidence. Two strong motion accelerometers were installed at the site in 1975 to monitor earthquake-induced ground motion at the site. The instruments were removed from service in 1985. The trigger threshold for the instruments was 0.009g. The instruments were never triggered during the period of time that they were installed. Refer to paragraph 3.7.4.2 for a description of the permanent seismic instrumentation.

The changes in soil condition caused by construction of the plant are essentially those produced by the earth-moving operations required to grade the area. The moderate-to-high strengths exhibited by the soils indicate that engineered temporary and permanent slopes at the site are designed and constructed with reasonable allowable slope inclinations to minimize erosion and slope failures. Fills, constructed of soils from onsite excavations and borrow areas, are compacted in accordance with criteria provided in the PVNGS 1, 2, and 3 PSAR, Appendix 2T. Fill and cut slopes will be stable under seismic conditions and will be protected against erosion.

Summary of Geology, Seismology, and Earthquake Engineering

The site is situated within the Basin and Range physiographic and tectonic province of southwestern Arizona.

The geology within a 25-mile radius of the site (site vicinity) is characterized by mountain ranges which are relatively short, irregular, and stand sharply above broad alluvium-filled basins. The rocks of these mountains vary from deformed crystalline rocks of Precambrian age to volcanic and sedimentary rocks of middle Tertiary age. Alluvium and volcanic rocks in the broad basins are Miocene to Holocene in age, based on potassium-argon age dates of basalt interbeds. The rocks of the site area (5-mile radius) consist of:

- Precambrian metamorphic and granitic rocks
- Miocene volcanic and interbedded sedimentary rocks
- Basin sedimentary deposits on the order of 200 to 500 feet thick consisting of lithified fanglomerate, unlithified fan, alluvial, and lacustrine deposits with basalt interbeds.

The dominant structure of the site is homoclinal folding of the volcanic bedrock 15 to 23 degrees to the southwest. The over-lying basin sediments are flat-lying and undeformed. Only one northwest trending fault, displacing the volcanic bedrock, has been observed within a 5-mile radius of the site. This fault does not displace Miocene fanglomerate.

The Palo Verde clay, a lithologically and geophysically distinct lacustrine member of the basin sediments, is

stratigraphically below and thus older than the base of the Arlington basalt flow (about 2 million years, based on potassium-argon age dates). The Palo Verde clay can be continuously traced in borings across the site and at least 5 miles to the southeast and northeast of the site with no evidence of faulting since the clay was deposited more than 2 million years ago.

The geotechnical investigation at the site indicates that:

- There are no capable faults within 5 miles of the site
- Geologic conditions at the site are favorable for construction of the plant
- Foundation conditions are favorable for construction of the plant

The historic seismicity of Arizona has been characterized into four general zones:

- Zone A, the southern San Andreas Shear Zone, is approximately 120 miles from the site with a maximum historic earthquake of magnitude 7.1
- Zone B, the Pinacate volcanic area, is about 70 miles from the site with a maximum historic earthquake of about 4.9
- Zone C is more than 70 miles from the site at its nearest point and has produced a maximum earthquake, not associated with a fault, of magnitude 5.6. The

maximum earthquake associated with a fault is the 1887 Sonoran earthquake (estimated magnitude 8.0)

- Zone D, a nearly aseismic zone in which the site is located, with a maximum historic earthquake of about magnitude 4.5

The safe shutdown earthquake (SSE) assumed to be of magnitude 8.0 and to be located 72 miles from the site, is postulated to be similar to the 1887 Sonora earthquake whose estimated magnitude was recently revised downward to 7.4[1]. Through use of attenuation curves, extrapolation of response spectra, and analysis of intensity data, 0.2g is considered a conservative representation of the severity of vibratory ground motion for the SSE.

2.5.1 BASIC GEOLOGIC AND SEISMIC INFORMATION

2.5.1.1 Regional Geology

2.5.1.1.1 Regional Physiography

2.5.1.1.1.1 General. The area within the site region (200-mile radius) includes most of Arizona, part of southeastern California, southern Nevada, and northern Mexico (figure 2.5-1). The major physiographic provinces within the 200-mile radius of the site include the Colorado Plateau, Transition Zone, Basin and Range, Peninsular Ranges, and the Transverse Ranges (figure 2.5-1). For Arizona, physiographic province boundaries and descriptions follow Fenneman[2] and Wilson[3]. Province boundaries in California are taken from Fenneman[2], Oakeshott[4], and Jahns[5]. A detailed description

of the physiography of the site vicinity (25-mile radius), which is in the Basin and Range province, is given in the description of the site geology (paragraph 2.5.1.2.1).

2.5.1.1.1.2 Colorado Plateau Province. The Colorado Plateau province is centered near the four corners of Arizona, Utah, Colorado, and New Mexico and is bounded on the north by the Central Rocky Mountains, on the east by the Southern Rocky Mountains and Rio Grande Valley, and on the west and south by the Basin and Range and Transition Zone provinces (figure 2.5-1). The southwestern province boundary in the site region is a series of rugged cliffs, up to 1500 feet in height, trending northwest across Arizona. Within the site region, the Colorado Plateau is subdivided into the Grand Canyon, Mogollon Slope, and Navajo Country regions (figure 2.5-1).

The Grand Canyon region includes several individual plateaus which are elongated in a north-south direction. Highest of these is the Kaibab Plateau which has been incised by the Colorado River to form the Grand Canyon. The relief decreases west of the Kaibab and Coconino Plateaus. To the east, these plateaus descend to the Marble Platform. The Grand Canyon region is separated from the adjacent Basin and Range province by the Grand Wash Cliffs, a major physiographic break. The southeastern edge of this region contains the high mountains and volcanoes of the San Francisco Peaks volcanic field.

The Mogollon Slope is bordered by the Mogollon Rim on the south and the Little Colorado River on the north (figure 2.5-1). The relief generally declines northward from the uptilted Mogollon

Rim toward the Little Colorado River and Black Mesa Basin. The southeast edge of the region is covered by the White Mountains-Mogollon volcanic field.

The Navajo Country area includes plateaus, mesas, and canyons of the Plateau interior north and east of the Little Colorado River. The generally flat-lying terrain is interrupted at Hopi Buttes by the necks of eroded volcanoes which protrude above the general level of the plateau.

2.5.1.1.1.3 Transition Zone. The Transition Zone lies between the Colorado Plateau and the Basin and Range province[3] (figure 2.5-1). The strata and structure of the Transition Zone are similar to the southern Colorado Plateau except for a greater abundance of faulting. Physiographically it differs from the plateau because of its more rugged topography with steep-sided mountains locally rising as high as the plateau rim. The topography commonly reflects the influence of underlying bedrock in that mesas occur in areas underlain by the sedimentary and volcanic rocks, sharp and rugged terrain in metamorphic rocks, and rugged to rounded topography in granitic rocks.

2.5.1.1.1.4 Basin and Range Province. The Basin and Range province is the most extensive province in the site region and encompasses southern and western Arizona, Nevada, western Utah, southeastern California, and northern Mexico. Physiographic boundaries of the Basin and Range province are generally broad

transitions which are not precisely definable, especially between the Basin and Range and Colorado Plateau.

Most of the province (for example, the Great Basin region in Nevada and western Utah) is characterized by subparallel, steep-sided, linear mountain ranges separated by relatively flat, alluviated basins which abut the ranges with a sharp break in slope. The linearity of the mountain ranges has resulted largely from block faulting, and many mountain ranges are bounded by faults or fault-line scarps. Many basins or groups of basins have interior drainage with central playas.

In the site region, the Basin and Range province is subdivided into the Arizona Mountains and Sonoran Desert subprovinces.

A. Arizona Mountains

The ranges of the Arizona Mountains comprise the Mexican Highlands, which trend northward out of Mexico, and similar but northwest-trending mountain blocks between the Transition Zone and the Sonoran Desert (figure 2.5-1). Topography is generally rugged, suggesting that tectonic activity has occurred more recently here than in the Sonoran Desert. The ratio of the area of the ranges to basins is approximately 1 to 1.

B. Sonoran Desert

The Sonoran Desert includes the deserts of southeastern California and southwestern Arizona. The region is typified by low-relief mountains and extensive

pediments and open drainage(6). The heterogeneous trends of mountain ranges in this region contrast with the pronounced northerly trends in the Nevada-Utah and Mexican Highlands portions of the province. Mountain ranges rarely have peaks higher than 4000 feet. The topography appears old and subdued compared to the Nevada-Utah and Arizona Mountains portions of the Basin and Range province. Basins are the dominant landscape features and several, including the Tucson and Phoenix Basins, contain alluvial accumulations thicker than 2000 feet. The area of the ranges totals only about one-fifth of the total subprovince area indicating long periods of erosion of a relatively stable landscape.

2.5.1.1.1.5 The Salton Trough. The Salton Trough province lies southwest of the site, south and southwest of the eastern Transverse Ranges, and west of the Basin and Range province. The Salton Trough comprises the Coachella Valley, Imperial Valley, and the Gulf of California (figure 2.5-1). The trough boundaries are along mountain ranges bounded by major northwest-trending fault zones, the San Andreas on the northeast, and the San Jacinto, Elsinore, and Sierra Juarez on the southwest. The northern Salton Trough is separated from the Gulf of California by the Colorado River delta, the sediments of which have created a closed inland basin to the north, much of which is below sea level. Colorado River flood water poured into the trough in 1905 initiating the present Salton Sea. However, strand lines, shell deposits, and

calcareous deposits around the rim of the trough indicate the existence of previous Holocene and Pleistocene lakes. As a result of prevailing northwesterly winds, active and inactive sand dunes are common south of the Salton Sea on the east side of the Imperial Valley. The Gulf of California is an elongate body of water between the Mexican mainland and the Baja peninsula. Maximum depth of the seafloor is about 11,500 feet but the northern portion, within the site region, is much shallower, no more than about 1600 feet deep. The floor of the trough is marked by bathymetric depressions which get progressively smaller towards the head of the Gulf; only one of these basins, Wagner Basin, is within the 200-mile site region radius.

2.5.1.1.1.6 Peninsular Range Province. The Peninsular Range province occupies the southwestern corner of California and forms the "backbone" of the Baja Peninsula. It is characterized by northwesterly trending mountain blocks of granitic rocks which are terminated on the north by the Los Angeles Basin and the east-west trending ranges of the Transverse Ranges province. The site region includes only the eastern portion of the Santa Ana block; the eastern margin of which drops off steeply to the floor of the Salton Trough in spectacular scarps about 6000 to 9000 feet high.

2.5.1.1.1.7 Transverse Ranges Province. The Transverse Ranges province of southern California is an elongate series of mountain ranges trending east-west. The eastern edge of the

province (the Little San Bernardino Mountains) extends into the site region where it is bounded on the north by the Mojave Desert, the east by the Sonoran Desert, and on the south by the Salton Trough.

The mountain ranges of the province are rugged and are separated by narrow to moderately-narrow valleys. These east-west oriented physiographic features are transverse to the general northerly grain of most ranges in the western U.S.

2.5.1.1.2 Regional Stratigraphy and Lithology

2.5.1.1.2.1 Geologic Setting. The stratigraphy and lithology in the site region are extremely complex (figure 2.5-2) but can be simplified by grouping areas with similar geology into large provinces. In many cases these geologic provinces coincide quite closely with tectonic provinces and physiographic provinces because of the intimate relationship between physiography, lithology, and geologic structure. However, the physiographic boundaries are not always perfectly coincidental with geologic and tectonic boundaries for provinces with the same name (for example, the Basin and Range province). Figure 2.5-3 shows the major tectonic provinces in the site region and the following discussion groups lithologic and stratigraphic descriptions according to these provinces.

The PVNGS site is within the portion of the Basin and Range tectonic province generally referred to as the Sonoran Desert (figure 2.5-3). The Basin and Range province is bounded about 40 miles northeast of the site by the Colorado Plateau tectonic

province and by the Salton Trough tectonic province about 120 miles to the southwest. The Peninsular Ranges tectonic province lies beyond the latter province along the California and Baja California coasts about 180 miles from the site.

2.5.1.1.2.2 Colorado Plateau. The rocks exposed on the Colorado Plateau are relatively undeformed Paleozoic to early Tertiary rocks (figure 2.5-2). The southwest portion of the Colorado Plateau, within the 200-mile radius surrounding the site, is characterized by a thick sequence of slightly deformed Paleozoic marine sandstone, mudstone, and limestone unconformably overlying highly deformed Precambrian rocks.

The older Precambrian rocks of schist, granite, quartzite, and meta-volcanics are unconformably overlain by up to 4000 feet of younger Precambrian to Permian units of shale, limestone conglomerate, and sandstone. The deposition of the Paleozoic sediments found on the Colorado Plateau was greatly influenced by the Defiance-Mazatzal land mass which transected Arizona with a northeast-southwest trend throughout much of Paleozoic time. Deposition on the flanks of this mass resulted in progressively thicker deposits to the northwest and southeast. The younger strata are nearly horizontal over large areas with broad regional flexures, monoclinal folds, and igneous domes. These strata are broken by faults, joints, and a multitude of dikes. Cenozoic intrusive rocks occur as stocks, laccoliths, and bysmaliths. Late Tertiary extrusions of basaltic lava and pyroclastic rocks cap much of the plateau periphery[3].

Cenozoic sedimentary deposits are well represented in the northern portion of the Colorado Plateau but are missing in the site region. Within the site region, late Cenozoic rocks consist primarily of Tertiary and Quaternary volcanic rocks. The volcanic activity appears to have been localized by Laramide and later tectonic influences because the volcanic cones, necks, plugs, and diatremes are thought to be localized at intersections of deep structural features(3).

The San Francisco volcanic field consists of large central volcanoes surrounded by a multitude of small cinder cones and vents. The central San Francisco Mountain, and the surrounding Kendrick, O'Leary, Sitgreaves, Bill Williams, and Mormon Mountain vents erupted 86 cubic miles of basalt, andesite, latite, dacite, and rhyolite flows and pyroclastic rocks, during Pliocene and early Pleistocene time(7).

2.5.1.1.2.3 Basin and Ranges. The Basin and Range province, west and southwest of the Colorado Plateau, comprises more than 50,000 square miles in Arizona. It is composed of fault-block mountain ranges generally oriented northwest-southeast, northeast-southwest and north-south with the northwest-southeast trends somewhat predominant. The rocks of this province range from intensely deformed Precambrian metamorphic rocks to undeformed Pliocene and Quaternary sedimentary and volcanic rocks (figure 2.5-2). The rocks were folded, faulted, and intruded throughout Precambrian and early Tertiary time but it was the block-fault activity and volcanism during the middle

to late Tertiary that gave the province its distinctive physiography and geology.

The rocks exposed in the Basin and Range province in the site region (Sonoran Desert region) are grouped into eight sequences:

- Older Precambrian granite and schist
- Younger Precambrian granite and schist
- Paleozoic sedimentary rocksMesozoic-early Tertiary sedimentary and igneous rocks
- Mesozoic to early Tertiary crystalline rocks
- Tertiary volcanic and sedimentary rocks
- Late Tertiary-Quaternary volcanic rocks
- Tertiary-Quaternary continental deposits

The Mesozoic and older rocks are discussed in detail in the PVNGS 1, 2, and 3 PSAR(8). The Tertiary and younger volcanic and sedimentary rocks are discussed in detail herein because they determine the important geologic relationships in the site area.

Tertiary volcanic rocks generally range in composition from rhyolite to andesite whereas the late Tertiary-Quaternary volcanic rocks are predominantly basalts. In the Sonoran Desert, volcanic eruptions were small and limited to the vicinities of the Batamonte and Childs Mountains near Ajo, near Gila Bend, Arlington, Gillespie Dam, Crater Mountains, and the Sentinel Plain. Dating by potassium-argon techniques(8)

indicates ages of 16 to 28 million years before present (m.y. BP) on the deformed Tertiary volcanic rocks near Gillespie Dam and the Palo Verde Hills. Ages on the undeformed basalt flows are:

- Sentinel 1.71 ±0.25 million years
- Gila Bend 2.2 to 6.4 million years
- Gillespie Dam 1.3 to 4.2 million years
- Arlington 1.2 to 3.2 million years

The Tertiary to Quaternary continental deposits are predominantly sedimentary deposits with some associated volcanic rocks which were deposited in structural basins characteristic of the present Basin and Range physiography. These basin-fill deposits consist of alluvial fan, fluvial floodplain, and lakebed deposits. The potassium-argon age dating of the four basalt flows which overlie the continental deposits indicate a late Pliocene or early Pleistocene minimum age for basin-fill deposits in southwestern Arizona.

2.5.1.1.2.4 Transverse Ranges. The eastern extremity of the Transverse Ranges of California lies slightly within the site region. The Transverse Ranges, as the name implies, are oriented transversely (east-west) to the northwest trending Sierra Nevada and Coastal Ranges. The total length of the province is approximately 300 miles, from the region offshore of Point Conception in south-central California to the Eagle Mountains, 50 miles from the Colorado River. The eastern

segment is separated from the larger western segment of the province by the San Andreas fault set.

The eastern Transverse Ranges are composed primarily of crystalline basement rocks (figure 2.5-2). The Little San Bernardino, Pinto, and Eagle Mountains primarily consist of biotite quartz monzonite of Mesozoic age, referred to as the Cactus Granite, which contains numerous inclusions of metamorphic rocks. Some large areas are underlain by gneiss, schist, amphibolite, quartzite, and other metamorphosed rocks of possible Precambrian age(9).

2.5.1.1.2.5 Salton Trough. The Salton Trough province is a downwarped, downfaulted, and laterally translated structural trough which contains highly seismically active faults of the San Andreas Shear Zone. The strata of this province consist primarily of late Tertiary to Quaternary continental alluvial, aeolian, lacustrine, and marine sediment (figure 2.5-2) which reach thicknesses in excess of 16,000 feet in the central Imperial Valley(10). Quaternary volcanic extrusions occur at the south end of the Salton Sea and at Cerro Prieto in Mexico. The northern trough is underlain and bounded by Mesozoic and older Crystalline rocks. The Gulf of California comprises up to 3000 feet of modern marine sediment overlying oceanic basalts of Pliocene to Holocene age(11).

2.5.1.1.2.6 Peninsular Ranges. The Peninsular Ranges province occupies the southwestern corner of California and extends southeastward into Baja, California. The Peninsular

Ranges within the site region consist primarily of Mesozoic (90 to 100 m.y. BP) batholiths ranging from gabbro to granite in composition. The batholiths extend at least 500 miles down the Baja Peninsula but may extend much farther under the concealment of younger volcanic rocks.

These plutonic bodies intruded Jurassic and Triassic rocks which now comprise schists, quartzites, and marbles, and some shales and volcanics. Younger rocks are largely sedimentary, partly marine and partly continental, and range in age from late Cretaceous to Pleistocene. The marine rocks are exposed mostly at the northern end of the province and along the coast. Continental deposits were laid down in inland basins. Volcanic rocks are about middle Miocene age but are very limited in extent.

2.5.1.1.3 Regional Tectonics

2.5.1.1.3.1 Introduction. Tectonic features of the region are depicted in figures 2.5-3 through 2.5-7. Tectonic features in the region surrounding the site (200-mile radius) are depicted on figure 2.5-4. Faults and folds are shown on figure 2.5-5. Quaternary faults are shown on figure 2.5-6. The tectonic features shown in these figures are grouped according to broad generalized characteristics into five major tectonic provinces (figure 2.5-3): the Colorado Plateau, Basin and Range, Salton Trough, Transverse Ranges, and Peninsular Ranges.

Several large regional structural lineaments have also been postulated in the site region by various authors. These

features are the San Andreas Shear Zone, Death Valley-Furnace Creek Shear Zone, Walker Lane-Las Vegas Shear Zone, Texas Lineament, and Jerome-Wasatch Structural Zone (figure 2.5-7). Some of these features are capable faults and seismically active (San Andreas Shear Zone) whereas others may be partly capable (Death Valley-Furnace Creek Shear Zone), and others may represent ancient geologic and tectonic trends which no longer act as throughgoing tectonic features (for example, the Texas Lineament).

2.5.1.1.3.2 Tectonic Provinces.

A. Basin and Range Province

The largest tectonic province in the site region, and the one in which the site is located, is the Basin and Range province. This province extends over large portions of the western United States including southern Oregon and Idaho, Nevada, western Utah, south-eastern California, southern Arizona, southwestern and central New Mexico, and northern Mexico. This region has been considered as one structural province because of similarity of Cenozoic tectonic features and tectonic mechanisms[12]. However, more than a decade of research and tectonic syntheses subsequent to Hamilton and Myers[12], for example,[13-23] have shown that late Cenozoic tectonic processes provide a basis for subdividing this large province into smaller neotectonic zones or seismotectonic zones. In the following discussion,

some of the important neotectonic zones are discussed but the basic tectonic province approach used in the PVNGS 1, 2, and 3 PSAR[8] remains unchanged because it still represents a conservative framework within which to determine seismic design parameters.

The Basin and Range province is typified by elongate mountain ranges separated by broad alluvial valleys. The boundaries between the valleys (basins) and mountains (ranges) are generally quite abrupt and commonly represent faults. These boundary faults are predominantly normal faults.

The province has experienced numerous orogenic episodes since Precambrian time. The younger major episodes of deformation within the province occurred in early Mesozoic (Nevadan Orogeny), late Cretaceous, early Tertiary (Laramide Orogeny), and middle Tertiary-late Tertiary (Basin and Range disturbance) times. The Paleozoic and Mesozoic compressional orogenic features are largely obscured by extensional Basin and Range-type block faulting which has separated the former contiguous terrain into numerous widely spaced blocks. This extensional tectonic phase may have begun as early as Eocene or Oligocene times[12][24] but the present episode of Basin and Range-type faulting began in the middle Miocene time[20]. The extent of tectonic activity in late Cenozoic time varies throughout different areas of the province. The distribution of Quaternary faults (figure 2.5-6)

shows that the Quaternary activity in the site region was largely restricted to the

Nevada-Utah (Great Basin), Mojave, and Mexican Highlands regions of the province. The predominance of north-northeast oriented normal faulting in the Great Basin (Nevada and Utah), north-south oriented normal faulting in the Mexican Highlands, northwest-trending strike-slip structures in the Mojave Desert, northwest-trending normal faults associated with abundant volcanic activity along the southern and southwestern edge of the Colorado Plateau, and very little Quaternary faulting in the Sonoran Desert region indicates that each of these regions have been under different tectonic regimes or have reacted differently to pervasive regional stresses during Quaternary time. The relatively heterogeneous structural fabric of the Sonoran Desert region, its relatively subdued physiography, and its near lack of Quaternary faulting indicate that this province escaped the Quaternary tectonic activity occurring in its bordering provinces.

The subdued Basin and Range topography of the Sonoran Desert region is separated from the well developed Basin and Range topography in the Great Basin by a transverse tectonic zone across the southern tip of Nevada. This transverse zone was first noted by Slemmons(25) who thought that it might represent the southern edge of the Basin and Range province. This

zone has been termed the Southern Nevada Seismicity Zone by Smith and Sbar[17] and Smith[26] who were impressed by the abundance of seismicity in the region. Anderson[27] noted that the geologic and geophysical data indicate a "major structural corridor" that transects the northerly trending structural grain. Howard, et al,[21] noted the difference in fault characteristics between the Great Basin and Sonoran Desert regions and placed a boundary between the two which coincides with the southern edge of the transverse zone. Focal mechanism solutions[28] in this area indicate both strike-slip and normal faulting mechanisms which are indicative of a stress regime which is somewhat different from the central Great Basin to the north and its eastern and western boundaries[29].

The only area within the Sonoran Desert region that demonstrates any appreciable seismicity or Quaternary faulting is the Pinacate volcanic area along the Mexico-Arizona border. This volcanic field is the largest family of Holocene volcanoes in the Sonoran Desert region and also the youngest. Some of the volcanoes have erupted within the last few thousand years[30][31]. The lavas and pyroclasts are chiefly basalt which have emanated from a number of deep-seated volcanoes as gaseous, violent eruptions[31]. Short, et al,[32] suggest that the origin of this volcanism is related to the rifting processes that

created the Gulf of California. The volcanic field lies astride the projection of the eastern edge of the Salton Trough and is directly northeast of a dense cluster of earthquakes near Wagner Basin beneath the waters at the head of the Gulf of California (figure 2.5-2 and subsection 2.5.2). These earthquakes probably represent activity on a small seafloor spreading center in Wagner Basin, between transform faults within the San Andreas Shear Zone[33]. There are a few, very small capable and Quaternary faults in the Pinacate region[8][21] which are related to young volcano-tectonic activity[29].

The southeastern corner of the province, in south-eastern Arizona, southwestern New Mexico, and northern Sonora and Chihuahua, Mexico is referred to as the Mexican Highlands region. The Mexican Highlands region is distinguished from adjacent regions by its well developed north-south trending Basin- and Range-type physiography which is a result of earthquake activity and geologic structural trends[21][34]. These trends are accompanied by predominantly north-south trending Quaternary faults, several of which are of great length but there is only one instance of historic surface rupture. This occurred during the 1887 Sonoran earthquake (paragraph 2.5.2.1.4.2). Similar to the Great Basin portion of the tectonic province, and in contrast to the Sonoran Desert region, the Mexican Highlands region has a ratio of

basin area to mountain area of about 1 to 1. This ratio, the relatively youthful geomorphic appearance of the basins and ranges, and the recency of faulting suggest that this region has undergone much more recent tectonism than the adjacent Sonoran Desert region.

B. Colorado Plateau Province

The Colorado Plateau province occupies the four adjacent corners of Colorado, Utah, Arizona, and New Mexico. This province comprises flat-lying, relatively undeformed, Paleozoic through early Tertiary strata overlying deformed Precambrian basement. This province is the remnant of a formerly much more extensive continental terrain which has been chipped away at the edges by extensional tectonics[35-38]. In general, the Colorado Plateau is topographically high and does not display much internal Quaternary geologic deformation. Most of the present tectonic activity occurs along its boundaries in zones such as the Wasatch-Hurricane frontal fault system on the west, the southern Rocky Mountains and Rio Grande rift on the east, and the Transition Zone-Arizona Mountains physiographic province/subprovince on the south and southwest.

The continental crust comprising the Colorado Plateau is 27 miles thick and is shieldlike, whereas the normal faulted regions surrounding the plateau have

thinner crusts[35]. Prior to Miocene time, the area of the Basin and Range province was topographically high relative to the Colorado Plateau. Between about 18 and 10 m.y. BP, the situation reversed and the Colorado Plateau has remained high ever since[37].

C. Salton Trough

The Salton Trough province is a structural trough between the Basin and Range and Peninsular Ranges provinces. The Salton Trough deepens gradually to the south and appears to be structurally continuous with the Gulf of California[39]. This trough is bordered by and contains the most seismically active faults in the site region; the San Andreas, San Jacinto, and Elsinore fault sets (paragraph 2.5.2.2.2).

The San Andreas fault is generally considered to be the contact between the North American and Pacific plates (paragraph 2.5.1.1.5) and as such is highly seismically active with several historic surface ruptures and abundant evidence of repeated movement during Quaternary time on its northern segment. However, the vast majority of seismicity in the Salton Trough clusters around the San Jacinto fault set[40] and strands of the San Jacinto fault set such as the Coyote Creek, Superstition Hills, and the Imperial faults have been historically active. This higher rate of activity indicates that the San Jacinto fault

set is the most important plate-boundary fault within the Salton Trough.

The three major fault sets in the Salton Trough and the numerous faults lying between are herein referred to as the southern San Andreas Shear Zone. The principal movement along this system is right-lateral but lateral crustal inhomogeneities and unfavorable structural trends set up a very complex stress-strain system and thus other types of movements occur locally, such as reverse faulting in the "big bend" area of the Transverse Ranges and normal faulting along the southern margin of the trough. Displacement of several hundred miles along this shear zone was documented by Hill and Dibblee(41), but it was not until plate tectonic concepts were developed that the broader aspects of this fault system as a transform-fault plate boundary were understood(42). The San Andreas Shear Zone has been episodically active along the northern portions of its trace since before Late Cretaceous time(43). However, in southern California, the most severe, if not the first, displacements have occurred since Miocene time(44-48). Much of this movement has occurred within the last 4 to 6 m.y. when spreading activity opened the Gulf of California(11)(13)(49).

The northeastern boundary of the Salton Trough (San Andreas Shear Zone) is along the San Andreas fault

set, which comprises the Mission Creek, Banning, and the San Andreas faults, between the floor of the trough and the adjacent mountain ranges (figure 2.5-6). The San Andreas fault set cannot be traced south of the Salton Sea on the basis of surface geology or seismicity and numerous speculations have been advanced on the location and even the very existence of the southern extension of the San Andreas. There appears to be two viable hypotheses; either it terminates near the southern end of the Salton Sea with major activity shifting to the Imperial fault, or it continues directly southeastward where its active nature is masked by the mobile sand dunes and rapid alluviation of the Colorado River. The Algodones fault in the Yuma, Arizona area lies along the southeasterly projection of the San Andreas and has been hypothesized as its direct continuation(50). Merriam(51) postulated that the San Andreas continues well into Mexico east of the Gulf of California. Geophysical and geotechnical studies in the Yuma, Arizona area(52) show that the Algodones fault has been active in late Pleistocene time but that its displacement is down to the east in a dip-slip sense. This sense of displacement does not favor the hypothesis of the Algodones fault as the southeastern extension of the San Andreas, but the location of the Algodones fault and its recent activity suggest that it probably functions as one of

the eastern bounding faults of the Salton Trough and thus it should be considered as one of the faults in the San Andreas Shear Zone.

D. Transverse Ranges Province

The east-west structural trend of the Transverse Ranges is a notable exception to the general northerly and northwesterly trend of most western United States mountain belts. Quaternary left-lateral and reverse faults, similar earthquake focal-mechanism solutions, and east-west trending fold axes indicate that the province is under a north-south compressional stress regime. The San Andreas fault separates the Transverse Ranges into eastern and western segments and movement along the San Andreas plate boundary may have played a role in formation of the east-west trends(13)(15). The eastern segment has the same compressional tectonic patterns as the western segment but these patterns appear to be caused by movement between different crustal blocks on each side of the San Andreas.

The eastern Transverse Ranges province bounds the Mojave block on the south. The major faults in the eastern Transverse Ranges province are the Quaternary-age, east-west trending Pinto Mountain and Blue Cut faults. The frontal fault is a reverse fault along which the San Bernardino Mountains have been uplifted from the Mojave Desert. The Pinto Mountain fault has

a cumulative left-lateral displacement of about 10 miles[53]; and the Blue Cut fault shows 3 to 4 miles of left slip[54]. Abundant seismic activity, displacement of alluvium, and uplift of the San Bernardino Mountains[55] indicate active tectonic forces in the province and along its boundaries.

E. Peninsular Ranges Province

The Peninsular Ranges occupy the southwestern part of the state of California and most of the Baja California peninsula. In California, mountains that comprise the Peninsular Ranges are the San Jacinto, Santa Ana, Santa Rosa, and Laguna Mountains. These ranges trend northwest-southeast and are separated by the major, northwest-striking, San Jacinto and Elsinore fault sets. These fault sets are members of the San Andreas Shear Zone, thus the northeastern portion of the Peninsular Ranges physiographic province is not part of the Peninsular Ranges tectonic province as defined herein. The Elsinore fault set forms the boundary between the San Andreas Shear Zone and the Peninsular Ranges which, under this definition, consists predominantly of the Santa Ana block, a stable, massive, continuous Mesozoic plutonic massif forming the backbone of the California and the northern Baja Peninsular Ranges. Such a division of tectonic provinces is consistent with Richter's zones[56] and the Peninsular Ranges province corresponds to his Coastal Stable Block.

The Santa Ana block is nearly aseismic and is bounded on the west by the Santa Monica to Baja zone of deformation and on the south by the numerous faults associated with the San Miguel, and Agua Blanca fault zones in Mexico. These Mexican faults have been identified as capable faults on the basis of Quaternary displacement and seismicity[57]. The province's eastern bounding fault, the Elsinore fault, aligns with the Laguna Salada fault near the U.S.-Mexico border and lies just within the site region. The low level of Quaternary and historic tectonic activity renders this fault subordinate to the San Andreas and San Jacinto fault sets[38][58], but it is considered a capable fault (paragraph 2.5.2.2.2).

2.5.1.1.3.3 Major Tectonic Lineaments. Four major structural zones or tectonic lineaments have been postulated to trend through the site region. These features are:

- The San Andreas Shear Zone
- The Death Valley-Furnace Creek Shear Zone
- The Jerome-Wasatch Structural Zone
- The Walker Lane-Las Vegas Shear Zone and Texas Lineament

The San Andreas Shear Zone (figure 2.5-7), lying about 120 miles southwest of the site, is the most pronounced tectonic lineament in western United States and has been postulated to be a transform fault system along the Pacific-North American

plate boundary (paragraph 2.5.1.1.3.2). It is a zone of active right-lateral shear with displacements in southern California estimated to be in excess of 190 miles[59] and about 350 miles in northern California[41], and a high rate of historic seismicity.

The northwest-trending Death Valley-Furnace Creek fault system is a right-lateral shear system in the Death Valley, California region -- its type locality. Hunt[60] and Hamilton and Myers[12] postulate an extension of the Death Valley-Furnace Creek fault zone toward the southeast into southern California and Arizona. However, the extension is based solely on small local displacements at scattered localities and diffuse seismicity in the southwest corner of Arizona. There is no geologic expression of this zone in Arizona and recent, more detailed tectonic studies[61][62] in the eastern Mojave Desert show that the Death Valley-Furnace Creek fault zone does not extend very far southeast of the eastern Garlock fault-Avawatz Mountain region.

The Jerome-Wasatch structural zone comprises several different tectonic elements along the Colorado Plateau-Basin and Range boundary, the Arizona Mountains-Transition Zone along the southern boundary of the Colorado Plateau, and the linear mountain ranges in the Mexican Highlands region. Neotectonic syntheses[21][22] show these areas as discrete zones and do not consider the lineament to represent a continuous, through-going fault zone.

The Walker Lane-Las Vegas Shear Zone is a discontinuity between the north-northeast trending basins and ranges of the Great

Basin in Nevada and the northwest-southeast trending ranges of the Owen's Valley-Death Valley region. The feature is primarily a late Tertiary, right-lateral feature[63] and is not associated with any concentration of seismicity or Quaternary faulting; thus is not an active or capable fault zone.

The Texas Lineament is a diffuse zone of structural disturbance that was postulated to trend northwest from southwestern Texas[64] across southwestern New Mexico and central Arizona, and which has been further postulated by some authors to ultimately connect with the Walker Lane-Las Vegas Shear Zone[60]. Various authors have commented on the lineament's characteristics, continuity, association with active faulting, association with copper mineralization belts and its sense of movement [17][60][63-76]. The geologic evidence for the location, trend, and even the existence of the Texas lineament through New Mexico and Arizona is scanty and ambiguous and this ambiguity allows an abundance of permissive arguments. Evidence suggests that it is an ancient feature which no longer acts as a through going tectonic element. Several lines of evidence indicate that these are not young fault zones. The most notable negative arguments are:

- Age relationships of the mineral deposits appear to relegate its activity to Laramide time[77].
- Reconstruction of the late Cretaceous-early Tertiary Cordilleran Orogeny[63] shows no indication of a major throughgoing transcurrent fault.

- The Las Vegas Shear Zone which supposedly connects the lineament with the Walker Lane has not shown any activity in Quaternary time. Where it is postulated to transect the Rio Grande Rift, it does not affect Tertiary-Quaternary north-south tectonic features associated with the rift.

2.5.1.1.4 Regional Geologic History

The regional geologic history can be divided into three major intervals; pre-Laramide, Laramide, and post-Laramide.

2.5.1.1.4.1 Pre-Laramide Interval. The pre-Laramide interval (Precambrian-late Mesozoic) in the site region was generally a period of synclinal sedimentation in the Sonoran and Californian geosynclines. Periods of major tectonic deformation in the Precambrian, the Mazatzal Revolution (1200 m.y. BP), and the Grand Canyon disturbance (late Precambrian), disrupted sedimentation by igneous intrusive activity, uplifting, faulting, and folding. Paleozoic geosynclinal sedimentation was interrupted by episodes of uplift and erosion in the Cambrian, Devonian, and Mississippian periods.

During the Triassic-Jurassic period, the Nevadan Orogeny caused a disruption of the Cordilleran geosyncline and a major uplift and erosional unconformity in pre-Cretaceous rocks.

2.5.1.1.4.2 Laramide Interval. The Laramide Orogeny began in late Cretaceous and extended into earliest Cenozoic time.

Laramide folding and faulting were relatively minor on the Colorado Plateau but were intense in the Basin and Range province[3]. Laramide igneous activity was marked by the emplacement of batholiths, stocks, dikes, plugs, and volcanic rocks, especially within the Basin and Range province. Within the Colorado Plateau province, the Laramide orogeny produced folds and faults which created a basin or trough area surrounded by newly formed mountains. Deposition continued in this basin until Eocene time.

2.5.1.1.4.3 Post-Laramide. In post-Laramide time, structural movements, volcanic and igneous activity, erosion and sedimentation all acted upon preexisting geologic features to form the present plateaus, mountains, valleys, and drainage patterns[78].

Regional uplift, as well as flexing and faulting, increased during the Miocene and culminated in the Miocene or early Pliocene. The effects included the gentle northeast tilting of the Colorado Plateau and further arching in the Transition Zone(3). During this time the Colorado Plateau and the Basinand Range area became separate features(79).

This uplift served to disrupt the southwesterly drainage. Gorges were cut in the rising mountains before complete disruption occurred, and some of these gorges form a part of the present drainage system. Formation of the present Basin and Range topography in the southern part of the state disrupted drainage diverting it into newly formed basins.

Pediments and other erosion surfaces were locally developed before the Pliocene basin fill accumulated.

Continuing structural movement, volcanic activity, and diversion of waters during the Pliocene resulted in complex changes of the drainage pattern. The reduction of stream gradients or blocking of valleys allowed the deposition of hundreds to thousands of feet of sediments during much of the Pliocene. The character and stratigraphic relationships of these sediments suggests that much of the material was brought into the valleys by through-flowing rivers. Coarse deposits in the form of alluvial fans and pediment gravels were shed from the mountains in middle and late Pleistocene time[78]. Holocene deposition of alluvium continued locally, but the presence of surficial Pliocene-Pleistocene basalt flows indicates that Holocene sediments are thin in many parts of southwestern Arizona and that most basin fill may actually be Pliocene and Pleistocene in age rather than Holocene as shown on many published geologic maps.

2.5.1.1.5 Regional Tectonic History

A clear understanding of the tectonic evolution of the south-western United States can only be approached through an understanding of global tectonic events. The complex geology of the western United States is due to a long history of complex plate tectonic events requiring that orogenic belts be viewed as collages of diverse tectonic elements jumbled together in many possible ways and with a great deal of overprinting of different structural and metamorphic events.

The Precambrian and Paleozoic history is fragmental and too far in the past to be of much consequence to the safety of the Palo Verde site; thus it is highly summarized below. It is primarily the middle Cenozoic to Holocene tectonic activity that is responsible for formation of the features present today in southwestern Arizona.

Western North America appears to have been the passive trailing edge of a lithospheric plate during Precambrian and early Paleozoic time[80]. Exactly when subduction began under western North America is not clear. Churkin[81] argues that subduction and the opening and closing of marginal ocean basins began as early as the Ordovician; the Devonian-Mississippian Antler orogeny, which occurred from Nevada north to the Yukon, suggests that plate convergence had begun at least by Devonian time. However, andesitic volcanism, generally considered indicative of subduction, did not occur extensively until Permian through Cretaceous time. By late Jurassic time, a broad, high magmatic arc edifice had developed along the site of the present Sierra Nevada, and granitic batholiths formed beneath, especially in Late Cretaceous time[82]. Essentially conformable Cretaceous, Paleocene, and Eocene strata with similar bedding characteristics in western California suggest continuation of the Mesozoic subduction regime until about 40 m.y. BP[83].

Major tectonic reorganization occurred in middle Tertiary time, not only in the western United States but throughout the whole circum-Pacific area. In the Pacific Northwest, the north-south trending Cascade volcanic belt was superimposed across older

arcuate, eastwardly convex structures. Basin and Range block faulting began to segregate a previously continuous broad Laramide uplift comprising much of the western United States[37]. Also, the most severe -- if not the first -- displacements along the San Andreas fault system began in Miocene time[44][45][47][48]. These middle Cenozoic tectonic events, combined with similar accelerated tectonism and volcanism in areas such as the Alaska-Aleutian area, Japan, Mexico, Central America, and South America suggest a major middle Cenozoic change in sea-floor spreading[84]. Atwater[13] postulated that the major changes in the western United States were due to the encounter of the Americas plate with the East Pacific spreading center. Herron[85] demonstrated that the present East Pacific ridge has developed in the past 30 m.y. at the expense of a former north-northwest trending ridge, and Handschumacher[86] documented a major reorganization of the spreading regime in early Miocene. The geologic record in the western United States suggests that the Basin and Range disturbance was not a single episode but apparently consisted of two or three phases. The earliest extensional phase in the Great Basin area in the Oligocene and early Miocene (42 to 18 m.y. BP) may have been oriented quite differently than today's[24]. Middle Miocene (17 to 14 m.y. BP) extension was oriented S68°W-N68°E (±5°) about 45 degrees counterclockwise from the present direction of extension which is oriented about N65°W-S65°E (±20°)[20].

About 4 to 6 m.y. ago, sea-floor spreading activity abruptly began in the region of the Gulf of California[13][86],

establishing the San Andreas Shear Zone as the plate boundary. This spreading activity changed the stress regime in southern California and Arizona, creating the Transverse Ranges and initiating eastward movement of the Mojave block which effectively neutralizes the Sonoran Desert block's extensional tectonic regime[15][87]. In very recent time (late Holocene), the major plate-boundary movements appear to have shifted westward from the San Andreas to the San Jacinto fault set.

At present, the major tectonic mechanisms operative in the southwestern U.S. are extension in the Great Basin and Rio Grande Rift-Mexican Highlands regions and shearing along the San Andreas Shear Zone.

2.5.1.1.6 Regional Geophysics

Regional gravity and aeromagnetic maps reflect the known regional geologic conditions[8]. Both maps show the Sonoran Desert area to be a region of relatively randomly oriented, low-gradient trends representative of heterogeneous faultblock structures masked by large thicknesses of sediments. In contrast, the southeastern part of the state and a curvilinear area across central Arizona from the New Mexico border to the Utah border are regions of high contrast, more-linear trends representative of more rugged terrains of surface and near-surface rocks. The gradients in the northeastern corner of the state are relatively smooth and reflect the relatively homogeneous structure of the Colorado Plateau.

2.5.1.1.7 Regional Subsidence

Regional subsidence due to processes such as tectonic down-warping is not prevalent in the site region, but subsidence due to compaction of basin fill due to lithostatic loading and groundwater withdrawal does occur in local areas throughout the site region.

Tectonic downwarping suggested by Cooley[88], in the form of a large syncline extending northwesterly from the Tucson area through the Phoenix area and westward toward the site, does not extend into site area and thus does not represent a hazard to the Palo Verde site. The very existence of such a zone of subsidence is questionable because it crosses known structural trends and is not consistent with any known or postulated tectonic stresses.

Subsidence that occurs when groundwater is withdrawn from basins, allowing the sediments to consolidate due to loss of pore fluid, is generally slow and generally does not result in great amounts of subsidence. Sometimes, however, surface cracks, land-surface tilting, and rapid subsidence occur and these processes could present a hazard. Areas of subsidence and ground cracking in the site region due to groundwater withdrawal (Eloy-Picacho, Luke Air Force Base, Las Vegas, Nevada) have been analyzed[8] and the analyses have shown that certain conditions must exist to permit consolidation. The areas most affected by subsidence are basins filled with great thicknesses (greater than 2000 feet) of permeable, low density alluvial sediments where large amounts of groundwater are

withdrawn resulting in water level declines on the order of 100 feet or more[89]. Comparison of these conditions (both gross field characteristics and laboratory test results) to conditions in the site region (table 2.5-1) reveal that subsidence is not a hazard at the site (paragraph 2.5.4.1).

2.5.1.1.8 Miscellaneous Regional Geologic Hazards

Geologic studies in the region surrounding the site have shown that there is no potential hazard due to processes such as salt diapirism, landsliding, ground collapse due to cavernous or karst terrain, and unusual weathering or erosion.

2.5.1.2 Site Geology

2.5.1.2.1 Site and Site Vicinity Physiography

The site is located in one of the intermontane valleys of the Sonoran Desert region of the Basin and Range physiographic province. This valley, known as the Tonopah Desert, is broad and relatively flat-floored, with through-flowing, intermittent drainage graded to the Gila River, the regional trunk stream. The site lies between two major intermittent drainages, the Hassayampa River on the east and the Centennial Wash on the southwest. These two drainages are within 3 to 5 miles of the site and drain toward the northern bend of the Gila River near Arlington. The major surrounding mountain ranges are the Palo Verde Hills to the west, the Belmont Mountains to the north, the White Tank Mountains and Buckeye Hills to the northeast and southeast, and the Gila Bend Mountains to the south. Like most mountain ranges in the Sonoran Desert, the flanks of the

surrounding mountains consist of pediment and alluvial fan surfaces that grade gently to the basin floor. The basin floor slopes gently southward from about 1500 feet above sea level at the edge of the Belmont Mountains to about 800 feet elevation along the course of the Gila River southeast of the site. The site is nestled between outliers of the Palo Verde Hills on a flat surface, at about 950-foot elevation, herein referred to as the Palo Verde Hills Basin. The nearest edge of the Palo Verde Hills is about 2 miles west of the site; the outliers are low-relief, rounded knobs protruding through the alluvium north and south of the site. The Palo Verde Hills range in elevation from about 1200 feet directly adjacent to the site to more than 2100 feet at their highest point about 5 miles northwest of the site. The basin floor is dissected by several small ephemeral streams which flow southward and are integrated with the Gila River, about 10 miles southeast of the site. The natural, intermittent flow of water in the washes has now been interrupted by an agricultural irrigation system and by PVNGS construction activities. The micro-relief system, leveled in local areas by agriculture, consists of small rills and gullies that carry the normal runoff into the washes.

Table 2.5-1

COMPARISON OF GEOLOGIC AND HYDROLOGIC CONDITIONS, LUKE AIR FORCE BASE AREA, LAS VEGAS VALLEY, PALO VERDE HILLS AREA (Sheet 1 of 2)

	Luke AFB (Eaton, et al., 1972)[a]	Las Vegas (Mindling, 1971)[b]	Palo Verde Site
Thickness of basin sediments	Greater than 2350 feet	Greater than 4000 feet	480 feet
Thickness of compres-sible sediments	Not available	500+ feet	250 feet (includes very stiff clay and dense granu-lar soils
Depth interval from which water is derived	300 to 1400 feet	200 to 700 feet	700 to 1000 feet (from confined, bedrock aquifers below compres-sible sediments)

a. Eaton, G. P., Peterson, D. L., and Schumann, H. H., 1972, Geophysical, geo-hydrological and geochemical reconnaissance of the Luke Salt body, central Arizona: U. S. Geol. Surv. Prof. Paper 753, 28 p.

b. Mindling; A., 1971, A summary of data relating to land subsidence in Las Vegas Valley: Desert Research Institute Univ. of Nevada, Reno.

Table 2.5-1

COMPARISON OF GEOLOGIC AND HYDROLOGIC CONDITIONS, LUKE AIR FORCE BASE AREA, LAS VEGAS VALLEY, PALO VERDE HILLS AREA (Sheet 2 of 2)

	Luke AFB (Eaton, et al., 1972)[a]	Las Vegas (Mindling, 1971)[b]	Palo Verde Site
Drawdown	250+ feet	180+ feet	In site area for the period 1955 to 1975, approximately 40 to 50 feet
Subsidence	0 to 3 feet	0 to 5 feet	None
Earth fissures	Three areas of fissuring related to large scale withdrawal of groundwater. Fissures possibly associated with differential consolidation over crest of the Luke salt body and compressibility differences in subsurface deposits.	Four areas of fissures localized by differential consolidation across older compaction fault scarps.	None

2.5.1.2.2 Site Vicinity Geology and Relationship to Regional Geology

2.5.1.2.2.1 Site Vicinity Stratigraphy. Figure 2.5-8 is a geologic map and simplified stratigraphic column of the area within a radius of 25 miles of the site (site vicinity). Figure 2.5-9 shows geologic cross-sections illustrating the subsurface geologic relationships of the site vicinity.

The geologic formations within the site vicinity are typical of the Sonoran Desert subprovince and include highly deformed metamorphic and granitic rocks of Precambrian age and moderately deformed volcanic and sedimentary units of Tertiary age in the mountains, and undeformed volcanics and sediments of Pliocene to Holocene age in the basins. The metamorphic and granitic rocks are termed basement and the moderately deformed volcanic and sedimentary units are termed bedrock, and the undeformed volcanics and sediments are termed basin sediments.

The emplacement of Precambrian plutons of granitic and gabbroic composition are generally associated with the culmination of the Mazatzal Revolution, and resulted in the metamorphism of surrounding rock to schist and gneiss(3).

The metamorphic rocks are the oldest rocks in the site vicinity and are subdivided into three subgroups: greenschist facies metamorphics, metadiorites, and gneissic, granitic and hornfelsic rocks.

The greenschist metamorphic rocks make up only a small fraction of the rocks in the site vicinity. They crop out 5 miles west of Gillespie Dam and on the east flank of Saddle Mountain. The

metadiorites are rare intrusive bodies found only in conjunction with the greenschist metamorphics in the Gillespie Dam area. The gneissic rocks are the predominant metamorphic subgroup in the site vicinity and compose about one-third of the Belmont Mountains and all of the White Tank Mountains. A large segment of the Gila Bend Mountains, 20 miles west of Gillespie Dam, is composed of gneiss. Scattered outcrops of gneiss are also exposed 2 miles south of Gillespie Dam. The granitic rocks are represented by granite and quartz monzonite, including aplite and alaskite, outcrops in the eastern portion of the Belmont Mountains, Maricopa Mountains, the entire Buckeye Hills, and in the Gila Bend Mountains. Although not exposed in the Palo Verde Hills, granitic basement rocks were encountered in exploratory borings beneath the site property (figure 2.5-10).

Bedrock in the site vicinity consists almost entirely of Tertiary volcanic rocks and Tertiary volcano clastic and sedimentary rocks unconformably overlying the Precambrian basement rocks (figure 2.5-9). The age and composition of these rocks are similar to those throughout the entire Basin and Range province. Tertiary sedimentary and volcanic rocks are exposed in the western portion of the Belmont Mountains and the south-central flanks of the Gila Bend Mountains. Sedimentary rocks in the Gillespie Dam area consist of arkosic conglomerate, lahar deposits, tuffaceous sandstone, and cross-bedded sandstone. The Tertiary sedimentary members of the sequence are interbedded with the Miocene andesite and basalt flows, flow breccias, and pyroclastic rocks. The Gila Bend

Mountains are primarily composed of andesite and basalt which range in age from 19 to 28 m.y. BP. In the Palo Verde Hills, basaltic andesite, diabase, and basalt, with minor amounts of interbedded tuff, are approximately 17 to 21 m.y. old.

Basin filling deposits overlying the Tertiary volcanic-sedimentary bedrock sequence are talus, colluvium, alluvial fan, basin alluvium, lacustrine, and fanglomerate. Ages of alluvial fan deposits on the surrounding mountain flanks range from Tertiary to Holocene, based on potassium-argon ages of overlying basalt flows. Two series of alluvial fan deposits (QTfn and TVfn) are stratigraphically below the Arlington and Gillespie basalt flows and, therefore, are late Pliocene in age (greater than 2 m.y. BP). Massive, extensive clay deposits penetrated by numerous water wells in the Phoenix and Gila Bend basins attain a thickness of more than 700 feet between Phoenix and Litchfield Park and 850 feet in the Gila Bend Basin. These clay deposits are usually continuous across individual basins but there is no direct evidence that they are continuous between adjoining basins.

Late Tertiary and early Quaternary basalt flows interbedded with and overlying the basin sediments are the youngest volcanic rock units in the site vicinity. Four extensive olivine-basalt flows overlie Gila River terrace deposits and alluvial fan deposits. Whole-rock, potassium-argon ages of these flows are:

- Gillespie: 1.3 to 4.2 million years (nine samples) -- average age 3.3 million years

- Arlington: 1.2 to 3.2 million years (six samples) -- average age 2.2 million years
- Sentinel: 1.71 ±0.25 million years (one sample)
- Gila Bend: 2.5 to 6.5 million years (three samples) -- average age 4.5 million years

The youngest volcanic flows appear to be similar to widely scattered geomorphically young vents and flows throughout the Sonoran Desert subprovince. These volcanics are generally shown on published maps(90) as Quaternary basalts, but the age data given above shows them to be earliest Quaternary and/or latest Tertiary in age.

2.5.1.2.2.2 Site Vicinity Structure.

A. General

The structure of volcanic bedrock in the Palo Verde Hills is homoclinal with the volcanic flow-bedding striking approximately N40°W and dipping 15 to 23°SW. To the north of the 5-mile radius, scattered northerly and northeasterly dips have also been noted. These dips suggest small intraformational folding probably associated with irregularities on the original surface of flow deposition or proximity to one of the numerous vent or source areas.

B. Faults

Published detailed geologic maps of Arizona and Maricopa County do not indicate any faults within the site

vicinity. The existence and position of mountain-basin boundary faults (figures 2.5-8 and 2.5-11) have not been directly documented in the site vicinity and are only inferred from published regional geologic maps and gravity data(8)(88)(91). The existence of these inferred and hypothetical faults in the site vicinity is based on extrapolations of regional Basin and Range-type geologic characteristics. Our investigations could find no surface or near-surface evidence of these faults; therefore, if they are assumed to exist, they are in older rocks at depths beyond the reach of state-of-the-art geotechnical methods and would not be considered capable faults under existing criteria.

Techniques used to investigate these inferred faults included interpretation of aerial photographs, ERTS-1 imagery, and side-looking radar imagery; reconnaissance and detailed geologic mapping; detailed borehole and trenching investigations; and gravimetric and surface magnetic surveys. The detailed geophysical surveys were able to detect only a few of these inferred faults within 15 miles of the site (figures 2.5-8 and 2.5-11) and inferred and hypothetical faults and lineaments were shown not to be capable faults on the basis of:

- The existence and continuity of the Palo Verde Clay (LZ-3 described in paragraph 2.5.1.2.3) which underlies the Palo Verde Hills Basin without any signs of disruption by faulting.

- The continuation of the distinctive Palo Verde Clay, in the subsurface, to Arlington and Gillespie Dam where it is overlain by basalt flows dated as about 2 m.y. old (paragraph 2.5.1.2.2.1); based on the principle of stratigraphic superposition, the Palo Verde clay and any faults underneath it are much older than the basalts.

- The presence of extensive elevated terraces along the Gila River which overlie the trends of several faults and lineaments and were found to be undisturbed; a prominent 40-foot terrace is overlain by both the Arlington and Gillespie basalt flows indicating the terrace is greater than at least 2 m.y. old.

Reconnaissance and detailed geologic mapping by Fugro within the site vicinity and the site have revealed a few small faults (figures 2.5-11 and 2.5-12) which were not shown on published maps; but these are Tertiary in age and, except for one, are outside of the 5-mile radius. None of these faults displace late Quaternary rocks[8].

LANDSAT, aerial photograph, field reconnaissance studies, compilation of unpublished data, and published maps by M. Cooley during the period 1963 to 1974 has led to publication[88] of a "Map of Arizona

Showing Selected Alluvial, Structural, and Geomorphic Features." The faults shown by Cooley[88] are "known and

inferred faults" which, according to him, were active mostly during the Miocene Epoch. In general, his faults coincide with buried faults shown on previously published maps (see figures 2.5-4 and 2.5-11). The areas of these faults were investigated during the fault and lineament analysis and no displacement or disturbance of late Tertiary or Quaternary strata or geomorphic features could be found.

See also appendix 2A, Questions 2A.11, 2A.13, 2A.15, and 2A.16.

C. Lineaments

Lineaments observed in the site vicinity are shown on figure 2.5-13. These lineaments were observed on aerial photographs, side-looking radar imagery, and space photographs and imagery. These features were investigated and none were found to represent geologic structure.

Photogeologic lineaments identified in the Belmont and White Tank Mountains (figure 2.5-13) were found to be restricted to deformed Precambrian crystalline rocks with no evidence of Quaternary displacement[8].

The Gila River lineament trends N70°E about 8 miles south of the site. This lineament defines the north side of the Buckeye Hills along the straight east-northeast-trending segment of the Gila River and projects toward Saguaro Lake east of Phoenix. To the west, the lineament aligns with the straight course of

the Gila River and projects toward Yuma. A similar subparallel lineament exists on the south edge of the Buckeye Hills and appears to converge with the Gila River lineament near Phoenix (figure 2.5-13). Detailed geologic investigations along these lineaments did not disclose any faulting which could be associated with the lineament. In the vicinity of the site, the lineament is chiefly the result of the linear Gila River along the north side of the Buckeye Hills. The straightness of the river is controlled by the straight northern edge of the Buckeye Hills which is probably a remnant of middle to late Tertiary Basin and Range block-faulting[(91)]. Features near the east end of the Gila River lineament, such as faulting at Saguaro Lake, are cut off by northwest striking faults and thus are not continuous to the west and do not represent faulting associated with the lineament. Indirect evidence for uplifted early Tertiary conglomerate was observed at Tempe, but no fault or indication of geologic structure could be found.

Eberly and Stanley[(92)] postulated that the Gila River between Phoenix and Yuma coincided with an ancient northeast-southwest trending structural trough. This trough, however, is transected by late Miocene north-west-southeast trending block faults and thus is no longer an active structural feature. The Gila River follows the trough to the Colorado River and appears to be the reason for the apparent prominence of the Gila

River lineament. The inactivity of the trough as a tectonic element is further substantiated by its being overlain by at least two extensive Pliocene and Pleistocene basalt flows at Gila and Sentinel. Both of these flows have been inspected in detail and were shown to be continuous and unbroken across the lineament[8]. Detailed geomorphic studies were conducted on the elevated terraces of the Gila River from Hassayampa south to Gila Bend. Both the Arlington basalt flow and the Gillespie flow overlie a prominent terrace (40-foot terrace) indicating the terrace is no younger than late Pliocene (2 to 3 m.y. ago). Leveling surveys on terrace benches between Arlington and Enterprise Ranch show no evidence of deformation or displacement of the terrace across the projected lineament.

Investigation of the Gila Bend lineament (figure 2.5-13) shows that it is the result of alignment of the western margin of the Maricopa Mountains, the portion of the Gila River south of Gillespie Dam, the eastern margin of the Gillespie basalt flow, and vegetation in the mouth of Centennial Wash. No surface evidence could be found to indicate that major through-going faults or Quaternary faults are associated with this lineament. Like the Gila River lineament, the Gila Bend lineament is an area of continuous undisturbed Quaternary-Tertiary terraces and the Pliocene Palo Verde clay demonstrating that if the lineament were structurally controlled it would be older than at least 2 million years. Thus, it

appears that a chance arrangement of the unrelated features has created an alignment, but one which is not a surface expression of geologic structure.
The Harquahala lineament trends approximately N45°W and can be interpreted to be about 100 miles long, although it is not distinct for that entire length (figure 2.5-13). Its expression is purely topographic and it does not disrupt Quaternary formations such as the Gila Bend basalt flow, the river terraces near Gila Bend, or the sediments filling Harquahala Valley.

Approximately 7 miles southeast of the site, a short northeast trending lineament called the Arlington lineament projects toward the Arlington basalt flow (figure 2.5-13). The lineament is approximately 2.5 miles long, is defined by an abrupt change in vegetation, and terminates at the basalt flow. The area around the lineament and basalt flow was mapped in detail and no evidence could be found for disturbance or faulting of the surface of the basalt. A backhoe trench was excavated across the projection of the features at the west edge of the basalt flow. Prebasalt strata, including buried paleosols form distinctive horizons, which could be directly correlated or stratigraphically overlapped along the full length of the trench. Because the unbroken strata are older than the overlying Arlington basalt (about 2 m.y. BP), the undeformed prebasalt strata demonstrate that no faulting or

deformation has occurred along the Arlington lineament for more than 2 million years.

D. Joints

Regional Basin and Range joint-trend investigations[93] attributed systems of north to northwest, east to northeast, and east-west joint trends to regional Laramideage and Basin and Range tectonism[8]. No evidence has been observed of joints or fractures in the basin sediments.

2.5.1.2.3 Site Stratigraphy

The rocks of the site area are divided into three groups: the basement complex, bedrock, and basin sediments. The areal distribution of these rocks is shown on figure 2.5-12. Figures 2.5-14 and 2.5-15 show several typical geologic cross-sections through the site area. Figure 2.5-15 shows one of these cross-sections enlarged and figure 2.5-16 is a generalized cross-section. Figure 2.5-17 is a stratigraphic chart.

A. Basement Complex

Precambrian granitic and metamorphic rocks are called the basement complex. Metamorphic rocks, chiefly amphibolite schist, are exposed in outcrop on the southwest and west flanks of the Palo Verde Hills approximately 7 miles west and northwest of the site (figure 2.5-8). The basement complex is not exposed at the ground surface within the site area, but granitic

rocks encountered in boreholes at the site (figure 2.5-10) indicate that the basement rocks extend under the site. The basement rock is weathered to as much as 60 feet below its upper contact.

B. Bedrock

Miocene volcanics and interbedded sedimentary rocks unconformably overlying the basement complex are termed bedrock. Figure 2.5-18 is a structure contour map of the bedrock surface below the site. Bedrock is well exposed in the Palo Verde Hills as massive flows, plugs, dikes, and flow breccia, with scattered, discontinuous interbeds of tuff and tuffaceous sandstone (figure 2.5-12). Within exploratory drill holes, arkosic conglomerate at least 140 feet thick was found in the volcanic rock section near the unconformity with granitic basement rocks. Driller's logs from water wells in the northern part of the Palo Verde Basin suggest the volcanic-sedimentary bedrock sequence may reach thicknesses greater than 1400 feet (near borehole PV-21) and contain numerous interbedded sandstone and conglomerate layers.

The volcanic bedrock varies, in order of relative abundance, from basalt to diabase to andesite to dacitic welded tuff and quartz-latite tuff. Whole-rock potassium-argon ages from seven localities range from 17.7 to 20.3 m.y. old[8].

The interbedded arkosic conglomerate includes red to brown argillaceous quartz sandstone, lithic sandstone, and granitic pebble-cobble conglomerate. Clasts are primarily of feldspar, quartz, and granitic debris. Tuffaceous zones are also noted within the unit and reach thicknesses of at least 107 feet. Ferruginous cement is common throughout the unit as are calcareous zones.

C. Basin Sediments

Lithified and unlithified sediments overlying the basement and bedrock groups have been divided into six lithologic units or zones (abbreviated LZ) (figures 2.5-16 and 2.5-17).

In order of descending stratigraphic position and increasing age, the stratigraphic subdivisions of the basin sediments at the site area are:

- LZ-6 Fan deposits (Pleistocene to Holocene)
- LZ-5 Upper sand and gravel
- LZ-4 Upper silty clay
- LZ-3 Palo Verde clay (upper Pliocene)
- LZ-2 Lower silt and lower sand and gravel
- LZ-1 Fanglomerate (Miocene-Pliocene)

LZ-2 through LZ-5 are unlithified units of Pliocene and Pleistocene age, and together with more recently deposited LZ-6, are designated the "alluvial sequence".

LZ-1 is lithified and in most respects is a rock formation. The average thickness of the alluvial sequence is approximately 320 feet with a variation of thickness in the site area of approximately 100 feet.

LZ-1: The Tertiary fanglomerate contains rounded to angular clasts of predominantly andesite and basalt in a well-cemented matrix of sand, silt, and occasionally tuffaceous sand. The fanglomerate is exposed along the lower slopes of the Palo Verde Hills unconformably overlying the volcanic bedrock. In the subsurface the fanglomerate fills bedrock depressions but is generally absent on the highest bedrock surfaces (figure 2.5-10). Thickness of the fanglomerate ranges from about 35 to 285 feet. A basalt interbed in the fanglomerate showed evidence of horizontal cleavage and a brecciated contact indicating the basalt is a flow that was deposited during deposition of the fanglomerate. The basalt has been dated as 16.7 m.y. BP, indicating a middle Miocene age for the fanglomerate.

LZ-2: LZ-2 unconformably overlies the fanglomerate and consists of uncemented sand and gravel grading upward into sandy and clayey silt. This unit is generally light brown and contains scattered caliche stringers. The gravel clasts are commonly volcanic rocks, but granitic gravel and cobbles are also present.

LZ-3: The Palo Verde clay is the most distinctive lithologic zone in the alluvial sequence. It is

continuous throughout the site property and extends at least 5 miles southeast and northeast of the site (figures 2.5-19 through 2.5-22). It is generally 80 to 100 feet thick with a maximum known thickness of 136 feet (figure 2.5-23). In addition to its lithology, the Palo Verde clay is readily distinguished from other units in the alluvial sequence by a distinctive natural gamma response (figures 2.5-10 and 2.5-15). Nine subunits within the Palo Verde clay were identified through detailed analysis of natural gamma, gamma-gamma, neutron-neutron, neutron-gamma, spontaneous potential, and resistivity logs (figure 2.5-15). Horizons located by geophysical interpretation are usually accurate within 2 feet but where the geophysical subunits were compared with continuous core or closely spaced samples, the resolution of subunits was found to be within a few inches.

The Palo Verde clay appears to have been deposited under lacustrine or playa conditions. The lower contact is generally gradational and the clay is commonly interlayered with silt or sand near its base. The upper contact of the clay is distinct and in several borings the top of the clay is marked by a paleosol suggesting a relatively long period of landscape stability prior to deposition of overlying sediments.

LZ-4: An upper silty clay unit, 150 to 200 feet thick, contains brown to red-brown silty clay, clayey silt, and silt with lenses of fine-grained sand and silty sand.

Coarse-grained sand and gravel up to 20 feet thick are found at the base of this unit at many locations. The unit is generally calcareous with irregular caliche stringers and nodules. It is continuous throughout the site area and over bedrock highs where the Palo Verde clay is not deposited (figure 2.5-10). Stratigraphic Unit E, the uppermost subunit of this lithologic zone was exposed in power-block excavations (appendix 2D). The west and northwest boundaries of the Palo Verde clay interfinger with coarser alluvial fan and basin sediments before reaching the Palo Verde Hills volcanic bedrock.

The Arlington basalt flow (about 5 miles southeast of the site) unconformably overlies the coarse-grained sediments of LZ-4 and a silt unit which is equivalent to at least the lower portion of LZ-5.

LZ-5: Lithologic Zone 5 ranges from 25 to 53 feet thick in the northwest, thins to 10 or 12 feet farther south, and is not present beneath the Arlington basalt to the southeast. It is generally much coarser grained than the underlying units, although it also contains silt, clayey silt, and silty clay in thin irregular beds. LZ-5 and the upper portion of LZ-4 (stratigraphic unit E) have been mapped in detail in the powerblock excavations (appendix 2D). Geologic inspection and mapping indicate that the geology and stratigraphy exposed during construction confirm geologic interpretations made during PSAR[8][94] investigations.

South and southwest of the Palo Verde Hills, a surficial unit described on the geologic map (figure 2.5-12) as Tertiary-Quaternary fan deposits (QTfn), includes gravel and sandy clayey gravel which appear to be derived primarily from the Saddle Mountain and Palo Verde Hills area. These deposits grade south-eastward into the basin fill deposits and are considered to be time-equivalent to the Tertiary-Quaternary basin fill (QTbf) deposits in the site area.

LZ-6: The younger fan deposits are 8 to 15 feet thick and range in composition from brown sand, sandy silt, and sandy gravel to brown gravelly silt with interbedded sand. These deposits are chiefly volcanic rock fragments derived from the nearby hills and quartz, granitic, and metamorphic debris derived from the Belmont Mountains and areas to the north.

The younger fan deposits occur in the site area as erosional remnants of fan deposits east of the site area in the Hassayampa River drainage. The stratigraphic relationship between the younger fan deposits and the underlying basin fill is best seen at the Arlington basalt where the flow separates the under-lying basin fill deposits from the overlying younger fan deposits.

2.5.1.2.4 Site Geologic Structure

The geologic structure of the bedrock and basement complex in the site area has been investigated by detailed geologic mapping of surface outcrops, trenching, boring, seismic

refraction, gravity, magnetic, and downhole geophysical surveys. Analysis of structure within the basin sediments is based on correlation of lithology using samples from exploratory borings, high-resolution downhole geophysical logs, and excavations at and adjacent to the site.

The faults in the vicinity of the site (25-mile radius) were discussed in paragraph 2.5.1.2.2. In that section two basic classifications of faults were discussed; mappable and inferred or hypothetical faults. These faults are shown on figure 2.5-11 which also shows that one mappable and four hypothetical or inferred faults are within the 5-mile site area radius. The one mappable fault within the 5-mile radius is in Miocene volcanic rock about 3 miles west of the site (figures 2.5-11 and 2.5-12). This fault is exposed for about 2000 feet and is overlain by fanglomerate (Tvfn) on the southeast (figure 2.5-12). The age of the overlying fanglomerate is 16.7 m.y. (Miocene) based on potassium-argon dating of a basalt interbedded within the fanglomerate. Numerous trenches dug across the fault (see figure 2.5-12) could find no evidence of post-Miocene movement.

Geophysical anomalies about 4.5 to 5 miles north of the site (figure 2.5-12) were inferred to be faults(8). These features do not displace the Pliocene-Pleistocene basin sediments and therefore are not capable faults.

In paragraph 2.5.1.2.2.2, faults inferred by Cooley(88) were shown as generally coinciding with hypothetical faults on other published regional maps(91). However, two of Cooley's inferred

faults are not shown on published maps, and trend through the site area radius (figure 2.5-11). The fault inferred to lie beneath the site has been shown by detailed field mapping, borehole lithologic, seismic refraction, downhole geophysical, gravimetric, and magnetic studies not to displace the Palo Verde clay or younger strata. The fault inferred north of the site extends southeastward from near a linear volcanic dike complex at the southern tip of the Big Horn Mountains past the site along the highway to the Arlington Basalt flow. Directly north of the site, it coincides quite closely with the Tertiary-age buried faults postulated from gravity data (figure 2.5-11). Detailed borehole lithologic, geophysical, and paleomagnetic studies have shown that this buried fault does not displace the ground surface or the Pliocene-age Palo Verde clay (figure 2.5-19). The fault was most likely inferred on the basis of linear alignment of Tertiary (19 to 20 m.y.) volcanic features in the Big Horn Mountains, natural drainages, Tertiary volcanic hills at the north edge of the site, and manmade trails and highways. The linearity and alignment of the natural features in the Big Horn Mountains and those north of the site could be attributed to the existence of ancient faults. The bend in the "fault", as shown by Cooley(88), suggests two different faults and the difference in structural trends between the Big Horn Mountains segment and the Palo Verde Hills segment (figure 2.5-11) supports this view. The linearity of the Big Horn Mountains is due to the presence of a linear dike extrusion. Published maps(91) indicate that the Big Horn Mountains are bounded by a buried fault on the

southwest side rather than through the range as shown by Cooley. The location of a fault on the southwest would suggest that it is a basin-bounding fault, and this is more consistent with known geologic relationships in the Sonoran Desert where it is thought that Tertiary volcanics were block-faulted into basins and ranges in late Tertiary time. Regardless of the existence or exact location of the inferred faults, geologic studies in the site area demonstrate that they do not displace late Pliocene or Pleistocene strata. If the fault extends toward and under Arlington basalt flow, as inferred by Cooley, it would be a pre late-Pliocene fault because it does not displace the Palo Verde clay or the Arlington basalt flow.

Two photo lineations lie at the northern edge of the site property line (figure 2.5-12). These short lineations were identified from low level (1000 feet to the inch), color, aerial photographs of the site area. One lineament coincides with a short section of stream channel and an indistinct northwest trending alignment of vegetation for a distance of about 5000 feet, approximately 0.75 mile northeast of the site. A second lineation corresponds to a straight segment of stream channel about 4500 feet long, approximately 0.5 mile northwest of the site. Backhoe trenches excavated across these lineaments exposed continuous, undeformed Quaternary strata. There was no evidence of faulting or other structural origin for these lineations.

2.5.1.2.5 Site Geologic History

Pre-Laramide geologic history is discussed in paragraph 2.5.1.1.4 and no new information can be added to that discussion from results of site area investigations.

Some of the volcanic and sedimentary rocks in the site area had been considered Laramide in age, but recent potassium-argon radiometric dating indicates that most of these rocks are of middle Tertiary age(8).

Tectonic activity, which resulted in the current Basin and Range physiographic and structural features, began in middle Tertiary time, after the Laramide orogeny, and culminated in middle Miocene to middle Pliocene time with large-scale tilt-block faulting of the basement complex and Tertiary volcanic and sedimentary sequences. Basin and Range tectonism continued at a diminished rate through the end of Pliocene time.

During and after the development of the mountain ranges and intermontane basins into approximately their present configuration, alluvial fans and pediments developed at the bases of the ranges. These pediment-fan systems provided considerable detritus to the basins and are probably the oldest, clearly post-orogenic deposits in the site area. Alluvium accumulating in the basins during the post-orogenic Pliocene period covered the pediments and basin bounding faults. In the site region, alluviation did not exceed about 1000 feet, but in the adjacent Phoenix Basin more than 2000 feet of sediment accumulated. Closed-basin conditions existed in the site region until late Pliocene time with several

hundred feet of fine-grained basin fill accumulating under playa-like conditions. The Palo Verde clay was deposited in such an environment in late Pliocene time; it is now overlain by 150 feet of sediments containing well developed paleosols and local calcareous zones.

Through-flowing drainage developed in late Pliocene time when the basins became full. The Gila River was integrated through the site area as it flowed west from the Phoenix Basin into Arlington Valley through an outlet on the east side of the Gila Bend Mountains. Apparently the last episode of local uplift occurred prior to extrusion of the Gillespie basalt flow as indicated by older Gila River gravels tilted about 25 degrees to the south. The tilted late tertiary gravels are most likely the result of local faulting in the Gillespie Dam area.[(8)]. Following this localized faulting, stability continued as indicated by well-developed paleosols on an erosional surface between the tilted gravels and subsequently deposited, horizontally stratified, Gila River deposits and the overlying Gillespie basalt flow, (about 3.3 m.y. old).

The Gila River has undergone several episodes of downcutting since its initial integration, probably the result of climatic as well as localized tectonic changes. One episode of down-cutting had already occurred prior to the eruption of the Arlington basalt flow, about 3 m.y. ago. Both of these flows occurred while the river was at a level 40 feet above the present level; they locally constricted the river channel, with the Gillespie flow probably damming the river for a short time and forcing it to cut a new outlet through Miocene basalt east

of the former channel. This higher river level was a major base level in the site area throughout much of Pleistocene time. Tributary streams of the Gila River and tributary pediment-fan systems along mountain fronts were graded to this level both in pre- and post-basalt flow time. The Hassayampa River probably did not enter the site area until after extrusion of the Arlington flow; Hassayampa alluvium blanketed the fine-grained basin fill, the Gila River gravel, and the northern half of the Arlington basalt flow. This large alluvial blanket was apparently graded to the 40-foot level of the Gila River.

A second downcutting occurred in Pleistocene time (post-Arlington basalt) with a corresponding base-level change. The coarse-grained Hassayampa material overlying the fine-grained basin fill in the site area was dissected and partially removed. Tributary system incision caused wide-spread degradation of alluvial fans.

The third downcutting probably began in late Pleistocene time and is continuing today.

Aggradation during the Pleistocene was largely limited to fluvial deposits in local floodplains and windblown deposition. A mantle of fine-grained windblown material covered the site area and sand dunes derived from the Gila River floodplain developed locally in the site area.

2.5.1.2.6 Miscellaneous Site Geologic Hazards

The detailed geologic and engineering analysis of the site area has shown that there are no hazards due to geologic processes such as subsidence (paragraph 2.5.4.1.1), salt dissolution or diapirism, liquefaction (paragraph 2.5.4.8), erosion, landsliding, collapse due to cavernous or karst terrain, or to man's activities such as fluid and mineral extraction or dam breakage.

2.5.1.2.7 Site Geophysical Surveys

The following geophysical surveys were conducted at the site and the surrounding area:

- Surface magnetometer
- Gravimetry
- Crosshole seismic velocity
- Downhole seismic velocity
- Downhole geophysical logging

Gravity and magnetic surveys of the site area and up to 10 miles from the site[8] indicate that the Palo Verde Hills represent a positive basement block bounded by a gravity low to the northeast and southwest. To the north and northeast the gravity contours indicate a steep gravity gradient interpreted to represent buried northwest-trending normal faults. These features are interpreted to be subparallel and approximately 10 miles in length but are overlain by unfaulted Palo Verde clay beds (paragraph 2.5.1.2.4).

2.5.1.2.8 Engineering Geologic Evaluation of Local Features Which Affect Seismic Category I Structures

There is no reported or observable physical evidence indicating adverse response or failure of bedrock or basin sediments during prior earthquakes. The continuity of the Palo Verde clay (paragraph 2.5.1.2.3) indicates the site area has been tectonically stable and unfaulted for at least 2.8 million years, and historic seismicity indicates the site has been subjected only to very mild ground shaking during the last 100 years (paragraph 2.5.2.1.3).

Seismic Category I foundations are on undeformed basin sediments with a minimum thickness of about 200 feet. These sediments are firm, consolidated, continuous, and show no evidence of shears, faults, joints, folds or other tectonic features (paragraph 2.5.1.2.4 and appendix 2D).

No zones of structural weakness, crushed, or disturbed materials have been identified in the basin sediments underlying the site. Zones of alteration and irregular weathering profiles also are not present in these units (paragraph 2.5.1.2.4 and appendix 2D).

Bedrock is not exposed in the powerblock area and is not present at depths which could adversely influence the foundations (appendix 2D). There is no evidence of unrelieved residual stresses in the bedrock or in the basin sediments.

A detailed description of the rock and soil properties underlying the site is in subsection 2.5.4 and appendix 2D.

There is no evidence of subsidence in the site area such as basin downwarps, fissures, or cracks. The closest known occurrence of land subsidence and earth fissuring is in the Luke Air Force Base region, about 25 miles east of the site. A comprehensive analysis of areas of known subsidence and comparison of those areas to the site area has shown that land subsidence and earth fissures should not be anticipated at the site (paragraphs 2.5.1.1.7 and 2.5.4.1.1).

No mineral extraction has taken place in the area of the site and none is anticipated. However, according to the Arizona Oil and Gas Commission, two applications are on file to drill exploratory test holes in the site vicinity. Table 2.5-2 lists the location and status of the applications.

Groundwater withdrawal has been analyzed (subsection 2.4.13) and does not represent a hazard.

2.5.1.2.9 Groundwater

A detailed discussion of site groundwater conditions is presented in subsection 2.4.13.

Table 2.5-2

MINERAL RESOURCE EXPLORATION APPLICATIONS

IN THE SITE VICINITY

Applicant	Location	Status[a]
Gemini Oil and Mineral	SW 1/4, SW 1/4, Sec. 27 T2N, R7W	2500 feet test hole complete
Phillips Petroleum	NE 1/4, NE 1/4, Sec. 16 T2N, R4W	8000 feet test hole proposed, no drilling performed to Date

a. Due to proprietary nature of exploration drilling, drill logs are not available for public inspection until one year following submittal of logs to the Arizona Oil and Gas Commission.

2.5.2 VIBRATORY GROUND MOTION

2.5.2.1 Seismicity

2.5.2.1.1 Data Base

Data describing the earthquake history of the region surrounding the Palo Verde site are found in a number of sources. A basic compilation of historical records of earthquakes in the region is the catalog of Townley and Allen[95] which lists earthquakes for 1769 through 1928. In 1971, Sturgul and Irwin[96] published an "Earthquake History of Arizona and New Mexico, 1850-1966". They supplemented the Townley and Allen data with subsequent reports of earthquakes that had been felt and some instrumentally determined epicenters to bring the

list up to 1966. Annual issues of "United States Earthquakes" by the U.S. Department of Commerce, beginning in 1928, contain about 30 additional small shocks that were not included in the Sturgul and Irwin catalog. A worldwide seismicity catalog on magnetic tape is maintained by the National Oceanic and Atmospheric Administration (NOAA), and the catalog is updated periodically. The most recent Arizona catalog, "Arizona Earthquakes 1776-1980", has been compiled by DuBois, et al[97].

Figures 2.5-24 and 2.5-24a show the locations of the maximum intensities assigned for shocks felt (Modified Mercalli Intensity IV or more) in the site region.

The source for instrumentally determined seismicity data in the Arizona region is currently the National Geophysical and Solar-Terrestrial Data Center (Boulder, Colorado) operated by NOAA. A catalog has been compiled of the reported, instrumentally determined epicenters in the region since 1927. The catalog is periodically updated. There are certain limitations to the data, but the data are necessarily the best available because Arizona does not have a local network of seismograph stations. For many years, a seismograph station established at Tucson in 1925 was the only station within the state. Several stations were installed near Lake Mead at Boulder City, Nevada in 1942 during the dam construction, and were operated for many years. A similar station has been installed at Glen Canyon Dam. In 1963, the Tonto Forest Seismological Observatory was established with a sophisticated array of seismometers. However, this project was oriented towards teleseismic data and no attempt was made to locate local tremors. An amateur

station was operated by W. L. Groene with relatively sophisticated equipment near Phoenix from 1967 until his death in 1975. Arizona State University staff were performing studies of local seismicity through early 1976. Since that time the studies have been terminated, their station has been inoperative, and no results have been reported.
Table 2.5-3 lists the locations of the stations in Arizona. Other stations throughout the western United States provide useful records for any larger events that might occur. Parts of the Imperial Valley and the Gulf of California are within 200 miles of the Palo Verde site; instrumental observations of shocks in these areas are gathered by the Southern (California Seismograph Network, California Institute of Technology, and U.S. Geological Survey) and to a lesser extent by Scripps Institute of Oceanography and the University of Mexico. Epicenter data for the region are shown in figure 2.5-25.

2.5.2.1.2 Limitations of the Data

Historical records can give an incomplete picture of the regional seismicity. The location of a shock often cannot be determined more accurately than to say it occurred near a community reporting the strongest effects from ground shaking. In addition, other shocks may have occurred in sparsely populated areas and may not have been reported. However, the historical records do provide a good measure of any large, damaging earthquakes that might have occurred. Maximum intensities, assigned on the basis of historical records, are

often uncertain because many earthquake accounts tend to be highly subjective.

Several restrictions should be considered when using the NOAA data for instrumentally determined epicenters: location accuracy, detection threshold, and magnitude assignment. The NOAA data have a detection threshold judged to be about magnitude 4.5 prior to 1945 and about 4.0 thereafter. Detection threshold means that, while smaller events are sometimes reported, the catalog may not contain a complete record of the smaller shocks. Locations are reported only to the nearest 0.1 degree (about 6 miles) prior to July 1968, and the accuracy of most events before the early 1950s may be only 1/4 to 1/2 degree (about 17 to 33 miles). These uncertainties in epicenter locations require that the data be used mostly to define seismic zones (refer to paragraph 2.5.2.3) rather than to delineate individual, active tectonic structures. The Imperial Valley in California is less restricted by this requirement because of better station coverage and surface ruptures associated with some of the larger earthquakes. The third consideration is that of magnitude assignment, in that many of the earlier events, especially those prior to 1945, do not have magnitudes recorded in the NOAA catalog. However, it is unlikely that earthquakes with magnitudes greater than 4.5 to 5.0 would appear without an assigned magnitude. Similarly, these events are probably of at least 3.5 to 4.0 magnitude so that they would have been recorded sufficiently well by the regions' seismograph stations to be included in the NOAA catalog.

Table 2.5-3

SEISMIC STATIONS IN ARIZONA[98] (Sheet 1 of 3)

Station	Location	Elev (ft)	Remarks
Glen Canyon Dam, GCA	36°58'25" N 111°35'35" W	4393	SP Benioffs; 3-component installed in 1960.
Sunset Crater, SCN	35°22'08" N 111°32'33" W	6959	An SP instrument installed in 1970 by the National Park Service. Inadequate timing for use in locating events. Inoperative since late 1977.
Mummy Mountain Observatory, MMO	33°33'16" N 111°57'28.6" W	1398	Private station operated by Mr. W. L. Groene from May 1967 to January 1973.
Tucson, TUC	32°18'35" N 110°46'56" W	3232	In 1962, the WWSSN standardized instruments were installed
Tucson, TUO	32°14'48" N 110°50'06" W	2526	The station was established with two Bosch-Omori's in 1909. Two Wood-Anderson seismographs were

Notes: (1) The Southern California Seismographic Network has operated stations in the extreme southwest corner of Arizona; but the operations have not been for extended periods of time, and the locations are not included in this table.

(2) Teledyne-Geotech operated stations at 16 sites for various short periods up to about 18 months between 1961 and 1968; locations are not included in this table.

Table 2.5-3

SEISMIC STATIONS IN ARIZONA[98] (Sheet 2 of 3)

Station	Location	Elev (ft)	Remarks
Tucson, TUO Continued			installed in 1925. A Benioff short-period system was added in 1936, later supplemented with a Long-Period galvo.
Tuscon, TUT	32°20'06" N 110°43'24" W	4721	SP tetemetered to Tucson, 1958-1962.
Tonto Forest Observatory TFO	34°16'04" N 110°16'13" W	4895	Installed in 1963 with a 37-element, 30-km-diameter array of short-period (SP) instruments; a linear, cross array of 21 SP elements; and a 50-km-diameter, 7-element (3 comp), long-period (LP) array. Intended primarily for teleseismic data, but local seismic events were noted. Closed 1975.
Tonto Hills Observatory, THO	33°52'31" N 111°52'35" W	3720	Private station operated by Mr. W. L. Groene since January 1973, when it replaced the Mummy Mountain Observatory started in May 1967. Inoperative since 1975.
Arizona State University	33°25' N 111°57' W	1162	An LP instrument since 1971. Inoperative since 1976.
Boulder Dam, BDA	36°00'56" N 114°44'12" W	778	A Benioff SP operated from 1941 to 1961.

Table 2.5-3

SEISMIC STATIONS IN ARIZONA[98] (Sheet 3 of 3)

Station	Location	Elev (ft)	Remarks
Flaggstaff, FLG	35°17°36' N 111°42°09' W	8022	A 20-sec. seisometer operated by USGS 1966-1972.
Arizona State University, ASU	33°24'59" N 111°56'05" W	1161	A 13-sec. seismograph operated From 1971 to 1975.
Tsarle, TSL	36°22'22" N 109°14'37" W	6601	A SP sismograph installed in 1975 by Los Alamos Scientific Lab and Navajo Community College.
Pierce Ferry, PFA	36°07'15" N 114°00'17" W	1368	SP Benioff, 3-component operated from 1940 to 1952.
Black Peak, BPK	34°07'29" N 114°12'35" W	1654	SP telemetry to Pasadena, 1974 to 1976.
Fortune Mine, FTM	32°33'17" N 114°20'01" W	863	SP telemetry to Pasadena since 1975.
Laguna Mts., LGA	32°45'35" N 114°29'34" W	223	SP telemetry to Pasadena since 1975.
San Luis, SLU	32°30'06" N 114°46'38" W	135	SP telemetry to Pasadena since 1973.
Yuma Desert, YMD	32°33'17" N 114°32'41" W	249	SP telemetry to Pasadena since 1975.

2.5.2.1.3 Selection of Events Affecting the Site

With the above considerations in mind, the data describing the earthquake history of the site are presented in the following way. A distinction is made between small, local earthquakes and larger, more distant earthquakes. The site history is well-described by considering all shocks within a radius of 50 miles and only those earthquakes of magnitude 6.0 or larger at distances from 50 miles to 200 miles. The limit for events of magnitude less than 6.0 is derived from the work of Schnabel and Seed[99] who predict that the upper bound for maximum accelerations produced by a magnitude 6.0 earthquake at a distance of 50 miles is less than 0.1g. Thus, the site has experienced only minor levels of shaking (compared to the seismic design level) from shocks occurring more than 50 miles away and having magnitudes less than 6.0.

2.5.2.1.4 Large Earthquakes in the Site Region

A list of all large earthquakes affecting the site is given in table 2.5-4. Events of magnitude 6.0 and above to a distance of 200 miles are included and some more-distant shocks, 1887 and 1966, that are significant for the site. For events that predate instrumental observations, recorded magnitudes are not available. However, because a magnitude 6.0 earthquake usually produces a maximum epicentral intensity of at least VII or greater, earlier events of intensity VII and greater have been included in the list. The site intensities shown in the table for earthquakes since 1928 were estimated using the reports published in "U.S. Earthquakes". For shocks before 1928, site

intensities were estimated by comparison with later, better-known events.

Earthquakes occurring in the Imperial Valley and the Colorado delta dominate the list of table 2.5-4. Generally, the maximum magnitudes seem to be no larger than 7.1. Considering the earthquakes of 1852, 1934[2], 1940, and 1956, there have been five events in the magnitude range 6.7 to 7.1 during a period of at least 128 years up to the present. The recurrence rate for these shocks is on the order of once every 25 years, but their occurrence is irregular, as shown in the above dates. For earthquakes of magnitude 6.0 and greater, the data suggests a 7-year recurrence interval. It is emphasized that these rates do not imply periodic occurrence of earthquakes but only reflect the average level of recent seismic activity on a portion of the San Andreas Shear Zone at its closest approach to the site.

Four earthquakes in table 2.5-4 originate in the band of seisicity that cuts across Arizona almost diagonally from northwest to southeast (Zone C, figure 2.5-25). The earthquakes in 1906 and 1910 probably affected the site only slightly and were probably smaller than magnitude 6.0, but they are included to be complete. A 1923 earthquake near Granados, Mexico is not listed because there are no records indicating it affected the site area (paragraph 2.5.2.1.4.2). The 1912 shock is beyond 200 miles, but its location is very uncertain.

Table 2.5-4

LARGE EARTHQUAKES (MAGNITUDE 6.0 OR GREATER)

WITHIN 200 MILES OF THE PALO VERDE SITE (Sheet 1 of 4)

No.	Date	Location	Distance (mi)	Seismic Zone	Magnitude[c] or Maximum Intensity	Estimated[a] Palo Verde	Comments	Reference[b]
1	Nov 29, 1852	Imperial Valley Southwest of Yuma, Arizona	140	A	VIII-IX (RF) IX-X, 6-7	(V)	Violent at Fort Yuma many aftershocks; steam geysers formed in lower Imperial Valley	1, 2, 4, 5
2	Nov 9, 1852 and Dec, 1853	Fort Yuma region					Dates are erroneous and accounts refer to Nov 29, 1852 earthquake	4
3	May, 1868	33-1/4°N, 116°W north end of Salton Sea	190	A	IX (RF)	(I-II)	Long fissure, probably San Andreas fault: the size of this earthquake is discredited by Toppozada & others, 1981	1
4	May 3, 1887	30.9°N, 109.2°W Bavispe, Sonora Mexico	275	C	VIII-IX (RF) XII, 7-1/4, 7.4	(I-II)	A great earthquake included here because it is in the extension of Zone C.	1, 2, 5, 6
5	Jan 23, 1903	3.15°, 115.5°W Colorado Delta	200+	A	7+	(IV-V)	Uninhabitated region, shock recorded seismographically worldwide	1, 2

a. Estimated from other felt reports in region. When no other reports were available, estimates were based on comparisons with other events of similar size and indicated by parenthesis.

b. References:
1. Townley and Allen, 1939.
2. Coffman and Von Hake, 1973.
3. United States Earthquake, annual publications since 1928.
4. Balderman and others, 1978.
5. DuBois et al, 1982.
6. Natali and Sbar, 1982.

c. Intensities are modified Mercalli unless followed by (RF) to indicate Rossi-Forel.

Table 2.5-4

LARGE EARTHQUAKES (MAGNITUDE 6.0 OR GREATER)

WITHIN 200 MILES OF THE PALO VERDE SITE (Sheet 2 of 4)

No.	Date	Location	Distance (mi)	Seismic Zone	Magnitude[c] or Maximum Intensity	Estimated[a] Palo Verde	Comments	Reference[b]
6	Jan 25, 1906	35.2°N. 111.7°W Flagstaff	140	C	VII-VIII (RF), VII	(I-II)	Felt area 15,000 square miles, probably smaller than 6.0	1, 2, 5
7	Apr 18, 1906	33°N, 115°W Imperial Valley	130	A	6+, VIII (RF)	(III)	Felt at Yuma, location uncertain	2
8	Sept 10-23, 1910	36°N, 111.1°W 45 miles north of Flagstaff	200	C	VI, VII	Not felt	Series of 52 shocks, shock of Sept 23 felt throughout northern Arizona	1, 2, 5
9	Aug 10, 1912	36.5°N, 111.5°W North of San Francisco Mountains	220	C	X (RF), VII-VIII, 5.5	Not felt	Earth cracking for 50 miles reported by Indians (not verified)	1, 2, 5
10	Jun 22, 1915	32.8°N, 115.5°W Imperial Valley	160	A	6-1/4,VIII	(III)	IV in Yuma, IV in Parker. Two large shocks 57 min. apart. Heavy damage in Imperial Valley	1, 2
11	Nov 21, 1915	32°N, 115°W Colorado Delta	160	A	7.1	(IV-V)	Remote region	3
12	Dec 30, 1934	32-1/4°N, 115-1/2°W Colorado Delta	170	A	6.5, IX	III-IV	Remote region	2, 3
13	Dec 31, 1934	32°N, 114-1/4°W Colorado Delta	140	A	7.1, X	IV-V	IV in Phoenix-Gila Bend, III in Buckeye. Surface rupture in Colorado Delta	2, 3
14	Feb 24, 1935	32.0°N, 115.2°W Colorado Delta	170	A	6.0	(I-II)	Possibly aftershock of December 1934 earthquake	3

Table 2.5-4

LARGE EARTHQUAKES (MAGNITUDE 6.0 OR GREATER)

WITHIN 200 MILES OF THE PALO VERDE SITE (Sheet 3 of 4)

No.	Date	Location	Distance (mi)	Seismic Zone	Magnitude[c] or Maximum Intensity	Estimated[a] Palo Verde	Comments	Reference[b]
15	Mar 25, 1937	33.4°N, 116.3°W Imperial Valley area	200	A	6.0, VII	Not felt	Terwilliger Valley	2
16	May 19, 1940	32.7°N, 115.5°W Imperial Valley	160	A	7.1, X	IV-V	40 miles of surface rupture, maximum off-set 15 feet, important accelerograms recorded in El Centro	2, 3
17	Dec 7, 1940	31.7°N, 115.1°W Colorado Delta	180	A	6.0	(I-II)	Chandeliers swayed in San Diego at similar epicenter distance as Palo Verde	2, 3
18	Apr 9, 1941	31°N, 114°W Gulf of California	180	A	6.0	(I-II)	Chandaliers swayed in San Diego	2
19	Oct 21, 1942	33.0°N, 116.0°W Imperial Valley	180	A	6.5, VII	Not felt	Felt in western Arizona	2
20	Dec 4, 1948	33.9°N, 116.3°W Eastern Trans-verse Ranges	200	-	6.5, VII	Not felt	Desert Hot Springs earthquake Intensity IV in Yuma	2, 3
21	Mar 19, 1954	33.3°N, 116.2°W Imperial Valley	200	A	6.2, VI	Not felt	Intensity V in Yuma	2, 3
22	Feb 9, 1956	31.8°N, 115.9°W Northern Baja	210	A	6.8, VIII-IX	III	Felt in Tucson, also 6.1, 6.3, 6.4 after-shocks, San Miguel fault	2, 3
23	Aug 7, 1966	31.8°, 114.5°W Colorado Delta	150	A	6.3	V	V reported from Palo Verde and Gila Bend, IV in Phoenix	2, 3

Table 2.5-4

LARGE EARTHQUAKES (MAGNITUDE 6.0 OR GREATER)

WITHIN 200 MILES OF THE PALO VERDE SITE (Sheet 4 of 4)

No.	Date	Location	Distance (mi)	Seismic Zone	Magnitude[c] or Maximum Intensity	Estimated[a] Palo Verde	Comments	Reference[b]
24	Apr 8, 1968	32.2°N. 116.1°W Imperial Valley	180	A	Mag 6.4, VIII	1-III	I reported at Gila Bend	2, 3
25	Oct 15, 1979	32.6°N, 115.3°W Imperial Valley	160	A	Mag 6.6, IX	III-IV	Imperial fault, 15 miles of surface rupture, maximum surface displacement about 2 inches	3

The other event is the 1887 Sonora, Mexico earthquake which occurred approximately 300 miles from the site and is beyond the usual range of consideration (NRC criteria). However, the 1887 earthquake occurred within a seismic zone that is within the 200-mile range, and its magnitude was estimated at about 7.7 to 8.0 (Richter, personal communication, 1974). More recent work places the magnitude at about 7.75 - 7.5[1][98][100][101].

Two of the large earthquakes in the region are of particular significance to the evaluation of the Palo Verde site. The 1852 Fort Yuma earthquake and the 1887 Sonora earthquake are discussed in the following sections.

2.5.2.1.4.1 Fort Yuma Earthquake of November 28, 1852. The literature contains various references to strong shocks felt at the frontier post of Fort Yuma on November 9, 1852; Novemer 28, 1852; and in December 1853[95][96][102]. Because conflicting dates and locations were reported, a study of orignal documents was undertaken by Balderman, et al[103]. The results of their study indicated the following:

> A major earthquake was reported near Yuma, Arizona, in November 1852. Because of the sparse population and frontier conditions in this region at that time, reports of the earthquake were incomplete and partially inaccurate. Subsequent accounts in historic earthquake catalogs repeated erroneous reports on the data, locations, and intensity of the Fort Yuma earthquake. Review of original earthquake accounts indicates that the Fort Yuma earthquake occurred about noon on November 28, 1852. Analysis of the regional geology suggests that the earthquake would have been associated with the seismically

> active Salton Trough. Comparison of effects of the Fort Yuma earthquake with those of subsequent large earthquakes in the region indicates that the event probably was located about 25 to 50 miles southwest of Yuma and had a probable magnitude of 6 to 7.

Major Samuel P. Heintzelman, post commander, noted in his diary: "At 20 minutes past 12 ... we had a violent shock of an earthquake last (sic) half a minute ... first a considerable shock, then a slight lull and then quite severe. Sufficient to have shaken down a house of several stories of the ordinary construction." Another officer at the post, Lieutenant Thomas W. Sweney wrote: "... Hendershott and myself ... rushed out of the house and had enough to do to prevent our falling down, the earth shook so. Large openings were made in the ground all around us, and water and steam thrown up in large quantities."

At Volcano Lake (near Cerro Prieto in Mexico, about 45 miles southwest of Fort Yuma), eruption of large steam geysers accompanied the earthquake. Steam rose to a height of 1000 feet as estimated by Major Heintzelman and probably much higher as concluded by Balderman, et al[103]. The earthquake also caused a large rockfall in California, at Chimney Peak (now called Picacho Peak) about 17 miles north of Fort Yuma. However, high cliffs and vertically oriented jointing in the rocks are present, such that the rockfall may not be a good intensity indicator. The lower Colorado River was considerably affected by caving river banks, changing water depths, and changing channel position. All the effects mentioned here, as well as others, are discussed in detail by Balderman, et al[103].

Figure 2.5-26 shows the estimated location for this earthquake. Most writers have estimated the maximum epicentral intensity as IX (for example, [95] and [102]), but Sturgul and Irwin[96] give XI for the larger of the "two shocks."

2.5.2.1.4.2 Sonora Earthquake of May 4, 1887. The Sonora earthquake occurred along the eastern side of San Bernardino Valley in northeastern Sonora, Mexico (figures 2.5-6 and 2.5-27). The epicenter has been estimated to be about 35 miles south-southeast of Douglas, Arizona along the east side of the San Bernardino Valley. The town of Bavispe, largest in the region, was totally destroyed, and 42 people were killed. Maximum epicentral intensities of VII-IX are reported in History of U.S. Earthquakes[102], but values of IX-X are estimated by DuBois, et al[98] based on, (1) extensive ground fissures caused by lurching, (2) 30 to 47 miles of primary fault rupture, and (3) observed groundwaves. High intensities must have been localized because towns 9 miles north and 3-1/2 miles south of Bavispe were practically undamaged[95].

The earthquake was felt over an area of about 450,000 square miles (figure 2.5-28) bounded by Mexico City to the south, El Bolson de Mapimi and El Paso to the east, Santa Fe and Prescott to the north, Yuma to the northwest, and the Gulf of California to the west[104].

Aguilera describes the fault as 30 miles in length, with an average offset of 7 feet, and a maximum offset of 26 feet. Based on recent field studies, Sumner[105] has described the faulting that accompanied the Sonora earthquake as "... a

normal sense of movement ... with vertical offsets of as much as 4 meters (13 feet) and a fault trace 50 kilometers (31 miles) long". Herd[101] believes the surface rupture was about 45 miles long, an estimate similar to that of Gianella[106]. Natili and Sbar[1] describe the faulting as 80 kilometers long (50 miles) with an average displacement of 3 meters (10 feet), and propose the name Pitaycachi fault. The fault scarp is still preserved in many localities after more than 90 years because of the desert climate and soil cementation with caliche. There is no indication of surface faulting extending as far north as the Mexico-U.S. border. Sumner's map of the faulting is shown in figure 2.5-27.

MacDonald[107] estimated that ground fissures and cracks were distributed over an area 350 miles long by 100 miles wide (about 35,000 square miles). His estimate is in doubt because he observed ground cracks only along the road between Tepic and Tombstone (approximately 120 miles) and along another road about 35 miles west. Because the Tepic-Tombstone road traverses the epicentral area, the long cracks reported by MacDonald are consistent with details from the more precise and authoritative report by Aguilera[104]. However, MacDonald's description of cracking and damage outside the epicentral area is not consistent with other reports.

Goodfellow's report[108] of the Sonora earthquake indicated no damage to buildings of "any stability" in Tombstone and noted no ground fissures. He did report, "in Sulphur Springs Valley, about 25 miles east of here, some fissures occurred in the bed

of an old stream". Sulphur Springs Valley is approximately 25 miles west of San Bernardino Valley, the epicentral area of the earthquake.

Descriptions of cracking by Aguilera[104] clearly indicate that large cracks did occur, probably as a result of consolidation and lurching of alluvium. Aguilera points out that the largest and greatest number of fissures occurred in the San Bernardino Valley, and that similar cracks appeared farther south and in the nearby Sulphur Springs Valley. There is no evidence in the published reports or the newspaper accounts that significant cracking occurred outside the general vicinity of the epicenter.

Richter[56] refers to a matching fault scarp on the east side of the northern Sierra Tejas Mountains in Chihuahua. Apparently it was reported to Goodfellow by another observer that a duplicate fault existed east of the Espuelas and Pitaycachi Mountains; however, this fault was never confirmed by either Aguilera or Goodfellow, and there is no evidence of scarps on the eastern part of the Sierra Tejas Mountains.

A recent compilation and review (figure 2.5-28a) of the various intensity reports is given in DuBois, et al[98]. Magnitude estimates based on seismic movement calculations place the magnitude at about 7.25 - 7.5[1][97][100]. The 1887 Sonora earthquake has been considered a rare event because of its size and its occurrence within a zone of apparently low seismicity. Townley and Allen[95] state that investigations (not cited) subsequent to the shock revealed that earlier ruptures had

taken place along the same fault zone. MacDonald[107] experienced the shock and reported that "no other earthquake had occurred within the memory of the inhabitants or in their tradition." A recurrence interval on the order of thousands of years between major earthquakes near the site of the 1887 earthquake has been estimated by Sumner[105] after field studies in the area. Herd[101] saw evidence of at least two and possibly three pre-1887 surface ruptures along this fault and estimated that the last one occurred about 10,000 to 15,000 years ago and the earlier ones several hundreds of thousands of years earlier. Bull and Pearthree[109] estimate that the youngest previous earthquake occurred more than 100,000 years ago.

At least one earthquake in this region has caused extensive damage and casualties but is not included in most earthquake catalogs. On December 20, 1923 an earthquake caused extensive damage and 12 casualties in the villages of Huasabas and Granados (intensity IX) in Sonora, Mexico very near to the locality of the 1887 event[98]. The shock was felt in Douglas, Arizona but affected an area much smaller than the 1887 earthquake. The rediscovery of the 1923 shock suggests that damaging earthquakes in this region of Sonora may be more frequent than previously believed.

2.5.2.1.4.3 Isoseismal Maps. Isoseismal maps for many earthquakes are gathered together for convenience in figures 2.5-28 through 2.5-39E. The selection includes all earthquakes for which isoseismal maps have been prepared and whose areas of perceptibility (felt by persons) included, or came near, the

Palo Verde site area. Also included are isoseismal maps for a number of other earthquakes in the western U.S. that are referenced in other parts of this text in discussions on seismic zones, attenuation effects, etc. Many of the maps are found in annual issues of "U.S. Earthquakes"; these and other sources are indicated on the figures. The following earthquakes are included in the selection:

- 1872, Owens Valley, California
- 1887, Sonora, Mexico
- 1906, San Francisco, California
- 1906, Flagstaff, Arizona
- 1907, Morales, Mexico
- 1910, Cedar Wash, Arizona
- 1912, Lockett Tanks, Arizona
- 1916, St. Michaels, Arizona1918, San Jacinto, California
- 1922, Miami, Arizona
- 1931, Snowflake, Arizona
- 1931, Cottonwood, Arizona
- 1932, Gabbs, Nevada
- 1934, Colorado Delta, Mexico
- 1938, Buckhorn, New Mexico
- 1939, Hoover Dam, Arizona
- 1940, El Centro, California
- 1942, Superstition Mountains, California
- 1947, Manix, California

- 1948, Desert Hot Springs, California
- 1949, Desert Center, California
- 1950, Calipatria, California
- 1951, Calipatria, California
- 1952, Kern County, California
- 1954, Borrego Springs, California
- 1955, Brawley, California
- 1956, North Central Baja California, Mexico
- 1958, Northeast Baja California, Mexico
- 1959, Kanab, Utah
- 1963, Globe, Arizona
- 1966, Colorado River Delta, Mexico
- 1968, Borrego Mountains, California
- 1969, Warner Springs, California
- 1969, San Carlos, Arizona
- 1971, San Fernando, California
- 1975, Brawley, California
- 1976, Prescott, Arizona
- 1976, Chino Valley, Arizona
- 1977, Standing Rock, New Mexico
- 1979, Yucca Valley, California
- 1979, Calexico, California

These isoseismal maps and the individual reports that were used in preparing the site intensity column in table 2.5-3 indicate that the maximum intensity experienced by the site has been V.

This intensity has been experienced three or four times; two of these were direct reports from the town of Palo Verde. In all cases, these intensities were developed by earthquakes origiating in the California Imperial Valley region.

2.5.2.1.5 Small Earthquakes in the Site Vicinity

Figures 2.5-24 and 2.5-24A show the historically-reported earthquakes since 1852, and figure 2.5-25 shows 50 years of instrumental data and some larger, older shocks. These data show no instrumentally determined epicenters and only a few historical reports of small shocks felt within 50 miles of the site. However, the limitations discussed in paragraph 2.5.2.1.2 must be kept in mind. In particular, the NOAA data are incomplete for earthquakes with small magnitudes. The distribution and significance of any microseismic activity near the site can only be speculative for the present. However, some limited instrumental observations in the area are useful in placing an upper bound on the level of microseismic activity in recent years.

2.5.2.1.5.1 Accounts of Local Shocks Felt. The catalogs by Sturgul and Irwin[96] and DuBois, et al.[98] lists only a few local earthquakes felt at towns within 50 miles of Palo Verde: one report in 1875 at Maricopa Wells (about 25 miles south of Phoenix) and reports at Phoenix in the years 1906 and 1937. "U.S. Earthquakes" for 1935 adds several small shocks felt at Phoenix. Although the 1976 Prescott earthquake is well beyond 50 miles from the site, it is included here because of its

size, M_L = 5.2 (PAS), and its proximity to the boundary of the seismic zone containing the site. Various other shocks at locations such as Flagstaff and Williams in northern Arizona or Globe and Whitewater in eastern Arizona have been perceived in the site vicinity, but their epicenters are clearly within seismic Zone C.

A. Maricopa Wells, 1875

A small event was reported for December 15, 1875, at 2:45 p.m. near Maricopa Wells (now Maricopa) approximately 25 miles south of Phoenix[95]. No accounts of ground shaking or damage to document this event could be found by DuBois, et al.[97].

B. Phoenix, Arizona, 1906

On April 18, about 5:48 a.m., a slight shock occurred with motion west to east. At 5:59 a.m., another shock of intensity II (Rossi-Forel) occurred[95]. No other accounts are given in the published reports. Examination of the Phoenix Republican for the period April 18 to April 24 disclosed no historical accounts.

These shocks should not be confused with the great San Francisco earthquake which occurred about 35 minutes earlier on the same day. The time differential is too great even for the normal travel time of 5 to 7 minutes for surface waves[56] from the San Francisco earthquake, unless there are major errors in the times noted at Phoenix. Furthermore, Phoenix is 250 miles beyond the farthest extent of reported shaking from the San

Francisco earthquake, and no exceptionally strong aftershocks are reported along the southernmost portion of the fault rupture. DuBois, et al.[98] questions the validity of a local shock in Phoenix on this date.

C. Phoenix, Arizona, 1937

On July 21, at about 4:55 p.m. (MST), one short, heavy thud occurred, with slight upward motion, then "settling quiet". The event is said to have disturbed small objects and to have been felt by all. One observer described the thud as sounding like a heavy charge of powder in soft ground. The event frightened no one[96].

There were no newspaper accounts of this event in the Phoenix, Arizona Republican (July 21-28), the Tucson Citizen Daily Star (July 21-24), or the Yuma Daily Sun (July 21-24). DuBois, et al.[98] suggests these reports may, in fact, represent an earthquake the day before at Seligman, Arizona and not effects felt in Phoenix.

D. Cave Creek, 1974 (formerly termed New River earthquakes)

Two small shocks were felt at Cave Creek, about 60 miles northeast of Palo Verde; the first on December 19 at 8:01 p.m. (MST) with intensity VI and a magnitude of M = 2.5, and the second on December 23 at 10:47 p.m. (MST) with intensity V and magnitude of about 3.0[98]. Intensity VI from a magnitude 2.5 earthquake seems quite unusual. Intensities II and III for these shocks were reported at New River 12 miles to the west-northwest

(U.S. Earthquakes, 1974; and W. A. Sauk, personal communication).

E. Prescott, Arizona, 1976

A magnitude 5.2 earthquake (M^L = 5.2, M^b = 4.9) occurred at 5:05 p.m. (MST) on February 3 about 20 kilometers north-northwest of Prescott (34° 40' N, 112° 30' W)[110]. The fault did not rupture the surface, and focal mechanism studies are not conclusive. The preferred focal mechanism solution[111] is right-lateral motion on a steeply dipping plane trending N 80° E or left-lateral motion on a steeply dipping plane trending N 15° W. Eberhart and Phillips, et al,[112] derived a solution with a preferred fault plane striking N 60° W and dipping 40° southwest. Aftershocks continued until February 23.

Strong-motion instruments in the Prescott Veterans Administration Hospital recorded short accelerograms, but the two accelerographs at the Palo Verde site were not triggered. In the epicentral area, where the maximum intensity reached VI (Modified Mercalli), objects were thrown from shelves, but no significant structural damage was reported[111]. Intensities were IV or less in the Phoenix area. An isoseismal map for this shock is included in paragraph 2.5.2.1.4.3.

F. Phoenix, Arizona, 1983

A small shock was reported felt in Phoenix metropolitan area at about 8:15 a.m. (MST) on January 28, 1983. According to news accounts, the event was recorded on a university of Arizona seismograph registering a magnitude of about 2.5. Felt reports indicate intensities ranged from II to III.

2.5.2.1.5.2 Instrumental Data Relating to the Presence of Microseismicity. Arizona lacks a local network of seismograph stations that is necessary to systematically detect and locate small-magnitude earthquakes. Some limited instrumental observations that have been made can be useful in estimating the levels of seismicity. Figures 2.5-24, 2.5-24A, and 2.5-25 show that the site vicinity has experienced a low level of seismicity in historic times, and paragraph 2.5.2.3.4 describes the area as being in a tectonic zone characterized by low seismicity. The objective of the analyses in the following paragraphs is to establish an upper limit to the rate of occurrence of small shocks in the site vicinity. First, records from an amateur seismograph station near Phoenix were studied to determine how many shocks might have come from the area around the site (based on S-P intervals) and what magnitude corresponds to the smallest detectable shock. Then, phase arrival times for selected shocks that were also recorded at the Tonto Forest Observatory array were obtained so that possible locations for the shocks could be further limited. These studies indicated that no more than three shocks, and

probably only one shock, with magnitudes greater than 1.7 occurred in the site vicinity over a period of nearly 5 years.

A. S-P Intervals at Tonto Hills Seismograph Station.

Mr. Willard L. Groene operated excellent amateur seismograph observatories in the Tonto Hills and the Mummy Mountains near Phoenix from 1967 until his death in 1975. The Palo Verde site is about 65 miles from the Tonto Hills Observatory (THO); thus, earthquakes within 25 miles of the site will have S-P intervals in the range of 8 to 17 seconds when recorded at THO. These intervals are obtained from the travel-time tables of Richter (1958) and checked against a velocity model from a refraction survey between Gila Bend and Phoenix, Arizona by Warren[(113)]. A total of 21 events with acceptable S-P intervals were recorded in Mr. Groene's catalog for a 5-1/2-year period from July 1967 through February 1973. In addition, there were eight otherwise acceptable events that were known to be mining blasts. These blasts suggest that some of the other events might also be unidentified mining blasts rather than natural earthquakes. The lower limit of detection for events in the site area and recorded at THO is estimated to be magnitude 1.7 at 40 miles (the nearest distance of approach) and 2.2 at 90 miles (the farthest distance). An operating gain of 500,000 was occasionally used, but such a level was generally too noisy, and 100,000 was the usual magnification. After

looking at representative THO records, a basic assumption is made that an earthquake must register with a maximum amplitude of at least 3 mm zero-to-peak to be reliably identified as an earthquake. Signals with smaller maximum amplitudes might be observed, but their corresponding P-wave arrivals would be difficult to separate from the background noise. The definition of local magnitude involves the instrumental characteristics of the Wood-Anderson torsion seismograph. Although the response characteristics of the THO short-period seismograph are not identical to those of the Wood-Anderson torsion seismograph, the two responses are close enough that the peak amplitudes can be assumed to occur at nearly the same frequency on both systems for small, local earthquakes.

Then the registration of earthquakes on the two systems will differ in proportion to their magnifications (gain). Finally, magnitudes corresponding to 3 millimeter amplitude on the THO records and the appropriate distances are estimated using Richter's[56] fundamental definition of magnitude modified for the magnification of the THO instruments:

$$M = \log \frac{A' \times 2800}{100{,}000} - \log A_o$$

A' is the measured amplitude, A_o is a reference amplitude dependent on distance and given in a table by Richter[56]. Because of the logarithmic nature of the

magnitude scale, the magnitude estimates given above are not strongly dependent on the assumptions used.

The THO data suggest that about four or five events per year in the magnitude range of 1.7 to 3.0 occur at such a distance from THO that they could have originated within 25 miles of the site. Earthquakes of magnitude larger than 3.0 would probably have been identified as such during the period of the data. Any, or all, of the events could have originated in other equally distant locations, and some events may be mining blasts. The following section shows that a much lower level activity is appropriate for the site.

B. Approximate Locations of Some Local Events.

The preceding analysis naturally leads to the question of whether further constraints might be placed on the occurrence of microearthquakes in the site vicinity. Additional data are available from the Tonto Forest Observatory (TFO) for the period September 1967 through July 1972. The Tonto Forest Observatory was a large (tens of kilometers across), experimental array of seismographs designed to study seismic waves from distant earthquakes worldwide. Local earthquakes were noted and their arrival times logged, but the determination of epicenters was not attempted. Normally two seismograph stations are inadequate to determine an epicenter. In this case, the TFO array provides additional information in the form of the

approximate azimuth from which the seismic waves arrive as well as their arrival times, so that crude estimates of epicenter can be made. In principle, the difference in arrival times at two stations can reduce possible epicenter locations to a particular curved line if the seismic velocities are known and the hypocentral depth is known or can be fixed. For a simple case in which velocity is constant and there is no source-depth effect, the appropriate curve is one branch of a hyperbola symmetric about the line joining the two recording stations (analogous to LORAN radio positioning). For any realistic model of crustal velocity structure and a fixed hypocentral depth, the curves are not simple, and they may involve two different wave phases at the two recording stations such as direct P and refracted P. Epicentral distances from the seismograph stations, calculated from S-P intervals, reduce the locus curve to two points. Finally the azimuth information from one station determines the correct point.

A velocity model was chosen on the basis of central Arizona crustal structures as determined by Warren[113]. Then a map was constructed showing the travel-time differences for possible epicenters in the site vicinity. Mr. Groene's station catalogs were reexamined and the Tonto Forest Observatory data were examined to identify all events with the appropriate time differences during the period September 1967

through July 1972. A larger area around the site, radius 65 miles, was included in this analysis. From these logs only 12 events were found with acceptable time differences (3-1/2 to 15-1/2 seconds) and TFO data arriving second (TFO is more distant from the site). An additional five events were noted for which the time differences were too large, 17 to 69 seconds, for any possible epicenter. These spurious data result from timing or picking errors, and imply the possibility of similar errors in some of the other events.

A detailed discussion of the velocity model, the derivation of the travel-time difference map, the significant features of the map, and the parameters of each of the 12 acceptable events is contained in paragraph 2.5.2.5.4.5 of the PVNGS 1, 2, and 3 PSAR. In summary, the analysis showed that eight of the events were clearly away from the site vicinity, two events were indeterminant because of inadequate or conflicting data and only a single event could be shown to have occurred in the site vicinity. The single event was recorded July 2, 1972 at 1829 (GMT); its location would appear to be about 10 to 15 miles north of the site, but the uncertainty is on the order of 25 miles. No felt reports for this event are cited by DuBois, et al[98].

The analysis of travel-time differences suggests that no more than three earthquakes (one reasonably certain and two indeterminant) in the magnitude range 1.7 to 3.0 occurred in the site vicinity during a period of nearly 5 years. Only one of these earthquakes can be shown to have occurred in the site vicinity. These data indicate very low levels of seismic activity near the site, but the levels cannot be established conclusively because the observation periods are short in relation to the recurrence intervals of the earthquakes.

2.5.2.1.6 Strong Motion Data

Very few accelerographs have been installed in Arizona and the neighboring portions of Nevada because of the low levels of seismicity. Recent regulations have caused accelerographs to be placed in Veterans Administration hospitals, some dam sites, and the Palo Verde site. Conversely, many accelerographs have been installed in the neighboring portions of California and Yuma, Arizona because of high seismicity associated with the San Andreas fault system and related features. The Arizona station locations are listed in table 2.5-5 and all locations are shown on figure 2.5-40.

No significant accelerograms have been recorded in Arizona. The 1976 earthquake near Prescott triggered accelerometers at the VA hospital in Prescott, but the epicentral distance was about 20 miles and maximum acceleration levels were only 0.045g[111]. Recordings at epicentral distances of only a few

miles are desirable for Prescott-sized earthquakes, magnitude 5.2, because such earthquakes may affect design criteria only if they are considered to occur nearby.

The 1940 Imperial Valley earthquake wrote accelerograms in California (none in Arizona) with maximum accelerations of 0.35g at an epicentral distance of 5.8 miles[114] and 0.001g at about 180 miles in the Los Angeles area (U.S. Earthquakes, 1940). Los Angeles and the Palo Verde site are at comparable distances from the Imperial Valley. During the 1968 Borrego Mountain earthquake, the maximum recorded accelerations were 0.13g at El Centro 45 miles from the epicenter (closest record); about 0.005g was measured at Mohave Generating Plant, Nevada (Arizona border) at a distance of 170 miles, and the levels in the Los Angeles area were 0.004 to 0.015g[115]. The 1979 Imperial Valley earthquake had a maximum acceleration locally of over 1.0g, but did not trigger accelerographs in the Los Angeles area that had trigger levels of about 0.01 to 0.02g nor did the event trigger either of the two accelerographs (with trigger levels of 0.009g) operating at PVNGS.

Because the maximum earthquakes which control the seismic design criteria for the Palo Verde site are large (a magnitude 8.0 shock along the southern portion of the San Andreas fault, or a magnitude 8.0 Sonora-type earthquake), there are no appropriate accelerograms from the site region. The necessary data from other areas are introduced as they are needed in paragraph 2.5.2.6. There are also many accelerograms of small shocks in the Imperial Valley recording because of the dense

network of stations or as the results of special studies. These records are not listed here because they do not have an impact on the development of the seismic design criteria.

2.5.2.1.7 Earthquake-Induced Geologic Failures

No geologic failures caused by ground shaking are known to have occurred within 100 miles of the Palo Verde site during historic times. The 1976 Prescott earthquake, magnitude 5.2, did not cause any recognized failures nor are any suspected after intensive field investigations. The larger earthquakes of seismic zones B and C might be capable of inducing some slumping or rockfalls under suitable conditions, although no instances are known. MacDonald[107] reported that the 1887 Sonora earthquake caused ground cracks in Tombstone.

Table 2.5-5

ARIZONA ACCELEROGRAPH SITES, MAY 1977

USGS No.	Name	Coordinates	Foundation	Structure	Placement	Agency[a]
2301	Alamo Dam	34.23°N 113.60°W		Earth dam	Abutment, toe, Crest	ACOE
2304	Glen Cayon Dam	36.97°N 111.59°W		Instr shelter	Ground level	USBR
2305	Phoenix VA Hospital	33.49°N 112.07°W	125m alluvium over granite	4-story bldg	Basement	VA
2306	Tucson VA Hospital	32.17°N 110.83°N		1-story bldg	Ground level	VA
2307	Prescott VA Hospital	34.55°N 112.45°W	more than 17m alluvium	6-story bldg	Basement	VA
2316	Yuma, Strand Ave	32.73°N 114.70°W		Instr shelter	Ground level	USBR
-	PVNGS	33.38°N 112.86°W	alluvium	Instr shelter	Ground level	Ariz Public Service

a. Agencies: ACOE, Army Corps of Engineers
USBR, U.S. Bureau of Reclamation
VA, Veterans Administration

MacDonald's report is not confirmed by Goodfellow[108], and Tombstone is more than 200 miles from Palo Verde.

The 1852 Fort Yuma earthquake, located in the lower Imperial Valley, caused liquefaction around Fort Yuma and a rockfall at Picacho Peak (then called Chimney Peak) about 17 miles north of the fort. Numerous other geologic failures have occurred in portions of the Imperial Valley and Colorado Delta that are within 200 miles of the Palo Verde site. Faulting has ruptured the surface during earthquakes in 1934 on the Colorado Delta, 1940 near El Centro, 1968 at Borrego Mountain, 1975 near Brawley, and probably others. Sand boils, indicative of liquefaction, have been induced by the larger earthquakes such as 1852 Fort Yuma, 1940 Imperial Valley, and 1968 Borrego Mountain.

2.5.2.2 Geologic Structures and Tectonic Activity

2.5.2.2.1 Tectonic Provinces and Tectonic History

Regional geologic and tectonic structures are shown on figures 2.5-4, 2.5-5, and 2.5-6. Figure 2.5-25 shows the spatial relationship between Quaternary faults and earthquake epicenters. Figure 2.5-3 shows the major regional tectonic provinces within the site region based on gross similarities of geologic and tectonic features. These provinces are the Basin and Range, Colorado Plateau, Salton Trough, Transverse Ranges, and Peninsular Ranges. The geologic and tectonic characteristics of these provinces and the regional tectonic history describing present and past stress regimes that

distinguish the various tectonic provinces are described in paragraphs 2.5.1.1.3 and 2.5.1.1.5. The following paragraphs describe the capable faults found in these provinces.

2.5.2.2.2 Capable Faults

2.5.2.2.2.1 Introduction. The major capable faults within the site region (200-mile radius) are in southeastern California, the Grand Canyon region, and in Sonora, Mexico. There are no capable or Quaternary faults within the site vicinity (25-mile radius).

Figure 2.5-6 shows the known capable faults (less than 500,000 years old) and the Quaternary faults (500,000 years to about 1.8 or 2 million years old) in the site region. These faults are described below under the headings of the tectonic provinces in which they occur.

2.5.2.2.2.2 Salton Trough. The Salton Trough tectonic province has, by far, the largest and most historically active capable faults. These faults trend southeasterly through the trough and are generally considered to be members of the San Andreas Shear Zone (see figure 2.5-7). The major faults within this Shear Zone are:

- The Mission Creek, Banning, and southern San Andreas faults which make up the southern San Andreas fault set
- The San Jacinto, Superstition Hills, Coyote Creek, Clark, Buck Ridge, Hot Springs, Imperial, and Cerro Prieto faults which comprise the San Jacinto fault set

- The Elsinore and Laguna Salada faults which make up the southern end of the Elsinore fault set
- Other faults, lying between the above major fault sets, such as the Brawley and Calipatria faults at the southern end of the Salton Sea, the Algodones near Yuma, and the Sierra Juarez fault zone in Baja California, Mexico

The San Jacinto fault set is principally a group of right-lateral, strike-slip faults and fault zones with a cumulative displacement of about 15 miles(116). The feature extends from the head of the Gulf of California to the Transverse Ranges north of the city of San Bernardino, California, a distance of about 250 miles. The rate of slip on the San Jacinto has been estimated at about 0.1 to 0.5 inch per year(117)(118). Seismic activity in the site region is concentrated in the central Salton Trough in the vicinity of the San Jacinto fault set. The largest historic earthquakes in the site region occurred in the vicinity of the San Jacinto fault set and were the magnitude 7.0 Imperial Valley earthquake of 1940 and the magnitude 7.1 and 7.0 earthquakes near the head of the Gulf of California in 1934. The 1940 event was associated with surface rupture of the Imperial fault which amounted to about 19 feet of displacement. The 1934 events have not been associated with any known faults, but surface cracks were noted shortly after the shock had occurred. In contrast, the southern San Andreas fault set has not been associated with a large number of earthquakes. However, minor surface ruptures occurring in 1868

and 1968 and geomorphic expression of faulting indicate that the fault is active and its great length (totaling about 600 miles when connected with its central and northern segments) suggest that it is capable of generating great earthquakes. The slip rate on the Cholame to Cajon Pass segment is about 1.3 to 2.4 inches per year[119]. Rates on the southern segment appear to be much slower and a major earthquake has not occurred in several hundred years[120]. A major earthquake occurred on the northern segment of the fault zone in the San Francisco area in 1906. This earthquake registered a magnitude of 8.3 with maximum displacement of about 21 feet. An earthquake in 1857 which ruptured the central segment of the fault zone between Cholame and Cajon Pass, a distance of about 200 miles, may have had displacements of about 30 feet[121]. Comparison of these large displacements has led to magnitude estimates of 8.0 to 8.5 for the 1857 earthquake.

The southeasterly continuation of the San Andreas fault set past the Salton Sea has been the topic of much debate among geoscientists. There is little geomorphic evidence of a southeasterly continuation, but direct alignment with the Quaternary Algondones fault in the vicinity of Yuma, Arizona has led Olmstead, et al[50] to postulate an association of the two. Kovach, et al[39] postulated a subsurface fault in the vicinity of Sand Hills but did not believe that it was a direct continuation of the San Andreas. Merriam[51] has suggested that the San Andreas fault set continues through the Yuma area into Mexico east of the Gulf of California. Detailed geotechnical studies[52] near Yuma, Arizona have shown that the Algodones

fault is capable, but that its history of movement has been primarily dip slip with the northeast side of the fault down. Such a displacement is not compatible with the hypothesis that it is a direct continuation of the San Andreas fault, which is a right-lateral fault, but rather that it is just one of the bounding faults of the Salton Trough. The extension of faults of the San Jacinto set toward the head of the Gulf of California along with the high rate of seismicity on the San Jacinto set indicate that most of the plate movement is taken up along the younger, more active, San Jacinto fault set.

The Elsinore fault set is a zone of fractures extending about 200 miles from the Whittier branch near Los Angeles to the Laguna Salada fault in Baja California. Near the Mexico-U.S. border, the fault traces are mostly concealed by the alluvium of Imperial Valley. Cumulative, strike-slip displacement on the Elsinore fault set probably is small compared to the San Jacinto and San Andreas fault sets[58]. Historic surface rupture has not been recognized on the Elsinore fault set, but appreciable low-magnitude seismicity occurs along the fault. The slip rate on the Elsinore fault zone has been estimated at about 0.03 inch per year[117].

2.5.2.2.2.3 Transverse Ranges. Offset Quaternary sediments indicate Quaternary activity on the Pinto Mountain fault, the largest fault in the eastern Transverse Ranges. This fault is about 65 miles long, strikes nearly east along the north flank of the Pinto Mountains[122], and extends about 20 miles into the 200-mile radius. Offset streams and lithologic contacts

indicate up to 10 miles of left-lateral movement on this fault with the maximum displacement near the central portion of the fault[53]. There have been no known surface ruptures on this fault, but a magnitude 5.9 earthquake in 1949 occurred near its eastern end. However, it has not been established whether this earthquake was associated with the Pinto Mountain fault or one of the northwest striking faults of the Mojave block.

2.5.2.2.2.4 Colorado Plateau. The major capable faults in the Colorado Plateau province are the southern ends of faults that form the boundary between the Colorado Plateau and Basin and Range provinces in Utah. Major Quaternary faults in this transition zone are the Hurricane, Main Street, Toroweap, Sevier, and Wasatch faults. These faults coincide with the Intermountain Seismicity Belt[17] and various geophysical anomalies which indicate a major change in crustal and upper mantle characteristics under the region[14][38]. Major capable faults in this system that extend into the 200-mile radius are the Main Street, Hurricane, and Toroweap, all of which lie in the western Grand Canyon region (figure 2.5-6). No historic surface ruptures have been recorded on these faults, but displaced Quaternary features have been interpreted to be as young as late Pleistocene[123] and possibly Holocene[124][125]. Historic seismicity in this region is widely scattered. The maximum historic earthquake in this southern region of the Hurricane-Wasatch fault system was a magnitude 5.6 event near the Arizona-Utah border in 1959 (figure 2.5-25). The maximum earthquake associated with this same zone of faults to the

north was a 1901 event near Richfield, Utah with a magnitude estimated to be 6.7[126]. However, the lengths and displacements of faults along the Wasatch front suggest that earthquakes as large as 7.1 to 7.5 may be expected[127][128].

A zone of short, northwest-southeast trending Quaternary and capable faults extends from the southern end of the Grand Canyon region to the southeastern corner of Arizona (figure 2.5-6). These faults coincide with the Transition Zone and Basin and Range (Arizona Mountains) physiographic provinces (figure 2.5-1).

Most of these faults are minor features with the longest being about 27 miles in length.

2.5.2.2.2.5 Basin and Range. Capable and Quaternary faults are rare within the Basin and Range tectonic province in the site region. The greatest concentration of capable faults within the province occurs in the Mexican Highlands region of southeastern Arizona and Mexico (figure 2.5-6). Faults in the Mexican Highlands are very minor features within the site region where they do not exceed about 10 miles in length. Howard, et al[21] characterized these faults as "small cracks and faults associated with groundwater withdrawal which may be partially of tectonic origin." Similarly trending features in Mexico extend as far south as Guaymas (26° N lat) along the western edge of the Sierra Madre Occidental Plateau and are much longer. The great 1887 Sonoran earthquake occurred on one of these faults (Pitaycachi fault). Long faults of the type generally considered capable of generating great earthquakes,

such as the Sonoran event, are not present north of the Mexican border (figure 2.5-6).

The capable and Quaternary faults within the Sonoran Desert region of the Basin and Range province are widely scattered, short, and have very small displacements. Known capable faults are the Blythe and Chemhuevi grabens in California, the Sand Tank Mountain fault in Arizona, and several small unnamed faults near the Arizona-Mexico border(129) and within the Pinacate volcanic field. The Pinacate area is a very unusual area for the Sonoran Desert region because it has a relatively high concentration of minor Quaternary faults (figure 2.5-6). The longest of these faults is only about 4 to 6 miles long. These faults are commonly restricted to the young volcanic flows and generally do not displace Quaternary sedimentary formations surrounding the volcanics. This suggests that they are local volcano-tectonic features rather than surface manifestations of larger through-going subsurface faults.

2.5.2.3 Correlation of Earthquake Activity with Geologic Structures or Tectonic Provinces

The spatial distribution of instrumentally determined epicenters, figure 2.5-25, clearly shows that seismic activity is concentrated in certain areas and relatively rare in others. The locations of these earthquakes can be described in terms of geologic structures and the tectonic processes responsible for those structures. However, the locations of the epicenters have some unavoidable uncertainties, as discussed in paragraph 2.5.2.1.2, so that most earthquakes cannot be

attributed unequivocally to a particular fault. Instead, the general distribution of seismicity is described in terms of seismic zones, and particular shocks as belonging to a particular zone. A seismic zone is meant to generally encompass an area with relatively similar characteristics of its geology and seismicity.

In the Palo Verde region, the seismological data represent too short a time period to be fully representative of all the earthquake processes that might occur. Therefore, the seismicity data alone do not provide complete, distinct boundaries for the zones. Similarly, many of the geologic and tectonic characteristics are gradational rather than abrupt near zone boundaries. For these reasons, the seismic zones identified in this study have some approximate boundaries.

Within a 200-mile radius of the site, four seismic zones can be recognized. These zones have been identified as Zones A through D because there is no generally recognized nomenclature. The Palo Verde site is within Zone D which extends beyond 200 miles from the site. Therefore, Zone E is also discussed to define fully the bounds of Zone D. The geologic and tectonic characteristics of these zones have been discussed in detail, with some references to seismicity, in paragraph 2.5.1.1.3. The following sections will describe the seismological data for each zone.

2.5.2.3.1 Seismic Zone A

The most conspicuous feature of the seismicity distribution, figure 2.5-25, is the concentration of activity in the southwest quadrant from the site at distances beyond about 120 miles. This seismicity is related to faults of the San Andreas Shear Zone in the Salton Trough and to the eastern portions of the Transverse Ranges and the Mojave block. Zone A extends to the northwest and to the southeast considerably beyond the 200-mile radius of the Palo Verde site region. Because the level of seismicity in the San Andreas Shear Zone is high, only earthquakes of magnitude 4.0 and greater have been shown in figure 2.5-25.

Zone A is dominated by the San Andreas Shear Zone which is the boundary between the American crustal plate to the east and the Pacific crustal plate to the west. This plate boundary is the major tectonic feature of the site region. These two crustal plates are in motion so that the Pacific plate is moving northwest relative to the American plate at the rate of a few inches per year. The major fault displacements and the largest earthquakes are associated with right-lateral, strike-slip faults that trend northwesterly. Allen(130) pointed out changes in the characteristic seismicity along this plate boundary. Some portions generate great earthquakes, magnitude 8+, such as in 1906 at San Francisco (rupture from Cape Mendocino to Hollister) and 1857 at Fort Tejon (rupture from Parkfield to Cajon Pass). Other portions, such as the length from Hollister to Parkfield (lying between ruptures of the two great

earthquakes), are characterized by only moderate shocks, magnitudes up to about 6.0, and episodes of aseismic creep. North of the Transverse Ranges in central and northern California, relative plate motion is predominantly along the San Andreas fault, a zone no more than a few kilometers wide. South of the Transverse Ranges, the plate boundary becomes a broad zone of faulting that includes the San Andreas, San Jacinto, and Elsinore fault sets. There have been no great earthquakes (magnitude 8.0 or larger) historically on the southern portion of the San Andreas fault.

In the northern Gulf of California, seismic activity is very high, but lower levels are indicated southward in the vicinity of the islands of Angel de la Guarda and Tiburon. This difference may represent a change in tectonic characteristics, or it may simply reflect incomplete observation of the area.

Near 33° 30' N, the boundary of Zone A has been taken along a more northerly trend to include seismicity associated with the eastern Transverse Ranges and the Mojave block. These areas are intimately related to the plate boundary tectonics, but they are secondary to the San Andreas Shear Zone. Geologic and seismotectonic studies[21][22] support separate seismotectonic zones for the Transverse Ranges and the Mojave block. However, these zones have not been considered separately in keeping with the somewhat generalized nature of the seismicity zones. The largest earthquake in these portions of Zone A was the 1947 Manix earthquake with a magnitude of 6.2. Capable faults are long enough to produce shocks up to about magnitude 7.0,

considerably smaller than those postulated for the San Andreas fault.

In general, seismic Zone A is the plate boundary and its associated seismic activity. There are some geologic and seismic data to suggest limits of the zone along the plate boundary such as the Transverse Ranges to the north and the major gulf islands to the south, but these limits are not considered further here. A great earthquake, magnitude 8+, has been assumed credible along the San Andreas fault at the eastern margin of the Salton Trough, and further consideration of the extent of Zone A would have no impact on the design criteria.

Seismic activity is high in Zone A with several earthquakes in the magnitude range of 6.5 to 7.1 such as in 1852, 1903, 1915, 1934, 1940[56], and 1979. Earthquake swarms such as the Brawley swarm in 1975[131] and 1976[132] and the Gulf of California swarm in 1969[33] are a characteristic feature of the Imperial Valley and Colorado Delta areas. Quaternary movement is evident on many faults within the zone, although most historic surface ruptures have been along the San Jacinto fault set (including the Coyote Creek and Imperial Faults). The 1934 ruptures were on a presumed extension of the San Jacinto fault set. Minor surface offsets have occurred on other faults. Rupture on the San Andreas fault near the north end of the Salton Sea is reported for an 1868 earthquake[95] but the size of the earthquake has been questioned[133]. The San Andreas fault is considered to be the only fault capable of

producing a magnitude 8+ earthquake in this zone. At its closest approach to the site, the fault is on the order of 120 miles distant. The San Andreas fault has not been mapped in areas south of the international border, and may not extend south of the Salton Sea (paragraph 2.5.2.2.2). Seismicity in the area continues southward along the San Jacinto fault set.

2.5.2.3.2 Seismic Zone B

Seismic Zone B is a roughly circular zone of epicenters about 80 miles in diameter and lying astride the Arizona-Sonora border (figure 2.5-25). This zone was first recognized on the basis of the distribution of epicenters reported in the USGS catalog, and its limits were drawn to simply envelope the seismicity. Subsequent analysis of the seismological data indicated that many of the epicenters should be relocated southward in, or very close to, seismic Zone A. However, a significant number of the events have no indication of mislocation and must be presumed correct for this study. This area is centered on the Pinacate volcanic field which has been the site of numerous late Quaternary age volcanic eruptions. Small earthquakes, of the type mentioned previously which could not be relocated from this area, could be related to the volcano tectonic processes of the volcanic field.

The largest historic earthquake in Zone B was a magnitude 4.9 shock (previously listed as 5.0 in NOAA file) on March 15, 1958 with a reported epicenter near the south end of the Mohawk Mountains (NOAA: 32.5°N, 113.5°W), but the epicenter could be in error by 30 to 40 miles. DuBois, et al[98] eliminates this

event from the Arizona catalog because the instrumental data were "unconvincing" and there were no felt reports. All of the earthquakes reported for this zone have magnitudes of 4.0 or greater, if a magnitude is reported. Smaller events have not been registered well enough at regional seismographs to permit epicenter determinations.

The quality of the epicenter locations in Zone B was examined in detail. Each earthquake was checked for entries in the International Seismological Summary (ISS), U.S. Earthquakes, and Seismological Notes in the Bulletin of the Seismological Society of America. This study indicated that all of the epicenters in Zone B have large location uncertainties, about 15 to 30 miles generally, and sometimes much larger. Furthermore, the ISS data strongly suggest that many of the epicenters reported in the USGS catalog have a consistent northeast bias and should be located farther to the south within or very close to Zone A. Figure 2.5-41 shows how the ISS determinations relocate some of the epicenters in Zone B. Earthquake locations, as determined independently by the ISS, are available for events in or near Zone B only since 1964 when ISS began to include smaller events. Earthquakes occurring prior to 1964 probably present the same location difficulties as those studied here. Several factors indicate problems in determining these epicenters. Standard deviations for the ISS locations were large, 0.3 to 0.5 degree, even though ISS used more data than was available for determinations in the NOAA catalog. The usable data are from stations to the northwest, north, and northeast of Zone B leaving an angular gap of about

200 degrees. S-wave arrivals are available from only Barrett and Pasadena, both of which are on nearly the same azimuths from the epicenters. Travel time residuals of about -8 seconds at Barrett and +5 seconds at Pasadena indicate difficulties with the travel-time tables or phase identification.

Table 2.5-6 provides a tabular comparison of the epicenter determinations. Individual earthquakes are discussed in paragraph 2.5.2.6.3 of the PSAR[8]. The ISS epicenters are preferred because more data were available and certain earthquakes with swarm-like association were placed by the ISS in an area characterized by earthquake swarms. This location problem seems to be limited to the Zone B shocks; three shocks in central Arizona have consistent locations by USGS and ISS (within 10 miles), and a fourth shock has locations that differ by about 30 miles.

In summary, many of the epicenters in Zone B should probably be relocated farther south into Zone A. The epicenters that have similar locations by NOAA and ISS, or remain stationary from lack of any comparative data, are in an area with evidence of young volcanic activity. Since there is not conclusive evidence for relocating all the Zone B shocks southward into Zone A, Zone B and the original epicenter location have been retained as a conservative approach to seismic consideration of this area.

2.5.2.3.3 Seismic Zone C

Seismic Zone C is a band of rather diffuse seismicity extending diagonally across Arizona from its northwest corner (figure 2.5-25). Since the beginning of seismic instrumentation in Arizona, there have been a moderate number of earthquakes (shown in table 2.5-7) with magnitudes less than 4.0, four earthquakes with magnitudes from 4.0 to 4.9, and five earthquakes with magnitudes from 5.0 to 5.6. This distribution of magnitude with number of events (relatively few small shocks with respect to the number of larger shocks) is attributed to a deficiency in recording smaller shocks rather than an unusual recurrence relationship.

Zone C corresponds to a transition zone between the Colorado Plateau to the northeast and the Sonoran Desert portion of the Basin and Range province to the southwest. This area was called the Arizona Mountain Belt by Howard, et al[21]. This transition zone is characterized by Quaternary and capable faults and volcanism in addition to its seismicity. The geologic description of the zone is presented in paragraph 2.5.1.1.1.3.

In the PSAR studies[8] and figure 2.5-25 herein, seismic Zone C broadens to the south and includes the area of the 1887 Sonora earthquake. For a conservative estimate of the safe shutdown earthquake (SSE) (see paragraphs 2.5.2.4.3 and 2.5.2.6), a Sonora-type earthquake has been postulated on other Quaternary faults in Zone C. Recent studies[21] suggest the existence of a Mexican Basin and Range province (a subdivision of the Basin

and Range province) in which the Sonora earthquake occurred. Identification of the Mexican Highlands as a separate province may be important to understanding the regional tectonics. However, this interpretation has no adverse impact on the previous estimates[8] of seismic hazard at the Palo Verde site, because the nearest boundary of the province is at a distance

Table 2.5-6

EARTHQUAKES OCCURRING WITHIN SEISMIC ZONE B

						DuBois[a]					NOAA[b]				
Year	Mo	Day	Hour	Min	Sec	Latitude	Longitude	Depth (km)	Mag	Int	Latitude	Longitude	Depth (km)	Mag	Int
1942	10	14	0	14	54.0						32.500	115.500	0	0.00	
1949	6	26	1	35	24.0						32.100	113.900	0	4.30	
1951	4	12	6	20	11.0	32.000	112.900	0	4.50						
1958	3	15	8	34	4.0						32.500	113.500	16	4.90	
1963	11	2	8	47	43.0	32.400	113.700	14	4.70		32.400	113.700	16	4.70	
1963	11	18	22	1	10.0						31.900	113.300	16	4.90	
1964	4	16	6	45	43.9	32.500	113.200	0	4.10		32.500	113.200	33	4.10	
1964	8	22	7	34	17.0						32.000	113.800	16	4.60	
1964	12	25	14	9	48.0	32.300	113.700	0	4.00		32.300	113.700	16	4.40	
1965	6	17	22	58	20.9						31.700	113.300	10	4.40	
1965	11	26	13	57	2.6						31.800	112.700	33	4.10	

a. DuBois, et al[160][161]

b. NOAA Data Set, 1982, National Geophysical and Solar-Terrestrial Data Center, Boulder, Colorado.

Table 2.5-7

EARTHQUAKES OCCURRING WITHIN SEISMIC ZONE C

(Sheet 1 of 5)

Year	Mo	Day	Hour	Min	Sec	DuBois[a] Latitude	DuBois[a] Longitude	DuBois[a] Depth (km)	DuBois[a] Mag	DuBois[a] Int	NOAA[b] Latitude	NOAA[b] Longitude	NOAA[b] Depth (km)	NOAA[b] Mag	NOAA[b] Int
1830	0	0	0	0	0.0	31.900	110.100	0	0.00	VIII					
1887	5	3	21	13	0.0						31.000	109.000	0	0.00	IX
1887	5	30	14	0	0.0	31.710	110.070	0	0.00	V					
1887	11	11	0	0	0.0	32.000	110.580	0	0.00	VII					
1887	12	5	15	30	0.0						37.100	112.500	0	0.00	VI
1888	7	25	0	0	0.0	31.710	110.070	0	0.00	VI					
1892	2	2	0	30	0.0	35.190	111.650	0	0.00	VI					
1893	6	5	6	40	0.0	31.710	110.070	0	0.00	V					
1899	10	6	23	30	0.0	31.710	110.070	0	0.00	V					
1906	1	25	13	32	30.0	35.200	111.700	0	0.00	VII	35.200	111.700	0	0.00	VII
1906	1	28	9	15	0.0	35.190	111.650	0	0.00	II					
1910	9	24	4	5	0.0	35.750	111.500	0	0.00	VII					
1912	8	18	21	12	0.0	35.950	111.950	0	5.50	VII-VIII					
1913	12	6	0	15	0.0	35.250	112.170	0	0.00	V					
1916	12	12	11	45	0.0						34.000	110.000	0	0.00	V
1918	4	20	8	45	0.0	35.190	111.650	0	0.00	IV					
1918	4	28	12	58	0.0	35.190	111.650	0	0.00	IV					
1919	5	23	11	5	0.0	35.190	111.650	0	0.00	III					
1921	6	17	23	42	0.0	33.380	110.860	0	0.00	VI					
1923	9	28	0	0	0.0	35.190	111.650	0	0.00	IV					
1923	9	30	18	27	0.0	34.200	111.500	0	0.00	IV					
1931	4	17	12	38	0.0						34.000	110.500	0	0.00	V
1932	2	8	6	30	0.0	34.900	112.190	0	0.00	II					
1934	1	11	7	15	0.0	31.910	109.820	0	0.00	V					
1934	3	12	0	0	0.0	35.100	110.900	0	0.00	III					
1934	12	25	12	20	0.0	36.950	112.500	0	0.00	V					
1935	1	1	8	50	0.0	36.050	112.140	0	0.00	VI					
1935	1	3	14	35	0.0	36.950	112.500	0	0.00	IV					
1935	1	5	4	25	0.0	36.050	112.140	0	0.00	V					
1935	1	10	8	10	0.0	36.050	112.140	0	0.00	VI					
1935	1	15	8	50	0.0	36.050	112.140	0	0.00	II					
1935	12	5	21	25	0.0	36.950	112.500	0	0.00	IV					
1936	1	12	0	0	0.0	36.050	112.140	0	0.00	V					
1936	11	6	11	38	0.0						33.000	108.000	0	0.00	
1937	12	17	23	30	0.0	35.190	111.650	0	0.00	IV					

a DuBois, et al[160][161]

b NOAA Data Set, 1982, National Geophysical and Solar-Terestrial Data Center, Boulder, Colorado.

Table 2.5-7

EARTHQUAKES OCCURRING WITHIN SEISMIC ZONE C

(Sheet 2 of 5)

						DuBois[a]					NOAA[b]				
Year	Mo	Day	Hour	Min	Sec	Latitude	Longitude	Depth (km)	Mag	Int	Latitude	Longitude	Depth (km)	Mag	Int
1938	9	17	17	20	18.0						33.250	108.750	0	5.50	VI
1938	9	18	11	45	0.0	32.270	109.230	0	0.00	V					
1938	9	18	23	30	0.0	32.720	109.100	0	0.00	IV					
1938	9	19	6	31	0.0	32.720	109.100	0	0.00	V					
1938	9	20	5	38	48.0						33.200	108.600	0	0.00	V
1938	9	24	18	0	0.0	32.620	109.970	0	0.00	IV					
1938	9	29	23	32	0.0	33.050	109.300	0	0.00	IV	33.200	108.600	0	0.00	
1938	9	29	23	35	0.0						33.200	108.600	0	0.00	V
1938	11	1	6	35	0.0						33.200	108.600	0	0.00	
1938	11	1	8	26	6.0						33.000	108.700	0	0.00	
1938	11	2	9	0	0.0						33.200	108.600	0	0.00	
1938	11	11	10	26	18.0						32.900	108.700	0	0.00	
1938	11	27	0	12	42.0						33.000	109.000	0	0.00	
1938	11	27	0	13	0.0						33.200	108.600	0	0.00	
1938	12	28	22	7	0.0	33.050	109.300	0	0.00	V	33.000	109.000	0	0.00	
1939	2	19	11	0	0.0	36.050	112.140	0	0.00	IV					
1939	3	9	13	30	0.0	36.100	112.100	0	0.00	VI					
1939	6	4	1	19	12.0	32.750	109.100	0	0.00	VI	33.000	109.000	0	0.00	
1939	7	17	6	58	30.0						33.000	109.000	0	0.00	
1940	10	16	13	25	0.0	35.190	111.650	0	0.00	V					
1941	2	19	10	11	54.0						34.000	111.000	0	0.00	
1942	1	8	2	42	0.0	35.190	111.650	0	0.00	III					
1943	12	21	9	30	0.0	35.190	111.650	0	0.00	IV					
1944	1	31	4	24	58.0	36.950	112.500	0	0.00	IV	36.900	112.400	0	0.00	
1945	1	7	22	25	32.0						36.500	111.800	0	5.10	VI
1947	10	27	4	15	40.0	35.750	111.480	0	0.00	IV					
1948	1	24	2	57	0.0	36.100	111.500	0	0.00	IV					
1948	8	8	23	20	0.0	36.800	112.100	0	0.00	V					
1948	12	3	18	45	0.0	35.030	110.700	0	0.00	V					
1951	3	5	23	0	0.0	36.950	112.500	0	0.00	IV					
1953	10	8	20	19	46.0	34.660	111.010	0	0.00	V	34.750	111.000	0	0.00	V
1958	9	18	6	3	0.0	31.400	109.850	0	0.00	V					
1959	2	11	14	1	0.0	35.190	111.650	0	0.00	V					
1959	7	21	17	39	29.0	36.800	112.370	0	5.65	VI	37.000	112.500	16	5.70	VI
1959	10	5	8	10	0.0	36.950	112.500	0	0.00	IV					
1959	10	13	8	15	0.0	35.500	111.500	0	5.00	V	35.500	111.500	0	5.00	V
1959	11	10	6	58	43.0	36.950	112.500	0	0.00	IV					
1961	2	12	3	51	14.0						31.300	109.200	25	0.00	IV
1961	12	3	19	56	44.0	32.380	109.960	0	2.60						
1962	1	17	16	9	0.0	36.950	112.500	0	0.00	IV					

Table 2.5-7

EARTHQUAKES OCCURRING WITHIN SEISMIC ZONE C

(Sheet 3 of 5)

						DuBois[a]					NOAA[b]				
Year	Mo	Day	Hour	Min	Sec	Latitude	Longitude	Depth (km)	Mag	Int	Latitude	Longitude	Depth (km)	Mag	Int
1962	2	15	7	12	42.9	36.900	112.400	0	4.50	V	36.900	112.400	16	4.50	V
1962	2	25	9	6	45.0						37.000	112.900	16	4.50	
1962	3	4	16	35	38.6	32.910	109.540	5	2.70						
1962	3	7	19	57	37.5	32.290	109.770	0	2.90						
1962	3	9	18	13	43.1	33.050	109.340	0	2.90						
1962	3	11	20	29	5.0	33.140	109.310	0	2.80						
1962	3	17	22	27	12.5	34.880	112.090	0	2.90						
1962	3	22	19	33	19.2	33.080	109.420	0	2.60						
1962	3	23	19	5	16.2	33.050	109.430	0	2.60						
1962	3	30	17	32	10.9	32.650	109.170	0	2.70						
1962	3	31	17	56	49.5	33.070	109.390	0	2.70						
1962	4	25	21	3	49.2	33.040	109.350	2	2.70						
1962	4	29	15	34	1.5	33.040	109.420	5	2.60						
1962	5	1	17	1	13.5	32.930	109.490	0	2.70						
1962	5	9	16	39	6.1	32.060	110.320	0	2.90						
1962	10	1	13	11	6.7	36.140	111.740	0	2.50						
1962	10	9	10	35	6.1	33.020	109.440	8	2.70						
1962	10	15	21	4	14.0	33.620	109.230	0	2.70						
1962	10	21	16	1	39.7	33.120	109.320	0	2.90						
1962	10	22	16	36	51.0	33.060	109.420	7	2.70						
1962	10	25	16	45	59.7	33.340	109.190	0	2.60						
1962	10	30	15	45	12.7	33.260	109.340	0	2.50						
1962	11	3	19	51	53.1	33.090	109.350	5	2.80						
1962	11	5	20	9	37.7	33.040	109.430	9	2.50						
1962	11	16	17	49	15.7	33.070	109.370	0	2.80						
1962	11	17	16	44	58.5	33.180	109.330	8	2.60						
1962	11	20	20	20	34.2	33.070	109.450	12	2.60						
1962	11	23	16	58	34.7	33.460	109.090	0	2.50						
1962	11	30	19	27	2.7	33.050	109.430	3	2.70						
1962	12	1	19	44	54.4	33.010	109.470	0	2.70						
1962	12	3	20	55	29.1	33.030	109.450	0	2.60						
1962	12	5	19	16	29.7	33.400	109.120	0	2.60						
1962	12	15	16	33	0.9	33.180	109.330	0	2.50						
1962	12	28	16	11	10.6	33.360	109.140	11	2.80						
1963	1	12	16	33	23.2	33.110	109.360	12	2.50						
1963	1	12	21	52	34.1	33.190	109.220	4	2.70						
1963	2	5	19	23	40.0	32.900	109.420	11	2.70						
1963	2	7	20	0	48.6	32.790	109.620	0	2.80						
1963	3	3	20	12	54.7	33.490	109.070	0	2.50						
1963	3	6	20	37	52.1	33.230	109.270	9	2.60						

Table 2.5-7

EARTHQUAKES OCCURRING WITHIN SEISMIC ZONE C

(Sheet 4 of 5)

						DuBois[a]					NOAA[b]				
Year	Mo	Day	Hour	Min	Sec	Latitude	Longitude	Depth (km)	Mag	Int	Latitude	Longitude	Depth (km)	Mag	Int
1963	3	8	16	16	45.7	33.030	109.300	0	2.70						
1963	3	10	19	41	22.2	33.070	109.400	0	2.60						
1963	3	19	21	27	57.0	33.010	109.450	0	2.70						
1963	4	8	19	38	1.5	32.940	109.540	0	2.50						
1963	4	17	20	56	10.2	32.790	109.560	0	2.60						
1963	4	19	16	48	11.6	33.000	109.450	0	2.70						
1963	4	21	22	9	35.5	33.100	109.140	0	2.80						
1963	4	25	20	38	51.4	33.050	109.420	0	2.60						
1963	5	1	16	37	20.4	32.890	109.540	0	2.70						
1963	5	2	19	29	58.0	33.020	109.390	0	2.80						
1963	5	5	16	59	45.4	33.130	109.250	14	2.70						
1963	6	15	19	47	48.7	34.570	112.070	0	2.60						
1963	9	11	11	59	41.2	33.200	110.700	0	4.10	VI	33.200	110.700	33	4.20	
1963	10	3	18	27	40.5	33.100	109.350	0	3.10						
1963	10	7	16	54	39.1	33.380	109.160	0	2.80						
1963	10	9	19	37	25.2	33.080	109.430	0	2.70						
1963	10	19	17	8	3.2	32.900	109.600	0	2.90						
1963	10	20	18	24	14.7	33.060	109.450	4	2.80						
1963	10	21	11	17	28.4	33.450	110.630	0	3.50						
1963	12	5	20	13	16.2	32.840	109.550	0	2.70						
1965	6	7	14	28	1.3	36.100	112.200	15	3.70		36.100	112.200	33	0.00	
1965	11	7	16	19	43.8						37.100	112.400	1	0.00	
1966	1	22	12	16	35.1	36.570	111.990	7	2.70						
1966	4	13	9	36	15.3	36.700	112.900	0	3.30						
1966	5	2	14	59	13.1	36.400	112.500	0	3.50						
1966	5	5	6	15	20.5	36.820	112.380	7	2.26						
1966	5	5	3	32	55.7	37.030	112.380	10	2.80						
1966	9	3	7	53	20.2	36.500	112.300	0	0.00		36.500	112.300	33	0.00	
1966	10	3	16	3	50.9	35.800	111.600	34	4.40		35.800	111.600	34	0.00	
1967	3	2	6	29	24.4	34.480	110.960	13	3.90		34.475	110.964	14	3.90	
1967	3	28	3	48	59.1						35.453	111.732	5	0.00	
1967	5	21	18	0	5.1	34.290	110.570	11	3.80		34.291	110.565	9	3.80	
1967	7	20	13	51	10.4						36.300	112.100	33	0.00	
1967	8	7	16	24	49.3	36.500	112.400	0	3.86		36.500	112.400	33	0.00	
1967	8	7	16	40	32.1	36.400	112.600	0	4.00		36.400	112.600	33	0.00	
1967	9	4	23	27	44.7	36.200	111.700	0	4.60		36.200	111.700	33	0.00	
1969	12	25	12	49	10.1	33.400	110.600	15	4.40	VI	33.400	110.600	15	5.10	
1970	8	3	19	24	17.8						34.318	110.519	0	0.00	
1970	9	16	12	17	0.0	35.190	111.650	0	0.00	II					
1970	11	24	16	47	56.0	36.360	112.270	6	3.00		36.357	112.273	6	3.00	

Table 2.5-7

EARTHQUAKES OCCURRING WITHIN SEISMIC ZONE C

(Sheet 5 of 5)

						DuBois[a]					NOAA[b]				
Year	Mo	Day	Hour	Min	Sec	Latitude	Longitude	Depth (km)	Mag	Int	Latitude	Longitude	Depth (km)	Mag	Int
1970	12	3	3	47	24.6	35.870	111.900	5	2.80		35.874	111.906	5	2.80	
1971	3	27	4	39	11.7	36.760	112.390	5	2.60		36.762	112.393	5	2.60	
1971	5	6	16	57	18.1	36.420	113.080	0	2.20		36.419	113.084	5	2.20	
1971	11	4	2	18	58.7	35.200	112.200	5	3.70		35.220	112.168	5	3.70	
1971	12	15	12	58	14.5	36.790	111.820	5	3.00		36.791	111.824	5	3.00	
1972	3	9	18	45	0.0						32.752	110.493	0	4.50	
1972	4	20	13	28	16.3	35.310	111.640	5	3.70	IV	35.311	111.640	5	3.70	
1973	7	14	10	54	1.0	37.000	112.900	0	2.30		37.001	112.913	18	0.00	
1975	12	3	10	12	22.8						32.830	108.663	27	3.90	V
1976	2	28	20	52	58.5	35.910	111.790	5	3.00		35.910	111.788	5	0.00	
1977	6	8	13	9	7.4						31.024	109.227	5	4.60	
1979	12	11	20	35	0.0	33.650	111.100	0	2.50	IV					
1980	6	1	8	40	27.5	35.390	111.990	5	3.60	II					

comparable to that used before to evaluate the effects of a Sonora-type earthquake. The Mexican Highlands are defined mostly in terms of their geologic characteristics because there is very poor seismographic coverage for small shocks, and only a few earthquakes are known there.

The 1887 and 1923 Sonora earthquakes are described in paragraph 2.5.2.1.4.2. Only two other small shocks are listed in the NOAA catalog for the Mexican Highlands area (north of 31° 30' N). A shock with no assigned magnitude occurred just south of the Arizona border in 1961 and was felt in Bisbee with intensity II. In 1977, there was a magnitude 4.6 shock very close to the epicentral area of the 1887 earthquake.

Excluding the Mexican Highlands, the largest earthquake that has been recorded in Zone C is a July 21, 1959 shock with a magnitude of 5.6. The earthquake occurred near the Arizona-Utah border (37°N, 112-1/2°W) and was felt most strongly in the communities of Kanab, Utah and Fredonia, Arizona. In both places, the shock was felt by all and there were some fallen bricks and cracked plaster. The epicenter of this shock is probably not determined more closely than 20 to 30 miles as suggested by the precision of the coordinates assigned.

The northern portion of Zone C in Arizona has experienced four other earthquakes with magnitudes of 5.0 or greater: January 7, 1945 (M=5.1), October 13, 1959 (M=5.0), a January 25, 1906 shock near Flagstaff whose magnitude is not known but probably exceeds 5.0 as indicated by intensity reports (U.S. Earthquakes), and an August 18, 1912 shock north of the San

Francisco mountains with a reported intensity of X. In the southeastern portions of Zone C, there have been two shocks with magnitudes greater than 5.0: September 17, 1938 (M=5.5) near the Arizona-New Mexico border and December 25, 1969 (M=5.1) near Globe, Arizona.

The 1976 Prescott earthquake, M=5.2, occurred very close to the boundary between seismic Zone C and D as drawn here. Recent seismotectonic studies[22] suggest that the boundary (approximate at best) of Zone C is farther westward and that the Prescott earthquake should be identified with Zone C. These same interpretations would include the northern portions of Zone C (and the 1959 event) in a zone extending northward coinciding with the Intermountain Seismic Belt. Then, the largest event recorded in Zone C becomes the magnitude 5.5 shock near the Arizona-New Mexico border.

2.5.2.3.4 Seismic Zone D

After the prominent concentrations of seismicity have been recognized as seismic Zones A, B, and C, the remainder of the region within 200 miles of the site has very sparse seismic activity and is termed Zone D. Seismic Zone D generally corresponds to the Sonora Desert portion of the Basin and Range province. The mountain ranges here are small and relatively low-relief; there is little Quaternary faulting known (figure 2.5-25). The geologic characteristics of Zone D are described in paragraphs 2.5.1.1.3.2 and 2.5.2.2.2.5 as part of the Basin and Range province.

Earthquakes are infrequent in Zone D and no shocks larger than magnitude 4.5 (as shown in table 2.5-8) have occurred here. The magnitude 5.2 Prescott earthquake in 1976 is considered to be associated with seismic Zone C. Other moderate shocks have been located within this zone. The largest is a 1956 earthquake of magnitude 4.5 (or possibly smaller) with a poorly known epicenter about 50 miles west or northwest of Tucson. The general location of this 1956 earthquake, the precision of its coordinates, and the lack of any felt reports suggest considerable uncertainty in the epicenter, perhaps 20 to 40 miles. None of the shocks in Zone D have caused surface ruptures or other phenomena indicating geologic failure. In evaluating the seismic hazard for Zone D, shocks as large as magnitude 4.5 were considered at distances as close as 5 miles to the site (see paragraph 2.5.2.6). Closer distances are excluded because detailed geologic studies in the site area, out to 5 miles, have shown the absence of any capable faults.

Since the PSAR studies(8)(94), several small changes have been suggested in the description of seismic Zone D as a result of additional data and interpretations, but none of these impact the seismic design criteria. As mentioned above, the boundary with Zone C may be a little farther westward than originally drawn, and the Prescott earthquake then is associated with Zone C. The 1956 earthquake, M=4.5, did not have an assigned magnitude in the earlier NOAA catalog listing; it is currently listed as M=5.0, but analysis of original Pasadena seismograms indicates that the correct value should be no more than 4.5, including uncertainties.

2.5.2.3.5 Seismic Zone E

Seismic Zone E is a band of seismicity trending northwestward across southern Nevada and into central Utah. This zone is about 100 miles wide and has been called the Southern Nevada Transverse Zone(17)(25)(26). The zone is transverse to most of the structural grain of the region, and the tectonic significance of the trend is poorly understood. Although seismic Zone D, containing the site, extends 200 miles northwest from the site, Zone E is included here because it bounds the site zone and separates the site zone from Nevada Basin and Range tectonics further to the north.

There is pronounced increase in the level of seismic activity in Zone E as compared to Zone D. In addition, moderately large earthquakes have occurred there: a magnitude 6.1 (U.S. Earthquakes) or 5.6(134) earthquake shook southern Nevada near the Utah border on August 16, 1966, with a maximum intensity of VI in the epicentral region. The seismicity cluster around Lake Mead has been attributed to reservoir filling(97)(135)(136). In addition, numerous small earthquakes induced locally by large nuclear explosions at the Nevada Test Site have been attributed to tectonic prestress(137). These two examples indicate stressed conditions in Zone E, but there are no data for comparison in other areas of the region.

Table 2.5-8

EARTHQUAKES OCCURRING WITHIN SEISMIC ZONE D

(Sheet 1 of 2)

						DuBois[(a)]					NOAA[(b)]				
Year	Mo	Day	Hour	Min	Sec	Latitude	Longitude	Depth (km)	Mag	Int	Latitude	Longitude	Depth (km)	Mag	Int
1852	11	9	0	0	0.0						33.000	114.500	0	0.0	IX
1870	3	11	10	20	0.0	34.550	112.470	0	0.00	V					
1870	8	12	0	0	0.0	34.550	112.470	0	0.00	IV					
1871	2	7	15	8	0.0	34.100	112.440	0	0.00	V					
1875	1	21	19	45	0.0	33.650	114.500	0	0.00	V					
1875	3	9	0	0	0.0	33.460	112.070	0	0.00	III					
1875	12	15	15	45	0.0	33.200	112.100	0	0.00	III					
1888	11	25	4	5	0.0	32.220	110.970	0	0.00	IV					
1891	4	26	20	30	0.0	35.180	114.520	0	0.00	III					
1899	9	20	0	0	0.0	35.190	114.060	0	0.00	IV					
1915	6	27	8	30	0.0	33.400	111.800	0	0.00	III					
1916	3	30	5	20	0.0	31.340	110.940	0	0.00	VI					
1927	2	11	3	40	0.0	31.540	110.750	0	0.00	V					
1930	7	16	19	0	0.0	34.200	112.500	0	0.00	V	34.200	112.500	0	0.0	
1933	11	27	0	0	0.0	34.420	112.910	0	0.00	V					
1935	1	2	7	30	0.0	32.670	114.140	0	0.00	VI					
1935	10	28	2	9	0.0	33.460	112.070	0	0.00	II					
1936	2	25	6	30	0.0	35.190	114.060	0	0.00	IV					
1937	7	20	22	49	0.0	35.330	112.880	0	0.00	V					
1937	7	21	23	55	0.0	33.460	112.070	0	0.00	V					
1938	6	8	12	14	24.0						35.200	114.800		0.0	
1940	5	19	18	0	0.0	32.670	114.140	0	0.00	V					
1940	6	6	5	42	0.0	32.670	114.360	0	0.00	V					
1945	10	19	16	57	42.0						34.000	114.000	0	0.0	
1949	11	1	19	9	58.0						31.500	112.000	0	0.0	
1956	11	2	10	38	55.0	32.000	112.000	0	5.00		32.000	112.000	16	5.0	
1957	9	16	2	2	30.0						33.000	114.000	0	0.0	
1961	6	18	8	12	7.0	32.200	112.500	0	4.70		32.200	112.500	16	4.7	
1963	4	22	22	41	57.6	32.540	112.080	0	2.70						
1963	5	10	23	49	50.5	35.040	113.820	0	2.70						
1963	5	19	22	55	21.7	35.460	114.210	0	2.90						
1963	6	29	3	3	50.0	34.810	114.540	0	2.70						
1964	9	6	18	51	18.6	34.200	114.000	15	3.40						
1966	4	28	0	42	57.4	35.600	113.000	20	2.90						
1966	6	8	21	34	37.1	36.700	113.400	20	3.40						
1966	6	14	10	45	17.1	36.400	113.300	0	3.30						

a DuBois et al[(160)(161)]

b NOAA Data Set, 1982, National Geophysical and Solar-Terrestrial Data Center, Boulder, Colorado.

c Unofficial Report of Arizona Bureau of Geology and Mineral Technology, 1983.

Table 2.5-8

EARTHQUAKES OCCURRING WITHIN SEISMIC ZONE D

(Sheet 2 of 2)

						DuBois[a]					NOAA[b]				
Year	Mo	Day	Hour	Min	Sec	Latitude	Longitude	Depth (km)	Mag	Int	Latitude	Longitude	Depth (km)	Mag	Int
1966	6	17	20	12	23.9	36.600	113.500	0	3.50						
1966	12	1	9	20	40.9						36.200	113.900	26	3.70	
1967	5	1	19	48	7.1	34.460	112.860	26	3.80		34.457	112.864	26	3.80	
1971	5	1	3	11	19.9						36.518	113.575	5	2.90	
1971	5	23	21	31	51.6	35.020	113.890	0	3.00		35.017	113.888	5	3.00	
1973	4	12	10	57	48.3						35.416	113.718	8	0.00	
1973	4	19	16	59	42.7						34.300	112.617	4	4.50	
1974	3	14	20	59	57.2						34.245	112.699	0	4.10	
1974	12	20	3	1	10.3	33.870	112.080	10	2.50	VI	33.860	111.880	4	2.50	
1974	12	24	5	47	20.7	33.900	111.900	4	3.00	V	33.864	111.879	4	0.00	
1976	2	4	0	4	58.0	34.660	112.500	12	5.10	VI	34.655	112.500	12	5.20	
1976	2	5	21	2	40.1	34.700	112.570	10	2.90		34.703	112.574	10	2.90	
1976	2	6	9	18	52.0	34.710	112.460	9	2.10						
1976	2	7	5	54	57.0	34.710	112.490	11	2.60						
1976	2	7	8	29	38.0	34.700	112.490	12	2.90						
1976	2	7	12	5	11.0	34.710	112.500	9	1.30						
1976	2	7	13	37	16.0	34.710	112.500	9	2.80						
1976	2	9	3	7	22.0	34.610	112.530	10	3.30	III	34.614	112.530	10	4.60	
1976	2	23	14	9	54.0	34.680	112.430	10	3.50	VI	34.524	112.705	10	1.80	
1976	5	4	10	6	34.8	34.700	112.540	10	3.00	II	34.679	112.432	10	0.00	
1977	10	21	2	55	13.4	34.630	112.480	10	2.50	V	34.702	112.535	10	3.00	
1977	11	10	14	30	0.0	33.010	113.350	0	0.00	IV	34.634	112.479	10	2.50	
1983	1	28	8	15	0.0								0	2.50	III[c]

An alternate interpretation of regional tectonics and seismicity by the NRC staff in their Safety Evaluation Report of the PVNGS 1, 2, and 3 PSAR adopts a single province of basins and ranges from Mexico, through Arizona and Nevada, and extending partially into Utah and Oregon. At the same time, this approach recognizes that:

- Major seismic events are associated with large, recognizable Quaternary faults.
- Large Quaternary faults are present in Sonora, Mexico and are numerous in Nevada.
- Large Quaternary faults are demonstrably absent in the Basin and Range areas of Arizona.
- Only a few Quaternary faults of any size have been recognized in the Basin and Range areas of Arizona.

As a result, both interpretations lead to essentially the same estimate of the seismic hazard for the Palo Verde site. The differences are a matter of degree in the requirements to characterize separate zones.

2.5.2.4 Maximum Earthquake Potential

The level of maximum vibratory ground motion that might occur at the site is determined by considering the largest earthquakes that might credibly occur in each of the seismic zones. The following sections discuss the maximum earthquake for each zone; discussions of the seismicity and tectonics of the zones are found in paragraphs 2.5.2.3 and 2.5.1.1.3,

respectively. When attenuation of strong ground motions because of distance from the epicenter is considered (paragraph 2.5.2.6), the most severe case at the site is found to be the postulated occurrence of a Sonora-type (1887) earthquake located 72 miles from the site. This case results from considering an epicenter approximately 250 miles northwest of the 1887 event along a series of north-west trending valleys and associated Quaternary and capable faults which project north from Mexico toward the Grand Canyon region (paragraph 2.5.2.4.3). Since submittal of the PSAR(8)(94), geologic and earthquake studies(18)(21)(22) have continued to substantiate the neotectonic contrasts between the Mexican Highlands subprovince and the Transition Zone, both of which are generally included by seismic Zone C. Because of these contrasts, the USGS(21) characterized the Mexican Highlands as distinct from the Arizona Mountains (Transition Zone) in terms of the nature and distribution of young faults. The USGS recognition and documentation of this distinction reinforces the very conservative procedure used to locate a Sonora-type earthquake over 250 miles from the 1887 rupture. The nearest approach of the Mexican Highlands subprovince to the site is about the same as the epicentral distance already postulated in the maximum earthquake analysis.

2.5.2.4.1 Seismic Zone A

The San Andreas fault, from the Transverse Ranges southward, is the only fault in Zone A that is considered capable of producing a great earthquake with a magnitude of 8.0. Such an

earthquake may represent a conservative assumption because there has been very little historic activity along this portion of the San Andreas fault, and there has been a high level of earthquakes (up to magnitude 7.1) on the nearby San Jacinto fault set (paragraphs 2.5.2.2.2.2 and 2.5.2.3). At its closest approach to the site, the San Andreas fault is at a distance of about 120 miles. A level of vibratory ground motion less than 0.10g at the site is expected from an earthquake of magnitude 8+ at a distance of 120 miles (paragraph 2.5.2.6). Because the San Andreas fault and the postulated maximum earthquake lie along the edge of the zone nearest to the site, all other shocks in the zone would produce lesser levels of shaking at the site.

2.5.2.4.2 Seismic Zone B

This zone shows evidence of Quaternary fault activity, but epicenter uncertainties prevent assignment of shocks to particular causative faults. For maximum earthquake considerations, the shocks are presumed capable of occurring anywhere within this zone and in particular at the edge of the zone closest to the site. The largest earthquake observed in Zone B was a magnitude 4.9 shock in 1958. The maximum earthquake is taken to be a magnitude 5.0 shock with its epicenter at the edge of the zone and approximately 65 miles from the site. The maximum earthquake would cause a 0.02g level of vibratory ground motion at the site based on Donovan's[138] attenuation relationship. Capable faults are not

extensive enough to suggest that larger shocks should be expected.

2.5.2.4.3 Seismic Zone C

Determination of the maximum earthquake for Zone C involves two cases depending on the interpretation chosen for the tectonic relationship of the 1887 Sonora earthquake (see paragraphs 2.5.2.3.3 and 2.5.2.3.6). In the first case, Zone C comprises the band of seismicity crossing Arizona diagonally, and the 1887 Sonora earthquake is contained in a separate zone, the Mexican Highlands of the Basin and Range province. For this case, the maximum earthquake recorded in Zone C is a 1959 shock with magnitude 5.6; several other shocks greater than magnitude 5 have also occurred. The geologic and seismologic data are not adequate for this area to correlate individual shocks with particular faults, so a magnitude 5.6 earthquake is presumed possible at the closest approach to the zone to the site, more than 70 miles. Shaking from such an earthquake would be on the order of 0.03g at the site(138).

For the second case, Zone C is considered to widen southward and to contain the epicentral area of the 1887 Sonora earthquake. Then the occurrence of a Sonora-type earthquake of about magnitude 8.0 at some location closer to the site represents the maximum earthquake for Zone C. Faults about 200 miles long are needed to generate a magnitude 8.0 earthquake(139)(140) and no such Quaternary age faults are present within the Arizona portion of Zone C. However, there are several long, northwest trending valleys with associated

Quaternary and capable faults along a trend that projects northward from Mexico to the Grand Canyon region. Associating a great earthquake with these unconnected, Quaternary faults represents a very conservative assumption. The closest approach of these faults to the site is 72 miles. Evaluating a magnitude 8.0 earthquake at a distance of 72 miles provides a 0.20g estimate for vibratory ground motion at the site (paragraph 2.5.2.6). This level of shaking at the site is more severe than that of all other postulated earthquakes that might credibly occur in the site region.

2.5.2.4.4 Seismic Zone D

In Zone D, the largest earthquake must be presumed to occur at a random location because the geologic and seismologic data are generally not adequate to prove otherwise. However, detailed geologic investigations in the immediate vicinity of the site have precluded the existence of any capable faults within 5 miles of the site (paragraph 2.5.1.2.3). Shocks as large as magnitude 4.5 have occurred within Zone D: 1956, M=4.5 about 110 miles southeast of the site. The maximum earthquake for Zone D is taken to be a magnitude 4.5 shock at a distance of 5 miles. Such an earthquake would cause a level of vibratory ground motion at the site of less than 0.15g (paragraph 2.5.2.6).

DuBois, et al[97][98] have identified a few earthquakes in Zone D occurring prior to instrumental observations and for which they assign intensity VI. These authors have associated intensity VI with the magnitude range from 4.0 to 4.9.

However, for the particular intensity VI shocks in Zone D, the reported effects clearly suggest the lower portion of the intensity VI effects range. Thus, these shocks do not provide clear evidence for magnitudes greater than 4.5.

The 1976 Prescott earthquake, magnitude 5.2, occurred within the Colorado Plateau tectonic province very near the boundary between seismic Zones C and D. Although not identified with a particular fault, the earthquake is considered to be associated with a group of Quaternary faults(111) typical of the southwestern edge of the Colorado Plateau. Therefore, the event was not used to fix the magnitude of the randomly occurring earthquake in Zone D which is within the Sonoran Desert portion of the Basin and Range tectonic province.

2.5.2.4.5 Seismic Zone E

Seismic Zone E is beyond 200 miles from the site and would not generate vibratory ground motion at the site comparable to that from great earthquakes at much closer distances.

2.5.2.5 Seismic Wave Transmission Characteristics of the Site

Ground motions which would result at the site from the postulated maximum earthquake were assessed by the extrapolation of real earthquake accelerograms recorded on soils generally similar to those at the site rather than by using wave transmission methods. This approach does not depend upon seismic compressional and shear wave velocities, bulk densities, soil properties and classifications, shear

moduli and their variation with strain level and water table elevation. Site conditions, and the extent they influence ground motions, are accounted for as part of the procedure to select representative accelerograms. Paragraph 2.5.2.6.1 provides a summary of this methodology; paragraph 2.5.2.6.6 provides a discussion of amplification potential at the site.

2.5.2.6 Safe Shutdown Earthquake

The SSE has been selected as an event similar in size to the 1887 Sonora earthquake of magnitude 8.0 occurring at a distance of 72 miles northeast of the site. The selection of the SSE is conservative and is described in paragraph 2.5.2.4. The level of vibratory ground motion associated with this event was found to be conservatively represented by horizontal and vertical design response spectra normalized to 0.20g with the characteristics recommended in NRC Regulatory Guide 1.60 (figures 2.5-94 and 2.5-95). See section 3.7 for the seismic design basis SSE value.

The vibratory ground motion determined for the SSE is based essentially on free-field surface motions. Accordingly, it is applicable to the grade level of the plant. In a conservative manner, the SSE level of acceleration and the associated design spectra are applied to both the plant grade and the foundation level for the purpose of structural design and soil-structure interaction analyses.

As postulated in paragraph 2.5.2.4, there are two other sources capable of generating strong ground motion at the site. They are the San Andreas Shear Zone and an earthquake of magnitude 4.5 randomly located no closer than 5 miles from the site.

The San Andreas Shear Zone is not capable of producing vibratory ground motion at the site as strong as that of the SSE because the magnitude 8.5 maximum earthquake on the San Andreas Shear Zone would be located at a considerably greater distance from the site (120 versus 72 miles) than the SSE of magnitude 8.0.

A simplified evaluation of the level of shaking that could be expected at the site during an earthquake of magnitude 8.5 at a distance of 120 miles on the San Andreas Shear Zone can be obtained using the following attenuation relations:

	Maximum Ground Acceleration
Schnabel and Seed[99]	
Average	Less than 0.05g
Housner[141]	Less than 0.10g
Donovan[138]	0.06g

	Maximum Ground Acceleration
Esteva[142]	0.02g
Davenport[143]	0.04g

All of these values of maximum acceleration indicate shaking at the site considerably less severe than that represented by the recommended 0.20g NRC design spectra.

An earthquake of magnitude 4.5 in the vicinity of the site is also not capable of producing stronger vibratory ground motion at the site than the postulated SSE. The values of acceleration obtained in this case from the attenuation relations are:

	Maximum Ground Acceleration
Schnabel and Seed[99]	
Average	Less than 0.11g
Housner[141]	Less than 0.15g
Donovan[138]	0.10g
Esteva[142]	0.04g
Davenport[143]	Not applicable in near field

All these values are also representative of less severe shaking than the recommended 0.20g NRC design spectra. See also appendix 2A, Question 2A.5.

2.5.2.6.1 Basis of Approach

The design level of vibratory ground motion associated with the SSE (as expressed by the design response spectra) has been established by the extrapolation of response spectra of accelerograms recorded during past earthquakes. The results obtained by this method are corroborated with the results of methods which establish peak accelerations from attenuation relationships (paragraph 2.5.2.6.3) or intensity observations (paragraph 2.5.2.6.5). These latter two methods, involving the use of peak acceleration, have been used on other, previously

licensed nuclear power plants to determine the design level of vibratory ground motion associated with the SSE.

The response spectra of selected accelerograms of past earthquakes in the western United States were extrapolated to the conditions of the postulated SSE. The earthquake accelerograms were selected on the criteria that the recording conditions of the actual accelerograms should have, to the maximum extent possible, the same magnitude, source-site distance, local soil, and fault characteristics as the postulated SSE event for which design spectra are to be generated. Such criteria minimize the degree of scaling and extrapolation required and provides the greatest degree of assurance that the results reflect the postulated SSE realistically.

The approach is technically sound and leads to realistic results for the following reasons:

A. The selection of design spectra is based on examination of spectra over the entire frequency range of interest, rather than on the peak acceleration. Peak acceleration is only one point on the spectrum and is a poor measure of the strength of motion, except at very high frequencies. The same comment holds with respect to maximum ground velocity and displacement, which are not related, except in a statistical sense, to points on the design spectrum. (The peak ground displacement does control the spectrum at very long periods, but these are beyond the range of interest).

B. By making a selection of accelerograms recorded under circumstances as comparable as possible to the postulated SSE, the extrapolation and the associated inaccuracies are minimized. The scaling of accelerograms and spectra for magnitude and distance is by necessity an approximate operation, as any examination of basic data will show. The closer the characteristics of the actual earthquake are to those of the postulated earthquake, the more reliable the results.

C. The method is complete in the sense that existing records from all major U.S. earthquakes are the base of data from which selected records are drawn; while at the same time the existing records are limited enough so that no obvious significant data will be overlooked.

D. The approach does not depend on concepts such as bedrock motion, period of soil, depth to bedrock, and soil damping that are ill-defined or not as yet measured(144). Site conditions, and the extent they influence motions, are accounted for as part of the records selection procedure, except in the case of very soft soils.

Because of the limited data, some scaling of the response spectra with respect to magnitude and distance is necessary. The attenuation relations developed by Schnabel and Seed(99), Housner(141), and Donovan(138), were used to perform the scaling. These attenuation relations were used because they yield values

of maximum acceleration which are indicative of the severity of shaking. Donovan's relation was also considered to be one of the most appropriate of the statistical relationships for use with this procedure.

In the scaling procedure, the attenuation relations are considered correlations of the severity of the vibratory ground motion (as represented by the whole response spectrum) with magnitude and distance, and not merely as predictions of maximum ground accelerations. The scaling factor is obtained by dividing the acceleration that corresponds to the distance and magnitude of the postulated SSE, by the acceleration that corresponds to the distance and magnitude of the accelerogram being scaled. The distance associated with the accelerogram being scaled is the distance from the recording station to the center of energy release. An average depth of 10 miles has been assumed for the postulated event.

2.5.2.6.2 Safe Shutdown Earthquake Level of Vibratory Ground Motion

Table 2.5-9 identifies the accelerograms of past real earthquakes that are considered appropriate for extrapolation to represent the postulated SSE, an earthquake of magnitude 8 at a distance of 72 miles from the site. The two recorded horizontal components and the vertical component of motion were used in the extrapolation. In every case, the more conservative scaling factors obtained from the Schnabel and Seed[99], Housner[141], and Donovan[138] average attenuation curves

were used to scale the existing records to the postulated conditions.

The four records in table 2.5-9 generated by the Kern County earthquake of 1952, are the accelerograms whose recording conditions most closely resemble the conditions of the postulated earthquake. The Kern County earthquake was of high magnitude (7.7), similar to the magnitude of the postulated SSE event (8.0). The distance of the recording stations to the central portion of the causative fault are very similar to the source-site distance postulated for the SSE (60 and 80 miles versus 72 miles). Both the recording stations and the site are located on firm and moderately deep alluvium.

The two records from the San Fernando earthquake of 1971 were selected because they are the records with the highest acceleration levels recorded at distances comparable to that of the postulated SSE (68 and 78 miles versus 72 miles). However, they are not as representative as the records from the Kern County earthquake because considerably more scaling is necessary for magnitude (from 6.5 to 8.0 magnitude) resulting in large scaling factors (3.38 and 3.79).

Large scaling of the records to account for magnitude produces results that are very conservative because the attenuation relations used were obtained from data taken from small to moderate magnitude earthquakes; the application of these relations to large magnitude earthquakes requires an extension of the empirical relationships beyond the limits of the recorded data. It is widely agreed by researchers[139][145], and

acknowledged by the authors of the attenuation relations used, that such an extension results in values that are much higher than would actually be expected. This situation does not invalidate the scaling technique, it merely indicates that under these circumstances, the scaling is very conservative. It also indicates, however, that the records from the 1971 San Fernando earthquake, because they need large scaling for magnitude, are less representative of the SSE shaking than those from the Kern County earthquake. This is probably true with respect to both the general level of the response spectra and their relative frequency content.

Figures 2.5-42 through 2.5-47, which include the scaled spectra of the records from the Kern County earthquake (more representative set), indicate that 0.20g horizontal and vertical NRC Regulatory Guide 1.60 design spectra are a very conservative envelope of the level of ground shaking to be expected at the site due to an earthquake of magnitude 8.0 at a distance of 72 miles. For the period range of 0.5 second and less, the recommended design spectra are 1.5 to 4 times higher than the peaks of the scaled spectra. Figures 2.5-42 to 2.5-44 indicate that the conservatism of the recommended horizontal design spectra increases with increasing levels of damping. At the 10% damping level, which is on the order of the damping used for structure-foundation interaction, the scaled spectra do not reach the design spectrum at any period. The peaks that exceed the 0.20g NRC spectrum at 2% damping (figure 2.5-42) for periods between 0.6 to 2 seconds do not indicate less conservatism because considerably higher levels of damping

determine the vibratory response of the structures due to soil-structure interaction.

Table 2.5-9

SCALING FACTORS FOR ACCELEROGRAMS USED IN THE EVALUATION OF THE SSE DESIGN RESPONSE SPECTRA LEVEL[a]

Earthquake Record	Recorded Magnitude	Distance Between Recording Station and center of Energy Release (mi)		Scaling Factor for Record		
		Horizontal	Depth	Schnabel and Seed Average Attenuation Curves (1973)	Housner's Attenuation Curves (1965)	Donovan's Attenuation Relation (1973)
From the Kern County Earthquake of 1952						
Santa Barbara	7.7	60	10	0.88	0.80	0.98
Pasadena	7.7	80	10	1.57	1.69	1.33
Hollywood Storage Basement	7.7	80	10	1.57	1.69	1.33
Hollywood Storage P.E. Lot	7.7	80	10	1.57	1.69	1.33
From the San Fernando Earthquake of 1971						
San Bernardino	6.5	68	4	3.13	3.38	2.0
San Juan Capistrano	6.5	78	4	3.79	Beyond range	2.34

a. The largest of the three scaling factors computed for each accelerogram was used in the actual scaling of the accelerogram to simulate a magnitude 8.0 earthquake, 72 miles from the site.

At 10% damping (figures 2.5-44 and 2.5-50) there are no portions of the scaled response spectra that exceed the 0.20g NRC spectrum for either the records from the Kern County earthquake of 1952 or the San Fernando earthquake of 1971. At 5% damping (figures 2.5-43 and 2.5-49), only a few peaks of the scaled spectra slightly exceed the 0.20g NRC design spectrum; however, the 0.20g design spectrum envelops the scaled spectra well above the 84.1 percentile level implicit in the NRC Regulatory Guide 1.60.

Figures 2.5-48 through 2.5-53 show a comparison of the scaled response spectra of the records from the San Fernando earthquake listed in table 2.5-9 with the recommended 0.20g design spectra. They indicate that the 0.20g spectra are also a conservative envelope of these scaled records (especially at 5 and 10% damping, figures 2.5-49 and 2.5-50).

2.5.2.6.3 Maximum Accelerations Based on Attenuation Relations

The procedure described in paragraph 2.5.2.6.1 reflects the best use of the existing accelerogram data and provides a rational and conservative estimate of the design spectra associated with the SSE at the site. In utilizing this procedure, the most appropriate existing accelerograms recorded during past earthquakes have been scaled to the magnitude and distance associated with the postulated SSE.

The procedure results in a more representative determination of the maximum vibratory ground motion at the site than would be obtained by directly normalizing NRC Regulatory Guide 1.60

design spectra to peak acceleration values obtained from the different attenuation relationships presented in literature. Nevertheless, to demonstrate the reasonableness of the applicant's procedure, this paragraph presents comparisons of results with those obtained from a direct application of some pertinent attenuation curves. The peak ground accelerations estimated at the site for the postulated SSE are listed below:

	Magnitude 8.0 at a Distance of 72 Miles
Schnabel and Seed[99]	0.07g
Average	
Housner[141]	0.11g
Donovan[138]	0.09g
Esteva[142]	0.04g
Davenport[143]	0.17g
Cloud and Perez[125] Envelope	0.07g

It should be noted that all these attenuation curves were obtained from data taken from small to moderate magnitude earthquakes. The application of these curves to larger magnitude earthquakes requires an extension of the empirical relationships beyond the limits of the recorded data. It is widely agreed by researchers[139][145] that such an extension results in ground accelerations that are much higher than would actually be expected. Nevertheless, it can be seen that the peak ground accelerations shown above indicate the conservatism of the 0.20g NRC Regulatory Guide 1.60 design spectra determined by the procedure described in paragraph 2.5.2.6.1.

2.5.2.6.4 Attenuation of Vibratory Ground Motions in Arizona

The attenuation curves used in specifying the SSE have been derived mostly from instrumental data from California earthquakes. Thus, their use deserves justification for Arizona application. This aspect of the seismic evaluation in different geographic areas is important since it has been postulated by some investigators[147] that seismic shaking is attenuated more slowly with distance in the eastern United States than in the west. Because instrumental data are lacking in Arizona, the available intensity data were reviewed and found to support two lines of reasoning with similar results.

The first relates to the shape of isoseismal lines from single large events which affect both areas (California and Arizona). Shown in figures 2.5-31, 2.5-32, 2.5-35, and 2.5-38 are isoseismal maps for large earthquakes in the Imperial Valley Region in 1934 and 1940, the Desert Hot Springs earthquake of 1948, and the Borrego Mountain earthquake of 1968, respectively. The limits of the felt area are about equidistant in the northwesterly direction in California, and in the easterly direction into Arizona. This radius is not exactly constant, but such is common for events within California. If the crust under the southwestern corner of Arizona possessed attenuation properties greatly different from those in California, the limiting distance of perceptibility would be considerably less or considerably more in Arizona than in California. At most, these examples would admit to about 20 to 25% difference in distance, but this amount is not significant in light of the small number of events large enough

to be felt in both areas and the irregular shape of the isoseismal lines in general.

The second method compares the area enclosed by the isoseismals produced by earthquakes of the same magnitude in Arizona and California. Of particular interest, because of the 1887 Sonora earthquake, are events in the central seismic zone (Zone C) of Arizona. Although there are five moderate events (1938, M=5.5; 1945, M=5.1; 1959, M=5.0; 1959, M=5.6; and 1976, M=5.2), only the 1938 event near the Arizona-New Mexico border, the 1959 event on the Arizona-Utah border, and the 1976 event north of Prescott, Arizona have reported isoseismal data. The 1938 event, magnitude 5.5, is reported as having affected 8000 square miles. The 1959 event of magnitude 5.6 was also reported to have been felt over 8000 square miles; however, if the felt reports are plotted (figure 2.5-37), the felt area is indicated to range from 15,000 to 32,000 square miles. The 1976 Prescott event was reported as being felt over 9000 square miles. For comparison, the felt areas as reported in the publication, Earthquake History of the United States (1973), for California events in the magnitude range of 5.4 to 5.8 were plotted against magnitude in figure 2.5-54. Shown also are open symbols representing the Arizona events described above. There is great scatter in these data, but the Arizona data do fall within the California data.

These two studies indicate that the attenuation of ground motion in Arizona is approximately the same as that for California.

Furthermore, the observations of damage and shaking during the 1887 Sonora earthquake towards Arizona and to the west of the fault break clearly indicate that the attenuation of vibratory ground motion in these directions is the same order as has been experienced in California. (The detailed discussion and data supporting this conclusion can be found in paragraph 2.5.2.10.4 and Appendix W of the PVNGS 1, 2, and 3 PSAR). Consequently, the use of attenuation relations based on California data is adequate for Arizona.

2.5.2.6.5 Estimations of Vibratory Ground Motion from Intensity Observations

This paragraph is presented also as a corroboration that the recommended 0.20g NRC design spectra are a conservative representation of the maximum level of shaking for the site. It is pointed out, however, that intensity scales are not a scientifically quantitative measure, and so the results obtained by their use are not as reliable as those obtained by the extrapolation of real earthquake response spectra. The Modified Mercalli (MM) intensity to be expected at the site during an earthquake of magnitude of 8.0 at a distance of 72 miles, as determined from figure 2.5-55(148), is between VI and VII. The curves in figure 2.5-55 are based on data for southern California earthquakes(149)(150)(151). They are, however, considered applicable to Arizona in view of the data presented in paragraph 2.5.2.6.4. The conservatism of the estimated intensity VII is apparent in the isoseismal maps of the high magnitude earthquakes in California shown in figures 2.5-29,

2.5-30, and 2.5-36. In every case, the highest intensity at a distance of 72 miles is MM VII, with the exception of the intensity VII-VIII indicated for the Yosemite Valley during the Owens Valley earthquake of 1872. This intensity is based on the poetic description of the earthquake by the explorer John Muir who indicates only the falling of rocks from the almost vertical granite walls of the canyon; no damage to his cabin is mentioned(152). Only intensities VI-VII of the

Rossi-Forel scale (which is equivalent to MM VI), were reported to distances of 72 miles from the San Andreas fault during the 8.3 magnitude San Francisco earthquake of 1906; this is considered to be the most representative because of relatively good documentation and because it was caused by a high-angle fault as is the fault system producing the SSE.

The intensity VII reported for Visalia during the 1872 Owens Valley earthquake is considered to be overestimated because it is based on the following description of damage:

> "People ran into the street; front wall of brick saloon moved 1 inch; fissures of 1 inch or more opened in clay ground." From the Los Angeles Evening News of 3/27/1872 (R. Greensfelder, 1974 personal communication)

The values of maximum ground acceleration that have been associated with the modified Mercalli intensity VII by a number of authors are (see Table 1 of reference 153 for citations):

Ishimoto (1932)	0.05g
Kawasumi (1951)	0.09g
Hershberger (1956)	0.13g
Richter (1958)	0.07g

Neumann (1954)	0.13g
Medvedev and Sponheuer (1969)	0.05g-0.10g
Japan Meteorological Agency (Okamoto, 1973)	0.04g-0.10g
Trifunac and Brady (1975)	0.13g

All these values are below the 0.20g recommended for the SSE.

2.5.2.6.6 Amplification Potential at Site

This paragraph addresses three points concerning the treatment of soil amplification and other potential site effects by the procedure used to determine the SSE level of design spectra (see paragraph 2.5.2.6.1).

A. For alluvial deposits as firm as those at the Palo Verde site, effects of local site conditions upon the ground motion are much less significant than effects of source mechanisms and travel paths.

B. The procedure incorporates potential site effects, and other effects, in the most fundamental way, by making full use of available measured data obtained under comparable conditions.

C. The use of a soil column analysis to calculate the site vibratory ground motion would be inappropriate.

Regarding item A above, the measured wave velocities at the site (table 2.5-10) indicate that the surface materials are somewhat firmer than at El Centro, California, and are also comparable to the surface deposits in other places in southern California, such as the Pasadena and Los Angeles basins. At

the El Centro site, a detailed analysis of 15 measured strong-motion records, including the 1934 and 1940 events, showed conclusively that consistent local site effects, if any, are overshadowed by variations in the motion attributable to variations in the source mechanism and travel path[130]. This study of a single site for several earthquakes is complemented by Hudson's[154] study of records obtained on many sites in the Pasadena area for the San Fernando earthquake. In this later study, it was found that the motion bore no simple relationship to depth of alluvium or rock types. There were no characteristics of the motion that could be ascribed to local site conditions.

Table 2.5-10

P-WAVE VELOCITY (fps) PROFILES AT THE SITE

AND STRONG MOTION RECORDING STATIONS IN SOUTHERN CALIFORNIA

Depth (ft)	Palo Verde Site	El Centro	Pasadena	Santa Barbara	Hollywood Storage	San Bernardino
10	1900	1200	1000	2500	1090	1300
20	1900	1200	2200	4100	2400	1300
50	2100	1200	2200	4100	2400	5200
75	5000	5900	2200	4100	2400	5200
100	5500	5900	5300	5200	2400	5200
150	5700	5900	5300	5200	2400	5200
200	5700	5900	5300	5200	5000	5800
250	6100	5900	5300	5200	5000	5800
300	6500	5900	5300	5200	5000	5800

NOTE: No P-wave velocity profile for San Juan Capistrano.

In addition, motions in the Los Angeles area during the San Fernando earthquake, and at sites where four earthquakes have been recorded[155], show no effects on the motion that are identifiable with local conditions. There are indications, however, from Hanks[156], that the surface wave motions of long period were enlarged in passing laterally from basement rock and firm sediments into the softer sediments of the southern Los Angeles basin. This occurred during the San Fernando earthquake at distances from 20 to 40 miles from the fault.

These surface waves appear to be responsible for the peaks at periods of 3 to 4 seconds in the response spectra at sites in southern Los Angeles studied by Crouse[157], and may also be the source of the long-period motions discussed by Scott[158] for sites at Long Beach and Vernon. This very general effect of basin-wide conditions on the amplitude of surface waves in the San Fernando earthquake is the only observed "site effect" and does not, in general, occur at frequencies that are important in nuclear power plant design.

With regard to item B above, by beginning with records of ground motion obtained under as comparable conditions of epicentral distance, local site conditions, and source mechanisms as possible, the applicant's procedure considers the effects of these features directly. For example, selecting records at comparable distances and from comparable sites in the San Fernando earthquake ensures that surface-wave effects of the type noted above are correctly accounted for. (They are not of major importance in this application, however, because of their long periods.)

With respect to local site conditions, table 2.5-10 shows that the sites where the records selected for extrapolation to represent the SSE (table 2.5-9) were obtained have wave propagation characteristics that are comparable to those at the Palo Verde site. It is noted that many of the records used to establish the shape of the spectra set forth in Regulatory Guide 1.60 were obtained on firm alluvium.

Regarding item C above, the use of soil-column analysis to study site effects is inappropriate for a number of reasons. First, the soil-column analysis assumes vertically propagating shear (SH) waves as the only mode of wave propagation. This is a gross simplification that neglects the contribution of surface waves and body waves coming at other angles of incidence. Secondly, there are essentially no measurements of strong motion obtained at depth that can serve as reliable excitations for such models. Thus, the excitation must be estimated from motions obtained at the ground surface which is a circuitous way of determining ground surface motion. Finally, the two properties of the soil column that are paramount in determining its calculated effects on surface motions are the fundamental frequency and the damping in the fundamental mode. The fundamental frequency is determined, in large part by the depth of the column, with larger periods associated with deeper soil columns. However, at the El Centro site, no specified site period can be identified either from strong-motion records or from microtremor recordings(159), and no such site periods are present in the records studied by Hudson(154) and Crouse(157). The amount and type of damping associated with the soil column analysis is uncertain and is based primarily on empirical data having wide scatter.

In view of the oversimplifications and uncertainties inherent in a soil column analysis, it is thought preferable to make a more direct extrapolation from measured data.

2.5.2.7 Operating Basis Earthquakes

The level of vibratory ground motion selected as the OBE is represented by the 0.10g design response spectra presented in figures 2.5-96 and 2.5-97. This earthquake level is half that of the postulated SSE (0.20g spectra) as required in 10CFR Part 100, Appendix A. The level of shaking represented by the 0.10g design response spectra is greater than the shaking levels that may be reasonably expected to occur at the site during the operating life of the plant. This conclusion is based on the following:

- Low seismicity of the region
- Absence of capable faults within approximately 70 miles of the site
- Results of probabilistic analyses contained in Algermissen and Perkins[160][161] and ATC.[162]

According to these references, the accelerations at the site with a 10% probability of being exceeded in 50 years (which corresponds to an average return period of 475 years) are less than 0.05g. See section 3.7 for the seismic design basis OBE value.

2.5.3 SURFACE FAULTING

2.5.3.1 Geologic Conditions of the Site

The geologic conditions of the region surrounding the site (200-mile radius) are discussed in paragraph 2.5.1.1. A more detailed discussion of the geology in the site vicinity and its

relation to the regional geology is presented in paragraph 2.5.1.2.2. Geologic conditions of the foundations of PVNGS Units 1, 2, and 3 are described in subsection 2.5.4 and appendix 2D.

In summary, the distinctive Palo Verde Clay underlying the site has been shown to be greater than 2.8 million years old and its unfaulted nature provides the basis for proving that there are no capable faults within 5 miles of the site.

2.5.3.2 Evidence of Fault Offset

2.5.3.2.1 General

Techniques used to determine the presence or absence of fault displacements at or near the ground surface within the 5-mile radius of the site, and in adjacent areas outside this radius, included: analysis of stereo, vertical, aerial photographs; ERTS-1 imagery, and side-looking radar imagery; detailed geologic field mapping; trench and foundation excavations; lithologic and high-resolution, geophysical, borehole correlations; gravimetric and magnetic surveys; and seismic refraction surveys. These studies have shown that there is no evidence of capable fault offset at or near the ground surface within a 5-mile radius of the site.

2.5.3.2.2 Mappable Faults

Detailed geologic mapping within the 5-mile radius revealed only one mappable fault (figures 2.5-11 and 2.5-12). This fault is in the Miocene volcanic bedrock about 3 miles west of

the site, strikes northwest, and has been traced for approximately 2000 feet. The fault plane is vertical and is indicated by a crushed zone of volcanic rock 1 to 3 feet wide. This fault has been investigated in closely-spaced backhoe trenches ranging from 15 to 200 feet apart[8]. Plunges of slickensides in four trench exposures of the fault indicate that the sense of movement is dip slip. Based on the orientation of slickensides and a distinctive 30 to 50-foot-wide tuff unit exposed on both sides of the fault, displacement is calculated to be about 50 to 75 feet. The fault was traced to a point where it is overlain by Tertiary fanglomerate (Tvfn). A trench exposing the fault at this point clearly demonstrates that the fanglomerate is not displaced. The age of the fanglomerate is 16.7 million years (Miocene) based on a potassium-argon date of a basalt interbed (paragraph 2.5.1.2.1).

2.5.3.2.3 Inferred Faults

Gravity and magnetic surveys in the site area reveal two anomalies inferred to be buried faults. These inferred faults are from 4.5 to 5 miles north of the site, trend northwest to eastwest, and are approximately 10 miles long (figures 2.5-11 and 2.5-12). These features do not displace the ground surface or the thick sequence of Pliocene and Pleistocene basin sediments, including the Palo Verde clay (figure 2.5-19): thus, they must be older than the Palo Verde clay (greater than 2.8 million years).

2.5.3.2.4 Lineaments

Several lineaments were noted within 10 miles of the site (paragraph 2.5.1.2): two short ones within the 5-mile radius (figure 2.5-12), one about 7 miles southeast of the site, and two about 8 miles south of the site coinciding with alignments of the Gila River (figure 2.5-13). Detailed investigations (paragraphs 2.5.1.2.2.2 and 2.5.1.2.4) revealed that none of these lineaments represent capable faults.

2.5.3.3 Earthquakes Associated with Capable Faults

Figure 2.5-25 shows that there are no capable faults or historic earthquakes within 5 miles of the site.

2.5.3.4 Investigation of Capable Faults

There are no capable faults within 5 miles of the site.

2.5.3.5 Correlation of Epicenters with Capable Faults

The absence of capable faults within 5 miles of the site precludes the correlation of epicenters with capable faults.

2.5.3.6 Description of Capable Faults

There are no capable faults within the 5-mile radius of the site (paragraph 2.5.3.2).

2.5.3.7 Zone Requiring Detailed Faulting Investigation

There is no zone requiring detailed faulting investigation.

2.5.3.8 Results of Faulting Investigation

This paragraph is not applicable because there is no zone requiring detailed faulting investigation (paragraph 2.5.3.7).

2.5.4 STABILITY OF SUBSURFACE MATERIALS AND FOUNDATIONS

2.5.4.1 Geologic Features

2.5.4.1.1 Subsidence Potential

There is no physical evidence or published information that indicates any occurrence of subsidence in the site area (5-mile radius). Mineral resources are not known to exist within the site area and geologic conditions beneath the site are not conducive to formation of mineral resources. Therefore, any subsidence due to extraction of mineral resources is precluded. The potential for subsidence due to groundwater withdrawal at the site is not significant because of a favorable combination of three factors:

- Projected groundwater level changes beneath the site are small (see paragraph 2.4.13.2).
- The thickness of unlithified deposits beneath the site is less than 480 feet; less than half of this thickness corresponds to deposits below the regional water level.
- The compressibility of the unlithified deposits at the site is small (see paragraph 2.5.4.10.1).

Although the potential for subsidence is considered to be minor at this site, detailed analyses were performed to verify this condition. Conservative parametric analyses of the effects of

hypothetical (not anticipated) water level declines were presented in the PVNGS 1, 2, and 3 PSAR. The potential for deep-seated subsidence due to declines in the piezometric level of the regional aquifer was discussed in paragraph 2.5.1.1.6, Listing G.3, of the PVNGS 1, 2, and 3 PSAR. The elastic compression of the sedimentary and volcanic rocks comprising the regional aquifer was conservatively estimated to be about 2, 3, and 4 inches for hypothetical water level declines of 250, 350, and 450 feet, respectively.

The potential for subsidence due to dewatering of the perched water zone was discussed in Appendix 2T (Section 2T.7) of the PVNGS 1, 2, and 3 PSAR. Based on the very conservative groundwater assumption that hydrostatic conditions prevailed below the perched water zone, and using conservative compressibility parameters for the soils, total subsidence due to complete dissipation of the perched water zone was estimated to be in the range of 6 to 10 inches. However, based on the more realistic groundwater model presented in paragraph 2.4.13.1, dewatering of the perched water zone is not expected to result in subsidence. Since the fine grained soils encountered below approximately 50 feet act as the aquitard for the perched water zone, dewatering of this perched zone can be expected to cause a slight reduction in effective stresses within and below the aquitard resulting in a slight amount of heave, not subsidence. Some evidence of this is provided by excavation heave and subsidence monitoring data presented in paragraph 2.5.4.13. Maximum heave/rebound measured at the bottom of power block excavations at Units 1, 2, and 3 ranged

between 2 and 3 inches. While the subsurface conditions are similar under all three units, the amount of measured heave increased with the degree of dewatering. Dewatering was not required at Unit 1, while total water levels were lowered approximately 20 and 30 feet at Units 2 and 3, respectively. Similarly, survey data from the subsidence monitoring network, away from the influence of excavations, show no measurable subsidence over a 2-year period from 1977 to March 1979 (see paragraph 2.5.4.13.2.2) even though perched water levels declined about 5 feet over the same period and about 15 feet since 1975. These observations confirm that declines in perched water levels do not result in subsidence at this site.

2.5.4.1.2 Loading History of Foundation Materials

Historic erosion/deposition at the site has provided for the development of uniform sequences of dense or stiff soils that have been naturally consolidated during loading cycles. The mode of deposition and mineralogical composition of the soils and rock underlying the site is described in paragraph 2.5.1.2.2. Historic seismicity indicates that the site soils have been subjected to mild dynamic loading due to events with epicentral locations far removed from the site (paragraph 2.5.2.1). However, no evidence of seismically-induced ground failure has been observed at the site. The site has not been adversely subjected to other forms of loading phenomena such as glaciers or tidal effects or meteor impact.

2.5.4.1.3 Localized Soil and Rock Structures

Bedrock is not exposed in the site-specific area nor at depths which would influence the foundations due to joint patterns or fracturing. Category I structures are founded either on engineered backfill or undeformed basin sediments (paragraph 2.5.4.3 and appendix 2D) with a minimum thickness in the power block areas of about 200 feet (paragraph 2.5.4.2). No zones of structural weakness, such as crushed or disturbed materials caused by shears, faults, and folds, have been identified in the basin sediments underlying the site. No abnormal zones of alteration, irregular weathering profiles or seams, and lenses of weak materials are present in the soil and rock units beneath the powerblock areas.

2.5.4.1.4 Unrelieved Residual Stress

No bedrock is exposed at the foundation elevation of Category I structures (appendix 2D). There is no evidence to indicate that there are unrelieved residual stresses in the bedrock.

2.5.4.1.5 Rock and Soil Response Characteristics

There is no evidence that the characteristics of rocks or soils at the site are such that they may result in hazardous foundation conditions. The dense rock is consolidated and soils are generally overconsolidated (paragraph 2.5.4.2). No abnormal water content in the site soils or rock has been observed or is expected during the operational life of the facility (paragraphs 2.4.1.3 and 2.5.4.2). No significant

quantity of soluble minerals exists at the site (paragraphs 2.5.1.2).

The response of rock and soil to natural loading conditions, i.e., seismic events and anticipated static loads induced at the site, is expected to be favorable (paragraphs 2.5.4.8 and 2.5.4.10).

2.5.4.2 Properties of Subsurface Materials

Soil properties presented herein were derived from investigations conducted at five unit areas which included the location of two potential units (Units 4 and 5). Licensing activities for these two potential additional units have been terminated.

The engineering properties of subsurface soils were investigated by drilling, sampling, laboratory testing, and geophysical testing techniques. A summary of the generalized stratigraphy and associated engineering properties is presented in this section. Specific details of the drilling and sampling program are presented in paragraph 2.5.4.3. Details of the laboratory testing program and of the geophysical exploration are presented in appendix 2E and paragraph 2.5.4.4, respectively.

Profiles depicting the generalized stratification of subsurface materials at the units down to bedrock (approximately 300± feet deep) are shown on figures 2.5-56 through 2.5-58. The actual detailed soil stratification of the upper 65± feet is shown in the detailed excavation mapping of each of the

powerblock excavations, presented in appendix 2D. The stratigraphy disclosed by the mapping is consistent with that derived from borehole information.

2.5.4.2.1 Layer Descriptions

To determine representative engineering properties, the subsurface profile has been subdivided into three soil depth zones representing different depositional environments and generally exhibiting different engineering characteristics. For discussion purposes, these zones are defined as the upper zone (0 to 30 feet), intermediate zone (30 to 55± feet), and lower zone (55 to 300± feet). These depth zones correspond approximately to the following geologic lithozones and stratigraphic members presented on the geologic profiles and maps of excavations:

Depth Zone (feet)	Geologic Lithozone	Stratigraphic Members
Upper (0 to 30±)	Upper LZ5	A and B
Intermediate (30 to 55±)	Lower LZ5 (Transition)	C, D, and Upper E
Lower (55 to 300±)	LZ4 and LZ3	E, F, G, H, I, J, and K

The upper zone contains granular soils deposited in a high energy environment. Such deposits primarily consist of relatively well-graded silty and clayey sands with some fine gravel. Relatively uniform, fine, and medium sand layers are also present to a lesser extent. With the exception of the

upper 2 or 3 feet which are generally loose, the deposit is generally medium dense to dense. Zones of caliche cementation are common.

The intermediate zone represents a gradational interface between the upper coarse-grained pluvial deposits and the underlying, fine-grained lacustrine deposits. It consists of crudely stratified clay, silt, and sand layers of limited lateral extent. The clays are generally medium plastic, hard, and exhibit extensive calcareous cementation. Gradational mixtures of fine sands, silts, and clays of low plasticity are also common within the transition zone. Such soils, classified as SM-ML and SC-CL, are generally stiff to hard and exhibit localized calcareous cementation. Layers of sands with low silt and clay content (typically less than 30% fines) are also encountered within the transition zone. The sands within the intermediate zone are generally medium dense to very dense.

The intermediate zone generally increases in thickness and complexity of layering from Unit 1 southward. At Unit 1, the transition between the upper coarse-grained and lower fine-grained zones is very abrupt in most areas and the intermediate zone is discontinuous in those areas. At Units 2 and 3, the intermediate zone generally occurs within the interval of approximately 30 to 50 feet deep, immediately above the well-defined stratigraphic member E contact.

The lower zone deposits primarily consist of medium to highly plastic, hard clays. Sands and silts comprise a very small portion of the formation. Layering within the deposits is

uniform and relatively flat. Several major layers are traceable across the site.

2.5.4.2.2 Static Soil Properties

The results of the field and laboratory testing program were used to evaluate the engineering properties of site soils. Typical static material properties for site soils are presented in figure 2.5-59. Grain size and plasticity characteristics of the various soil layers are presented in figures 2.5-60 through 2.5-62. Results of standard penetration tests in granular soils beneath Units 1, 2, and 3 are presented in figure 2.5-63. A summary of shear strength test results is presented in figure 2.5-64. The resulting strength parameters used in design are summarized in figure 2.5-59.

2.5.4.2.3 Dynamic Soil Properties

See paragraph 2.5.4.7.

2.5.4.3 Exploration

2.5.4.3.1 General

An extensive subsurface exploration program was conducted to provide regional engineering and geology data for making preliminary site selection, and to provide detailed data at the site-specific areas after the unit locations had been finalized. The subsurface investigation included:

- 578 borings ranging in depth from 5 to 721 feet
- 3 backhoe trenches

- High resolution downhole geophysical logging
- seismic refraction lines (3 at site-specific areas)
- 4 outflow type borehole pump tests
- 27 inflow type borehole permeability tests

Site plans showing the locations of exploratory borings, trenches, and seismic refraction lines are presented in figures 2.5-66 through 2.5-68. An extensive tabulation of details concerning the subsurface exploration is presented in appendix 2F; included are details about drilling and trenching, such as coordinates, elevations, depths, drilling methods, sample types, and purpose.

Details concerning the geophysical investigation are presented in paragraph 2.5.4.4. Details concerning the borehole permeability testing are presented in appendix 2E. Exploratory borings were sealed by continuously grouting to prevent hydraulic communication between aquifers.

2.5.4.3.2 Subsurface Profiles

Geologic profiles illustrating the generalized stratigraphy under the power block areas are presented in figures 2.5-56 through 2.5-58. Detailed stratigraphy of the upper soils in the Units 1, 2, and 3 power block areas is presented in the geologic mapping of the power block excavations (appendix 2D).

2.5.4.4 Geophysical Surveys

Compressional and shear wave velocity surveys were performed at each unit to evaluate the low strain amplitude dynamic

characteristics of foundation soils and to establish the general occurrence of predominant soil layers. These surveys were accomplished using refraction, downhole, and crosshole testing methods. The methods used to conduct these tests, together with test results, are briefly summarized in the following paragraphs. Detailed information about test procedures, test results, interpretation of results and discussion of results is given in Appendix 2U of the PVNGS 1, 2, and 3 PSAR and the PVNGS 4 and 5 PSAR.

2.5.4.4.1 Refraction Surveys

Refraction tests were conducted at the Units 1, 2, and 3 locations (figure 2.5-68). Five source points were used during each refraction test. Explosive charges were used as energy sources. Geophone receivers were located at 20-foot intervals over a 250-foot spread distance.

Results of the refraction tests are summarized in figure 2.5-69. Three to four major velocity units can be identified in these profiles. Compressional wave velocities beneath the units vary from about 1100 feet per second near the ground surface to 5000 feet per second or more below the apparent groundwater table (60 to 80 feet below the ground surface at the time of the refraction tests).

2.5.4.4.2 Downhole Surveys

Downhole travel time measurements were made at the Units 1, 2, and 3 locations (figure 2.5-68). The energy was generated on the ground surface by striking a concrete block embedded in

surficial soils with a sledge hammer. Wave arrivals were recorded at 10-foot depth intervals in a borehole located about 30 feet from the source. Measurements were made to depths of 300 feet or more. Travel times for depths less than 200 feet were corrected to an equivalent vertical time according to the ratio between the slant distance and the vertical distance.

Travel times from the downhole tests are plotted as a function of depth in figure 2.5-70. Compressional and shear wave velocities derived from the time-distance relationships are noted in each plot. Velocity values at each unit increase with depth. Shear wave velocities typically vary from about 1000 feet per second in the upper 50 feet to 4000 feet per second or more at a depth of 4000 feet. Compressional wave velocities vary from 1300 to 2000 feet per second in the unsaturated, upper 50 feet of the soil profile to velocities in excess of 7000 feet per second at depths greater than 300 feet. The water table typically was interpreted to occur at depths of 50 to 80 feet on the basis of a sharp increase in compressional wave velocities (from about 2400 feet per second to slightly more than 5000 feet per second).

2.5.4.4.3 Crosshole Surveys

Crosshole tests were conducted at six locations (figure 2.5-68). Explosive and mechanical source mechanisms were employed during crosshole testing to enhance identification and interpretation of wave arrivals. Receiving holes were typically located in a linear pattern on both sides of the source hole. Arrays generally covered approximately

80 feet with adjacent receiving holes being 10 to 35 feet apart. Crosshole tests were normally performed at 10-foot depth intervals from depths of 10 feet to depths of 300 feet or more.

Results from the crosshole tests performed at Units 1, 2, and 3 are plotted as a function of depth in figure 2.5-71. These velocity values were used with elastic theory to compute shear moduli, Young's moduli, bulk moduli, and Poisson's ratio, as presented in tables 2.5-11 through 2.5-13.

As shown in figure 2.5-71, shear and compressional wave velocities generally increase uniformly with depth. Shear wave velocities vary from about 1000 feet per second in the upper 50 feet to values in excess of 2000 feet per second at 300 feet. Compressional wave velocities increase from about 1500 feet per second in the upper 50 feet to in excess of 6000 feet per second at a depth of 300 feet. These shear and compressional wave velocities are generally consistent with those recorded during the downhole program, suggesting that little material anisotropy exists. The water table, indicated by compressional wave velocities of approximately 5000 feet per second, is at 50 to 80 feet below the ground surface. These observations are also consistent with those recorded during downhole and refraction surveys.

2.5.4.5 Excavations and Backfill

2.5.4.5.1 Extent of Excavations, Fills, and Slopes

There are no Seismic Category I excavations at the site. Temporary excavations related to construction of plant facilities are backfilled before the plant is in operation. Therefore, the stability of temporary excavation slopes will not affect the safe operation of the plant.

The existing ground surface at the site is relatively flat, and only minor grading is required in the vicinity of the plant facilities.

The excavation details for Units 1, 2, and 3 temporary powerblock excavations are presented in figures 2.5-72, 2.5-73, and 2.5-74. Temporary excavations have slopes ranging from approximately 1-3/4:1 to 1:1 (horizontal to vertical).

See also appendix 2A, Questions 2A.7, 2A.9, and 2A.10.

2.5.4.5.2 Dewatering and Excavation Methods

Dewatering was carried out during excavation of the powerblock areas at Units 2 and 3. To facilitate construction activities, the ground water level was kept at a depth of at least 1 foot below final grade. Dewatering operations did not have any adverse effects on the underlying foundation soils. Dewatering was accomplished by use of open trenches and sumps.

The foundation excavations were made with conventional earth moving equipment in soils. Foundation excavations at the base of slab were protected against disturbance by use of a 3-inch

concrete mud mat, and where overexcavation was done, the excavation was backfilled with lean concrete or processed sand to the specification indicated in paragraph 2.5.4.5.3.

Foundation heave and settlement of critical structures in the Units 1, 2, and 3 excavations were measured by:

- Multiposition extensometers anchored at various depths between bedrock and the bottom of the excavation
- Mechanical rebound anchors located near the bottom of the excavation

Details and results of the heave/settlement monitoring program are presented in paragraph 2.5.4.13.

2.5.4.5.3 Backfill

Soil backfill placed adjacent to Category I structures and pipelines meets the requirements of the PVNGS 1, 2, and 3 PSAR. The shape of construction excavations and the extent of backfill at each powerblock is shown in figures 2.5-72, 2.5-73, and 2.5-74. During backfilling, fills were benched into firm, undisturbed native soils along construction slopes. This was done in order to remove any loose, eroded soil at the construction slope surface, and to facilitate uniform compaction to the edges of the backfill.

Structural backfill under Category I structures consists primarily of excavated granular soils. Suitable granular soils are abundant in the upper granular strata to depths of approximately 50 feet in the unit areas. Material gradation

specifications are presented as a grain size band in figure 2.5-75. Structural backfill is compacted to a density of 95% of the maximum dry density determined in accordance with ASTM D1557. The above gradation and compaction requirements were developed as a result of extensive static and dynamic

Table 2.5-11

CROSSHOLE SEISMIC SURVEY

SUMMARY OF VELOCITY VALUES AND ELASTIC MODULI, UNIT 1

Depth (ft)	Predominant Soil Types	P-wave Velocity (ft/s)	S-wave Velocity (ft/s)	Unit Weight (lb/ft^3)	Poisson's Ration	Shear Modulus ($psi \bullet 10^{-5}$)	Young's Modulus ($psi \bullet 10^{-5}$)	Bulk Modulus ($psi \bullet 10^{-5}$)
10 to 30	Sand	1625	1025	119	0.17	0.270	0.632	0.319
30 to 45	Sands, silts, Clays	2100	1100	120	0.31	0.314	0.822	0.725
45 to 75	Sands, silts, Clays	3350	1150	123	0.43	0.351	1.077	2.513
75 to 165	Silts, clays	5525	1300	124	0.47	0.453	1.331	7.572
165 to 210	Sands, silts, Clays	5900	1500	126	0.47	0.612	1.795	8.657
210 to 235	Clays	6200	1800	126	0.45	0.882	2.564	9.286
235 to 260	Clays	6550	2100	126	0.44	1.200	3.463	10.076
260 to 295	Sands, silts, clays	6550	2300	124	0.43	1.417	4.051	9.602
295 to 350	Fanglomerate	6200	2120	140	0.43	1.359	3.897	9.812
350 to 400	---	7500	2800	140	0.42	2.371	6.728	13.849
400 to 460	---	8500	3850	140	0.37	4.482	12.290	15.872

Table 2.5-12

CROSSHOLE SEISMIC SURVEY

SUMMARY OF VELOCITY VALUES AND ELASTIC MODULI, UNIT 2

Depth (ft)	Predominant Soil Types	P-wave Velocity (ft/s)	S-wave Velocity (ft/s)	Unit Weight (lb/ft^3)	Poisson's Ration	Shear Modulus (psi•10^{-5})	Young's Modulus (psi•10^{-5})	Bulk Modulus (psi•10^{-5})
10 to 35	Sands	1900	1000	119	0.31	0.257	0.672	0.585
35 to 50	Sands, silts, clays	2100	1100	123	0.31	0.321	0.843	0.743
50 to 80	Clays	5000	1150	121	0.47	0.346	1.018	6.073
80 to 105	Sands, silts, clays	5500	1200	124	0.48	0.386	1.138	7.588
105 to 150	Clays, silts	5400	1275	124	0.47	0.435	1.280	7.230
150 to 215	Sands, silts, clays	5700	1475	127	0.46	0.597	1.747	8.117
215 to 230	Clays	6000	1900	123	0.44	0.959	2.770	8.206
230 to 255	Clays	6100	2000	127	0.44	1.097	3.160	8.744
255 to 300	Clays	6500	2400	126	0.42	1.568	4.455	9.409
300 to 360	Sands, silts	6300	2100	136	0.44	1.295	3.762	9.932
360 to 390	Fanglomerates	8600	3800	140	0.38	4.367	12.043	16.543
390 to 470	Fanglomerates	9500	5750	140	0.21	9.998	24.215	13.961

Table 2.5-13

CROSSHOLE SEISMIC SURVEY

SUMMARY OF VELOCITY VALUES AND ELASTIC MODULI, UNIT 3

Depth (ft)	Predominant Soil Types	P-wave Velocity (ft/s)	S-wave Velocity (ft/s)	Unit Weight (lb/ft^3)	Poisson's Ration	Shear Modulus ($psi \bullet 10^{-5}$)	Young's Modulus ($psi \bullet 10^{-5}$)	Bulk Modulus ($psi \bullet 10^{-5}$)
10 to 20	Sands	1675	1000	121	0.22	0.261	0.639	0.385
20 to 45	Sands, silts, clays	2125	1175	127	0.28	0.379	0.969	0.734
45 to 70	Clays	3600	1250	123	0.43	0.415	1.188	2.890
70 to 80	Silts, sands	5150	1250	123	0.47	0.415	1.219	6.493
80 to 145	Clays, silts	5400	1250	124	0.47	0.418	1.232	7.252
145 to 180	Sands, silts, clays	5500	1375	126	0.47	0.514	1.509	7.547
180 to 200	Silts, sands, clays	5650	1550	128	0.46	0.664	1.939	7.940
200 to 220	Clays	5875	1675	121	0.46	0.733	2.135	8.043
220 to 245	Clays	6100	1850	127	0.45	0.939	2.721	8.956
245 to 275	Clays	6550	2100	128	0.44	1.219	3.518	10.236
275 to 300	Sands, silts	6925	2125	133	0.45	1.297	3.757	12.047
300 to 340	Andesite	7250	2150	133	0.45	1.328	3.853	13.329

laboratory testing of remolded granular soils from Units 1, 2, and 3.

Physical properties of the upper sand strata which are the source of Seismic Category I backfill material are presented and discussed in paragraph 2.5.4.2. Details and results of the testing program performed to evaluate structural backfill and formulate compaction and gradation requirements are presented in a report(163).

A test fill program(164) which complies with the PVNGS 1, 2, and 3 Safety Evaluation Report was also performed to develop compactive effort requirements. This report was submitted to and approved by the NRC.

2.5.4.6 Groundwater Conditions

A detailed description of groundwater conditions at the site is presented in subsection 2.4.13. A discussion of the effects of groundwater conditions on the loading and stability of structures and foundation materials is presented in the following paragraphs.

2.5.4.6.1 Groundwater Conditions Relative to Plant Facilities

The groundwater studies discussed in subsection 2.4.13 indicate the presence of a deep regional aquifer and a local perched water zone beneath the site. Piezometric and water table elevations for these two groundwater bodies are presented in figures 2.4-29 and 2.4-30, respectively.

The regional water levels are typically at depths in excess of 200 feet below the ground surface. Therefore, fluctuations in these water levels, will not have a significant effect on the stability of critical plant structures. The subsidence potential due to water level changes in the regional aquifer is discussed in paragraph 2.5.4.1.1.

The perched water zone, on the other hand, is in direct contact with some of the structures in Units 2 and 3 (below all structures in Unit 1). The presence of a perched groundwater condition at the site has prompted the assessment of four safety-related considerations:

A. The potential for liquefaction of granular soil within the perched zone (refer to paragraph 2.5.4.8)

B. The potential for subsidence due to dewatering or dissipation of the perched zone (refer to paragraph 2.5.4.1.1)

C. Hydrostatic loading on the walls of Category I structures in contact with the perched groundwater zone (refer to paragraphs 2.4.13.5 and 2.5.4.10.3)

D. Flotation of Category I structures (refer to paragraph 2.4.13.5)

The design water levels presented in paragraph 2.4.13.5 conservatively envelope all anticipated groundwater level fluctuations at the site.

2.5.4.6.2 Control of Groundwater Levels

Groundwater levels at the site are not expected to exceed design levels during the operational life of the plant. Therefore, special measures to control groundwater levels are not deemed necessary.

2.5.4.6.3 Dewatering During Construction

Dewatering of excavations is discussed in paragraph 2.5.4.5.2.

2.5.4.6.4 Groundwater Conditions Experienced During Construction

Refer to paragraph 2.5.4.5.2 for a discussion of groundwater conditions during construction.

2.5.4.6.5 Permeability Tests

Permeability tests are presented in appendix 2G. Results of the tests are discussed in paragraph 2.4.13.1.

2.5.4.6.6 Groundwater Fluctuations

A detailed discussion of water level fluctuations within and around the site area is presented in paragraph 2.4.13.2.

2.5.4.6.7 Periodic Monitoring of Local Wells and Piezometers

A detailed discussion of the groundwater monitoring program is presented in paragraph 2.4.13.4.

2.5.4.6.8 Direction of Groundwater Flow, Gradients, and Velocities

Direction of groundwater flow, including contour maps which indicate gradients and velocities, is discussed in paragraph 2.4.13.1.

2.5.4.7 Response of Soil and Rock to Dynamic Loading

PSAR studies for Units 1, 2, and 3 included an assessment of soil response during dynamic loading. This assessment involved the determination of low-strain amplitude, in situ shear moduli at each unit, and the evaluation of the manner in which shear moduli and material damping (expressed as a percent of critical damping) vary with the level of shearing strain. The results of these assessments were used together with earthquake information in the computer program SHAKE to perform dynamic response studies at each unit. Details of these assessments and studies are briefly summarized in the following sections. Soil-structure interaction analyses and the response of buried pipelines and earthworks during earthquake loading are described in paragraph 3.7.2.4.

2.5.4.7.1 In Situ Shear Modulus Profiles

In situ values of low-strain amplitude (less than 0.001%) shear modulus (G_{max}) were established at each unit by determining shear wave velocities from seismic crosshole tests and then using elastic theory to compute shear moduli. Figure 2.5-76 shows the resulting in situ modulus profiles for each unit. The shaded zone superimposed on the profiles

defines the limits on moduli used in dynamic response studies, as will be discussed subsequently.

All modulus values are plotted together in figure 2.5-77 to show the general similarity in modulus values at the site. The low-amplitude, in situ shear modulus profiles are similar in trend as well as in magnitude.

The low-amplitude shear moduli derived during the laboratory testing program are also shown in this figure for comparative purposes. The difference between average laboratory and field values of shear modulus will be discussed in the next paragraph.

2.5.4.7.2 Laboratory Dynamic and Cyclic Tests

Twenty-three sets of resonant column and strain-controlled cyclic triaxial tests were performed on undisturbed samples of sands, silts, and clays from the Units 1, 2, and 3 power block areas. In addition, 26 sets of tests were performed on materials from Units 1, 2, and 3 compacted to 95% relative compaction (ASTM D1557). These laboratory tests were performed to establish the relationships between shear modulus ratio (G/G_{max}) and shearing strain level and between material damping ratio and shearing strain. The manner in which the dynamic and cyclic tests were conducted, as well as individual test results, are presented in Appendix 2T of the PVNGS 1, 2, and 3 PSAR.

Data from individual tests were combined to establish composite modulus-strain and damping-strain relationships for the following six conditions:

- Undisturbed silts, very fine sands and coarser sands originating in the upper 50 feet
- Undisturbed clays originating in the 50- to 100-foot depth interval
- Undisturbed clays originating in the 100- to 150-foot depth interval
- Undisturbed clays originating at depths greater than 150 feet
- Remolded silts and sands originating in the upper 50-feet of soil profile

Composite curves for undisturbed and remolded samples are shown in figures 2.5-78 and 2.5-79, respectively.

Low amplitude values of shear modulus (G_{max}) were also obtained during the laboratory program. These moduli are compared to shear moduli obtained from seismic crosshole tests in figure 2.5-77. This comparison indicates that the laboratory moduli are typically less than the field moduli by a factor of 1.5 to 2.5. The difference in moduli is attributed to unavoidable disturbance to samples which occurs during any sampling operation. Because of this difference, composite modulus ratio plots were generally used to define the shape of the modulus-strain relationship for dynamic response studies; the magnitude

of the modulus curve was keyed to the low-amplitude shear moduli determined from the seismic crosshole tests.

2.5.4.7.3 One-Dimensional Response Studies

One-dimensional ground response studies were performed to assess the manner in which shearing stresses developed at depth for different types and levels of earthquake shaking. The shearing stress determinations served as a basis for determining the liquefaction potential of sands, silty sands, and sandy silts, as discussed in paragraph 2.5.4.8. The results of the dynamic response studies are not used as a basis for establishing the horizontal and vertical design response spectra for the SSE as discussed in paragraphs 2.5.2.6.1 and 2.5.2.6.6.

The computer program SHAKE[165] was used to perform the ground response studies. The program computes response of a system of homogeneous visco-elastic layers of infinite horizontal extent subjected to vertically traveling shear waves. The program is based on the continuous solution to the wave equation adapted for use with transient motions through the Fast Fourier Transform algorithm. The nonlinearity of the shear modulus and damping is accounted for by the use of equivalent linear soil properties using an iterative procedure to obtain values for modulus and damping compatible with the effective strains in each layer. The following assumptions are implied in the analysis:

A. The soil system extends infinitely in the horizontal direction.

B. Each layer in the system is completely defined by its value of shear modulus, critical damping ratio, density, and thickness. These values are independent of frequency.

C. The responses in the system are caused by the upward propagation of shear waves from the underlying rock formation.

D. The shear waves are given as acceleration values at equally spaced time intervals. Cyclic repetition of the acceleration time-history is implied in the solution.

E. The strain dependence of modulus and damping is accounted for by an equivalent linear procedure based on an average effective strain level computed for each layer.

These SHAKE analyses were conducted with five accelerograms. Four of the accelerograms are actual recordings of the 1952 Kern County earthquake scaled to be representative of a magnitude 8.0 event at a distance of 72 miles. These records include the Santa Barbara (S48E) record with a peak acceleration of 0.128g, the Hollywood PE Lot (S00W) record with a peak acceleration of 0.10g, the Hollywood Basement (S00W) record with a peak acceleration of 0.093g, and the Pasadena (S50W) record with a peak acceleration of 0.090g. The fifth accelerogram was the Bechtel record scaled to 0.20g. The Bechtel accelerogram is an artificial record with a spectra which conforms closely to the shape of the standard NRC

spectra. The basis for selecting these records is given in paragraph 2.5.2.6.

The ground response studies included an assessment of the influence of soil-parameter variation. This assessment was accomplished by varying the low-amplitude shear modulus to which the shear modulus ratios (presented in paragraph 2.5.4.7.2) were keyed. The modulus variations included:

- Average low-amplitude in situ moduli
- Average in situ moduli plus and minus 50%
- Average laboratory moduli.

Variations were introduced to assess the possible effects on ground response caused by differences in values of shear modulus. Figure 2.5-76 illustrates the range in modulus values used in dynamic response studies as compared to low-amplitude moduli determined during seismic crosshole tests. Additional details about these studies are discussed in Appendix 2T of the PVNGS 1, 2, and 3 PSAR, and appendix 2A, response to Question 2A.8.

Typical values of maximum shearing stress determined during the ground response studies are presented in figure 2.5-80. These results show that the level of maximum shearing stress varied with earthquake shaking level as well as in situ values of modulus. Shearing stresses for average in situ soil moduli and the Bechtel earthquake record were subsequently used as a basis for evaluating liquefaction potential.

2.5.4.8 Liquefaction Potential

The potential for liquefaction of saturated, cohesionless soils underlying the three units was evaluated by comparing liquefaction strengths obtained from field and laboratory investigations to shearing stresses predicted on the basis of simplified and one-dimensional wave propagation methods. Two different methods were used to predict liquefaction strengths: one based on blowcounts obtained during a field standard penetration testing program, the other based on the results of laboratory testing. The following subsections present a review of soil conditions at the units relevant to a liquefaction discussion, the methodology used during the investigations, and the results of the study. Additional details about liquefaction studies are presented in Appendix 2T of the PVNGS 1, 2, and 3 PSAR.

2.5.4.8.1 Site Conditions

The PVNGS site essentially consists of a relatively thin veneer of dense cohesionless soils, 30 to 60 feet in thickness, underlain by about 250 feet of stiff to hard clays. Cohesionless soils include layers and lenses of sands with some gravels, silty sands, clayey sands, and silts. A third general material type, granular backfill, will be placed beneath and adjacent to some Category I structures. Backfill materials are primarily on site sands with up to 30% fines, compacted to 95% of maximum dry density (determined in accordance with ASTM D1557). Maximum thickness of backfill varies from zero in the free-field to nearly 65 feet around the auxiliary building.

A perched water level presently (1979) occurs about 40 to 70 feet below the ground surface. This water level is attributed to irrigation water perched on top of deeper clay layers. The regional water level is approximately 200 feet below the ground surface. As irrigation has been discontinued in proximity to the site, the perched water level has been receding in recent years (paragraph 2.4.13.2.2).

Although the water level is presently receding or is too deep to consider from a liquefaction standpoint (i.e., within the clay layer), a potential exists for increases in water level due to seepage from evaporation ponds and the water storage reservoir (paragraph 2.4.13.2.3). Analyses of water seepage from these sources indicate that the maximum predicted height of rise in water will be well below design water level, which is at a depth of 30 feet below ground surface. For conservatism, design levels have been specified as a basis for liquefaction analyses presented herein.

Considering the presence of cohesionless soils and the potential occurrence of water within 30 feet of the ground surface, natural and backfill soils located between the depths of 30 and 70 feet are identified as being potentially susceptible to liquefaction during earthquake-induced ground shaking. Soils below the depth of 70 feet are generally stiff to hard over-consolidated clays; and hence, are not of interest in terms of liquefaction. It is worthwhile noting at this point that the amount of potentially liquefiable soils (i.e., cohesionless soils below the design water elevation) beneath Category I structures is generally limited. The

containment and auxiliary buildings are supported directly on hard nonliquefiable soils. Most of the other Category I structures (main steam support structure, control building, fuel building, and refueling water tank) are primarily supported on granular backfill, the maximum thickness of which is 40 feet or less. Only the spray ponds, diesel generator buildings, and condensate tanks are primarily supported on natural sands. The maximum thickness of these potentially liquefiable materials is typically less than 30 feet.

2.5.4.8.2 Blowcount Analyses

The blowcount analysis procedure suggested by Seed, et al[166] was used to assess liquefaction potential of in situ sands. This procedure involved adjusting blowcounts from the standard penetration test to an equivalent overburden pressure of 2 kips per square foot. The adjusted blowcounts were then used to determine the liquefaction strength of the material on the basis of a limiting plot between liquefaction strength and adjusted blowcount, as developed by Seed, et al[166]. Liquefaction strengths were then compared to shearing stresses induced by earthquake ground shaking to determine liquefaction potential.

To be consistent with the methodology used to develop the relationship between liquefaction strength and blowcounts, shearing stresses were computed on the basis of the following equation developed by Seed and Idriss[167]:

$$\tau_{avg} = 0.65\ \gamma_t H \frac{a_{max}}{g}\ r_d$$

where γ_t is the total unit weight of the soil, H is the depth below the ground surface, a_{max} is the peak acceleration at the ground surface, g is the acceleration due to gravity, and r_d is a soil deformability factor. Figure 2.5-81 presents curves used in this methodology to compute normalized blowcount values, liquefaction strengths, and soil deformability.

Blowcount analyses were performed for each unit using average lower bound blowcount values from the sites, existing and design water level elevations, and a SSE maximum ground surface acceleration of 0.2g. The effects of possible low blowcount zones were evaluated by analyzing liquefaction potential for a lower bound blowcount profile, as determined from mean-minus-one-standard-deviation blowcount values.

The results of the blowcount analyses in terms of the factors of safety against liquefaction for design water table elevations (30 feet below the ground surface) are presented in Table 2.5-14. For lower bound blowcount analyses, the minimum factor of safety was 2.0 and occurred at Unit 1. It is worthwhile noting that the water level at the units is predicted to be lower than the design elevation during the design life. As shown in figure 2.5-82, the factor of safety

increases as the design water table elevation drops; hence the actual factors of safety will always be greater than those used for design. It is concluded from these investigations that the factor of safety against liquefaction will be adequate for the SSE.

2.5.4.8.3 Dynamic Response Studies

The dynamic response study involved performing cyclic liquefaction strength tests on undisturbed samples of sands and silts and compacted samples of granular backfill. Liquefaction strengths determined from these laboratory tests were compared to shearing stresses predicted on the basis of one-dimensional computer simulation of site response during earthquake loading to establish liquefaction potential. The one-dimensional computer simulation is described in paragraph 2.5.4.7.4.

Forty-five controlled-stress, cyclic triaxial tests were performed on undisturbed samples obtained from the three units to define the strength of in situ soils; 12 tests were performed on granular backfill compacted to 95% of maximum dry density. Undisturbed samples were generally obtained by Pitcher-tube sampling methods; however, undisturbed block samples were also obtained. Details about the laboratory programs, including individual test results, are presented in Appendix 2T of the PVNGS 1, 2, and 3 PSAR.

Composite plots of liquefaction strengths for granular backfill and for undisturbed sands are shown in figure 2.5-83. Liquefaction strengths in these plots were defined on the basis of either initial liquefaction or 5% peak

Table 2.5-14

SUMMARY OF FACTORS OF SAFETY AGAINST LIQUEFACTION

BY BLOWCOUNT AND LABORATORY ANALYSES

Unit	Design Groundwater Elevation (ft)	Blowcount Analyses			Laboratory Analyses		
		Depth of Minimum FS (ft)	Minimum Factor of Safety		Depth of Minimum FS (ft)	Minimum Factor of Safety	
			Average[a]	Bound[b]		C_r[c] = 0.57	C_r = 0.70
1	927	47	2.9	2.0	35 to 43	1.2	NA
2	924	50	3.4	2.1	40 to 50	1.2	NA[d]
3	921	32	3.6	2.6	42 to 45	1.1	NA
Back-fill-Unit 2	924	NA	NA	NA	40 to 50	1.6	NA
Back-fill-Unit 3	921	NA	NA	NA	35 to 45	1.6	NA

a. Average blowcount values

b. Lower bound blowcount values

c. C_r = laboratory to field correction factor

d. NA = not applicable

to peak strain, whichever came first, and were adjusted to field conditions before assessing liquefaction potential.

This adjustment involved multiplying the laboratory strength curve by 0.57. The resulting field strength curves are shown in figure 2.5-84.

Liquefaction potential was determined by comparing the earthquake induced shearing stress to the adjusted liquefaction strength of the soil. The maximum levels of shearing stress occurred under the SSE shaking level (0.2g) using the Bechtel earthquake. Liquefaction strengths were determined at 15 to 20 cycles of loading. For these studies, a cycle counting procedure suggested by Lee and Chan[168] was used to determine the number of equivalent cycles of loading. Factors of safety against liquefaction, as determined during dynamic response studies, are tabulated in table 2.5-14 for design water table elevations. From table 2.5-14 it can be seen that minimum factors of safety are greater than 1.1 even for conservative values of liquefaction strength and design earthquake. Granular backfill materials exhibited nearly 50% more resistance to liquefaction than natural soils. Figure 2.5-85 shows that the factors of safety by this approach will be even higher when the water table elevation is deeper than the design elevation. It is concluded from this analysis that the potential for liquefaction of cohesionless soils is low.

2.5.4.8.4 Summary of Liquefaction Potential

Liquefaction studies, as discussed in the preceding two paragraphs and as summarized in table 2.5-14, show that:

A. The minimum factors of safety for average blowcount values are equal to or greater than 2.0 at each unit. These factors of safety will represent lower bound values because:

   1. The curve used as a basis for determining liquefaction strengths from blowcount values is a lower bound curve enveloping all recorded data

   2. Analyses were based on design water elevations which are higher than predicted water elevations

B. The minimum factors of safety from dynamic response (laboratory) methods are equal to or greater than 1.1 for undisturbed soils and 1.6 for compacted soils. Values for undisturbed soils will be very conservative because:

   1. In situ strengths will be higher than laboratory strengths because of the unavoidable disturbance which occurs during undisturbed sampling of dense granular soils(169)(170)

   2. Design water elevations exceed those predicted

The above factors of safety are also based on a very conservative SSE (0.2g at the ground surface). More credible levels of earthquake acceleration will result in appreciably lower shearing stresses which will increase the factors of

safety against liquefaction. In summary, all evidence indicates that the cohesionless soils at PVNGS will not undergo liquefaction during the design life of the plant. See also Appendix 2A, Question 2A.8.

2.5.4.9 Earthquake Design Basis

A detailed discussion of the earthquake design basis is presented in paragraphs 2.5.2.6 and 2.5.2.7.

2.5.4.10 Static Stability

Seismic Category I structures were analyzed for stability under anticipated loading conditions. The analyses presented in the following paragraphs include evaluations of bearing capacity, foundation heave and settlement, and lateral earth pressure. In view of the similar subsurface conditions displayed in the geologic profiles (figures 2.5-56 through 2.5-58) for the three units, stability analyses were based on conservative soil parameters representative of all three units. The plant layout and foundation loading information are presented in figure 2.5-86. All Seismic Category I structures utilize mat-type foundations.

2.5.4.10.1 Bearing Capacity

Seismic Category I structure foundations were analyzed for stability against general shear failure under anticipated static and dynamic loading conditions. The effects of confinement due to adjacent structure(s) were conservatively neglected in the analysis.

2.5.4.10.1.1 Soil Model. A two-layer soil model was used for the bearing capacity analyses. The first layer, extending from the ground surface to a depth of 50 feet, consists of native or compacted backfill sands. The second layer, underlying the sands, consists of native clays. Two Category I structures, the containment and auxiliary buildings, are founded directly on the clays. The remaining structures are founded on the sands at depths ranging from 2 to 30 feet below the ground surface. The groundwater level was conservatively assumed to be at a depth of 30 feet below the ground surface which is the design level. Actual groundwater levels are expected to remain well below the design level. The soil parameters used for the analyses are as follows:

	Sand Layer	Clay Layer
Friction angle, degrees	36	0
Cohesion, kips per square foot	0	5.0 (static) 5.5 (dynamic)
Total Unit Weight, pounds per cubic foot	120	N/A
Buoyant Unit Weight, pounds per cubic foot	70	60

The shear strength parameters listed above were conservatively derived from laboratory test results summarized in figure 2.5-64. The undrained shear strength of the clays was increased by 10% for the dynamic analyses to account for the effects of the rapid strain rates induced during dynamic loading. Research data[171-174] indicate that for typical

earthquake loading rates on clays of the type found at PVNGS, at equivalent water contents and under similar stresses and stress histories, the increase in strength over that measured in the standard laboratory static triaxial test will range from about 50 to 150%. Considering that this strength increase does not account for the mass action (inertial effects) of soil under rapid loading, it is seen that the 10% strength increase used for the analyses is very conservative.

2.5.4.10.1.2 Method of Analysis. State-of-the-art methods outlined by Vesic' in the Foundation Engineering Handbook[175] were used to evaluate bearing capacities under static and dynamic loading conditions. Static loads included the dead weight of the structures and ordinary live loads. Dynamic loads additionally included the effects of the SSE as outlined in paragraph 3.7.2.1. The analyses were based on the Buisman-Terzaghi equation modified for eccentric and inclined loading[175]. In its general form the equation is:

$$q_o = \frac{Q_o}{B'L'} = CN_c\zeta_c\zeta_{ci} + qN_q\zeta_q\zeta_{qi} + 1/2_\gamma BN_\gamma\zeta_\gamma\zeta_\gamma i$$

where:

q_o = ultimate bearing capacity

Q_o = ultimate vertical load

B', L' = effective foundation dimensions under eccentric loading; for zero eccentricity, the actual footing dimensions B and L are used (B is the smaller of the two)

c = shear strength intercept (cohesion)

q = effective overburden stress

γ = effective density of soil below foundation level

N_c, N_q, N_γ = bearing capacity factor

$\zeta_c, \zeta_q, \zeta_\gamma$ = foundation shape factors

$\zeta_{ci}, \zeta_{qi}, \zeta_{\gamma}i$ = load inclination factors

For structures founded in the upper sand layer, the bearing capacity was calculated for both a two-layer system (sand over clay) and for a single-layer system (sand only). The lower of the two values was selected as the bearing capacity of the structure in question. The two-layer analysis was based on the following relationship for a dense sand overlying clay:

$$q_o = q''_o \exp\left\{ 0.67 \left[1 + (B'/L') \right] (H/B') \right\}$$

where:

q_o = ultimate bearing capacity

B', L' = effective footing dimensions under eccentric loading. For zero eccentricity, the actual footing dimensions B and L are used (B is the smaller of the two)

H = distance from base of footing to top of underlying clay layer

q''_o = bearing capacity of a fictitious footing of the same size, shape, and lateral loading as

the actual footing, but resting on the clay; q''_o is computed by the modified Buisman-Terzagh: equation presented previously

The effects of the water level were also incorporated in the analysis by defining the unit weight, γ, used in the modified Buisman-Terzaghi equation as follows:

$$\gamma = \gamma' + (z_w / B')(\gamma_m - \gamma')$$

where:

γ' = buoyant unit weight of soil below the water level

γ_m = total (moist) unit weight of soil above the water level

B' = effective width of foundation, and

z_w = distance between the bottom of foundation and water level ($0 < z_w < B'$)

If the base of the foundation is at or below the water surface, γ is equal to γ'. If the base of the foundation is at least one effective foundation width above the water level, γ can be equated to γ_m.

2.5.4.10.1.3 Results. The results of static and dynamic bearing capacity analyses together with structural data used for the analyses are summarized in tables 2.5-15 and 2.5-16, respectively. The computed factors of safety against a bearing capacity failure range between 4.5 and 32.1 for static loading conditions, and between 2.0 and 13.5 for short-

duration dynamic overload conditions. These factors of safety are considered adequate for the types of structures analyzed and meet the design criteria outlined in paragraph 2.5.4.11.

2.5.4.10.2 Heave/Settlement Analysis

A detailed analysis was performed to calculate heave and settlement at various points beneath the power block structures. The analysis incorporated the effects of the magnitude and complex timing of the application and removal of loads imposed by excavated soil, backfill, and a large number of structures. Both time-rate of settlement effects caused by consolidation of saturated fine-grained soils and immediate elastic settlements were evaluated. Details concerning the assumptions and refinements applied to the revised analysis are presented in Appendix 2AA of the PVNGS 1, 2, and 3 PSAR.

Preliminary analyses for Units 1, 2, and 3 indicated that the soil parameters obtained from the laboratory testing on samples from Unit 2 yielded the largest computed settlements. Settlements were calculated using Unit 2 soil parameters and are presented as being conservative estimates for all three units.

Table 2.5-15

STATIC BEARING CAPACITY OF CATEGORY I STRUCTURES

Structure	Average Static Design Load $q_s (k/ft^2)$	Ultimate Bearing Capacity $q_o (k/ft^2)$	Factor of Safety (q_o/q_s)
Containment building	7.9	35.7	4.5
Auxiliary building (deep section)	6.2	34.9	5.6
Main steam support structure	7.1	64.8	9.1
Control building	3.3	45.3	13.7
Fuel building	5.3	54.9	10.4
Diesel generator building	3.1	79.5	25.6
Refueling water tank	4.4	90.4	20.5
Condensate storage tank	3.5	112.4	32.1

Table 2.5-16

DYNAMIC BEARING CAPACITY OF CATEGORY I STRUCTURES[a]

Structure	Equivalent Uniform Vertical Stress q_d (k/ft^2)	Ultimate Bearing Capacity q_o (k/ft^2)	Factor of Safety (q_o/q_d)
Containment building	16.1	32.2	2.0
Auxiliary building (deep section)	10.3	25.8	2.5
Main steam support structure	25.3	60.6	2.4
Control building	9.8	39.8	4.1
Fuel building	19.1	50.3	2.6
Diesel generator building	5.6	75.5	13.5
Refueling water tank	13.2	58.7	4.4
Condensate storage tank[b]	13.2	30.2	2.3

a. Based upon maximum dynamic loads derived from analyses described in section 3.7.

b. Condensate storage tank loads were conservatively chosen to be equal to the dynamic design load for the refueling water tank. Actual loads will be less.

Results of the heave/settlement analysis are presented in figures 2.5-87, 2.5-88, and 2.5-89. These figures present predicted amounts of heave, total recompression settlements, and post construction settlements, respectively. In summary:

A. Heave estimates range to a maximum of approximately 7 inches near the center of the deepest portion of the excavation, underlying the auxiliary building.

B. Estimates of total recompression settlements range from approximately 0.2 inch at the corners of the essential spray ponds to about 7 inches under the containment and auxiliary buildings.

C. Estimates of post-construction total settlements are less than 1-1/2 inches for any structure, and less than 1/2 inch for most structures. Calculated post-construction differential settlements are less than 0.1 inch.

D. Settlements are expected to occur soon after load application and to be well within tolerable limits for the structures involved.

Heave at the base of the powerblock excavations at Units 1, 2, and 3 has been monitored by extensometer installations and by optical surveying means. Results of the heave monitoring program are presented in paragraph 2.5.4.13. The heave measured by both extensometer installations and optical surveying means is on the order of one-third of the magnitude predicted by the heave/settlement analysis.

The response of the site to load changes was, as anticipated, quite rapid due to the overconsolidated nature of the foundation soils. These observations confirm the conservatism of the heave and settlement estimates and support the conclusion that post-construction settlements should be very small and well within tolerable limits.

2.5.4.10.3 Lateral Earth Pressures

Static active and passive horizontal earth pressures have been determined for both in situ soils and backfill. For the analysis of active and passive pressures, a conservative, simplifying choice of $\varnothing = 36°$, $C = 0$, and $\gamma_t = 126$ pounds per cubic foot has been used. Active earth pressures are developed with relatively small wall movements while theoretical passive pressures require much larger wall movements before development. For this reason, the passive lateral pressures recommended for design have been reduced by one-half from Rankine theoretical values. Passive pressures computed based on Rankine theory are very conservative because friction between the soil and walls, that would increase the passive resistance, is neglected. For compacted backfill, the at-rest lateral earth pressure has been calculated assuming an earth pressure coefficient of $K_o = 0.7$ and average unit weight $\gamma^t = 129$ pounds per cubic foot. A summary of recommended static lateral design earth pressure parameters is presented in table 2.5-17.

Table 2.5-17
SUMMARY OF DESIGN LATERAL EARTH PRESSURE PARAMETERS

Case	K	Equivalent Fluid Pressure[a]	
		Above Water Table	Below Water Table
Active	0.26	33	15
Passive	3.85	240	122
Backfill	0.7	80	46

a. Expressed as pounds per square foot per foot of wall height, for horizontal backfill.

2.5.4.11 Design Criteria

Foundation stability and settlement analyses were performed for each structure in the three units. In addition, the overall liquefaction potential at each unit was analyzed. A description of the settlement and bearing capacity analyses are presented in paragraph 2.5.4.10. The liquefaction analysis is presented in paragraph 2.5.4.8.

The following geotechnical design criteria, based on state-of-the-art engineering practice and structural constraints, were followed:

- Bearing Capacity — Factor of safety = 3 for static loading

  Factor of safety = 2 for dynamic loading

• Total Settlement	Post-construction settlements less than 1-1/2 inches for each structure (survey accuracy ± 1/8 inch)
• Differential Settlement	Post-construction differential settlements less than 1/2 inch at a common point between any two adjacent structures (survey accuracy ± 1/8 inch)

2.5.4.12 Techniques to Improve Subsurface Conditions

Soils and underlying rock as described in paragraph 2.5.4.2 are adequate for supporting Category I structures. Remedial or special foundation treatment will not be necessary except for soils at very shallow depths (less than 4 feet) which have been disturbed by agricultural activity. Where these shallow soils are encountered below Category I structures, they will be excavated and replaced with structural backfill compacted as specified in paragraph 2.5.4.5.2.

2.5.4.13 Subsurface Instrumentation

An extensive instrumentation program is being implemented at PVNGS to monitor foundation response and ground movement during excavation, construction, and throughout the life of the plant.

This data is being collected and analyzed primarily to establish the degree of conservatism that exists in the

settlement analysis, which impacts structural and critical piping connection designs.

To compare actual post-construction settlements with the criteria given above, a program of settlement monitoring has been instituted. The locations of settlement markers are shown in engineering drawings 01, 02, 03-C-OOA-030, and the frequency of readings is shown in table 2.5-19. All markers will be surveyed; however, particular attention will be given to those pairs of settlement markers which would indicate differential settlements between structures in the vicinity of critical connections, and those markers which would indicate deformation or tilt within a critical structure (table 2.5-18).

Table 2.5-18

CRITICAL CONNECTION/STRUCTURE SETTLEMENT MARKERS

Deformation	Critical Connection Location/Structure	Settlement Marker Number
Differential settlement	Between auxiliary and control building	21, 22, 36, 37
Differential settlement	Between containment and MSSS	19, 20
Differential settlement	Between containment and fuel building	24, 28, 29
Settlement	Auxiliary building (south side)	21, 22, 23
Tilt	Containment building	20, 24, 25

If actual post-construction settlement reaches 90% of the design criteria values given above, then the frequency of

monitoring for those markers will be increased from that indicated in table 2.5-19 to an interval of 1 month. If no significant settlement occurs over a 3-month period, then the frequency of monitoring at those markers will be quarterly for a year, and then return to the normal frequency in table 2.5-19.

If settlements could impose unacceptable additional stresses within structures or on critical connections, then a remedial action plan would be formulated. Remedial action would necessarily be a function of the nature and location of the problem.

2.5.4.13.1 Instrumentation

The heave, settlement, and subsidence instrumentation consist of four component systems: multiposition extensometers, mechanical rebound anchors, settlement markers, and subsidence network benchmarks. Table 2.5-19 details the type of response being monitored and the frequency of monitoring schedule for each system.

A detailed description of the installation and monitoring of each system is presented in a report submitted previously to the NRC[176]. A brief description of each system follows:

A. Multiposition extensometers (MPEs) with electronic readout capability are utilized to monitor both heave resulting from excavation and recompression settlements resulting from structural loading. As of March 1979, extensometers were installed in six

locations, three near the containment centers of each of Units 1, 2, and 3, two more at selected points in Unit 1, and an additional backup sensor (MPE-6) near the containment center in Unit 3. All but one of the six existing MPE installations monitor relative ground movement between each of three sensors anchored to bedrock. The exception is MPE-6 which contains only one sensor, installed as a backup for a damaged sensor in the adjacent MPE-5 installation. In each extensometer installation the top sensor is anchored at a depth a few feet below the estimated bottom of excavation, in order to monitor the full amount of heave and recompression settlement. Instrument locations are shown in figure 2.5-90.

B. Mechanical rebound anchors (MRAs) are used to monitor heave by optical survey methods. Each MRA installation consists of a 3-foot long stainless steel pipe, embedded in soil at the bottom of a cased borehole. The top of the pin is typically located 2.5 feet below the bottom of excavation and serves as a reference point for elevation measurements. Calibrated aluminum rods are used to reach the pin from the ground surface. As of March 1979, mechanical rebound anchors had been installed at six locations in Units 1, 2, and 3, as shown in figure 2.5-90.

C. Settlement markers are pins installed in structural members of critical structures to monitor settlements by optical surveying methods. Fifty-eight markers are

installed in each powerblock in Units 1 and 2; 56 markers are installed in the powerblock in Unit 3 at locations/elevations shown in engineering drawings 01, 02, 03-C-OOA-030.

D. Subsidence monitoring benchmarks have been established to monitor regional subsidence at the site relative to two benchmarks on rock outcrops. The locations of the benchmarks used are shown in figure 2.5-91.

2.5.4.13.2 Results

As of March 1979, power block excavations for Units 1, 2, and 3 had been completed. Structural construction and backfill placement was underway in Units 1 and 2. Results of excavation heave monitoring at Units 1, 2, and 3 and subsidence onitoring over the entire site are discussed in the following paragraphs.

2.5.4.13.2.1 Excavation Heave. Results of heave/rebound monitoring in the powerblock excavations for Units 1, 2, and 3 were presented and discussed in detail in Appendix 2AB of the PVNGS 1, 2, and 3 PSAR. Briefly, observed maximum heave ranged from 1.8 inches in Unit 1 to 2.4 inches in Unit 3. The foundation soils responded rapidly to overburden removal with the full amount of heave measured within 2 months after completion of the excavation. On the average, observed heave in various parts of the excavations was on the order of one-third of the values predicted by the heave/settlement analysis (see figure 2.5-92).

Table 2.5-19

SUBSURFACE INSTRUMENTATION DETAILS

Instrumentation System Name	Response Being Monitored: Heave Resulting From Excavation	Response Being Monitored: Recompression Due to Structural and Backfill Loading	Response Being Monitored: Regional Subsidence	Minimum Specified Monitoring Frequency-Time Between Readings[a]
Multiple position extensometers (MPEs)	X	X	X	1) Pre-excavation, excavation, pouring of overlying foundations -1 week 2) The following 18 months -1 week 3) Until end of construction -3 months 4) For a 3-year period following end of construction -6 months 5) After last 6-month reading -5 years
Mechanical rebound anchors (MRAs)	X			1) Pre-excavation, excavation -1 week
Settlement markers		X	X	1) 18 months following first concrete placement for a given structure -1 month 2) Until end of construction of the last major power block structure -3 months 3) For a 3-year period following end of construction -6 months 4) After last 6-month reading -5 years
Subsidence monitoring network			X	1) During construction -1 year 2) After end of construction -5 years

a. Settlement monitoring will be increased to 1-month intervals at markers showing greater than 90% of design post-construction settlement criteria. Refer to the discussion in paragraph 2.5.4.13 for the increase in time interval if no significant settlement occurs over a 3-month period.

The difference between predicted and observed values of heave is attributed to conservative compressibility parameters and groundwater assumptions included in the predictive analyses. Based on the results of the heave monitoring data, it is concluded that:

A. The conservatism of the heave/settlement analysis is verified.

B. Recompression settlements can be expected to take place rapidly after load application and be lower in magnitude than the predicted values.

C. Post-construction settlements can be expected to be small and well within tolerable limits.

2.5.4.13.2.2 Subsidence. Movement of the survey benchmarks within the subsidence monitoring network, relative to benchmarks established on bedrock, have been measured to within an accuracy of approximately ±0.25 inch. Results of the subsidence network monitoring program are presented in figure 2.5-93. The benchmark monitoring data exhibits random scatter within the accuracy of the survey and there has been no measurable subsidence over the period monitored.

2.5.4.14 Construction Notes

No construction problems that would adversely affect the safety of the plant facilities have been encountered.

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2.5.5 STABILITY OF SLOPES

There will be no natural or man-made slopes at the site, the failure of which could adversely affect the safe operation of the plant. Natural slopes are sufficiently distant (at least 3/4 mile) from the nearest Category I structures; therefore, their stability need not be considered. The natural ground surface in the vicinity of the plant is essentially flat with ground surface gradients on the order of 1% or less.

2.5.6 EMBANKMENTS AND DAMS

There will be no Seismic Category I embankments or dams at the site.

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APPENDIX 2A

RESPONSES TO NRC REQUESTS FOR INFORMATION

APPENDIX 2A

CONTENTS

TABLES

FIGURES

APPENDIX 2A

QUESTION 2A.1 (NRC comment on section 2.5.2.7) (6/18/80) (2.5.2.7)

No probability for operating basis earthquake

RESPONSE: The response is given in amended paragraph 2.5.2.7.

QUESTION 2A.2 (NRC Question 451.2)

Appendix E to 10CFR Part 50 outlines requirements for Emergency Planning and Preparedness. NUREG-0737 and NUREG-0654 provide further guidance on the requirements which include an upgraded meteorological measurements program. Provide a description of your upgraded program to meet these requirements. Include details about any new instrumentation to be installed, the atmospheric transport and diffusion model used in the dose assessment methodology, and data availability to emergency response organizations.

RESPONSE: Refer to amended section 2.3 and section 18.III.

QUESTION 2A.3 (NRC Question 230.1)

Include table similar to table 2.5-2, listing earthquakes in Seismic Zones C and D. Identify and discuss all significant earthquake activity in Seismic Zones B, C, and D, which has occurred since Supplement No. 2 to the Safety Evaluation Reports for Units 1, 2, and 3, published in 1976.

RESPONSE: Tables 2.5-7 and 2.5-8 are provided which list all earthquakes in Seismic Zones C and D. The tables are compiled from the most recent NOAA files available for the period ending 1980 and from local sources. An updated

(through mid-1981) epicenter map and list has been finalized by S. Dubois as part of an NRC funded program. Tables and maps have been updated and are provided in amended section 2.5.

See amended paragraph 2.5.2.3.3.

QUESTION 2A.4 (NRC Question 230.2)

Discuss the following recent studies and their significance to the Palo Verde site:

a. Brumbaugh, D., 1980, Analysis of the Williams Arizona Earthquake of November 4, 1971, Bull. Seism. Soc. Amer., v. 70, 885 - 891.

b. Dubois, S., 1980, Historical Seismicity and Late Cenozoic Faulting in Arizona, Technical Progress Report, Arizona Bureau of Geology and Mineral Technology.

c. Racine, D. et al, 1979, A Seismicity Study of the Southwest Region of the United States, 1 December 1961 to 1 January 1964, Teledyne Geotech, Alexandria, Virginia, AL-79-5.

d. Dubois, S. and A. Smith, 1980, the 1887 Earthquake in San Bernardino Valley, Sonora: Historic Accounts and Intensity Patterns in Arizona, Special Paper No. 3, State of Arizona, Bureau of Geology and Mineral Technology, The University of Arizona, 112 pages.

e. Dubois, S. and M. Sbar, 1981, the 1887 Earthquake in Sonora: Analysis of Regional Ground Shaking and Ground Failure, Proceedings of Conference XIII, Evaluation of Regional Seismic Hazards and Risk, Santa Fe, New Mexico,

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f. Pierce H., 1979, Subsidence - Fissures and Faults in Arizona, Arizona Bureau of Geology and Mineral Technology, Fieldnotes, v. 9, no. 2, 1 - 6.

g. Dubois, S., 1979, Sonic Booms, Arizona Bureau of Geology and Mineral Technology, Fieldnotes, v. 9, no. 2, 4 - 5.

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i. Eberhard - Phillips, et al, 1981, Analysis of the 4 February 1976 Chino Valley Arizona Earthquake, Bull. Seism. Soc. Amer., v. 71, no. 3, 787 - 801.

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k. Holzer, T., Davis, S., and B. Lofgren, 1979, Faulting caused by Groundwater Extraction in Southcentral Arizona, J. Geophys. Res., v. 84, 603 - 612.

l. Holzer, T., 1979, Elastic Expansion of the Lithosphere Caused by Groundwater Depletion, J. Geophys. Res., v. 84, 4689 - 4698.

m. Sumner, J., 1976, Earthquakes in Arizona, Fieldnotes, Arizona Bureau of Mines, v. 6, 1 - 5.

n. Raymond, R., Cordy, G. and G. Tuttle, 1980, Is There a Casa Grande Bulge and Will It Cause Earthquakes in Arizona? Fieldnotes, Arizona Bureau of Geology and Mineral Technology, v. 10, no. 3, 10 - 11.

o. Holzer, T., 1981, Ups and Downs, A Reply to "Is There a Casa Grande Bulge and Will It Cause Earthquakes in Arizona?", Fieldnotes, Arizona Bureau of Geology and Mineral Technology, v. 11, no. 1.

RESPONSE:

a. Brumbaugh, D., 1980:

The Williams earthquake was a 3.7 magnitude event occurring along the edge of the Colorado Plateau about 10 miles SW of Williams, Arizona. The earthquake described in this study is significant mainly because the collection of station data were adequate for a focal mechanism solution, an unusual situation for Arizona.

Brumbaugh's analysis primarily consisted of calculating a new location and focal mechanism solution. Locations for the shock are: ISC, 35.13°N, 112.22°W; NEIS, 35.2°N, 112.2°N, NEIS revised, 25.16°N, 112.25°W, depth restrained to 5 kilometers, M_l = 3.7 from ERL. The new location does not differ significantly (less than 0.05 degrees in any direction) from that shown on figure 2.5-25 of the FSAR. The focal mechanism, based on 16 first-motion readings, is consistent with reverse faulting along a NW trending fault. There are no faults in the vicinity of the epicenter with which the earthquake could unambiguously be associated.

Neither the Williams earthquake nor Brumbaugh's analysis has any direct bearing on the PVNGS. The earthquake was within the belt of small-magnitude earthquakes trending NW-SE across the state and designated as Seismic Zone C

in the FSAR (figure 2.5-25). The orientation of the focal mechanism solution is compatible with the preferred NW-SE orientation of major faults in the region, but the reverse faulting mechanism may be anomalous. Geologic data (nature and orientation of faults and volcanic fields) suggest that this region is under tensional tectonic regime but the axis of extension is ambiguous. Extension appears to be oblique to the major faults with E-W to WNW-ESE orientations being most favorable (Zoback and Zoback, 1980; Schell and Wilson, 1981). Reverse faulting along minor fractures is not completely incompatible with this type of oblique extension. However, the focal-mechanism solution is based on too little data to justify revision of existing tectonic hypotheses and therefore results of such a revision have no significance with respect to PVNGS.

b. Dubois, S., 1981, Historical Seismicity in Arizona Final Report; Arizona Bureau of Geology and Mineral Technology, 845 N. Park Avenue, Tucson, Arizona 85719; 199 pp. Partially funded by USGS Contract No. 14-18-0001-18396 and NRC Contract No. 04-79-212.[a]

This report represents a comprehensive assessment of historical seismicity in Arizona. A comparison of information in the Dubois (1981) report with the PSAR indicates the latest work both confirms and refines

a. Final report of Dubois 1980 study referenced in NRC Question.

the data presented in the FSAR relating to Arizona seismicity. The major items affected are as follows:

- The 1887 Sonora Earthquake has been assigned a magnitude of 7.25 (moment magnitude) whereas a conservative estimate of magnitude 8.0 was assigned to the event in the FSAR.

- The seismic zones shown on Dubois (1981), based solely on historical seismicity, are clearly less conservative with respect to SGE analysis than the Seismic Zonation model presented in FSAR figure 2.5-25. Dubois (1981) shows separate zones of seismicity in the northwest and southeast corners of the state. The FSAR shows Zone C as continuous across the state from northwest to southeast, and the zone is, therefore, clearly more conservative for the risk evaluation. From a scientific viewpoint, a new analysis with the benefit of the upgraded data base might lead to a modification of the zone model presented in the FSAR. However, the FSAR results are conservative with respect to any proposed changes in the seismic zonation.

- If the seismic zones depicted by Dubois (1981) were used to develop the SSE, the SSE (an earthquake similar to the 1887 Sonora earthquake) would be located farther away from PVNGS than the 72 miles now used in the FSAR. Seismic analysis using a greater epicentral distance and a lesser magnitude of 7.25 (Dubois, 1981), would predict significantly

less SSE ground motion than the 0.2g used for seismic design at PVNGS.

- Earthquake epicenters have been redefined and many unverified events have been eliminated. Other seismologic data, such as isoseismal maps, have been added or updated as a result of the study by Dubois.

In summary, this recent assessment of historical seismicity in Arizona strongly suggests that the approach used to define the regional seismicity and to develop the seismic design criteria for PVNGS was, in fact, conservative.

c. Racine, D., et al, 1979:

The microseismicity study by Racine and others identify a number of earthquake epicenters located in the Transition Zone and Colorado. Of particular importance are three clusters of low-magnitude events: one, a cluster of 72 earthquakes located near the Arizona-New Mexico border at latitude 31° north; another cluster on the Arizona-New Mexico border at latitude 36° north include 14 events; and the third, a small cluster of nine earthquakes located about 50 miles west of the Prescott earthquake epicentral area or about 34.6° north and 113.3° west. Racine, et al, feel that the characteristics of the shock indicated them to be earthquakes.

This conclusion was evaluated further because their presence would be significant if the events were earthquakes. An analysis of the clusters was made by

constructing histograms of origin time for each event occurring in the clusters. The results indicated that all events occurred during normal working hours, local time. Also, all magnitudes fall in a very narrow range of 2.2 to 2.9 and do not have a normal logarithmic distribution. Considering these points, and the fact that the clusters occurred in the vicinity of a major mining activity, we conclude the clusters are directly associated with mine blasting and are, therefore, not significant with respect to PVNGS.

d. Dubois, S. and Smith, A., 1980:

The main emphasis of this study is the compilation and critical use of intensity reports for the 1887 Sonora earthquake. There is an extensive table quoting the various reports. Isoseismal maps are drawn and important correlations made between high intensities and valley fill material. The isoseismals are greatly extended to the south to account for reports of Mexico City. However, the isoseismals out to about intensity VIII are reasonably symmetric (although elongated). Perhaps Mexico City, with its special soil column, should have been considered as an anomalous intensity. Their intensity maps show a value of about IV to V at the Palo Verde site.

The 1887 earthquake is assigned a magnitude of 7.25 on the basis of seismic moment $M. = 7.2 \times 10^{26}$

(L = 50 kilometers, W = 16 kilometers, s = $\bar{3}$ m) and the relation $M^1 = 2/3 \log M_o - 10.7$. Because of the

presence of several Quaternary faults in the seismically active zones of Arizona, western New Mexico and the 1887 epicentral area, a "magnitude 7+ should be considered as the likely maximum magnitude for this region." In a conservative manner, the FSAR analysis has assumed an earthquake as large as magnitude 8+ occurring at the closest approach of the active zone (Zone C) to the site. The studies of Dubois and Smith suggest that the magnitude for the Sonora earthquake should be downgraded from the value of 8+ used in the FSAR.

e. Dubois, S. and Sbar, M., 1981:

This paper also reports the magnitude and intensity map results of Dubois and Smith (1980, Special Report No. 3). In addition, intensity data are plotted as a function of distance and compared with some attenuation models. The data (Figure 4) for distances on the order of 70 miles (nearest approach for the SSE) show intensities ranging from VII to X. However, they have used epicentral distances rather than distance to the fault rupture which would be a better choice here. At 70 miles perpendicular to the fault trace (Figure 3), the intensity is VIII. The attenuation data are widely scattered, but seems to favor a western U.S. model (Howell and Schultz, 1975) better than an eastern U.S. model (Bollinger, 1977) for distances beyond about 100 miles. For distances up to about 100 miles, the models are comparable.

They present a preliminary map of historical epicenters (Figure 7) that shows several small earthquakes, intensity II to IV, that are not shown in the FSAR. They did much more extensive search using original sources, and the FSAR only compiled published data. They show the 1852 Fort Yuma earthquake incorrectly at Chimney Peak. They also have two intensity VII events east of Yuma and within Zone D (M - 5 to 5.9) that the FSAR does not show. According to Dubois (personal communication, 1981) the epicenter locations shown in Figure 7 at Chimney Peak and east of Yuma are questionable because of the lack of reliable location data. The final epicenter map in preparation will reflect location changes.

f. Pierce, H., 1979:

Article describes subsidence problems of the Picacho Basin, Arizona. The author suggests that other areas surrounding Phoenix may experience similar problems.

There is no evidence of subsidence in the Palo Verde site area such as basin downwarps, fissures, or cracks (paragraph 2.5.1.2.8, FSAR). Comparison of geologic conditions at the site to geologic conditions in the areas of known subsidence indicate that sediment consolidation is not a hazard at the Palo Verde Nuclear Station (paragraph 2.5.1.17, FSAR). For a more detailed discussion, see following item k.

g. Dubois, S., 1980:

The paper discusses reports by various government agencies and individuals in the Tucson, Arizona area of several reportedly small earthquakes. The investigators evaluated these reports and determined the shock wave travel time between recording stations was too slow to be an earth-propagated event. They concluded that sonic booms generated by supersonic aircraft caused the localized ground vibrations. We agree with the authors. It is conceivable that the strong motion instrument at PVNGS could be triggered by sonic boom-induced ground vibration under optimum atmospheric conditions, but this is of no safety-related significance to PVNGS.

h. Dubois, S., and Smith, A., 1980:

This is a brief description of work-compiling damage reports for earthquakes affecting Arizona. Particular attention is given to older, historic earthquakes that are known only from their felt reports. The paper includes a table of representative earthquakes, but the full results of the study are not included. A preliminary map of all the epicenters is given. A final map and/or listing has not yet been released. These results, when available, will modify the historical seismicity map in the FSAR, but there should be no significant changes in the delineation of seismic zones on the maximum earthquakes chosen. See the comments under preceding Item e.

i. Eberhard-Phillips, et al, 1981:

The earthquake studied in this paper has been called the Prescott earthquake in the FSAR text. The author determined the following parameters: Mb = 4.9, Mo = 1 x 1023, location at 34.7°N, 112.5° W and depth 10 to 15 km, northwest trending model planes with the preferred solution having a strike of 120° and dip of 40° southwest. The location is consisted with the shock possibly occurring on the downdip extension of the Big Chino fault but the location of the fault at 10 to 15 km depth is speculative. A brief microearthquake survey indicated about one recordable shock every 3 days in the vicinity of the Prescott earthquake. Considerable discussion is given concerning the tectonic significance of the earthquake closing with the sentence: "In summary, several different models explain the Chino Valley earthquake and other characteristics of the Transition Zone, but we cannot uniquely explain the tectonics of the area due to insufficient and possibly conflicting data". The results of this paper suggest a fault association for the earthquake, but do not affect any of the implications drawn relative to the earthquake hazard at the Palo Verde site.

j. Sinno, et al, 1981:

This paper describes a refraction experiment that results in a crustal model 23 - 25 kilometers thick, having two layers, and overlying an upper mantle with Pn velocity of only 7.67 kilometers per second. The

refraction profile extended from Parker to Globe and passed about 100 kilometers north of the Palo Verde site. The authors propose that the lithosphere has thinned from 40 to 24 kilometers over the past 5 m.y. and will probably continue to thin. The crustal structure model will not impact any of the seismological studies for the FSAR. In one case, the FSAR assumes a crustal structure to estimate the locations of any near-site shocks, but details of the crustal structure model would not alter the conclusions significantly. Crustal thickness is also a consideration in differentiation of the seismotectonic zones, but the model in this paper is not significantly different as to alter the PVNGS zoning analysis.

k. Holzer, T., Davis, S., and Lofgren, B., 1979:

Modern surface faulting, in the Picacho Basin, has created a scarp ranging from 0.2 to 0.6 m high and approximately 15 kilometers long. The scarp has been steadily increasing in height since it began to form in 1961. Faulting is concluded to be related to groundwater withdrawal. Conclusion based on: (1) scarp is restricted to an area underlain by alluvium in which groundwater levels have declined; (2) faulting post-dates the beginning of water-level declines and associated land subsidence; (3) observed vertical displacements associated with faulting are compatible with results from a model of subsurface faulting in which rupture does not extend beneath the zone affected by stresses related to declines of water levels; and

(4) analysis of levelings of bench marks unaffected by man-induced subsidence indicates minor regional crustal movements that do not appear to be compatible with the magnitude of fault offset. There is no evidence of subsidence in the site area such as basin downwarps fissures, or cracks. The closest known occurrence of land subsidence and earth fissuring is in the Luke Air Force Base region, approximately 25 miles east of the site (paragraph 2.5.1.2.8, FSAR). A subsidence monitoring program has been in effect at the Palo Verde site since early 1977 to meet objectives outlined in PSAR Section 2T.7 of Appendix 2T. Analysis of the results of this continuing program indicate that the data exhibits random scatter with no discernable trends relative to vertical movement on the site (figure 2.5-96, FSAR). Analyses of areas that have undergone surface cracking and subsidence indicate that certain conditions must exist to permit consolidation. The areas affected by subsidence are basins filled with great thicknesses (greater than 2000 feet) of permeable, low-density alluvial sediments where large amounts of groundwater are withdrawn resulting in water level declines on the order of 100 feet or more. Comparison of these conditions to conditions in the site region reveal that subsidence is not a hazard at the site (paragraph 2.5.1.1.7, FSAR).

l. Holzer, T., 1979

Based on leveling surveys in 1905, 1948-49, 1967, and 1977, Holzer estimated that the land surface rose

(elastic expansion) 6 centimeters from 1948 and 1967 in areas northwest and northeast of the town of Casa Grande in southcentral Arizona. He suggested that this rise was the result of removal of 43.5 x 10^{12} kilograms of groundwater and subsequent diminishment of surface stresses. Also, he speculated that in the tectonically active areas, unloading may cause earthquakes.

The results of this paper have no significance with respect to conditions at the PVNGS site. Since initiation of construction, groundwater depletion in the site area is negligible with preconstruction water levels having recovered in the immediate site area (figure 2.4-32). Since monitoring was initiated at the site, (FSAR figure 2.5-94) no measurable subsidence or uplift has been recorded.

m. Sumner, J., 1976:

This paper presents a very brief summary of Arizona earthquakes along with general summaries on causes of earthquakes, seismic measurements, safety and damage prevention, earthquake prediction, and earthquake control in four pages of text. A seismic zone map is presented which appears to be a modification of prior maps in the PSAR; no detailed supporting discussion is given. The zones chosen seem less conservative than the FSAR analysis in terms of estimating seismic hazard at the Palo Verde site. This paper was reviewed for amendments to the PSAR, but was not used in the analysis.

n. Raymond, R., Cordy, G., and Tuttle, G., 1980:

It is apparent the Raymond, **et al**, 1980 paper addresses comments to specific ideas presented in Holzer's (1979) paper, "Elastic Expansion of the Lithosphere Caused by Groundwater Depletion". The authors questioned Holzer's conclusions on the basis that:

1) unadjusted data with varying degrees of accuracy are compared,
2) data points are widely spaced and may have been disturbed or destroyed in some cases,
3) elevation changes are computed in relation to a single benchmark, and
4) leveling errors were evaluated by nominal accuracy methods which yield minimal values of one-half of the permissible error.

The new paper, in itself, has no impact on PVNGS.

o. Holzer, T., 1981:

Rebuttal to Raymond, et al, 1980 paper which questioned the hypothesis of crustal expansion caused by the depletion of groundwater in southcentral Arizona (Holzer, 1979). The main emphasis of Raymond, et al, paper was directed toward the analysis of leveling data that supported hypothesis. Holzer suggests that Raymond, et al, questions were based on 1) misunderstandings of how geodetic data are collected and reduced, and 2) misinterpretations of Holzer's (1979) data. The significance of this paper relative to PVNGS is

discussed in responses to studies 1 and n and reflects the divergent conclusion of the authors.

QUESTION 2A.5 (NRC Question 230.3)

Current staff practice is to approach the development of response spectra by performing statistical analyses on the strong motion records for sites with similar foundation conditions. The applicant used this approach to demonstrate that the safe shutdown earthquake (SSE) response spectrum exceeds the ground motion expected from a magnitude 8 event at a distance of 115 kilometers (72 miles).

The SSE can also be compared to the largest random earthquake near the site - a magnitude (m_b) = 5.0 ± 0.5 event at epicentral distances less than 25 kilometers (15 miles) for records on soil sites similar to Palo Verde. A similar collection of records has been made by Lawrence Livermore Laboratory (LLL, 1979 Draft, Seismic Hazard Analysis: Site Specific Response Spectra Results).

a. Either compare the results of the LLL study to the SSE or perform a similar analysis using mb = 5.0 + 0.5 events and recording sites on soil conditions similar to Palo Verde for epicentral distances less than 25 kilometers.

b. Determine whether the strong-motion records recorded in the Prescott Veterans Administration Hospital for the 1976 Prescott earthquake are consistent with this data set.

RESPONSE:

a. The conservatism of the 0.2g SSE design spectrum with respect to the ground motions from a nearby small-

magnitude earthquake was demonstrated by comparing the SSE and LLL[1] spectra. This comparison, presented in figure 2A-1, shows that the SSE spectrum (0.2g NRC Regulatory Guide 1.60) exceeds the 50th percentile LLL soil-site spectrum at all periods by factors between 2 and 10. The SSE spectrum also exceeds the 84th percentile LLL spectrum at periods longer than 0.05 second. The margin is a factor of approximately 1.3 for periods less than 0.4 second; at longer periods the margin gradually increases from factors of 1.4 to 3.7 at 2.0 seconds. Between 0.04 and 0.05 second, the 84th percentile LLL spectrum is slightly greater than the NRC spectrum, but this is of no practical significance. The conservatism of the 0.2g SSE design spectrum with respect to spectra for a nearby $m_b = 5.0 \pm 0.5$ event is greater than that indicated in figure 2A-1 because the LLL spectra are applicable for events in a larger magnitude range ($m_b = 5.3 \pm 0.5$ range).

b. The February 4, 1976, Chino Valley, Arizona, earthquake with a body-wave magnitude (m_b) of 4.9 occurred 17 kilometers north of the Prescott Veterans Administration Hospital in the Transition Zone between the Basin and Range and Colorado Plateau provinces[2]. The hospital rests on unconsolidated alluvial fan and stream channel deposits. The deposits are intercalated, stratified sand and gravel, and well-graded clayey sand and gravel to a depth estimated between 50 and 100 feet.

These deposits, underlain by Precambrian granodiorite, are unsaturated and above the water table (Blume, 1973).

A Kinematrics SMA-1 accelerograph recorded the motions in the basement of the Veterans Administration Hospital. Maximum accelerations reported by King and Ohm[3] are 0.020g and 0.045g for the two horizontal components and 0.026g for the vertical component, which are well below the SSE level of 0.2g.

The Veterans Administration Hospital accelerogram meets the criteria for the selection of representative records stated in Question 2A.5 (paragraph a). The body-wave magnitude (m_b = 4.9) falls within the specified range (m_b = 5.0 ± 0.5). The epicentral distance (17 kilometers) is less than the specified upper limit (25 kilometers). The local geologies at the Prescott Veterans Administration Hospital and the Palo Verde site[a] are both alluvium, and in this general sense both soil deposits are similar.

REFERENCES

1. LLL (Lawrence Livermore Laboratory), 1979, "Seismic Hazard Analysis: Site-Specific Response Spectra Results," by D. L. Bernreuter, C. P. Mortgat and L. W. Wright, Draft report, August 23, 1979.

a. The Palo Verde site basically consists of firm layers of silty sand, clayey sand, sandy silt, silty clay and clayey silt to a depth of approximately 300 feet where bedrock is encountered (see figure 2.5-58 for more detail on the site's stratigraphy).

2. Eberhard-Phillips, D., Richardson, R. M., Sbar, M. L., Herrmann, R. B., 1981, Analysis of the 4 February 1976 Chino Valley, Arizona, Earthquake: Bull. Seism. Soc. Am., v. 71, n. 3, p. 787-801.

3. King, K. W., Harding, S. T., Ohm, M., 1977, unpublished data.

QUESTION 2A.6 (NRC Question 230.4)

Provide the staff with the following:

a. Mokhtar, T. A., 1979, The Relationship Between the Seismicity and Late Cenozoic Tectonics in Arizona, M.S. Thesis, Univ. of Arizona, Tucson, 53 pp.

b. King, K. W., Harding, J.T. and Ohm, M., 1977, Notes on the Prescott Earthquake, 1976, U.S. Geological Survey Open-File Report.

c. Schell, B. A. and K. L. Wilson, in prep., Regional Seismotectonic Analysis of the Sonoran Desert, U.S. Geological Survey Open-File Report (Referenced in FUGRO 1981 Report on Stewart Mountain Dam).

d. R. E. Wallace, 1978, Patterns of Faulting and Seismic Gaps in the Great Basin Province: U.S. Geological Survey Open-File Report 78-943, 858-868.

RESPONSE: Copies of the requested references have been provided to the NRC.

QUESTION 2A.7 (NRC Question 241.1) (2.5.4.5)

Excavation and Backfill

1. Provide the as-built drawings showing the locations and limits of excavation, fills, backfills of the essential spray pond and structures on plot plans (i.e., figures 2.5-74 through 2.5-76, and figures 2D-1, 2D-3, and 2D-5) and on geological sectional profiles (i.e., figures 2.5-56 through 2.5-58 or figures 2.5-74 through 2.5-76). The structures shown on those figures should be identified. Also, indicate where the as-built condition has been changed from what was proposed in the PSAR and quantitatively justify the change.

2. Provide field control test results, such as field density, moisture content, and gradation tests, obtained during construction.

RESPONSE:

1. The response is given in figure 2A-2.

2. Backfill placed in the power block areas has been extensively tested during placement to ensure that the as-built compacted density and gradation are within specifications. In terms of total volume, the power block backfill was essentially complete as of the end of June 1981, with only small areas in Unit 3 remaining to be filled. The volume of power block backfill placed between start of construction through June 1981 is roughly 1,000,000 cubic yards. Over the same time interval, the approximate number of tests performed on power block backfill is summarized below:

- in-place field density (ASTM D1556) - 10,110
- gradation (ASTM D422) - 8,000
- compaction (ASTM D1557) - 720

Specified acceptance criteria for backfill require that all backfill soils, which did not fall within specified gradation or compaction limits, were removed or reworked until retests indicated compliance to specifications. Gradation tests were performed on material sampled at each density test location except at density test locations in native soils below fills, and at density retest locations, where gradation tests had already been performed. Thus, compliance to specified limits on gradation and compacted density has been documented throughout the power block backfill.

Tables 2A-1 and 2A-2 present a summary of Category I field control tests for the period from January 1, 1981, through March 31, 1981. These tests include measurements for density, moisture content, and gradation. The results of these tests are representative of previous tests performed during construction. Field control test results for the entire construction period are available at the PVNGS site for NRC review.

QUESTION 2A.8 (NRC Question 241.2) (2.5.4.7.3)

As stated in the FSAR, one-dimensional ground response studies were performed to assess the liquefaction potential of the in situ soils. Figure 2.5-78 seems to indicate that a soil column

of 100-foot depth was selected for those analyses. Provide quantitative and qualitative justification for the selection of the maximum cut-off depth of 100 feet (i.e., provide parametric analyses with varying depths to demonstrate that the seismic induced shear stresses would not be affected significantly should 150 feet or 200 feet be selected as the cut-off depth). The soil profile with the appropriate shear moduli and damping values used in all analyses should be provided. The bases for selecting the dynamic properties should be given (including reference to figures or tables where they are presented).

RESPONSE: The liquefaction potential of cohesionless soils was evaluated using the one-dimensional ground response program SHAKE(1) in conjunction with liquefaction strengths obtained by laboratory testing methods. Procedures for making this assessment are summarized in Appendix 2T of the PVNGS 4 and 5 PSAR. The purpose of this documentation is to provide a qualitative and quantitative justification for using a 100-foot soil column when performing the SHAKE analyses.

Table 2A-1

SUMMARY OF CATEGORY I FILL GRADATION TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 1 of 8)

Test No.	Loca-tion	Elevation (ft)	Site Coordinates N	Site Coordinates E	Gradation Tests – Percent Passing By Dry Weight, U.S. Sieve Size 1-1/2"	3/4"	3/8"	4	10	20	40	60	100	200	Remarks
Unit 1															
CIP2498	3	949-957	870,390.0	211,436.0	-	-	100	98	3	81	55	30	16	7	Radwaste Building
CIP2452	6	955-963	870,022.0	211,282.0	100	97	97	83	70	55	40	30	25	21	Spray Pond
CIP2452	6	955-963	870,365.0	210,875.0	100	99.21	95	46	74	58	43	32	27	22	Spray Pond
CIP2452	6	955-963	870,150.0	211,080.0	-	100	91	81	68	53	40	30	25	20	Spray Pond
CIP2452	6	955-963	870,248.0	210,996.0	98	89	89	79	63	49	35	26	21	18	Spray Pond
CIP2452	6	955-963	870,275.0	210,988.0	-	100	88	76	60	45	31	22	18	14	Spray Pond
CIP2452	6	955-963	870,345.0	210,895.0	100	97	93	93	71	57	42	30	24	19	Spray Pond
CIP2452	6	955-963	870,140.0	211,116.0	100	98	91	81	69	56	40	29	23	18	Spray Pond
CIP2452	6	955-963	870,270.0	210,995.0	100	95	85	77	66	53	39	29	24	20	Spray Pond
CIP2452	6	955-963	870,132.0	211,133.0	100	95	89	80	69	56	43	32	26	21	Spray Pond
CIP2452	6	955-963	870,125.0	211,156.0	100	97	90	80	68	53	39	29	24	19	Spray Pond
CIP2452	6	955-963	870,375.0	211,296.3	100	95	84	74	60	46	33	24	20	17	Spray Pond
CIP2452	6	955-963	870,997.0	211,307.2	100	94	85	76	64	45	34	25	20	16	Spray Pond
CIP2452	6	955-963	870,032.0	211,271.2	100	96	84	74	61	49	36	27	23	19	Spray Pond
CIP2452	6	955-963	870,130.0	211,140.0	100	98	91	81	68	54	40	30	26	21	Spray Pond
CIP2452	6	955-963	870,297.0	210,955.0	100	96	88	69	59	51	37	28	24	20	Spray Pond
CIP2452	6	955-963	870,355.0	210,855.0	100	95	88	77	64	51	39	30	26	22	Spray Pond
CIP2452	6	955-963	870,310.0	210,932.0	-	100	93	84	73	60	46	35	29	23	Spray Pond
CIP2452	6	955-963	870,340.0	210,905.0	100	94	85	78	68	56	43	33	27	20	Spray Pond
CIP2452	6	955-963	870,068.0	211,252.4	-	100	94	86	75	63	49	38	32	25	Spray Pond
CIP2452	6	955-963	870,236.0	211,343.0	100	99	94	84	72	58	42	32	27	22	Spray Pond
CIP2452	6	955-963	870,182.0	211,385.0	100	94	88	78	67	54	41	32	26	22	Spray Pond
CIP2452	6	955-963	870,150.0	221,481.0	100	96	86	76	64	50	35	26	21	18	Spray Pond
CIP2452	6	955-963	870,195.0	211,325.0	100	97	88	78	66	51	36	27	22	19	Spray Pond
CIP2452	6	955-963	870,230.0	211,330.0	100	96	88	78	65	50	37	28	24	20	Spray Pond

Table 2A-1

SUMMARY OF CATEGORY I FILL GRADATION TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 2 of 8)

Test No.	Loca-tion	Elevation (ft)	Site Coordinates		Gradation Tests – Percent Passing By Dry Weight										Remarks
					U.S. Sieve Size										
			N	E	1-1/2”	3/4”	3/8”	4	10	20	40	60	100	200	
Unit 1															
CIP2452	6	955-963	870,057.0	211,393.0	100	96	91	83	93	61	61	34	26	20	Spray Pond
CIP2452	6	955-963	870,062.6	211,271.5	100	94	85	74	62	50	36	26	22	18	Spray Pond
CIP2452	6	955-963	870,025.4	211,356.5	100	98	93	81	67	53	39	29	24	20	Spray Pond
CIP2452	6	955-963	870,163.0	211,410.0	100	93	85	76	64	50	36	27	23	18	Spray Pond
CIP2452	6	955-963	870,244.9	211,322.5	100	97	91	83	74	63	51	39	32	26	Spray Pond
CIP2452	6	955-963	870,219.6	211,189.7	100	98	91	83	71	58	42	31	26	20	Spray Pond
CIP2469	3	948-952	870,368.7	211,302.1	98	98	86	73	59	43	30	21	17	14	Holdup Tank
CIP2469	3	948-952	870,374.0	211,299.0	100	92	83	72	58	44	31	23	19	16	Holdup Tank
CIP2469	3	948-952	870,378.0	211,290.9	100	93	82	70	57	42	29	20	17	14	Holdup Tank
CIP2469	3	948-952	870,366.0	211,300.5	100	93	84	74	59	48	31	22	18	15	Holdup Tank
CIP2469	3	948-952	870,391.0	211,281.0	100	95	90	81	68	53	38	30	25	21	Holdup Tank
CIP2488	6	952-957	870,375.0	211,200.0	-	100	99	96	88	73	47	28	19	14	Spray Pond
CIP2488	6	952-957	870,480.0	211,037.0	100	96	90	82	71	60	47	37	30	24	Spray Pond
CIP2488	6	952-957	870,365.0	211,190.0	100	92	83	74	62	50	38	29	24	20	Spray Pond
CIP2493	5	951-952	870,448.9	211,229.6	-	-	100	98	92	78	52	27	15	6	Makeup Tank
CIP2473	5	954-957	870,973.0	211,359.2	100	95	87	78	65	50	36	27	23	19	Condensate Tank

Table 2A-1

SUMMARY OF CATEGORY I FILL GRADATION TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 3 of 8)

Test No.	Loca-tion	Elevation (ft)	Site Coordinates		Gradation Tests – Percent Passing By Dry Weight										Remarks
					U.S. Sieve Size										
			N	E	1-1/2"	3/4"	3/8"	4	10	20	40	60	100	200	
Unit 1															
CIP2460	3	948-952	870,374.8	211,314.0	-	100	99.54	95	89	75	49	28	16	7	Holdup Tank
CIP2460	3	948-952	870,375.0	211,305.0	95	92	83	71	56	42	29	21	17	14	Holdup Tank
CIP2460	3	948-952	870,394.2	211,327.8	-	100	99.64	97	91	76	51	28	15	6	Holdup Tank
CIP2465	4	952-957	41' W. of GA	12' S, of G1	100	97	89	80	68	56	42	32	26	21	"Q" Duct Bank
CIP2465	4	952-957	22' W. of GA	42' S. of G1	-	100	87	71	65	53	40	31	25	20	"Q" Duct Bank
CIP2418	4	954-957	870,355.0	211,640.0	-	100	99	95	88	72	46	23	12	5	Diesel Generator Building
CIP2418	4	954-957	870,382.0	211,661.0	-	-	100	98	91	75	44	21	11	5	Diesel Generator Building
CIP2418	4	954-957	870,379.0	211,667.0	-	100	99.6	96	88	73	44	22	11	5	Diesel Generator Building
CIP2423	3	949-957	870,400.0	211,279.0	100	99	94	85	73	59	45	34	28	22	Holdup Tank
CIP2423	3	949-957	870,402.0	211,264.0	-	100	93	86	75	64	51	40	33	27	Holdup Tank
CIP2423	3	949-957	870,447.0	211,275.0	100	96	88	78	68	57	44	34	28	23	Holdup Tank
CIP2437	3	952-955	12' S. of A8	146' W. of AA	100	97	93	87	75	61	43	30	23	18	Holdup Tank
CIP2437	3	952-955	6' S, of A8	157' W. of AA	100	92	87	79	67	54	40	29	23	19	Holdup Tank
CIP2437	3	952-955	2' N. of A8	162' W. of AA	100	98	89	79	65	49	35	26	22	18	Holdup Tank

Table 2A-1

SUMMARY OF CATEGORY I FILL GRADATION TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 4 of 8)

Test No.	Loca-tion	Elevation (ft)	Site Coordinates N	Site Coordinates E	1-1/2"	3/4"	3/8"	4	10	20	40	60	100	200	Remarks
					Gradation Tests – Percent Passing By Dry Weight, U.S. Sieve Size										
Unit 1															
CIP2365	3	955-957	3' S. of L1	68' W. of RE	100	96	91	82	70	57	41	31	25	20	Laundry Facility
CIP2365	3	955-957	7' S. of G3	78' W. of GA	100	95	89	80	70	57	43	32	27	22	Laundry Facility
CIP2365	3	955-957	4' N. of L1	27' W. of RE	100	97	91	81	68	54	39	29	25	20	Laundry Facility
CIP2371	3	948-949	14' S. of R1	6' W. of RA	-	100	99	95	88	73	46	25	14	6	Radwaste Building
CIP2401	3	944-945	1' S. of A8	138.5 W. of AA	-	100	99	95	85	67	39	20	11	5	Pipe Density Tunnel
CIP2356	3	946-952	870,387.2	211,335.0	-	100	99.6	95	87	72	46	25	14	6	Holdup Tank
CIP2361	5	954-957	870,756.2	211,359.4	-	100	99	95	88	74	47	26	14	6	Demineralizer Water Tank
CIP2363	4	952-957	12' N. of G3	18' E. of G6	100	98	89	77	63	47	31	23	19	15	Diesel Generator Building
CIP2363	4	952-957	870,475.0	211,715.0	100	87	81	72	66	51	37	27	23	18	Diesel Generator Building
CIP2333	4	954-957	870,440.0	211,640.0	100	99	94	85	74	61	45	34	27	21	Diesel Generator Building
CIP2333	4	954-957	870,435.0	211,639.0	-	100	93	84	73	61	46	34	28	23	Diesel Generator Building

Table 2A-1

SUMMARY OF CATEGORY I FILL GRADATION TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 5 of 8)

Test No.	Location	Elevation (ft)	Site Coordinates N	Site Coordinates E	Gradation Tests – Percent Passing By Dry Weight, U.S. Sieve Size 1-1/2"	3/4"	3/8"	4	10	20	40	60	100	200	Remarks
Unit 1															
CIP2346	3	945-957	870,373.0	211,255.0	-	100	97	92	85	69	41	21	12	6	Holdup Tank
CIP2346	3	945-957	870,465.7	211,224.7	100	99	93	86	76	65	48	33	27	21	Holdup Tank
CIP2346	3	945-957	870,407.2	211,243.7	100	96	88	80	69	56	39	28	22	18	Holdup Tank
CIP2346	3	945-957	870,397.8	211,254.3	100	97	89	80	69	57	42	29	22	16	Holdup Tank
CIP2346	3	945-957	870,367.3	211,302.0	100	97	88	80	70	59	43	30	23	17	Holdup Tank
CIP2346	3	945-957	870,361.0	211,292.9	100	94	90	82	70	57	42	31	26	21	Holdup Tank
CIP2346	3	945-957	870,370.9	211,286.0	100	94	87	80	70	59	44	33	28	23	Holdup Tank
CIP2346	3	945-957	870,360.8	211,303.5	100	95	87	77	66	53	38	28	24	20	Holdup Tank
CIP2352	3	944[5]-946[4]	870,444.7	211,318.0	-	100	99	94	87	73	47	25	15	6	Refueling Water Tank
CIP2322	4	951-955	47' S. of G3	10'E. of GC	100	98	92	84	73	60	43	32	27	22	Diesel Generator Building
CIP2324	4	951-957[5]	37' S. of G3	15' E. of GL	100	99	92	84	73	59	44	33	28	23	Diesel Generator Building
CIP2324	4	951-957[5]	58' S. of G3	40' E. of GC	100	97	94	87	77	65	48	34	27	21	Diesel Generator Building
CIP2324	4	951-957[5]	53' S. of G3	10' W. of GC	100	95	90	83	73	61	46	33	27	21	Diesel Generator Building

Table 2A-1

SUMMARY OF CATEGORY I FILL GRADATION TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 6 of 8)

Test No.	Loca-tion	Elevation (ft)	Site Coordinates		Gradation Tests – Percent Passing By Dry Weight										Remarks
					U.S. Sieve Size										
			N	E	1-1/2"	3/4"	3/8"	4	10	20	40	60	100	200	
Unit 1															
CIP2324	4	951-957[5]	43' S. of G3	24' W. of GA	-	-	100	97	92	77	50	27	15	6	Diesel Generator Building
CIP2324	4	951-957[5]	870,460.0	211,170.0	100	96	91	85	76	64	47	33	26	20	Diesel Generator Building
CIP2324	4	951-957[5]	870,350.0	211,703.0	100	97	88	78	66	52	38	27	22	17	Diesel Generator Building
CIP2324	4	951-957[5]	870,495.0	211,740.0	100	96	87	78	65	52	37	26	22	17	Diesel Generator Building
CIP2324	4	951-957[5]	45' S. of G3	23' W. of GA	100	94	89	81	69	56	41	31	26	21	Diesel Generator Building
CIP2324	4	951-957[5]	46' S. of G3	22' W. of GA	100	92	86	78	68	56	41	30	25	21	Diesel Generator Building
CIP2328	3	944[5]-946	4' S. of R4	12' W. of RE	100	99	93	85	75	63	47	35	28	22	Radwaste Building
CIP2307	6	951-954	870,309.0	211,232.0	-	100	92	83	72	59	44	32	26	21	Spray Pond
CIP2304	6	955-959	870,533.0	210,969.0	-	100	93	82	69	53	39	28	23	19	Spray Pond
CIP2304	6	955-959	870,550.0	210,958.0	100	99	93	86	76	63	47	34	28	22	Spray Pond
CIP2304	6	955-959	870,533.0	210,957.0	100	96	87	79	69	56	41	29	23	18	Spray Pond
CIP2304	6	955-959	870,492.0	211,027.0	-	100	95	89	80	66	48	33	26	20	Spray Pond
CIP2304	6	955-959	870,473.0	211,030.0	-	100	94	87	76	63	45	32	26	20	Spray Pond
CIP2304	6	955-959	870,502.0	210,993.0	100	96	88	80	71	58	44	34	28	23	Spray Pond
CIP2304	6	955-959	870,512.0	211,050.0	100	99	94	86	76	63	48	36	29	23	Spray Pond

Table 2A-1

SUMMARY OF CATEGORY I FILL GRADATION TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 7 of 8)

Test No.	Loca-tion	Elevation (ft)	Site Coordinates		Gradation Tests – Percent Passing By Dry Weight										Remarks
					U.S. Sieve Size										
			N	E	1-1/2"	3/4"	3/8"	4	10	20	40	60	100	200	
Unit 1															
CIP2326	8	953-957	45' S. of G3	30' W. of GA	-	100	99	95	87	69	41	21	11	5	Diesel Storage Tank
CIP2326	8	953-957	39' S. of G3	49' W. of GA	100	99.6	95	89	79	66	50	37	29	23	Diesel Storage Tank
CIP2265	3	897-942[5]	39' N. of A8	57' W. of AA	100	98	91	81	68	54	40	30	25	21	Refueling Water Tank
CIP2265	3	897-942[5]	16' N. of A8	15' W. of AA	100	95	89	79	67	53	39	30	25	20	Refueling Water Tank
CIP2305	3	950-957	870,342.0	211,255.0	-	100	99	96	90	74	48	26	14	6	Spray Pond
CIP2305	3	950-957	870,353.0	211,251.0	100	96	91	84	74	62	46	33	27	21	Spray Pond
CIP2305	3	950-957	870,297.0	211,346.0	100	96	92	84	74	60	44	32	26	21	Spray Pond
CIP2305	3	950-957	870,255.0	211,307.0	100	99	91	83	71	55	39	28	23	19	Spray Pond
CIP2305	3	950-957	870,250.0	211,310.0	100	99	95	88	77	62	46	33	27	22	Spray Pond
Unit 2															
CIP2335	3	936-939	869,553.0	210,675.0	-	100	94	85	74	60	45	33	27	21	Refueling Water Tank
CIP2348	4	951-953	14' S. of G3	3' E of G4	100	95	90	82	71	57	41	31	26	22	Diesel Generator Building
CIP2349	3	938-940	869,539.0	210,690.0	100	92	85	76	65	52	38	28	23	19	Refueling Water Tank
CIP2419	6	950-954	150' E. of TR	4' from T6	100	92	81	70	57	43	30	21	18	15	Spray Pond

Table 2A-1

SUMMARY OF CATEGORY I FILL GRADATION TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 8 of 8)

Test No.	Loca-tion	Elevation (ft)	Site Coordinates N	Site Coordinates E	Gradation Tests – Percent Passing By Dry Weight, U.S. Sieve Size 1-1/2”	3/4”	3/8”	4	10	20	40	60	100	200	Remarks
Unit 3															
CIP2358	3	921-935	35’ S. of A10	36’ W. of JA	100	98	91	82	71	57	41	31	25	21	Radwaste Building
CIP2358	3	921-935	31’ S. of A10	2’ W. of TA	100	93	88	81	70	58	43	31	23	18	Radwaste Building
CIP2358	3	921-935	10’ S. of A10	38’ W. of TA	100	97	86	74	61	48	34	24	19	15	Radwaste Building
CIP2358	3	921-935	2’ S. of A10	12’ W. of TA	100	93	81	71	58	45	32	23	18	15	Radwaste Building
CIP2358	3	921-935	21’ S. of RI	55’ E. of RA	100	92	83	73	61	48	34	26	22	18	Radwaste Building
CIP2358	3	921-935	4’ S. of A10	2’ W. of JA	-	96	86	75	62	49	35	26	21	18	Radwaste Building
CIP2358	3	921-935	21’ S. of A10	2’ W. of JA	100	94	88	81	69	57	43	32	27	23	Radwaste Building
CIP2358	3	921-935	25’ S. of A10	22’ W. of JA	100	99	93	83	70	56	41	31	25	21	Radwaste Building
CIP2358	3	921-935	19’ S. of R1	44’ E. of RA	100	94	88	79	66	53	36	25	20	16	Radwaste Building
CIP2358	3	921-935	31’ S. of R1	15’ W. of RE	100	94	89	82	72	59	44	32	27	22	Radwaste Building
CIP2358	3	921-935	2’ S. of A10	11’ W. of JA	100	97	92	83	72	60	45	33	27	21	Radwaste Building
CIP2358	3	921-935	22’ S. of A10	51’ W. of JA	100	96	91	84	75	63	46	32	26	20	Radwaste Building
CIP2358	3	921-935	23’ S. of A10	1.5” W. of JA	100	97	91	82	72	60	45	32	25	20	Radwaste Building
CIP2358	3	921-935	23’ S. of A10	34’ W. of JA	100	95	90	84	72	60	46	35	29	24	Radwaste Building
CIP2358	3	921-935	1’ S. of A10	21’ W. of JA	100	94	84	76	66	55	42	32	26	21	Radwaste Building
CIP2358	3	921-935	20’ S. of A10	25’ W. of JA	100	98	94	86	76	64	48	36	30	24	Radwaste Building
CIP2358	3	921-935	9’ S. of A10	8’ W. of JA	100	97	91	82	71	58	42	32	27	22	Radwaste Building
CIP2358	3	921-934	2’ S. of A10	16’ W. of JA	100	98	89	79	67	55	41	31	26	21	Radwaste Building
CIP2358	3	921-934	25’ S. of A10	44’ W. of JA	100	99	93	83	70	57	42	32	26	21	Radwaste Building
CIP2358	3	921-935	3’ S. of A10	45’ W. of JA	100	96	87	80	68	56	41	31	25	20	Radwaste Building
CIP2416	5	943-954	147’ N. of T1	5’ W. of TA	100	89	81	71	60	46	33	25	21	17	Condensate Pump House
CIP2416	3	913-921	868.227.0	210,396.0	100	97	90	79	65	51	36	28	24	20	Radwaste Building
CIP2416	3	913-921	868,215.0	210.438.0	100	97	89	79	67	53	39	30	25	21	Radwaste Building

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 1 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2498	3	949-957	99	14	Radwaste Building
CIP 2452	6	955-963	95	8	Spray Pond
CIP 2452	6	955-963	98	8	Spray Pond
CIP 2452	6	955-963	95	11	Spray Pond
CIP 2452	6	955-963	98	11	Spray Pond
CIP 2452	6	955-963	100	11	Spray Pond
CIP 2452	6	955-963	95	11	Spray Pond
CIP 2452	6	955-963	94[(a)]	12	Spray Pond
CIP 2452	6	955-963	96	11	Spray Pond
CIP 2452	6	955-963	87[(a)]	10	Spray Pond
CIP 2452	6	955-963	96	10	Spray Pond
CIP 2452	6	955-963	92[(a)]	13	Spray Pond
CIP 2452	6	955-963	97	10	Spray Pond

a. Backfill was reworked and then retested to verify compliance with minimum requirements (95%). Retested values are also included in the construction inspection planning.

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 2 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2452	6	955-963	93[(a)]	8	Spray Pond
CIP 2452	6	955-963	101	10	Spray Pond
CIP 2452	6	955-963	97	9	Spray Pond
CIP 2452	6	955-963	96	13	Spray Pond
CIP 2452	6	955-963	95	11	Spray Pond
CIP 2452	6	955-963	98	9	Spray Pond
CIP 2452	6	955-963	99	11	Spray Pond
CIP 2452	6	955-963	95	11	Spray Pond
CIP 2452	6	955-963	98	11	Spray Pond
CIP 2452	6	955-963	97	10	Spray Pond
CIP 2452	6	955-963	98	11	Spray Pond
CIP 2452	6	955-963	98	11	Spray Pond
CIP 2452	6	955-963	95	11	Spray Pond
CIP 2452	6	955-963	97	11	Spray Pond

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 3 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2452	6	955-963	101	10	Spray Pond
CIP 2452	6	955-963	99	9	Spray Pond
CIP 2452	6	955-963	98	12	Spray Pond
CIP 2452	6	955-963	99	9	Spray Pond
CIP 2452	6	955-963	99	9	Spray Pond
CIP 2452	6	955-963	96	11	Spray Pond
CIP 2452	6	955-963	99	9	Spray Pond
CIP 2452	6	955-963	97	10	Spray Pond
CIP 2452	6	955-963	100	10	Spray Pond
CIP 2452	6	955-963	99	11	Spray Pond
CIP 2452	6	955-963	101	11	Spray Pond
CIP 2469	3	948-952	96	9	Holdup Tank
CIP 2469	3	948-952	95	12	Holdup Tank

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 4 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2469	3	948-952	93[a]	10	Holdup Tank
CIP 2469	3	948-952	87[a]	12	Holdup Tank
CIP 2469	3	948-952	99	11	Holdup Tank
CIP 2469	3	948-952	95	12	Holdup Tank
CIP 2469	3	948-952	93[a]	15	Holdup Tank
CIP 2469	3	948-952	91[a]	15	Holdup Tank
CIP 2469	3	948-952	98	10	Holdup Tank
CIP 2469	3	948-952	98	12	Holdup Tank
CIP 2488	6	952-957	98	11	Spray Pond
CIP 2488	6	952-957	97	12	Spray Pond
CIP 2488	6	952-957	97	9	Spray Pond
CIP 2488	6	952-957	95	10	Spray Pond

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 5 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2493	5	951-952	99	8	Makeup Tank
CIP 2493	5	951-952	100	11	Makeup Tank
CIP 2473	5	954-957	95	10	Condenser Tank
CIP 2460	3	948-952	102	7	Holdup Tank
CIP 2460	3	948-952	97	9	Holdup Tank
CIP 2460	3	948-952	102	11	Holdup Tank
CIP 2465	4	952-957	98	11	“Q” Duct Bank
CIP 2465	4	952-957	100	10	“Q” Duct Bank

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 6 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2418	4	97-100	97	6	Diesel Generator Building
CIP 2418	4	97-100	97	7	Diesel Generator Building
CIP 2418	4	97-100	100	8	Diesel Generator Building
CIP 2423	3	949-957	97	10	Holdup Tank
CIP 2423	3	949-957	97	10	Holdup Tank
CIP 2423	3	949-957	100	10	Holdup Tank
CIP 2437	3	952-955	98	10	Holdup Tank
CIP 2437	3	952-955	100	9	Holdup Tank
CIP 2437	3	952-955	90[a]	9	Holdup Tank
CIP 2437	3	952-955	96	10	Holdup Tank

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 7 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2365	3	98-99$^{\underline{5}}$	96	9	Laundry Facility
CIP 2365	3	98-99$^{\underline{5}}$	94[a]	11	Laundry Facility
CIP 2365	3	98-99$^{\underline{5}}$	98	10	Laundry Facility
CIP 2365	3	98-99$^{\underline{5}}$	95	11	Laundry Facility
CIP 2365	3	98-99$^{\underline{5}}$	97	11	Laundry Facility
CIP 2371	3	948-949	96	6	Radwaste Building
CIP 2401	3	944-945	100	14	Pipe Density Tunnel
CIP 2356	3	946-952	100	10	Holdup Tank
CIP 2361	5	954-957	97	12	Demineralizer Water Tank

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 8 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2363	4	952-957	95	11	Diesel Generator Building
CIP 2363	4	952-957	95	10	Diesel Generator Building
CIP 2333	4	954-957	98	11	Diesel Generator Building
CIP 2333	4	954-957	99	10	Diesel Generator Building
CIP 2346	3	88-100	99	12	Holdup Tank
CIP 2346	3	88-100	98	12	Holdup Tank
CIP 2346	3	88-100	96	10	Holdup Tank
CIP 2346	3	88-100	96	11	Holdup Tank
CIP 2346	3	88-100	93[a]	11	Holdup Tank
CIP 2346	3	88-100	97	11	Holdup Tank
CIP 2346	3	88-100	97	9	Holdup Tank
CIP 2346	3	88-100	99	10	Holdup Tank
CIP 2346	3	88-100	99	10	Holdup Tank

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 9 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2352	3	944^{5}-946^{9}	101	11	Refueling Water Tank
CIP 2322	4	951-955	95	10	Diesel Generator Building
CIP 2322	4	951-955	97	10	Diesel Generator Building
CIP 2324	4	951-957^{5}	96	12	Diesel Generator Building
CIP 2324	4	951-957^{5}	96	11	Diesel Generator Building
CIP 2324	4	951-957^{5}	97	12	
CIP 2324	4	951-957^{5}	98	11	Diesel Generator Building
CIP 2324	4	951-957^{5}	96	7	Diesel Generator Building
CIP 2324	4	951-957^{5}	97	11	Diesel Generator Building
CIP 2324	4	951-957^{5}	95	10	Diesel Generator Building
CIP 2324	4	951-957^{5}	96	11	Diesel Generator Building
CIP 2324	4	951-957^{5}	100	11	Diesel Generator Building
CIP 2324	4	951-957^{5}	101	11	Diesel Generator Building

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 10 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2328	3	$952^{\underline{5}}$-956	99	10	Radwaste Building
CIP 2307	6	951-954	100	11	Spray Pond
CIP 2304	6	955-959	94[a]	8	Spray Pond
CIP 2304	6	955-959	92[a]	7	Spray Pond
CIP 2304	6	955-959	98	8	Spray Pond
CIP 2304	6	955-959	100	11	Spray Pond
CIP 2304	6	955-959	94[a]	12	Spray Pond
CIP 2304	6	955-959	94[a]	11	Spray Pond
CIP 2304	6	955-959	99	11	Spray Pond
CIP 2304	6	955-959	96	12	Spray Pond
CIP 2304	6	955-959	97	12	Spray Pond
CIP 2304	6	955-959	98	11	Spray Pond
CIP 2304	6	955-959	101	10	Spray Pond

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 11 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2326	8	96-100	102	10	Diesel Storage Tank
CIP 2326	8	96-100	96	12	Diesel Storage Tank
CIP 2265	3	85'-6"- 90'-7-3/4"	92[(a)]	8	Refueling Water Tank
CIP 2265	3	85'-6"- 90'-7-3/4"	92[(a)]	8	Refueling Water Tank
CIP 2265	3	85'-6"- 90'-7-3/4"	93[(a)]	9	Refueling Water Tank
CIP 2265	3	85'-6"- 90'-7-3/4"	101[(a)]	9	Refueling Water Tank
CIP 2305	3	950-957	95	11	Spray Pond
CIP 2305	3	950-957	101	12	Spray Pond
CIP 2305	3	950-957	99	12	Spray Pond
CIP 2305	3	950-957	92[(a)]	11	Spray Pond

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 12 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
			Unit 1		
CIP 2305	3	950-957	100	10	Spray Pond
CIP 2305	3	950-957	96	10	Spray Pond
CIP 2305	3	950-957	95	9	Spray Pond
CIP 2335	3	82-85’-6”	97	12	Refueling Water Tank
CIP 2348	4	97-99	98	10	Diesel Generator Building
CIP 2349	3	84-85’-7”	88[(a)]	11	Refueling Water Tank
CIP 2349	3	84-85’-7”	96	11	Refueling Water Tank
CIP 2419	6	950-954	100	10	Spray Pond

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 13 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2358	3	70-84	96	7	Radwaste Building
CIP 2358	3	70-84	98	13	Radwaste Building
CIP 2358	3	70-84	93[(a)]	10	Radwaste Building
CIP 2358	3	70-84	96	11	Radwaste Building
CIP 2358	3	70-84	96	10	Radwaste Building
CIP 2358	3	70-84	90[(a)]	10	Radwaste Building
CIP 2358	3	70-84	98	9	Radwaste Building
CIP 2358	3	70-84	101	11	Radwaste Building
CIP 2358	3	70-84	96	12	Radwaste Building
CIP 2358	3	70-84	95	10	Radwaste Building
CIP 2358	3	70-84	99	10	Radwaste Building
CIP 2358	3	70-84	96	11	Radwaste Building
CIP 2358	3	70-84	97	11	Radwaste Building
CIP 2358	3	70-84	99	10	Radwaste Building
CIP 2358	3	70-84	94[(a)]	11	Radwaste Building

Table 2A-2

SUMMARY OF CATEGORY I FILL DENSITY AND MOISTURE CONTENT TESTS

PERIOD: 01-01-81 THROUGH 03-31-81 (Sheet 14 of 14)

Test No.	Location	Elevation	Density (%)	Moisture Content (%)	Remarks
Unit 1					
CIP 2358	3	70-84	101	11	Radwaste Building
CIP 2358	3	70-84	101	9	Radwaste Building
CIP 2358	3	70-84	95	12	Radwaste Building
CIP 2358	3	70-84	96	9	Radwaste Building
CIP 2358	3	70-84	93[a]	11	Radwaste Building
CIP 2358	3	70-84	95	11	Radwaste Building
CIP 2358	3	70-84	95	13	Radwaste Building
CIP 2358	3	70-84	97	11	Radwaste Building
CIP 2358	3	70-84	99	10	Radwaste Building
CIP 2416	5	943-954	97	11	Condensate Pump House
CIP 2417	3	62-70	103	11	Radwaste Building
CIP 2417	3	62-70	96	11	Radwaste Building

ANALYTICAL CONCEPT: In an overall sense, the potential for liquefaction at the PVNGS site is of interest only in the upper 80 feet. Soils below this depth are cohesive, and hence, are not of direct concern from the standpoint of liquefaction.

The ground response studies for Units 1, 2, and 3 involved use of an analytical procedure which was essentially independent of the depth of the soil model. This procedure, which is called deconvolution, involved the specification of earthquake acceleration at the ground surface and derivation of compatible ground motions and shear stresses at various depths.

The surface motion was determined by scaling earthquake records from sites with similar soil conditions for earthquake magnitude and distance, as discussed in paragraph 2.5.2.6. An artificial time-history (Bechtel record) scaled for a maximum acceleration of 0.2g was also used for this purpose.

The ground response analyses were conducted using the computer program SHAKE(1). This program is based on the assumptions that the soil profile consists of horizontal layers of linear viscoelastic material and that the earthquake motions result from shear waves propagating vertically from the base of the soil column. Each layer is characterized by a thickness, mass density, shear modulus, and damping factor. Under dynamic excitation, the system satisfies the wave equation. Hence, if motion is known in any one layer in the system, the motion can be uniquely computed in any other layer. In other words, the response for a layer within the soil profile model would be the same whether the motion is deconvoluted directly from the ground surface to the layer, or the motion is deconvoluted to

the base of the soil profile model and the resulting motion at the base is used as a source motion for propagating upward to the layer. This uniqueness in the analysis results from the characterization of layers within the soil model by constant values of shear modulus and damping during excitation by an earthquake record.

Once deformation functions are uniquely described in any analysis, strains and accelerations can then be derived from the displacement functions. A Fast Fourier Transfer algorithm is used to solve the equations of motion for transient excitation, such as caused by an earthquake. The nonlinearity of shear modulus and damping is accounted for by the use of equivalent linear soil properties in conjunction with an iterative procedure to obtain values for modulus and damping compatible with the effective strain in each layer.

QUANTITATIVE CONFIRMATION: To demonstrate the validity of using a 100-foot soil profile, a series of parametric SHAKE analyses were conducted. In these studies the model of the site was extended to a depth of 200 feet. Acceleration and shearing stress profiles were then computed to the base of the model.

The comparative study was performed for Unit 3. Results of previous studies for Units 1, 2, and 3 indicate that this unit is the most crucial of the three. The study was performed using the Hollywood Basement S0°W, the Santa Barbara S48°E, and the synthetic Bechtel earthquake records. These records defined minimum, average, and maximum ground response during previous studies.

APPENDIX 2A

Table 2A-3

SOIL MODEL LIQUEFACTION POTENTIAL ANALYSES - UNIT 3

(Sheet 1 of 2)

Layer No.	Layer Thickness (ft.)	Soil Type[(a)]	Total Unit Weight (PCF)	Low-Strain Shear Modulus X 10^6 (PSF)
1	5	2	115	3.76
2	5	2	115	3.76
3	5	2	121	3.76
4	5	2	121	3.76
5	5	2	128	6.68
6	5	2	131	6.68
7	5	2	129	6.68
8	5	2	128	6.68
9	5	2	128	6.68
10	5	1	123	6.68
11	5	1	123	6.68
12	5	1	123	6.68
13	5	1	123	5.98
14	5	1	123	5.98
15	5	1	123	5.98
16	5	1	124	5.98
17	5	1	124	6.03
18	5	1	124	6.03
19	5	1	124	6.03
20	5	1	124	6.03
21	5	1	125	6.57

Table 2A-3

SOIL MODEL LIQUEFACTION POTENTIAL ANALYSES - UNIT 3

(Sheet 2 of 2)

Layer No.	Layer Thickness (ft.)	Soil Type[a]	Total Unit Weight (PCF)	Low-Strain Shear Modulus X 10^6 (PSF)
21	10	1	125	6.05
22	15	1	126	6.31
23	15	1	126	6.63
24	10	2	128	6.65
25	10	1	128	6.83
26	20	1	128	7.11
27	20	2	129	7.45
28	Base	-	129	7.70

a. Soil types:

1 - clays and silty clays
2 - sands and silty sands

The site model used in the study is presented in table 2A-3. The variation of modulus and damping ratio with shear strain was based on the normalized relationship presented in figures 2A-7 and 2A-8.

The results of the comparative studies are summarized in table 2A-4. As might be expected, these results verify that the depth of the soil model used with SHAKE[1] has no effect on the computed stresses. Any major variation in computed stresses are due to the iterative process involved in the analyses. In the cases analyzed herein, these differences are insignificant (less than ±0.5%).

REFERENCE

1. Schnabel, P. B., Lysmer, J., and Seed, H. B., "SHAKE: A Computer Program for Earthquake Response Analysis of Horizontally Layered Sites," Report No. EERC 72-12, Earthquake Engineering Research Center, University of California, Berkeley, California, December, 1972.

QUESTION 2A.9 (NRC Question 241.3) (2.5.4)

As shown on figures 2.5-74 through 2.5-76, "As-Built Temporary Excavation Plan and Profile", many buildings are founded on fills with variable thicknesses over excavated slopes. Because the fills and the in situ soils possess different properties; the stability, settlement, and seismic behavior of these buildings are of concern.

1. The construction excavations, as indicated in paragraph 2.5.4.5.1, have slopes ranging from 1-3/4:1 to 1:1 (horizontal to vertical). The stability of those buildings founded on slopes of 1:1, such as control building, must be evaluated. The evaluation should consider that the frictional resistance along the construction slopes could be affected by seepage, the softening of the clayey soils, and the under-compaction of the fill along and adjacent to the construction slopes. Provide the details and results of your analysis for review.

Table 2A-4

RESULTS OF COMPARATIVE SHAKE ANALYSES (Sheet 1 of 2)

Layer No.	Layer Mid Depth (ft.)	Maximum Shear Stress (psf)					
		Hollywood Basement		Santa Barbara		Bechtel Horizontal	
		200 Ft. Model	100 Ft. Model	200 Ft. Model	100 Ft. Model	200 Ft. Model	100 Ft. Model
1	2.5	26.48	26.48	36.47	36.47	56.73	56.73
2	7.5	79.10	79.09	109.17	109.20	169.71	169.71
3	12.5	132.07	132.00	182.89	183.05	284.35	284.35
4	17.5	186.38	186.29	259.11	259.69	402.75	402.75
5	22.5	241.11	241.03	340.50	341.31	527.75	527.75
6	27.5	294.38	294.31	419.19	420.11	647.92	647.92
7	32.5	345.52	345.43	496.33	497.51	764.67	764.67
8	37.5	394.90	394.88	571.07	573.98	873.88	873.88
9	42.5	441.71	441.79	643.85	646.57	977.80	977.80
10	47.5	488.11	488.31	723.79	725.31	1096.07	1096.07
11	52.5	531.00	531.33	794.05	796.38	1192.00	1192.00
12	57.5	572.29	572.78	863.54	865.94	1281.38	1281.38
13	62.5	611.75	612.45	930.63	933.45	1362.25	1362.25
14	67.5	649.53	650.62	997.07	1000.25	1433.24	1433.24
15	72.5	682.51	648.72	1028.51	1037.86	1448.83	1448.83
16	77.5	718.83	720.56	1124.08	1128.06	1540.87	1540.87

Table 2A-4

RESULTS OF COMPARATIVE SHAKE ANALYSES (Sheet 2 of 2)

Layer No.	Layer Mid Depth (ft.)	Maximum Shear Stress (psf)					
		Hollywood Basement		Santa Barbara		Bechtel Horizontal	
		200 Ft. Model	100 Ft. Model	200 Ft. Model	100 Ft. Model	200 Ft. Model	100 Ft. Model
17	82.5	750.42	752.51	1184.70	1189.11	1576.94	1576.94
18	87.5	779.87	782.39	1243.14	1248.00	1602.26	1602.26
19	92.5	807.19	810.18	1299.37	1304.70	1617.57	1617.57
20	97.5	832.39	835.82	1353.28	1359.10	1623.66	1623.66
21	105.0	868.29	-	1452.04	-	1624.08	-
22	117.5	923.08	-	1561.73	-	1578.25	-
23	132.5	976.10	-	1680.11	-	1654.11	-
24	145.0	1025.72	-	1759.49	-	1715.25	-
25	155.0	1028.33	-	1817.82	-	1788.44	-
26	170.0	1044.79	-	1882.98	-	1861.87	-
27	190.0	1067.08	-	1964.32	-	2085.74	-

2. Bearing capacity analyses, as stated, utilize a two-layer soil model. Apparently, those analyses do not represent the as-built condition as discussed above. Provide additional analyses with the critical bearing failure surfaces developed along the construction slopes.

3. Since many buildings are founded on fills of various thickness, the post-construction differential settlements are of concern. Provide differential settlement calculations for those buildings, i.e., fuel, control, etc. The documented as-built soil properties should be used for the analyses. In addition, the available data on structural settlements obtained from monitoring instrumentation should be plotted and provided. The structural settlement plots should cover at least two sections for each unit with the main structures identified. Settlement versus time plots for instruments installed at the fuel and control buildings should also be provided.

4. As shown on figure 2.5-74, since the buildings were founded on fills of various thickness, differential settlements, tilting, and potential stability problems are of concern. Provide analyses to demonstrate that: (1) the rotation of those buildings due to differential settlements would not have any significant impact on adjacent buildings or building internals, (2) the lateral earth pressures used in the original design would not be significantly affected if the critical failure plane was along the construction slopes, and (3) the seismic-induced loads and responses would be less or equal to what was calculated in the original design configuration.

RESPONSE: The major slopes of the power block excavations occur in the native sands of the upper 50 feet of the site (see figures 2.5-74 through 2.5-76). Native soils below the base of excavation are predominantly silty clays. Sands excavated from the power block excavations were reused as power block backfill. The shear strength properties of the compacted sands and the native sands are essentially the same, based on laboratory shear tests summarized in figure 2.5-66; thus, a two-layer model consisting of sand over clay was used in stability and bearing capacity analysis.

There is no evidence to indicate a plane of weakness or undercompaction along construction slopes. Any loose or softened native soils were removed during backfilling because fills were benched into firm native soils. Compaction was performed to specified densities, as documented in the response to NRC Question 241.1, part 2. Settlement instrumentation data presented in "Foundation Instrumentation Report Supplement for Responses to NRC Questions 241.3 and 241.4" (sent to the NRC under separate cover), indicates that measured structural settlements are well within design criteria limits and thus show no evidence of back-fill undercompaction.

Although there is no evidence to indicate a plane of weakness along buried construction slopes, the effects of a hypothetical plane of weakness upon structural stability and upon design static and seismic earth pressures were evaluated. The following conclusions were drawn:

- A relatively small portion of both the control building and the containment overlie a small (roughly 16 feet high) backfilled 1:1 construction slope. Both of these slopes are in the native clay soils. A small wedge of granular backfill is confined between the 1:1 slopes and the auxiliary building. Softening and/or undercompaction along the 1:1 slopes would not significantly reduce the overall stability of either the containment or the control building due to the small size of the weakened zone relative to the potential bearing failure surface and the confinement provided by the lower portion of the auxiliary building.

- For static conditions, structural walls were designed to resist at-rest lateral earth pressure exerted by compacted backfill, assuming rigid, nonyielding walls. This design condition conservatively assumed no movement in the soil; therefore, any slippage that might occur along a hypothetical plane of weakness would reduce the earth pressures from the at-rest design value. Thus, the presence of a plane of weakness along construction slopes would have no adverse impact on static earth pressures used in design.

- For seismic conditions, structural walls were designed to resist earthquake-induced loading. A check was made to compare the dynamic wall pressures used in design to the pseudo-static pressures that would result if the wedge of backfill between structural walls and construction slopes were free to accelerate toward the

structure under earthquake loading. To stimulate a hypothetical plane of weakness, it is assumed that no frictional forces could be mobilized along construction slopes. For all structures, the dynamic pressures used in design were larger than the pressures generated by the pseudo-static wedge forces; therefore, the seismic-induced loads used in design will not be increased if a plane of weakness is assumed along construction slopes.

QUESTION 2A.10 (NRC Question 241.4) (2.5)

Essential Spray Pond

1. As shown on figure 2.5-88, the essential spray pond will be excavated. Since the pond is a Seismic Category I structure with man-made slopes or embankments, the design and analysis information for these slopes should be provided. The information required for staff review can be found in either Section 2.5.5 or 2.5.6 of Regulatory Guide 1.70 "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants."

2. Provide an analysis to demonstrate that the groundwater levels will not be higher than those used in the design and confirmed by data obtained from groundwater level monitoring program.

3. Buried pipelines and associated earthwork should be discussed. This discussion should include the design and construction of the foundation support for the pipelines, excavation, bedding and backfills, compaction requirements, estimated settlements along the pipelines (particularly in

fills). The confirmation test results of moisture, density and compaction during installation should be provided. The settlement monitoring results along the pipelines should also be provided.

RESPONSE:

1. The essential spray ponds are watertight reinforced concrete structures (refer to paragraphs 3.8.4.1.6, 9.2.5.2, and engineering drawing 13-C-SPS-375). The base slab has a minimum thickness of 2 feet and is 3 feet thick under the walls. The walls are 15 feet 6 inches high, extending 8 feet above the plant grade and are 2 feet thick. All vertical and horizontal construction joints located in the exterior walls and base slab have 6 inch dumbbell waterstops. A nonstructural embankment, approximately 4 feet 6 inches high, is provided around the outside walls of the ponds for vehicle access. Failure of the nonstructural embankment would have no impact on the safety function of the ponds. Sections 2.5.5 and 2.5.6 of Regulatory Guide 1.70 do not apply to this nonstructural embankment. The design philosophy is explained in amended paragraph 3.7.2.3.3.

2. Data from the groundwater monitoring program have established the groundwater level to be the same as described in paragraph 2.4.13.4.1.

3. Buried Category I pipelines which service the essential spray pond consist of steel water pipes and concrete encased PVC electrical conduits referred to as

electrical duct runs. These pipelines are supported directly on either native soils, or on compacted power block fill in areas where they cross the power block excavation ramp backfill. A plan view of the spray pond area showing the location of Category I pipelines and power block backfill is presented on figure 2A-5.

Bedding, gradation, and compaction requirements are summarized in figure 2A-6.

All fills placed in the power block excavation are granular soils compacted to at least 95% of the ASTM D1557 maximum density. Compaction requirements, equipment, and procedures are the same for fills underlying structures and for fills supporting pipelines only. Results of field density testing on these fills is presented in the response to NRC Question 241.1, part 2.

Category I pipelines impose very little net load on the foundation soils; therefore, settlements in the spray pond area are caused primarily by the weight of backfill and by spray pond structural loads. Settlements caused by the considerable weight of backfill will be essentially complete prior to installation of the pipelines. This is due to the fact that the backfill will have been placed up to grade for at least 6 months prior to both spray pond and Category I pipeline installation. The predicted rapid rate of backfill-induced settlement is supported by instrumentation data presented in the "Foundation Instrumentation Report"

(sent to NRC under separate cover). Category I pipelines are installed at about the same time the spray ponds are constructed, and after backfill-induced settlements are essentially complete. Category I pipeline settlements will, therefore, be caused primarily by spray pond loading. Pipeline settlements will be maximum at connections to the spray pond structure and will decrease gradually.

With increasing distance from the structure. Total predicted recompression settlements for the perimeter walls of the spray pond are small, ranging from 0.2 to 0.4 inch. These predictions were obtained in a detailed analysis presented in Appendix 2AA, Amendment 18 of the PSAR. Therefore, estimated settlements of Category I utilities are also small, ranging between 0.0 and 0.4 inch.

Because of the very small settlements anticipated along pipelines, no instrumentation has been installed on the pipelines; however, settlement markers have been installed at six locations around the perimeter of the spray ponds. Data from these spray pond settlement markers at Unit 1 are available for the 13-month period beginning roughly 6 months after construction began on the spray ponds. Results are presented graphically in the "Foundation Instrumentation Report." Measured settlements are low, ranging from 0.0 to 0.3 inch; thus, the measured settlements provide evidence that very small settlements have occurred along pipelines in the spray pond area.

<u>QUESTION 2A.11</u> (NRC Question 231.1)

Eberly and Stanley's (1978) paper addresses the structural geology in the site vicinity (within 5 to 10 miles). Discuss the impact and validity of their interpretation of the subsurface with respect to:

a. The existence of mountain-basin bounding faults in the Arlington Gillespie Dam area.

b. The validity of their interpretation of the site vicinity geologic structure as shown on their Figure 8, p. 933.

c. The significance of Eberly's and Stanley's interpretation with respect to site safety.

RESPONSE: The field work and research leading to Eberly and Stanley's 1978 paper was accomplished between 1971 and 1973 and represented about an 18-month effort to synthesize a broader picture of Arizona's Cenozoic stratigraphic and tectonic history than was currently available in published literature. The ultimate purpose of the study was for application to Exxon's oil and gas exploration program. Their study involved:

- incorporation of all previous geologic data
- reconnaissance geologic mapping from 93 outcrop locations
- results of 57 water, gas, and oil borings
- four new test borings
- hundreds of miles of vibroseis reflection profiling

- 57 radiometric age dates

The greatest emphasis of Eberly and Stanley's work was on the correlation of one major and several minor unconformities in the Cenozoic stratigraphic section throughout southwest Arizona. As a result of this broad stratigraphic work, they were able to document two distinct orogenic episodes and provide a chronologic framework for the development of two major structural trends throughout southwest Arizona. Eberly and Stanley interpreted structural trends along their traverses based on seismic lines and reconnaissance mapping. These interpretations were depicted in a series of small-scale, vertically-exaggerated cross-sections which extend east from Yuma along the Gila River and south along the Phoenix-Tucson corridor.

In terms of PVNGS, Eberly and Stanley's Figure 8, page 933, is most significant because it shows the east end of their Section B-B' which extends east-northeast through the vicinity of the Palo Verde Hills. Their structural interpretation of the Saddle Mountain - Palo Verde Hills high is based on reconnaissance mapping of the outcrops, a single Exxon vibroseis reflection profile and a single exploratory boring (Reaves No. 1 Fuqua, [see FSAR figure 2A-3] drilled and abandoned in 1939, total depth 4117 feet) located in Buckeye about 15 miles east of PVNGS. Five normal faults were interpreted across the area between Centennial Wash and the Hassayampa River: two on each side of the horst, apparently defining the "step down" into each adjacent basin, and one normal fault within the horst. All

these faults were interpreted to be northwest trending based on reconnaissance mapping. The quality of the seismic profile and reflectors was considered only fair by Eberly (1981, personal communication), and the prime purpose for placing faults in the vicinity of the Saddle Mountain - Palo Verde Hills high was to account for the tilting of the volcanic units. He believes that the Exxon seismic line showed some permissive evidence for placing faults in the area, but the exact number and location of specific faults, as shown on Figure 9, represents some "artistic license" according to the authors (Eberly, 1981, personal communication).

FSAR figures 2.5-8 and 2.5-9 show tectonic interpretations for the Palo Verde site vicinity based on: 1) the reconnaissance and detailed investigation for PVNGS, and 2) tectonic interpretations from all available geologic sources. Cross-section B-B' on FSAR figure 2.5-9 roughly coincides with the area between Hassayampa and Centennial Wash shown on the Eberly and Stanley Figure 8. FSAR figure 2.5-9, Section B-B', shows or infers five faults: two forming the west boundary of the structural high near Centennial Wash, two forming a graben near the Hassayampa River, and one small fault in the Palo Verde Hills. The original FSAR figure 2.5-9, Section B-B', has not shown the Centennial Wash faults projecting onto the section. The revised figure has corrected this. So, in terms of the numbers and locations of faults considered in the PVNGS site vicinity, Eberly and Stanley do not indicate any essentially unique interpretation. Therefore, the style of

tectonics presented in the FSAR is conservative and, considering scale differences and vertical exaggeration, the PVNGS analysis would be more accurate. The detailed geologic mapping and geophysical surveys conducted in the site vicinity have documented the absence of any surface fault (other than the one noted in the Palo Verde Hills) and have confirmed the general integrity of the Saddle Mountain - Palo Verde structural high.

Regarding the age of the faulting, Figure 8 shows some range bounding faults as displacing the lower sections of Unit 1 which implies tectonic activity ranging from 13 million years to about 10 million years before present (late Miocene block faulting episode or "mid-Tertiary" orogeny). Eberly and Stanley interpret that between 10 and 6 million years ago the period of closed basins ended, streams were integrated and the area began to demonstrate a general tectonic stability. The PVNGS investigations established that major tilting of volcanic units occurred after about 17 m.y. and apparently stopped at about 16 m.y. (age of untilted fanglomerate). Actually, basin faulting must have stopped later but well prior to deposition of the Palo Verde clay (i.e., well before 2.7 m.y.). Therefore, the minimum age of faulting presented in the FSAR is more conservative than Eberly and Stanley's observations.

Eberly and Stanley also discuss the Gila trough and describe it as a "northeast-trending, sediment-filled trench underlying the Gila River Valley east of Ligurta, Arizona (east of Yuma). Thick deposits of Unit 1 indicate that the Gila trough predated late Miocene block faulting.

The block faulting overprinted the older northeast-southwest structural trend, forming horsts and grabens within the Gila trough that are aligned with the northwest-southeast trend of the present day valleys and ranges." Therefore, their study indicates that the northeast structural trends of the Gila trough and the Gila lineament are clearly older than the mid-Miocene block faulting, and, therefore, are not capable or significant to the site.

In total, the Eberly and Stanley paper confirms, in a regional sense, many of the more important findings of PVNGS related to: 1) the general location and distribution of major faults near the Saddle Mountain - Palo Verde Hills high, 2) the age of faulting and basin development, and 3) the age of basin filling, stream integration, and achievement of tectonic stability in southwest Arizona.

There has been no new information presented which would alter the opinions or conclusions of safety at PVNGS and, therefore, there is no impact or significance to the FSAR.

QUESTION 2A.12 (NRC Question 231.2)

Describe your post-1978 Palo Verde 4 and 5 PSAR activities with respect to the geologic and seismological updating of the Palo Verde 1, 2, and 3 FSAR.

RESPONSE: Preparation of the PVNGS Final Safety Analysis Report (FSAR) reflects the thorough assessment, reevaluation, and compilation of previously-submitted data for PVNGS Units 1, 2, and 3 and PVNGS 4 and 5 obtained through March 1979. Following March 1979, an ongoing,

multifaceted program continues to update the geologic seismological and geotechnical engineering data base for subsequent amendments to FSAR. The updating program includes, but is not limited to:

- review and evaluation of geologic and seismologic research developing in the southwest and other regions that may influence geotechnical and conclusion regarding PVNGS.
- review and evaluation of published report, maps, and other records, as they become available, pertaining to the geology and seismology of the southwest.
- periodic personal contact with the various governmental agencies, academic institutions and the private organizations involved in geotechnical projects in the southwest.
- investigation and evaluation of seismic events reported as occurring within Arizona and adjacent regions.
- continuous in-grading geologic inspection and mapping of construction excavations at PVNGS.
- analysis of settlement and subsidence network data and the reporting of results on an interim basis.
- monitoring of regional and perched groundwater conditions in the site area.

QUESTION 2A.13 (NRC Question 231.3)

Figure 2 (page 6) of a November 1979 Department of Energy Report shows two inferred faults in the Hassayampa Plain northeast of the Palo Verde site. Discuss the validity of these faults and their site-safety significance. The DOE report is titled "Geothermal Studies in Arizona with Two Area Assessments (DOE/ID/12009-T4)."

RESPONSE: The existence and location of the intersecting northwest and northeast trending faults shown on Figure 2 of the Geothermal Reservoir Site Evaluation in Arizona were inferred from regional geologic relationships supplemented by some reconnaissance geophysical data and a previous regional lineament study. In the case of both faults, there was no directly mappable geologic or structural discontinuities to confirm their existence (Stone, 1981, personal communication). The actual locations of the faults shown on Figure 2 were inferred from: a) the assumed position and shape of the buried pediment edge along the northeast Belmont Mountains (i.e., the northwest trending fault), and b) buried basin topography interpreted from low resolution gravity and aeromagnetic surveys of the northern Hassayampa Plain (northeast trending fault).

According to the author, Claudia Stone, a second phase of the geothermal study has produced a higher resolution gravity survey of the northern Hassayampa Plain. This latest geophysics is just being analyzed and will be reported in a second publication available before the end of 1981. Although currently incomplete, the revised analysis

will make two important changes to the structural interpretation on Figure 2. First, the northeast trending fault will be removed because the detailed data apparently do not substantiate the inferences of the original study. Second, the buried fault along the north edge of the Belmont Mountains will be sinuous to follow the shape of the pediment rather than straight as now shown (C. Stone, 1981, personal communication). Therefore, we may conclude that the northeast trending fault is not valid.

FSAR figure 2.5-8 shows a northeast trending hypothetical fault along the north boundary of the Belmont Mountains. However, it is located about 2 miles west of the northwest trending fault on Figure 2 of the referenced article. The fault in FSAR figure 2.5-8 was taken from a small-scale tectonic map of North America which placed faults along margins of most major mountain ranges. The accuracy of location of those hypothetical faults is unknown and the geologic reasoning for their location is not described. Therefore, the fault on FSAR figure 2.5-8 represents essentially the same range bounding structure in Figure 2 except that locations of the two faults vary slightly due to map scale and minor interpretive differences. FSAR figure 2.5-8 has been revised to reflect the results of these latest studies.

The ages of faulting are not discussed in detail in the referenced article; however, it was noted that the orientations of the two faults in Figure 2 are representative of the two prominent structural trends in central Arizona: northeast trends are attributed to the

Laramide Orogeny and north-northwest trends are attributed to the mid-Tertiary orogeny. This is consistent with the tectonic history outlined in the FSAR and brackets the age of movement on the younger northwest trending faults from about 13 million years to about 10 million years before present.

Surface studies in the form of aerial photographic analysis, flyover, and ground reconnaissance have not revealed any evidence of Quaternary activity along the northern margin of the Belmont Mountains. Lineaments have been placed along the relatively straight segment of Jackrabbit Wash which parallels the north margin of the Belmont Mountains, but no evidence has been generated by previous studies to indicate that the stream alignment is due to Quaternary faulting.

Therefore, we conclude that the revised maps of the referenced study will be consistent with the geology as represented in the FSAR and that the postulated fault along the northeast margin of the Belmont Mountains is not capable and is not of safety significance to the site.

QUESTION 2A.14 (NRC Question 231.4)

Describe the basis used for categorizing the fault (see FSAR figure 2.5-6) in the Sand Tank Mountains area some 35 miles SE of the Palo Verde site as older than 500,000 years.

RESPONSE: The weight of line used to depict the age of the fault near the Sand Tank Mountains is a drafting error. In the absence of any detailed geologic investigations, we consider the Sand Tank fault as younger than 500,000 years

and FSAR figure 2.5-6 was modified accordingly. Richard Van Horn of the U.S. Geological Survey describes the Sand Tank scarp as follows:

The scarp, about 3 kilometers long and 2 meters high, slopes about 20 degrees west. It is formed on an old alluvial fan that slopes about 2 degrees west-ward. Desert varnish is about half as well developed on the scarp as on the upper surface of the fan. The old fan deposit and the scarp have been eroded by ephemeral streams, which have deposited a younger fan alluvium in the gulches and over the old fan alluvium west of the scarp. The younger fan alluvium over-lies and conceals the scarp at its north and south-ends. No scarp was seen on the young fan. The young fan deposit is not stained by desert varnish.

The scarp is believed to have been formed by a fault that displaced the old fan deposit downward to the west. The fault and downdropped block of old fan deposit have been completely covered by the young fan deposit. Alternative origins for the scarp that were considered and rejected include erosion by the Gila River and subsidence into a depositional basin. The age of faulting was not determined, but is probably Pleistocene.

Since the exact age within the Pleistocene has not been determined and no detailed analysis is available, no definitive statement can be made regarding the capability of the Sand Tank fault. However, for this analysis we have assumed it is capable. In terms of site safety, the existence of the Sand Tank fault, about 35 miles south of

the site, is not considered significant because of the very conservative model used to establish the seismic design for PVNGS. The Sand Tank fault is too short and too distant from the site to represent a surface faulting hazard or to exceed the safe shutdown earthquake. Therefore, there is no impact to the seismic evaluation of the site by assuming that the fault is capable.

QUESTION 2A.15 (NRC Question 231.5)

Detailed geophysical surveys (gravity and magnetic) recently conducted by C. Cloran (Geophysics, Hydrology and Geothermal Potential of the Tonopah Basin, Maricopa County, Arizona, MS Thesis, Arizona State University, May 1977) within 5 miles of the Palo Verde site indicate that the Tonopah Basin is bounded by normal faults. Discuss the impact of Cloran's interpretation of the subsurface with respect to:

a. Site safety

b. The capability (or noncapability) of the basin-bounding faults suggested by Cloran.

c. The validity of the structural interpretation of the Tonopah Desert area as shown on FSAR figure 2.5-8 and other related FSAR figures.

RESPONSE: The masters thesis by Courtney Ann Cloran (Geophysics, Hydrology and Geothermal Potential of the Tonopah Basin, Maricopa County, Arizona, 1977) provides a reasonably detailed geophysical and structural analysis covering about two-thirds of the Tonopah Basin. Cloran performed a gravity and ground magnetic survey on 1 mile and

one-half mile centers, respectively, which refined earlier geophysical work in the area by others including, in part, the work by Sumner for the PVNGS PSAR (i.e., the area north of the Palo Verde Hills and into the Tonopah Desert).

In terms of safety significance to PVNGS, the most pertinent conclusions to Cloran's work were that:

- The Tonopah Basin is a large (15 kilometers) Basin and Range style, block-faulted structure.

- Steep gravity gradients on the basin margins to the north and south indicate steep scarps of normal faults or a series of normal faults. The number of interpreted faults vary depending on the density model, but the position of major structural blocks remain about the same.

- Maximum thickness of alluvium ranges from about 7500 feet to about 10,000 feet.

- The greatest depth of the basin is in the southeast corner and the basin trends about N56°W.

  The basin is bounded on the north by the buried pediment of the Belmont Mountains, to the south by the Saddle Mountains and Palo Verde Hills, to the west by the connection between Big Horn Mountains and the Belmont Mountains, and on the east by the buried granitic high trending south from the southeast end of the Belmont Mountains.

- A prominent nose exists in the southwest part of the Tonopah Basin which may be a northeast trending fault.

- Magnetic anomalies in the northwest part of the Saddle Mountains have been speculated to be faulted volcanic flows which have been intercalated into the basin sediments. The magnetic contours suggest the faults might trend northeast and project into the central basin.
- A water temperature anomaly coincides with the general location and orientation of the northeast trending fault. The northeast trending fault is postulated to act as a conduit to high water transfer.
- There is no discussion in Cloran's study of geologic history, tectonic history of minimum age of last displacement on faults in the Tonopah Basin.

Cloran's interpretation of faults within the Tonopah Basin is based on consistently steep gravity gradients and a few abrupt magnetic anomalies. The basin bounding faults interpreted from gravity data are shown in section (plate 8) using two interpretations of the geophysical model. Model 2 shows the most faults and has been discussed here as the most conservative alternative. Unfortunately, there is no plan which shows the interpreted length and orientation of northwest basin bounding faults between the three cross sections. Similarly, there is no section or plan showing the location, orientation, or length of the northeast trending fault along the "Tonopah Nose" or of the northeast faults defining the abrupt, high-low magnetic anomalies. These locations must be inferred from the text description. Figure 2A-4 is a reduced version of plate 4 showing our

interpretation of Cloran's faults described in the text and cross-sections. In addition, we have superimposed the locations of the inferred and geophysical faults from FSAR figure 2.5-8 for ease of comparison in the following discussion.

The PVNGS geophysical and subsurface investigations concentrate on the southeast edge of the Tonopah Basin closest to the site. Cloran's survey overlapped the northern edge of the PVNGS investigation and covered the remaining southern two-thirds of the entire valley. The two southernmost faults (A and B, figure 2A-4), which were interpreted as basin-bounding structures in the FSAR, appear in good alignment and form a reasonable correlation with Cloran's basin-bounding faults farther northwest (i.e., faults F and G). Fault F, which marks the change in gravity values from about -6 to -12 milligals, seems the most consistent structure and possibly correlative with fault B of the PVNGS investigation. Sumner (personal communication, 1981) has commented that Cloran's gravity contours suggest another alternative interpretation, i.e., a structural change along the 0 milligal line which roughly parallels the northwest trend of the valley. This inferred structure would project into the vicinity of faults A and B and also might be correlative with them. Therefore, a complete acceptance of Cloran's work would suggest at least one and possibly two faults (A and B) may be longer than shown on FSAR figure 2.5-8. Another alternate interpretation could postulate one fault which might correlate to faults A or B.

Along the northern Tonopah Basin, Cloran has interpreted two bounding faults (H and I) at the change in gravity gradient near the -14 milligal contour. Fault H roughly follows the -14 milligal contour and appears to correlate among all three cross sections. The correlation of fault I among all three cross-sections requires cutting across one prominent gradient near section C-C' (Figure 8); therefore fault I may not be as continuous as fault H. FSAR figure 2.5-8 shows a geophysical fault (fault E) about two or three miles north of Cloran's fault (H and I). The existence and location of fault E was based on a single gravity profile performed during the PVNGS investigation which was supplemented by regional gravity data and regional geology. Fault E was interpreted along the steep gravity gradient along the south margin of the Belmont Mountains.

Cloran's work refined the shape and location of the northern basin contours and, as a result, permits a more refined interpretation of basin faulting. Upon reviewing Cloran's work, we agree that the data suggest a range-bounding fault along the northern Tonopah Basin. However, we favor placing the fault in the areas of the steepest gravity gradient; i.e., approximately along the -4 milligal contour (Sumner, 1981, personal communication). This latter interpretation would place the range bounding fault about 1 mile south of and slightly subparallel to fault E and about 1 or 2 miles north of faults H and I. Although the locations of the different interpretations of range-bounding faults may vary by a few miles, the general concept of a bounding fault along the northern edge of the Tonopah Desert has been

accepted and considered in the FSAR. In addition, the FSAR has considered a hypothetical fault from published tectonic maps along the entire southern boundary of the Belmont Mountains (FSAR figure 2.5-8).

The "Tonopah Nose" was interpreted by Cloran from the abrupt kink in gravity contours in the southwest corner of the basin (Figure A). Based on the text description, there was a northeast trending fault interpreted along the aligned contours of the kink. Although the original gravity readings and station data are not available and have not been analyzed, it is clear that the contours have been pulled out of position by an anomalous reading on one station. This leads us to suspect the accuracy of the station readings of elevations and, as a result, to question the existence of the "Tonopah Nose".

The shorter, east-west trending geophysical faults near the center of Tonopah Basin (faults C and D) correlate, in one instance, with a basin fault shown on Cloran's section A-A' (plate 8). Fault D has no obvious correlation to any structure shown on Cloran's section B-B'. Fault C, if projected west, would generally align with several short northeast faults that Cloran interpreted at the southwest margin of the basin; however, there is no basis for a reliable correlation.

In summary, it can be said that Cloran's work has expanded the geophysical interpretation of the Tonopah Basin, and in terms of the basin-bounding faults nearest the site, has shown that one of the southern basin faults might be

continued 8 to 10 miles farther northwest. The interpretations between Cloran and PVNGS studies regarding faults forming the north margin of the Tonopah Basin agree in principle as to the existence of a basin-bounding fault, but these interpretations have placed the faults at different locations (a few miles apart) and slightly subparallel in orientation. Cloran's work has identified some short northeast trending faults near the southwest edge of the basin which would project toward Saddle Mountains. These latter faults are the only really new interpretations introduced. It is important to note that these interpretations of northeast trending faults are somewhat suspect because; 1) the high-magnetic anomalies used to infer the faults occur near great thicknesses of basalt near Saddle Mountain, and 2) the kink in the gravity contours used to infer the "Tonopah Nose" is based on a single station anomaly. It is a reasonable alternative to postulate the presence of northeast trending dikes which are known to produce similar magnetic patterns.

Regarding the impact of this information to site safety, we can conclude:

- Cloran's work has not identified any new structures which are closer to the site or project toward the site from those structures already presented in FSAR figure 2.5-8.

- The original PVNGS analysis considered the impact of basin-bounding faults along the north and south margin of the Tonopah Basin (i.e., those determined from direct

investigation or from faults inferred on other tectonic maps). The FSAR model is conservative and its safety significance has not been changed by Cloran's studies.

- The unbroken correlation of the Palo Verde clay across the southern basin-bounding faults (A and B) still demonstrates no movement in at least 2.7 million years. This age is valid regardless of how far the faults might project to the northwest (i.e., correlate with faults F and G).

- Potential northern basin-bounding faults were evaluated with various remote sensing techniques, reconnaissance geologic mapping, and geomorphic evaluations. It was concluded that there are no signs of displacement of any Quaternary formations along the south edge of the Belmont Mountains or the pediment.

- The postulated northeast trending faults interpreted by Cloran are subordinate to the northwest basin bounding faults in terms of length and inferred amounts of displacement. Although there is no discussion of the tectonic history of the basin or evaluation of ages of fault development and last movement, these northeast trending faults fit a regional tress pattern in central Arizona which usually places the northeast faults as Laramide structures. As a result, they precede the mid-Tertiary orogeny and are older than the northwest trending faults. There is no surface expression of the northeast trending faults nor is there any evidence

raised by Cloran's work that would suggest that they should be considered capable.

In direct answer to the three questions raised by the NRC, we conclude:

a) There is no impact to site safety or to the geotechnical evaluation from Cloran's work.

b) The basin bounding faults as postulated by Cloran are not considered capable in terms of NRC siting criteria.

c) The structural interpretation shown on FSAR figures 2.5-8 and 2.5-9 is still valid in terms of the basic basin geometry and the significant structural features of safety significance to the site. There will be the addition of some details from Cloran's work to make the data base more complete.

QUESTION 2A.16 (NRC Question 231.6)

Geologic features, which may possibly be faults, have been recently identified within approximately 8 to 13 miles of the Palo Verde Nuclear Generating Station by a geologist with the Arizona Bureau of Geology and Mineral Technology. Preliminary estimates indicate that at least some of the features (faults) may be of tectonic origin and may be capable - ranging from 10,000, perhaps 50,000 years old. Conduct field studies and investigations as necessary in order to better understand the nature and age of the reported faulting. For any feature which is determined to be a fault, determine whether it is capable. If capable, determine the effect, if any, on the seismic design bases for the Palo Verde plant.

RESPONSE: Christopher Menges, Research Geologist for the Arizona Bureau of Geology and Mineral Technology, identified a series of anomalous, scarp-like features near the Hassayampa River about 12 miles north-northeast of the Palo Verde Nuclear Generating Station.

Mr. Menges' discoveries were an outgrowth of a two year statewide study of Quaternary faulting in Arizona funded by the U.S. Geological Survey. His preliminary work, which included photointerpretation, aerial overflight, and reconnaissance ground-field checks, provided data suggestive, although not diagnostic, of a fault origin for the Hassayampa scarps. These data included: 1) linear topographic scarps oriented oblique to local drainage throughout much of their extent, 2) approximately the same surface, as indicated by relative degree of soil and pavement development, above and below many of the topographic scarps, and 3) disruption of drainage and local sedimentation at or adjacent to the scarps.

Menges also noted that certain characteristics of the scarps made interpretation of the origin difficult and problematic, especially compared to other well-documented fault scarps in Arizona. These characteristics included the position of the scarps relative to the direction of the pediment (i.e., the scarps were nestled among inselbergs), the funnel-shaped aerial pattern, and the subparallel orientation of the scarps to the pediment and adjacent piedmont drainage. Because the surface evidence was ambiguous and the scarp morphology suggested a late Pleistocene age of scarp formation, a field program was

undertaken to clarify the origin and significance of the scarps to PVNGS. The field program was designed and conducted in cooperation with Menges and he was directly involved with the location of trenches and interpretation of results.

Figure 2A-9 shows the location of the Hassayampa scarps originally interpreted by Menges. Their degree of certainty based on anomalous characteristics and field checking is also indicated by appropriate symbols. Based on the field evidence and the degree of certainty, the scarps were considered in two groups: 1) the westernmost group of relatively short scarps (1-2 miles in length), and 2) the eastern group of relatively long scarps (3-5 miles in length).

The western group of scarps, although shorter, had been field checked and contained the most anomalous characteristics. Therefore, they were the most prominent and were the most likely to be of fault origin. The eastern group were not field checked and were so closely associated with active drainage channels that they were considered by Menges to be less likely of fault origin. As a result, the subsurface investigation concentrated on the most diagnostic and anomalous scarps of the western group and the results of that study were used to refine the interpretation on the remaining scarps.

The investigative program included:

- several meetings between APS, their geologic consultants and the Arizona Bureau of Geology and Mineral Technology;
- research and analysis of U-2 and Army Map Service aerial photography of the Hassayampa area;
- aerial flyovers by helicopter and fixed wing aircraft at low sun angle conditions;
- field reconnaissance of scarp areas with and without Menges;
- selection of trench locations with Menges;
- excavation of two backhoe trenches across the most prominent and diagnostic scarps;
- Analysis and documentation of the excavations with Menges and the NRC geologist.

Figure 2A-9 shows the location of the western scarps and the two trenches investigating them.

Trench PV-BH-32 was excavated across a north-northwest trending scarp in an area where the scarp separated the elevated, paved fan surface from the lower, more recent alluvial plain. In this area the scarp angle dips to the west and ranges from a few degrees to a maximum of 9 degrees. The trench ranged in depth from about 12 to 16 feet and revealed six distinctive stratigraphic horizons.

At least four horizons could be traced continuously throughout the full length of the trench (figure 2A-10).

For the most part the contacts could be identified within an inch and could be confidently correlated across the trench without any evidence of warping or displacement. Since the strata are nearly horizontal, the uppermost gravelly sand unit gradually pinched out to the west against the erosional scarp. The lowest clay unit was only exposed in the deepest part of the excavation.

The lithologies exposed in trench PV-BH-32 range from coarse gravelly sands to fine grain deposits of silt and clay. In general, the lithologic groupings from top to bottom of the trench are: 1) reddish brown, gravelly sand which forms the desert pavement on the upper paleosurface, 2) massive gray brown silt, 3) thick sequences of fine to coarse well-stratified gravelly sands and sandy gravels, and 4) brown to red brown silty clay.

There is evidence of soil development on the existing paleosurface in the form of red oxidation zone and a slight calcareous development at the base. A possible paleosol may exist at the upper surface of the lowermost silty clay. Otherwise, none of the intervening contacts appear to represent surfaces of long-term stability. The strongly oxidized soils on the eastern side of the trench are discontinuous to the west because of the modern alluviation by the regional drainage.

Trench PV-BH-33 was excavated across a broad scarp connecting two levels of paved surfaces which were known to have similar soil profile development. The actual scarp was

about 4 to 5 degrees, necessitating a relatively long trench (about 225 feet) (figure 2A-11).

Essentially, trench PV-BH-33 showed a similar lithologic grouping as PV-BH-32, i.e., from top to bottom: 1) red brown gravelly silty sand than was strongly oxidized, 2) gray brown massive silt and sandy silt, 3) brown, well stratified gravelly sands and sandy gravels. At the west end of PV-BH-33, these three main stratigraphic divisions extend uninterrupted throughout the length of the scarp, i.e., from about station 00 to 150. The contacts are distinct and can be located within 1 inch. The lower sand and gravel unit is commonly well stratified, and contains many continuous distinctive subunits too numerous to be included as detailed in the log on figure 2A-11. As in trench PV-BH-32, the major continuous contacts have minor irregularities due to erosion, but are continuous and essentially horizontal across the scarp area.

Throughout the entire lithologic section, the eastern end of trench PV-BH-33, starting from about station 150, shows the influence of strong lateral variation in deposition. Prominent channeling and in-filling has created cut and fill structures and interfingering between fine and coarse grain units (figure 2A-11). All of the areas between stations 145 and 175 were carefully inspected and logged in detail for any indication of faults or shears. Numerous interbeds within the main lithologic units were traced to show direct or overlapping continuity of the strata. Interfingering contacts were carefully inspected for any sign of shearing or other surfaces which might suggest a fault. In each case

the abrupt termination of contacts is due to normal erosional/depositional processes. These conclusions were confirmed by continuity of subunits above and below such features.

Trenches PV-BH-32 and 33 begin on the same elevated paleosurface and extend across the scarps to lower, more recent surfaces. In terms of relative elevation between the two trenches, level surveys indicate that the highest paleosurface (i.e., the point of highest ground surface encountered by the trenches) varies from 100 (assumed) in PV-BH-33 to 96.5 in PV-BH-32 or about 3.5 feet difference in about 1200 feet of horizontal distance.

Based on lithology and soil profile development, each of the trenches terminates in a different lower surface. PV-BH-32 terminates in a Holocene surface at about relative elevation 92.5. PV-BH-33 terminates on a late Pleistocene surface at elevation 93.

In terms of relative elevations on the main stratigraphic division between the two trenches:

	PV-BH-32 east end	PV-BH-33 west end
Ground Surface	96.5	100.0
Contact between sandy gravel and massive gray brown silt	94.0	97.5
Contact between massive gray brown silt and stratified sand and gravels	88.2	91.7
Contact between stratified sand and gravel and red brown clay	79.5	not exposed

Therefore, there is a remarkable consistency in the elevation of the paleosurface between the two trenches and that consistency (about 3.5 feet difference) is maintained between the major stratigraphic divisions exposed in both trenches.

The results of the trenching were definitive in establishing the following characteristics about the scarp origin:

1) There are distinctive strata within the alluvial deposits underlying the scarps whose contacts can be clearly identified to within at least 1 inch.

2) The stratigraphic horizons are continuous, unwarped, and unbroken throughout the length of the trenches. Where local lateral variation has made direct correlation of gross contacts difficult, there are numerous subunit contacts which can be correlated or overlapped to confirm stratigraphic continuity.

3) The continuity of the stratigraphy confirms that the origin of the scarps cannot be due to faulting or any other tectonic cause.

Regarding the origin of the scarps, our observations are in general agreement with the revised interpretations of Menges; viz., the data suggest the following history:

1) The primary surficial deposits which currently form the upper surface for the scarps were deposited, as a minimum, in late Pleistocene time. Estimates of 55,000 - 100,000 years have been made by Menges based on soil development.

2) The observed scarp was formed by downcutting or lateral cutting in late Pleistocene (30,000 - 80,000 years) along a channel system which is no longer present.

3) Subsequent changes to the pediment drainage network by stream capture and alterations in the Hassayampa River.

4) Late Pleistocene to Holocene slope degradation and stabilization followed by soil formation which have produced the presently observed geomorphic and soil stratigraphic characteristics at the scarp.

The results of the trenching demonstrated that similar sequences of nontectonic events can explain the formation of other anomalous features in the eastern scarp group of the Hassayampa scarp system. Specifically, the field inspections of the eastern scarps showed the following:

1) The most obvious scarps nearest the Hassayampa River coincide exactly with the margins of the flood channel of Jackrabbit Wash. The scarps are smoothly arcuate in plan and have steep scarp angles up to 35 to 40 degrees indicating active influences of erosion. Tributary drainages across the scarp have carved deep embayments and have made nearly all the scarps irregular with no evidence of disruption of tributary drainages or their associated alluvial deposits.

2) In contrast, the scarps farther west from the Hassayampa River and Jackrabbit Wash are shorter,

more subtle and range in angle from 10° to 30°. The scarps occur along the edges of older, elevated alluvial fan deposits which have been incised by tributary drainages to the Hassayampa River. Similar to the scarps which were trenched (PV-BH-32 and 33), the paleosurface in the eastern scarp area has been preserved and the paleoslopes stabilized along the drainage divides between the tributary basins. Hand leveling shows that the preserved paleosurfaces are of uniform elevation across the drainages and could not have been differentially uplifted. In detail, the scarps are not linear and there has been no direct observation of faulting.

In addition, this region was closely inspected during the early site selection studies for PVNGS by two nationally recognized experts in tectonic geomorphology; viz., Dr. Lawrence Lattman and Dr. Roy Shlemon. Neither expert noted any anomalous conditions in this area to suggest faulting. We believe these latest studies confirm the original interpretation and give support to the conclusion that the scarps in the Hassayampa region are due to normal processes of basin deposition and erosion.

The final conclusion reached by this study is that the scarps interpreted by Menges are due to erosion and preservation of paleosurfaces. The trenches established conclusively that faults are not associated with the scarps and that nontectonic explanations must account for their origin. Menges has reviewed all the data and concurs with this conclusion. As a result, since no faults are

associated with the scarps, the scarps have no safety significance to the site and the original interpretation of the geomorphology of the site vicinity as presented in the FSAR has been confirmed.

APPENDIX 2B

ANNUAL JOINT FREQUENCY DISTRIBUTIONS OF WIND SPEED AND WIND DIRECTION BY ATMOSPHERIC STABILITY CLASS FOR PVNGS BASED ON 35-FOOT WINDS (1973 - 1978) and (1986 – 1991)

HISTORICAL INFORMATION

1973 - 1978

STABILITY CLASS: A

ELEVATION: 35 FEET DELTA T (200.0 - 35.0) FEET

MILES PER HOUR

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
N	0	1	0	1	1	1	0	8	9	3	3	0	27
NNE	0	0	2	3	1	5	2	5	4	4	2	0	28
NE	0	0	1	3	3	1	6	5	8	2	3	0	32
ENE	0	0	2	5	7	6	3	4	12	10	7	3	59
E	0	0	1	7	8	13	6	15	28	49	64	12	203
ESE	0	0	4	11	12	15	19	34	29	21	8	3	156
SE	0	0	4	16	12	28	22	29	8	3	2	0	124
SSE	0	1	2	10	13	15	24	32	18	7	3	0	125
S	0	0	3	7	14	23	29	48	32	21	23	3	203
SSW	0	0	1	11	15	18	39	77	137	75	61	15	449
SW	0	0	5	4	4	12	24	101	223	218	182	45	818
WSW	0	0	2	3	4	11	11	59	120	103	57	7	377
W	0	0	3	3	5	5	3	27	60	41	28	3	178
WNW	0	0	0	0	1	2	7	10	17	23	30	18	108
NW	0	1	1	0	2	2	1	5	6	17	20	9	64
NNW	0	0	0	0	0	1	0	9	8	21	24	6	69
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	0	3	31	84	102	158	196	468	719	618	517	124	3020

PERIODS OF CALMS 0 HOURS

STABILITY CLASS: B

ELEVATION: 35 FEET DELTA T (200.0 - 35.0) FEET

MILES PER HOUR

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
N	0	0	3	5	3	1	4	7	8	4	5	0	40
NNE	0	0	3	1	5	5	1	3	4	5	1	0	28
NE	0	0	1	3	7	12	3	6	4	7	4	0	47
ENE	0	0	1	7	11	17	16	9	13	9	5	3	91
E	0	0	3	20	22	22	19	46	59	53	31	5	200
ESE	0	1	7	20	34	35	43	68	42	17	4	0	271
SE	0	0	7	14	38	48	29	43	12	0	1	3	195
SSE	0	0	8	28	34	41	37	34	18	3	3	2	208
S	0	0	9	17	26	41	44	49	38	14	5	2	245
SSW	0	0	2	7	22	25	30	66	80	27	20	3	282
SW	0	1	0	8	14	23	37	90	127	77	59	8	444
WSW	0	0	1	3	8	13	11	60	106	47	21	0	270
W	0	0	2	2	5	10	13	22	49	27	9	3	142
WNW	0	0	1	1	2	3	2	8	24	18	18	4	81
NW	0	0	1	2	4	3	5	4	7	9	10	0	45
NNW	0	0	0	1	5	2	4	5	10	6	9	2	44
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	0	2	49	139	240	301	298	520	601	323	205	35	2713

PERIODS OF CALMS 0 HOURS

HISTORICAL INFORMATION

1973 - 1978

STABILITY CLASS: C

ELEVATION: 35 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	0	0	0	6	6	7	1	6	2	0	1	1	30
NNE	0	0	3	4	7	4	5	6	4	2	0	0	35
NE	0	1	2	6	10	10	7	10	5	4	3	2	60
ENE	0	1	6	13	20	17	10	15	12	9	5	1	109
E	0	1	5	26	30	44	51	45	56	39	23	1	321
ESE	0	2	12	45	46	46	44	52	41	12	2	1	303
SE	0	3	17	38	56	54	32	39	8	5	1	1	254
SSE	0	0	11	27	42	46	45	23	8	1	4	1	208
S	0	0	11	38	49	47	37	37	15	7	4	0	245
SSW	0	0	7	24	32	35	36	78	36	27	15	5	295
SW	0	1	4	4	16	35	40	106	88	50	44	7	395
WSW	0	1	4	5	15	15	18	66	63	28	20	2	237
W	0	0	3	9	8	13	9	24	39	13	13	1	132
WNW	0	0	0	3	9	9	3	16	20	16	12	3	91
NW	0	0	1	3	6	11	10	9	14	16	12	1	83
NNW	0	0	2	4	6	2	6	9	10	5	6	1	51
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	0	10	88	255	358	395	354	541	421	234	165	28	2849

PERIODS OF CALMS 0 HOURS

STABILITY CLASS: D

ELEVATION: 35 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	0	14	31	26	11	7	9	11	10	5	5	0	129
NNE	0	10	25	33	32	17	12	13	19	8	5	0	174
NE	1	6	32	65	42	39	23	22	8	6	12	5	261
ENE	2	5	33	80	95	55	38	64	38	17	18	2	447
E	4	26	70	134	143	91	82	134	123	77	52	11	947
ESE	0	13	87	165	158	132	86	112	78	21	11	4	867
SE	2	22	110	178	144	118	57	49	20	9	2	1	712
SSE	0	23	115	136	134	95	48	26	12	7	11	5	612
S	2	22	89	147	124	99	68	40	29	27	29	7	683
SSW	0	16	59	134	110	101	66	94	101	57	92	37	867
SW	0	20	54	110	96	86	63	157	219	139	187	13	1144
WSW	0	10	39	56	61	57	60	110	140	98	81	13	725
W	0	12	23	41	38	36	35	72	101	56	43	5	462
WNW	0	5	21	31	28	29	20	35	41	35	55	21	321
NW	0	6	21	22	18	21	10	27	22	23	28	20	218
NNW	0	13	25	24	16	19	11	13	19	13	13	1	167
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	11	223	834	1382	1250	1002	688	979	980	598	644	145	8736

PERIODS OF CALMS 7 HOURS

HISTORICAL INFORMATION

1973 - 1978

STABILITY CLASS: E

ELEVATION: 35 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	2	12	44	38	26	15	17	11	15	17	9	0	206
NNE	2	16	25	39	39	30	23	22	22	7	11	1	237
NE	3	14	35	52	46	32	25	23	22	4	9	1	266
ENE	1	15	26	49	37	39	38	52	44	17	3	0	321
E	0	15	25	46	40	41	30	58	74	52	19	3	403
ESE	0	12	33	44	42	34	29	43	33	15	1	1	287
SE	2	7	38	57	29	26	21	38	19	6	9	2	254
SSE	1	8	59	52	55	28	28	22	15	11	9	1	289
S	1	19	52	72	43	48	29	44	31	15	11	0	365
SSW	0	15	49	51	46	61	50	97	119	61	56	6	611
SW	0	19	33	41	54	72	83	190	314	215	120	4	1145
WSW	1	15	38	28	43	49	52	157	280	132	39	3	837
W	2	11	30	32	28	36	48	119	106	49	20	0	481
WNW	0	11	18	23	21	23	20	54	94	57	47	2	370
NW	1	15	26	33	26	21	13	31	49	70	57	8	350
NNW	2	10	32	24	17	16	11	20	24	17	19	0	192
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	18	214	563	681	592	571	517	981	1261	745	439	32	6614

PERIODS OF CALMS 13 HOURS

STABILITY CLASS: F

ELEVATION: 35 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	0	23	71	99	71	54	28	33	23	10	2	0	414
NNE	1	17	66	73	79	68	41	31	19	14	3	0	412
NE	0	14	64	93	67	50	33	32	14	9	1	0	377
ENE	0	8	50	66	55	40	36	34	26	6	0	0	321
E	6	23	51	69	55	50	24	41	30	4	3	1	357
ESE	0	16	56	56	54	37	22	14	9	1	2	1	268
SE	2	18	51	61	33	24	21	20	3	1	1	1	236
SSE	0	21	58	42	39	22	25	18	9	0	0	1	235
S	1	15	51	79	60	38	33	26	10	4	1	0	318
SSW	0	20	42	47	67	45	41	64	67	5	0	0	398
SW	1	14	47	61	63	72	77	167	187	35	1	0	725
WSW	0	22	52	62	66	77	42	106	115	9	0	0	551
W	2	22	50	64	56	58	56	117	71	3	0	0	499
WNW	0	12	40	46	37	42	40	61	40	0	1	0	319
NW	0	22	48	60	45	49	26	51	44	3	1	0	349
NNW	0	17	53	61	67	50	35	42	41	10	1	0	377
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	13	284	850	1039	914	776	580	857	708	114	17	4	6156

PERIODS OF CALMS 20 HOURS

HISTORICAL INFORMATION

1973 - 1978

STABILITY CLASS: G

ELEVATION: 35 FEET DELTA T (200.0 - 35.0) FEET

MILES PER HOUR

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
N	5	99	234	394	391	229	144	97	40	9	0	0	1642
NNE	3	75	213	355	422	319	211	158	101	23	5	0	1865
NE	1	59	173	246	200	155	96	75	44	7	2	0	1058
ENE	1	37	115	119	94	56	29	27	7	3	1	0	489
E	2	43	122	130	148	96	54	49	14	1	0	0	659
ESE	3	41	117	121	122	85	35	22	3	0	0	0	549
SE	3	37	76	80	49	35	15	5	1	0	1	0	302
SSE	4	24	77	56	41	31	6	4	1	1	0	0	245
S	5	42	103	185	167	103	50	24	8	0	0	0	687
SSW	4	44	74	73	60	21	10	12	3	1	0	0	302
SW	3	30	71	69	49	24	13	31	23	2	2	0	317
WSW	3	32	97	115	62	44	30	10	5	0	0	0	398
W	3	36	89	79	78	48	32	14	6	0	0	0	385
WNW	5	42	83	74	44	22	16	15	2	0	0	0	303
NW	5	48	140	142	82	56	29	20	6	2	1	0	531
NNW	2	73	197	258	193	130	47	47	11	2	1	0	961
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	52	762	1981	2496	2202	1454	817	610	275	51	13	0	10713

PERIODS OF CALMS 33 HOURS

STABILITY CLASS: ALL

ELEVATION: 35 FEET DELTA T (200.0 - 35.0) FEET

MILES PER HOUR

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
N	7	149	383	569	509	314	203	173	107	48	25	1	2488
NNE	6	118	337	508	585	448	295	238	173	63	27	1	2799
NE	5	94	308	468	375	299	193	173	105	39	34	8	2101
ENE	4	66	233	339	319	230	170	205	152	71	39	9	1837
E	12	108	277	432	446	357	268	388	384	275	192	33	3170
ESE	3	85	316	462	468	384	278	345	235	87	28	10	2701
SE	9	87	303	444	361	333	197	223	71	24	17	8	2077
SSE	5	77	330	351	358	278	213	159	81	30	30	10	1922
S	9	98	318	545	483	399	290	266	163	88	73	12	2746
SSW	4	95	234	347	352	306	272	488	543	253	244	66	3204
SW	4	85	214	297	296	324	337	842	1181	736	595	77	4988
WSW	4	80	233	272	259	266	224	568	829	417	218	25	3395
WWNW	7	81	200	230	218	206	196	395	432	189	113	12	2279
NW	5	70	163	178	142	130	108	199	238	149	163	48	1593
NNW	6	92	238	262	183	163	94	147	148	140	129	38	1640
VARIABLE	4	113	309	372	304	220	114	145	123	74	73	10	1861
TOTALS	0	0	0	0	0	0	0	0	0	0	0	0	0
	94	1498	4396	6076	5658	4657	3450	4956	4965	2683	2000	368	40801

PERIODS OF CALMS 73 HOURS

APPENDIX 2B

HISTORICAL INFORMATION

1973 - 1978

OBSERVATIONS WITH MISSING DATA 2944

TOTAL OBSERVATIONS FOR THE PERIOD ARE 40874

PERCENTAGE OCCURRENCE OF STABILITY CLASSES

A	B	C	D	E	F	G
7.39	6.64	6.97	21.39	16.21	15.11	26.29

APPENDIX 2B

1986 – 1991 JOINT FREQUENCY DISTRIBUTION TABLES

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SARGENT & LUNDY, ENGINEERS JOINT FREQUENCY DISTRIBUTION

ANALYSIS AND TECHNOLOGIES DIV. (WIND SPEED, DIRECTION, AND STABILITY

FOR 1986 -1991

PALO VERDE 35 FT LEVEL

PASQUILL STABILITY CLASS A

DISTRIBUTION OF OCCURENCES BY SPEED AND DIRECTION

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	0
0.00<WS< 1.51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.51<WS< 2.51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.51<WS< 3.51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
3.51<WS< 4.51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.51<WS< 5.51	1	1	0	0	1	3	2	0	1	0	0	0	0	1	1	0	11
5.51<WS< 6.51	0	2	1	1	3	1	1	5	2	2	3	4	0	0	0	0	25
6.51<WS< 8.50	1	2	4	2	7	14	8	8	27	61	89	46	14	6	3	0	292
8.50<WS< 11.50	2	3	5	9	51	18	7	11	64	212	316	140	55	23	5	3	924
11.50<WS< 14.50	4	1	3	4	31	10	3	3	30	118	245	46	36	26	17	11	588
14.50<WS< 20.50	5	2	5	11	24	2	1	1	20	92	190	27	16	48	25	21	490
WS> 20.50	0	0	2	1	1	0	0	1	5	8	30	11	5	9	1	4	78
TOTALS	13	11	20	28	118	48	22	29	149	493	873	274	126	113	53	39	2409

FREQUENCY OF OCCURRENCE (% OF TOTAL OBSERVATIONS)

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	.00
0.00<WS< 1.51	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1.51<WS< 2.51	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
2.51<WS< 3.51	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
3.51<WS< 4.51	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
4.51<WS< 5.51	.00	.00	.00	.00	.00	.01	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.02
5.51<WS< 6.51	.00	.00	.00	.00	.01	.00	.00	.01	.00	.00	.01	.01	.00	.00	.00	.00	.05
6.51<WS< 8.50	.00	.00	.01	.00	.01	.03	.02	.02	.05	.12	.17	.09	.03	.01	.01	.00	.56
8.50<WS< 11.50	.00	.01	.01	.02	.10	.03	.01	.02	.12	.40	.60	.27	.10	.04	.01	.01	1.76
11.50<WS< 14.50	.01	.00	.01	.01	.06	.02	.01	.01	.06	.23	.47	.09	.07	.05	.03	.02	1.12
14.50<WS< 20.50	.01	.00	.01	.02	.05	.00	.00	.00	.04	.18	.36	.05	.03	.09	.05	.04	.93
WS> 20.50	.00	.00	.00	.00	.00	.00	.00	.00	.01	.02	.06	.02	.01	.02	.00	.01	.15
TOTALS	.02	.02	.04	.05	.23	.09	.04	.06	.28	.94	1.66	.52	.24	.22	.10	.07	4.59

APPENDIX 2B

1986 – 1991 JOINT FREQUENCY DISTRIBUTION TABLES

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SARGENT & LUNDY, ENGINEERS JOINT FREQUENCY DISTRIBUTION

ANALYSIS AND TECHNOLOGIES DIV. (WIND SPEED, DIRECTION, AND STABILITY)

FOR 1986 -1991

PALO VERDE 35 FT LEVEL

PASQUILL STABILITY CLASS B

DISTRIBUTION OF OCCURENCES BY SPEED AND DIRECTION

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	0
0.00<WS< 1.51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.51<WS< 2.51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.51<WS< 3.51	0	1	0	1	0	0	0	0	0	0	0	0	0	0	1	0	3
3.51<WS< 4.51	0	1	3	4	1	1	1	1	1	1	0	1	2	2	1	1	21
4.51<WS< 5.51	3	2	5	8	6	4	15	14	16	18	12	8	1	4	1	0	117
5.51<WS< 6.51	2	9	7	10	18	27	28	42	56	48	58	16	13	7	4	5	350
6.51<WS< 8.50	7	10	19	34	63	60	31	57	121	197	196	97	58	17	6	5	978
8.50<WS< 11.50	4	4	13	28	91	47	29	31	65	131	222	112	49	13	13	7	859
11.50<WS< 14.50	1	9	3	9	56	12	6	0	15	34	85	37	10	14	13	10	314
14.50<WS< 20.50	0	3	5	12	37	4	1	0	4	22	45	15	10	22	8	11	199
WS> 20.50	0	0	2	0	3	0	1	0	0	3	8	4	1	1	0	2	25
TOTALS	17	39	57	106	275	155	112	145	278	454	626	290	144	80	47	41	2866

FREQUENCY OF OCCURRENCE (% OF TOTAL OBSERVATIONS)

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	.00
0.00<WS< 1.51	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1.51<WS< 2.51	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
2.51<WS< 3.51	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01
3.51<WS< 4.51	.00	.00	.01	.01	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.04
4.51<WS< 5.51	.01	.00	.01	.02	.01	.01	.03	.03	.03	.03	.02	.02	.00	.01	.00	.00	.22
5.51<WS< 6.51	.00	.02	.01	.02	.03	.05	.05	.08	.11	.09	.11	.03	.02	.01	.01	.01	.67
6.51<WS< 8.50	.01	.02	.04	.06	.12	.11	.06	.11	.23	.38	.37	.18	.11	.03	.01	.01	1.86
8.50<WS< 11.50	.01	.01	.02	.05	.17	.09	.06	.06	.12	.25	.42	.21	.09	.02	.02	.01	1.64
11.50<WS< 14.50	.00	.02	.01	.02	.11	.02	.01	.00	.03	.06	.16	.07	.02	.03	.02	.02	.60
14.50<WS< 20.50	.00	.01	.01	.02	.07	.01	.00	.00	.01	.04	.09	.03	.02	.04	.02	.02	.38
WS> 20.50	.00	.00	.00	.00	.01	.00	.00	.00	.00	.01	.02	.01	.00	.00	.00	.00	.05
TOTALS	.03	.07	.11	.20	.52	.30	.21	.28	.53	.87	1.19	.55	.27	.15	.09	.08	5.47

APPENDIX 2B

1986 – 1991 JOINT FREQUENCY DISTRIBUTION TABLES

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SARGENT & LUNDY, ENGINEERS JOINT FREQUENCY DISTRIBUTION

ANALYSIS AND TECHNOLOGIES DIV. (WIND SPEED, DIRECTION, AND STABILITY)

FOR 1986 -1991

PALO VERDE 35 FT LEVEL

PASQUILL STABILITY CLASS C

DISTRIBUTION OF OCCURENCES BY SPEED AND DIRECTION

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	0
0.00<WS< 1.51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.51<WS< 2.51	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1
2.51<WS< 3.51	0	3	3	1	1	3	2	5	1	1	03	1	1	1	1	3	30
3.51<WS< 4.51	9	10	10	8	15	7	13	17	27	23	12	15	6	2	5	2	181
4.51<WS< 5.51	14	12	31	27	24	37	66	73	126	105	61	40	9	17	8	9	659
5.51<WS< 6.51	9	10	30	28	51	58	56	117	184	154	106	63	26	15	9	8	924
6.51<WS< 8.50	11	14	38	70	83	88	68	94	136	162	192	93	53	16	8	6	1132
8.50<WS< 11.50	1	11	11	46	76	44	21	25	33	61	136	101	38	26	17	15	662
11.50<WS<14.50	2	5	7	20	53	8	1	4	6	22	75	32	21	15	4	7	282
14.50<WS<20.50	3	0	6	18	46	4	0	3	4	13	34	11	8	13	8	5	176
WS> 20.50	1	0	1	1	9	1	0	1	0	4	3	4	1	1	1	1	29
TOTALS	50	65	137	220	358	250	227	339	517	545	622	360	163	106	61	56	4076

FREQUENCY OF OCCURRENCE (% OF TOTAL OBSERVATIONS)

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	.00
0.00<WS<1.51	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1.51<WS< 2.51	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
2.51<WS< 3.51	.00	.01	.01	.00	.00	.01	.00	.01	.00	.00	.01	.00	.00	.00	.00	.01	.06
3.51<WS< 4.51	.02	.02	.02	.02	.03	.01	.02	.03	.05	.04	.02	.03	.01	.00	.01	.00	.35
4.51<WS< 5.51	.03	.02	.06	.05	.05	.07	.13	.14	.24	.20	.12	.08	.02	.03	.02	.02	1.26
5.51<WS< 6.51	.02	.02	.06	.05	.10	.11	.11	.22	.35	.29	.20	.12	.05	.03	.02	.02	1.76
6.51<WS< 8.50	.02	.03	.07	.13	.16	.17	.13	.18	.26	.31	.37	.18	.10	.03	.02	.01	2.16
8.50<WS<11.50	.00	.02	.02	.09	.14	.08	.04	.05	.06	.12	.26	.19	.07	.05	.03	.03	1.26
11.50<WS<14.50	.00	.01	.01	.04	.10	.02	.00	.01	.01	.04	.14	.06	.04	.03	.01	.01	.54
14.50<WS<20.50	.01	.00	.01	.03	.09	.01	.00	.01	.01	.02	.06	.02	.02	.02	.02	.01	.34
WS> 20.50	.00	.00	.00	.00	.02	.00	.00	.00	.00	.01	.01	.01	.00	.00	.00	.00	.06
TOTALS	.10	.12	.26	.42	.68	.48	.43	.65	.99	1.04	1.19	.69	.31	.20	.12	.11	7.77

APPENDIX 2B

1986 – 1991 JOINT FREQUENCY DISTRIBUTION TABLES

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SARGENT & LUNDY, ENGINEERS JOINT FREQUENCY DISTRIBUTION

ANALYSIS AND TECHNOLOGIES DIV. (WIND SPEED, DIRECTION, AND STABILITY)

FOR 1986

-1991

PALO VERDE 35 FT LEVEL

PASQUILL STABILITY CLASS D

DISTRIBUTION OF OCCURENCES BY SPEED AND DIRECTION

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	4
0.00<WS<1.51	7	4	4	2	4	1	5	3	2	4	1	1	4	6	4	3	55
1.51<WS<2.51	49	33	45	37	48	53	62	50	55	71	65	54	50	42	50	38	802
2.51<WS<3.51	89	109	106	116	110	133	144	166	228	217	185	129	104	81	79	85	2081
3.51<WS<4.51	79	105	121	148	145	134	149	209	299	260	238	108	71	58	61	70	2255
4.51<WS<5.51	64	58	90	113	82	85	101	169	271	278	209	90	54	46	31	31	1772
5.51<WS<6.51	43	51	85	89	67	59	54	94	146	140	157	76	40	23	20	26	1170
6.51<WS<8.50	20	44	71	123	119	92	89	69	90	142	206	124	68	35	28	29	1349
8.50<WS<11.50	16	22	43	107	129	132	50	33	34	106	276	199	68	47	30	18	1310
11.50<WS<14.50	7	13	15	53	174	31	19	13	28	74	195	96	28	50	19	15	830
14.50<WS<20.50	2	14	16	45	180	11	10	13	30	81	182	48	27	42	23	17	741
WS>20.50	2	2	0	1	31	4	1	3	8	20	12	12	4	7	3	1	111
TOTALS	378	455	596	834	089	735	684	822	1191	1393	1726	937	518	437	348	333	12480

FREQUENCY OF OCCURRENCE (% OF TOTAL OBSERVATIONS)

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	.01
0.00<WS<1.51	.01	.01	.01	.00	.01	.00	.01	.01	.00	.01	.00	.00	.01	.01	.01	.01	.10
1.51<WS<2.51	.09	.06	.09	.07	.09	.10	.12	.10	.10	.14	.12	.10	.10	.08	.10	.07	1.53
2.51<WS<3.51	.17	.21	.20	.22	.21	.25	.27	.32	.43	.41	.35	.25	.20	.15	.15	.16	3.97
3.51<WS<4.51	.15	.20	.23	.28	.28	.26	.28	.40	.57	.50	.45	.21	.14	.11	.12	.13	4.30
4.51<WS<5.51	.12	.11	.17	.22	.16	.16	.19	.32	.52	.53	.40	.17	.10	.09	.06	.06	3.38
5.51<WS<6.51	.08	.10	.16	.17	.13	.11	.10	.18	.08	.27	.30	.14	.08	.04	.04	.05	2.23
6.51<WS<8.50	.04	.08	.14	.23	.23	.18	.17	.13	.17	.27	.39	.24	.13	.07	.05	.06	2.57
8.50<WS<11.50	.03	.04	.08	.20	.25	.25	.10	.06	.06	.20	.53	.38	.13	.09	.06	.03	2.50
11.50<WS<14.50	.01	.02	.03	.10	.33	.06	.04	.02	.05	.14	.37	.18	.05	.10	.04	.03	1.58
14.50<WS<20.50	.00	.03	.03	.09	.34	.02	.02	.02	.06	.15	.35	.09	.05	.08	.04	.03	1.41
WS> 20.50	.00	.00	.00	.00	.06	.01	.00	.01	.02	.04	.02	.02	.01	.01	.01	.00	.21
TOTALS	.72	.87	1.14	1.59	2.08	1.40	1.30	1.57	2.27	2.66	3.29	1.79	.99	.83	.66	.64	23.80

APPENDIX 2B

1986 - 1991 JOINT FREQUENCY DISTRIBUTION TABLES

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SARGENT & LUNDY, ENGINEERS JOINT FREQUENCY DISTRIBUTION

ANALYSIS AND TECHNOLOGIES DIV. (WIND SPEED, DIRECTION, AND STABILITY)

FOR 1986

-1991

PALO VERDE 35 FT LEVEL

PASQUILL STABILITY CLASS E

DISTRIBUTION OF OCCURENCES BY SPEED AND DIRECTION

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	11
0.00<WS<1.51	12	6	8	3	4	4	4	3	2	7	6	6	10	14	13	6	108
1.51<WS<2.51	71	58	37	37	21	26	31	27	34	34	48	57	72	65	82	67	767
2.51<WS<3.51	80	78	61	45	21	29	32	39	53	65	74	82	71	89	110	99	1028
3.51<WS<4.51	83	69	56	33	24	28	31	34	77	99	112	70	61	46	62	61	946
4.51<WS<5.51	57	60	55	33	25	12	28	34	63	120	136	76	37	31	39	50	856
5.51<WS<6.51	43	52	27	35	24	24	22	23	46	124	150	116	63	24	40	31	844
6.51<WS<8.50	33	58	70	83	49	44	47	50	64	230	346	229	111	53	40	29	1536
8.50<WS<11.50	15	31	54	112	101	78	54	41	58	255	512	320	114	85	76	30	1936
11.50<WS<14.50	11	14	18	60	110	39	14	12	49	143	301	104	47	50	56	21	1049
14.50<WS<20.50	5	11	16	23	126	4	3	8	20	75	77	27	18	46	22	16	497
WS> 20.50	0	0	2	2	11	0	1	0	2	4	2	5	0	3	0	3	35
TOTALS	410	437	404	466	516	288	267	271	468	1156	1764	1092	604	506	540	413	9613

FREQUENCY OF OCCURRENCE (% OF TOTAL OBSERVATIONS)

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	.02
0.00<WS<1.51	.02	.01	.02	.01	.01	.01	.01	.01	.00	.01	.01	.01	.02	.03	.02	.01	.21
1.51<WS<2.51	.14	.11	.07	.07	.04	.05	.06	.05	.06	.06	.09	.11	.14	.12	.16	.13	1.46
2.51<WS<3.51	.15	.15	.12	.09	.04	.06	.06	.07	.10	.12	.14	.16	.14	.17	.21	.19	1.96
3.51<WS<4.51	.16	.13	.11	.06	.05	.05	.06	.06	.15	.19	.21	.13	.12	.09	.12	.12	1.80
4.51<WS<5.51	.11	.11	.10	.06	.05	.02	.05	.06	.12	.23	.26	.14	.07	.06	.07	.10	1.63
5.51<WS<6.51	.08	.10	.05	.37	.05	.05	.04	.04	.09	.24	.29	.22	.12	.05	.08	.06	1.61
6.51<WS<8.50	.06	.11	.13	.16	.09	.08	.09	.10	.12	.44	.66	.44	.21	.10	.08	.06	2.93
8.50<WS<11.50	.03	.06	.10	.21	.19	.15	.10	.08	.11	.49	.98	.61	.22	.16	.14	.06	3.69
11.50<WS<14.50	.02	.03	.03	.11	.21	.07	.03	.02	.09	.27	.57	.20	.09	.10	.11	.04	2.00
14.50<WS<20.50	.01	.02	.03	.04	.24	.01	.01	.02	.04	.14	.15	.05	.03	.09	.04	.03	.95
WS> 20.50	.00	.00	.00	.00	.02	.00	.00	.00	.00	.01	.00	.01	.00	.01	.00	.01	.07
TOTALS	.78	.83	.77	.89	.98	.55	.51	.52	.89	2.20	3.36	2.08	1.15	.96	1.03	.79	18.33

APPENDIX 2B

1986 – 1991 JOINT FREQUENCY DISTRIBUTION TABLES

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SARGENT & LUNDY, ENGINEERS JOINT FREQUENCY DISTRIBUTION

ANALYSIS AND TECHNOLOGIES DIV. (WIND SPEED, DIRECTION, AND STABILITY)

FOR

1986

-1991

PALO VERDE 35 FT LEVEL

PASQUILL STABILITY CLASS F

DISTRIBUTION OF OCCURENCES BY SPEED AND DIRECTION

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	8
0.00<WS<1.51	18	8	9	7	2	6	4	3	1	0	5	6	6	12	16	7	110
1.51<WS<2.51	111	73	53	39	30	19	20	18	24	19	37	54	65	95	110	88	855
2.51<WS<3.51	193	120	94	43	35	26	28	29	50	64	80	137	133	116	179	218	1545
3.51<WS<4.51	173	114	73	27	19	12	13	25	38	66	102	103	95	101	103	183	1247
4.51<WS<5.51	114	87	48	21	15	12	11	13	31	66	112	108	74	71	70	109	962
5.51<WS<6.51	57	63	32	19	9	4	11	15	200	61	152	88	81	56	57	68	793
6.51<WS<8.50	54	54	49	37	16	8	8	17	28	163	349	168	151	72	63	88	1325
8.50<WS<11.50	31	20	29	3	11	7	7	10	8	108	188	82	42	17	31	63	687
11.50<WS<14.50	4	9	9	15	4	3	3	0	0	5	9	1	2	2	12	10	88
14.50<WS<20.50	0	0	4	2	3	0	0	0	1	0	3	0	0	0	1	3	17
WS>20.50	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
TOTALS	755	548	400	243	145	97	105	130	201	552	1037	747	649	542	642	837	7638

FREQUENCY OF OCCURRENCE (% OF TOTAL OBSERVATIONS)

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	.02
0.00<WS<1.51	.03	.02	.02	.01	.00	.01	.01	.01	.00	.00	.01	.01	.01	.03	.03	.01	.21
1.51<WS<2.51	.21	.14	.10	.07	.06	.04	.04	.03	.05	.04	.07	.10	.12	.18	.21	.17	1.63
2.51<WS<3.51	.37	.23	.18	.08	.07	.05	.05	.06	.10	.12	.15	.26	.25	.22	.34	.42	2.95
3.51<WS<4.51	.33	.22	.14	.05	.04	.02	.02	.05	.07	.13	.19	.20	.18	.19	.20	.35	2.38
4.51<WS<5.51	.22	.17	.09	.04	.03	.02	.020	.02	.03	.13	.21	.21	.14	.14	.13	.21	1.83
5.51<WS<6.51	.11	.12	.06	.04	.02	.01	.02	.03	.04	.12	.29	.17	.15	.11	.11	.13	1.51
6.51<WS<8.50	.10	.10	.09	.07	.03	.02	.02	.03	.05	.31	.67	.32	.29	.14	.12	.17	2.53
8.50<WS<11.50	.05	.04	.06	.06	.02	.01	.01	.02	.02	.21	.36	.16	.08	.03	.06	.12	1.31
11.50<WS<14.50	.01	.02	.02	.03	.01	.01	.01	.00	.00	.01	.02	.00	.00	.00	.02	.02	.17
14.50<WS<20.50	.00	.00	.01	.00	.01	.00	.00	.00	.00	.00	.01	.00	.00	.00	.00	.01	.03
WS>20.50	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
TOTALS	1.44	1.05	.76	.46	.28	.18	.20	.25	.38	1.05	1.98	1.42	1.24	1.03	1.22	1.60	14.57

APPENDIX 2B

1986 - 1991 JOINT FREQUENCY DISTRIBUTION TABLES

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SARGENT & LUNDY, ENGINEERS

ANALYSIS AND TECHNOLOGIES DIV.

JOINT FREQUENCY DISTRIBUTION
(WIND SPEED, DIRECTION, AND STABILITY)
FOR 1986
-1991
35 FT LEVEL

PALO VERDE

PASQUILL STABILITY CLASS G

DISTRIBUTION OF OCCURENCES BY SPEED AND DIRECTION

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	11
0.00<WS<1.51	37	23	12	8	4	1	3	3	5	6	3	8	10	20	36	25	204
1.51<WS<2.51	322	205	143	52	21	17	34	30	30	38	42	77	111	155	223	333	1828
2.51<WS<3.51	916	590	239	87	45	32	30	22	33	62	58	99	133	214	456	797	3813
3.51<WS<4.51	1106	758	239	85	29	17	14	13	20	24	48	51	76	110	269	636	3495
4.51<WS<5.51	718	564	153	44	16	6	3	8	14	16	28	30	35	30	96	259	2020
5.51<WS<6.51	349	287	85	12	6	2	3	2	4	9	24	20	14	20	35	133	1005
6.51<WS<8.50	202	205	85	20	4	0	0	2	2	14	27	13	8	10	19	73	684
8.50<WS<11.50	50	91	27	15	0	0	2	1	0	14	28	4	2	0	0	24	258
11.50<WS<14.50	6	16	4	5	0	0	1	0	0	0	0	0	0	0	0	1	33
14.50<WS<20.50	0	1	0	0	0	0	0	0	0	4	0	0	0	0	0	0	5
WS> 20.50	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	2
TOTALS	3706	2740	987	328	125	75	90	81	108	189	258	302	389	554	1134	2281	13358

FREQUENCY OF OCCURRENCE (% OF TOTAL OBSERVATIONS)

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	.02
0.00<WS<1.51	.07	.04	.02	.02	.01	.00	.01	.01	.01	.01	.01	.02	.02	.04	.07	.05	.39
1.51<WS<2.51	.61	.39	.27	.10	.04	.03	.06	.06	.06	.07	.08	.15	.21	.29	.43	.64	3.49
2.51<WS<3.51	1.75	1.13	.46	.17	.09	.06	.06	.04	.06	.12	.11	.19	.25	.41	.87	1.52	7.27
3.51<WS<4.51	2.11	1.45	.46	.16	.06	.03	.03	.02	.04	.05	.09	.10	.14	.21	.51	1.21	6.66
4.51<WS<5.51	1.37	1.08	.29	.08	.03	.01	.01	.02	.03	.03	.05	.06	.07	.06	.18	.49	3.85
5.51<WS<6.51	.67	.55	.16	.02	.01	.00	.01	.00	.01	.02	.05	.04	.03	.04	.07	.25	1.92
6.51<WS<8.50	.39	.39	.16	.04	.01	.00	.00	.00	.00	.03	.05	.02	.02	.02	.04	.14	1.30
8.50<WS<11.50	.10	.17	.05	.03	.00	.00	.00	.00	.00	.03	.05	.01	.00	.00	.00	.05	.49
11.50<WS<14.50	.01	.03	.01	.01	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.06
14.50<WS<20.50	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.00	.00	.00	.00	.00	.00	.01
WS> 20.50	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
TOTALS	7.07	5.23	1.88	.63	.24	.14	.17	.15	.21	.36	.49	.58	.74	1.06	2.16	4.35	25.47

APPENDIX 2B

1986 - 1991 JOINT FREQUENCY DISTRIBUTION TABLES

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SARGENT & LUNDY, ENGINEERS JOINT FREQUENCY DISTRIBUTION

ANALYSIS AND TECHNOLOGIES DIV. (WIND SPEED, DIRECTION, AND STABILITY)

FOR

1986 -1991

PALO VERDE 35 FT LEVEL

PASQUILL STABILITY CLASS A

DISTRIBUTION OF OCCURENCES BY SPEED AND DIRECTION

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	34
0.00<WS<1.51	74	41	33	20	14	12	16	12	10	17	15	21	30	52	69	41	477
1.51<WS<2.51	553	369	278	166	120	115	147	125	143	162	192	242	298	352	465	526	4253
2.51<WS<3.51	1278	901	503	293	212	223	236	261	365	409	400	448	442	501	827	1202	8501
3.51<WS<4.51	1450	1057	502	305	233	199	221	299	462	473	512	348	311	319	501	953	8145
4.51<WS<5.51	971	784	382	246	169	159	226	311	522	603	558	352	210	200	246	458	6397
5.51<WS<6.51	503	474	267	194	178	175	175	298	458	538	650	383	237	145	165	271	5111
6.51<WS<8.50	328	387	336	369	341	306	251	297	468	969	1405	770	463	209	167	230	7296
8.50<WS<11.50	119	182	182	350	459	326	170	152	262	887	1678	958	368	211	172	160	6636
11.50<WS<14.50	35	67	59	166	428	103	47	32	128	396	910	316	144	157	121	75	3184
14.50<WS<20.50	15	31	52	111	416	25	15	25	79	287	531	128	79	171	87	73	2125
WS>20.50	3	2	7	5	56	5	3	5	15	41	55	36	11	21	5	11	281
TOTALS	5329	4295	2601	2225	2626	1648	1507	1817	2912	4782	6906	4002	2593	2338	2825	4000	52440

FREQUENCY OF OCCURRENCE (% OF TOTAL OBSERVATIONS)

SPEED (MPH)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	TOTAL
CALM																	.06
0.00<WS<1.51	.14	.08	.06	.04	.03	.02	.03	.02	.02	.03	.03	.04	.06	.10	.13	.08	.91
1.51<WS<2.51	1.05	.70	.53	.32	.23	.22	.28	.24	.27	.33	.37	.46	.57	.67	.89	1.00	8.11
2.51<WS<3.51	2.44	1.72	.96	.56	.40	.43	.45	.50	.70	.78	.76	.85	.84	.96	1.58	2.29	16.21
3.51<WS<4.51	2.77	2.02	.96	.58	.44	.38	.42	.57	.88	.90	.98	.66	.59	.61	.96	1.82	15.53
4.51<WS<5.51	1.85	1.50	.73	.47	.32	.30	.43	.59	1.00	1.15	1.06	.67	.40	.38	.47	.87	12.20
5.51<WS<6.51	.96	.90	.51	.37	.34	.33	.33	.57	.87	1.03	1.24	.73	.45	.28	.31	.52	9.75
6.51<WS<8.50	.63	.74	.64	.70	.65	.58	.48	.57	.89	1.85	2.68	1.47	.88	.40	.32	.44	13.91
8.50<WS<11.50	.23	.35	.35	.67	.88	.62	.32	.29	.50	1.69	3.20	1.83	.70	.40	.33	.31	12.65
11.50<WS<14.50	.07	.13	.11	.32	.82	.20	.09	.06	.24	.76	1.74	.60	.27	.30	.23	.14	6.07
14.50<WS<20.50	.03	.06	.10	.21	.79	.05	.03	.05	.15	.55	1.01	.24	.15	.33	.17	.14	4.05
WS>20.50	.01	.00	.01	.01	.11	.01	.01	.01	.03	.08	.10	.07	.02	.04	.01	.02	.54
TOTALS	10.16	8.19	4.96	4.24	5.01	3.14	2.87	3.46	5.55	9.12	13.17	7.63	4.94	4.46	5.39	7.63	100.00

RECOVERY RATE = 99.73 %

Stability class summary table:

	A	B	C	D	E	F	G
Number	2,409	2,866	4,076	12,480	9,613	7,638	13,358
Percent	4.59	5.47	7.77	23.80	18.33	14.57	25.47

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APPENDIX 2C

ANNUAL JOINT FREQUENCY DISTRIBUTIONS

OF WIND SPEED AND WIND DIRECTION

BY ATMOSPHERIC STABILITY CLASS

FOR PVNGS BASED ON 200-FOOT WINDS

(AUGUST 13, 1973 - AUGUST 13, 1978)

STABILITY CLASS: A
ELEVATION: 200 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	0	0	1	0	1	0	1	6	8	6	3	2	28
NNE	0	0	1	0	4	3	5	6	11	6	4	0	40
NE	0	0	2	1	2	2	2	4	9	6	8	4	40
ENE	0	0	0	2	4	7	10	7	11	12	13	4	70
E	0	1	0	5	11	9	6	10	22	31	72	32	199
ESE	0	1	1	4	13	11	13	31	23	27	11	4	139
SE	0	0	2	15	12	16	21	26	13	8	3	0	116
SSE	0	0	0	7	13	12	15	43	26	11	3	0	130
S	0	0	2	7	8	11	27	47	46	26	29	9	212
SSW	0	0	1	6	7	7	17	46	124	103	119	39	469
SW	0	0	0	1	5	14	12	65	162	174	253	82	768
WSW	0	0	1	3	3	3	13	18	77	74	78	23	293
W	0	0	1	3	4	1	4	18	41	42	42	16	172
WNW	0	0	0	1	2	2	2	7	14	10	37	24	99
NW	0	0	1	1	1	1	4	5	5	12	21	20	71
NNW	0	1	1	1	1	2	1	5	7	8	29	16	72
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	0	3	14	57	91	101	153	344	599	556	725	275	2918

PERIODS OF CALMS 0 HOURS

STABILITY CLASS: B
ELEVATION: 200 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	0	0	0	1	3	2	2	6	7	7	4	1	33
NNE	0	0	1	1	5	5	8	4	6	5	6	1	42
NE	0	0	2	6	2	7	14	10	9	5	6	0	61
ENE	0	0	3	6	10	16	7	19	19	9	13	3	105
E	0	0	0	15	13	19	17	60	53	57	41	14	289
ESE	0	1	0	13	23	28	33	51	54	14	4	2	223
SE	0	0	4	15	29	34	35	44	19	6	1	3	190
SSE	0	0	4	9	20	37	40	32	25	4	1	5	177
S	0	0	6	15	22	23	31	61	55	26	7	5	251
SSW	0	0	2	10	21	22	25	57	89	55	25	13	319
SW	0	0	0	7	6	17	25	60	94	86	94	21	410
WSW	0	0	0	2	6	9	18	29	64	64	29	10	231
S	0	0	1	2	2	9	10	17	32	30	23	8	134
WNW	0	0	0	2	1	6	5	4	11	14	27	9	79
NW	0	0	0	2	3	4	5	6	7	5	11	4	47
NNW	0	0	0	2	3	1	5	8	8	9	8	4	48
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	0	1	23	108	169	239	280	468	552	396	300	103	2639

PERIODS OF CALMS 0 HOURS

STABILITY CLASS: C
ELEVATION: 200 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	0	1	2	5	4	9	7	1	5	2	1	2	39
NNE	0	0	4	5	3	8	8	8	5	5	1	0	47
NE	0	1	0	6	13	18	12	10	4	5	4	2	75
ENE	0	0	2	11	15	20	18	22	15	10	8	3	124
E	0	0	7	24	33	32	37	65	64	38	28	10	338
ESE	0	2	2	21	45	54	40	47	31	14	9	3	268
SE	0	0	9	25	37	37	35	49	13	5	3	2	215
SSE	0	0	8	28	31	47	30	51	15	2	2	1	215
S	0	0	5	27	33	33	32	42	29	9	11	1	222
SSW	0	0	6	9	22	40	31	63	60	24	25	15	295
SW	0	0	4	14	10	28	24	73	105	63	55	21	397
WSW	0	0	2	4	10	9	16	42	57	40	25	10	215
W	0	1	1	3	8	13	11	12	29	17	21	4	120
WNW	0	0	0	3	6	2	6	11	15	13	27	9	92
NW	0	0	0	1	5	7	2	16	17	4	8	9	69
NNW	0	0	1	1	7	6	3	6	3	6	10	2	45
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	0	5	53	187	282	363	312	518	467	257	238	94	2776

PERIODS OF CALMS 0 HOURS

STABILITY CLASS: D
ELEVATION: 200 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	0	6	25	27	71	13	10	6	12	5	13	2	136
NNE	2	4	26	41	25	31	16	11	21	9	13	6	205
NE	2	5	22	63	51	46	20	36	21	14	9	13	302
ENE	2	7	35	80	94	63	46	56	51	29	26	18	507
E	3	8	58	121	128	123	98	134	137	93	77	29	1009
ESE	2	11	79	104	133	89	76	121	88	32	21	10	766
SE	2	17	78	114	124	111	85	60	37	16	10	6	660
SSE	1	12	75	106	105	79	51	42	22	9	7	13	522
S	0	8	62	106	114	98	79	62	35	28	36	30	658
SSW	0	13	53	105	89	99	57	93	100	69	87	105	870
SW	0	4	33	82	56	81	73	105	194	153	252	132	1165
WSW	0	6	25	49	48	49	40	76	106	98	107	38	642
S	0	6	27	34	40	28	28	46	65	64	57	32	427
WNW	0	6	19	20	13	16	18	36	36	22	64	65	315
NW	0	5	12	21	15	17	12	16	19	13	27	24	181
NNW	0	3	15	21	18	10	9	18	11	10	11	9	135
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	14	121	644	1094	1076	953	718	918	955	664	817	532	8500

PERIODS OF CALMS 5 HOURS

STABILITY CLASS: E

ELEVATION: 200 FEET DELTA T (200.0 - 35.0) FEET

MILES PER HOUR

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
N	0	3	14	13	17	9	15	15	13	8	28	16	151
NNE	1	8	11	22	17	28	12	23	26	13	25	6	192
NE	0	5	19	38	32	29	24	43	34	15	20	10	269
ENE	3	4	24	24	21	29	33	55	68	36	43	9	349
E	7	6	18	34	42	37	29	63	84	73	82	26	501
ESE	1	7	23	28	27	29	26	36	32	24	30	4	267
SE	1	6	24	30	29	21	15	26	19	21	20	2	214
SSE	1	8	9	28	18	27	18	27	28	12	14	17	207
S	1	8	34	32	29	24	20	47	43	28	26	9	301
SSW	1	6	19	30	26	29	21	55	103	105	163	56	614
SW	0	7	23	27	36	39	50	115	184	258	431	145	1315
WSW	0	7	19	17	15	22	32	75	122	183	232	33	757
W	0	10	14	15	21	13	16	44	74	111	114	17	449
WNW	0	6	16	15	12	11	10	24	43	35	133	59	364
NW	1	3	11	9	12	6	13	30	19	36	93	69	302
NNW	1	4	13	12	8	14	5	12	20	17	15	26	147
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	18	98	291	374	362	367	339	690	912	975	1469	504	6399

PERIODS OF CALMS 2 HOURS

STABILITY CLASS: F

ELEVATION: 200 FEET DELTA T (200.0 - 35.0) FEET

MILES PER HOUR

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
N	0	7	23	25	13	17	17	29	29	19	18	1	198
NNE	2	9	20	31	29	39	25	45	55	34	28	20	337
NE	2	11	20	46	51	70	51	76	46	17	18	12	420
ENE	2	8	25	44	44	38	41	44	56	21	21	8	352
E	2	20	24	43	35	36	45	58	61	42	41	7	414
ESE	0	9	34	27	26	26	25	42	27	18	11	5	250
SE	1	12	23	28	21	21	9	32	14	5	2	1	169
SSE	0	9	22	23	22	16	17	17	20	11	4	2	163
S	0	10	28	22	24	36	24	43	31	20	16	4	258
SSW	0	8	23	30	33	42	33	68	74	69	72	9	461
SW	1	7	22	25	54	40	55	140	207	183	208	13	955
WSW	0	7	20	21	45	24	55	99	140	127	98	3	619
S	1	7	22	30	25	33	28	52	114	100	63	1	476
WNW	0	7	13	12	24	16	19	40	72	57	59	0	319
NW	1	7	22	17	16	17	17	38	56	56	76	7	330
NNW	0	9	13	25	14	22	13	29	33	32	31	4	225
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	12	147	354	449	476	493	474	852	1035	811	766	97	5966

PERIODS OF CALMS 3 HOURS

STABILITY CLASS: G
ELEVATION: 200 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	1	24	78	122	96	99	68	140	91	30	31	4	784
NNE	10	32	74	103	138	179	153	248	219	72	70	28	1326
NE	9	27	88	151	161	208	203	324	237	83	48	18	1557
ENE	2	20	91	122	134	151	135	184	98	25	31	2	995
E	1	28	102	103	123	110	73	116	55	23	17	3	754
ESE	3	28	76	99	89	59	32	47	21	13	5	1	473
SE	2	21	83	76	56	43	18	22	12	2	1	0	336
SSE	4	28	72	74	58	33	21	17	7	4	0	1	319
S	1	29	74	101	76	50	51	49	22	13	3	0	469
SSW	2	32	81	71	48	48	26	39	34	17	17	1	416
SW	2	23	73	78	77	60	44	75	53	32	25	1	543
WSW	0	20	78	88	69	49	44	75	70	37	5	0	535
W	3	24	61	73	55	42	37	60	68	32	7	0	462
WNW	1	17	42	50	53	31	24	37	40	22	4	2	323
NW	0	24	63	71	72	49	40	78	73	52	29	2	553
NNW	2	20	55	91	80	67	53	114	99	44	26	2	653
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	43	397	1191	1473	1385	1278	1022	1625	1199	501	319	65	10498

PERIODS OF CALMS 18 HOURS

STABILITY CLASS: ALL
ELEVATION: 200 FEET DELTA T (200.0 - 35.0) FEET

DIRECTION	.5-.74	.75-1.5	1.51-2.5	2.51-3.5	3.51-4.5	4.51-5.5	5.51-6.5	6.51-8.5	8.51-11.5	11.51-14.5	14.51-20.5	>20.5	TOTAL
					MILES PER HOUR								
N	1	41	143	193	151	149	120	203	165	77	98	28	1369
NNE	15	53	137	203	221	293	227	345	343	144	147	61	2189
NE	13	49	153	311	312	380	326	503	360	145	113	59	2724
ENE	9	39	180	289	322	324	290	387	318	142	155	47	2502
E	13	63	209	345	385	366	305	506	476	357	358	121	3504
ESE	6	59	215	296	356	296	245	375	276	142	91	29	2386
SE	6	56	223	303	308	283	218	259	127	63	40	14	1900
SSE	6	57	190	275	267	251	192	229	143	53	31	39	1733
S	2	55	211	310	306	275	264	351	261	150	128	58	2371
SSW	3	59	185	261	246	287	210	421	584	442	508	238	3444
SW	3	41	155	234	244	279	283	633	999	949	1318	415	5553
WSW	0	40	145	184	196	165	218	414	636	623	574	117	3312
S	4	48	127	160	155	139	134	249	423	396	327	78	2240
WNW	01	36	90	103	111	84	84	159	231	173	351	168	1591
NW	2	39	109	122	124	101	93	189	196	178	265	135	1553
NNW	3	37	98	153	131	122	89	192	181	126	130	63	1325
VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS	87	772	2570	3742	3835	3794	3298	5415	5719	4160	4634	1670	39696

PERIODS OF CALMS 28 HOURS

OBSERVATIONS WITH MISSING DATA 4094

TOTAL OBSERVATIONS FOR THE PERIOD ARE 39724

PERCENTAGE OCCURRENCE OF STABILITY CLASSES

A	B	C	D	E	F	G
7.35	6.64	6.99	21.41	16.11	15.03	26.47

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APPENDIX 2D

GEOLOGIC MAPPING OF EXCAVATIONS

FOR CATEGORY I STRUCTURES

APPENDIX 2D

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APPENDIX 2D
GEOLOGIC MAPPING OF EXCAVATIONS FOR CATEGORY I STRUCTURES

2D.1 INTRODUCTION

2D.1.1 PURPOSE

This appendix presents the results of the detailed geologic inspection and mapping of excavations for Category I structures at the Palo Verde Nuclear Generating Station (PVNGS). The purpose of the inspection and mapping program at PVNGS is to establish and document in detail the subsurface geologic conditions in the power block areas to confirm that conclusions regarding geologic and geotechnical properties made during earlier investigations are valid.

2D.1.2 SCOPE AND METHODOLOGY

The scope of the documentation of geologic conditions in these excavations included:

- Detailed mapping of geologic units in the walls and floors of each excavation at a scale of 1 inch = 10 feet
- Identification of soils exposed in the excavation
- Detailed logging of areas requiring special attention at scales of 1 inch = 1 foot or other appropriate scales
- Verification by the NRC staff of preliminary maps, profiles, and detailed logs during their onsite inspection of the power block excavations

- Finalization of the as-graded geologic maps and production of a brief report of the geology of each unit. The methodology employed during mapping operations was as follows:
- Divide the excavation into map areas based on slope configurations
- Locate survey control points to establish control for the base map
- Map the geology to identify the major stratigraphic units and locate the contacts between them
- Tag key points along contacts for surveying
- Plot surveyed points on base maps and sections of the map units at a scale of 1 inch = 10 feet (these plotted points were used for location control during mapping)
- Prepare detailed graphic logs of areas requiring special attention by establishing a control grid system across the area and making measurements to critical points

2D.1.3 SUMMARY OF RESULTS

The results of detailed mapping in the power block excavations demonstrate that the geology exposed in the walls and floors of the excavations conforms to the geologic model of the powerblock areas developed from surface and subsurface data during earlier siting studies. The models were reported in the PVNGS Units 1, 2, and 3 PSAR. The geologic units exposed in the excavations are lithologic zones (LZs) 5 and 4

(figures 2.5-16 and 2.5-17). The only deviation from the earlier geologic model is the character of stratigraphic unit C. This unit has been removed locally by erosion prior to or during deposition of the over-lying coarse-grained sands and gravels of stratigraphic unit B, and thus it is discontinuous throughout the area. The original model showed stratigraphic unit C as a continuous layer in the power block area.

No safety-related geologic features such as faults, subsidence, liquefaction, or other tectonic features or processes were revealed by mapping. The contact between stratigraphic units D and E was well defined and could be traced continuously around the base of the excavations. The continuity of the D/E contact, which is also the contact between LZs 5 and 4, demonstrates an absence of faulting of sediments older than 500,000 years (figure 2.5-17).

Preliminary copies of all maps, cross-sections, and detailed logs for Units 1, 2, and 3 were presented to the NRC staff during their onsite inspections of the excavations (September 1976, May 1977, September 1978). Following an examination of the maps and cross-sections and visual inspection of the geology, the excavations were approved by the NRC for construction.

2D.1.4 GEOLOGY

2D.1.4.1 Geologic Models

The geologic models were developed from surface and subsurface investigations conducted during the siting study and borehole foundation investigation for PVNGS (refer to subsection 2.5.1).

The initial geologic investigation of the PVNGS site determined that the stratigraphic column beneath the site could be divided into three major groups:

- Precambrian metamorphic and granitic rocks - designated basement rock
- Miocene volcanic and interbedded sedimentary rock - designated bedrock
- Middle Miocene to Holocene basin sediments consisting of alluvial, colluvial, fluvial, and lacustrine basin-filling deposits, with local interbeds of Pliocene-lower Pleistocene volcanic flows

The areal distribution of these groups is shown in figures 2.5-2, 2.5-8, and 2.5-12 and in cross-section (figure 2.5-9). Age data and brief lithic descriptions are shown on figure 2.5-17. The rocks and sediments of the basin sediments (QTbf) which overlie the basement and bedrock groups were further subdivided into six LZs using data from continuously sampled borings. The stratigraphic relationships between these lithologic zones are shown in figure 2.5-17. From youngest to oldest, the lithologic zones identified during the siting study within the basin sediments are:

- LZ-6 Fan deposits (Pleistocene to Holocene)
- LZ-5 Upper sand and gravel deposit
- LZ-4 Upper silt deposit
- LZ-3 Palo Verde clay (upper Pliocene)

- LZ-2 Lower silt and lower sand and gravel deposits
- LZ-1 Fanglomerate (Miocene-Pliocene)

LZ-2 through LZ-5 are unlithified zones of Pliocene and Pleistocene age, and together with the overlying deposit, LZ-6, were designated the "alluvial sequence".

A total of 17 horizons, designated A through M, were recognized in the alluvial sequence (LZ 2-6) beneath the PVNGS units.

These horizons are referred to as "stratigraphic units" in this appendix. The upper five stratigraphic units, A through E, are exposed in the power block excavations. Table 2D-1 summarizes the approximate thickness of these stratigraphic units and the major soil types. Stratigraphic units A through D correspond to LZ-5. They are coarse-grained soils with only the relatively thin, discontinuous, stratigraphic unit C containing any appreciable amount of clay. Stratigraphic unit E is a fine-grained sequence of silts and clays corresponding to the upper portion of LZ-4. The contact between the fine-grained stratigraphic unit E and the overlying coarse-grained material of stratigraphic unit D forms a major change in the stratigraphic column beneath the PVNGS site.

APPENDIX 2D

Table 2D-1

STRATIGRAPHIC UNITS A THROUGH E BASED ON BORING LOG INFORMATION

Stratigraphic Unit	Approximate Thickness (ft)	LZ Desig-nation	Soil Type
A	5 to 17	LZ-5	Sandy silt, silty sand, gravelly silty sand, clayey sand
B	10 to 24	LZ-5	Sand with silt, sand
C	3 to 8	LZ-5	Sandy clay, clayey sand
D	3 to 20	LZ-5	Gravelly silty sand, sandy gravel, clayey sand, silty sand, sandy silt
E	20 to 32	LZ-4	Silty clay, clayey silt

2D.2 PVNGS UNIT 1

2D.2.1 GENERAL

Stratigraphic units A through E can be recognized in the walls of the excavation, and demonstrate stratigraphic continuity beneath PVNGS Unit 1. The most easily defined contact lies between stratigraphic units D and E. This contact marks a major change in the basin stratigraphic column, separating light-colored sand and gravel (LZ-5) above from the dark-colored silt and clay (LZ-4) below. The contact is marked by numerous small erosional cut-and-fill sedimentary structures, but due to the sharp contrast in both color and lithic type, the contact can be precisely located to within a few inches. Detailed geologic mapping (figure 2D-1) shows that the contact extends around the Unit 1 excavation, unbroken, demonstrating an absence of faulting in the basin sediments.

Except for stratigraphic unit C, the 40 to 45 feet of sediments which lie above the D/E contact are coarse-grained and represent moderate to high energy alluvial depositional environments not unlike that occurring in the area today. Portions of stratigraphic unit C have been removed by erosion locally. Both erosional and gradational depositional features separate the stratigraphic units. Stratigraphic unit C consists of silty sand, sandy clay, clayey silt, and clayey sand and may be the result of deposition in a shallow playa or fluvial overbank deposits in abandoned stream channels and depressions.

Stratigraphic units C and D were combined to form a composite map unit designated CD on the preliminary as-graded geologic

map and profiles presented to the NRC regulatory staff at the time of their onsite inspection of the Unit 1 excavation. However, stratigraphic units C and D are shown separately in this appendix (figure 2D-1) to present the geology beneath PVNGS Unit 1 in as much detail as possible. This format does not alter any of the contacts shown on the preliminary geologic map.

2D.2.2 STRATIGRAPHY

2D.2.2.1 Geologic Models

Stratigraphic unit A is the uppermost map unit exposed within the PVNGS Unit 1 excavation. The average thickness of this unit is approximately 11 feet. The predominant soil types include brown, sandy and clayey silt, clayey sand, silty sand, sandy clay, and locally, gravelly sand. The coarse-grained soils are generally dense, noncalcareous to slightly calcareous, and consist of poorly sorted, angular to subangular, very fine-grained to coarse-grained quartz and lithic rock fragments. The largest clasts within the sands are 2 inches in diameter. The fines vary from about 12 to 35% of the coarse-grained soils.

The fine-grained soils have a low to medium plasticity and are stiff to hard. Silt, grading to very fine sand, is the most abundant fine-grained material. The soils are calcareous and contain abundant caliche nodules and root casts.

Individual soil types within stratigraphic unit A are discontinuous both horizontally and vertically and frequently grade into one another. No subunits of stratigraphic unit A

were differentiated in the PVNGS Unit 1 excavation. The stratigraphic unit's lower contact is undulatory and gradational with the underlying sediments.

2D.2.2.2 Stratigraphic Unit B

Stratigraphic unit B consists of gray to brown, silty sand and gravelly sand which is in conformable, gradational contact with the overlying stratigraphic unit A sediments. The average thickness of this unit is approximately 16 feet. Sands within stratigraphic unit B are loose, noncalcareous to slightly calcareous and consist of poorly to moderately sorted, angular to subangular, very fine-grained to coarse-grained quartz and lithic sand. Fines within the sands vary in percentage from about 12 to 25%. The sand grains of this unit grade from very fine to coarse and become cleaner with depth. Near the lower contact of the unit, the sands contain 10 to 30% gravel. Cross-bedded gravels and coarse-grained sands usually occur as fill in erosional channels cut into stratigraphic unit B sands. Lenses of finer grained clayey material also occur within the sands of stratigraphic unit B.

The fine-grained clayey soils have a low to medium plasticity, are very stiff to hard, and are slightly to highly calcareous. The sand in the fine-grained soils varies from about 10 to 40%. The soils are of limited horizontal and vertical extent, discontinuous, and frequently contain caliche nodules. The large, more-continuous, fine-grained beds are shown as B_1 on the as-graded map (figure 2D-1).

The contact of stratigraphic unit B with unit C is erosional with much of stratigraphic unit C being removed by erosion when unit B was deposited. This is suggested by erosional channels cut into stratigraphic unit C and by deposits of stratigraphic unit B in direct contact with unit D. Where unit C was not removed by erosion, the B/C contact is marked by a caliche unit.

2D.2.2.3 Stratigraphic Unit C

Stratigraphic unit C is 3 to 6 feet thick where exposed in the Unit 1 excavation. The predominant soil types found within this unit are brown to red-brown, silty clays, sandy clays, clayey silts, and clayey sands. The fine-grained soils are very stiff, have medium plasticity, are locally calcareous, and contain about 12 to 30% fine-grained sand. These fine-grained soils are capped by a 1- to 2-foot-thick discontinuous zone of hard, dense, white caliche and clay (figure 2D-1).

The fine-grained sediments found in stratigraphic unit C represent low energy depositional conditions such as presently occurs in shallow playa lakes or topographically low areas which collect overbank flood deposits. The interfingering bedding relationships with the overlying stratigraphic unit B sands indicate fluctuating water levels within the depositional basin.

Much of the contact between stratigraphic units B and C is erosional and reflects high energy deposition of stratigraphic unit B. Where stratigraphic unit C has not been completely removed by erosion, the contact with the underlying sands,

silts and clays of stratigraphic unit D is depositional. Geologic map area 21 (figure 2D-2) was mapped in detail because of a discontinuity in the caliche horizon C_1 and the underlying unit C. The discontinuity was determined to be an erosional irregularity not related to tectonic processes; units E and A are undisturbed above and below the area.

2D.2.2.4 Stratigraphic Unit D

Stratigraphic unit D is about 2 to 12 feet thick and is predominantly brown to red sand, silty sand, and gravelly sand. The sands are dense, noncalcareous to slightly calcareous and consist of poorly sorted, angular to subangular, very fine-grained to coarse-grained quartz and lithic rock fragments. The sands also contain cobbles to 10 inches in diameter and about 12 to 35% fines. The sands within stratigraphic unit D are locally cross-bedded. Locally discontinuous, thin lenses of stiff to hard clay and silt of low to medium plasticity are found interbedded with the coarse-grained material.

Individual horizons within this map unit are discontinuous both horizontally and vertically and commonly grade into one another. Lenses of brown silty clay and clayey silt, designated as D_1 on the as-graded geologic map (figure 2D-1), were mapped to clarify contact relationships. These fine-grained soils have a low to medium plasticity and are stiff to very stiff.

Stratigraphic unit D can be distinguished from stratigraphic unit B by its darker brown to red color, the higher percentage

of clay and silt, the presence of numerous soil horizons, and by its much more dense nature. The contact between stratigraphic unit D and the underlying soils and clays of unit E is a very sharp erosional contact marked by numerous and fill features.

2D.2.2.5 Stratigraphic Unit E

Stratigraphic unit E consists of homogeneous, dark-red-brown, silty clays and clayey silts with a lens of very fine-grained sand up to 4 feet thick. Maximum thickness of this stratigraphic unit exposed in the Unit 1 excavation is 28 feet. The silts and clays are very stiff to hard, exhibit medium to high plasticity, are noncalcareous to moderately calcareous, and contain scattered caliche nodules and up to 10% sand. Contacts between the silts and clays are highly gradational so it was not practical to separate these materials on the map. One silty sand horizon, designated E_1, was mapped in this unit. Sand within this horizon is brown to gray, dense, slightly calcareous, and contains poorly sorted, angular to subangular, very-fine- to medium-grained quartz and lithic sand.

2D.3 PVNGS UNIT 2

2D.3.1 GENERAL

Stratigraphic units A through E are recognized in the walls of the excavation and demonstrate stratigraphic continuity beneath PVNGS Unit 2 (figure 2D-3). The most obvious stratigraphic feature is the contact between stratigraphic units D and E. As

in the PVNGS Unit 1 excavation, this contact marks a distinctive change in the stratigraphic column, separating light-colored sand and gravel (LZ-5) above from the dark-colored silt and clay (LZ-4) below. The contact is erosional and marked along its length by numerous, small cut-and-fill structures, but due to the sharp contrasts in both color and lithic type across the contact, it can be located to within a few inches. The contact extends around the PVNGS Unit 2 excavation in a continuous, unbroken manner, demonstrating the absence of faulting in the basin sediments (figure 2D-3).

Except for stratigraphic unit C, the 40 to 45 feet of sediments which lie above the D/E contact are coarse-grained and represent moderate to high energy depositional environments. Strati-graphic unit C consists of silty and sandy clay, clayey silt, and clayey sand and may represent playa deposits or overbank sediments deposited in topographically low areas of the depositional basin. The PVNGS Unit 2 excavation exhibits the same erosional characteristics discovered in the PVNGS Unit 1 excavation. Both erosional and gradational contacts separate the stratigraphic units above the D/E contact. Cross-beds, cut-and-fill sedimentary structures, and other primary depositional features were identified during the detailed mapping. No evidence of faulting, liquefaction, or subsidence was observed.

2D.3.2 STRATIGRAPHY

2D.3.2.1 Stratigraphic Unit A

Stratigraphic unit A is the uppermost unit exposed within the PVNGS Unit 2 excavation. The average thickness of this unit is approximately 10 feet. The predominant soil types include brown, brownish yellow, and yellowish red, sandy and clayey silt, silty and sandy clay, silty and clayey sand, and gravelly sand. The coarse-grained soils are slightly dense to dense, calcareous, and consist of poorly sorted, angular to subrounded, very fine- to coarse-grained quartz, lithic and mica sands and gravels. The percentage of low- to medium-plasticity fines varies from about 21 to 35% in the coarse-grained soils.

The fine-grained soils have low to medium plasticity and are moderately firm to hard. Silt, grading to very fine-grained sand, is the most abundant fine-grained material. The fine- to coarse-grained sand within the fine-grained soils varies from 10 to 50%. These soils are calcareous with abundant caliche nodules and root casts.

Individual soils within stratigraphic unit A are discontinuous both horizontally and vertically and frequently grade into one another. Two subunits within stratigraphic unit A, designated A_1 and A_2 on the geologic map (figure 2D-3), were differentiated in the PVNGS Unit 2 excavation. The subunits comprise silty sands (A_2) and gravelly sands with occasional lenses of gravel and (or) silt (A_1). Subunit A_1 lies at the top of the stratigraphic unit A and is continuous around the PVNGS Unit 2 excavation. The lower contact of A_1 is erosional and commonly

has cut-and-fill sedimentary features. Subunit A_2 occurs as a lens near the base of stratigraphic unit A. The lower contact of stratigraphic unit A is undulatory and gradational into the underlying sediments.

2D.3.2.2 Stratigraphic Unit B

Stratigraphic unit B consists of gray to yellow brown, silty sand, sand, and gravelly sand which are in conformable, gradational contact with the overlying stratigraphic unit A sediments. The thickness of this unit varies from about 10 to 28 feet. Sands within stratigraphic unit B are loose to moderately dense, noncalcareous to slightly calcareous, and consist of poorly to moderately sorted, angular to subangular, fine- to coarse- grained quartz and lithic sand. Fines comprise from about 12 to 25% of the sands and exhibit low plasticity. The sands of this unit have fewer fines and grade from
fine-grained to coarse-grained as depth increases. Near the lower contact of the unit, the sands contain 10 to 35% gravel. Locally cross-bedded, coarse-grained gravels and sands are usually deposited as fill in erosional channels within the stratigraphic unit B sands. Lenses of fine-grained material occur locally within the sands of stratigraphic unit B.

The fine-grained soils have low to medium plasticity, are stiff, and are slightly to highly calcareous. Percentage of sand in the fine-grained soils varies from about 10 to 40%. The soils are of limited horizontal and vertical extent, discontinuous, and frequently contain caliche nodules. Local discontinuous lenses of silty clay, clayey silt, silt, sandy

silt, and gravelly sand are shown on the as-graded geologic map (figure 2D-3) as B_1 and B_2.

As was the case in the PVNGS Unit 1 excavation, the lower contact of stratigraphic unit B in the PVNGS Unit 2 excavation appears to be both erosional and depositionally contemporaneous with the underlying sediments. Large cut-and-fill structures are found along this contact and have removed much of unit C whereas in other areas the sediments of stratigraphic units B and C appear to be interbedded. A large cut-and-fill feature exposed on the bench near geologic map area 37 shows sands of stratigraphic unit B filling an old channel incised into stratigraphic units C and D.

2D.3.2.3 Stratigraphic Unit C

Stratigraphic unit C is thin, varying from about 4 to 10 feet in thickness where exposed in the PVNGS Unit 2 excavation. The predominant soil types within this unit are brown to reddish brown silty clays, sandy clays, clayey silts, and clayey sands. The fine-grained soils are very stiff, have medium plasticity, are locally calcareous, and contain about 12 to 30% fine-grained sand. The 1- to 2-foot-thick zone of hard white caliche and clay(C_1) capping the fine-grained soils in the PVNGS Unit 1 excavation is not present in the PVNGS Unit 2 excavation.

As in the PVNGS Unit 1 area, much of the contact between stratigraphic units B and C is erosional and reflects the high energy depositional conditions of stratigraphic unit B. As a result, stratigraphic unit C has been completely removed by

erosion in portions of the PVNGS Unit 2 excavation. The contact between stratigraphic units C and D is depositional.

2D.3.2.4 Stratigraphic Unit D

Stratigraphic unit D varies from 2 to 18 feet in thickness and is predominantly brown to red sand, silty sand, clayey sand, and gravelly sand. These sands are loose to dense, noncalcareous to slightly calcareous, and consist of poorly-sorted, angular to subangular, very fine-grained to coarse-grained quartz and lithic rock fragments. The sands also contain cobbles up to 10 inches in diameter and about 12 to 35% fines. Sands within stratigraphic unit D are locally cross-bedded. Locally discontinuous, thin lenses of stiff to hard clays and silts of low to medium plasticity are interbedded with the coarse-grained material.

Individual soils within this stratigraphic unit are discontinuous both horizontally and vertically and commonly grade into one another. Lenses of silty clay, clayey silt, sand, clayey sand and sandy silt, designated as D_1, D_2, D_3, and D_4 on the as-graded geologic map (figure 2D-3), were mapped to clarify contact relationships. The fine-grained soils, D_1, D_3, and D_4, have a low to medium plasticity and are firm to very stiff. The coarse-grained soils (D_2) are loose to moderately dense, poorly sorted to well sorted, angular to subangular, fine- to coarse-grained sand containing 12 to 30% fines. Stratigraphic unit D can be distinguished from stratigraphic unit B by its darker brown to red color, higher percentage of clay and silt, numerous distinct soils, and by its much more dense nature.

The contact between stratigraphic unit D and the underlying silts and clays of unit E is erosional and very sharp.

2D.3.2.5 Stratigraphic Unit E

Stratigraphic unit E consists of brown to reddish brown, silty clays and clayey silts with occasional thin lenses of very fine-grained sand. Maximum thickness of this stratigraphic unit, exposed in the PVNGS Unit 2 excavation, is 23 feet. The silts and clays are very stiff to hard with low to high plasticity, dry to saturated, noncalcareous to moderately calcareous, with locally caliche nodules, and 12 to 20% sand. Contacts between the silts and clays are highly gradational and it was not practical to map these soils separately.

Four fine- and coarse-grained horizons, designated E_1, E_2, E_3, and E_4, are exposed in the PVNGS Unit 2 auxiliary building excavation. These horizons are continuous to discontinuous and the contacts are gradational. The fine-grained soils (E_1, E_2, and E_3) are red to dark reddish brown, mottled brown-white and brown, stiff to hard with low to high plasticity. Horizon E_2 is clay, caliche, and caliche nodules. The coarse-grained soil, E_4, is brown to black and sand and silty sand. The sands are loose to moderately dense and consist of poorly to moderately sorted, angular to subangular, very fine- to fine-grained quartz sand.

2D.4 PVNGS UNIT 3

2D.4.1 GENERAL

Stratigraphic units A through E are exposed in the walls and floor of this excavation as in PVNGS Units 1 and 2 excavations and demonstrate stratigraphic continuity throughout the excavation and the site. As in the other excavations, the most obvious stratigraphic horizon is the contact between stratigraphic units D and E which marks the change from light-colored sand and gravel (LZ-5) on top to the dark-colored silt and clay below (LZ-4). The contact is irregular due to erosion that accompanied deposition of stratigraphic unit D, but the contact is easily mapped because of the difference in color and grain size of the two stratigraphic units. The contact is continuous around the excavation and demonstrates a lack of faulting.

Stratigraphic unit C is discontinuous and commonly completely removed by erosion during deposition of the overlying unit B. This forms a complex relationship and thus stratigraphic units C and D are not differentiated on the geologic map of the PVNGS Unit 3 excavation (figure 2D-5). Distinctive soils are differentiated, however, within the combined C/D stratigraphic unit. It should be noted that the stratigraphic units are generally similar from excavation to excavation but that the subdivisions (for example, A_1, A_2, etc.) do not represent directly correlative units. Detailed descriptions of subunits are given on figure 2D-5.

2D.4.2 STRATIGRAPHY

2D.4.2.1 Stratigraphic Unit A

Stratigraphic unit A is the uppermost stratigraphic unit exposed in the PVNGS Unit 3 excavation. This stratigraphic unit is generally about 10 feet thick. The unit has been subdivided into four soil units (figure 2D-5). Subunits A and A_1 are the most extensive.

Unit A_2 is a reddish brown to grayish, quartz and lithic sand exposed in the east wall of map areas 7 and 8. Unit A_3 is a caliche and clay unit exposed as small, scattered lenses generally between units A and A_1. Unit A is a silty sand, clayey and sandy silt, and silty and sandy clay which is distinguished from stratigraphic unit A_1, which is comprised of sands and gravel, by its grain size and color.

2D.4.2.2 Stratigraphic Unit B

Stratigraphic unit B is a sand and gravel unit which is distinguished primarily by its coarse grain size. The stratigraphic unit is subdivided into six subunits based on varying proportions of sand and gravel. Subunits B_1, B_2, and B_3 are generally finer than subunits B, B_4 and B_5. Subunits B and B_1 are the most pervasive. The contact between them is gradational.

Stratigraphic unit B is about 18 feet thick. Its upper contact with unit A is generally quite regular and distinct. The lower contact with stratigraphic unit CD is highly irregular with numerous erosional channels cut into the underlying unit.

2D.4.2.3 Stratigraphic Unit CD

Stratigraphic unit CD is comprised of seven subunits (figure 2D-5). The cumulative thickness is about 15 feet with subunit CD comprising at least 75% of the total thickness. Subunit CD is a reddish brown to yellowish brown, clayey gravelly sand, clayey sand, and sand. Gravel clasts reach diameters up to about 6 inches. The other subunits are generally finer grained and are very discontinuous both vertically and laterally. The upper contact with stratigraphic unit B is highly irregular, and as in PVNGS Units 1 and 2, is a result of extensive erosion of stratigraphic unit C and D. The lower contact with stratigraphic unit E is irregular but quite obvious due to the difference in grain size between the two stratigraphic units.

2D.4.2.4 Stratigraphic Unit E

Stratigraphic unit E is distinctive because of its fine grain size compared to other stratigraphic units exposed in the PVNGS Unit 3 excavation. This stratigraphic unit is mostly clay with a few scattered silts and sands. Four subunits are identified; subunits E and E_1 are the most extensive with subunits E_2 and E_3 occurring only as scattered lenses and pockets. Subunit E is a dark reddish brown to brown, silty clay to sandy clay. It is medium stiff to very stiff and has low to medium plasticity. Subunit E_1 is a grayish brown to reddish brown silty sand to sandy silt and clay.

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APPENDIX 2E

LABORATORY TESTS

APPENDIX 2E

LABORATORY TESTS

An extensive laboratory testing program was undertaken at PVNGS to classify soils and to determine subsurface engineering parameters for stability, settlement, and liquefaction analyses. A summary of the purpose and approximate number of tests presented in both the Units 1, 2, and 3 PSAR and the Units 4 and 5 PSAR is shown in table 2E-1.

Permeability test results are summarized in Appendix 2G.

X-ray diffraction tests are presented in Appendix 2R of the Units 1, 2, and 3 PSAR. Moisture-density test results are presented on the boring logs, Appendix 2K, of both the PVNGS 1, 2, and 3 PSAR and the PVNGS 4 and 5 PSAR. With a few minor exceptions, all other laboratory testing on soil samples is presented in Appendix 2T of the two PSARs.

In addition to the testing summarized in this appendix, a large number of in-place density tests, grain size analyses, compaction tests, and other index tests are being performed in conjunction with construction activities at the site.

APPENDIX 2E

Table 2E-1

LABORATORY TEST SUMMARY

Test	Primary Purpose	Total Number
Moisture-density	Physical properties and classification	7275
Atterberg limits	Physical properties and classification	1410
Grain-size analyses	Physical properties and classification	2224
Specific gravity	Physical properties and classification	601
X-ray diffraction	Chemical properties	30
Compaction	Compaction characteristics	35
Minimum/maximum density	Relative density	11
Static triaxial compression	Static strength and elastic parameters	198
Direct shear	Static strength	56
Cyclic triaxial	Modulus and damping parameters; liquefaction potential	237
Resonant column	Modulus and damping parameters	167
Consolidation	Compressibility	82
Permeability	Permeability	258
Unconfined compression (rock)	Static strength and elastic parameters	5
Disk tensile strength (rock)	Static strength	2

APPENDIX 2F

SUMMARY OF SUBSURFACE EXPLORATION

APPENDIX 2F

SUMMARY OF SUBSURFACE EXPLORATION

This appendix presents a summary of borings drilled and trenches excavated at the PVNGS site. A total of approximately 578 borings and 3 trenches were drilled and excavated, respectively, at locations shown in figure 2.5-70. A tabulation of detailed information for each boring and trench, such as coordinates, elevation, boring type, depth, drilling method, sample type, and remarks is presented in table 2F-1. Unless otherwise specified in table 2F-1, boring logs are presented in Appendix 2K of the PVNGS 1, 2, and 3 and PVNGS 4 and 5 PSARs. The borings included in the Units 1, 2, and 3 PSAR have the following prefixes: PV-, U1-, U2-, U3-, and borings E-18-1 through E-18-6. Included in the Units 4 and 5 PSAR are borings with a U4- or U5- prefix.

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 1 of 12)

Explanation of Symbols Used:		
Boring Type:	P =	Principal, S = Supplementary
Drilling Type:	R =	Rotary wash, A = Flight auger
	BA =	Bucket auger
	BH =	Backhoe
Sample Type:	P =	Pitcher tube, D = Drive sample, SPT = Standard penetration test, B = Bulk, C = Core, HB = Hand-carved block sample, SH = Shelby tube
Remarks:	1 =	Supplementary boring to evaluate effects of drill method on SPT blowcount.
	2 =	Limited interval boring.
	3 =	Groundwater observation well being monitored on a regular schedule as of March 1979.
	4 =	Crosshole seismic survey boring.
	5 =	Pump test well.
	6 =	Boring used to obtain block samples for liquefaction testing.
	7 =	Coordinates estimated using nearby surveyed boring locations for reference.
	8 =	Borings for which logs are not presented due to lack of sampling; typically in an area where logs are presented for nearby sampled borings.
	9 =	Inflow-type borehole permeability test.
	10 =	Logs presented in Appendix 21 of Units 4 and 5 PSAR.

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 2 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
PV- 1	869399	207209	934.9	357.5	P	R	P,D,C	-
PV- 2	864929	187771	970.0	450.0	P	R	D,P	-
PV- 3	876450	200500	968.0	489.0	P	R	D,P,C	-
PV- 4	874000	207650	957.0	500.0	S	R	-	-
PV- 5	866070	209800	937.8	430.0	P	R	D,C	-
PV- 6	866850	204450	930.0	290.0	P	R	D,C	-
PV- 7	869115	199656	940.1	490.0	S	R	-	3
PV- 8	871750	204900	942.0	450.0	P	R	D	-
PV- 9	872150	199050	949.2	297.5	S	R	C	-
PV-10	860350	196700	926.0	500.0	S	R	-	-
PV-11	858272	188917	940.0	500.0	P	R	D,C	-
PV-12	879650	191100	1059.6	237.0	P	R	D,P,C	-
PV-13	850000	208400	868.8	498.0	P	R	P,D	-
PV-14	860914	215138	919.8	200.0	P	R	D	-
PV-15	861000	220250	930.7	199.3	P	R	D	-
PV-16	855419	224481	884.4	241.5	P	R	D	-
PV-17	857198	238967	870.4	300.3	P	R	P	-
PV-18	868800	203950	933.0	431.5	S	R	C	-
PV-19	871595	209749	953.8	424.0	S	R	C	-
PV-20	871428	207297	942.1	552.5	P	R	D,P,C	-
PV-21	871549	212601	960.0	307.0	P	R	D,C	-
PV-22	871444	215182	950.2	488.5	P	R	D,P,C	-
PV-23	868876	209987	948.4	350.0	P	R	D,C	-
PV-24	868700	212485	944.6	535.0	P	R	D,P,C	-
PV-25	860939	215715	939.2	483.5	P	R	D,P,C	-
PV-26	857150	240600	892.0	307.5	P	R	C,D,P	-
PV-27	865150	207150	940.1	404.0	P	R	D,P,C	-
PV-28	866295	212780	926.6	721.0	P	R	P,C	-
PV-29	866098	215235	923.9	504.0	P	R	P,C,D	-
PV-30	863542	209933	924.7	526.0	P	R	D,P,C	-
PV-31	863717	212477	914.7	341.0	P	R	D,P,C	-
PV-32	863739	214891	917.2	437.0	P	R	D,P,C	-
PV-33	860827	209948	912.4	363.0	P	R	D,C	-
PV-34	860610	212380	906.5	337.0	P	R	D,C	-
PV-35	860685	217760	921.3	303.0	P	R	P	-
PV-36	858172	221940	911.8	300.0	P	R	P	-
PV-37	855251	228293	887.9	300.0	P	R	P	-
PV-38	856647	234013	875.0	300.0	P	R	D,P	-
PV-39	871103	196001	982.0	165.0	P	R	P,C	-
PV-40	871085	197729	944.0	149.0	P	R	P,D,C	-
PV-41	871739	198587	947.0	210.0	P	R	P,C	-
PV-42	870151	208597	945.1	545.0	P	R	P,C	-
PV-43	870053	211309	950.0	452.0	P	R	P,C	-
PV-43A	870125	211167	954.5	295.0	P	R	P,C	-
PV-43B	870053	211207	950.0	460.0	S	R	-	-
PV-43C	870033	211309	950.0	460.0	S	R	C	-
PV-44	869967	211115	946.2	465.5	P	R	P,C	-
PV-45	867486	211276	941.0	436.0	P	R	P,C	-
PV-46	867475	213922	933.9	374.0	P	R	P,C	-
PV-47	870507	216493	946.9	374.5	P	R	P,C	-
PV-48	874046	210050	963.0	251.0	P	R	P,C	-
PV-49	872655	212635	963.8	369.0	P	R	D,P,C	-
PV-50	874045	215234	962.0	494.0	P	R	P,C	-
PV-51	871350	217900	963.4	268.0	P	R	P,C	-

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 3 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
PV-52	868735	217878	952.1	505.0	P	R	D,P,C	-
PV-53	866111	217817	958.0	647.0	P	R	P,C	-
PV-54	855499	209736	885.6	300.0	P	R	P	-
PV-55	858164	209763	899.0	301.0	P	R	P	-
PV-56	870481	203577	936.5	248.0	P	R	P,C	-
PV-57	871355	201192	948.7	212.0	P	R	P,C	-
PV-58	877958	220525	983.0	306.0	P	R	P	-
PV-59	875234	217857	974.0	351.0	P	R	P	-
PV-60	858535	220334	922.0	250.0	P	R	P	-
PV-61	856353	221797	910.0	250.0	P	R	P	-
PV-62	857387	226570	901.0	250.0	P	R	P	-
PV-63	858249	230673	881.0	250.0	P	R	P	-
PV-64	859500	236450	914.0	250.0	P	R	P	-
PV-65	868515	209955	956.0	300.0	P	R	SPT,P,C	-
PV-66	868335	209950	945.0	357.0	P	R	P,SPT	-
PV-67	871449	209918	955.0	362.0	P	R	P,SPT	-
PV-68	871492	209976	956.0	300.0	P	R	SPT,P	-
PV-69	871380	209941	955.0	300.0	P	R	SPT,P	-
PV-70	871463	209846	952.0	300.0	P	R	P,SPT	-
PV-71	871259	210149	957.0	400.0	P	R	P,SPT	-
PV-72	871544	210152	957.0	300.0	P	R	P,SPT,D	-
PV-73	871510	209984	953.0	310.0	S	R	-	-
PV-74	871653	209917	955.0	300.0	P	R	P,SPT	-
PV-75	871789	209918	956.0	300.0	P	R	P,SPT	-
PV-76	871716	210013	958.0	300.0	P	R	D	-
PV-77	871887	210012	957.0	365.0	P	R	SPT	-
PV-78	871885	209861	956.0	360.0	P	R	D	-
PV-79	871715	209860	956.0	300.0	P	R	SPT	-
PV-80	871551	209960	955.0	300.0	P	R	D,SPT	-
PV-81	871716	209944	956.0	142.0	P	R	SPT	-
PV-82	871494	209702	954.0	360.0	P	R	D,SPT	-
PV-83	871601	210066	956.0	200.0	P	R	D,SPT	-
PV-84	871323	209992	955.0	300.0	P	R	SPT	-
PV-85	871449	211415	958.0	368.0	P	R	P,SPT	-
PV-86	871503	211467	957.0	249.5	P	R	P,SPT	-
PV-87	871379	211431	958.0	300.0	P	R	P,SPT	-
PV-88	871467	211349	958.0	300.0	P	R	P,SPT	-
PV-89	871193	211593	955.0	360.0	P	R	P,SPT,D	-
PV-90	871482	211667	957.0	300.0	P	R	SPT,P	-
PV-91	871264	211328	953.0	360.0	P	R	SPT,P	-
PV-92	871646	211467	958.0	302.0	P	R	P,SPT	-
PV-93	871779	211501	958.0	300.0	P	R	P,SPT	-
PV-94	871677	211572	958.0	300.0	P	R	D,SPT	-
PV-95	871945	211616	959.0	150.0	P	R	D,SPT	-
PV-96	871887	211469	959.0	315.0	P	R	D	-
PV-96A	871950	211541	959.0	76.0	P	R	SPT	-
PV-97	871722	211427	959.0	150.0	P	R	D,SPT	-
PV-98	871562	211386	958.0	150.0	P	R	D,SPT	-
PV-99	871700	211510	958.0	150.0	P	R	D,SPT	-
PV-100	871527	211216	959.0	300.0	P	R	D,SPT	-
PV-101	871558	211584	958.0	300.0	P	R	D,SPT	-
PV-102	871310	211460	956.0	80.0	P	R	D,SPT	-
PV-103	870703	211058	958.0	310.0	S	R	-	-
PV-104	871658	209686	954.0	350.0	P	R	P,SPT,D	-

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 4 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
PV-105	871353	209680	952.0	300.0	P	R	P,SPT	-
PV-106	871244	209917	954.0	300.0	P	R	P	-
PV-107	871118	209918	954.0	300.0	P	R	SPT,P	-
PV-108	871015	209917	953.0	350.0	P	R	SPT,D	-
PV-109	871013	209977	955.0	340.0	P	R	D,SPT	-
PV-110	871484	211406	958.2	300.0	S	R	-	-
PV-111	871519	211396	958.1	230.0	S	R	-	-
PV-112	869951	211055	955.0	370.0	P	R	P,SPT	-
PV-113	869689	211230	949.0	365.0	P	R	P,SPT,D	-
PV-114	869980	211309	951.0	300.0	P	R	P,SPT	-
PV-115	869761	210960	954.0	366.0	P	R	P,SPT,D	-
PV-116	870152	211109	956.0	300.0	P	R	P,SPT	-
PV-117	870287	211145	956.0	302.0	P	R	P,SPT	-
PV-118	870067	211230	951.0	100.0	P	R	D,SPT	-
PV-119	869807	211092	953.0	300.0	S	R	-	-
PV-120	871758	211863	960.0	100.0	P	R	D,SPT	-
PV-132	878770	211253	982.0	400.0	P	R	P,SPT	-
PV-133	881801	223140	989.0	400.0	S	R	-	-
PV-134	884434	225850	1010.0	400.0	S	R	-	-
PV-161	882492	220634	968.0	451.0	P	R	P	-
PV-162	887332	227683	1037.0	455.0	P	R	P	-
PV-163	889471	228118	1039.0	450.0	P	R	P	-
PV-164	870415	212697	954.0	100.0	S	R	-	-
PV-165	870520	212450	952.0	100.0	S	R	-	-
PV-168A	869550	211988	947.5	335.0	S	R	-	-
PV-168B	869526	211988	947.5	285.0	S	R	-	-
PV-168C	869579	212000	947.5	180.0	S	R	-	-
PV-169A	871679	212611	961.2	310.0	S	R	-	-
PV-169B	871661	212626	961.1	255.0	S	R	-	-
PV-169C	871675	212629	961.4	165.0	S	R	-	-
PV-170A	868993	212659	944.2	350.0	S	R	-	-
PV-170B	868993	212659	944.2	350.0	S	R	-	-
PV-170C	869009	212624	944.2	175.0	S	R	-	-
PV-171A	866354	212773	929.4	320.0	S	R	-	-
PV-171C	866339	212774	929.0	170.0	S	R	-	-
PV-172	871320	214460	922.5	80.0	P	R	P	-
PV-173	871168	213799	950.3	120.0	P	R	P	-
PV-173A	871169	213811	950.4	42.5	P	R	P	-
PV-174	871020	213130	955.1	92.5	P	R	SPT,P	-
PV-175	870822	212438	954.0	100.0	P	R	SPT,P	-
PV-176	871800	213690	953.5	87.5	P	R	SPT,P	-
PV-177	870550	213930	947.8	80.0	P	R	SPT,P	-
PV-178	870580	214685	922.7	20.0	P	R	SPT,P	-
PV-179	871738	214337	951.0	20.0	P	R	SPT,P	-
PV-180	871898	214479	921.6	22.5	P	R	SPT,P	-
PV-181	872021	215906	922.5	20.0	P	R	SPT,P	-
PV-182	871360	216223	922.5	20.0	P	R	SPT,P	-
PV-183	869575	214447	949.7	100.0	P	R	P	-
PV-184	871350	208600	948.3	34.5	P	R	SPT	-
PV-185	864501	208999	929.4	47.5	P	R	SPT	-
PV-185A	864498	209008	929.4	41.0	S	R	-	-
PV-186	864500	208000	931.1	42.1	P	R	SPT	-
PV- 5H	866215	209945	937.8	50.0	S	R	-	8
PV-14H	860939	215075	918.4	50.0	S	R	-	3,8

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 5 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
PV-20H	371360	207300	942.0	80.0	S	R	-	8
PV-21H	871430	212470	960.1	70.0	S	R	-	3,8
PV-22H	871464	214634	950.2	70.0	S	R	-	3,8
PV-24H	868667	212797	944.6	70.0	S	R	-	3,8
PV-25H	869131	215443	939.2	50.0	S	R	-	3,8
PV-28H	866240	212755	926.6	50.0	S	R	-	3,8
PV-29H	866119	215240	923.9	50.0	S	R	-	3,8
PV-30H	863487	209928	924.7	50.0	S	R	-	3,8
PV-31H	863769	212452	914.7	50.0	S	R	-	3,8
PV-32H	863740	214941	917.0	70.0	S	R	-	8
PV-33H	860827	210008	912.4	50.0	S	R	-	3,8
PV-34H	860613	212351	906.5	50.0	S	R	-	3,8
PV-Q1	870300	209619	951.9	126.5	S	R	-	3,8
PV-Q3	868500	210600	950.0	56.5	P	R	SPT	3,9
PV-Q5	865560	210600	936.2	75.0	S	R	-	3,8
PV-Q8	861100	207460	922.6	94.0	S	R	-	3,8
PV-TR-1	871138	212751	960.3	85.0	S	R	-	3,8
PV-TR-2	870986	212927	957.1	65.0	S	R	-	8
SB-A	870524	214168	945.5	350.0	S	R	-	4,8
SB-B	870518	214135	945.5	320.0	S	R	-	4,8
SB-C	870526	214080	945.5	350.0	S	R	-	4,8
SB-D	870527	213986	946.0	300.0	S	R	-	4,8
SB-E	870468	214227	945.0	300.0	S	R	-	4,8
SB-F	870469	214256	945.0	300.0	S	R	-	4,8
U1-B 1	870634	211439	953.0	483.0	P	R	SPT,P,C	-
U1-B 2	870647	211511	953.0	300.0	P	R	SPT,P	-
U1-B 3	870558	211418	954.0	300.0	P	R	SPT,P	-
U1-B 4	870689	211390	953.0	300.0	P	R	SPT,P	-
U1-B 5	870325	211472	952.0	365.0	P	R	SPT,D,P	-
U1-B 6	870522	211689	953.0	300.0	P	R	SPT,D,P	-
U1-B 7	870528	211259	956.7	365.0	P	R	SPT,D,P	-
U1-B 8	870785	211635	954.0	300.0	P	R	SPT,P,C	-
U1-B 9	870887	211760	954.0	300.0	P	R	SPT,P	-
U1-B10	870773	211734	954.0	300.0	P	R	SPT,D	-
U1-B11	870885	211885	954.0	370.0	P	R	SPT,D	-
U1-B12	870998	211946	955.0	370.0	P	R	SPT,D,P	-
U1-B13	870878	211647	954.0	300.0	P	R	SPT,D	-
U1-B14	870761	211506	954.0	300.0	P	R	SPT,D	-
U1-B15	870816	211699	954.0	150.0	P	R	SPT,D	-
U1-B16	870787	211343	957.0	300.0	P	R	SPT,D,P	-
U1-B17	870634	211681	953.0	300.0	P	R	SPT,P	-
U1-B18	870455	211432	952.9	300.0	P	R	SPT,P	-
U1-B19	870671	211441	953.0	300.0	S	R	-	-
U1-B20	870707	211559	953.2	300.0	S	R	-	-
U1-B21	870609	211439	953.0	130.0	S	R	-	4
U1-B23	870016	211301	950.0	50.5	P	R	SPT,P	-
U1-B24	870164	211437	951.0	50.5	P	R	P	-
U1-B22	870834	211442	954.3	300.0	S	R	-	-
U1-B25	870157	211154	955.0	52.5	P	R	P	-
U1-B26	870299	211289	952.0	49.5	P	R	SPT,P	-
U1-B27	870287	211007	957.0	52.5	P	R	P,SPT	-
U1-B28	874434	211142	957.0	49.5	P	R	P	-
U1-B29	870388	210896	958.4	53.0	P	R	P	-
U1-B30	870535	211031	958.0	50.0	P	R	SPT,P	-

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 6 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
U1-B31	870523	210749	959.0	52.5	P	R	SPT,P	-
U1-B32	870671	210884	960.0	49.5	P	R	P	-
U1-B33	870658	210601	958.0	250.0	P	R	P	-
U1-B34	870806	210736	959.0	50.0	P	R	SPT,P	-
U2-B 1	869719	210672	955.0	501.0	P	R	SPT,P,C	-
U2-B 2	869756	210735	955.0	300.0	P	R	SPT,P	-
U2-B 3	869647	210671	953.0	300.0	P	R	SPT,P	-
U2-B 4	869755	210609	956.0	300.0	P	R	SPT,P	-
U2-B 5	869424	210772	953.0	389.0	P	R	P,SPT,D	-
U2-B 6	869683	210923	953.0	305.0	P	R	P,SPT,D	-
U2-B 7	869546	210547	954.7	300.0	P	R	P,SPT,D	-
U2-B 8	869891	210753	955.0	300.0	P	R	SPT,P	-
U2-B 9	870014	210841	956.0	300.0	P	R	SPT,P	-
U2-B10	869898	210883	955.0	300.0	P	R	D,SPT	-
U2-B11	870050	210971	955.0	370.0	P	R	D,SPT	-
U2-B12	870125	210841	957.0	370.0	P	R	D,SPT	-
U2-B13	869983	210747	957.0	300.0	P	R	D,SPT	-
U2-B14	869836	210674	956.0	300.0	P	R	D,SPT	-
U2-B15	869935	210830	955.3	150.0	P	R	D,SPT	-
U2-B16	869848	210503	956.0	300.0	P	R	P,SPT,D	-
U2-B17	869780	210865	954.0	300.0	P	R	P,SPT	-
U2-B18	869571	210675	954.0	300.0	P	R	P,SPT	-
U2-B19	869770	210672	955.0	300.0	S	R	-	-
U2-B20	869917	210672	956.0	305.0	S	R	-	-
U2-B21	869466	210717	950.0	304.0	S	R	-	-
U2-B22	869885	210599	957.0	304.0	S	R	-	-
U2-B23	869092	210753	952.0	50.0	P	R	P	-
U2-B24	869276	210830	951.0	50.0	P	R	SPT,P	-
U2-B25	869168	210569	952.0	50.0	P	R	SPT,P	-
U2-B26	869353	210645	953.0	50.0	P	R	SPT,P	-
U2-B27	869245	210384	954.0	50.0	P	R	P	-
U2-B28	869429	210460	954.0	52.5	P	R	SPT,P	-
U2-B29	869302	210245	954.0	50.0	P	R	SPT,P	-
U2-B30	869487	210322	955.0	50.0	P	R	P	-
U2-B31	869379	210061	953.0	52.5	P	R	P	-
U2-B32	869563	210137	953.0	52.5	P	R	SPT,P	-
U2-B33	869455	209876	953.0	50.0	P	R	SPT,P	-
U2-B34	869639	209962	955.0	250.0	P	R	SPT,P	-
U3-B 1	868597	210263	950.0	356.0	P	R	SPT,P,C	-
U3-B 2	868652	210310	950.3	305.0	P	R	SPT,P	-
U3-B 3	868524	210288	950.0	300.0	P	R	SPT,P	-
U3-B 4	868610	210192	950.6	399.0	P	R	SPT,P,C	-
U3-B 5	868359	210460	949.0	370.0	P	R	SPT,P	-
U3-B 6	868651	210512	950.0	310.0	P	R	SPT,P	-
U3-B 7	868404	210192	950.0	360.0	P	R	SPT,P	-
U3-B 8	868799	210297	951.0	332.0	P	R	SPT,P	-
U3-B 9	868931	210323	952.0	318.0	P	R	SPT,P,C	-
U3-B10	868837	210400	952.0	300.0	P	R	D,SPT	-
U3-B11	869011	210431	953.0	361.0	P	R	D,SPT	-
U3-B12	869037	210284	953.0	335.0	P	R	D,SPT	-
U3-B13	868869	210254	952.0	300.0	P	R	SPT,D,C	-
U3-B14	868708	210225	951.0	310.0	P	R	SPT	-
U3-B15	868855	210338	952.0	151.0	P	R	SPT,D	-
U3-B16	868661	210074	951.0	338.0	P	R	SPT,P,C	-

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 7 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
U3-B17	868721	210424	950.0	300.0	P	R	SPT,P	-
U3-B18	868459	210317	949.5	300.0	P	R	SPT,P	-
U3-B19	868632	210252	950.7	300.0	S	R	-	-
U3-B20	868667	210240	950.7	300.0	S	R	-	-
U3-B21	868574	210271	950.0	90.0	S	R	-	-
U3-B22	868732	210141	951.0	271.0	S	R	-	-
U3-B23	868035	210555	947.0	50.0	P	R	P	-
U3-B24	868235	210564	949.0	50.0	P	R	SPT,P	-
U3-B25	868043	210355	948.0	50.0	P	R	SPT,P	-
U3-B26	868244	210364	949.0	50.5	P	R	P	-
U3-B27	868052	210155	948.0	50.0	P	R	P	-
U3-B28	868252	210164	949.0	50.0	P	R	SPT,P	-
U3-B29	868059	210005	949.0	52.5	P	R	SPT,P	-
U3-B30	868259	210014	949.0	50.0	P	R	P	-
U3-B31	868068	209806	948.0	50.0	P	R	P	-
U3-B32	868268	209814	948.0	50.0	P	R	SPT,P	-
U3-B33	868076	209606	947.0	252.0	P	R	SPT,P	-
U3-B34	868276	209614	947.0	50.0	P	R	P	-
U1-PT0-1	870240	211191	952.2	70.0	S	R	-	5
U1-PT0-2	870524	211434	952.7	70.0	S	R	-	5
U1-PT0-3	870663	211538	953.2	70.0	S	R	-	5
U2-PT0-1	869267	210594	952.4	55.0	S	R	-	5
U2-PT0-2	869598	210673	954.0	53.0	S	R	-	5
U2-PT0-3	869787	210748	954.7	55.0	S	R	-	5
U2-PT0-4	869758	210731	955.1	70.0	S	R	-	5
U2-PT0-5	869732	210719	955.0	60.0	S	R	-	5
U2-PTW-2	869713	210709	955.4	86.0	S	BA	-	5
U3-PT0-1	868557	210438	950.2	60.0	S	R	-	5
U3-PT0-2	868552	210468	949.7	57.0	S	R	-	5
U3-PT0-3	868538	210516	949.6	57.0	S	R	-	5
U3-PT0-4	868241	210322	948.6	65.5	S	R	-	5
U3-PT0-5	868491	210303	949.6	67.0	S	R	-	5
U3-PT0-6	868682	210308	950.3	55.0	S	R	-	5
U3-PTW-1	868560	210418	946.7	65.3	S	BA	-	5
U5-PTO1	864724	211097	928.5	41.5	P	R	SPT,P	5,10
U5-PTO2	864719	211088	928.0	46.0	P	R	SPT,P	5,10
U5-PTO3	864709	211069	928.6	43.5	P	R	SPT,P	5,10
U5-PTO4	864712	211115	928.0	41.0	P	R	SPT,P	5,10
U5-PTO5	864764	211124	928.0	44.0	P	R	SPT,P	5,10
U5-PTO6	864738	211111	928.1	41.0	P	R	SPT,P	5,10
U5-PTW1	864729	211105	927.9	44.0	P	BA	B	5,10
U1-TR1	870574	211479	956.0	15.0	S	BH	-	7
U2-RT1	869679	210762	955.0	15.0	S	BH	-	7
U3-TR1	868554	210348	950.0	15.0	S	BH	-	7
U2-LB1	869720	210707	955.3	55.0	S	BA	BL	6
U3-LB1	868565	210413	949.7	36.0	S	BA	BL	6
U3-LB2	868574	210419	950.0	53.0	S	BA	BL	6
E-19- 1	870401	215122	944.5	5.8	S	A	-	8,9
E-19- 2	870427	215048	937.1	5.3	S	A	-	8,9
E-19- 3	870460	214938	930.9	6.2	S	A	-	8,9
E-19- 4	871898	214493	921.4	5.1	S	A	-	8,9
E-19- 5	872013	215898	922.5	10.4	S	A	-	8,9
E-19- 6	871359	216214	922.5	6.5	S	A	-	8,9
E-19- 7	871303	214466	922.5	5.3	S	A	-	8,9

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 8 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
E-19- 8	868586	210307	902.2	6.6	S	A	-	8,9
E-19- 8A	868596	210310	902.1	6.2	S	A	-	8,9
E-19- 9	868472	210258	902.0	5.9	S	A	-	8,9
E-19-10	868513	210277	900.5	5.7	S	A	-	8,9
E-19-11	871017	213150	949.5	20.7	S	A	-	8,9
E-19-12	871179	213819	945.4	20.9	S	A	-	8,9
E-19-13	864755	211159	922.2	13.0	S	A	-	8,9
E-19-14	865008	210279	929.7	15.0	S	A	-	8,9
E-18- 1	871311	214482	922.5	44.0	S	R	P	9
E-18- 2	870532	213920	948.1	62.0	S	R	P	9
E-18- 3	871154	213784	950.4	49.0	S	R	P	9
E-18- 3A	871150	213808	950.4	69.0	S	R	P	9
E-18- 4	871781	213696	953.7	63.0	S	R	P	9
E-18- 5	870801	212422	952.5	69.0	S	R	P	9
E-18- 6	871016	213107	956.0	37.0	S	R	P	9
E-18-7A	864452	209841	930.5	52.3	S	R	P	9
E-18- 8A	864646	210619	931.0	46.5	S	R	SH	9
E-18- 9	865129	211164	930.4	45.3	S	R	D	9
E-18-10	869548	214440	949.9	45.0	S	R	SH	9
U4-H1	866208	209830	940.3	43.8	P	A	SPT	3
U4-H2	866207	210288	940.3	48.5	P	A	SPT	3
U4-H3	866207	210872	937.0	48.1	P	A	SPT	3
U4-H4	866597	209831	941.5	46.5	P	A	SPT	3
U4-H5	866597	210300	941.5	44.0	P	A	SPT	3
U4-H6	866598	210870	938.2	47.8	P	A	SPT	3
U4-H7	867319	210267	936.1	51.5	P	A	SPT	3
U4-S1	866612	210369	941.5	140.0	S	R	-	4,8
U4-S2	866610	210359	941.7	160.0	S	R	-	4,8
U4-S3	866609	210344	941.6	160.0	S	R	-	4,8
U4-S4	866605	210324	941.5	160.0	S	R	-	4,8
U4-S5	866616	210403	941.5	164.0	S	R	-	4,8
U4-B 1	866597	210263	941.5	301.0	P	R	P	-
U4-B 2	866510	210265	941.2	127.0	P	A	SPT	-
U4-B 3	866597	210187	941.8	126.4	P	A	SPT	-
U4-B 3A	866587	210188	941.8	65.2	S	R	SPT	1
U4-B 4	866707	210267	942.1	127.0	P	A	SPT	-
U4-B 4A	866709	210277	942.1	65.3	S	R	SPT	1
U4-B 5	866715	210404	942.0	62.0	P	A	SPT	-
U4-B 6	866713	210535	941.5	62.0	P	A	SPT	-
U4-B 7	866598	210403	941.4	278.0	P	R	P,D	-
U4-B 7A	866604	210389	941.4	152.5	S	R	P	2
U4-B 8	866597	210538	941.2	51.3	P	A	SPT	-
U4-B 8A	866589	210538	941.2	66.7	S	R	SPT	1
U4-B 9	866639	210628	938.4	127.0	P	A	SPT	-
U4-B10	866362	210268	940.7	127.0	P	A	SPT	-
U4-B11	866397	210535	940.5	51.5	P	A	SPT	-
U4-B12	866202	209858	939.7	127.0	P	A	SPT	-
U4-B12A	866200	209863	939.7	68.8	S	R	SPT	1
U4-B13	866200	210054	940.9	62.0	P	A	SPT	-
U4-B14	866210	210263	940.4	299.0	P	R	P,D	-
U4-B15	866200	210470	940.7	62.0	P	A	SPT	-
U4-B16	866184	210675	937.3	126.5	P	A	SPT	-
U4-B16A	866182	210684	937.3	65.3	S	R	SPT	1
U4-B17	867073	210270	943.5	127.0	P	A	SPT	-

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 9 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
U4-B18	867607	210263	947.9	333.5	P	R	P,D	-
U4-B19	866828	210264	942.6	64.0	P	R	P	-
U4-B20	867063	210179	943.7	63.5	P	R	SPT	-
U4-B20A	867068	210184	943.7	52.0	S	R	P	2
U4-B20B	867058	210184	943.7	52.5	S	R	P	2
U4-B21	866847	210138	943.0	70.5	P	R	SPT	-
U4-B22	866625	210078	941.3	67.0	P	R	SPT	-
U4-B23	866656	210469	941.6	63.5	P	R	SPT,P	-
U4-B24	866757	210591	939.1	71.5	P	R	SPT	-
U4-B25	866491	210535	940.6	65.0	P	R	P	-
U4-B26	965925	210151	939.6	66.5	P	R	SPT	-
U4-B27	866127	210146	940.2	66.4	P	R	SPT	-
U4-B27A	866122	210156	940.2	47.0	S	R	P	2
U4-B28	866359	210422	940.7	63.0	P	R	SPT	-
U4-B29	866231	210768	937.0	65.0	P	R	P	-
U4-B30	866035	210672	937.1	65.4	P	R	SPT	-
U4-B31	866062	210262	940.0	66.5	P	R	SPT	-
U4-B31A	866052	210262	940.0	50.0	S	R	P	2
U4-B32	866022	210062	939.6	66.0	P	R	P	-
U4-B33	866937	210202	943.2	66.5	P	R	SPT	-
U4-B33A	866941	210207	943.2	47.0	S	R	P	2
U4-B34	866599	210283	941.5	33.0	S	BA	B	-
U4-B35	866516	210274	941.1	32.5	S	BA	B	-
U4-B36	866893	210341	942.8	66.5	P	R	SPT	-
U4-B37	866064	210489	933.7	70.5	P	R	SPT	-
U4-B38	866706	210174	942.5	65.0	P	R	P	-
U4-B39	866753	210478	941.8	65.0	P	R	P	-
U4-B40	866124	210336	939.8	60.0	P	R	P	-
U4-B41	866023	210057	939.6	60.0	P	R	P	-
U4-B42	865998	210401	940.0	66.5	P	R	SPT	-
U4-B42A	866008	210405	940.0	64.0	S	R	P	2
U4-B42B	865998	210411	940.0	62.0	S	R	P	2
U4-B42C	865993	210411	940.0	64.0	S	R	P	2
U4-B43	865966	210266	939.4	75.5	P	R	SPT	-
U4-B44	866091	210595	937.5	64.5	P	R	SPT	-
U4-B44A	866097	210611	937.5	45.0	S	R	P	2
U4-B44B	866091	210610	937.5	51.0	S	R	P	2
U4-B45	866254	210388	940.2	64.3	P	R	SPT	-
U4-B46	866181	210193	939.9	72.5	P	R	SPT	-
U4-B47	866165	210111	939.8	65.5	P	R	SPT	-
U4-B48	866290	210489	940.4	66.5	P	R	SPT	-
U4-B49	866368	210680	936.9	66.5	P	R	SPT	-
U4-B50	866231	210600	937.2	65.5	P	R	SPT	-
U4-B51	866042	210148	939.8	64.5	P	R	SPT	-
U5-H 1	865007	209830	933.2	36.0	P	A	SPT	3
U5-H 2	865008	210300	935.8	48.4	P	A	SPT	3
U5-H 3	865009	210859	931.4	41.5	P	A	SPT	3
U5-H 4	865395	209800	935.7	41.5	P	A	SPT	3
U5-H 5	865433	210291	939.0	49.0	P	A	SPT	3
U5-H 6	865396	210870	934.0	41.5	P	A	SPT	3
U5-H 7	865295	210540	934.5	60.5	P	R	SPT	3
U5-H 8	865304	210540	934.5	44.0	P	R	-	3,8
U5-H 9	865284	210540	934.5	30.0	P	A	-	3,8
U5-H10	865407	211323	931.7	45.0	P	R	SPT	3

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 10 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
U5-H11	865739	211132	933.5	45.0	P	R	SPT	3
U5-S1	865397	210280	938.8	296.0	S	R	-	4,8
U5-S2	865397	210303	938.8	294.0	S	R	-	4,8
U5-S3	865397	210323	938.2	296.0	S	R	-	4,8
U5-S4	865527	210759	935.5	149.5	S	R	-	4,8
U5-S5	865533	210773	935.5	154.0	S	R	-	4,8
U5-S6	865539	210781	935.5	150.0	S	R	-	4,8
U5-B 1	865397	210260	938.6	305.0	P	R	P	-
U5-B 1A	865394	210264	938.6	393.7	S	R	-	-
U5-B 2	865307	210267	938.0	126.5	P	A	SPT	-
U5-B 2A	865312	210261	938.0	61.5	S	R	SPT	1
U5-B 3	865397	210193	938.6	126.5	P	A	SPT	-
U5-B 4	865512	210236	939.6	121.5	P	A	SPT	-
U5-B 5	865517	210407	936.9	51.5	P	A	SPT	-
U5-B 6	865517	210553	935.8	51.5	P	A	SPT	-
U5-B 6A	865517	210561	935.8	64.5	S	R	SPT	-
U5-B 7	865396	210403	936.5	330.5	P	R	P	-
U5-B 8	865397	210545	935.2	61.3	P	A	SPT	-
U5-B 8A	865397	210556	935.2	61.5	S	R	SPT	1
U5-B 9	865437	210628	935.2	126.5	P	A	SPT	-
U5-B10	865164	210268	937.7	126.6	P	A	SPT	-
U5-B11	865193	210540	934.0	51.5	P	A	SPT	-
U5-B11A	865198	210550	934.0	61.5	S	R	SPT	1
U5-B12	865002	209858	933.3	126.5	P	A	SPT	-
U5-B13	865001	210056	934.5	51.1	P	A	SPT	-
U5-B14	865004	210265	935.8	332.8	P	R	P	-
U5-B15	865006	210469	933.4	51.5	P	A	SPT	-
U5-B15A	865001	210478	933.4	61.5	S	R	SPT	1
U5-B16	865002	210678	932.1	126.0	P	A	SPT	-
U5-B17	865872	210267	939.2	126.3	P	A	SPT	-
U5-B18	865754	210269	938.7	68.5	P	R	SPT,P	-
U5-B19	865631	210265	939.7	67.5	P	R	SPT,P	-
U5-B20	865851	210416	937.9	65.0	P	R	SPT	-
U5-B20A	865860	210424	937.9	61.0	S	R	P	2
U5-B20B	865851	210425	937.9	60.0	S	R	P	2
U5-B20C	865841	210425	937.9	63.0	S	R	P	2
U5-B20D	865841	210416	937.9	62.4	S	R	P	2
U5-B21	865635	210405	936.9	65.3	P	R	SPT	-
U5-B22	865504	210081	938.2	64.0	P	R	SPT,P	-
U5-B23	865455	210473	935.5	62.5	P	R	SPT,P	-
U5-B24	865515	210650	935.6	63.5	P	R	SPT,P	-
U5-B25	865306	210415	936.4	63.5	P	R	SPT	-
U5-B26	864784	210783	930.4	66.5	P	R	SPT	-
U5-B27	865150	210061	935.6	63.5	P	R	SPT,P	-
U5-B28	865176	210414	935.2	65.0	P	R	SPT,P	-
U5-B29	865153	210674	933.0	65.4	P	R	SPT	-
U5-B30	864856	210677	931.1	67.5	P	R	SPT	-
U5-B30A	864866	210867	931.1	59.0	S	R	P	2
U5-B30B	864856	210687	931.1	57.0	S	R	P	2
U5-B30C	864846	210687	931.1	58.0	S	R	P	2
U5-B30D	864866	210677	931.1	60.0	S	R	P	2
U5-B30E	864846	210677	931.1	57.0	S	R	P	2
U5-B30F	864666	210697	931.1	58.0	S	R	P	2
U5-B31	864855	210274	933.3	65.6	P	R	SPT	-

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 11 of 12)

BORING NUMBER	COORDINATES (FT) NORTH	EAST	ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
U5-B32	865143	211168	930.3	73.5	P	R	SPT	-
U5-B33	864970	210800	931.3	65.0	P	R	SPT	-
U5-B33A	864962	210792	931.3	60.0	S	R	P	2
U5-B33B	864962	210802	931.3	58.5	S	R	P	2
U5-B33C	864955	210797	931.3	58.0	S	R	P	2
U5-B33D	864970	210810	931.3	58.0	S	R	P	2
U5-B33E	864962	210810	931.3	58.0	S	R	P	2
U5-B34	865061	210912	931.5	232.0	P	R	P,D	-
U5-B35	865281	211092	931.8	76.5	P	R	SPT	-
U5-B36	865489	210972	933.8	65.2	P	R	SPT	-
U5-B37	865602	210891	935.1	65.0	P	R	SPT	-
U5-B38	865737	210891	935.9	75.0	P	R	SPT	-
U5-B38A	865742	210896	935.9	75.0	S	R	P	2
U5-B38B	865737	210896	935.9	75.0	S	R	P	2
U5-B38C	865732	210896	935.9	74.0	S	R	P	2
U5-B38D	865742	210891	935.9	73.5	S	R	P	2
U5-B38E	865732	210891	935.9	73.0	S	R	P	2
U5-B38F	865742	210886	935.9	74.0	S	R	P	2
U5-B38G	865737	210886	935.9	72.0	S	R	P	2
U5-B39	865714	210827	936.2	64.5	P	R	SPT	-
U5-B40	865672	210750	936.2	67.5	P	R	SPT	-
U5-B41	865670	210562	936.8	65.0	P	R	SPT	-
U5-B42	865516	210742	935.4	152.0	P	R	P	-
U5-B43	865476	210673	935.4	386.5	P	R	P	-
U5-B44	865336	210755	934.1	65.0	P	R	SPT	-
U5-B45	865180	210844	932.9	65.0	P	R	SPT	-
U5-B46	865557	210812	935.5	151.0	P	R	SPT	-
U5-B46A	865547	210807	935.5	150.5	S	R	P	2
U5-B47	865522	210751	935.2	27.0	S	BA	B	-
U5-B48	865485	210691	935.2	27.5	S	BA	B	-
U5-B49	865941	210528	938.2	66.5	P	R	SPT	-
U5-B49A	865945	210528	938.2	46.0	S	R	P	2
U5-B50	865785	210640	937.0	66.5	P	R	SPT	-
U5-B51	865780	210492	937.1	66.5	P	R	SPT	-
U5-B51A	865780	210498	937.1	49.0	S	R	P	2
U5-B52	865410	211132	932.0	67.9	P	R	SPT	-
U5-B53	865646	210954	934.8	75.4	P	R	SPT	-
U5-B54	865549	211025	933.4	76.0	P	R	P	-
U5-B55	865620	210840	935.5	64.0	P	R	P	-
U5-B56	865681	210897	935.5	65.0	P	R	P	-
U5-B57	865499	210891	934.4	65.0	P	R	P	-
U5-B58	865329	211197	931.0	74.0	P	R	P	-
U5-B58A	865334	211202	931.0	33.0	S	R	P	2
U5-B58B	865329	211200	931.0	32.0	S	R	P	2
U5-B59	865137	211008	931.2	73.5	P	R	P	-
U5-B59A	865142	211013	931.2	37.6	S	R	P	2
U5-B59B	865137	211003	931.2	37.0	S	R	P	2
U5-B59C	865130	211003	931.2	36.0	S	R	P	2
U5-B60	864942	210970	930.1	66.1	P	R	SPT	-
U5-B61	865678	210749	936.1	65.0	P	R	P	-
U5-B62	865815	210452	937.5	62.0	P	R	P	-
U5-B63	865593	210606	936.0	66.5	P	R	SPT	-
U5-B64	865740	210415	937.0	66.5	P	R	SPT	-
U5-B64A	865750	210425	937.0	61.5	S	R	P	2

Table 2F-1

DETAILS OF SUBSURFACE EXPLORATION PROGRAM (Sheet 12 of 12)

BORING NUMBER	COORDINATES (FT)		ELEVATION ABOVE MSL (FT)	DEPTH (FT)	BORING TYPE	DRILLING METHOD	SAMPLE TYPE	REMARKS
	NORTH	EAST						
U5-B64B	865740	210425	937.0	71.6	S	R	P	2
U5-B65	865033	211039	930.2	65.5	P	R	SPT	-
U5-B66	864856	210870	930.1	64.2	P	R	SPT	-
U5-B67	865207	211088	931.1	48.2	P	R	SPT	-
U5-B68	865099	210960	931.4	48.4	P	R	SPT	-
U5-B68A	865094	210962	931.4	36.5	S	R	P	2
U5-B68B	865084	210962	931.4	38.0	S	R	P	2
U5-B69	865250	210962	932.5	70.6	P	R	SPT	-
U5-B70	865242	211267	930.4	47.3	P	R	SPT	-
U5-B71	864913	210743	931.2	29.0	P	R	P	-
U5-B71A	864903	210743	931.2	22.0	S	R	P	2
U5-B72	864640	210605	932.8	80.0	P	R	P	-
U5-B73	864425	209847	929.8	80.0	P	R	P	-
U5-B74	864478	209437	930.0	80.0	P	R	P	-
U5-B75	864655	208368	929.6	80.0	P	R	P	-
U5-B76	863799	210436	926.9	200.0	P	R	P	-
U5-B77	863682	210974	925.1	80.0	P	R	P	-
U5-B78	864189	211000	928.8	80.0	P	R	P	-
U5-B79	864060	209468	928.3	80.0	P	R	P	-
U5-B80	864144	208885	927.3	80.0	P	R	P	-
U5-B81	863854	210127	927.0	80.0	P	R	P	-
U5-B82	864276	207696	932.7	301.0	P	R	P	-
U5-B83	865512	211562	928.6	60.0	P	R	SPT,P	-
U5-B84	865781	211858	928.5	68.0	P	R	SPT,P	-
U5-B85	866043	212174	927.2	60.0	P	R	SPT.P	-
U5-B86	866329	212455	929.7	63.0	P	R	SPT,P	-
U5-B87	866550	212768	929.5	49.5	P	R	SPT,P	-
U5-B88	866852	213059	930.3	62.0	P	R	SPT,P	-
U5-B89	867140	213337	932.3	71.0	P	R	SPT,P	-
U5-B90	867197	212859	934.4	62.0	P	R	SPT,P	-
U5-B91	866989	212088	933.6	62.0	P	R	SPT,P	-
U5-B92	866775	211318	934.7	63.0	P	R	SPT,P	-
U5-B93	864920	211508	927.3	62.0	P	R	SPT,P	-
U5-B94	864602	211752	924.3	72.0	P	R	SPT,P	-
U5-B95	865773	213210	925.7	68.0	P	R	SPT,P	-
U5-B96	866457	212129	931.1	58.0	P	R	SPT,P	-
U5-B97	867074	212445	933.5	56.0	P	R	P	-
U5-B98	866922	211727	933.8	60.0	P	R	P	-
U5-B99	867196	213097	932.3	52.0	P	R	P	-
U5-B99A	867175	213091	932.3	30.5	P	R	P	-

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APPENDIX 2G

SUMMARY OF PERMEABILITY TESTING

APPENDIX 2G

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TABLES

FIGURES

APPENDIX 2G

SUMMARY OF PERMEABILITY TESTING

2G.1 INTRODUCTION

The permeability characteristics of the soils underlying PVNGS have been evaluated by field and laboratory tests. The tests were performed for various purposes during several phases of geotechnical investigations at the site, and results were presented in several reports. This appendix summarizes all permeability test data related to the site and provides references to the documents where more detailed discussions of tests can be found.

2G.2 FIELD TESTS

The permeability of the site soils was investigated by both inflow and outflow type field permeability tests. Inflow type tests were conducted in accordance with Bureau of Reclamation Procedures E-18 and E-19 on both coarse- and fine-grained soils encountered in the upper 80 feet of the subsurface profile. Outflow type pumping tests were conducted to determine the permeability of both shallow perched water zone and the deeper, regional aquifer. Test locations are shown in figure 2G-1.

Field permeability test data from the upper coarse-grained unit, the middle fine-grained unit, and the lower coarse-grained unit are presented in tables 2G-1, 2G-2, and 2G-3, respectively.

2G.3 LABORATORY TESTS

Laboratory permeability tests were performed on undisturbed samples of mostly fine-grained soils from the site.

During the early siting studies, permeability tests were performed on undisturbed samples of soils representative of the entire subsurface profile of the site. The test specimens were enclosed in brass rings 1.5 inches in diameter and 1 inch high, and were tested under constant head conditions. Results of these tests, that measured both horizontal and vertical permeabilities, were presented in Appendix 2J of the PVNGS 1, 2, and 3 PSAR, and are also summarized in table 2G-4. Similar tests were performed during the preliminary geotechnical investigations for siting of the water storage reservoir and the evaporation ponds. Results of these tests are summarized in table 2G-5.

During more recent studies, related to the seepage analysis, permeability tests were performed on undisturbed samples representative of the upper 20 to 30 feet of the aquitard soils at the site. The test specimens were trimmed to 2.5 inches in diameter and 4 to 6 inches high and were enclosed in rubber membranes. The tests were conducted in triaxial test cells under confining pressures representative of in situ conditions. Results of these tests are summarized in table 2G-6.

APPENDIX 2G

Table 2G-1
SUMMARY OF FIELD PERMEABILITY TEST DATA[a]
UPPER COARSE-GRAINED UNIT

Individual Test Data			Integrated Test Data[b]	
Test No.	Elevation of Tested Interval (ft)	Permeability (cm/sec)	Elevation Range (ft)	Effective Horizontal Permeability (cm/sec)
E-19-1	944-939	1.3×10^{-3}		
E-19-2	937-932	1.2×10^{-3}	944-925	9.9×10^{-4}
E-19-3	930-925	4.3×10^{-4}		
E-19-11	949-935	4.9×10^{-5}	949-935	4.9×10^{-5}
E-19-12	945-930	5.2×10^{-4}	949-930	5.2×10^{-4}
Unit 2 Pump Test	913-873	1.2×10^{-4}	913-873	1.2×10^{-4}
Unit 3 Pump Test	908-898	7.0×10^{-3}	908-898	7.0×10^{-3}
E-19-14	929-914	6.6×10^{-4}	929-914	6.6×10^{-4}
E-19-13	922-909	5.5×10^{-4}		
Unit 5 Pump Test	909-892	1.0×10^{2}	922-892	5.9×10^{-3}

a. Detailed descriptions of these tests are provided in the following PSAR sections:

E-19 tests: PVNGS 1, 2 and 3 PSAR, Appendix 2AE
Unit 2 and 3 pump tests: PVNGS 1, 2 and 3 PSAR, Appendix 2I
Unit 5 pump test: PVNGS 4 and 5 PSAR, Appendix 2I

b. Where two or more tests were performed over different intervals at the same general location, the effective horizontal permeability was calculated over the entire interval tested.

Table 2G-2

SUMMARY OF FIELD PERMEABILITY TEST DATA
MIDDLE FINE-GRAINED UNIT (AQUITARD)

		TEST INTERVAL			
LOCATION	TEST No.	DEPTH BELOW GROUND SURFACE (Ft.)	ELEVATION (Ft.)	PERMEABILITY COEFFICIENT (Cm/Sec)	REMARKS
NEAR PV-172	E19-7	0.6 - 5.3	921.9 - 917.2		Week long test
	E18-1	12.0 - 14.5	910.5 - 908.0	7.7 x 10^{-7}	Overnight test
	E18-1	18.0 - 20.5	904.5 - 902.0	*	15-minute test, pressurized
	E18-1	39.0 - 44.0	883.5 - 878.5	8.6 x 10^{-7}	Overnight test
NEAR PV-173	E18-3	33.0 - 38.0	917.4 - 912.4	*	36 minute test, pressurized
	E18-3a	64.0 - 69.0	886.4 - 881.4	[9.7 x 10^{-7} 8.0 x 10^{-7}	3-hour test Overnight test
NEAR PV-174	E18-6	22.8 - 28.0	933.2 - 928.0	6.5 x 10^{-6}	75 minute test
	E18-6	33.0 - 37.0	923.0 - 919.0	[5.2 x 10^{-6} 5.1 x 10^{-6}	90 minute test Overnight test
	E18-6	66.0 - 69.0	890.0 - 887.0	2.1 x 10^{-6}	110 minute test
NEAR PV-175	E18-5	23.0 - 25.5	929.5 - 927.0	3.7 x 10^{-6}	200 minute test
	E18-5	53.0 - 57.0	899.5 - 895.5	[2.1 x 10^{-6} 2.2 x 10^{-6}	Overnight test 90 minute second day test
	E18-5	66.0 - 69.0	886.5 - 883.5	1.2 x 10^{-6}	130 minute test
NEAR PV-176	E18-4	0 - 19.9		8.9 x 10^{-7}	Uncased borehole, overnight test
	E18-4	38.0 - 43.0	915.7 - 910.7	5.2 x 10^{-6}	150 minute test
	E18-4	58.0 - 63.0	895.7 - 890.7	5.1 x 10^{-7}	240 minute test
NEAR PV-177	E18-2	30.0 - 35.0	918.1 - 913.1	*	30 min. test, pressurized
	E18-2	57.2 - 62.2	890.9 - 885.9	[5.5 x 10^{-7} 2.0 x 10^{-7}	140 minute test 50 min. test, pressurized
NEAR PV-180	E19-4	0.7 - 5.1	920.7 - 916.3	2.2 x 10^{-6}	Week long test
NEAR PV-181	E19-5	0.8 - 10.4	921.7 - 912.1	2.9 x 10^{-7}	Week long test
NEAR PV-182	E19-6	0.8 - 6.5	921.7 - 916.0	1.1 x 10^{-6}	Week long test
NEAR PV-183	E18-10	43.5 - 45.0	908.4 - 904.9	4.6 x 10^{-7}	4-day test
UNIT 3- EXCAVATION	E19-8A	0.8 - 6.2	901.3 - 895.9	2.2 x 10^{-5}	Week long test
	E19-9	0.6 - 5.9	901.6 - 896.3	4.7 x 10^{-5}	2-day test
	E19-10	2.2 - 5.7	899.8 - 896.3	2.6 x 10	6-day test
NEAR U5-B32	E18-9	41.2 - 45.3	889.2 - 885.7	6.4 x 10^{-5}	4-day test
NEAR U5-B72	E18-8a	45.3 - 46.5	885.7 - 884.5	1.3 x 10^{-6}	4-day test
NEAR U5-B73	E18-7a	50.8 - 52.3	879.7 - 878.2	4.0 x 10^{-7}	4-day test

Notes: * No measurable flow.
[Two-stage test in the same depth interval.

Table 2G-3

SUMMARY OF AQUIFER PUMPING TEST DATA

LOWER COARSE GRAINED UNIT (REGIONAL AQUIFER) Test Location:
Irrigation well (B-1-6)34abb, near the construction water storage reservoir

Depth of Well	=	1413 feet
Aquifer Thickness	=	Approximately 1000 feet
Transmissivity	=	100,000 gallons per day per foot
Permeability	=	100 gallons per day per square foot ($5x10^{-3}$ centimeters per second)
Storage Coefficient	=	0.005

A detailed description of the test is provided in Appendix 2I, PVNGS 1, 2, and 3 PSAR.

Table 2G-4
SUMMARY OF LABORATORY PERMEABILITY TEST DATA
EARLY SITING STUDIES (Sheet 1 of 2)

BORING NO.	SAMPLE DEPTH (FEET)	SOIL TYPE	% PASSING SIEVE		DRY UNIT WEIGHT (PCF)	MOISTURE CONTENT (%)	SPECIFIC GRAVITY	POROSITY	PERMEABILITY (cm/sec)	
			#40	#200					VERTICAL	HORIZONTAL
PV-24	10.0	SM	63	18	108.6	6.0	2.707	36	1.0×10^{-4}	1.9×10^{-6}
	21.0	CL	98	75	104.1	20.2	2.717	39	2.5×10^{-7}	2.2×10^{-7}
	31.0	SM	93	35	116.7	9.7	2.686	30	1.1×10^{-6}	1.0×10^{-5}
	41.0	CH	100	96	106.9	13.6	2.668	36	1.8×10^{-7}	3.4×10^{-7}
	52.0	ML	98	81	106.5	18.3	2.683	36	1.1×10^{-5}	4.8×10^{-5}
	62.0	SP/SM	31	10	113.5	15.1	2.620	31	1.0×10^{-4}	5.8×10^{-4}
	72.0	CL	100	91	97.9	27.2	2.653	41	1.3×10^{-6}	2.1×10^{-6}
	78.0	CL	100	63	101.6	22.6	2.691	39	1.3×10^{-7}	1.2×10^{-6}
	88.0	CH	99	88	109.6	18.1	2.697	35	8.5×10^{-7}	7.0×10^{-6}
	99.0	CL	100	96	93.9	30.3	2.687	44	2.6×10^{-7}	-
	115.0	CL	100	98	95.0	29.3	2.649	43	2.0×10^{-8}	-
	125.0	CL	100	98	-	-	2.624	-	4.3×10^{-6}	1.5×10^{-7}
	135.0	CL	100	96	100.1	25.6	2.675	40	2.4×10^{-7}	-
	146.0	CL	100	93	101.4	24.3	2.688	40	3.2×10^{-5}	5.9×10^{-6}
	198.5	ML	-	-	112.0	22.1	-	-	5.5×10^{-8}	-
PV-28	10.5	ML	99	81	94.3	29.0	2.691	43	4.5×10^{-6}	3.6×10^{-6}
	21.0	ML	99	59	96.2	26.3	2.740	44	2.8×10^{-6}	-
	32.0	SM	36	24	109.1	17.5	2.650	34	2.7×10^{-8}	5.0×10^{-7}
	41.5	CL/ML	89	84	98.7	24.7	2.710	41	5.4×10^{-6}	1.6×10^{-6}
	52.0	SM	99	48	103.2	23.6	2.715	39	4.0×10^{-6}	5.8×10^{-6}
	62.0	CL	99	62	97.3	25.7	2.715	48	6.3×10^{-6}	4.0×10^{-6}
	72.0	ML	100	95	97.0	28.1	2.714	43	5.0×10^{-7}	4.0×10^{-8}
	83.5	CL	99	73	106.5	19.5	2.680	36	1.5×10^{-7}	2.9×10^{-7}
	94.0	CL	99	96	107.2	21.5	2.717	37	2.2×10^{-7}	-
	104.5	CL	100	97	94.9	27.7	2.660	43	5.0×10^{-7}	-
	115.0	CL	99	91	102.4	23.4	2.752	41	3.8×10^{-7}	1.3×10^{-7}
	125.5	CL	100	93	99.4	21.3	2.731	42	8.6×10^{-7}	1.0×10^{-8}
	199.0	CL	100	96	95.5	26.4	2.694	43	9.4×10^{-9}	6.0×10^{-8}
	220.0	CL	100	87	95.4	27.5	2.688	43	7.9×10^{-8}	8.0×10^{-7}
PV-30	10.5	SM	46	14	106.9	17.4	2.760	38	1.90×10^{-4}	2.00×10^{-4}
	20.5	SM	46	18	106.6	17.5	2.669	36	9.93×10^{-4}	2.99×10^{-3}
	30.5	CL	97	67	105.0	24.5	2.681	37	5.60×10^{-6}	-
	40.5	CL	100	92	119.6	13.0	2.710	29	1.10×10^{-6}	8.00×10^{-7}
	50.5	SC	91	43	113.8	14.9	2.723	33	1.02×10^{-5}	1.00×10^{-6}
	60.5	CL	99	53	109.3	17.0	2.704	35	5.0×10^{-6}	3.7×10^{-7}
	70.5	CH	100	99	90.2	29.9	2.732	47	2.0×10^{-6}	-
	80.5	CL	99	80	111.6	17.4	2.735	34	6.0×10^{-8}	3.0×10^{-8}
	90.5	ML	100	56	102.6	22.8	2.730	40	6.2×10^{-5}	9.9×10^{-6}
	100.5	CL	99	96	97.5	26.6	2.705	42	3.4×10^{-7}	5.4×10^{-7}
	120.5	CL	100	97	91.0	27.0	2.702	31	1.0×10^{-8}	-
	231.5	CL	-	-	93.6	23.2	-	-	6.7×10^{-8}	2.6×10^{-7}
	242.0	CL	-	-	96.4	24.3	-	-	7.4×10^{-7}	5.2×10^{-7}
PV-31	10.5	ML	98	90	112.4	19.2	2.717	34	4.0×10^{-5}	4.3×10^{-6}
	31.5	ML	98	77	113.2	17.5	2.676	32	7.6×10^{-7}	3.0×10^{-7}
	43.0	ML	96	63	96.0	27.2	2.717	43	3.0×10^{-7}	-
	53.5	CL	99	87	98.4	24.9	2.733	43	1.2×10^{-7}	3.4×10^{-6}
	64.0	ML	99	86	115.2	15.9	2.701	32	2.5×10^{-5}	4.4×10^{-5}
	75.0	CH	99	93	101.3	26.2	2.730	41	3.3×10^{-5}	4.0×10^{-8}
	85.0	CL	99	93	105.1	20.0	2.729	38	2.2×10^{-6}	-
	96.0	CL	100	97	101.2	24.9	2.732	41	7.0×10^{-7}	-
	106.0	ML	99	79	111.8	19.6	2.732	34	6.0×10^{-8}	3.5×10^{-7}
	116.0	CL	99	94	99.1	26.6	2.720	42	1.8×10^{-7}	1.1×10^{-7}
	127.0	CL	99	97	98.7	25.0	2.717	42	3.5×10^{-7}	-
	138.0	CL	100	98	90.9	31.8	2.748	47	1.9×10^{-5}	9.6×10^{-7}
	149.0	CL	99	86	107.0	20.7	2.702	37	1.2×10^{-5}	-
	242.5	CL	-	-	97.0	27.0	2.700	-	6.2×10^{-8}	2.9×10^{-7}
	263.5	CL	-	-	-	-	-	-	5.6×10^{-8}	1.4×10^{-7}
PV-32	10.5	ML	-	-	96.3	26.7	-	-	1.80×10^{-8}	2.68×10^{-6}
	21.0	CL	-	-	111.0	19.4	-	-	1.40×10^{-9}	8.80×10^{-10}
	31.0	CL	-	-	106.1	20.3	-	-	2.97×10^{-9}	2.86×10^{-7}
	42.0	SM	-	-	99.5	21.5	-	-	1.03×10^{-5}	4.74×10^{-5}
	53.0	ML	-	-	108.0	19.2	-	-	9.58×10^{-9}	1.62×10^{-9}
	62.5	ML	-	-	100.7	23.8	-	-	5.11×10^{-8}	-
	73.0	CL	-	-	102.3	23.1	-	-	2.47×10^{-8}	1.81×10^{-7}
	83.5	CL	-	-	95.0	30.0	-	-	2.44×10^{-7}	-
	94.5	CL	-	-	104.9	21.0	-	-	1.10×10^{-7}	5.93×10^{-7}
	115.0	ML	-	-	102.0	23.6	-	-	2.19×10^{-7}	-
	125.5	ML	-	-	96.0	27.4	-	-	1.89×10^{-7}	2.36×10^{-7}
	136.0	ML	-	-	97.5	28.3	-	-	4.83×10^{-7}	1.51×10^{-6}
	146.5	ML	-	-	106.3	21.0	-	-	1.80×10^{-8}	-
	253.0	CL	-	-	-	25.6	-	-	2.20×10^{-6}	2.60×10^{-7}
	296.0	CL	-	-	-	25.8	-	-	5.60×10^{-9}	9.50×10^{-7}

APPENDIX 2G

Table 2G-4

SUMMARY OF LABORATORY PERMEABILITY TEST DATA

EARLY SITING STUDIES (Sheet 2 of 2)

BORING NO.	SAMPLE DEPTH (FEET)	SOIL TYPE	% PASSING SIEVE		DRY UNIT WEIGHT (PCF)	MOISTURE CONTENT (%)	SPECIFIC GRAVITY	POROSITY	PERMEABILITY (cm/sec)	
			#40	#200					VERTICAL	HORIZONTAL
PV-33	94.5	CL	100	92	108.5	20.3	2.714	0.36	-	4.58×10^{-8}
	104.5	CL	99	99	96.8	26.7	2.743	0.43	3.69×10^{-9}	-
	114.0	CL	99	93	102.5	21.8	2.690	0.39	5.11×10^{-9}	-
	125.5	CL	100	97	106.9	19.2	2.736	0.37	2.67×10^{-6}	-
	136.0	CL	99	80	100.0	24.3	2.709	0.41	4.97×10^{-6}	-
	146.5	CL	99	85	93.6	28.0	2.709	0.44	6.05×10^{-6}	-
	157.0	CL	99	94	100.0	24.8	2.733	0.41	-	-
	240.5	CL	-	-	-	-	-	-	3.90×10^{-8}	8.10×10^{-8}
	241.5	CL	-	-	-	23.2	-	-	9.50×10^{-8}	2.66×10^{-6}
PV-34	11	SC	-	-	111.2	19.9	-	0.33	2.97×10^{-4}	5.92×10^{-4}
	21	SM	-	-	106.6	23.0	2.707	0.37	4.13×10^{-6}	-
	32	SM	-	-	107.9	18.7	2.727	0.36	2.47×10^{-6}	-
	42	ML	-	-	93.0	29.1	2.735	0.46	2.55×10^{-5}	1.93×10^{-6}
	52	CL	-	-	105.6	18.0	2.764	0.39	3.90×10^{-8}	2.74×10^{-8}
	63	ML	-	-	103.3	22.8	2.750	0.40	5.61×10^{-8}	5.24×10^{-8}
	73	CL	-	-	99.1	25.7	2.706	0.41	1.52×10^{-8}	-
	84	CL	-	-	97.4	23.5	2.745	0.43	-	7.32×10^{-7}
	95	CL	-	-	107.1	21.6	2.721	0.37	-	6.12×10^{-9}
	105	CH	-	-	93.0	21.3	2.744	0.45	3.37×10^{-10}	3.4×10^{-10}
	116	CL	-	-	86.4	30.2	2.725	0.49	9.23×10^{-10}	-
	126	CL	-	-	100.3	27.1	2.705	0.41	1.66×10^{-6}	3.30×10^{-7}
	137	ML	-	-	-	-	2.719	-	1.35×10^{-7}	-
	147	ML	-	-	101.4	19.8	2.731	0.41	5.25×10^{-7}	-
	157	CL	-	-	103.8	23.0	2.729	0.40	-	-
	208	CL	-	-	-	-	-	-	9.40×10^{-9}	4.50×10^{-8}
	233	CL	100	71	102.7	24.3	2.68	0.39	2.20×10^{-8}	1.50×10^{-6}
U1-B5	15.0	SP/SM	93	16	110.9	14.6	2.70	0.34	6.15×10^{-5}	1.08×10^{-3}
	23.0	SP/SW	66	9	N/A	N/A	2.70	-	1.50×10^{-5}	8.76×10^{-6}
U1-B6	28.0	SP	80	29	103.8	20.6	2.70	0.38	6.74×10^{-7}	3.96×10^{-6}
	33.0	SP	32	13	N/A	N/A	2.68	-	1.75×10^{-4}	1.21×10^{-5}
U1-B7	17.0	SP/SM	77	19	-	18.5	2.70	-	6.74×10^{-7}	2.08×10^{-5}
	33.0	SM	59	29	N/A	N/A	2.68	-	7.35×10^{-5}	1.70×10^{-4}
	36.0	ML/CL	87	51	109.3	18.4	2.68	0.35	2.70×10^{-6}	6.74×10^{-4}
U1-B8	6.0	ML	90	52	98.8	18.0	2.72	0.42	9.23×10^{-5}	3.59×10^{-5}
	37.0	SP	63	26	N/A	N/A	2.68	-	5.13×10^{-6}	1.50×10^{-4}
U1-B9	6.0	SM/SC	93	39	95.2	24.1	2.72	0.44	3.24×10^{-6}	3.50×10^{-6}
	55.0	ML	98	81	102.2	24.3	2.66	0.38	9.80×10^{-6}	1.12×10^{-5}
	60.0	SM/CL	98	53	96.3	26.2	2.66	0.42	4.04×10^{-6}	1.35×10^{-4}
U3-B3	38	SP/SM	32	8	N/A	N/A	2.69	-	4.04×10^{-7}	2.31×10^{-5}
U3-B4	35	SM/SC	89	43	104.7	23.5	2.70	0.38	1.28×10^{-5}	7.69×10^{-6}
	56	ML	90	82	N/A	29.1	2.68	-	9.51×10^{-5}	7.05×10^{-5}
U3-B5	22	SM	86	21	N/A	20.4	2.68	-	3.64×10^{-5}	1.20×10^{-4}
U3-B6	58	ML/CL	99	90	100.0	25.4	2.68	0.40	3.77×10^{-6}	1.21×10^{-5}
U3-B7	6	ML	91	81	N/A	27.0	2.73	-	5.39×10^{-7}	4.56×10^{-7}
U3-B8	33	SC/SM	78	48	107.1	18.6	2.70	0.36	9.44×10^{-7}	4.36×10^{-5}
U3-B9	9	SM/SC	67	31	N/A	19.3	2.73	-	8.24×10^{-6}	4.04×10^{-7}
	20	SM/SP	75	12	N/A	N/A	2.68	-	9.88×10^{-7}	2.09×10^{-4}
	24	SM	55	16	120.7	13.0	2.68	0.28	2.70×10^{-7}	-
	40	N/A	59	20	N/A	N/A	2.70	-	1.62×10^{-6}	-
	49	ML/CL	98	94	97.0	26.2	2.68	0.42	5.39×10^{-7}	3.64×10^{-6}

Table 2G-5

LABORATORY PERMEABILITY TEST RESULTS - NON-CATEGORY I STUDIES

FOR SITING OF WATER STORAGE RESERVOIR A ND EVAPORATION PONDS

WATER STORAGE RESERVOIR

BORING NO.	DEPTH (Ft.)	SOIL TYPE	COEFFICIENT OF PERMEABILITY (Cm/Sec.) VERTICAL	HORIZONTAL
PV-WR-1	2.5 - 3.5	SC	2.2×10^{-5}	-
	20 - 21	SC	1.2×10^{-7}	1.7×10^{-7}
	35 - 36	SM	1.1×10^{-5}	5.5×10^{-6}
	40 - 41	CL	6.2×10^{-10}	2.7×10^{-8}
	50 - 51	ML	6.7×10^{-6}	2.0×10^{-5}
PV-WR-2	26 - 27	SM-SP	3.8×10^{-6}	-
	35 - 36	CH	9.9×10^{-7}	3.2×10^{-6}
	50 - 51	CL-CH	9.9×10^{-9}	1.1×10^{-7}
PV-WR-3	5 - 6	SC	6.7×10^{-6}	1.4×10^{-6}
	15 - 16	CH	4.0×10^{-6}	6.7×10^{-7}
	25 - 26	SM-SC	1.0×10^{-5}	9.6×10^{-6}
	30 - 31	SM-SP	4.5×10^{-7}	-
	35 - 36	CL	3.4×10^{-9}	9.3×10^{-10}
	40 - 41	CL	2.1×10^{-7}	6.9×10^{-9}
	45 - 46	SM	8.8×10^{-6}	9.4×10^{-6}
	50 - 51	CH	5.0×10^{-9}	4.6×10^{-10}
	60 - 61	ML	1.1×10^{-5}	2.7×10^{-6}
PV-WR-5	5 - 6	SM	6.7×10^{-6}	-
	10 - 11	ML-CL	1.6×10^{-6}	3.4×10^{-6}
	15 - 16	SM-SC	1.2×10^{-5}	6.5×10^{-4}
	30 - 31	CH	1.2×10^{-9}	8.1×10^{-9}
	50 - 51	CH	6.2×10^{-10}	-
	65 - 66	SC	1.8×10^{-6}	9.4×10^{-7}
	75 - 76	ML	5.7×10^{-6}	-
PV-R1	30.3 - 30.8	CH	1.6×10^{-10}	-
	40.8 - 41.3	CH	1.6×10^{-10}	-
	50.3 - 50.8	CL	7.0×10^{-10}	-
PV-R2	10.1 - 10.8	MH	5.8×10^{-7}	5.4×10^{-7}
	25.1 - 25.8	CH	1.8×10^{-5}	7.8×10^{-10}
	30.1 - 30.8	CH	5.5×10^{-10}	8.1×10^{-6}
	40.3 - 40.8	CL	1.1×10^{-6}	-
	50.6 - 51.3	CH	1.6×10^{-6}	-
PV-R3	5.2 - 5.8	CL	5.4×10^{-7}	5.4×10^{-7}
	20.1 - 20.8	CL	6.3×10^{-6}	6.8×10^{-5}
	25.1 - 25.8	CH	2.2×10^{-9}	1.6×10^{-9}

EVAPORATION PONDS

BORING NO.	DEPTH (Ft.)	SOIL TYPE	COEFFICIENT OF PERMEABILITY (Cm/Sec.) VERTICAL	HORIZONTAL
PV-EP-5	14.5 - 16	SM-SP	1.1×10^{-5}	-
	29.5 - 31	ML-CL	1.6×10^{-7}	-
	44.5 - 46	CL	3.7×10^{-6}	-
PV-EP-6	14.5 - 16	SM	6.7×10^{-6}	-
	25.5 - 26	CL	2.9×10^{-9}	9.0×10^{-8}
	50.5 - 51	CL	1.1×10^{-5}	-
PV-EP-8	20.5 - 21	CL-CH	5.6×10^{-8}	-
	30.5 - 31	SM	1.8×10^{-6}	-
PV-EP-11	15.5 - 16	SC	3.0×10^{-8}	-
	34.5 - 36	CL	1.0×10^{-7}	-
	45.5 - 46	CH-CL	1.5×10^{-8}	-
PV-EP-12	9.5 - 11	CL	4.5×10^{-8}	-
	29.5 - 31	SM-SP	1.4×10^{-6}	-
	39.5 - 41	SM	1.5×10^{-6}	-
	49.5 - 51	CL	1.5×10^{-7}	-
PV-EP-15	9.5 - 11	SM-SP	1.6×10^{-3}	-
	19.5 - 21	CL	3.6×10^{-7}	-
	24.5 - 26	SP-SM	2.3×10^{-7}	-
	34.5 - 36	CL-ML	1.8×10^{-7}	-
PV EP-17	35 - 35.5	SM-SP	6.7×10^{-6}	-
	40.5 - 41	SM	4.5×10^{-5}	-

NOTE: R series borings were drilled east of the selected location of the water storage reservoir.

Table 2G-6

SUMMARY OF LABORATORY PERMEABILITY TEST DATA

RELATED TO SEEPAGE ANALYSIS

				INDEX PROPERTIES									PERMEABILITY TEST DETAILS					
BORING NO	DEPTH (Ft.)	ELEVATION (Ft.msl)	SOIL CLASS.	-#200 (%)	LL	PL	PI	INITIAL WATER CONTENT (%)	DRY UNIT WEIGHT (PCF)	SPECIFIC GRAVITY	VOID RATIO	INITIAL DEGREE OF SATURATION (%)	CELL PRESS. (Psi)	BACK PRESS. (Psi)	LENGTH OF SAMPLE (In.)	HYDRAULIC GRADIENT	K (cm/sec)	REMARKS
WATER RESEVOIR AREA																		
PV-172	8.0 - 8.8	914.5 - 913.7	CL	83	43	26	17	17.5	101.5	2.71	0.67	71	41	20	5.9	94	9.5×10^{-8}	
	12.0 - 12.8	910.5 - 907.7	SM	16		NP		7.6	94.1	2.68	0.78	26	30	2	5.0	9.2	1.4×10^{-5}	
	16.0 - 16.8	906.5 - 905.7	CH	93	75	28	47	29.1	90.3	2.70	0.84	89	52	20	4.0	138	3.4×10^{-6}	1/32" wide steak along sample
	20.2 - 21.0	902.3 - 901.5	CH	92	54	23	31	24.3	99.6	2.66	0.67	97	51	20	5.93	93	3.8×10^{-7}	
	30.2 - 31.0	892.3 - 891.5	CL	91	41	27	14	26.3	93.6	2.68	0.79	92	55/46	20/2	4.50	123/12	2.9×10^{-5}	Fine root holes noted
PV-173a	32.0 - 32.8	918.3 - 917.5	CH	80	67	24	43	24.0	100.1	2.68	0.67	96	39	20	6.0	92	9.4×10^{-8}	Some cementation
	34.0 - 34.8	916.3 - 915.5	CH	89	63	23	40	22.9	102.5	2.68	0.63	97	39	20	6.0	92	8.0×10^{-8}	
	36.0 - 36.8	914.3 - 913.5	CH	96	60	26	34	23.3	101.1	2.71	0.67	94	39	20	6.0	92	1.1×10^{-7}	
PV-173	57.7 - 58.5	892.6 - 891.8	CH	98	61	27	34	32.0	86.3	2.72	0.97	90	55	20	5.88	94	3.1×10^{-7}	
PV-174	24.2 - 25.0	930.9 - 930.1	CH	76	53	25	28	22.4	93.9	2.74	0.82	75	31	20	5.0	110	8.5×10^{-7}	
	55.0 - 55.8	900.1 - 899.3	CH	70	61	21	40	25.5	99.0	2.72	0.71	90	39	20	6.0	92	5.7×10^{-8}	
	60.0 - 60.8	895.1 - 894.3	CL	69	36	25	11	23.9	102.3	2.69	0.64	97	44	4	6.0	18	1.4×10^{-5}	2" thick sandy layer within sample
PV-175	22.0 - 22.8	932.0 - 931.2	CL	80	42	23	19	26.0	95.4	2.75	0.80	90	31	20	5.0	110	4.9×10^{-7}	1/4" Ø root channel inside sample
	50.2 - 51.0	903.8 - 903.0	CL	98	45	24	21	29.0	93.2	2.69	0.80	97	52	20	5.0	110	1.3×10^{-6}	
	52.2 - 53.0	901.8 - 901.0	ML	77	34	24	10	26.4	97.5	2.73	0.75	95	47	10	5.0	55	4.0×10^{-6}	
	56.8 - 57.5	897.2 - 896.5	CL	94	39	22	17	26.3	96.3	2.71	0.76	77	52	20	5.0	110	4.6×10^{-8}	
PV-176	32.0 - 32.8	921.5 - 920.7	CH	83	63	29	34	27.7	90.0	2.72	0.89	85	39	20	5.0	110	2.0×10^{-7}	
	34.0 - 34.8	919.5 - 918.7	CL	79	46	23	23	20.4	99.5	2.71	0.70	79	39	20	6.0	92	1.8×10^{-7}	Pores in upper part of sample
	49.1 - 49.7	904.4 - 903.8	CH	83	55	22	33	19.0	101.6	2.73	0.68	77	52	20	5.0	110	2.2×10^{-8}	Sample contains cementation nodules
PV-177	28.8 - 29.6	919.0 - 918.2	CH	80	69	22	47	21.7	102.4	2.73	0.66	89	39	20	5.0	110	1.2×10^{-7}	A few small pores noted
	30.2 - 31.0	917.6 - 916.8	CH	87	60	21	39	18.1	106.7	2.73	0.60	83	39	20	6.0	92	1.4×10^{-7}	Silty sand layer at center of sample
	34.0 - 34.8	913.8 - 913.0	CH	84	63	23	40	23.5	101.2	2.68	0.65	97	39	20	6.0	92	4.5×10^{-7}	1/2" thick sand layer within sample
	47.5 - 48.3	900.3 - 899.5	CH	94	74	27	47	28.3	94.3	2.73	0.81	96	52	20	5.0	110	2.6×10^{-8}	
PV-178	3.2 - 4.0	918.8 - 918.0	CH	79	50	23	27	19.4	108.6	2.70	0.55	95	39	20	6.0	92	7.2×10^{-8}	Sample contains cementation nodules
	5.8 - 6.6	916.2 - 915.4	CH	82	56	25	31	22.2	103.2	2.72	0.63	95	39	20	5.0	110	2.6×10^{-7}	
	11.0 - 11.8	911.0 - 910.2	CL	72	41	24	17	19.7	107.7	2.70	0.58	93	39	20	5.0	110	8.8×10^{-6}	Small pores noted
PV-180	3.2 - 4.0	918.4 - 917.6	CL	69	46	22	24	13.5	115.7	2.73	0.47	78	40	20	5.0	110	1.5×10^{-8}	
	5.2 - 6.0	916.4 - 915.6	CH	98	75	26	49	24.4	99.8	2.76	0.73	91	39	20	5.0	110	2.6×10^{-9}	
PV-181	3.2 - 4.0	919.3 - 918.5	CH	98	17	25	46	24.1	100.8	2.78	0.72	93	35	30	5.0	165	$\leq 10^{-9}$	No flow detected for one month
PV-182	4.0 - 4.6	918.5 - 917.9	CH	84	77	19	58	20.0	106.9	2.73	0.59	91	35	30	5.0	165	3.2×10^{-9}	
	5.5 - 6.3	917.0 - 916.2	CH	95	58	22	36	18.7	106.6	2.74	0.60	86	35	30	5.0	165	4.0×10^{-9}	
PV-183	38.8 - 39.6	910.9 - 910.1	CH	81	95	26	59	22.9	100.9	2.71	0.68	92	52	20	5.0	110	2.3×10^{-8}	
EVAPORATION POND AREA																		
U5-B72	44.2 - 45.0	888.6 - 887.8	CH	97	66	22	44	26.4	96.3	2.72	0.76	94	50	20	5.0	110	5.2×10^{-8}	
U5-B73	48.0 - 48.8	881.3 - 881.0	CH	92	51	26	25	20.8	104.9	2.70	0.61	93	40	20	5.0	110	1.0×10^{-6}	
	50.8 - 51.7	879.0 - 878.1	CL	97	38	23	15	18.4	108.8	2.69	0.55	91	52	40	4.1	269	2.5×10^{-7}	Root holes
	67.0 - 67.8	862.8 - 862.0	CL	97	49	25	24	28.8	92.8	2.74	0.82	96	50	20	4.1	135	4.2×10^{-8}	
	73.0 - 73.7	856.8 - 856.1	CH	98	69	35	34	40.8	80.2	2.73	1.12	99	53	20	5.95	93	2.4×10^{-8}	
U5-B74	43.0 - 43.4	887.0 - 886.6	CL	73	37	24	13	21.6	100.9	2.70	0.67	87	40	20	4.0	138	4.7×10^{-8}	
U5-B75	45.0 - 45.5	884.6 - 884.1	CL	91	35	23	12	15.6	113.8	2.72	0.49	87	40	20	5.0	110	2.6×10^{-8}	Cemented
U5-B78	45.0 - 45.8	883.8 - 883.0	CL	87	39	18	21	21.3	105.3	2.71	0.61	95	50	20	5.0	110	3.8×10^{-7}	5% small cemented nodules
U5-B79	47.0 - 47.7	881.3 - 880.6	CL	90	----	----	----	21.2	106.3	2.67	0.57	100	40	20	5.0	110	1.4×10^{-8}	A few cemented nodules
U5-B80	45.0 - 45.8	882.3 - 881.5	CL	92	42	22	20	21.3	105.8	2.69	0.59	98	50	20	5.0	110	2.4×10^{-7}	20" of sample w/cemented nodules
U5-B81	46.2 - 47.0	880 - 880.0	CH	83	51	25	26	21.4	105.0	2.71	0.61	97	40	20	5.0	110	1.2×10^{-7}	Cemented
	48.0 - 48.8	879.0 - 878.2	CL	94	40	23	17	21.0	106.0	2.69	0.58	91	50	20	5.0	110	5.2×10^{-8}	Layered cementation
U5-B82	51.0 - 51.6	881.7 - 881.1	CL	92	44	21	23	17.7	112.9	2.71	0.50	96	50	20	5.0	110	4.8×10^{-9}	

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CHAPTER 3

DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT AND SYSTEMS

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3. DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT AND SYSTEMS

3.1 CONFORMANCE WITH NRC GENERAL DESIGN CRITERIA

Brief discussions are presented in this section in response to the current General Design Criteria for Nuclear Power Plants, Appendix A to 10CFR50. These discussions summarize the manner in which the principal design features comply with the various individual criteria and include references to sections of CESSAR that provide additional specific information for the nuclear steam supply system. PVNGS design is in compliance with the NRC General Design Criteria, unless specifically stated otherwise under individual criteria.

3.1.1 CRITERION 1 -- QUALITY STANDARDS AND RECORDS

Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

RESPONSE:

The structures, systems, and components of the PVNGS are classified according to their importance in the prevention and mitigation of accidents using the classification system described in ANSI N18.2. Each safety-related component is given a safety class designation. The codes, standards, and quality control applicable to each component and its safety class designation are identified in section 3.2. Where applicable, design and fabrication are in accordance with the codes required in 10CFR50.55a. The quality assurance program, including record retention, conforms with the requirements of 10CFR50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants, and is presented in chapter 17. Chapter 14 describes initial tests and operation to assure performance of installed equipment commensurate with the importance of the safety function. The component safety classifications also are shown on P&IDs presented within their appropriate sections.

3.1.2 CRITERION 2 -- DESIGN BASES FOR PROTECTION AGAINST NATURAL PHENOMENA

Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect: (1) appropriate consideration of the most severe of the natural phenomena that have been

historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena, and (3) the importance of the safety functions to be performed.

RESPONSE:

Structures, systems, and components important to safety are designed to withstand the effects of earthquakes and tornadoes without loss of the capability to perform their safety functions.

The effects of tsunami and seiches are not considered because of the remote and elevated position of the site relative to any large body of water.

Sections 2.3, 2.4, and 2.5 give historical data on tornadoes, floods, and earthquakes, respectively. Effects of hurricanes are less than those of tornadoes and, therefore, are not treated. The data in sections 2.3, 2.4, and 2.5, in conjunction with a detailed site investigation, are used to predict the effects of the most severe natural phenomena incorporated in the design bases. Combinations of the effects of natural phenomena are described in sections 3.8, 3.9, and 3.10. The importance of safety functions being performed is identified by the classification system provided in section 3.2.

The design of safety related structures, systems and components is consistent with conservative structural envelopes. These "envelopes" have been selected based on the design bases earthquakes at the majority of potential plant sites in the continental U.S., using current containment structure designs.

In the design stage, normal operating and accident loads are appropriately combined with the seismic loads and allowable stress limits and deformations are defined so that safety functions are not jeopardized. Discussion of this material is found in section 3.7.

3.1.3 CRITERION 3 -- FIRE PROTECTION

Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat-resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and firefighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

RESPONSE:

Structures, systems, and components important to safety are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Equipment and facilities for fire protection, including detection, alarm, and extinguishment, are provided to protect plant equipment and personnel from fire, explosion, and the resultant release of toxic vapors. Wet and dry types of firefighting equipment are provided.

Normal fire protection is provided by deluge systems, sprinklers, carbon dioxide, halon, and portable extinguishers.

Rupture or inadvertent operation of the firefighting systems will not impair systems important to safety.

High grade noncombustible and fire-resistant materials are used in the containment, control room, components of safety features systems, and throughout each unit wherever practical. A description of the fire protection system is presented in subsection 9.5.1.

3.1.4 CRITERION 4 -- ENVIRONMENTAL AND MISSILE DESIGN BASES

Structures, systems, and components important to safety shall be designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of

missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, the dynamic effects associated with postulated pipe ruptures of primary coolant loop piping in pressurized water reactors may be excluded from the design basis when analyses demonstrate the probability of rupturing such piping is extremely low under design basis conditions.

RESPONSE:

Structures, systems, and components important to safety are capable of withstanding the effects of, and are compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents (LOCA).

Environmental conditions associated with postulated accidents are pressure, temperature, humidity, radiation, and chemical attack. Environmental design of electric equipment is discussed in section 3.11. The criteria for combining the effects of accident conditions with conditions associated with normal operation, maintenance, and testing are given in sections 3.8, 3.9, and 3.10.

Design criteria based upon the dynamic effects of missiles, pipe whipping, and discharging fluids are treated in sections 3.5 and 3.6. Due to analysis submitted on the CESSAR docket, APS has excluded the dynamic effects associated with postulated pipe ruptures of primary coolant loop piping from the design basis. Events and conditions outside the nuclear

power unit that are considered in the design of structures, systems, and components important to safety are tornadoes, floods, and earthquakes. The bases of the design criteria for these events are presented in sections 3.3, 3.4, and 3.7.

C-E supplied structures, systems and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing and postulated accidents, including loss of coolant accidents, (see section 3.11). The Ansaldo supplied steam generators are also designed as stated above.

Interface requirements are invoked to ensure that these structures, systems and components will be appropriately protected against dynamic effects (including the effects of missiles, pipe whipping, and discharge of fluids) that may result from equipment failures, postulated accidents, and from events and conditions outside the nuclear power unit.

3.1.5 CRITERION 5 -- SHARING OF STRUCTURES, SYSTEMS, AND COMPONENTS

Structures, systems, and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

RESPONSE:

Separate systems important to safety are provided for each unit. The Station Blackout Gas Turbine Generation (SBOG) System is shared between units. The SBOG system provides AC electrical power of sufficient capacity and reliability to operate the systems required for coping with a station blackout in any one of the units for a period of 16 hours. Some nonsafety-related systems and components are directly shared by PVNGS Units 1, 2, and 3. These systems are as follows:

A. Water Treatment Systems

Various water treatment systems are shared. These systems include:

1. Domestic water system
2. Demineralized water system
3. Sanitary treatment system
4. Water reclamation plant
5. Secondary chemistry system

Details of these systems are presented in sections 9.2 and 10.4.

B. Switchyard

A common switchyard is provided for PVNGS Units 1, 2, and 3. This complies with General Design Criterion 17. Details of the offsite power system are discussed in section 8.2.

C. Fire Protection System

The fire protection water supply and pumping equipment is shared by Units 1, 2, and 3. The plant two-way radio system is one of the communications means available for coordinating fire response team activities and safe shutdown activities. The plant two-way radio system is shared among all three units. Other fire protection equipment is provided for each unit individually.

3.1.6 CRITERION 10 -- REACTOR DESIGN

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

RESPONSE:

Specified acceptable fuel design limits are stated in section 4.4.1. Operation within the operating limits (Limiting Conditions for Operations) specified by the Technical Specifications will keep the reactor fuel within the specified acceptable fuel design limits for normal operation and during any moderate frequency event. In accordance with Regulatory Guide 1.70, Revision 2 moderate frequency events have been selected and analysis of the most limiting of these is presented in Chapter 15. Section 15.0.1 presents all of the events considered and categorized by type and expected

frequency. Events were categorized as moderate or infrequent based on PWR operating history data.

The plant is designed such that operation within Limiting Conditions for Operation, with safety system settings not less conservative than the Limiting Safety System Settings prescribed in the Technical Specifications results in confidence that specified acceptable fuel design limits will not be exceeded as a result of any initiating event of moderate frequency. Operator action, aided by the control systems and monitored by plant instrumentation, maintains the plant within Limiting Conditions for Operation during normal operation.

For further discussion see the following sections: Classification of Transients and Accidents, section 15.0.1; Fuel System Design, section 4.2; Reactor Coolant Systems, Chapter 5; Residual Heat Removal, section 5.4.7; Reactor Protective System, section 7.2; and Technical Specifications.

3.1.7 CRITERION 11 -- REACTOR INHERENT PROTECTION

The reactor core and associated coolant systems shall be designed so that in the power operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

RESPONSE:

In the power operating range, the combined response of the fuel temperature coefficient, the moderator temperature coefficient, the moderator void coefficient, and the moderator

pressure coefficient to an increase in reactor power in the power operating range will be a decrease in reactivity; i.e., the inherent nuclear feedback characteristics will not be positive.

The reactivity coefficients for this reactor are discussed in detail in section 4.3.

3.1.8 CRITERION 12 -- SUPPRESSION OF REACTOR POWER OSCILLATIONS

The reactor core and associated coolant, control, and protection system shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

RESPONSE:

Power level oscillations do not occur. The effect of the negative power coefficient of reactivity (see Criterion 11), together with the coolant temperature program maintained by control of regulating rods and soluble boron, provides fundamental mode stability. Power level is continuously monitored by neutron flux detectors (Chapter 7).

Power distribution oscillations are detected by neutron flux detectors.

Axial mode oscillations are suppressed by means of part strength or full strength neutron absorber rods. All other modes of oscillation are expected to be convergent.

Monitoring and protective requirements imposed by Criteria 10 and 20 are discussed in those responses and in Chapter 4.

3.1.9 CRITERION 13 -- INSTRUMENTATION AND CONTROL

Instrumentation and control shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

RESPONSE:

Instrumentation and control systems are provided for the containment and its associated systems to ensure adequate safety under all conditions.

Instrumentation is provided to monitor significant process variables which can affect the fission process, the integrity of the reactor core, the Reactor Coolant Pressure Boundary (RCPB) and their associated systems. Controls are provided for the purpose of maintaining these variables within the limits prescribed for safe operation. The principal process variables to be monitored and controlled are: neutron flux level (reactor power); CEA positions; neutron flux distribution (at various axial positions); reactor coolant

temperature and pressure; reactor pump speed; pressurizer level; and steam generator level and pressure. In addition, Departure from Nucleate Boiling Ratio (DNBR) margin and Local Power Density (LPD) margin, in Kw/ft, are also monitored.

The Plant Protection System (PPS) consists of the Reactor Protective System (RPS) and the Engineered Safety Features Actuation System (ESFAS). The RPS is designed to monitor NSSS operating conditions and to initiate reliable and rapid reactor shutdown if monitored variables or combinations of monitored variables deviate from the permissible operating range to a degree that a safety limit may be reached.

The ESFAS is designed to monitor plant variables and to initiate Engineered Safety Feature (ESF) Systems during a design basis event.

The following are provided to monitor and maintain control over the fission process during transient and steady state periods over the lifetime of the core:

A. Eight independent channels of ex-core nuclear instrumentation, which constitutes the primary monitor of the fission process,

   1. Four safety channels for PPS input,

   2. Two control channels for the reactor control,

   3. Two startup channels for low power operation;

B. Three independent CEA Position Indicating Systems for each CEA,

1. Two independent Reed Switch Position Transmitter (RSPT) assemblies for PPS input,

2. A Pulse Counting System within the Plant Monitoring System;

C. Manual and automatic control of reactor power by means of CEAs;

D. Manual regulation of coolant boron concentration;

E. In-core instrumentation is provided to supplement information on core power distribution and to provide a means for calibration of ex-core flux detectors.

The non-nuclear instrumentation measures temperatures; pressures, flows and levels in the Reactor Coolant System and main steam and auxiliary systems and is used to maintain these variables within the prescribed limits. The instrumentation and control systems are described in detail in Chapter 7.0. The process radiation monitor is discussed in Chapter 9. When it is required that a variable be monitored during a Design Basis Event (DBE), in addition to normal operation, the results of analysis of the course of the event are used to ensure that the instruments provided will cover the range anticipated for the event conditions.

Instrumentation and control systems are described in detail in chapter 7.

3.1.10 CRITERION 14 -- REACTOR COOLANT PRESSURE BOUNDARY

The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

RESPONSE:

The reactor coolant pressure boundary is defined in accordance with 10CFR50, Section 50.2(v) and ANSI N18.2, (see response to GDC-55).

Reactor Coolant System components are designed to meet the requirements of the ASME Code, Section III. To establish operating pressure and temperature limitations during startup and shutdown of the Reactor Coolant System, the fracture toughness rules defined in the ASME Code, Section III, are followed. Quality control, inspection, and testing are performed as required by ASME Section III and allowable reactor pressure-temperature operations are specified to ensure the integrity of the Reactor Coolant System.

The reactor coolant pressure boundary is designed to accommodate the system pressures and temperatures attained under all expected modes of unit operation including all anticipated transients, and maintain the stresses within applicable limits.

Piping and equipment pressure parts of the reactor coolant pressure boundary are assembled and erected by welding unless applicable codes permit flanged or screwed joints. Welding procedures are employed which produce welds of complete fusion

and free of unacceptable defects. All welding procedures, welders, and welding machine operators are qualified in accordance with the requirements of Section IX of the ASME Boiler and Pressure Vessel Code for the materials to be welded. Qualification records, including the results of the procedure and performance qualification tests and identification symbols assigned to each welder; are maintained.

The pressure boundary has provisions for inservice inspection in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, to ensure continuance of the structural and leaktight integrity of the boundary (see response to GDC No. 32, also). For the reactor vessel, a material surveillance program conforming with the requirements of Appendix H to 10CFR Part 50 is provided.

3.1.11 CRITERION 15 -- REACTOR COOLANT SYSTEM DESIGN

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

RESPONSE:

The design criteria and bases for the reactor coolant pressure boundary are described in the response to Criterion 14.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between them and the design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the reactor coolant pressure boundary.

Plant Control Systems function to minimize the deviations from normal operating limits in the event of most anticipated operational occurrences. Where control systems response would be inadequate or fail upon demand, the Plant Protection System functions to mitigate the consequences of such events.

The Plant Protection System functions to mitigate the consequences in the event of accidents. Analyses show that the design limits for the reactor coolant pressure boundary are not exceeded in the event of any ANSI N18.2 Conditions.

3.1.12 CRITERION 16 -- CONTAINMENT DESIGN

Reactor containment and associated systems shall be provided to establish an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment and

to ensure the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

RESPONSE:

A steel-lined, prestressed, post-tensioned concrete containment encloses the entire RCPB. It is designed to sustain, without loss of required integrity, all effects of equipment failures up to and including the double-ended rupture of the largest pipe in the RCPB. In the event of a LOCA, the safety injection system (SIS) and containment spray system (CSS) are actuated, cool the reactor core, and return the containment to near atmospheric pressure. The containment, SIS, CSS, and containment isolation system ensure the functional capability of containing any uncontrolled release of radioactivity. Refer to sections 3.8 and 6.2 for details. Primary containment isolation is discussed in the response to General Design Criterion 56.

3.1.13 CRITERION 17 -- ELECTRICAL POWER SYSTEMS

An onsite electrical power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that: (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences, and (2) the

core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electrical power sources, including the batteries, and the onsite electric distribution system shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a LOCA to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining sources as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the

transmission network, or the loss of power from the onsite electric power sources.

RESPONSE:

For each nuclear power unit of PVNGS, an onsite electric power system and an offsite electric power system provide power for electric loads important to safety. Two completely independent and redundant electric load groups important to safety are provided for each unit. Each load group has sufficient capability, independent of the other load group for the same unit, to ensure that:

A. Specified acceptable fuel design limits and design conditions of the RCPB are not exceeded as a result of anticipated operational occurrences.

B. The core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

Each redundant load group is provided with two offsite (preferred) electric power supplies, an onsite diesel generator (standby) power supply, and two sets of batteries (subject to the limitations of power system development, paragraph 8.2.1.2.1). In addition, Station Blackout Generators (SBOGs) supply power to one of the safety related 4.16kV busses as discussed in section 8.3.1.1.10. These provide sufficient independence, redundancy, and testability to perform their safety functions, assuming a single failure.

Eight physically independent circuits on four separate rights-of-way provide electric power from the transmission network to

the Palo Verde 525kV switchyard which, in turn, supplies offsite (preferred) power to the onsite power system. Design of the offsite power system minimizes the possibility that failure of any one circuit will cause the failure of any other circuit. For each nuclear power unit, two physically independent, full-capacity electric power circuits supply offsite (preferred) power to the onsite power system. Each circuit is available following a postulated LOCA to ensure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions are included to minimize the probability of losing electric power from any of the remaining sources as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite diesel generator. Electric system stability studies indicate that major disturbances on one circuit of the transmission network will not cause loss of the transmission network circuits supplying off-site electric power to the units. Furthermore, separation of the transmission lines is such that physical failure of any transmission line or tower will not compromise the performance of adjacent transmission lines (a failure of the Mead-Perkins transmission line could affect both West-Wing transmission lines). A fault on any preferred power source circuit supplying offsite electric power to the units will be cleared automatically to prevent loss of other offsite preferred power sources.

In addition to its two offsite (preferred) electric power supplies, each redundant load group is supplied by an emergency diesel generator. The diesel generator is capable of providing the total load requirements for a safe shutdown of the unit, or for the engineered safety features, following a LOCA or other postulated accidents.

The inherent design of the onsite power system prevents automatic paralleling of the two redundant load groups for each unit, the paralleling of the two diesel generators for each unit, or the automatic paralleling of any diesel generator with any of the offsite (preferred) power supplies. The electric power system is described in chapter 8.

3.1.14 CRITERION 18 -- INSPECTION AND TESTING OF ELECTRICAL POWER SYSTEMS

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically: (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses; and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the

nuclear power units, the offsite power system, and the onsite power system.

RESPONSE:

Inspection and testing of the station service transformers, high voltage switchyard circuit breakers, and transformer and transmission line protective relaying are done on a routine basis without removal of the transformers, circuit breakers, and transmission lines from service. The transformer insulating oil is sampled and tested for dielectric strength on a routine basis. Drawout type protective relays with built-in test switches facilitate testing of protective devices and circuits without removal from service of the protected transformers, circuit breakers, and transmission lines.

Functional performance and operability of the preferred ac power system and components are inspected and tested on a routine basis in conformance with requirements of General Design Criterion 18. The electric power system is discussed in chapter 8.

3.1.15 CRITERION 19 -- CONTROL ROOM

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including LOCAs. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel

receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Equipment at appropriate locations outside the control room shall be provided: (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

RESPONSE:

The units are designed to provide safe occupancy of the control room during abnormal conditions. The control room is in a Seismic Category I structure. Under accident conditions, sufficient shielding and ventilation are provided to permit occupancy of the control room continuously for 30 days without receiving more than 5 rem whole body, or its equivalent, to any part of the body. The shielding is described in subsections 12.1.2 and 12.3.2. Habitability and ventilation is discussed in section 6.4 and subsection 12.3.3.

In the unlikely event that the control room should become inaccessible, sufficient instrumentation and controls are provided outside the control room to:

- Achieve prompt hot shutdown of the reactor
- Maintain the unit in a safe condition during hot shutdown

- Achieve cold shutdown of the reactor through the use of suitable procedures

Refer to subsection 7.4.1 for details on the instrumentation and controls provided outside the control room.

3.1.16 CRITERION 20 -- PROTECTION SYSTEM FUNCTIONS

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

RESPONSE:

A Plant Protection System (PPS), consisting of a Reactor Protective System (RPS) and an Engineered Safety Features Actuation Systems (ESFAS) is provided. The RPS automatically initiates a reactor trip when the monitored variable or combination of variables reaches a trip function setpoint. The ESFAS automatically actuates Engineered Safety Features (ESF) and their support systems when the monitored variable or variables reach a predetermined setpoint.

The trip function setpoints of the RPS are selected to ensure that Design Basis Events which are expected to occur once or more during the life of the nuclear generating station, which credit the RPS, do not cause Specified Acceptable Fuel Design Limits (SAFDL), peak fuel centerline temperature and minimum

Departure from Nucleate Boiling Ratio (DNBR), to be violated. The reactor trips also help the ESF Systems in mitigating the consequences of Design Basis Events, which are expected to occur once during the life of several plants and arbitrary combinations of unplanned events and degraded systems that are never expected to occur, to within acceptable limits. Reactor trip is accomplished by de-energizing the Control Element Drive Mechanism (CEDM) coils through the interruption of the CEDM power supply either automatically or manually. The CEDM power supply is a pair of full capacity motor-generator sets. The path to the CEDMs is interrupted by opening the Reactor Trip Switchgear. With the CEDM coils de-energized, the CEAs are released to drop into the core by gravity, rapidly inserting negative reactivity to shutdown the reactor. The CEDMs are described in section 4.2, the specific reactor trips used are described in section 7.2.

The ESF Systems are actuated to minimize the effects of incidents which could occur. Controls are provided for manual actuation of the ESF System. The variables which automatically actuate the ESF System and the circuitry arrangements for the ESFAS are discussed in section 7.3, the ESF Systems are discussed in Chapter 6.0.

The SAFDL on peak fuel centerline temperature and DNBR are intended to enforce the principal thermal hydraulic design basis given in section 4.4.1 i.e., the avoidance of thermally induced fuel damage during normal steady state operation and during moderate frequency DBEs. The thermal hydraulic design limits are a minimum DNBR and a maximum fuel temperature as

described in Technical Specification Sections 2.1.1.1 and 2.1.1.2 and their associated Bases.

The SAFDL on fuel centerline temperature is specifically intended to prevent fuel melting.

3.1.17 CRITERION 21 -- PROTECTION SYSTEM RELIABILITY AND TESTABILITY

The protection system shall be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of the protection function and (2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

RESPONSE:

The PPS is designed to provide high functional reliability and inservice testability. The protection system is designed to comply with the requirements of IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations." No credible single failure will result in the loss of the

protection function. The protection channels are independent e.g., with respect to wire routing, sensor mounting and supply of power. Each channel of the protection system, including the sensors, up to the RTSS and ESFAS actuation devices, is capable of being checked during reactor operation. Measurement sensors of each channel used in the protection systems are checked by comparison of outputs of similar channels which are presented on indicators or recorders in the main control room, or which can be called up from the Remote Operators Modules of the DNBR/LPD Calculator Systems.

Trip channels and logic are tested by inserting a signal into the measurement channel ahead of the trip bistable and, upon application of a trip level input, observing that a signal is passed through the trip channels and the logic to the logic output relays. The logic output relays are tested individually for initiation of trip action. The parallel reactor trip circuit breakers which control power to the CEDM coils may be tested during reactor operation without effecting a reactor trip.

The ESFAS test circuitry in the PPS cabinet is identical to that of the RPS. This logic supplies initiation signals to the actuation logic contained in the ESFAS Auxiliary Relay Cabinets. The circuitry in the ESFAS Auxiliary Relay Cabinets operates the actuation relays for the various ESF Systems, these are tested so as not to actuate any components that could interfere with safe plant operation. ESFAS is discussed in detail in section 7.3.

To minimize inadvertent actuation of an ESF System or an inadvertent reactor trip, the protection systems require coincidence of two logic to operate. In addition, the channel being tested is bypassed so that the protection system converts to a two out of three logic while maintaining the coincidence of two. This allows periodic testing and operation of the various protective functions without reducing the availability of the protection systems.

3.1.18 CRITERION 22 -- PROTECTION SYSTEM INDEPENDENCE

The protection system shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing and postulated accident conditions on redundant channels do not result in loss of the protection function or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

RESPONSE:

The protection systems conform to the independence requirements of IEEE 279-1971. Four independent measurement channels, complete with sensors, sensor power supplies, signal conditioning units, and bistable trip channels are provided for each protective parameter monitored by the protection systems except for the CEA position sensors which are two-fold redundant. The measurement channels are provided with a high degree of independence by separate connection of the channel

sensors to the process systems. Refer to Chapter 7.0 for a more detailed discussion of the protection systems.

Power to the protection systems' channels is provided by independent vital power supply busses. The power supply systems are discussed in Chapter 8.0. Interface requirements of the protection systems on the power supply systems are discussed in Chapter 8.0.

Functional diversity has been incorporated into the system design to the extent that is practical, to prevent the loss of the protective function. Whenever an RPS trip function is required, it is frequently backed up by other trip functions. The ESFAS actuation signals are used to actuate two independent ESF trains. Where it is practical, and ESFAS can be generated by more than one parameter.

The design goals are accomplished without excessive complexity by using only four channels for each parameter. This allows for testing and maintenance of a channel without reducing the system to a single channel for trip, which would make the system susceptible to spurious trip or actuation signals.

The protection systems are each functionally tested to ensure satisfactory operation prior to installation in the plant. Environmental and seismic qualifications are also performed utilizing type tests, specific equipment tests, appropriate analyses, or prior operating experience. For further information, refer to section 3.10 and 3.11.

3.1.19 CRITERION 23 -- PROTECTION SYSTEM FAILURE MODES

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air) or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

RESPONSE:

Protection system trip channels have been designed to fail into a safe state or into a state established as acceptable in the event of loss of power supply. A failure is assumed to occur in only one channel (i.e., a single failure). This channel can be placed into bypass which places the RPS and/or ESFAS into a two-out-of-three logic which retains the coincidence of two for trip. Refer to sections 7.2 and 7.3 for detailed Failure Modes and Effects Analysis information.

A loss of power to CEDM coils will cause the CEAs to insert into the core. Redundance, channel independence and separation are incorporated into the protection systems' design to minimize the possibility of the loss of a protective function. The loss of off-site power will cause the standby generators to start and energize the ESF trains which have actuation signals present.

3.1.20 CRITERION 24 -- SEPARATION OF PROTECTION AND CONTROL SYSTEMS

The protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired.

RESPONSE:

Protection system components and control system components are electrically and functionally isolated from each other. See section 7.2 and 7.3 for details.

The protection systems are designed so that they can sustain one channel in a tripped condition and one channel bypassed indefinitely and still provide their safety actions.

3.1.21 CRITERION 25 -- PROTECTION SYSTEM REQUIREMENTS FOR REACTIVITY CONTROL MALFUNCTIONS

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems such as accidental withdrawal (not ejection or dropout) of control rods.

RESPONSE:

Shutdown of the reactor is accomplished by the opening of the RTSS circuit breakers which interrupts power to the CEDM coils. Actuation of the circuit breakers is independent of any existing control signals.

The protection systems are designed such that SAFDL are not exceeded for any single malfunction of the reactivity control systems, including the withdrawal of a single full- or part-strength CEA. Analysis of possible reactivity control system malfunctions are discussed in Chapter 15.0. The various CEA related DBE's for which the protection systems are designed are discussed in section 7.2.

3.1.22 CRITERION 26 -- REACTIVITY CONTROL SYSTEM REDUNDANCY AND CAPABILITY

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the

reactor core subcritical under cold conditions. For further discussion, see section 7.4, Systems Required For Safe Shutdown and section 7.7, Control Systems Not Required for Safety.

RESPONSE:

Two independent reactivity control systems of different design principles are provided. The first system, using Control Element Assemblies (CEAs), includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded. The CEAs can be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of anticipated operational occurrences that the highest worth CEA does not fall into the core.

The second system, using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that acceptable fuel design limits are not exceeded. This system is capable of holding the reactor subcritical under cold conditions.

Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical in the hot standby condition.

Either system is able to insert negative reactivity at a rate sufficient to prevent exceeding acceptable fuel design limits

as the result of a power change (i.e., the positive reactivity added by burnup of xenon).

3.1.23 CRITERION 27 -- COMBINED REACTIVITY CONTROL SYSTEMS CAPABILITY

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

RESPONSE:

Dissolved boron addition capability provided by the Safety Injection System (Chapter 6.0) in consideration with the control rod (CEA) system will be such that under postulated accident conditions (Chapter 15.0), even with the CEA of highest worth stuck out of the core, adequate reactivity control is available to maintain short and long term capability to cool the core.

3.1.24 CRITERION 28 -- REACTIVITY LIMITS

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the reactor coolant pressure boundary greater than limited local yielding nor (2) sufficiently disturb the core, its support

structures or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means) rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

RESPONSE:

The bases for control element assembly (CEA) design include ensuring that the reactivity worth of any one CEA is not greater than a preselected maximum value. The CEAs are divided into two sets, a shutdown set and a regulating set, further subdivided into groups as necessary. Administrative procedures and interlocks assure that only one group is withdrawn at a time, and that the regulating groups are withdrawn only after the shutdown groups are fully withdrawn. The regulating groups are programmed to move in sequence and within limits which prevent the rate of reactivity addition and the worth of individual CEAs from exceeding limiting values.

The maximum rate of reactivity addition which may be produced by the Chemical and Volume Control System is too low to induce any significant pressure forces which might rupture the reactor coolant pressure boundary or disturb the reactor vessel internals.

The reactor coolant pressure boundary (Chapter 5.0) and the reactor internals (Chapter 4.0) are designed to appropriate codes (refer for instance, to the response to Criterion 14)

and will accommodate the static and dynamic loads associated with an inadvertent, sudden release of energy, such as that resulting from a CEA ejection or steam line break (Chapter 15.0), without rupture and with limited deformation which will not impair the capability of cooling the core.

3.1.25 CRITERION 29 -- PROTECTION AGAINST ANTICIPATED OPERATIONAL OCCURRENCES

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

RESPONSE:

Plant events, designated in ANSI N18.2, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants", have been carefully considered in the design of the protection systems and the reactivity control systems. Consideration of redundancy, independence and testability in the design, coupled with careful component selection, overall system testing, and adherence to detailed quality assurance, assure an extremely high probability that safety functions are accomplished in the event of Design Basis Events.

Detailed discussions of the protection systems are provided in Chapter 7.0. Design quality assurance is discussed in Combustion Engineering Topical Report CENPD 210A, "Discussion of the C-E Nuclear Steam Supply System Quality Assurance

Program" (Reference 1) and Chapter 17. The analysis of DBE is contained in Chapter 15.0.

3.1.26 CRITERION 30 -- QUALITY OF REACTOR COOLANT PRESSURE BOUNDARY

Components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practicable, identifying the location of the source of reactor coolant leakage.

RESPONSE:

The reactor coolant pressure boundary components will be designed, fabricated, erected and tested in accordance with the ASME Code Section III. All components are classified Safety Class 1 or 2, in accordance with the ANSI N18.2, "Nuclear Safety Criteria for the Design of Stationary PWR Plants," definitions for Safety Classes and reactor coolant pressure boundary. Accordingly, they receive all of the quality measures appropriate to that classification.

Means are provided by C-E, or required to be provided by the applicant's, for the identification of the source of reactor coolant leakage. These include the detection of leakage to systems connected to the reactor coolant pressure boundary as well as leakage from the boundary into the containment.

C-E provides instrumentation to indicate and record makeup flow rate and integrated makeup flow to the primary water

system. This instrumentation permits detection of suddenly occurring leaks and those which are gradually increasing. Additional means for detecting leakage into the containment is required to be provided. Refer to section 5.2.5.

3.1.27 CRITERION 31 -- FRACTURE PREVENTION OF REACTOR COOLANT PRESSURE BOUNDARY

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions: (1) the boundary behaves in a nonbrittle manner; and (2) The probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining: (1) Material properties; (2) The effects of irradiation on material properties: (3) Residual, steady state, and transient stresses; and (4) Size of flaws.

RESPONSE:

All the reactor coolant pressure boundary components are designed and constructed in accordance with ASME Section III and comply with the test and inspection requirements of these codes. The test and inspection requirements assure that flow sizes are limited so that the probability of failure by rapid propagation is extremely remote. Particular emphasis is placed on the quality control applied to the reactor vessel on which tests and inspections exceeding ASME code requirements

are performed. The tests and inspections performed on the reactor vessel are summarized in section 5.3.

Carbon and low alloy steel materials which form part of the pressure boundary are tested in accordance with the requirements of the fracture toughness requirements for materials, ASME Code Section III. Nonductile failure prevention will be ensured by utilizing the appropriate sections of the ASME Code.

Excessive embrittlement of the reactor vessel material due to neutron radiation is prevented by providing an annulus of coolant water between the reactor core and the vessel. In addition, to minimize the effects of irradiation on material toughness properties of core beltline materials, restrictions on upper limits for residual elements that directly influence the NDT shift are required by the design specification for the plates and deposited welds. Specifically, upper limits are placed on copper, phosphorous, sulfur, and vanadium.

The maximum integrated fast neutron flux exposure of the reactor vessel wall opposite the midplane of the reactor core is estimated to be less than 3.29E+19 neutrons per square centimeter for a 40-year lifetime. This estimate is confirmed periodically during plant lifetime by a material surveillance program. The maximum expected increase in transition temperature is about 140°F. The actual change in material toughness properties due to irradiation will be verified periodically during plant lifetime by a material surveillance

program. Based on the RT_{NDT}, operating restrictions will be applied as necessary to limit vessel stresses.

The thermal stresses induced by the injection of cold water into the vessel, following a LOCA, have been examined. The test results and analysis have shown that there is no gross yielding across the vessel wall when using the minimum specified yield strength in the ASME Boiler and Pressure Vessel Code, Section III.

3.1.28 CRITERION 32 -- INSPECTION OF REACTOR COOLANT PRESSURE BOUNDARY

Components which are part of the reactor coolant pressure boundary shall be designed to permit:

(1) Periodic inspection and testing of important areas and features to assess their structural and leak-tight integrity; and

(2) An appropriate material surveillance program for the reactor pressure vessel.

RESPONSE:

Provisions have been made in the design for inspection, testing, and surveillance of the Reactor Coolant System boundary as required by ASME Boiler and Pressure Vessel Code Section XI. The Applicant is required to install the system so that the required inservice inspections per Section XI can be performed. C-E recommends a reactor vessel surveillance program to the owner.

The reactor vessel surveillance program capability provided to the Applicant conforms with ASTM-E-185, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels", as revised in 1979 for Unit 1 and 1982 for Unit 2 & 3. Sample pieces taken from the same shell plate material used in fabrication of the reactor vessel are installed between the core and the vessel inside wall. These samples will be removed and tested by the Applicant at intervals during vessel life to provide an indication of the extent of the neutron embrittlement of the vessel wall. Charpy tests will be performed on the samples to develop a Charpy transition curve. By comparison of this curve with the Charpy curve and drop weight tests for specimens taken at the beginning of the vessel life, the change of RT_{NDT} will be determined and operating procedures adjusted as required.

The surveillance program capability provided to the Applicant has provisions which comply with the AEC regulation, "Reactor Vessel Material Surveillance Program Requirements", 10CFR50, Appendix H, published in the Federal Register on July 17, 1973. The only exception between the recommended surveillance program and the requirements presented in Appendix H is the following:

A. Appendix H, Section II.C.2 - Attachments to the reactor vessel.

   In adhering to the requirement of placing the surveillance specimens as close as possible to the reactor vessel wall, the capsule holders are attached

to the cladding of the reactor vessel and are not major load-bearing components. By such placement, temperature, flux spectra, and fluence differences between the surveillance specimens and the reactor vessel are minimized, thereby permitting more accurate assessment of the changes in the reactor vessel properties.

3.1.29 CRITERION 33 -- REACTOR COOLANT MAKEUP

A system to supply reactor coolant makeup for protection against small breaks in the reactor coolant pressure boundary shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the reactor coolant pressure boundary and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished using the piping, pumps and valves used to maintain coolant inventory during normal reactor operation.

RESPONSE:

Reactor coolant makeup during normal operation is provided by the Chemical and Volume Control System (CVCS). Based on the analysis provided in UFSAR 9.3.4.4.11, it is concluded that this criterion is met.

3.1.30 CRITERION 34 -- RESIDUAL HEAT REMOVAL

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection and isolation and capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

RESPONSE:

Residual heat removal capability is provided by the Shutdown Cooling System for reactor coolant temperatures less than 350°F. For temperatures greater than 350°F, this function is provided by the steam generators. The design incorporates sufficient redundancy, interconnections, leak detection, and isolation capability to ensure that the residual heat removal function can be accomplished, assuming a single active

failure[a]. Within appropriate design limits, either system will remove fission product decay heat at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary will not be exceeded.

The Shutdown Cooling System and the steam generator auxiliaries are designed to operate either from offsite power or from onsite power sources.

Further discussion is included in Section 5.4.7 for the residual heat removal system and in Chapter 10.0 (see paragraph 10.3.2.2.4) for the Main Steam and Power Conversion System.

3.1.31 CRITERION 35 -- EMERGENCY CORE COOLING

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

a. An active failure is a malfunction, excluding passive failure, of a component which relies on mechanical movement to complete its intended function upon demand. Check valves which receive regular exercise to ensure operability are treated as passive components. Examples of active failures include the failure of a valve to move to its correct position, or the failure of a pump, fan, or diesel generator to start. Spurious action of a powered component originating within the actuation system or its supporting systems shall be regarded as an active failure, unless specific design features or operating restrictions preclude such spurious action.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation and containment capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

RESPONSE:

Emergency core cooling is provided by the Safety Injection System (described in Section 6.3). The system is designed to provide abundant cooling water to remove heat at a rate sufficient to maintain the fuel in a coolable geometry and to assure that zirconium-water reaction is limited to a negligible amount (less than one percent). Detailed analysis has been performed, utilizing models complying with 10CFR50, Appendix K, ECCS Evaluation Models, to verify that the system performance is adequate to meet the intent of the Acceptance Criteria for Emergency Core Cooling Systems for Light Water Power Reactors of 10CFR50, Paragraph 50.46(b).

The system design includes provisions to assure that the required safety functions are accomplished with either onsite or offsite electrical power system operation, assuming a single failure (qualified as described below) of any

component. The single failure may be an active failure[a] during the initial period following an accident (coolant injection phase of emergency core cooling) or an active or limited leakage passive failure[b] during the long term cooling (coolant recirculation) phase of emergency core cooling.

Though the ECCS is designed to accommodate a limited leakage passive failure during the recirculation phase, it does not accommodate arbitrary large leakage passive failures such as the complete double-ended severance of piping, which are extremely low probability events. Interface criteria require that the Applicant's layout and arrangement assure that the limited leakage passive failure does not preclude minimum acceptable recirculation capability. Where building design is not relied upon to mitigate and contain leakage from the ECCS passive failure, suitable automatic isolation and auxiliary equipment must be provided by the Applicant, as necessary, to comply with the interface criteria.

In lower Modes of plant operation (i.e., in Mode 3 with pressurizer pressure <1837 psia and RCS cold leg temperature <485°F, and in Mode 4), ECCS equipment operability

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a. An active failure is a malfunction, excluding passive failure, of a component which relies on mechanical movement to complete its intended function upon demand. Check valves which receive regular exercise to ensure operability are treated as passive components. Examples of active failures include the failure of a valve to move to its correct position, or the failure of a pump, fan, or diesel generator to start. Spurious action of a powered component originating within the actuation system or its supporting systems shall be regarded as an active failure, unless specific design features or operating restrictions preclude such spurious action.

b. A passive failure is defined as the blockage of a process flow path or a breach in the integrity of a component or piping (for example, a piping failure).

requirements are reduced, and protection against single failures is not required, in accordance with plant technical specifications.

3.1.32 CRITERION 36 -- INSPECTION OF EMERGENCY CORE COOLING SYSTEM

The emergency core cooling system shall be designed to permit appropriate periodic inspection of important components, such as spray rings in the reactor pressure vessel, water injection nozzles, and piping to assure the integrity and capability of the system.

RESPONSE:

The Emergency Core Cooling System (Safety Injection System (SIS)) is designed to facilitate access to all critical components. All pumps, heat exchangers, valves and piping external to the containment structure are readily accessible for periodic inspection to ensure system leak-tight integrity.

Valves, piping and tanks inside the containment may be inspected for leak-tightness during plant shutdowns for refueling and maintenance.

Reactor vessel internal structures, reactor coolant piping and water injection nozzles are designed to permit visual inspection for wear due to erosion, corrosion or vibration, and nondestructive inspection techniques where these are applicable and desirable.

Details of the inspection program are described in Chapters 5.0 and 6.0, and Technical Specification and Technical Requirements Manual.

3.1.33 CRITERION 37 -- TESTING OF EMERGENCY CORE COOLING SYSTEM

The emergency core cooling system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leak-tight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of the applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

RESPONSE:

The Emergency Core Cooling System (Safety Injection System) is provided with testing capability to demonstrate system and component operability. Testing can be conducted during normal plant operation with the test facilities arranged not to interfere with the performance of the systems or with the initiation of control circuits, as described in section 6.3 and Chapter 14.

3.1.34 CRITERION 38 -- CONTAINMENT HEAT REMOVAL

A system to remove heat from the reactor containment shall be provided. The system function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any LOCA and maintain them at acceptably low levels.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

RESPONSE:

The containment spray system consists of two completely independent subsystems. The heat removal capacity of the flow from either containment spray subsystem is adequate to keep the containment pressure and temperature below design conditions for any size break in the reactor coolant system piping up to and including a double-ended break of the largest reactor coolant pipe, with an unobstructed discharge from both ends.

Borated water is sprayed downward by the system from the upper regions of the containment to cool the atmosphere. Cooling reduces the containment pressure and temperature following a major LOCA.

Suitable redundancy in components and features is designed into the containment spray system to maintain the pressure and temperature conditions below containment design even in the event of a single failure, including the loss of onsite or offsite electrical power.

3.1.35 CRITERION 39 -- INSPECTION OF CONTAINMENT HEAT REMOVAL SYSTEM

The containment heat removal system shall be designed to permit appropriate periodic inspection of important components, such as the torus, sumps, spray nozzles, and piping to assure the integrity and capability of the system.

RESPONSE:

All essential equipment of the containment spray system is located outside the containment, except for spray headers, nozzles, containment sump, and associated piping. These components include the refueling water tank, two containment spray pumps, two shutdown cooling heat exchangers, and independent containment spray headers.

The detail arrangement and layout of system piping, pumps, heat exchangers, and valves will provide the separation, availability, and accessibility required for periodic inspection.

3.1.36 CRITERION 40 -- TESTING OF CONTAINMENT HEAT REMOVAL SYSTEM

The containment heat removal system shall be designed to permit appropriate periodic pressure and functional testing to assure: (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole, and, under conditions as close to the design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

RESPONSE:

System piping, valves, pumps, heat exchangers, and other components of the containment heat removal systems are arranged so that each component can be tested periodically for operability. Testing can be conducted during normal plant operation with the test facilities arranged not to interfere with the performance of the systems or with the initiation of control circuits, as described in section 6.2.

Performance testing of containment spray pumps is conducted in accordance with the Inservice Testing Program as described in Section 3.9.6.

Normal heat exchanger operation is verified during nominal plant cooldown. The low-pressure safety injection pumps

discharge into the safety injection header via the shutdown cooling heat exchangers and the low-pressure injection lines.

Actuator-operated valves can be cycled from the control room, and operation verified by observing control room indication of operation.

Check valves will be tested to ensure that the valves perform their safety functions. These valves include the refueling water storage tank check valves and the valves on the inlets and outlets of the containment spray pumps.

3.1.37 CRITERION 41 -- CONTAINMENT ATMOSPHERE CLEANUP

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that, for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available), its safety function can be accomplished, assuming a single failure.

RESPONSE:

Two systems, namely the containment spray and hydrogen recombiner systems, are provided to control fission products, hydrogen, oxygen, and other substances that may be released into the reactor containment.

The post accident hydrogen recombiner system is designed with redundancy of vital components so that a single failure does not prevent operation of the system.

These systems are described in sections 6.2.2 and 6.2.5.

3.1.38 CRITERION 42 -- INSPECTION OF CONTAINMENT ATMOSPHERE CLEANUP SYSTEMS

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic inspection of important components, such as filter frames, ducts, and piping to assure the integrity and capability of the systems.

RESPONSE:

The containment atmosphere cleanup systems are designed and located so that they can be inspected periodically as required.

All major components of the hydrogen recombiner system are located outside containment and are readily accessible for periodic inspection. Purge piping and valves located inside containment may be inspected during plant shutdown.

See sections 6.2 and 6.5 for further information.

3.1.39 CRITERION 43 -- TESTING OF CONTAINMENT ATMOSPHERE CLEANUP SYSTEMS

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure: (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the systems such as fans, filters, dampers, pumps, and valves, and (3) the operability of the systems as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.

RESPONSE:

Testing of the containment spray subsystem shall be conducted to assure structural and leaktight integrity, and operability and performance in accordance with Criterion 40.

The hydrogen recombiner system is designed to permit periodic testing for structural and leaktight integrity of components and for operability of the system. Testing may be conducted during normal plant operation or shutdown. See section 6.2 for details.

3.1.40 CRITERION 44 -- COOLING WATER

A system to transfer heat from structures, systems, and components important to safety, to an ultimate heat sink,

shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

RESPONSE:

The cooling water systems for safety-related functions consist of the essential cooling water system (ECWS) and the essential spray pond system (ESPS). Each system consists of two redundant and independent trains. The ECWS and ESPS trains are used for safe plant shutdown under normal shutdown and accident conditions.

During and following a postulated LOCA or loss of normal fuel pool cooling, the ECWS and ESPS are designed to meet the single failure criterion and still carry the essential heat load derived from safety-related components and systems.

The ECWS and ESPS perform their functions assuming that either offsite or onsite electric power is available.

The ultimate heat sink for each unit consists of two essential spray ponds that meet the guidelines of Regulatory Guide 1.27. These ponds are described in detail in subsection 9.2.5.

The ECWS and ESPS are described in subsections 9.2.2 and 9.2.1, respectively.

3.1.41 CRITERION 45 -- INSPECTION OF COOLING WATER SYSTEM

The cooling water system shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

RESPONSE:

The important components of the ESPS and ECWS are located in accessible areas. These components have suitable manholes, handholes, inspection ports, or other appropriate design and layout features to allow periodic inspection. Refer to section 9.2 for details.

3.1.42 CRITERION 46 -- TESTING OF COOLING WATER SYSTEM

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and the performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for LOCAs, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.

RESPONSE:

Active components of the ESPS and ECWS are tested periodically for operability and functional performance.

Preoperational performance tests of the components are made in the manufacturer's shop. An initial system flow test demonstrates proper functioning of the system. Thereafter, periodic tests ensure that components function properly.

Each active component of the ECWS and the ESPS may be individually connected to the preferred power source at any time during reactor operation to demonstrate operability.

Many active components function during normal plant operation, thereby demonstrating operability. The essential trains are tested to ensure proper system operation. Remotely operated valves are exercised and actuation circuits are tested. The automatic actuation circuitry, valves, and pump breakers also are checked when integrated system tests are performed during a planned cooldown of the RCS. Refer to section 9.2 for additional information.

3.1.43 CRITERION 50 -- CONTAINMENT DESIGN BASIS

The reactor containment structure, including access openings, penetrations, and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA. This margin shall reflect consideration of: (1) the effects of

potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

RESPONSE:

The reactor containment structure and its internal compartments, including access openings, penetrations, and the containment heat removal system, accommodate the calculated pressure and temperature conditions resulting from any LOCA, without exceeding the design leakage rate and with a sufficient margin. Subcompartment analyses and associated structural evaluations of containment internal structures consider the worst case line breaks that are not precluded by Leak Before Break Criteria. Refer to subsection 3.8.1 and section 6.2 for further details.

3.1.44 CRITERION 51 -- FRACTURE PREVENTION OF CONTAINMENT PRESSURE BOUNDARY

The reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions: (1) its ferritic materials behave in a nonbrittle manner, and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and

other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions, and the uncertainties in determining: (1) material properties, (2) residual, steady-state, and transient stresses, and (3) size of flaws.

RESPONSE:

The reactor containment boundary has sufficient margin to ensure that under operating, maintenance, testing, and postulated accident conditions its ferritic materials behave in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. To be assured of this, the steel-lined, prestressed concrete reactor containment is designed so that the 1/4-inch steel liner plate is in compression or nominal tension under all conditions stated above. The steel plate around penetrations may be in significant tension because of stress concentration. These areas are reinforced with thickened plates with a nil ductility transition temperature at least 30F below the minimum service temperature.

Uncertainties in determining material properties and flaw sizes are mitigated through the use of ultrasonic inspection and other nondestructive tests. Sufficient margin is provided in the design to account for residual, steady-state, and transient stresses. Refer to subsection 3.8.1 for details.

3.1.45 CRITERION 52 -- CAPABILITY FOR CONTAINMENT LEAKAGE RATE TESTING

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

RESPONSE:

The reactor containment, and any equipment subject to containment test conditions, incorporates provisions for conducting periodic local and integrated leakage rate tests. Details concerning these provisions and the nature and scheduling of leakage rate tests are provided in paragraph 3.8.1.7 and subsection 6.2.6.

3.1.46 CRITERION 53 -- PROVISIONS FOR CONTAINMENT TESTING AND INSPECTION

The reactor containment shall be designed to permit:
(1) appropriate periodic inspection of all important areas, such as penetrations, (2) an appropriate surveillance program, and (3) periodic testing at containment design pressure of the leaktightness of penetrations which have resilient seals and expansion bellows.

RESPONSE:

The reactor containment design permits periodic inspection of all important areas. Provisions are included for preoperational and post-operational testing and surveillance to assess the structural and leaktight integrity of the

containment and its penetrations. The post-operational surveillance program includes inservice tendon and liner plate inspection. Provisions also are included for periodic leakage rate testing of penetrations with resilient seals and expansion bellows. Refer to paragraph 3.8.1.7 and subsection 6.2.6 for details.

3.1.47 CRITERION 54 -- PIPING SYSTEMS PENETRATING CONTAINMENT

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

RESPONSE:

Piping systems penetrating primary reactor containment are provided with containment isolation valves.

Penetrations, except instrument lines, that are closed for containment isolation have redundant valving and associated apparatus. Valve testing during normal operation or during shutdown conditions is conducted as described in subsection 6.2.4 to ensure operability when needed.

Instrument lines are designed in accordance with the suggested requirements of Regulatory Guide 1.11, Instrument Lines Penetrating Primary Reactor Containment.

Fittings are provided to permit periodic leakage rate testing of isolation valves to ensure that leakage is within acceptable limits. Refer to subsection 6.2.4 for details.

3.1.48 CRITERION 55 -- REACTOR COOLANT PRESSURE BOUNDARY PENETRATING CONTAINMENT

Each line that is part of the reactor coolant pressure boundary and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power,

automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

RESPONSE:

The reactor coolant system pressure boundary is defined in accordance with ANSI N18.2 Section 5.4.3.2 and 10CFR50, Section 50.2(v). All reactor coolant pressure boundary lines penetrating containment meet the isolation criteria of GDC 55 using the following basis for specific lines in addition to those noted above.

1. Safety injection lines, as shown on engineering drawing 01-M-SIP-001 (penetration numbers 11 through 20) are used to mitigate the consequences of accidents and therefore do not receive an automatic closure signal and are not locked closed.

2. When in the shutdown cooling mode of operation the Shutdown Cooling System is an extension of the reactor coolant pressure boundary. In this mode the

system is isolated from the environment by two isolation valves in series.

3. The charging and seal injection lines shown on engineering drawings 01, 02, 03-M-CHP-001 through -005 (penetration numbers 41 and 57) have automatic valves outside the containment which do not receive a CIAS closure signal. This is because it is desirable to maintain charging and seal injection flow as long as the charging pumps are in operation.

Details are given in subsection 6.2.4.

3.1.49 CRITERION 56 -- PRIMARY CONTAINMENT ISOLATION

Each line that connects directly to the containment atmosphere and penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

RESPONSE:

Each line that connects directly to the containment atmosphere and penetrates containment is provided with containment isolation valves inside and outside containment. Where it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable, the additional isolation valves are not provided. Details are given in subsection 6.2.4.

3.1.50 CRITERION 57 -- CLOSED SYSTEM ISOLATION VALVES

Each line that penetrates primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. This valve shall be outside containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

RESPONSE:

Each line that penetrates containment and is not connected directly to the containment atmosphere and is not part of the RCPB has at least one isolation valve (not a check valve) located outside containment near the penetration. Details are given in subsection 6.2.4.

3.1.51 CRITERION 60 -- CONTROL OF RELEASES OF RADIOACTIVE MATERIALS TO THE ENVIRONMENT

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

RESPONSE:

The liquid radwaste system, gaseous radwaste system, and the solid radwaste system safely control the radioactive liquid, gaseous, and solid wastes generated during normal operation, including anticipated operational occurrences. These systems limit the release of radioactivity so that exposure to persons in restricted and unrestricted areas are as low as reasonably achievable in conformance with 10CFR20.1-20.601 and 10CFR50.

The facility also is designed with provisions to prevent radioactivity release during accidents from exceeding limits of 10CFR100.

The radwaste systems, the design criteria, and amounts of estimated releases of radioactive effluents to the environments are described in chapter 11.

3.1.52 CRITERION 61 -- FUEL STORAGE AND HANDLING AND RADIOACTIVITY CONTROL

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed: (1) with a capability to permit appropriate periodic inspection and testing of components important to safety, (2) with suitable shielding for radiation protection, (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

<u>RESPONSE</u>:

Fuel storage and handling and fuel pool cooling are discussed in section 9.1. Most of the components and systems in this category are in frequent use and no special testing is required. Those systems and components important to safety

that are not normally operating are tested periodically; e.g., the fuel handling equipment (prior to each refueling).

The spent fuel storage racks are located to provide sufficient shielding water over stored fuel assemblies to limit radiation at the surface of the water to no more than 2.5 mrem/h during the storage period. The exposure time during refueling is limited so that the integrated dose to operating personnel does not exceed the limits of 10CFR20.1001-20.2401.

Analysis has indicated that the accidental release of the maximum activity content of a gas decay tank will not result in doses in excess of 500 mrem whole body. See chapter 15 for details.

Cooling for the spent fuel pools is designed to prevent damage to fuel in the storage facilities that could result in radioactivity release to the plant operating areas or the plant environs.

The fuel building can withstand seismic events without loss of the pool water or damage to stored fuel.

The PVNGS Independent Spent Fuel Storage Installation (ISFSI) has been designed and licensed under 10 CFR Part 72 requirements, as appropriate, and is not subject to 10 CFR Part 50, Appendix A, General Design Criteria.

3.1.53 CRITERION 62 -- PREVENTION OF CRITICALITY IN FUEL STORAGE AND HANDLING

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

RESPONSE:

The new, intermediate and spent fuel racks are all designed in accordance with ANSI N18.2. Each type of rack is designed with rectangular arrays of storage cells spaced such that the minimum edge to edge distance of stored fuel assemblies precludes accidental criticality. The minimum edge spacing for each specific type of rack includes allowances for fabrication tolerances and predicted deflections due to postulated accidents.

The new fuel racks are designed for dry storage of new fuel only. The intermediate and spent fuel racks are designed for wet storage of either new or spent fuel. In addition to maintaining minimum edge to edge spacing, fuel stored in the spent fuel storage racks is controlled administratively, according to initial enrichment, burnup, and decay time.

Design of the new fuel racks assures a k_{eff} of less than .98. Design of the spent fuel racks assures a k_{eff} of less than .95 for all conditions given partial credit for soluble boron contained in the spent fuel pool water. Design of the dry fuel storage fuel basket assures a k_{eff} of less than .95 even with full moderator intrusion.

The fuel storage and handling system is described in Section 9.1.

The PVNGS Independent Spent Fuel Storage Installation (ISFSI) has been designed and licensed under 10 CFR Part 72 requirements, as appropriate, and is not subject to 10 CFR Part 50, Appendix A, General Design Criteria.

3.1.54 CRITERION 63 -- MONITORING FUEL AND WASTE STORAGE

Appropriate systems shall be provided in fuel storage and radioactive waste systems and associated handling areas: (1) to detect conditions that may result in loss of residual heat removal capability and excessive radiation levels, and (2) to initiate appropriate safety actions.

RESPONSE:

The spent fuel pool has monitoring equipment that alarms if the water level falls below a predetermined level or if high water temperatures are experienced. The fuel building has monitoring equipment that alarms if high radiation levels are experienced. The high radiation level instrumentation also actuates the fuel building essential ventilation system. See section 7.3 for details.

The radwaste equipment is located in the radwaste building. Local radiation monitors in the building alarm at a predetermined setpoint to indicate excessive radiation levels. Appropriate action is taken following a radiation alarm to verify the condition and isolate the cause. See section 12.3 for details.

The PVNGS Independent Spent Fuel Storage Installation (ISFSI) has been designed and licensed under 10 CFR Part 72 requirements, as appropriate, and is not subject to 10 CFR Part 50, Appendix A, General Design Criteria.

3.1.55 CRITERION 64 -- MONITORING RADIOACTIVITY RELEASES

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of LOCA fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

RESPONSE:

The reactor containment atmosphere is monitored as described in table 11.5-1. Local radiation monitors are located throughout the facility to detect excessive radiation levels. In particular, areas that contain potentially radioactive liquid or gas are continuously monitored. All discharge paths to the environment, which might be associated with potentially radioactive gas, are continuously monitored during discharge. Additionally, radiation monitors are located about the plant environs, and samples are collected and analyzed in accordance with the radiological-environmental monitoring program. See sections 11.5 and 12.3 for details.

3.2 CLASSIFICATION OF STRUCTURES, COMPONENTS, AND SYSTEMS

The classification of structures, components, and systems within the Combustion Engineering, Inc. (C-E) scope of supply as defined in section 1.9 does not deviate from the classifications designated in CESSAR Section 3.2, and is included in table 3.2-1 for completeness.

3.2.1 SEISMIC CLASSIFICATION

CE SCOPE

The seismic category and safety and quality classification of mechanical components within the CESSAR scope are listed in Table 3.2-1. The only process piping included in the CESSAR scope is the RCS main loop piping. The safety class boundaries of other process piping, (not included in CESSAR scope) is indicated on the P&ID's (Chapters 5.0, 6.0, and 9.0). Seismic Category I includes all mechanical components within the safety class boundaries and extends to the first seismic restraint beyond the boundary. Structures or supports essential to the performance of a safety function by a mechanical component or capable of disabling interaction with it are designed to Seismic Category I requirements for structural integrity only. Where structures or supports essential to the performance of a safety function are not provided by C-E, interface requirements are stated in the interface sections. This allows PVNGS to design in such a way that any structures, systems, or components that could potentially have a disabling interaction with C-E supplied Seismic Category I mechanical structures, systems, or components are either prevented from doing so or

are designed to meet Seismic Category I structural integrity requirements.

The listing of major electrical components, which are normally in the C-E scope of supply is listed in section 3.11, which also includes safety and quality classification. Electrical structures, systems, and components not classified as Seismic Category I, but whose failure could represent a hazard to the operator or could interfere with the performance of required safety functions of electrical structures, systems and components, are classified as Seismic Category II. Any electrical system or structure or component not in Seismic Category I or II is considered non-seismic; see section 3.10. The use of Seismic Category II is limited to non-safety control system components, which are designed and documented to maintain structural integrity during an SSE.

PVNGS Scope

Seismic Category I is applied to those structures, systems, and components that must remain functional during a safe shutdown earthquake (SSE). Regulatory Guide 1.29; 10CFR50, Appendix A, General Design Criterion 2; and 10CFR100, Appendix A, require that nuclear power plant structures, systems, and components important to safety be designed to withstand the effects of earthquakes. Specifically, 10CFR100, Appendix A, requires that all nuclear power plants be designed so that, if the SSE occurs, all structures, systems, and components important to safety remain functional. These plant features are those necessary to assure:

- The integrity of the reactor coolant pressure boundary (RCPB)
- The capability to shut down the reactor and maintain it in a safe condition.
- The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10CFR100.

Regulatory Guide 1.29 describes an acceptable method of identifying those plant features that should be designed to remain functional if the SSE occurs and which should be designated Seismic Category I. Seismic Category I structures, systems, and components are listed in table 3.2-1.

All Seismic Category I items are designed to remain functional and within applicable stress and deformation limits when subjected to the effects of the vibratory motion of the operating basis earthquake in combination with normal operating loads.

Structures, systems, and components not listed as Seismic Category I items are designed to appropriate static loads or comply with applicable building codes regarding seismic effects. The interface between different seismic classifications is indicated by the code breaks shown on the piping and instrumentation diagrams of the appropriate systems. Seismic Category I design requirements extend to the first seismic anchor beyond the interface of the classification change. All ASME Section III components and piping are Seismic

Category I and all components and piping identified as nonnuclear safety (NNS) are non-Seismic Category I.

3.2.2 SYSTEM QUALITY GROUP CLASSIFICATION

CE supplied equipment has been included in Table 3.2-1 as stated in section 3.2 above. Fluid systems or portions of fluid systems and their pressure-retaining components important to safety are classified in accordance with ANSI N18.2. The safety classes defined in these criteria are used as guides in designating codes, standards, and quality requirements for the safety-related fluid systems and components. This classification system influences the design, material selection, manufacture or fabrication, inspection, assembly, erection, and construction of the safety-related fluid systems and components. Safety class designations per ANSI N18.2, Quality Group Classifications per Regulatory Guide 1.26 and 10CFR50.55a, and the appropriate codes and standards for all plant components are delineated in table 3.2-1 and are shown on the applicable piping and instrumentation diagrams. For operational phase activities, including preoperational, initial startup, and operational testing, system classification is in accordance with Regulatory Guide 1.26 and 10CFR50.55a as indicated in table 3.2-1 and footnote (ff).

3.2.3 DRY CASK STORAGE CLASSIFICATION

Systems, structures and components associated with dry storage of spent fuel are classified in accordance with 10CFR72 and the guidance provided in NUREG/CR-6407 and Regulatory Guide 7.10,

Appendix A. As such, they are designated as Important to Safety Category A, B or C, or Not Important to Safety.

The classification of systems, structures and components designed and licensed by the cask certificate holder is identified in the cask FSAR. The classification of dry cask storage systems, structures and components other than those designed and licensed by the cask certificate holder has been established by APS. Significant systems, structures and components that have been classified by APS as Important to Safety Category A, B, or C are listed in Table 3.2-1.

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 1 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
1. Reactor equipment						
Reactor vessel	C	III-1	I	Q	A	1
Reactor vessel supports	C	(r)	I	Q	na	1
Core support structures	C	(q)	I(f)	Q	na	na
Fuel assemblies	C	na	I	Q	na	na
Control element assemblies	C	na	I	Q	na	na
Control element drive mechanisms(d)	C	na	I(e)	Q(dd)	na	na
2. Reactor coolant system						
Reactor coolant pumps (j,k)	C	III-1	I	Q	A	1
Reactor coolant pump motors	C	na	na(e)	na(ee)	na	na
Reactor coolant pump supports	C	(r)	I	Q	na	1
Pressurizer	C	III-1	I	Q	A	1
Pressurizer supports	C	(r)	I	Q	na	1
Steam generators	C	III-1/2	I	Q	A/B	1/2(1)
Steam generator supports	C	III-1/2	I	Q	A/B	1/2(1)
Pressurizer heaters	C	na	na(e)	na(ee)	na	na
Piping						
Reactor coolant pressure boundary	C	III-1(i)	I	Q	A(i)	1(i)
Reactor vessel head vent and pressurizer vent, upstream of flow restricting orifice	C	III-1	I	Q	A	1
Reactor vessel head vent and pressurizer vent, downstream of flow restricting orifice	C	III-2	I	Q	B	2
Pressurizer relief piping, from relief valves	C	B31.1	na(e)	na(cc)	D	NNS
Pressurizer surge & spray	C	III-1	I	Q	A	1
Pressurizer sample piping from containment isolation valve	AB	B31.1	na	na	D	NNS
Pressurizer sample piping from pressurizer to containment isolation valve	C	III-2	I	Q	B	2
Pressurizer auxiliary spray line						
From spray valve to spray line	C	III-1	I	Q	A	1
From regenerative heat exchanger to remote Isolation valve	C	III-2	I	Q	B	2
Containment penetrations	C	III-2	I	Q	B	2
Valves						
Reactor coolant pressure boundary valves	C,AB	III-1(i)	I	Q	A(i)	1(i)

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 2 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Safety and relief valves within reactor coolant pressure boundary	C	III-1	I	Q	A	1
Supports and hangers	C	III-NF (n)	(h)	(h)	na	1, 2
3. Chemical and volume control system						
Regenerative heat exchanger	C	III-2	I	Q	B	2
Letdown heat exchanger	AB	III-2/3	I	Q	B/C	2/3 (1)
Seal injection heat exchanger	AB	III-2/3	I	Q	B/C	2/3 (1)
Purification ion exchanger	AB	III-2	I	Q	B	2
Deborating ion exchanger	AB	III-2	I	Q	B	2
Purification filters	AB	III-2	I	Q	B	2
Volume control tank	AB	III-2	I	Q	B	2
Charging pumps	AB	III-2	I	Q	B	2
Charging pump motors	AB	IEEE-323/ 334/344	I	Q	na	na
Seal injection filter	AB	III-2	I	Q	B	2
Letdown control valves	AB	III-2	I	Q	B	2
Boric acid makeup pumps	AB	III-3	I	Q	C	3
Boric acid filter	AB	III-3	I	Q	C	3
Boric acid batching tank	AB	VIII	na	na	D	NNS
Boric acid batching tank heaters	AB	na	na	na	na	na
Chemical addition tank	AB	VIII	na	na	D	NNS
Boronometer – Abandoned in-place	AB	na	na	na	na	na
CVCS holdup tank	OU	API-650	na	na	D	NNS
CVCS holdup tank pumps	OU	(g)	na	na	D	NNS
Equipment drain tank	AB	III-3	I	Q	C (ff)	3
Reactor drain tank	C	VIII	na	na	D	NNS
Reactor drain tank pumps	AB	III-3	I	Q	C (ff)	3
Reactor drain filter	AB	III-3	I	Q	C (ff)	3
Preholdup ion exchangers	AB	III-3	I	Q	C (ff)	3
Gas stripper	AB	VIII	na (s)	na (s)	D	NNS
Reactor makeup water tank	OU	API-650	na	na	D	NNS
Reactor makeup water pumps	AB	(g)	na	na	D	NNS
Reactor makeup water filter	AB	VII	na	na	D	NNS
Boric acid concentrator	AB	VII	na	na	D	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 3 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Boric acid condensate ion exchanger	AB	VIII	na	na	D	NNS
Refueling water tank	OU	(a)	I	Q	B	2
Chemical addition pump	AB	(g)	na	na	D	NNS
Piping and valves						
Within reactor coolant pressure boundary	C	III-1(i)	I	Q	A(i)	1(i)
Containment penetrations	C	III-2	I	Q	B	2
Within purification system	AB	III-2	I	Q	B	2
Within seal water system	C,AB	III-2	I	Q	B	2
Within boric acid recovery system						
Containment isolation valve for reactor makeup water	AB	III-2	I	Q	B	2
Remainder	AB	B31.1	na	na	D	NNS
Within reactor makeup water system	AB	B31.1	na	na	D	NNS
Within boric acid makeup system	AB	III-3	I	Q	C(mm)	3
To boric acid batching tank	AB	B31.1	na	na	D	NNS
From refueling water tank to second isolation valve	OU	III-2	I	Q	B(ff)	2
Piping support and hangers	C,AB	III-NF(n)	(h)	(h)	na	2,3,NNS
4. Safety injection and shutdown cooling system						
Low-pressure safety injection pumps	AB	III-2	I	Q	B	2
Low-pressure safety injection pump motors	AB	IEEE-323/ 344	I	Q	na	na
Shutdown cooling heat exchangers	AB	III-2/3	I	Q	B/C	2/3(1)
High-pressure safety injection pumps	AB	III-2	I	Q	B	2
High-pressure safety injection pump motors	AB	IEEE-323/ 344	I	Q	na	na
Safety injection tanks	C	III-2	I	Q	B	2

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 4 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Piping and valves						
Safety injection tank test lines	C, AB	III-2	I	Q	B	2
Reactor coolant pressure boundary	C, AB	III-1(i)	I	Q	A(i)	1(i)
Safety injection tank nitrogen line from isolation valve	C	B31.1(t)	na	na	D	NNS
Relief piping from relief valves in containment	C	B31.1(t)	na	na	D	NNS
Relief piping from relief valves in auxiliary building	AB	III-3	I	Q	C(ff)	3
All other safety injection piping	C, AB	III-2	I	Q	B	2
Recirculations sump and sump screens	C	na	I	Q	na	na
Piping supports and hangers	C, AB	III-NF(n)	(h)	(h)	na	1, 2, 3, NNS
5. Containment spray system						
Containment spray pumps	AB	III-2	I	Q	B	2
Containment spray pumps motors	AB	IEEE-323/ 334/344	I	Q	na	na
Spray nozzles	C	III-2	I	Q	B	2
Piping, spray headers, and valves	C, AB	III-2	I	Q	B	2
Valves, containment isolation	C	III-2	I	Q	B	2
Valves, containment penetration	C	III-2	I	Q	B	2
Piping supports and hangers	C, AB	III-NF(n)	(h)	(h)	na	2, 3 NNS
6. Containment building combustible gas control system						
Piping, containment penetrations	C	III-2	I	Q	B	2
Valves, containment isolation	C, AB	III-2	I	Q	B	2
Hydrogen purge system						
Moisture Separator	AB	na	na	na	na	na
High efficiency particulate air (HEPA) filters	AB	na	na	na	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 5 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Charcoal filters	AB	na	na	na	na	na
Piping	AB	na	na	na	na	na
Valves	AB	na	na	na	na	na
Supports and Hangers	AB	na	(h)	(h)	na	na
Hydrogen recombiners system						
Hydrogen recombiners	AB	III-2	I	Q	B	2
Piping	AB	III-2	I	Q	B	2
Valves	AB	III-2	I	Q	B	2
Supports and hangers	AB	III-NF(n)	(h)	(h)	na	2
Containment atmosphere sampling system						
Piping	AB,C	III-2	I	Q	B	2
Valves	AB,C	III-2	I	Q	B	2
Pumps	AB	na	na	na	na	na
Supports and hangers	AB,C	III-NF(n)	(h)	(h)	na	NNS
7. Instrumentation and control systems						
Plant protection system (PPS)						
The PPS includes the electrical and mechanical devices and circuitry (from sensors to actuation device input terminals) involved in generating the signals associated with the two protective functions defined below:						
Reactor protective system (RPS)	C,CB	IEEE-279/ 323/344/ 379	I	Q(z)	na	na
That portion of the PPS which generates signals that actuate reactor trip						
Engineered safety features actuation system (ESFAS)	C,CB	IEEE-279/ 323/344 379	I	Q(z)	na	na
That portion of the PPS which generates signals that actuate engineered Safety features						

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 6 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Safe shutdown Systems						
The safe shutdown systems include those systems required to secure and maintain the reactor in a safe shutdown condition	C, AB, DG, CB	IEEE-279/ 323/344	I	Q(z)	na	na
All other systems required for safety	C, AB, DG CB, RW	IEEE-279/ 323/344/	I	Q(z)	na	na
Control systems not required for safety	C, AB, DG	na	na	na	na	na
Emergency response facility data acquisition and display system (ERFDADS)	CB, TSC	na	na	na(u)	na	na
Control room panels (safety-related)	CB	IEEE-279/ 323/344/420	I	Q	na	na
Control room panels (other)	CB	na	na(e)	na(cc)	na	na
Instrument valves and piping downstream of Quality Group B or C root valves (for safety-related instruments)						
Piping, tubing and fittings	All	111-2 or III-3	I	Q	B or C	2 or 3
Instrument Valves	All	B31.1	na	na	D	NNS
Accident monitoring Instrumentation (table 1.8-1)	CB, TSC, EOF	IEEE-297/ 323/344	I or na	(u)	na	na
8. Electric systems						
Class 1E ac equipment includes associated transformers, protective relays, instrumentation and control devices)						
4.16 kV busses	CB	IEEE-308/ 323/344/420	I	Q	na	na
480V load centers	CB	IEEE-308/ 323/344/420	I	Q	na	na
480V motor control centers	AB, CB	IEEE-308/ 323/344/420	I	Q	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 7 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Class 1E dc equipment						
125V station batteries and racks	CB	IEEE-308/ 323/344/450	I	Q	na	na
Battery chargers	CB	IEEE-308/ 323/344/420	I	Q	na	na
125V switchgear and distribution panels	CB	IEEE-308/ 323/344/420	I	Q	na	na
120V vital ac system equipment						
Static inverters	CB	IEEE-308/ 323/344	I	Q	na	na
120V distribution panels	CB	IEEE-308/ 323/344/420	I	Q	na	na
Electric cables for Class 1E system						
125 V-dc cables (including cable splices, connectors, and terminal blocks)	CB,DG,MS	IEEE-308/ 323/383/384	na(bb)	Q	na	na
5 kV power cables (including cable splices, connectors, and terminal blocks)	OU,CB, AB,DG,MS	IEEE-308/ 383/384/323	na(bb)	Q	na	na
600V power cables (including cable splices, connectors, and terminal blocks)	OU,C,CB, AB,DG,FB, MS	IEEE-308/ 383/384/323	na(bb)	Q	na	na
Control and instrumentation cables (including cable splices, connectors, and terminal blocks)	OU,C,CB AB,DG,FB, MS	IEEE-308/ 383/384/323	na(bb)	Q	na	na
Conduit and cable trays and their supports containing Class 1E cables	All	IEEE-308/ 383/384/323	I	Q	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 8 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Miscellaneous Class 1E electrical systems						
Containment building electrical penetration assemblies	C	IEEE-317/ 344/323	I	Q	na	na
Emergency lighting system for the Control room horseshoe area	CB	IEEE-344	I	(y)	na	na
Non-Class 1E electrical system	All	na	na	kk	na	na
Station Blackout Generators and associated auxiliary support/ distribution equipment	OU	na	na	ll	na	na
9. Component and fuel handling equipment and fuel storage						
Fuel handling and storage equipment						
Refueling machine	C	na	na(e)	Q(cc)	na	na
Spent fuel handling machine	FB	na	na(e)	Q(cc)	na	na
Spent fuel pool	FB	(a)	I	Q	na	na
Spent fuel pool liner	FB	(a)	na(e)	na(aa)	na	na
Spent fuel pool gates	FB	na	I	Q	na	na
Cask loading pit and decon washdown gate seals	FB	na	I	Q	na	na
Fuel pool transfer canal gate seals	FB	na	I	Q	na	na
Fuel transfer tube assembly quick operating closure device (QOCD)	C	III-MC	I	Q	na	2
Fuel transfer tube housing (from liner plate to QOCD)	C	III-MC	I	Q	na	2
Fuel transfer tube housing (from liner plate to fuel transfer tube - west end)	FB	na	I	Q	See note 13	See note 13
Bellows (other)	C, FB	na	II	NQR	na	NNS
Bellows (from fuel transfer tube to tube housing – west end	FB	na	I	Q	See note 13	See note 13
Fuel transfer valve	FB	na	I	Q	See note 13	See note 13
Fuel transfer tube support stand	FB	na	I	Q	na	na
Cask handling crane (oo)	FB	na	I(e)	Q(cc)	na	na
Dry Cask SafLift (oo)	FB	na	I(e)	Q(cc)	na	na
New fuel elevator	FB	na	na(e)	na(ee)	na	na
Fuel transfer carriage assembly	C,FB	na	na(e)	na(aa)	na	na
Spent fuel storage racks	FB	na	I	Q		
New fuel storage racks	FB,	na	I(hh)	Q(hh)	na	na
New fuel handling crane	FB	na	na(e)	Q(cc)	na	na
Cask Loading Pit Alignment Stand (nn)	FB	na	I	Q	na	na
Canister Isolation Piping, Valves & Supports (oo)	FB	III-3	I	Q	C	3
Canister Shield Lid Lift Rig (oo)	FB	na	na	na(kk)	na	na
ISFSI Storage Pads (pp)	OU	ACI 349-97	na(e)	na(kk)	na	na
ISFSI Earthen Berm (oo)	OU	na	na(e)	na(kk)	na	na
Cask Transporter Limit Switches (oo)	OU	na	na	na(kk)	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 9 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Component handling equipment						
Containment building polar crane	C	na	na(e)	Q(cc)	na	na
CEA change platform		na	na(e)	na(aa)	na	na
Reactor vessel heed lifting gear	C	na	na(e)	na(aa)	na	na
Internals lifting gear	C	na	na(e)	na(aa)	na	na
Fuel pool cooling and cleanup system						
Fuel pool pump motors	FB	IEE-323/ 344/334	I	Q	na	na
Fuel pool pumps	FB	III-3	I	Q	C	3
Fuel pool cleanup pumps	FB	(g)	na	na	D	NNS
Fuel pool heat exchangers	FB	III-3	I	Q	C	NNS
Demineralizers	FB	VIII	na	na	D	NNS
Filters	FB	VIII	na	na	D	
Strainers	FB	na	na	na	D	na
Valves and piping						
Containment penetration	C	III-2	I	Q	B	2
From isolation valve to shutdown cooling heat exchanger	FB,AB	III-3	I	Q	C	3
From second isolation valve to refueling water storage tank	FB	III-3	I	Q	C	3
Cooling loop	FB	III-3	I	Q	C	3
Cleanup loop	FB	B31.1(t)	na	na	D	NNS
Other	FB,AB	B31.1(t)	na	na	D	NNS
Supports and hangers	FB,AB	III-NF-(n)	(h)	(h)	na	2,3,NNS
10. Water systems						
Essential spray pond system						
ESPS pumps	OU	I11-3	I	Q	C	3
ESPS pump motors	OU	IEEE-323/ 344/334	I	Q	na	na
Diesel generator cooler	DG	III-3	I	Q	C	3
Spray headers, nozzles	OU	III-3	I	Q	C	3
Piping To safety-related components	OU/AB/ DG	III-3	I	Q	C	3
Valves						
To safety-related components	OU/AB/ DG	III-3	I	Q	C	3
Supports and hangers	OU/AB/ DG	III-NF(n)	(h)	(h)	na	3

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 10 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Circulating water system (nonsafety-related)						
Main condenser (refer to steam and power conversion system)						
Cooling tower (mechanical part)	OU	na	na	na	na	na
Circulating water pumps	OU	(g)	na	na	D	NNS
Steel piping/valves on steel piping	TG,OU	B31.1	na	na	D	NNS
Concrete piping	OU	AWWA C301	na	na	na	NNS
Valves on concrete piping	OU	AWWA C504	na	na	na	NNS
Support and hangers	TG,OU	na	(h)	(h)	na	na
Essential cooling water system						
Pumps	AB	III-3	I	Q	D	3
Pump motors	AB	IEEE-323/ 344/334	I	Q	D	na
Heat exchangers	AB	III-3	I	Q	C	3
Surge tanks	AB	III-3	I	Q	C	3
Chemical addition tanks	AB	API-620	na	na	D	NNS
Piping from ECWS to NCWS	AB	B31.1	na	na	D	NNS
Piping other	C,AB	III-3	I	Q	C	3
Valves	C,AB	III-3	I	Q	C	3
Supports and hangers	C,AB	III-NF(n)	(h)	na	na	3,NNS
Nuclear cooling water system						
Pumps	OU	(g)	na	na	D	NNS
Pump motors	OU	na	na	na	na	na
Heat exchanger	OU	VIII	na	na	D	NNS
Surge tanks	AB	API-620	na	na	D	NNS
Chemical addition tanks	OU	API-620	na	na	D	NNS
Containment penetration	C,AB	III-2	I	Q	B	2
Piping to and from fuel pool heat exchanger	AB,FB	III-2	I	Q	C	3
Piping other	C,AB	B31.1	na	Q	D	NNS
Valves, containment isolation	C,AB	III-2	I	Q	B	2
Valves, containment isolation overpressure protection	C	B31.1	I	Q	C	3
Valves, to and from fuel pool heat exchanger	AB,FB	III-3	I	Q	C	3
Valves, other	C,AB	B31.1	na	na	D	NNS
Supports and hangers	C,AB	III-NF(n)	(h)	(h)	na	3,NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 11 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Turbine cooling water system						
Pumps	TG	(g)	na	na	D	NNS
Tanks	TG	API-620	na	na	D	NNS
Heat exchanger	TG	VIII/TEMA C	na	na	D	NNS
Piping and valves	TG	B31.1	na	na	D	NNS
Supports and hangers	TG	na	(h)	(h)	na	na
Plant cooling water system						
Pumps	OU	(g)	na	na	D	NNS
Piping and valves	TG,OU	B31.1	na	na	D	NNS
Supports and hangers	TG,OU	na	(h)	(h)	na	na
Normal chilled water system						
Chillers	AB	B9.1	na	na	D	NNS
Pumps	AB	VIII-HIS(g)	na	na	D	NNS
Piping	All	B31.1	na	na	D	NNS
Valves, other	All	B31.1(t)	na	na	D	NNS
Supports and hangers	All	na	(h)	(h)	na	na
Valves, containment isolation	C,AB	III-2	I	Q	B	2
Expansion tank	AB	VIII	na	na	D	NNS
Chemical addition tank	AB	VIII	na	na	D	NNS
Containment penetration	C	III-2	I	Q	B	2
Essential chilled water system (for control room, ESF equipment rooms in CB, and safety-related equipment rooms)						
Chillers	CB	III-3	I	Q	C	3
Pumps	CB	III-3	I	Q	C	3
Pump motors	CB	IEEE-323/ 344/334	I	Q	na	na
Piping	CB,AB	III-3	I	Q	C	3
Valves	CB,AB	III-3	I	Q	C	3
Supports and hangers	CB,AB	III-NF(n)	(h)	(h)	na	3
Expansion tank	CB	III-3	I	Q	C	3
Chemical addition tank	AB	VIII	na	na	D	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 12 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classificatio n	ANSI N18.2 Safety Class
Domestic water system						
Storage tank	OU	API-620	na	na	na	na
Pumps	OU	(g)	na	na	na	na
Piping and valves	All	B31.1(t)	na	na	na	na
Supports and hangers	All	na	(h)	(h)	na	na
Reverse osmosis	OU	VIII	na	na	na	na
Domestic water filters	OU	VIII	na	na	na	na
Condensate storage facilities						
Condensate transfer pump	OU	III-3	I	Q	C	3
Condensate transfer pump motor	OU	IEEE-323/ 334/344	I	Q	na	na
Condensate tank	OU	(a)	I	Q	C	3
Piping and valves(Q-Class) • All piping below 129.5’ including Safety-related AF pump piping and recirculation lines • Piping to non-safety related AF pump up to and including second isolation valve • Piping for the Condensate Transfer Pumps • Piping for CST level transmitters LT-35 & LT-36 • Piping up to and includeing first isolation valve for CST level controller LC-6 and low-low level switch (LSLL-27) • Piping for PIC-34 to isolation valve V114 • Piping to breather valves	OU,AB	III-3	I	Q	C	3
Piping and valves, other	OU,AB, TG	B31.1	na	na	D	NNS
Supports and hangers	OU,AB, TB	III-NF(n)	(h)	(h)	na	3/NNS
Demineralized water system						
Demineralized water system	OU	API-620	na	na	na	na
Ion exchanger	OU	VIII	na	na	na	na
Caustic storage tank	OU	API-620	na	na	na	na
Acid storage tank	OU	API-620	na	na	na	na
Vacuum degasifier	OU	VIII	na	na	na	na
Vacuum pumps	OU	HIS(g)	na	na	na	na
Rinse water tank	OU	API-620	na	na	na	na
Booster pump	OU	HIS(g)	na	na	na	na
Transfer pumps	OU	HIS(g)	na	na	na	na
Containment penetration	C,AB	III-2	I	Q	B	2
Containment isolation valves	C,AB	III-2	I	Q	B	2
Acid metering pumps	OU	(g)	na	na	na	na
Caustic metering pumps	OU	(g)	na	na	na	na
Demineralized water transfer pumps	OU	(g)	na	na	na	na
Spent regeneration sump pumps	OU	(g)	na	na	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 13 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Water heaters	OU	na	na	na	na	na
Piping valves	OU,All	B31.1(t)	na	na	na	na
Supports and hangers	OU,All	na	(h)	(h)	na	na
Cooling tower makeup and blowdown system						
Cooling tower makeup pumps	OU	HIS(g)	na	na	na	na
Cooling tower makeup pump motors	OU	na	na	na	na	na
Piping and valves	OU	B31.1	na	na	na	na
Support and hangers	OU	na	(h)	(h)	na	na
Reservior and intake structural (see miscellaneous structures)						
11. Compressed air systems						
Instrument Air System						
Compressors	TG	na	na	na	na	NNS
Aftercoolers	TG	na	na	na	na	NNS
Receivers	TG	VIII	na	na	na	NNS
Dryers	TG	na	na	na	na	NNS
Filter	TG	VIII	na	na	na	NNS
Piping	All	B31.1	na	na	na	NNS
Containment peneration	C	III-2	I	Q	B	2
Valves, containment isolation	C,AB	III-2	I	Q	B	2
Valves, others	All	B31.1	na	na	na	NNS
Supports and hangers	All	na	(h)	(h)	na	NNS
Service Air System						
Compressor	TG	na	na	na	na	na
Aftercooler (integral to compressor)	TG	na	na	na	na	na
Dryer	TG	na	na	na	na	na
Receivers	TG	VIII	na	na	na	na
Piping	All	B31.1	na	na	na	na
Containment peneration	C	III-2	I	Q	B	2
Valves, containment isolation	C,AB	III-2	I	Q	B	2
Valves, others	All	B31.1	na	na	na	na
Supports and hangers	All	na	(h)	(h)	na	na
12. Sampling system						
Sample containers	AB,TG,RW	na	na	na	D,na	NNS,na
Sample coolers	AB,TG,RW	VIII	na	na	D,na	NNS,na
Piping						
On III-1 systems to containment isolation valves	C	III-2	I	Q	B(i)	2(i)

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 14 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
On III-2 systems to isolation valves	C,AB	III-2	I	Q	B	2
On III-3 sytems to isolation valves	AB,TG,RW	III-3	I	Q	C	3
Other	AB,TG,RW	B31.1(t)	na	na	D,na	NNS,na
Containment penetration	C	III-2	I	Q	B	2
Valves						
On III-1 systems	C	III-2	I	Q	B(i)	2(i)
On III-2 systems	C,AB	III-2	I	Q	B	2
On III-3 systems	AB	III-3	I	Q	C	3
Other	AB,TG,RW	B31.1(t)	na	na	D,na	NNS,na
Supports and hangers	AB,TG,RW	III-NF(n)	(h)	(h)	na	2,3,NNS
13. Equipment and floor drains						
Sump pumps						
Radioactive						
Containment radwaste	C	HIS(g)	na	na	D	NNS
Reactor cavity	C	HIS(g)	na	na	D	NNS
Aux buiding ESF	AB	HIS(g)	na	na	D	NNS
Aux building non-ESF	AB	HIS(g)	na	na	D	NNS
Radwaste building	RW	HIS(g)	na	na	D	NNS
Fuel building	FB	HIS(g)	na	na	D	NNS
Holdup tank area	OU	HIS(g)	na	na	D	NNS
Decontamination	SB	HIS(g)	na	na	D	NNS
Nonradioactive						
Control building	CB	HIS(g)				
Diesel generator	DG	HIS(g)	na	na	na	NNS
Turbine building	TG	HIS(g)	na	na	na	NNS
Condenser area	TG	HIS(g)	na	na	na	NNS
Oil/water separator	OU	HIS(g)	na	na	na	NNS
Yard area	OU	HIS(g)	na	na	na	NNS
Fire pumphouse	OU	HIS(g)	na	na	na	NNS
Retention Tank	OU	HIS(g)	na	na	na	NNS
Sanitary waste return	OU	HIS(g)	na	na	na	NNS
Chemical						
Spent regenerant pump	OU	HIS(g)	na	na	na	NNS
Water treatment building	OU	HIS(g)	na	na	na	NNS
Condensate polish demineral-izer high TDS and low TDS	TG	HIS(g)	na	na	na	NNS
Chemical production building	OU	HIS(g)	na	na	na	NNS
Sump pump motors	All	na	na	na	na	na
Horizontal centrifugal pumps						
Neutralizer transfer	OU	HIS(g)	na	na	na	NNS
Cooling water holdup tanks	AB	HIS(g)	na	na	na	NNS
Horizontal centrifugal pump motors	OU,AB	na	na	na	na	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 15 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Tanks						
Neutralizer	OU	API-650	na	na	na	NNS
Cooling water holdup	AB	API-650	na	na	na	NNS
Piping and valves						
Radioactive	C,AB,RW, FB,OU	B31.1	na	na	D	NNS
Nonradioactive	CB,DG,TG, OU	B31.1	na	na	na	NNS
Chemical	TG,OU	B31.1	na	na	na	NNS
Containment penetrations	C	III-2	I	Q	B	2
Supports and hangers	AB,TG,OU FB,RW,C CB,DG	na	(h)	(h)	na	NNS
14. Chemical addition system (secondary)						
Tanks, including heaters and agitators	AB	na	na	na	na	na
Pumps	AB	HIS(g)	na	na	na	na
Piping and valves	AB	B31.1(t)	na	na	na	na
Supports and hangers	AB	na	(h)	(h)	na	na
15. Heating, ventilating, and air conditioning						
Auxiliary building HVAC						
Supply						
Fans	AB	na	na	na	na	na
Filters, outside air	AB	na	na	na	na	na
Heating coils	AB	na	na	na	na	na
Cooling coils	AB	B31.1	na	na	D	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 16 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Ductwork	AB	SMACNA	na(e)	na(ee)	na	na
Dampers	AB	SMACNA	na	na	na	na
Normal exhaust						
Fans	AB	na	na	na	na	na
Isolation damper-100 ft penetration	AB	SMACNA	I	Q	na	na
Filters						
High efficiency particulate air filter (HEPA)	AB	na	na	na	na	na
Charcoal filters	AB	na	na	na	na	na
Fume hood – Normal exhaust fans and motors	AB	na	na	na	na	na
Ductwork	AB	SMACNA	na(e)	na(ee)	na	NNS
Dampers	AB	SMACNA	na(e)	na(ee)	na	na
Essential exhaust (Note 14)						
Fans	FB	IEEE-323/ 344/383	I	Q	na	3
Filters						
High efficiency particulate air filter (HEPA)	FB	HSI-306	I	Q	na	3
Charcoal filters	FB	na	I	Q	na	3
Ductwork	FB	SMACNA	I	Q	na	3
dampers	FB	SMACNA	I	Q	na	3
Normal air handling units						
Access control area HVAC						
Fan and motor	AB	na	na	na	na	na
Coils						
Heating	AB	B31.1	na	na	D	NNS
Cooling	AB	B31.1	na	na	D	NNS
Ductwork	AB	SMACNA	na	na	na	na
Dampers	AB	SMACNA	na	na	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 17 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
MG sets and CEDM control are normal ACU						
Fan and motor	AB	na	na	na	na	na
Cooling coil	AB	B31.1	na	na	D	NNS
Charging pump room normal ACU						
Fan and motor	AB	na	na(e)	na(ee)	na	na
Cooling coil	AB	B31.1	na(e)	na(ee)	D	NNS
Engineered safety features equipment room essential ACUs	AB					
HPSI pump room essen. ACU						
Fan	AB	IEEE-323/ 344/383	I	Q	na	na
Cooling coil	AB	III-3	I	Q	C	3
LPSI pump room essen. ACU						
Fan	AB	IEEE-323/ 344/383	I	Q	na	na
Cooling coil	AB	III-3	I	Q	C	3
CS pump room essen. ACU						
Fan	AB	IEEE-323/ 344/383	I	Q	na	na
Cooling coil	AB	III-3	I	Q	C	3
ECW pump room essen. ACU						
Fan	AB	IEEE-323/ 344/383	I	Q	na	na
Cooling coil	AB	III-3	I	Q	C	3
Aux. feedwater pump rooms essen. ACU						
Fan	AB	IEEE-323/ 344/383	I	Q	na	na
Cooling coil	AB	III-3	I	Q	C	3
Elec. pent.room essen. ACU						
Fan	AB	IEEE-323/ 344/383	I	Q	na	na
Cooling coil	AB	III-3	I	Q	C	3

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 18 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Fuel building HVAC						
Supply						
Fans	AB	na	na	na	na	na
Filters, outside air	AB	na	na	na	na	na
Evaporative Coolers	AB	na	na	na	na	na
Heating coils	AB	na	na	na	na	na
Ductwork	FB,AB	SMACNA	na(e)	na(ee)	na	na
Isolation dampers	AB,FB	SMACNA	I	Q	na	3
Dampers, other	FB	SMACNA	na(e)	na(ee)	na	na
Exhaust						
Fans	FB	na	na	na	na	na
Ductwork	FB	SMACNA	na(e)	na(ee)	na	na
Dampers	FB	SMACNA	I	Q	na	3
Exhaust (post accident)						
Fans and motors	FB	IEEE-323/ 344/334	I	Q	na	3
Filters						
High efficiency particulate air (HEPA)	FB	HSI-306	I	Q	na	3
Charcoal	FB	na	I	Q	na	3
Ductwork	FB	SMACNA	I	Q	na	3
Dampers	FB	SMACNA	I	Q	na	3
Supports and hangers	FB	na	(h)	(h)	na	3
Radwaste building HVAC						
Supply						
Fans	RW	na	na	na	na	na
Filters, outside air	RW	na	na	na	na	na
Air washer	RW	na	na	na	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 19 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Heating	RW	na	na	na	na	na
Ductwork	RW,AB	SMACNA	na	na	na	na
Dampers	RW,AB	SMACNA	na	na	na	na
Exhaust						
Fans	RW	na	na	na	na	na
Filters						
High efficiency particulate air (HEPA)	RW	HSI-306	na	na	na	na
Ductwork	RW	SMACNA	na	na	na	na
Dampers	RW	SMACNA	na	na	na	na
Supports and hangers	RW	na	(h)	(h)	na	na
Turbine building HVAC						
Fans	TG	na	na	na	na	na
Filters, outside air	TG	na	na	na	na	na
Air washer	TG	na	na	na	na	na
Ductwork	TG	SMACNA	na	na	na	na
Dampers	TG	SMACNA	na	na	na	na
Heating coil	TG	na	na	na	na	na
Unit heaters	TG	na	na	na	na	na
Piping and valves	TG	B31.1(t)	na	na	na	na
Supports and hangers	TG	na	(h)	(h)	na	na
Roof exhausters	TG	na	na	na		
Containment building HVAC						
Containment normal air cooling system						
Cooling fans and motors	C	na	na(e)	na(ee)	na	NNS
Cooling coils	C	B31.1	na(e)	na(ee)	na	NNS
Heating coils	C	na	na(e)	na(ee)	na	na
Ductwork	C	SMACNA	na(e)	na(ee)	na	NNS
Dampers	C	SMACNA	na(e)	na(ee)	na	NNS
CEDM air cooling system						
Fan and motors	C	na	na(e)	na(ee)	na	NNS
Cooling coil	C	B31.1	na(e)	na(ee)	na	NNS
Ductwork	C	SMACNA	na(e)	na(ee)	na	NNS
Dampers	C	SMACNA	na(e)	na(ee)	na	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 20 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Reactor cavity air cooling system						
Fans and motors	C	na	na(e)	na(ee)	na	NNS
Tendon gallery ventilation system						
Fans and motors	C,AB	na	na	na	na	na
Containment building preaccess filter system						
Fan and motors	C	na	na(e)	na(ee)	na	NNS
Filters						
High efficiency particulate air (HEPA)	C	na	na(e)	na(ee)	na	NNS
Charcoal	C	na	na(e)	na(ee)	na	NNS
Normal purge and filtration system (non-ESF related)						
Fans	AB	na	na	na	na	na
Filters						
High efficiency particulate air (HEPA)	AB	na	na	na	na	na
Charcoal	AB	na	na	na	na	na
Ductwork	AB	SMACNA	na	na	na	na
Containment, penetration	C	III-2(m)	I	Q	B	2
Dampers	AB	SMACNA	na	na	na	na
Valves, containment isolation	C	III-2	I	Q	B	2
Piping and valves, other	C,AB	B31.1(t)	na	na	na	na
Unit vent system						
Vent stack	OU	na	na	na	na	na
Supports and hangers	C,AB	III-NF(n)	(h)	(h)	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 21 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Diesel generator building heating and ventilating system						
Normal heating and ventilating system						
Hydraulic atomizing spray system (abandoned in place)	DG	na	na	na	na	NNS
Unit heaters, electric	DG	na	na(e)	na(ee)	na	na
Ventilating fans	DG	na	na(e)	na(ee)	na	NNS
Dampers	DG	SMACNA	na(e)	na(ee)	na	NNS
Support and hangers	DG	Na	(h)	(h)	na	NNS
Essential ventilating system						
Ventilating fans and motors	DG	IEEE-323/ 344/334	I	Q	na	NNS
Diesel generator control Equipment room fan and motor	DG	IEEE-323/ 344	I	Q	na	NNS
Supports	DG	na	(h)	(h)	na	NNS
Intake filter	DG	na	I	Q	na	NNS
Control building HVAC system						
Control room HVAC						
Essential ventilation system						
Coil, cooling	CB	III-3	I	Q	C	3
Fans and motors	CB	IEEE-323/ 344/334	I	Q	na	3
Filters						
High efficiency particuate air	CB	HSI-306	I	Q	na	3
Charcoal	CB	na	I	Q	na	3
Ductwork	CB	SMACNA	I	Q	na	3
Dampers	CB	SMACNA	I	Q	na	3
Supports and hangers	CB	III-NF(n)	(h)	(h)	na	3,na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 22 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Control room normal air conditioning system						
Fan	CB	na	na	na	na	na
Filters	CB	na	na	na	na	na
Coil, cooling	CB	B31.1	na	na	na	na
Ductwork	CB	SMACNA	na(e)	na(ee)	na	na
Dampers	CB	SMACNA	na(e)	na(ee)	na	na
Supports and hangers	CB	na	(h)	(h)	na	na
ESF switchgear and battery room HVAC system						
Essential ventilation system						
Supply fans and motors	CB	IEEE-323/ 344/334	I	Q	na	3
Filters	CB	na	I	Q	na	na
Cooling coils	CB	III-3	I	Q	C	3
Ductwork	CB	SMACNA	I	Q	na	na
Dampers	CB	SMACNA	I	Q	C(ff)	3
Piping and valves	CB	III-3	I	Q	C	3
Supports and hangers	CB	III-NF(n)	(h)	(h)	na	3,na
ESF equipment room (channel A and B)						
Supply fan and motor	CB	IEEE-323/ 344/334	I	Q	na	na
Cooling coil	CB	III-3	I	Q	C	3
Duct work	CB	SMACNA	I	Q	na	na
Dampers	CB	SMACNA	I	Q	C(ff)	3
Piping and valves	CB	III-3	I	Q	C	3
Support and hangers	CB	III-NF	I	Q	na	3,na
Battery room essential exhaust fans and motors	CB	IEEE 323/ 344/334	I	Q	na	3
Normal control building ventilation system						
Fan	CB	na	na	na	na	na
Filter	CB	na	na	na	na	na
Cooling coils	CB	B31.1	na	na	na	NNS
Ductwork	CB	SMACNA	na(e)	na(ee)	na	na
Dampers	CB	SMACNA	na(e)	na(ee)	na	na
Supports and hangers	CB	na	(h)	(h)	na	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 23 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
ESF switchgear room normal AHU						
Fan	CB	na	na	na	na	na
Cooling coil	CB	B31.1	na	na	na	NNS
Duct work	CB	SMACNA	na(e)	na(ee)	na	na
Dampers	CB	SMACNA	na(e)	na(ee)	na	na
Supports and hangers	CB	na	(h)	(h)	na	NNS
Battery room normal exhaust fans	CB	na	na(e)	na(ee)	na	na
Smoke exhaust system						
Fan	CB	na	na	na	na	na
Dampers	CB	SMACNA	na	na	na	na
Ductwork	CB	SMACNA	na	na	na	na
ESP pump house exhaust system						
Exhaust fan	OU	IEEE-323/ 344/334	I	Q	na	3
Ductwork	OU	SMACNA	I	Q	na	3
16. Fire protection system						
Fire suppressions and actuation system	See below	NFPA/ANI(t)	na	(y)	na	NNS
Fire water/well water reserve tanks and interconnecting pipe to fire pumps	OU	NFPA/ANI(t)	na	(y)	na	NNS
Fire pumps and associated drivers, controllers, fuel supplies	OU	NFPA/ANI(t)	na	(y)	na	NNS
Fire water underground main piping (Quality Class break at isolation valve discharge flange for NQR sections of system)	OU	NFPA/ANI(t)	na	(y)	na	NNS
Fire suppression system water riser supply branch piping	AB, CB, DG FB, RW, MS	NFPA/ANI(t)	na	(y)	na	NNS
Water, CO_2, Halon fixed fire suppression and actuation systems	AB, CB, DG FB, RW, MS, LL	NFPA/ANI(t)	na	(y)	na	NNS
CO_2, storage tank and associated piping and components	CB, OU	NFPA/ANI(t)	na	(y)	na	NNS
Supports and hangers	AB, CB, DG FB, RW, MS, LL	NFPA/ANI(t)	(h)	(y)	na	NNS
Fire hydrants for exterior fire exposure protection	OU	NFPA/ANI(t)	na	(y)	na	NNS
Fire detection and alarm systems (QK and FP system)	See below					
Panels	AB, CB, C, FB DG, RW, MS, OU, LL	NFPA	na	(y)	na	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 24 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Fire and smoke detectors	AB, CB, C, FB DG, RW, MS, OU	NFPA	na	(y)	na	NNS
Backup power supplies	AB, CB, C, FB DG, RW, MS, OU	NFPA	na	(y)	na	NNS
Alarms/annunciators (includes control room communication console, security computer, dorado racks and concentrators)	AB, CB, C, FB DG, RW, MS, OU	NFPA	na	(y)	na	NNS
AC power sources	All	na	na	na	na	NNS
Supports and hangers	AB, CB, C, FB DG, RW, MS, OU	na	(h)	na	na	NNS
Fire barriers	See below					
Fire walls, floors, ceilings partitions	AB, CB, C, FB corridor DG, RW, MS, OU	na	(h)	(y)	na	NNS
Acoustical ceilings	AB, CB, corridor	na	(h)	(y)	na	NNS
Fire doors	AB, CB, C, FB, corridor DG, RW, MS, OU	NFPA	(h)	(y)	na	NNS
Fire dampers	AB, CB, C, FB, corridor DG, RW, MS, OU	na	(h)	(y)	na	NNS
Penetration seals, seismic gap seals	AB, DB, C, FB, corridor DG, RW, MS, OU	na	(h)	(y)	na	NNS
Radiant energy shields	C	na	(h)	(y)	na	NNS
Fire-proofing (structural, electrical raceway, HVAC and electrical supports	AB, CB, MS, C, corridor	na	(h)	(y)	na	NNS
RCP lube oil collection system	C	B31.1	IX	(y)	na	NNS
Emergency lighting system						
8-hour-designed emergency lighting systems	AB, CB, DG, MS, TG, OU	na	(h)	(y)	na	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 25 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
In-plant communications systems	See below					
Sound-powered phone system	AB, CB, C, DG, FB, MS, RW, TURB	na	na	(y)	na	NNS
Plant maintenance radio system	AB, CB, C, RW, corridor	na	na	(y)	na	NNS
Plant telephone system	All	na	na	na	na	NNS
Supports and hangers	All	na	(h)	na	na	NNS
Lightning protection system	See below					
Structure protection	AB, CB, C, DG, FB, MS, TG, MS, CO	na	na	(y)	na	NNS
Lightning arrestors for start-up Transformers, main transformers, and 13.8-kV switchgear 13-E-NAN-S03 and 13-E-NAN-S04	OU	na	na	(y)	na	NNS
Interior manual fire suppression systems and equipment	See below					
Standpipe and hose systems including piping, valves, fire hose, hose racks/reels, nozzles, supports and hangers, and associated components	AB, CB, C, FB, DG, RW, MS, OU, LL	na	(h)	(y)	na	NNS
Portable fire extinguishers including Mounting bracket	AB, CB, C, FB, DG, RW, MS, OU	na	(h)	(y)	na	NNS
Manual fire fighting equipment for site fire department use	See below					
Fire emergency response vehicle(s)	na	na	na	(y)	na	NNS
Personal protective equipment (turnout gear SCBA)	na	na	na	(y)	na	NNS
Portable smoke ejectors and support equipment	na	na	na	(y)	na	NNS
Fire hose, valves, nozzles, and associated equipment	na	na	na	(y)	na	NNS
Tools (portable lanterns, axe, crowbars)	na	na	na	(y)	na	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 26 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
17. Diesel generator system						
Diesel fuel system						
Diesel fuel storage tanks	OU	III-3	I	Q	C	3
Diesel fuel day tanks	DG	III-3(jj)	I	Q	C	3
Diesel fuel transfer pumps	OU	III-3	I	Q	C	3
Diesel fuel transfer pump motors	OU	IEEE-323/ 344/334	I	Q	na	na
Piping and valves (w)	OU,DG	III-3	I	Q	C	3
Diesel generator package	DG	IEEE-387	I	Q	na	na
Cooling water system (w)	DG	III-3(jj)	I	Q	C	3
Starting system excluding air compressors and air dryers (w)	DG	III-3(jj)	I	Q	C	3
Lubrication system (w)	DG	III-3	I	Q	C	3
Combustion air intake and exhaust system						
Air intake filter	DG	na	I	Q	na	na
Intake silencer	DG	na	I	Q	na	na
Exhaust Silencer	DG	DEMA	I	Q	na	na
Combustion air cooler/heater	DG	III-3, TEMA R	I	Q	C	3
Supports and hangers (w)	OU,DG	III-NF(n)	(h)	(h)	na	3
18. Compressed gas storage system						
Hydrogen system						
Vessels	OU	VIII	na	na	D	NNS
Piping	OU,TG,AB	B31.1	na	na	D	NNS
Valves	OU,TG,AB	B31.1	na	na	D	NNS
Nitrogen system						
Vessels	OU	VIII	na	na	D	NNS
Piping	OU,AB,TG,RW	B31.1	na	na	D	NNS
Containment penetration	AB,C	III-2	I	Q	B	2
Valves, other	AB,TG,RW	B31.1(t)	na	na	D	NNS
Isolation valves	AB,C	III-2	I	Q	B	2
Supports and hangers	AB,TG,RW	na	(h)	(h)	na	NNS
19. Chemical production system						
Tanks	OU	ASTM D3299 PS 15-69	na	na	na	NNS
Pumps	OU	HIS(g)	na	na	na	na
Motors	OU	na	na	na	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 27 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Electrolytic cells	OU	na	na	na	na	na
Hydraulic module	OU	na	na	na	na	na
Piping and valves	OU	B31.1	na	na	na	na
Supports and hangers	OU	na	(h)	(h)	na	na
20. Steam and power conversion system						
Turbine-generator						
Turbine	TG	na	na	na	D	NNS
Main steam supply system						
Piping						
Steam generator to pipe restraint beyond all containment isolation valves	C,MS	III-2	I	Q	B(ff)	2
Piping, other	MS,TG	B31.1	na	na	D	NNS
Containment, penetration	C	III-2	I	Q	B	2
Valves						
Main steam safety valves	MS	III-2	I	Q	B	2
Isolation valves	MS	III-2	I	Q	B	2
Atmospheric dump valves	MS	III-2	I	Q	B	2
Turbine bypass valves	TG	B31.1	na	na	D	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 28 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Supports and hangers	C, TG, MS	III-NF(n)	(h)	(h)	na	2, NNS
Steam generator blowdown system						
Heat exchangers	AB	VIII/ TEMA C	na	na	D (Note 15)	NNS
Containment penetration	C	III-2(m)	I	Q	B	2
Piping, from steam generator to pipe restraint beyond Containment isolation valve	C, AB	III-2	I	Q	B(ff)	2
Piping, other	AB,MS,TG,OU	B31.1	na	na	D (Note 15)	NNS
Valves, from steam generator to and including containment isolation valve	C, AB	III-2	I	Q	B	2
Valves, other	AB,MS,TG,OU	B31.1(t)	na	na	D (Note 15)	NNS
Support and hangers	C,AB,MS,TG,OU	III-NF(n)	(h)	(h)	na	2, NNS
Other features of steam and power conversion system						
Condenser	TG	HEI	na	na	D	NNS
Condenser air removal system Pump, vacuum	TG	(g)	na	na	D	NNS
Moisture separator	TG	VIII/HEI	na	na	D	NNS
Air exhaust filter						
Filter, HEPA	TG	HSI-306	na	na	na	NNS
Filter, other	TG	na	na	na	na	NNS
Charcoal absorption unit		na	na	na	na	NNS
Condensers	TG	VIII/HEI	na	na	D	NNS
Blowers	TG	na	na	na	na	NNS
Piping and valves	TG	B31.1	na	na	D	NNS
Supports and hangers	TG	na	(h)	(h)	na	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 29 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Turbine gland sealing system						
Gland steam condenser	TG	na	na	na	D	NNS
Piping and valves	TG	B31.1	na	na	D	NNS
Plant maintenance radio system						
Tanks	OU	API-620	na	na	D	NNS
Pumps	OU	HIS(g)	na	na	D	NNS
Piping and valves	OU	B31.1(t)	na	na	D	NNS
Supports and hangers	OU	na	(h)	(h)	na	na
Condensate and feedwater systems						
Tanks (other than condensate storage)	TG	API-620	na	na	D	NNS
Vessels, pressure	TG	VIII	na	na	D	NNS
Pumps	TG	HIS(g)	na	na	D	NNS
Feedwater heaters	TG	VIII	na	na	D	NNS
Piping						
From containment isolation valve to steam generator	MS,C	III-2	I	Q	B	2
remainder	MS,TG	B31.1	na	na	D	NNS
Steam generator recirculation piping from steam generator to downcomer feedwater piping	C	III-2	I	Q	B	2
Valves						
Containment isolation	MS	III-2	I	Q	B	2
Downcomer feedwater flow control bypass valve	MS	B31.1	na	na(aa)	D	NNS
Steam generator recirculation valves	C	III-2	I	Q	B	2
Remainder	MS,TG	B31.1	na	na	D	NNS
Supports and hangers	MS,TG	III-NF(n)	(h)	(h)	na	2,NNS
Containment penetration	C	III-2(m)	I	Q	B	2
Auxiliary feedwater system						
Safety-related						
Pump (motor-driven)	MS	III-3	I	Q	C	3
Motor	MS	IEEE-323/ 344/334	I	Q	na	na
Pump (turbine-driven)	MS	III-3	I	Q	B	2
turbine	MS	III-3	I	Q	B	2

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 30 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Piping and valves						
From containment isolation valve to main feedwater system	MS, C	III-2	I	Q	B	2
From condensate tank to containment isolation	MS	III-3	I	Q	C	3
Steam to containment isolation valve	MS	III-2	I	Q	B	2
Steam from isolation to exhaust	MS	III-2	I	Q	B	2
Nonsafety-Related						
Pump (motor-driven)	TG	(g)	na	na(aa)	D	NNS
Motor	TG	NEMA	na	na(aa)	D	NNS
From condensate tank to second isolation valve	OU	III-3	I	Q	C	3
From second condensate tank isolation valve to containment isolation valve	OU, TG MS	B31.1(t)	na	na(aa)	D	NNS
Pump recirculation piping to condensate storage tank [Footnote (aa) only applies to minimum flow orifice]	TG, OU	B31.1	na	na	D	NNS
Vents and drains in flow path from condensate storage tank to first downcomer feedwater isolation valve	OU, TG MS	B31.1	na	na	D	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 31 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Supports and hangers	MS,TG	III-NF(n)	(h)	(h)	na	2,3,NNS
Auxiliary steam system						
Piping and valves	TG,AB,RW,MS	B31.1(t)	na	na	D	NNS
Supports and hangers	TG,AB,RW,MS	na	(h)	(h)	na	NNS
Secondary chemistry control system (steam generator pH control)						
Tanks	TG	API-620	na	na	D	NNS
Pumps	TG	HIS(g)	na	na	D	NNS
Piping and valves to auxiliary feedwater system and steam generating system	MS	B31.1	na	na	D(AUGM) (o) C	NNS
Other	TG	B31.1	na	na	D	NNS
Supports and hangers	TG	na	(h)	(h)	na	NNS
Condensate demineralizer system						
Demineralizer tank	TG	VIII	na	na	D	NNS
Regeneration tank	TG	VIII	na	na	D	NNS
Holding tank	TG	VIII	na	na	D	NNS
Storage tank	TG	VIII	na	na	D	NNS
Resin tank	TG	VIII	na	na	D	NNS
Caustic pumps	TG	HIS(g)	na	na	D	NNS
Acid pumps	TG	HIS(g)	na	na	D	NNS
Transfer pump	TG	HIS(g)	na	na	D	NNS
Water heater	TG	na	na	na	na	na
Blowdown heat exchanger	TG	VIII/ TEMA C	na	na	D	NNS
Piping and valves	TG	B31.1(t)	na	na	D	NNS
Supports and hangers	TG	Na	(h)	(h)	na	NNS

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 32 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Lube oil system						
Tanks, reservoirs	TG	API-650	na	na	na	NNS
Filters	TG	VIII	na	na	na	NNS
Pumps	TG	HIS(g)	na	na	na	NNS
Centrifuges	TG	na	na	na	na	NNS
Heat exchangers	TG	VIII/TEMA C	na	na	na	NNS
Piping and valves	TG	B31.1	na	na	na	NNS
Support and hangers	TG	na	(h)	(h)	na	NNS
21. Liquid radwaste system (p)						
Tanks	OU,RW	API-650	na	na	D(AUGM) (o)	NNS
Filters	AB	VIII	na	na	D(AUGM) (o)	NNS
Evaporators	RW	VIII	na	na	D(AUGM) (o)	NNS
Ion exchangers	RW	VIII	na	na	D(AUGM) (o)	NNS
Pumps	RW	HIS(g)	na	na	D(AUGM) (o)	NNS
Piping	AB,RW,OU	B31.1	na	na	D(AUGM) (o)	NNS
Valves	AB,OU,RW	B31.1(t)	na	na	D(AUGM) (o)	NNS
Supports and hangers	OU,RW,AB	na	(h)	(h)	na	NNS
22. Gaseous radwaste system (p) (v)						
Gas decay tanks	RW	VIII	na	na	D(AUGM) (o)	3
Waste gas surge tank	RW	VIII	na	na	D(AUGM) (o)	3
Heat exchangers	RW	VIII/HEI	na	na	D(AUGM) (o)	3
Compressors	RW	VIII	na	na	D(AUGM) (o)	3
Piping, penetration	C,AB	III-2	I	Q	B	2
Piping, other	AB,RW	B31.1	na	na	D(AUGM) (o)	3
Valves, containment isolation	C,AB	III-2	I	Q	B	2
Valves, other	RW	B31.1(t)	na	na	D(AUGM) (o)	3
Supports and hangers	C,RW,AB	III-NF(n)	(h)	(h)	na	2,3

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 33 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
23. Solid radwaste system (p)						
Tanks						
Spent resin tanks	RW	VIII, Div I	na	na	D(AUGM) (o)	NNS
Remainder (abandoned in place)	RW	API-650	na	na	D(AUGM) (o)	NNS
Pumps						
Resin transfer/dewatering pump	RW	HIS(g)	na	na	D	NNS
Remainder (abandoned in place)	RW	HIS(g)	na	na	D(AUGM) (o)	NNS
Piping	RW	B31.1	na	na	D(AUGM) (o)	NNS
Valves	RW	B31.1(t)	na	na	D(AUGM) (o)	NNS
Supports and hangers	RW	na	(h)	(h)	na	NNS
Waste/cement mixer (abandoned in place)	RW	na	na	na	D(AUGM) (o)	NNS
24. Water reclamation system	WR	(v)	na	na	na	na
25. Structures						
Buildings						
Diesel generator building	DG	(a)	I	Q	na	na
Radwaste building	RW	(a)	na	na(aa)	na	na
Chemical Waste Neutralizer Retention Tank	OU	(a)	na	na(aa)	na	na
Control building	CB	(a)	I	Q	na	na
Fuel building	FB	(a)	I	Q	na	na
Containment building	C	(a)	I	Q	na	2
Equipment building	C	III-MC(gg)	I	Q	na	2
Personnel air locks	C	III-MC	I	Q	na	2
Liner plate	C	(c)	I	Q	na	2
Penetration assemblies	C	III-2(m)	I	Q	na	2
Fuel transfer tube penetration	C	(c)	I	Q	na	2
Fuel transfer tube housing	C	III-MC	I	Q	na	2
Crane supports	C	(a)	I	Q	na	na
Auxiliary building	AB	(a)	I	Q	na	na
Main steam support structure	MS	(a)	I	Q	na	na
Turbine generator building	TG	(a)	na	na	na	na
Low Level Radioactive Material Storage Facility	LL	(a)	NA	NA(aa)	NA	NA
Dry Active Waste Processing and Storage Facility	OU	(v)	NA	NA(aa)	NA	NA
Outage Support Facility	OSF	(a)	NA	NA	NA	NA

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 34 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Old steam generator/old reactor vessel closure head storage facility	OU	(a)	na	na	na	na
Miscellaneous						
Control room ceiling structure (horseshoe area)	CB	IEEE-344	I	Q	na	na
Condensate tank foundation	OU	(a)	I	Q	na	na
Essential spray ponds including essential spraypond water intake structure	OU	(a)	I	Q	na	na
Refueling water tank foundation	OU	(a)	I	Q	na	na
Reservoirs	OU	(a)	na	na	na	na
BOP cooling towers including circulating water intake structure	OU	(a)	na	na	na	na
Power Conversion Room	OU	na	2	na	na	na
26. Water reclamation plant (structures)	WR	(v)	na	na	na	na
27. Water reclamation supply system	WR,OU	(v)	na	na	na	na
28. Radiation monitoring system						
Control room cabinets	CB	IEEE-344	I	Q	na	na
Remote indication and control units	CB	IEEE-323/344	I	Q	na	na
SRMS interface units	CB	IEEE-323/344	I	Q	na	na
Control room workstation	CB	na	na	na(aa)	na	na
Health physics workstation	AB	na	na	na(aa)	na	na
RMS Server	AB	na	na	na(aa)	na	na
Monitors						
Control room ventilation intake	CB	III-3, IEEE-323/344	I	Q	na	na
Fuel pool area	FB	IEEE-323/344	I	Q	na	na
Fuel building ventilation exhaust	FB	IEEE-323/344	I	Q	na	na
Refueling machine area	C,AB	IEEE-323/344	I	Q	na	na
Containment building purge exhaust	AB	III-3, IEEE-323/344	I	Q	na	na
Containment building atmosphere	AB	III-3, IEEE-323/344	I	Q	na	na
Post-accident purge area A	AB	IEEE-323/344	I	Q	na	na
Post-accident purge area B	AB	IEEE-323/344	I	Q	na	na
Essential cooling water	AB	Note 12	Note 12	Note 12	Note 12	Note 12
Steam generator blowdown	AB	B31.1	na	na(aa)	D	na
Nuclear cooling water	AB	B31.1	na	na(aa)	D	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 35 of 42)

Principal Components	Location	Principal Construction Codes and Standards	Seismic Category	PVNGS Quality Assurance Class	Regulatory Guide 1.26 Quality Group Classification	ANSI N18.2 Safety Class
Auxiliary steam cond receiver tank inlet	AB	B31.1	na	na(aa)	D	na
Steam generator blowdown discharge	OU	B31.1	na	na(aa)	D	na
Auxiliary building vent. exhaust filter inlet	AB	B31.1	na	na(aa)	D(ff)	na
Auxiliary building lower level vent. exhaust	AB	B31.1	na	na(aa)	D(ff)	na
Auxiliary building upper level vent. exhaust	AB	B31.1	na	na(aa)	D(ff)	na
Condenser vac pump/gland seal exhaust	TG	B31.1	na	na(aa)	D	na
Waste gas decay tank	RW	B31.1	na	na(aa)	D	na
Plant vent	TG	B31.1	na	na(aa)	D	na
Radwaste bldg. vent. exhaust filter inlet	RW	B31.1	na	na(aa)	D	na
Waste gas system area comb. vent. exh.	RW	B31.1	na	na(aa)	D	na
Operating level area	C, AB	na	na	na(aa)	na	na
Incore inst. area	C, AB	na	na	na(aa)	na	na
Control room area	CB	na	na	na(aa)	na	na
New fuel area	FB	na	na	na(aa)	na	na
Solid waste process station area	RW	na	na	na(aa)	na	na
Solid waste storage area	RW	na	na	na(aa)	na	na
Loading bay area	RW	na	na	na(aa)	na	na
Radiochem lab area	AB	na	na	na(aa)	na	na
Central calibration facility area	OU	na	na	na(aa)	na	na
Central machine shop area	RW	na	na	na(aa)	na	na
Sample room area	AB	na	na	na(aa)	na	na
Portable area	All	na	na	na(aa)	na	na
Movable airborne	All	B31.1	na	na(aa)	D	na
Portable/movable monitor connection boxes	All	na	na	na(aa)	na	na
29. Accident-related meteorological data collection equipment	OU	Na	na	na(ii)	na	na

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 36 of 42)

NOTES

1. <u>Location</u>

AB = Auxiliary building
CB = Control building
C = Containment building
FB = Fuel building
DG = Diesel generator building
OU = Outside
RW = Radwaste building
TG = Turbine building
SB = Service building
MS = Main steam support structure
WR = Water reclamation plant
TSC = Technical Support Center
EOF = Emergency Operations Facility
LL = Low Level Radioactive Material Storage Facility
OSF = Outage Support Facility

2. <u>Principal Construction Codes and Standards</u>

I	=	ASME Boiler and Pressure Vessel Code, Section I
III-1,2,3,MC	=	ASME Boiler and Pressure Vessel Code, Section III, Class 1, 2, 3, or MC
III-NF,NG	=	ASME Boiler and Pressure Vessel Code, Section III, Section NF or Section NG
VIII	=	ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 of Division 2
ACI 349-97	=	American Concrete institute, “Code Requirements for Nuclear Safety Related Concrete Structures”
ASTM A:	=	American Society for Testing and Materials: A242, Abrasion Resistant Steel; A447, Type 2, Castings, High Temperature
AWWA	=	American Water Works Association
B9.1	=	ANSI B9.1, Safety Code for Mechanical Refrigeration
B31.1	=	ANSI B31.1.0, Code for Pressure Piping
SMACNA	=	Sheet Metal and Air Conditioning Contractors National Association, Inc.
HEI	=	Heat Exchange Institute
TEMA C	=	Tubular Exchanger Manufacturers Association, Class C
TEMA R	=	Tubular Exchanger Manufacturers Association, Class R
ASTM C	=	American Society for Testing and Materials; C64, C106, Fire Brick; C155, Insulating Brick; C213, Castable Refractory (Regular); C401, Castable Refractory (Insulating), C612 Class 5, Insulating Block
ASTM D3299-74	=	Filament Wound Glass-Fiber Reinforced Polyester Chemical Resistant Tanks
PS 15-69	=	National Bureau of Standards - Voluntary Product Standard PS 15-69 - Custom Contact-Molded Reinforced-Polyester Chemical Resistant Process Equipment
HIS	=	Hydraulic Institute Standards
IEEE-279	=	Institute of Electric and Electronic Engineers, Criteria for Protection Systems for Nuclear Power Generating Stations, 1971
IEEE-308	=	Institute of Electric and Electronic Engineers, Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations, 1971
IEEE-317	=	Institute of Electric and Electronic Engineers, Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations, September 1972
IEEE-323	=	Institute of Electric and Electronic Engineers, Standard for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations, - 1974
IEEE-334	=	Standard for Type Tests of Continuous Duty Class 1E Motors for Nuclear Power Generating Stations - 1974
IEEE-338	=	Institute of Electric and Electronic Engineers, Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems, 1971
IEEE-344	=	Institute of Electric and Electronic Engineers, Guide for Seismic Qualification of Class 1 Electronic Equipment for Nuclear Power Generating Stations, 1975
IEEE-379	=	Institute of Electric and Electronic Engineers, Trial-Use Guide for the Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems
IEEE-383	=	Institute of Electric and Electronic Engineers, Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generation Stations
IEEE-384	=	Trial-Use Standard Criteria for Separation of Class 1E Equipment

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 37 of 42)

2. Principal Construction Codes and Standards (continued)

IEEE-387 = Institute of Electric and Electronic Engineers, Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations, 1972

IEEE-420 = Trial-Use Guide for Class 1E Control Switchboards for Nuclear Power Generating Stations - 1973

IEEE-450 = IEEE Recommended Practice for Maintenance Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Substations

HSI-306 = Health and Safety Information, United States Atomic Energy Commission, Revised Minimal Specification for the High-Efficiency Particulate Air Filter, Issue No. 306

NEMA = National Electrical Manufacturers Association

NFPA = National Fire Protection Association

AP1-650 = American Petroleum Institute, Welded Steel Tanks for Oil Storage, Atmosphere Tanks

AP1-620 = American Petroleum Institute, Recommended Rules for Design and Construction of Large, Welded, Low-Pressure Storage Tanks

ARI = Air Conditioning and Refrigeration Institute

na = Design requirements specified by designer with appropriate consideration of the intended service and operating conditions

ANI = American Nuclear Insurers

DEMA = Diesel Engine Manufacturers Association, Test Code for the Measurement of Sound from Heavy-Duty Reciprocating Engines

3. Seismic Category

I = Design and construction in accordance with seismic requirements of Regulatory Guide 1.29 and Appendix A to 10CFR100

na = Seismic Category I requirements are not applicable

4. PVNGS Quality Assurance Class

Q = Quality Assurance Class requires compliance with the requirements of 10CFR50, Appendix B

na = The requirements of 10CFR50, Appendix B, are not applicable

5. Regulatory Guide 1.26, Quality Group Classification

PVNGS has used the American Nuclear Society (ANS) Safety Classes 1, 2, 3 and NNS designation as defined in ANSI N18.2 for classification in the design, material selection, manufacture or fabrication, inspection, assembly, erection and construction of the safety-related fluid systems and components. The "Regulatory Guide 1.26, Quality Group Classification" column provides a summary of the relationship between the ANSI N18.2 safety class and the NRC quality group.

A,B,C,D = Quality group classification as defined in Regulatory Guide 1.26 and 10CFR50.55a.

na = Not applicable to quality group classification

6. ANSI N18.2 Safety Class

1,2,3,NNS = Safety classification as defined in ANSI N18.2

na = Not applicable to safety classification

7. Letter in Parentheses

Applicable portion of codes as identified in the following:

(a) American Concrete Institute, Building Code Requirements for Reinforced Concrete (ACI 318-71, or later edition)
American Institute for Steel Construction, Specifications for the Design, Fabrication, and Erection of Structural Steel for Buildings, adopted February 12, 1969, including Supplement Nos. 1 and 2, or later edition

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 38 of 42)

7. Letter in Parentheses (continued)

American Welding Society, Welding in Building Construction (AWS D1.1-72), (with 1973 revision, or later edition)

Uniform Building Code, 1973 Edition
See paragraph 3.8.1.2.

(b) Not used.

(c) Designated in accordance with BC-TOP-1, Rev. 1.

(d) The pressure boundary housing for this component is a reactor vessel appurtenance and is Safety Class 1 and Seismic Category I.

(e) These components and associated supporting structures must be designed to retain structural integrity during and after a seismic event but do not have to retain operability for protection of public safety. The basic requirement is prevention of structural collapse and damage to equipment and structures required for protection of the public safety.

(f) Only those core support structures necessary to support and restraint the core and to maintain safe shutdown capability are classified as Seismic Category I.

(g) There is no established standard for commercial pumps. ASME Section VIII, Division 1, and ANSI B31.1.0, Power Piping, represent related, available standards which, while intended for other applications, are used for guidance and recommendations in determining Quality Group D pump allowable stresses, steel casting quality factors, wall thicknesses, materials compatibility and specifications, temperature-pressure environment restrictions, fittings, flanges, gaskets, and bolting, installation procedures, etc.

(h) Hangers and supports are designed to the same classification as the associated equipment or piping when the equipment is required for safety. Nonsafety portions of structures, systems, or components whose failure could reduce the functioning of any safety-related structure, system, or component are designed and constructed such that a safe shutdown earthquake (SSE) would not cause such failure.

(i) Additional components that are part of the reactor coolant pressure boundary as defined in 10CRF50.2(v.), but excluded from the requirements of 10CFR50.55a pursuant to 10CFR50.55a(c) are Quality Group B and Safety Class 2 and designed to ASME Section III, Class 2.

(j) Loss of cooling water and/or seal water service to the reactor coolant pumps may require stopping the pumps. However, continuous operation of the pumps is not required during or after an SSE. The auxiliaries are, therefore, not necessarily Safety Class 2 or Seismic Category 1.

(k) Only those structural portions of the reactor coolant pumps which are necessary to assure the integrity of the reactor coolant pressure boundary are Safety Class 1.

(l) Two safety classes are used for heat exchangers to distinguish primary and secondary sides when they are different.

(m) Penetration sleeve is designed in accordance with BC-TOP-1, Rev. 1. Penetration head meets ASME B&PV Code, Section III, Class 2.

(n) Applies to supports for ASME Section III, Class 1, 2, 3 and MC components. ASME Section III, Appendix F, shall be used for designing supports for Class 1 components for the faulted condition. ASME Section III, Article NF (Draft), shall be used for the design of Class 2 and 3 plate- and shell-type component supports under emergency and faulted conditions.

Table 3.2-1

QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 39 of 42)

7. Letter in Parentheses (continued)

(o) D (AUGM) signifies Quality Group D augmented as defined in Branch Technical Position - ETSB 11 - 1 (Rev. 1), titled Design Guidance for Radioactive Waste Management Systems Installed in Light-Water-Cooled Nuclear Reactor Power Plants. Quality assurance shall be in accordance with the regulatory position of Regulatory Guide 1.143.

(p) Materials used for pressure retaining components conform to the requirements of Branch Technical Position, ETSB No. 11- 1 (Rev. 1).

(q) To be designed in accordance with CESSAR Section 4.5.2.

(r) To be designed in accordance with CESSAR Section 5.4.14.

(s) The gas stripper was originally designed and constructed to Seismic Category I requirements; however, this portion of the CVCS is not required to be Seismic Category I by Regulatory Guide 1.29, and is no longer maintained as Seismic Category I.

(t) Process solenoid valves will be constructed in accordance with manufacturer's standards.

(u) Equipment designated Category 1 or 2 (and some equipment designated Category 3) on table 1.8-1 is subject to Operations quality assurance requirements consistent with the regulatory position of Regulatory Guide 1.97.

(v) Designed to appropriate industry standards.

(w) External to the diesel engine package.

(x) Not used

(y) The requirements of NRC Branch Technical Position APCSB 9.5-1, Appendix A, Section C, are applied to operational phase activities associated with fire protection features relied on to protect safety related structures, systems or components.

(z) Refer to chapter 7 for further delineation of the components which comprise this system.

(aa) Operational phase activities of administration, control, operation, maintenance, inspection, etc., are considered to be quality-related activities and are subject to the pertinent requirements of the operational quality assurance program.

(bb) Connectors and terminal blocks are seismically qualified as part of the equipment in which they are installed.

(cc) The equipment is not required to remain functional following an SSE. However, the equipment has the capability to reduce the functioning of safety-related equipment, as defined in Regulatory Guide 1.29. Therefore, the design and the specific components critical to restraining this equipment during an SSE meet the requirements of Regulatory Guide 1.29 and shall be subject to the pertinent requirements of 10CFR50, Appendix B, during the operations phase.

(dd) The control rod drive mechanisms are not required to remain functional for the safety of the public during and after an SSE. Therefore, they are Quality Class Q in all aspects except operability.

(ee) Failure of the equipment, due to an SSE, could reduce the functioning of safety related equipment, as defined in Regulatory Guide 1.29. The design of the equipment is analyzed to preclude such failure during and after an SSE. The pertinent requirements of 10CFR50, Appendix B, are applied to this analysis. In addition, QA audits, monitoring and reviews verify that maintenance and modification activities are conducted in a manner such that the original design is not degraded.

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 40 of 42)

7. Letter in parentheses (continued)

(ff) For operational phase activities, including preoperational initial startup, and operational testing, system classification is in accordance with Regulatory Guide 1.26 and 10CFR50.55a. The following is a list of clarifications to the Regulatory Guide 1.26 column that will be used during operation phase activities:

PRINCIPAL COMPONENT	REGULATORY GUIDE 1.26 QUALITY GROUP CLASSIFICATION
Chemical and Volume Control System	
Equipment drain tank	D
Reactor drain tank pumps	D
Reactor drain filter	D
Preholdup ion exchangers	D
Piping and valves:	
From refueling water tank to first isolation valve	B
Safety Injection and Shutdown Cooling System	
Piping and valves:	
Relief piping from relief valves in auxiliary bldg	D
Control Building HVAC System	
ESF switchgear and battery rooms HVAC system:	
Dampers	na
ESF equipment room (channel A and B):	
Dampers	na
Steam and Power Conversion System	
Main steam supply system:	
Piping - steam generator to outboard containment isolation valve	B
Steam generator blowdown system:	
Piping from steam generators to outboard containment isolation valve	B
Radiation Monitoring System	
Monitors:	
Control room ventilation intake	na
Fuel pool area	na
Fuel building ventilation exhaust	na
Refueling machine area	na
Containment building purge exhaust	na
Containment building atmosphere	na
Post-accident purge area	na
Auxiliary building vent exhaust filter inlet	na
Auxiliary building lower level ventilation exhaust	na
Auxiliary building upper level ventilation exhaust	na

Table 3.2-1

QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 41 of 42)

7. Letter in Parentheses (continued)

(gg) All design, fabrication, materials, examination, inspection, and construction of the equipment hatch and its attachments shall comply with the requirements of ASME Section III, Division 1, Subsection NE. An ASME code stamp is not required.

(hh) The new fuel racks are designed to store new fuel in a noncritical array in accordance with Regulatory Guide 1.13. To fulfill this function they are required only to exhibit no permanent deformation following a seismic event. A QA program modified from the requirements of 10CFR50, Appendix B, is,therefore, acceptable. The design, specific components, and fabrication processes necessary for the structural integrity of the fuel racks provide that they will withstand the effects of a safe shutdown earthquake and remain functional per Regulatory Guide 1.29.

(ii) Meteorological system calibration is considered to be a quality-related activity and is subject to the pertinent requirements of the operational quality assurance program. The meteorological equipment is classified as not quality-related. This is in accordance with the Regulatory Guide 1.97, Rev. 2 requirements which require that Category 3 instrumentation be "high quality commercial grade." Regulatory Guide 1.97 does not impose any quality assurance program controls on Category 3 instrumentation.

(jj) Certain valves within these subsystems are not ASME Section III; however, engineering evaluation determined their acceptability for continued operation and use.

(kk) Specific QA requirements may exist for some non-Class 1E electrical systems or components based on regulations or commitments. Examples are, but not limited to, the following:

- Fire Protection (10 CFR Part 50, Appendix R)
- Rad Waste Management (RG 1.143)
- Post Accident Monitoring (RG 1.97)
- New Fuel Handling Equipment (RG 1.13)
- Heavy Load Handling Equipment (NUREG 0612 & GL 81-07)
- Anticipated Transient Without SCRAM (10 CFR Part 50.62)
- Station Blackout (10 CFR 50.63 & RG 1.155)
- Seismic Category IX Components (RG 1.133)
- Radiation Monitoring
- Non-Safety Related Auxiliary Feedwater
- Seismic Monitoring (RG 1.12 & RG 1.133)
- Permanent Plant Equipment
- Preferred Power Circuits (10 CFR Part 50, Appendix A Criterion 1)
- Dry Cask and Independent Spent Fuel Storage Installation (ISFSI) SSC's (10 CFR Part 72)

(ll) The quality assurance requirements of RG 1.155, "Station Blackout," Appendix A, Quality Assurance Guidance for Non-Safety Systems and Equipment, apply to the alternate ac source (10 CFR 50.2) installed to meet the requirements of 10 CFR Part 50.63.

(mm) = NRC has granted approval for the application of alternate quality assurance requirements to the flow sensor CH-FE210Y located in the normal borated makeup flowpath. See Section 1.8 for further detail on the exceptions to Regulatory Guide 1.26.

(nn) The system, structure or component has been classified as Important to Safety, Category A, as a result of its functions associated with dry storage of spent fuel, as governed by 10 CFR Part 72.

(oo) The system, structure or component has been classified as Important to Safety, Category B, as a result of its functions associated with dry storage of spent fuel, as governed by 10 CFR Part 72.

(pp) The system, structure or component has been classified as Important to Safety, Category C, as a result of its functions associated with dry storage of spent fuel, as governed by 10 CFR Part 72

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 42 of 42)

8. Expendable and Consumable Items
Expendable and consumable items necessary for the functional performance of safety-related structures, systems, and components are classified as safety-related items, and as such are subject to the pertinent requirements of the operational quality assurance program.

9. Radiation Protection Equipment
Radiation protection and chemistry equipment and services, limited to calibration standards procured for subsequent calibration of radiation protection and chemistry equipment and outside services procured to provide calibration of radiation protection and chemistry equipment, are subject to applicable requirements of the operational phase quality assurance program. Additionally, paragraphs 12.5.2.1.1, 12.5.2.1.2, and 12.5.2.1.3 are not subject to applicable requirements of the operational quality assurance program. This note does not supercede any of the requirements for radiation protection and chemistry systems and components which are contained in the body of table 3.2.1.

10. Emergency Plan Equipment
Emergency plan implementing procedures dealing with emergency plan equipment (including emergency kits, protective equipment, and supplies) are subject to quality assurance monitoring as described in chapter 17.

11. Valve Operators
Valve operators that are associated with safety-related valves which must perform a mechanical motion in order to shut down the plant, maintain the plant in a safe shutdown condition, or mitigate the consequences of a postulated event are classified as safety-related and as such are subject to the pertinent requirements of the operational quality assurance program.

12. EW System Radiation Monitors
These monitors and some associated tubing/piping and valves were originally installed to R2D Class requirements. These components have been upgraded to the equivalent of Q1C (for pressure boundary integrity) i.e. safety-related, seismic category I and ASME Sec III, Class 3. Future activities will be completed commensurate with the Q1C classification. (DFWOs 713354, 713350, 713353).

13. Fuel Transfer Valve and Associated Components
These components were originally installed as Quality Class NQR, Seismic Category II. The valve was designed per ANSI B31.1. The bellows was designed per the Expansion Joint Manufacturers Association Standards. The Fuel Transfer Tube Housing was designed per AISC. These components have been reclassified as Quality Class Q, Seismic Category I, Regulatory Guide 1.26 Quality Group C, ANSI N18.2 Safety Class 3. The components remain designed per their original design standards and remain non-ASME Section III components. Future activities will be completed commensurate with the Q1 classification.

14. Essential Exhaust
Shared with HF System located in FB

15. Steam Generator Blowdown System
The blowdown system piping and components which are associated with the Radwaste system are designed in accordance with Regulatory Guide 1.143 as mentioned in Note 7(o) above. Refer to the SC system P&ID for each component classification.

Table 3.2-1
QUALITY CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (Sheet 42 of 42)

8. Expendable and Consumable Items
Expendable and consumable items necessary for the functional performance of safety-related structures, systems, and components are classified as safety-related items, and as such are subject to the pertinent requirements of the operational quality assurance program.

9. Radiation Protection Equipment
Radiation protection and chemistry equipment and services, limited to calibration standards procured for subsequent calibration of radiation protection and chemistry equipment and outside services procured to provide calibration of radiation protection and chemistry equipment, are subject to applicable requirements of the operational phase quality assurance program. Additionally, paragraphs 12.5.2.1.1, 12.5.2.1.2, and 12.5.2.1.3 are not subject to applicable requirements of the operational quality assurance program. This note does not supercede any of the requirements for radiation protection and chemistry systems and components which are contained in the body of table 3.2.1.

10. Emergency Plan Equipment
Emergency plan implementing procedures dealing with emergency plan equipment (including emergency kits, protective equipment, and supplies) are subject to quality assurance monitoring as described in chapter 17.

11. Valve Operators
Valve operators that are associated with safety-related valves which must perform a mechanical motion in order to shut down the plant, maintain the plant in a safe shutdown condition, or mitigate the consequences of a postulated event are classified as safety-related and as such are subject to the pertinent requirements of the operational quality assurance program.

12. EW System Radiation Monitors
These monitors and some associated tubing/piping and valves were originally installed to R2D Class requirements. These components have been upgraded to the equivalent of Q1C (for pressure boundary integrity) i.e. safety-related, seismic category I and ASME Sec III, Class 3. Future activities will be completed commensurate with the Q1C classification. (DFWOs 713354, 713350, 713353).

13. Fuel Transfer Valve and Associated Components
These components were originally installed as Quality Class NQR, Seismic Category II. The valve was designed per ANSI B31.1. The bellows was designed per the Expansion Joint Manufacturers Association Standards. The Fuel Transfer Tube Housing was designed per AISC. These components have been reclassified as Quality Class Q, Seismic Category I, Regulatory Guide 1.26 Quality Group C, ANSI N18.2 Safety Class 3. The components remain designed per their original design standards and remain non-ASME Section III components. Future activities will be completed commensurate with the Q1 classification.

14. Essential Exhaust
Shared with HF System located in FB

15. Steam Generator Blowdown System
The blowdown system piping and components which are associated with the Radwaste system are designed in accordance with Regulatory Guide 1.143 as mentioned in Note 7(o) above. Refer to the SC system P&ID for each component classification.

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3.3 WIND AND TORNADO LOADINGS

Seismic Category I structures are designed for the extreme wind phenomena which are defined in Section 2.1 of BC-TOP-3-A[1]. BC-TOP-3-A defines tornado and extreme wind loadings and criteria for structures. It furnishes data, formulae, and procedures for determining maximum wind loading on structures and parts of structures. Seismic Category I structures are identified in subsection 3.2.1. Seismic Category I structures are designed for tornado effects. Additionally, structures that contain equipment required for safe shutdown after a tornado are designed for tornado effects.

3.3.1 WIND LOADINGS

3.3.1.1 Design Wind Velocity

The design wind velocity for all Seismic Category I structures is 105 miles per hour at 30 feet above ground for a 100-year recurrence interval.

3.3.1.2 Basis for Wind Velocity Selection

The selected design wind velocity is equal to the operating basis wind speed (100-year recurrence fastest mile wind) discussed in paragraph 2.3.1.2.3.

3.3.1.3 Vertical Velocity Distribution and Gust Factors

The vertical velocity distribution used is in accordance with exposure C (flat, open country; flat, open coastal belts; and grassland) of Section 6 of American National Standards Institute (ANSI) A58.1-1972[2]. Table 5 of this standard

contains the specific effective velocity pressures (q_F) for overall structural response. Table 6 of the standard contains the specific effective velocity pressure (q_p) for parts and portions of structure. Table 12 of the standard contains the specific effective velocity pressures for calculating internal velocity pressures (q_M). Values given in the above tables include appropriate gust factors. As an example, the range of gust factor variation for a basic wind velocity above 90 miles per hour is from 1.3 to 1.1 for heights ranging from 30 to 500 feet.

3.3.1.4 Determination of Applied Forces

The procedures used to convert the wind velocity into applied forces for structures are contained in ANSI A58.1-1972 and Sections 3.0 and 4.0 of BC-TOP-3-A. The wind velocity on which the applied forces depend is given in paragraph 3.3.1.1 above. The design pressures or design loads are obtained by multiplying the effective velocity pressures by the appropriate pressure coefficients as specified in Section 6.4 of ANSI A58.1-1972. Pressure coefficients are given in Sections 6.5 through 6.9 of the ANSI standard.

For Seismic Category I structures, the applied forces due to wind are calculated to determine if they are less severe than the applied forces due to tornado loadings. The applied tornado force magnitude and distribution are determined as discussed in paragraph 3.3.2.2. Appropriate stress levels and load factors discussed in section 3.8 are considered in determination of the governing loads. There are no Seismic

Category I structures for which wind governs the design. The total wind applied force magnitude and distribution were determined by procedures outlined in BC-TOP-3-A.

3.3.2 TORNADO LOADINGS

For purposes of structural analysis, the effects of a tornado are described in Section 3.0 of BC-TOP-3-A.

3.3.2.1 Applicable Design Parameters

Tornado-resistant Seismic Category I structures are analyzed for tornado loadings (not coincident with any unrelated accident condition or earthquake) as outlined in Sections 3.3 and 3.4 of BC-TOP-3-A. The loadings are calculated on the basis of having a maximum velocity of 300 miles per hour corresponding to a rotational speed of 240 miles per hour and a maximum translational speed of 60 miles per hour. The minimum translational speed is 5 miles per hour. The maximum design pressure drop is 2.25 psi with a maximum rate of change of 1.2 pounds per square inch per second. The radius (R_m) from the center of the tornado to the point at which the maximum wind velocity occurs is 150 feet. These parameters conform to those given in Regulatory Guide 1.76 for Region II. Tornado wind pressure loads, differential atmospheric pressure changes, associated time intervals, and missile effects are combined in accordance with BC-TOP-3-A. The design basis tornado missiles are discussed in subsection 3.5.1.

3.3.2.2 Determination of Forces on Structures

The methods employed to convert tornado loadings into forces and the distribution across the structures are outlined in Section 3.5 of BC-TOP-3-A. Loading combinations are listed in Section 3.4 of BC-TOP-3-A. A load factor of unity for a tornado is used for tornado effects.

3.3.2.3 Ability of Seismic Category I Structures to Perform Despite Failure of Structures Not Designed for Tornado Loads

The design of all permanent non-Seismic Category I structures, systems, and components was analytically checked to assure that no missiles will be generated which have more severe effects than those tornado-generated missiles listed in subsection 3.5.1. This is to ensure that Seismic Category I structures, systems, and components required for safe shutdown after a tornado will perform their intended functions.

Non-Seismic Category I structures whose collapse could result in loss of required function of Seismic Category I structures, equipment, or systems required for safe shutdown after a tornado were analytically checked to determine that they will not collapse when subjected to extreme environmental loads. The bases for analytical procedures that were used are discussed in paragraph 3.8.4.4.

3.3.3 REFERENCES

1. "Tornado and Extreme Wind Design Criteria for Nuclear Power Plants," BC-TOP-3-A, Revision 3, Bechtel Power Corporation, San Francisco, California, August 1974.

2. "American National Standard Building Code Requirements for Minimum Design Loads in Buildings or Other Structures," ANSI A58.1-1972.

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3.4 WATER LEVEL (FLOOD) DESIGN

3.4.1 FLOOD PROTECTION

The relationship of all Category I structures to design flood levels is discussed in subsection 2.4.3. All Seismic Category I structures are located beyond the extent of probable maximum flooding. Therefore, no flood protection measures for Category I structures are required, as discussed in subsection 2.4.10.

3.4.2 ANALYSIS PROCEDURES

All safety-related structures, systems, and components are located beyond the extent of probable maximum flooding. Therefore, static and dynamic loadings due to the design basis flood conditions are not applied.

The design basis groundwater conditions and the design bases for subsurface hydrostatic loadings are described in paragraph 2.4.13.5. Procedures by which the dynamic effects of the design basis groundwater conditions are applied are described in Section 4.4 of BC-TOP-4-A.

Structures that penetrate the maximum groundwater level (given in paragraph 2.4.13.5) are limited to the containment building and portions of the auxiliary building.

The interior of these structures is made watertight by the 2-foot minimum concrete thickness of the walls and base mat and the use of waterstops in construction joints. Waterstops are provided to minimum levels of 927 feet, 924 feet, and 921 feet msl for Units 1, 2, and 3, respectively. These levels provide adequate margin above the maximum predicted groundwater

levels. Auxiliary waterproofing of horizontal and vertical surfaces is not deemed necessary.

The essential spray pond intake structures are designed to withstand loads imposed by wind-caused waves. The loads are computed according to the methods outlined in references 1 and 2.

3.4.3 REFERENCES

1. U.S. Army Corps of Engineers "Shore Protection Manual", Vol I and II, U.S. Army Coastal Engineering Research Center, 1977.

2. U.S. Army Corps of Engineers, "Computation of Freeboard Allowances for Waves in Reservoirs," Engineer Technical Letter No. ETL 1110-2-9, August 1, 1966.

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3.5 MISSILE PROTECTION

Missile protection criteria for PVNGS conform to 10CFR50, General Design Criterion 4, Environmental and Missile Design Bases. Protection against the postulated missiles identified in subsection 3.5.1 is provided to fulfill the following design criteria:

A. Reactor Coolant Pressure Boundary Missiles

   1. A missile generated from a loop in the reactor coolant pressure boundary (RCPB) will not cause:

      a. Loss of integrity of another loop of the RCPB

      b. Loss of integrity of the main steam or feedwater system

   2. A missile generated from a loop in the RCPB will not cause loss of function to systems required to mitigate the consequences of the loss-of-coolant accident (LOCA) or required for safe shutdown, assuming the failure of a single active component. These systems are:

      a. Reactor protective system

      b. Engineered safety features actuation system

      c. Safety injection system (HPSI and LPSI, including hot leg injection lines and refueling water tank)

      d. Containment spray system

e. Auxiliary feedwater system (including safety-related condensate transfer and storage system and condensate storage tank)

f. Class 1E electrical systems, ac and dc (including switchgear, batteries, and distribution systems)

g. Diesel generator system, including diesel generator starting, lubrication, and combustion air intake and exhaust systems

h. Diesel fuel oil storage and transfer system

i. Hydrogen recombiner systems

j. Control building HVAC system

k. Essential cooling water system (portions required for operation of other listed systems)

l. Essential spray pond system

m. Fuel building HVAC system

n. Diesel generator building HVAC system

o. Main control board (see tables 7.3-2 and 7.3-14 for systems required)

p. Containment isolation systems:

    (1) Penetration assemblies

    (2) Isolation valves

    (3) Equipment hatch

    (4) Emergency personnel hatch

(5) Personnel lock

(6) Liner plate

(7) Test connections

(8) Piping between penetration assemblies and isolation valves.

q. Excore neutron monitoring system

r. Safety-related radiation monitors (refer to section 11.5)

s. Chemical and volume control systems (piping associated with sampling of the reactor coolant)

t. Shutdown cooling system

u. Essential chilled water system

B. Main Steam and Feedwater Missiles

1. A missile generated from the main steam or feedwater pump discharge pressure boundary will not cause:

a. Loss of integrity to the RCPB

b. Loss of integrity to nonisolatable main steam or feedwater piping in another loop

c. Loss of integrity of the spent fuel pool

2. A missile generated from the main steam or feedwater pump discharge pressure boundary will not cause loss of function to systems required to mitigate the consequences of a main steam or

feedwater line accident or required for safe shutdown, assuming the failure of a single active component. These systems are:

a. Reactor protective system

b. Engineered safety features actuation system

c. Auxiliary feedwater system (including safety-related condensate transfer and storage system and condensate storage tank)

d. Safety injection system (HPSI and LPSI, including refueling water tank)

e. Containment spray system (for breaks inside the containment only)

f. Chemical and volume control system (charging portion including boric acid makeup tanks and pumps, charging pumps, interconnecting piping, and reactor coolant sampling portion)

g. Main steam and feedwater system (from unaffected steam generator out to the containment isolation valves, including the atmospheric steam dump, steam supply to the turbine-driven auxiliary feedwater pump, and the steam generator blowdown line)

h. Shutdown cooling system

i. Class 1E electrical systems, ac and dc (including switchgear, batteries, and distribution systems)

j. Diesel generator system, including diesel generator starting, lubrication, and combustion air intake and exhaust systems

k. Diesel fuel oil storage and transfer system

l. Essential cooling water system (portions required for operation of other listed systems)

m. Essential spray pond system

n. Control building HVAC system

o. Main control board (see tables 7.3-2 and 7.3-14 for systems required)

p. Essential chilled water system

q. Containment isolation systems:

   (1) Penetration assemblies

   (2) Isolation valves

   (3) Equipment hatch

   (4) Emergency personnel hatch

   (5) Personnel lock

   (6) Liner plate

   (7) Test connections

   (8) Piping between penetration assemblies and isolation valves

r. Fuel building HVAC system

s. Diesel generator building HVAC system

C. Internal Missiles Generated from Systems Other Than Reactor Coolant, Main Steam, or Feedwater

A missile generated from a plant system, other than the reactor coolant system (RCS), the main steam system, or feedwater pressure boundary, shall not perforate the containment or control room or cause loss of integrity to the spent fuel pool. Criteria for missiles generated from the reactor coolant and main steam systems and feedwater pump discharge lines are discussed in section 3.5, listings A and B. In accordance with criteria listed in section 3.5, listing B, the missile shall not cause loss of function of any system required for safe shutdown. Since such missiles do not result in a LOCA or a steam generator steam/water release requiring protective action, a loss of redundancy for such systems is permitted, but a loss of function is not permitted.

D. Tornado Missiles

Missiles generated by a tornado shall not perforate the containment, the auxiliary building, the control building, the diesel generator building, the diesel generator fuel storage tanks, the condensate storage tank, the refueling water tank, or cause loss of integrity to the spent fuel pool. The missiles shall not cause loss of function to any system described in section 3.5, listing B, as required for safe shutdown.

MISSILE PROTECTION

3.5.1 MISSILE SELECTION AND DESCRIPTION

The sources of missiles which, if generated, could affect the safety of the plant are considered in this section. These are rotating component failure missiles, pressurized component failure missiles, and tornado generated missiles.

3.5.1.1 Internally-Generated Missiles (Outside Containment)

There are two general sources of postulated missiles outside containment:

- Rotating component failures
- Pressurized component failure

A tabulation of safety-related structures, systems, and components outside the containment, their locations, seismic categories, quality group classifications, and the applicable FSAR sections, which include system piping and instrumentation drawings describing safety design features, is given in table 3.2-1. General arrangement and section detail drawings are located in section 1.2.

3.5.1.1.1 Rotating Component Failure Missiles

A tabulation of missiles generated by postulated failures of rotating components, their sources and characteristics, and provided missile protection is given in table 3.5-1.

Missile selection was based on the following conditions:

A. Rotating components that are operated during normal operating plant conditions are capable of becoming missiles

B. The energy a rotating part associated with 120% overspeed is assumed sufficient for component failure

C. Determination of whether the energy of the missile is sufficient to perforate the protective housing.

3.5.1.1.2 Pressurized Component Failure Missiles

A tabulation of missiles generated by postulated failures of pressurized components, their sources and characteristics, and provided missile protection is given in table 3.5-2. The bases for selection were:

A. Pressurized components in systems whose service temperature exceeds 200F or whose design pressure exceeds 275 psig are evaluated as to their potential for becoming missiles.

Table 3.5-1
INTERNALLY-GENERATED ROTATING COMPONENT FAILURE
MISSILES OUTSIDE CONTAINMENT (Sheet 1 of 2)

Missile Identification	Source of Missile	Location	Missile Characteristics			Calculated Maximum Steel Perforation Depth (in.)	Casing Thickness (in.)	Casing Perfora-tion	Missile Residual Velocity After Casing Perforation (ft/s)	Calculated Thickness of Surrounding Material to Prevent		Remarks
			Velocity (ft/s)	Eq. Dia. (in.)	Weight (lbs)					Concrete Spalling (in.)	Steel Perforation (in.)	
Impeller	Cooling water holdup tank pumps	Auxiliary building El. 40'	105.4	3.0	9.5	0.069	0.5	No	--	--	--	--
Impeller	Chemical drain pumps	Auxiliary building El. 40'	85.6	2.7	5.4	0.040	0.5	No	--	--	--	--
Impeller	Reactor drain pumps	Auxiliary building El. 40'	79.	4.8	24.	0.055	0.31	No	--	--	--	--
Impeller	LPSI pumps	Auxiliary building El. 40'	112.	8.	193.3	0.21	0.75	No	--	--	--	--
Impeller	Auxiliary steam boiler feedwater pumps	Yard area El. 100'	77.	4.8	24.	0.053	0.5	No	--	--	--	--
Impeller	Boric acid makeup pumps	Auxiliary building El. 70'	125.2	6.	60.4	0.15	0.43	No	--	--	--	--
Impeller	Reactor makeup water pumps	Auxiliary building El. 70'	125.2	6.	60.4	0.15	0.43	No	--	--	--	--
Impeller	ECWS pumps	Auxiliary building El. 70'	97.5	5.3	115.5	0.186	1.25	No	--	--	--	--
Impeller	Crud pump	Auxiliary building El. 100'	85.6	2.7	5.4	0.040	0.5	No	--	--	--	--
Impeller	Normal chilled water pump	Auxiliary building roof	80.7	6.9	37.	0.052	0.56	No	--	--	--	--
Impeller	NCWS pump	Yard area El. 100'	91.8	6.0	120.	0.155	0.5	No	--	--	--	--

Table 3.5-1
INTERNALLY-GENERATED ROTATING COMPONENT FAILURE
MISSILES OUTSIDE CONTAINMENT (Sheet 2 of 2)

Missile Identification	Source of Missile	Location	Missile Characteristics			Calculated Maximum Steel Perforation Depth (in.)	Casing Thickness (in.)	Casing Perfora-tion	Missile Residual Velocity After Casing Perforation (ft/s)	Calculated Thickness of Surrounding Material to Prevent		Remarks
			Velocity (ft/s)	Eq. Dia. (in.)	Weight (lbs)					Concrete Spalling (in.)	Steel Perforation (in.)	
Fan blade	LPSI pump room essential ACU fans	Auxiliary building El. 51'-6"	37.6	0.23	0.14	0.014	0.028	No	---	--	--	--
Fan blade	Electrical pene-tration room essential ACU fans	Auxiliary building El. 120	74.2	0.47	0.26	0.026	0.028	No	---	--	--	--
Fan blade	ECW pump room essential ACU fans	Auxiliary building El. 70'	90.9	0.52	0.38	0.038	0.028 (inner casing)	Yes	55.8	0.42	0.02	Outer casing is 0.0359 in. thick - no penetration
Fan blade	Control building ESF SWGR room essential AHU fans	Control building El. 74	59.7	0.2	0.17	0.033	0.028 (inner casing)	Yes	28.4	0.43	0.013	Outer casing is 0.0359 in. thick - no penetration
Fan blade	Diesel generator building control room essential AHU fans	Diesel generator building El. 113'-5"	104.5	0.72	1.03	0.065	0.031 (inner casing)	Yes	85.4	1.1	0.05	Surrounding steel is thicker than 0.0065 in. - no penetration
							0.0478 (outer casing)	Yes	18.7	0.0	0.0065	
Fan blade	Containment refueling purge normal AHU fan	Auxiliary building roof	293.2	1.4	1.93	0.2	0.5625	No	---	--	--	--
Fan blade	Containment pre-access normal AHU fan	Auxiliary building roof	60.	0.6	0.97	0.035	0.0478	No	---	--	--	--
Fan blade	Auxiliary build-ing normal AHU fan	Auxiliary building roof	163.9	1.34	2.9	0.127	0.0598	Yes	134.5	0.92	0.096	Missile cannot hit other equipment
Fan blade	Access control area normal AHU fan	Auxiliary building roof	137.	1.66	3.6	0.093	0.0598	Yes	95.9	0.5	0.058	Missile cannot hit other equipment

B. Temperature or other detectors installed on piping or in wells are evaluated as potential missiles if failure of a single circumferential weld could cause their ejection.

C. Unrestrained sections of piping such as vents, drains, and test connections were evaluated as potential missiles if the failure of a single circumferential weld could cause their ejection.

D. Valves of ANSI rating 900 psig and above, constructed in accordance with Section III of the ASME Boiler and Pressure Vessel Code, are pressure seal bonnet-type valves. For pressure seal bonnet valves, valve bonnets are prevented from becoming missiles by the retaining ring, which would have to fail in shear, and by the yoke, which would capture the bonnet or reduce bonnet energy.

   Because of the highly conservative design of the retaining ring of these valves (safety factors in excess of 8 may be used), bonnet ejection is highly improbable, and hence bonnets are not considered credible missiles.

E. Most valves of ANSI rating 600 psig and below are valves with bolted bonnets. Valve bonnets are prevented from becoming missiles by limiting stresses in the bonnet-to-body bolting material by rules set forth in the ASME Boiler and Pressure Vessel Code, Section III, and by designing flanges in accordance with applicable code requirements. Even if bolt

Table 3.5-2
INTERNALLY-GENERATED PRESSURIZED COMPONENT FAILURE
MISSILES OUTSIDE CONTAINMENT
(Sheet 1 of 2)

Missile Identification	Source of Missile	Location	Missile Characteristics: Velocity (ft/s)	Missile Characteristics: Eq. Dia. (in.)	Missile Characteristics: Weight (labs.)	Steel (Concrete) Target Thickness (in.)	Residual Velocity (ft/s)	Calculated Maximum Steel (Concrete) Perforation Depth[a] (in.)	Remarks
Press ind. noz. with valve (G1)	Letdown heat exchanger	Auxiliary building El. 100'-0"	24.8	1.75	10.0	0.218	--	0.018	No perforation
Press ind. noz. with valve (G2)	Letdown heat exchanger	Auxiliary building El. 100'-0"	23.9	1.75	10.0	(18)	--	(<2)	No perforation
Temp. ind. nozzle (H1)	Letdown heat exchanger	Auxiliary building El. 100'-0"	79.9	1.75	1.0	(18)	--	(<2)	No perforation
Temp ind. nozzle	Letdown heat exchanger	Auxiliary building El. 100'-0"	244.8	1.75	1.0	(18)	--	(<2)	No perforation
0.50" Lev. ind. noz. with valve	Radwaste crud tank	Auxiliary building El. 100'-0"	10.12	0.84	6.33	(24)	--	(<2)	No perforation
Tube side. drain	Seal injection heat exchanger	Auxiliary building El. 100'-0"	27.5	0.75	0.61	(24)	--	(<2)	No perforation

a. For concrete, calculated maximum perforation depth is less than 2 inches.

Table 3.5-2
INTERNALLY-GENERATED PRESSURIZED COMPONENT FAILURE
MISSILES OUTSIDE CONTAINMENT (Sheet 2 of 2)

Missile Identification	Source of Missile	Location	Missile Characteristics			Steel (Concrete) Target Thickness (in.)	Residual Velocity (ft/s)	Calculated Maximum Steel (Concrete) Perforation Depth[a] (in.)	Remarks
			Velocity (ft/s)	Eq. Dia. (in.)	Weight (lbs.)				
Instrument noz. with valve (1) tube side	Shutdown cooling heat exchanger	Auxiliary building El. 70'-0"	26.1	1.75	9.0	(24)	---	(<2)	No perforation
Instrument noz. with valve (2) tube side	Shutdown cooling heat exchanger	Auxiliary building El. 70'-0"	26.7	1.75	9.0	(24)	---	(<2)	No perforation

failure were to occur, the likelihood of all bolts experiencing a simultaneous complete severance failure is very remote. The widespread use of valves with bolted bonnets, and the low historical incidence of complete severance valve bonnet failures confirm that bolted valve bonnets need not be considered as credible missiles.[1]

F. Valve stems were not considered as potential missiles if at least one feature, in addition to the stem threads, is included in their design to prevent ejection. Valves with backseats are prevented from becoming missiles by this feature. In addition, air- or motor-operated valve stems will be effectively restrained by the valve operators.

G. Nuts, bolts, nut and bolt combinations, and nut and stud combinations have only a small amount of stored energy and thus are of no concern as potential missiles.

3.5.1.2 Internally-Generated Missiles (Inside Containment)

There are two general sources of postulated missiles inside the containment:

- Rotating component failure
- Pressurized component failure

3.5.1.2.1 Rotating Component Failure Missiles

A tabulation of missiles generated by postulated failures of rotating components, their sources and characteristics, and provided missile protection is given in table 3.5-3.

Missile selection was based on the following conditions:

Table 3.5-3
INTERNALLY-GENERATED ROTATING COMPONENT FAILURE
MISSILES INSIDE CONTAINMENT

Missile Identification	Source of Missile	Location	Missile Characteristics			Calculated Maximum Steel Perforation Depth (in.)	Casing Thickness (in.)	Casing Perforation	Missile Residual Velocity After Casing Perforation (ft/s)	Calculated Thickness of Surrounding Material to Prevent		Remarks
			Velocity (ft/s)	Eq. Dia. (in.)	Weight (lbs.)					Concrete Spalling (in.)	Steel Perforation (in.)	
Fan blade	Containment normal ACU fan	Containment building El. 120'	318.9	2.	12.7	0.55	0.375	Yes	210.8	7.2	0.3	Missile has no effect on plant safe shutdown capability nor could it result in a condition causing uncontrolled release of radioactivity. (Because of equipment layout, a missile will not initiate a LOCA, nor vice versa. Therefore, these occurrences are considered independent events.
Fan blade	Containment preaccess normal AFU fan	Containment building El. 140'	200.	2	12.2	0.29	0.375	No	---	---	---	---
Fan blade	CEDM normal ACU unit fan	Containment building El. 140'	264.	2	7.5	0.3	0.375	No	---	---	---	---
Fan blade	Reactor cavity normal cooling fan	Containment building El. 80'	211.	2.5	18.3	0.33	0.375	No	---	---	---	---

A. Rotating components that are operated during normal operating plant conditions are capable of becoming missiles

B. The energy in a rotating part associated with 120% overspeed is assumed to be sufficient for component failures

C. Determination of whether the energy of the missile is sufficient to perforate the protective housing

3.5.1.2.2 Pressurized Component Failure Missiles

A. Reactor Coolant System Pressure Boundary

The selection of potential missiles is based on the application of single failure criteria to the normal retention features of plant equipment for which there is a source of energy capable of creating a missile in the event of the postulated removal of the normal retention features. Where redundancy is provided by the normal retention features such that sufficient retention capability remains to prevent creation of a missile in the event of a postulated failure of a single retention feature, no potential missile is postulated. Table 3.5-4 presents the potential missiles postulated to originate from RCPB equipment, summarizes their characteristics, and lists provided missile protection (including missiles from equipment within the C-E scope of supply).

The effects of secondary missiles were evaluated during separation reviews of the PVNGS scale model. The effects fell into one of three categories:

1. No secondary missile

Table 3.5-4
INTERNALLY-GENERATED PRESSURIZED COMPONENT FAILURE
MISSILES INSIDE CONTAINMENT (Sheet 1 of 3)

Missile Identification	Source of Missile	Location	Missile Characteristics			Steel (Concrete) Target Thickness (in.)	Residual Velocity (ft/s)	Calculated Maximum (Concrete) Perforation Depth[a] (in.)	Remarks
			Velocity (ft/s)	Eq. Dia. (in.)	Weight (lbs)				
1" temp. ind. nozzle	Pressurizer	Containment building El. 110'-0"	179.2	1.25	2.78	2.0	---	0.148	No perforation
0.75" instrument nozzle (2 each)	Pressurizer	Containment building El. 145'	187.5	1.08	1.72	(24)	---	(<2)	No perforation
0.75" instrument nozzle (2 each)	Pressurizer	Containment building El. 145'	197.7	1.05	1.96	(24)	---	(<2)	No perforation
0.75" instrument nozzle (2 each)	Pressurizer	Containment building El. 110'-0"	197.0	1.05	1.96	(24)	---	(<2)	No perforation
Safety valve flange bolt	Pressurizer	Containment building El. 153'	16.2	1.25	3.7	(24)	---	(<2)	No perforation
Manway stud and nut	Pressurizer	Containment building El. 149'	32.8	1.25	4.25	(24)	---	(<2)	No perforation
Vent nozzle with valves	Regenerative heat exchanger	Containment building El. 119'-'9-11/16"	38.9	1.05	15.0	(24)	---	(<2)	No perforation
0.75" primary instrument nozzle (4 each)	Steam generator	Containment building El. 99'-6"	200.6	1.05	1.47	(48)[c]	---	(<2)[d]	No perforation
0.75' level indication nozzle (L1, L2, L3, L4)	Steam generator	Containment building El. 120'	153.4	1.05	1.23	(48)	---	(<2)	No perforation

Table 3.5-4
INTERNALLY-GENERATED PRESSURIZED COMPONENT FAILURE
MISSILES INSIDE CONTAINMENT (Sheet 2 of 3)

			Missile Characteristics						
Missile Identification	Source of Missile	Location	Velocity (ft/s)	Eq. Dia. (in.)	Weight (lbs)	Steel (Concrete) Target Thickness (in.)	Residual Velocity (ft/s)	Calculated Maximum Steel (Concrete) Perforation Depth[(a)] (in.)	Remarks
0.75" level indication nozzle (L5, L6, L7, L8)	Steam generator	Containment building El. 141’-8”	152.6	1.05	1.23	(48)	---	(<2)	No perforation
0.75" level indication nozzle (L9, L10, L11, L12)	Steam generator	Containment building El. 156’-3”	177.3	1.05	1.23	(48)	---	(<2)	No perforation
0.75" Press. test nozzle	Steam generator	Containment building El. 166’-3”	179’-4”	1.05	1.23	0.25	---	0.10	No perforation
Primary manway stud and nut	Steam generator	Containment building El. 104'	32.8	1.5	7.96	(48)	---	(<2)	No perforation
Secondary handhole stud and nut	Steam generator	Containment building El. 111'-5"	19.8	1.00	3.59	(48)	---	(<2)	No perforation
Secondary manway stud and nut	Steam generator	Containment building El. 150'-10"	11.6	1.5	7.28	(48)	---	(<2)	No perforation
Control rod drive assembly	Reactor vessel	Containment building El. 120'	58.1	10.0	1100	1.5	---	(<1.5)	No perforation
Temperature nozzle w/RTD assembly	Reactor coolant pump	Containment building El. 104'	93.9	2.75	a	(48)	---	(<2)	No perforation

Table 3.5-4
INTERNALLY-GENERATED PRESSURIZED COMPONENT FAILURE
MISSILES INSIDE CONTAINMENT (Sheet 3 of 3)

Missile Identification	Source of Missile	Location	Missile Characteristics Velocity (ft/s)	Missile Characteristics Eq. Dia. (in.)	Missile Characteristics Weight (lbs)	Steel (Concrete) Target Thickness (in.)	Residual Velocity (ft/s)	Calculated Maximum Steel (Concrete) Perforation Depth[a] (in.)	Remarks
Surge and spray piping thermal wells with RTD assembly	Reactor coolant piping	Containment building El. 123'	69.0	2.75	3.75	(24)	---	(<2)	No perforation
Reactor coolant pump thermal well with RTD assembly	Reactor coolant piping	Containment building El. 104'	93.9	2.75	8	(48) 0.25[d]	---	(<2) <0.1	No perforation No perforation
Shutdown cooling valve stem	Reactor coolant piping	Containment building El. 88'	50.3	2.5	85	0.75	---	0.35	No perforation
Shutdown cooling pipe cap	Reactor coolant piping	Containment building El. 89'	272	3.6	3.5	1.7 (>24)	--- ---	0.1 (<2)	No perforation No perforation
Three Radiographic inspection port half couplings (Unit 3 only)	SG Feedwater piping line SG-014	Containment El. 100' to 115' inside bio-wall	412.7	2.25	2	(48)	---	(<2)	No perforation

a. For concrete, calculated maximum perforation depth is less than 2 inches.
b. Primary instrument nozzle missile targets include 6", 14", 16" and 24" piping with steel thickness of 0.432", 0.750", 0.844" and 1.219", respectively.
c. Maximum perforation depth on steel targets is 0.134".
d. Barrier to protect valve SI-651 from hot leg thermal well with RTD assembly missile.

2. Secondary missile with insufficient energy to cause damage

3. Secondary missile but without safety impact

As noted in paragraph 3.6.1.2, separation reviews were conducted to ensure that nonseismically supported equipment could not impair the function of essential equipment or structures.

B. Non-RCPB Systems

A tabulation of missiles generated from failures of pressurized components, their sources and characteristics, and provided missile protection is given in table 3.5-4. The bases for selection are identical to those described in paragraph 3.5.1.1.2.

3.5.1.3 Turbine Missiles

3.5.1.3.1 Turbine Placement and Orientation

The placement and orientation of the turbine generators is shown in figure 3.5-1.

3.5.1.3.2 Missile Identification and Characteristics

Analysis has indicated that high-pressure turbine missiles and generator missiles would be retained by their respective casings. Accordingly, the missiles discussed in this paragraph are limited to postulated low-pressure turbine missiles.

3.5.1.3.2.1 Nature of Missiles Released by Low-Pressure Turbine. For the originally installed General Electric low-pressure turbines, it is postulated that any shrunk-on

wheel on the low-pressure rotor could be a source of missiles, the missiles being large sectors of the wheel released by multiple radial fractures. In the event of such disc fragments penetrating the surrounding turbine casings, the debris of internal collisions might also be ejected as comparatively minor missiles.

In the original turbine missile analysis, adjacent turbine wheels are categorized by General Electric into three groups (designated stage groups I, II, and III). The approximate expected number of missiles generated after a hypothetical wheel burst is postulated by General Electric (GE) as 16 fragments of four size classes. Appropriate information regarding missile nomenclature, size, shape, weight, energy, and velocity is presented in Table 1 and Figure 1 of GE Memo Report.(3)

The replacement General Electric Low Pressure Turbine Rotors are of monoblock construction and do not have shrunk on wheels. Therefore, the formerly dominant brittle fracture failure mechanism is not applicable to the new rotors. The probability of ductile failure for a rotor of any type is considered to be a function of speed, temperature and material tensile strength. With stress below ultimate strength, the probability of a ductile failure is negligible. The brittle and ductile failure modes are statistically independent. The GE probabilistic analysis of turbine overspeed was also documented in the 1984 NRC report, and is applicable to units with LP monoblock rotors. For the Palo Verde #1, 2 and 3 rotors, the probability of attaining an overspeed of 120% is at or below 1.7×10^{-6} and there is a negligible probability of ductile failure at 120%.

Therefore, the probability of turbine missile generation caused by ductile failure is well below the NRC acceptance criterion of $1x10^{-4}$ for a favorably oriented turbine.

In addition, GE has analyzed the potential for L-1 to L-6 stage bucket missiles applying the methodology used to study wheel missiles. At up to 120% speed no postulated missiles from an L-1 through L-6 bucket would penetrate the inner casing. As discussed above, the probability of turbine speed exceeding 120% is below the NRC missile probability threshold; therefore the probability of an L-1 through L-6 bucket missile is below the NRC threshold. Potential L-0 bucket missiles have been reviewed as discussed in Attachment (1) of GE Letter Report, Dated March 25, 2002.[(6)]

The probability of failure of the L-0 bucket is bounded by the probability of failure of the L-0 wheel reported in Memo Report Hypothetical Turbine Missile Data, 43-Inch Last Stage Bucket Units, J.E. Downs, 3/15/73.[(3)] This probability is below the NRC threshold. Therefore, the historical background of the remaining sub-sections of the UFSAR, under turbine missiles, that discuss in detail the original wheel turbine missiles analysis are left in place since they provide the bounding case for the Potential L-0 bucket missiles.

3.5.1.3.3 Turbine Failure Missiles - Probability Analysis

Turbine missiles are ejected fragments of the turbine wheels or surrounding casing which originate due to brittle fracture at normal rated speed (low speed burst) or due to ductile fracture during turbine runaway (high speed burst).

Missiles may be ejected at any angle of the 360° arc about the turbine axis. The ejection path will not always be perfectly normal to the turbine axis, but may vary from -5° to +5° from the normal for the interior turbine wheels, according to GE data. For the two outer turbine wheels, GE postulates a range of missile ejection angles from -25° to +25° from the normal to the turbine axis.

The missile ejection angles are illustrated in figure 3.5-2. The vertical angle Φ is measured about the turbine axis from the horizontal plane; ψ is the angle measured from the normal to the turbine axis; and θ is the projection of ψ on the horizontal plane. The horizontal angle θ is related to ϕ and ψ by the formula:

$$\theta = \tan^{-1}\left(\frac{\tan \psi}{\cos \phi}\right) \qquad (1)$$

From equation 1, it is seen that the angular range of missile ejection measured on the horizontal plane increases with increasing ϕ, the vertical angle of ejection. For example, for a missile ejected in the horizontal plane, at $\phi = 0°$, the horizontal range of ejection angles varies from -5° to 5° for interior turbine wheels. At $\phi = 45°$, the angular range measured at the horizontal plane varies from -7° to +7°, and at $\phi = 90°$, it ranges from -90° to +90°. It is at least theoretically possible, therefore, for a missile to strike a target located in line with the turbine axis, although the probability of strike is, of course, much higher for targets located near the normal to the axis.

Due to plant layout, all missiles are high trajectory missiles as defined in figure 3.5-3.

3.5.1.3.3.1 Probabilities Considered. The following probabilities are considered in the determination of the likelihood of a turbine missile accident leading to damage of structures, systems, or components required for safe plant shutdown:

P_1 = the probability of missile genesis due to turbine failure which causes fragment ejection through the turbine casing.

P_2 = the probability that a fragment strikes a specified target given its generation and ejection.

P_3 = the probability that the fragment strike damages its target in a manner leading to unacceptable consequences.

The probability analysis is performed for a layout of the generating units with turbine buildings in a peninsular arrangement (figure 3.5-1).

3.5.1.3.3.2 Probability of Missile Genesis (P_1). The probability of missile genesis (P_1) has been determined by GE for turbine rotor failures at or near running speed (a low speed burst due to brittle fracture) and at high overspeed or runaway conditions (a high speed burst due to ductile yielding).

In this analysis, adjacent turbine wheels (or stages) are categorized by GE into three groups (designated stage groups I, II, III) rather than considering seven individual stages for each turbine flow. This approach reduces the complexity of calculations and is justified on the basis that hypothetical missiles of significant similarity are produced by adjacent stages. The approximate expected number of missiles generated after a hypothetical nuclear wheel burst is postulated by GE as 16 fragments of four size classes. Each size class (designated fragment group a, b, c, or d) contains a specified number of fragments with characteristic shape, size, mass, and velocity range.

For the low-speed burst condition, GE considers the last stage to be two orders of magnitude more likely to fail than the next more likely stage. Therefore, stage groups I and II do not make a statistically significant contribution to missiles occurring from low-speed failure and are eliminated from further consideration. For the high-speed burst case, all seven stages are designed to about the same general stress level and, therefore, are about equally likely to fail by general ductile yielding in the event of runaway.

The following annual failure probabilities have been considered as given in Regulatory Guide 1.115:

A. Probability of missile genesis: $P_1 = 1 \times 10^{-4}$/yr.

B. Annual low-speed burst:[a] (below 120% speed), Stage III 6×10^{-5}/yr.

C. Annual high speed bursts:[a] 4×10^{-5}/yr
(from 120 to 180% speed)

1. Stage Group I: 1.71×10^{-5}/yr
(Stages 1-3)

2. Stage Group II: 1.71×10^{-5}/yr
(Stages 4-6)

3. Stage Group III: 0.58×10^{-5}/yr
(Stage 7)

Appropriate information regarding missile nomenclature, size, shape, weight, energy, and velocity is presented in Table 1 and Figure 1 of a GE Memo Report.[3]

3.5.1.3.3.3 Probability of Missile Strike (P_2).

Calculation of P_2: Neglecting the effect of air resistance, a missile trajectory is determined by the initial ejection vector from the turbine casing. The direction of the ejection vector is defined by two angles: ϕ, which is measured about the turbine axis, and ψ, which is measured from the plane normal to the turbine axis. The magnitude of the ejection vector is V, the ejection velocity from the casing. Functions must be specified, $P(\phi)$, $P(\psi)$, and $P(V)$, which determine the distribution of the missile ejection probability over the range of the three variables.

The ejection probability distribution $P(\phi)$ is assumed to be uniform over the 360° arc about the turbine axis:

$$P(\phi)\ d\phi = \frac{d\phi}{2\pi} \tag{2}$$

The probability distribution for $P(\psi)$ is considered to be uniform within some specified angular limits:

$$P(\psi)\ d\psi = \frac{d\psi}{\psi_{max} - \psi_{min}},\ \psi_{min} < \psi < \psi_{max} \tag{3}$$

The limits ψ_{min} to ψ_{max} are typically -5° to +5° for missiles ejected from interior turbine wheels, and -25° to +25° for missiles ejected from the end turbine wheel.

---

a. Calculated from information contained in GE Memo Report.[2]

The ejection probability distribution P(V) is normally assumed to be uniform over the specified range of ejection velocities V_{min} to V_{max}:

$$P(V)dV = \frac{dV}{V_{max} - V_{min}}, V_{min} < V < V_{max} \tag{4}$$

The principle of the P_2 calculation is to determine, using the basic equations of missile ballistics, the ranges of the variables ϕ, ψ, and V which determine trajectories intersecting the specified target structure. The strike probability is determined by integrating the product of the three ejection probability distributions over the ranges of the variables corresponding to target strike:

$$P_2 = \int_{\phi_1}^{\phi_2} \int_{\psi_1(\phi)}^{\psi_2(\phi)} \int_{V_1(\phi,\psi)}^{V_2(\phi,\psi)} P(\phi)\, P(\psi)\, P(V)\, dV\, d\psi\, d\phi \tag{5}$$

The integral is evaluated by the computer code "TURMIS," (turbine missile). Discrete ejection directions are evaluated by first specifying a ϕ_i, for which the limits ψ_1 (ϕ_i) and $\psi_2(\phi_i)$ may be computed corresponding to target strike. Discrete values ψ_j within the range $\psi_1(\phi_i)$ to $\psi_2(\phi_i)$ are then specified. Given the values ϕ_i and ψ_j, the limits $V_1(\phi_i, \psi_j)$ and $V_2(\phi_i, \psi_j)$ corresponding to target strike are then computed, and the integral over V may be evaluated analytically. The subrange of velocities V_{min} to V_{max} is illustrated in figure 3.5-3.

3.5.1.3.3.4 Probability of Damage to Missile Targets (P_3). Calculation of P_3: The calculation of P_3 requires the

definition of a sufficient missile impact on a target structure to assume damage to safety-related systems contained inside. A missile of sufficient kinetic energy to penetrate the concrete structure surrounding a safety-related system will essentially ensure damage to the system. Damage may be incurred without missile penetration, however. A sufficient impact to generate spallation of concrete fragments from the interior surface will also constitute a hazard to unprotected equipment. Thus, a missile impact which initiates spallation in the concrete wall or roof slab immediately surrounding a safety-related system is conservatively defined as the threshold of target damage. Modified National Defense Research Council (NDRC) equations with a safety factor of 1.2 have been adapted to determine whether or not spallation (perforation for containment) will occur upon missile impact of a specified concrete slab.[(4)]

3.5.1.3.3.5 Analytical Results. Calculation of P_4: The value of P_4 for a particular target structure and a particular turbine failure mode is taken as $P_1xP_2xP_3$ for the worst missile.

The P_4 value for the plant is determined by summation of P_4 values corresponding to the critical failure mode for safety-related targets on the plant site. Table 3.5-5 lists missile targets, strike probabilities, and turbine missile damage probabilities, in case the turbine in Unit 1 fails. Similar numbers are listed in tables 3.5-6 and 3.5-7 for the cases when the turbine fails in Units 2 and 3, respectively.
Tables 3.5-5, 3.5-6, and 3.5-7 show the P_4 values for both the

high- and low-trajectory missiles. Figures 3.5-4 through 3.5-7 are provided to show physical locations and barriers of targets considered in this analysis. Since the targets in all units are similarly oriented within a unit relative to a functional operating axis, these figures are applicable to all units.

3.5.1.3.4 Turbine Overspeed Protection

A description of the turbine overspeed protection system, in terms of redundancy, diversity, component reliability, and testing procedures, is provided in subsection 10.2.2.

3.5.1.3.5 Turbine Valve Testing

Since the annual probability of attaining an overspeed of 120% or greater is 1.7×10^{-6} which is below the NRC threshold for probability of missile generation, protection against missile generation for the turbines can be shown by avoiding the potential for ductile failure at any operating speed below 120%. GE, in the course of designing the turbines, has evaluated tensile stresses in rotating components. All of the rotating components have sufficient margin to tensile strength at design component temperatures to support operating speeds well in excess of 120% of normal.

To keep the probability of a significant overspeed event very low, periodic maintenance and inspection of valves and other overspeed protection components are required. The intervals are established to maintain system reliability.

The 1.7 x 10^{-6} probability number assumes the longest permissible interval between valve inspections and would be lower with more frequent inspections. Assumed inspection intervals are:

Component	Inspection Interval
Main stop valve	Quarterly
Control valve	Quarterly
Intercept valve	Quarterly
Mechanical trip valve	Weekly
Electrical trip valve	Weekly
On-line overspeed trip	Weekly

The above inspection intervals are met by PVNGS Operations Department Repetitive Task program.

3.5.1.3.6 Turbine Characteristics

Turbine data pertinent to the evaluation of its failure characteristics, including a description of its overall configuration, major components (e.g., steam valves, reheaters, etc.), rotor materials and their properties, steam environment (e.g., pressure, temperature, quality, chemistry), and other appropriate properties, are provided in section 10.2.

Turbine operational and transient characteristics, including turbine startup and trip environments, as well as its overspeed parameters, also are provided in section 10.2.

3.5.1.3.7 Turbine Missile Barriers

In accordance with Regulatory Guide 1.115, no turbine missile barriers have been provided since the probability of damaging an essential system, summed over all such systems, is less than 0.001.

3.5.1.4 Missiles Generated by Natural Phenomena (Tornado)

Tornado-generated missiles were considered in design of structures which are required for safe shutdown. The missiles considered in design and their characteristics are listed in table 3.5-8.

Missiles generated by any other natural phenomena were not considered credible.

Table 3.5-5
TURBINE MISSILE STRIKE AND DAMAGE PROBABILITIES
(PER MISSILE FRAGMENT FROM UNIT 1) (Sheet 1 of 2)

I. Turbine Missile Genesis Probability (P_1) 1 x 10^{-4} per Turbine per Year.

II. Missile Damage Probabilities (P_4)

Location Unit	Target Building or Structure	Strike and Damage Probabilities (P_2) x (P_3)	Missile Damage Probabilities (P_4)
1	Containment	0.024 x 10^{-3}	0.024 x 10^{-7}
1	Control	0.205 x 10^{-3}	0.205 x 10^{-7}
1	Fuel	0.104 x 10^{-3}	0.104 x 10^{-7}
1	Auxiliary	0.057 x 10^{-3}	0.057 x 10^{-7}
1	Diesel Generator	0.073 x 10^{-3}	0.073 x 10^{-7}
1	Condensate Storage	0.009 x 10^{-3}	0.009 x 10^{-7}
1	Main Steam Support	0.068 x 10^{-3}	0.068 x 10^{-7}
2	Containment	0.032 x 10^{-3}	0.032 x 10^{-7}
2	Control	0.023 x 10^{-3}	0.023 x 10^{-7}
2	Fuel	0.031 x 10^{-3}	0.031 x 10^{-7}
2	Auxiliary	0.011 x 10^{-3}	0.011 x 10^{-7}
2	Diesel Generator	0.006 x 10^{-3}	0.006 x 10^{-7}
2	Condensate Storage	0.001 x 10^{-3}	0.001 x 10^{-7}
2	Main Steam Support	0.006 x 10^{-3}	0.006 x 10^{-7}

Table 3.5-5
TURBINE MISSILE STRIKE AND DAMAGE PROBABILITIES
(PER MISSILE FRAGMENT FROM UNIT 1) (Sheet 2 of 2)

I. Turbine Missile Genesis Probability (P_1) 1×10^{-4} per Turbine per Year.

II. Missile Damage Probabilities (P_4)

Location Unit	Target Building or Structure	Strike and Damage Probabilities (P_2) x (P_3)	Missile Damage Probabilities (P_4)
3	Containment	0.022×10^{-3}	0.022×10^{-7}
3	Control	0.017×10^{-3}	0.017×10^{-7}
3	Fuel	0.015×10^{-3}	0.015×10^{-7}
3	Auxiliary	0.007×10^{-3}	0.007×10^{-7}
3	Diesel Generator	0.004×10^{-3}	0.004×10^{-7}
3	Condensate Storage	0.001×10^{-3}	0.001×10^{-7}
3	Main Steam Support	0.005×10^{-3}	0.005×10^{-7}
	Total	0.721×10^{-3}	0.721×10^{-7}

Table 3.5-6
TURBINE MISSILE STRIKE AND DAMAGE PROBABILITIES
(PER MISSILE FRAGMENT FROM UNIT 2) (Sheet 1 of 2)

I. Turbine Missile Genesis Probability (P_1) 1×10^{-4} per Turbine per Year.

II. Missile Damage Probabilities (P_4)

Location Unit	Target Building or Structure	Strike and Damage Probabilities (P_2) x (P_3)	Missile Damage Probabilities (P_4)
2	Containment	0.024×10^{-3}	0.024×10^{-7}
2	Control	0.205×10^{-3}	0.205×10^{-7}
2	Fuel	0.104×10^{-3}	0.104×10^{-7}
2	Auxiliary	0.057×10^{-3}	0.057×10^{-7}
2	Diesel Generator	0.073×10^{-3}	0.073×10^{-7}
2	Condensate Storage	0.009×10^{-3}	0.009×10^{-7}
2	Main Steam Support	0.068×10^{-3}	0.068×10^{-7}
1	Containment	0.034×10^{-3}	0.034×10^{-7}
1	Control	0.032×10^{-3}	0.032×10^{-7}
1	Fuel	0.062×10^{-3}	0.062×10^{-7}
1	Auxiliary	0.017×10^{-3}	0.017×10^{-7}
1	Diesel Generator	0.009×10^{-3}	0.009×10^{-7}
1	Condensate Storage	0.001×10^{-3}	0.001×10^{-7}
1	Main Steam Support	0.006×10^{-3}	0.006×10^{-7}

Table 3.5-6
TURBINE MISSILE STRIKE AND DAMAGE PROBABILITIES
(PER MISSILE FRAGMENT FROM UNIT 2) (Sheet 2 of 2)

I. Turbine Missile Genesis Probability (P_1) 1 x 10^{-4} per Turbine per Year.

II. Missile Damage Probabilities (P_4)

Location Unit	Target Building or Structure	Strike and Damage Probabilities (P_2) x (P_3)	Missile Damage Probabilities (P_4)
3	Containment	0.032 x 10^{-3}	0.032 x 10^{-7}
3	Control	0.023 x 10^{-3}	0.023 x 10^{-7}
3	Fuel	0.031 x 10^{-3}	0.031 x 10^{-7}
3	Auxiliary	0.011 x 10^{-3}	0.011 x 10^{-7}
3	Diesel Generator	0.006 x 10^{-3}	0.006 x 10^{-7}
3	Condensate Storage	0.001 x 10^{-3}	0.001 x 10^{-7}
3	Main Steam Support	0.006 x 10^{-3}	0.006 x 10^{-7}
	Total	0.811 x 10^{-3}	0.811 x 10^{-7}

Table 3.5-7
TURBINE MISSILE STRIKE AND DAMAGE PROBABILITIES
(PER MISSILE FRAGMENT FROM UNIT 3) (Sheet 1 of 2)

I. Turbine Missile Genesis Probability (P_1) 1 x 10^{-4} per Turbine per Year.

II. Missile Damage Probabilities (P_4)

Location Unit	Target Building or Structure	Strike Probability (P_2)	Target Damage Probability (P_3)	Strike and Damage Probabilities (P_2) x (P_3)	Missile Damage Probabilities (P_4)
3	Containment	0.064 x 10^{-3}	0.374	0.024 x 10^{-3}	0.024 x 10^{-7}
3	Control	0.255 x 10^{-3}	0.804	0.205 x 10^{-3}	0.205 x 10^{-7}
3	Fuel	0.104 x 10^{-3}	0.996	0.104 x 10^{-3}	0.104 x 10^{-7}
3	Auxiliary	0.066 x 10^{-3}	0.861	0.057 x 10^{-3}	0.057 x 10^{-7}
3	Diesel Generator	0.074 x 10^{-3}	0.985	0.073 x 10^{-3}	0.073 x 10^{-7}
3	Condensate Storage	0.136 x 10^{-3}	0.066	0.009 x 10^{-3}	0.009 x 10^{-7}
3	Main Steam Support	0.088 x 10^{-3}	0.777	0.068 x 10^{-3}	0.068 x 10^{-7}
2	Containment	0.064 x 10^{-3}	0.535	0.034 x 10^{-3}	0.034 x 10^{-7}
2	Control	0.034 x 10^{-3}	0.943	0.032 x 10^{-3}	0.032 x 10^{-7}
2	Fuel	0.065 x 10^{-3}	0.949	0.062 x 10^{-3}	0.062 x 10^{-7}
2	Auxiliary	0.017 x 10^{-3}	0.994	0.017 x 10^{-3}	0.017 x 10^{-7}
2	Diesel Generator	0.009 x 10^{-3}	0.988	0.009 x 10^{-3}	0.009 x 10^{-7}
2	Condensate Storage	0.009 x 10^{-3}	0.117	0.001 x 10^{-3}	0.001 x 10^{-7}
2	Main Steam Support	0.006 x 10^{-3}	0.991	0.006 x 10^{-3}	0.006 x 10^{-7}

Table 3.5-7
TURBINE MISSILE STRIKE AND DAMAGE PROBABILITIES
(PER MISSILE FRAGMENT FROM UNIT 3) (Sheet 2 of 2)

I. Turbine Missile Genesis Probability (P_1) 1 x 10^{-4} per Turbine per Year.

II. Missile Damage Probabilities (P_4)

Location Unit	Target Building or Structure	Strike Probability (P_2)	Target Damage Probability (P_3)	Strike and Damage Probabilities (P_2) x (P_3)	Missile Damage Probabilities (P_4)
1	Containment	0.073 x 10^{-3}	0.490	0.036 x 10^{-3}	0.036 x 10^{-7}
1	Control	0.029 x 10^{-3}	0.986	0.029 x 10^{-3}	0.029 x 10^{-7}
1	Fuel	0.045 x 10^{-3}	0.970	0.044 x 10^{-3}	0.044 x 10^{-7}
1	Auxiliary	0.013 x 10^{-3}	0.993	0.013 x 10^{-3}	0.013 x 10^{-7}
1	Diesel Generator	0.008 x 10^{-3}	0.986	0.008 x 10^{-3}	0.008 x 10^{-7}
1	Condensate Storage	0.011 x 10^{-3}	0.177	0.002 x 10^{-3}	0.002 x 10^{-7}
1	Main Steam Support	0.006 x 10^{-3}	0.987	0.006 x 10^{-3}	0.006 x 10^{-7}
	Total			0.839 x 10^{-3}	0.839 x 10^{-7}

The missiles were considered as striking in all directions. Missiles A, B, C, D, and E were considered at all elevations and missiles F and G at elevations less than 30 feet above all grade levels within 1/2 mile of the facility structures.

A tabulation of structures and missile barriers used for missile protection is provided in subsection 3.5.2.

Tornado missile protection is not provided for the essential spray pond spray nozzles because the probability of loss of the ultimate heat sink safety function has been demonstrated by probabilistic risk assessment (PRA) to be less than a median value of 10^{-7} per reactor year or a mean value of 10^{-6} per reactor year without missile protection (Ref. 5). This PRA utilized the tornado missile spectrum in Standard Review Plan (SRP) Section 3.5.1.4 when considering potential missile sources. Class A through F missiles were averaged into a "standard missile." Class G missiles (automobiles) are excluded from explicit consideration because of the conservatism used in the number of “standard missiles” and the low probability of automobile injection compared to “standard missile” injection.

3.5.1.5 Missiles Generated by Events Near the Site

The potential for accidents in the vicinity of the site was discussed in section 2.2. Considering the distances from potential accident sites to the plant, missiles pose no credible hazard.

Table 3.5-8
TORNADO-GENERATED MISSILES CONSIDERED IN DESIGN OF SAFE SHUTDOWN STRUCTURES

Description	Weight (lbs)	Impact Area (ft^2)	Maximum Velocity (ft/s)	Kinetic Energy (ft-lbs)
(A) A 12-foot wood plank, 4 x 12 inches in cross-section, traveling end on at a speed of 240 mi/h.	200	0.333	352	3.85×10^5
(B) A steel pipe, Schedule 40, 3 inches in diameter by 10 feet long, traveling end on at 120 mi/h.	78	0.063	176	3.75×10^4
(C) A steel rod, 1 inch in diameter, 3 feet long, traveling end on at 180 mi/h.	8	0.005	264	8.66×10^3
(D) A steel pipe, Schedule 40, 6 inches in diameter by 15 feet long, traveling end on at 120 mi/h.	285	0.24	176	1.37×10^5
(E) A steel pipe, Schedule 40, 12 inches in diameter by 15 feet long, traveling end on at 120 mi/h.	743	0.886	176	3.57×10^5
(F) A utility pole, 13-1/2 inches in diameter, 35 feet long, traveling end on at 120 mi/h.	1490	0.994	176	7.17×10^5
(G) An automobile of 4,000 pounds weight, striking the structure at 60 mi/h.	4000	20.0	88	4.81×10^5

3.5.1.6 Aircraft Hazards

Aircraft hazards are discussed in paragraph 2.2.3.1.4.

3.5.2 STRUCTURES, SYSTEMS, AND COMPONENTS TO BE PROTECTED FROM EXTERNALLY-GENERATED MISSILES

3.5.2.1 General

The sources of missiles which, if generated, could affect the safety of the plant are considered in subsection 3.5.1. Safety-related structures and equipment that are protected from these postulated missiles are included in table 3.2-1.

Refer to sections 3A.13, 3A.14, and 3A.18 for additional discussions of missile barriers.

3.5.2.2 Missile Barriers Within Containment

The secondary shield, the primary shield, the refueling cavity walls, the reactor vessel and pressurizer missile shields, the various structural beams, and the operating floor act as missile barriers separating each reactor coolant loop from other protected components and missile sources (engineering drawings 13-P-OOB-002 through -011). These barriers also protect the RCPB in each loop from those identified missiles generated elsewhere in the containment. The containment protects the RCPB from externally generated missiles.

Except for short piping runs in the SIS, which must supply cooling water to the core after a LOCA, and SDC suction line and isolation valve, SI-651, the engineered safety features (ESFs) are located outside the secondary shield. The SIS and

SDC lines which penetrate the secondary shield do so in the vicinity of the loop segment to which they are attached.

A missile shield structure is provided over the control element drive mechanisms to block any identified missiles generated in that location. A barrier, or restraints, is provided to protect against identified missiles that originate in the region where the pressurizer extends above the operating deck.

Barriers or retainers are provided, as required, to prevent missiles generated by the failure of main steam or feedwater components inside the containment from causing loss of integrity to the containment liner, isolation system, or steam system associated with another steam generator, or from causing loss of function to other required systems or components inside the containment in accordance with the missile protection design criteria previously listed in this section.

3.5.2.3 Barriers for Missiles Generated Outside of Plant Structures

The protective structures, shields, components, and barriers designed to provide protection against identified missiles generated outside these structures, shields, and barriers are listed in table 3.5-9. The missile barriers listed were designed for the tornado and accident missiles described in subsection 3.5.1 utilizing the procedures stated in subsection 3.5.3.

3.5.2.4 Missile Barriers Within Plant Structures Other than Containment

Missile barriers or restraints are provided within plant structures outside containment in conformance with the missile protection design criteria discussed in section 3.5. For the pressurized and rotating component failure missiles that originate outside the containment, identified in subsection 3.5.1, the following steps are taken to assure that the missile protection design criteria are met:

A. Missiles were categorized according to the system in which they originate.

Table 3.5-9
MISSILE BARRIERS FOR TORNADO AND ACCIDENT
MISSILES (Sheet 1 of 4)

Protected Systems and Components	Missile Barrier	Concrete Thickness (in.)			Design Concrete Strength (psi)
		Walls	Roof	Floor	
Reactor equipment, reactor coolant system, containment piping and valves, containment electrical, instrumentation, and control systems and containment engineered safety features actuation systems	Containment Structure	44	42		6000
	Containment basemat			126	5000
	Internal structures				
	Primary shield	78			6000
	Secondary shield	48			5000
	Floor at elevation 100			30	5000
	Floor at elevation 120			20	5000
	Floor at elevation 140			36	5000
Control room and protected electrical, instrumentation, control, and ventilation equipment in control building	Control building		16[a]		5000
		21			4000

a. Plus 3-inch metal decking.

b. Plus 4-1/2-inch metal decking.

c. Three-inch thick protective carbon steel plate for 6-inch RWT drain valve(s) (CHV-011 and CHV-1009).

d. Three-inch thick protective carbon steel plate for 6-inch CST drain valve(s) (CT-V009, CT-V055, CT-V056, and CT-V057).

Table 3.5-9
MISSILE BARRIERS FOR TORNADO AND ACCIDENT
MISSILES (Sheet 2 of 4)

Protected Systems and Components	Missile Barrier	Concrete Thickness (in.)			Design Concrete Strength (psi)
		Walls	Roof	Floor	
Safety injection, containment spray, cooling water, ventilation, electrical, instrumentation and control equipment; essential cooling water pumps and pump motors; auxiliary feedwater pumps	Auxiliary building		16[b]		5000
		24			4000
	Floor at elevation 120		15[a]		4000
	Floor at elevation 140		15[a]		4000
Spent fuel pool	Fuel building		16[b]		5000
	Fuel pool walls	60			4000
Diesel generators, diesel generator fuel oil system	Diesel generator building		17[a]		5000
		21			4000
Diesel generator combustion air and ventilation air inlets and exhaust	Diesel generator building		17[a]		5000
		21			4000
Diesel generator fuel lines	Underground	NA	NA	NA	

Table 3.5-9
MISSILE BARRIERS FOR TORNADO AND ACCIDENT
MISSILES (Sheet 3 of 4)

Protected Systems and Components	Missile Barrier	Concrete Thickness (in.) Walls	Roof	Floor	Design Concrete Strength (psi)
Diesel generator fuel storage tank	Underground (10 feet below grade with DG fuel oil storage tank valve box located above it)	NA	NA	NA	
Diesel fuel transfer pumps and pump motors	Underground in DG fuel oil storage tank valve box		16[b]		5000
		16			4000
Main steam line isolation valves	Containment structure wall	44			6000
	Main steam support structure		20		5000
		39			4000
Condensate storage tank	Cylindrical walls		21	NA	5000
Condensate transfer pumps	Condensate Pump House		21	NA	5000
		21			4000
Condensate piping	Condensate Pump House/Underground		21/NA	NA	5000
		21/NA			4000
	Barriers[d]	NA	NA	NA	
Refueling water tank	Cylindrical walls	21	None	NA	5000
Refueling water piping	Underground	NA	NA	NA	
	Barriers[c]	NA	NA	NA	

Table 3.5-9
MISSILE BARRIERS FOR TORNADO AND ACCIDENT
MISSILES (Sheet 4 of 4)

Protected Systems and Components	Missile Barrier	Concrete Thickness (in.)			Design Concrete Strength (psi)
		Walls	Roof	Floor	
Essential spray pond pumps and pump motors	Pond discharge structure	24	24	24	4000
Essential spray pond system piping	Underground	NA	NA	NA	
Outside electric cables for Class 1E system	Underground	NA	NA	NA	

B. The components that must be protected from a missile were identified in accordance with the missile protection design criteria given in section 3.5.

C. The following methods were used as required to prevent a missile from causing loss of function to a protected component:

1. The missile characteristics are determined using the procedures given in subsection 3.5.1.

2. A determination is made as to whether the missile characteristics cause loss of function to protected components utilizing the procedures given in Section 2.0 of BC-TOP-9-A and Section 2.0 of Appendix 3C. Credit is taken for existing structures or components that are positioned between the point of missile origin and the protected component.

3. The trajectory is altered by changing the orientation or position of the missile and/or the position of the protected component if this is feasible.

4. If loss of function of the protected component can occur due to missile damage, either suitable restraints are provided to prevent the missile from leaving its point of origin, or barriers are installed to intercept the missile trajectory.

3.5.2.5 Missile Barrier Features

The layout and principal design features of structures serving primarily as missile-resistant barriers are shown in figures 3.5-4 through 3.5-7. Areas housing equipment, systems, and components that are required for a safe shutdown of the plant are considered targets. The target barrier is a slab (roof) over the target area that must be perforated before the target area can be struck.

3.5.3 BARRIER DESIGN PROCEDURES

Missile-resistant barriers and structures were designed to withstand and absorb missile impact loads without being perforated in order to prevent damage to protected components. The procedures employed in design of missile-resistant barriers are described in BC-TOP-9-A and appendix 3C.

3.5.4 NSSS INTERFACE

3.5.4.1 CESSAR Missile Barrier Design Interface Requirements

The following interface requirements are repeated from CESSAR Section 3.5.3.1:

1. For systems and parts of systems located inside containment (reactor coolant system and connecting systems, engineered safety features systems), appropriate missile barrier design procedures shall be used to insure that the impact of any potential missile shall not lead to a loss of coolant accident or preclude systems from carrying out their specified safety functions.

2. For systems and equipment outside containment, listed in Section 3.5.1, appropriate design procedures (for example, proper turbine orientation, natural separation, or missile barriers) shall be used to ensure that the impact of any potential missile does not prevent the system or equipment from carrying out its specified safety functions.

3. For all systems and equipment, appropriate design procedures shall be used to ensure that the impact of any potential missile does not prevent the conduct of a safe plant shutdown, or prevent the plant from remaining in a safe shutdown condition.

3.5.4.2 CESSAR Interface Evaluation

The CESSAR interface requirements set forth in paragraph 3.5.4.1 are satisfied in the FSAR sections and paragraphs indicated below for the corresponding requirements:

A. Paragraphs 3.5.1.1 and 3.5.1.2

B. Paragraphs 3.5.1.2 and 3.5.1.3

C. Section 3.5, listings A, B, C, and D.

3.5.5 REFERENCES

1. Kilsby, Jr., E. R., "Reactor Primary - Piping-System Rupture Studies," Nuclear Safety, Vol 7 (Winter 1965-1966) P 185.

2. Downs, J. E., "Hypothetical Turbine Missiles - Probability of Occurrence," General Electric Company Memo Report, March 14, 1973. Data cited applies to 43-inch last-stage blading.

3. Downs, J. E., "Hypothetical Turbine Missile Data, 43-inch Last Stage Bucket Units", General Electric Memo Report, March 15, 1973.

4. Kennedy, R. P., A Review of Procedures for Analysis and Design of Concrete Structures to Resist Missile Impact Effects, Nuclear Engineering and Design, 1976.

5. Study 13-NS-A106, Rev. 000, Probabilistic Risk Assessment of Tornado Missile Damage to the Station Ultimate Heat Sink, August 23, 2011.

6. GE Turbine Missile Analysis Statement For The LP Monoblock Rotors. GE letter to APS, March 25, 2002, SDR Log 13-M400-0303-01057.

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3.6 PROTECTION AGAINST DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

This section describes the design bases and protective measures that are used to ensure that the containment, essential equipment, and other essential structures are adequately protected from dynamic effects associated with the postulated rupture of high and moderate energy piping. The pipe failure protection criteria conform to 10CFR50, Appendix A, General Design Criterion 4, Environmental and Missile Design Bases. Protection against pipe failure effects is provided to fulfill the following system protection criteria:

A. Preserve the ability to safely shut down the reactor and maintain it in a safe shutdown condition.

B. Maintain the containment fission product barrier in the event of a loss-of-coolant accident (LOCA) or main steam line break within the containment.

C. A pipe break occurring in lines other than the reactor coolant system, main steam, or main feedwater lines must not cause a consequential pipe break in a reactor coolant, main steam, or main feedwater line.

D. A pipe break in the reactor coolant system hot leg must not cause a consequential pipe break in the cold leg, or vice versa, excluding the loss of an instrument line.

E. A steam or feedwater line break in one steam generator system must not cause a steam or feedwater line break in the other steam generator system.

F. Resultant offsite radiological doses must be below the limits of 10CFR100.

Structures, systems, and components, which provide protection of essential equipment and structures from the dynamic effects associated with the postulated rupture of high and moderate energy piping, shall be classified as quality related and applicable quality assurance requirements shall be applied.

3.6.1 POSTULATED PIPING FAILURES IN FLUID SYSTEMS

This section sets forth the design bases, description, and safety evaluation for determining the effects of postulated piping failures in fluid systems both inside and outside containment.

3.6.1.1 Design Bases

Systems or components important to plant safety or shutdown (hereinafter called essential systems) are listed in paragraph 3.6.1.2. The criteria for determining the location of the break are given in paragraph 3.6.2.1 and the general design features used to protect essential systems are discussed in paragraph 3.6.1.3. For additional discussion, refer to sections 3A.19 and 3A.20.

3.6.1.2 Description

A listing of the high energy lines inside the containment is given in table 3.6-1. A listing of high energy lines outside the containment is given in table 3.6-2. Since the turbine and

radwaste buildings contain no safety-related equipment, high energy line breaks in those buildings are generally excluded from this table.

Essential systems are those systems that are needed to safely shut down the reactor or mitigate the consequences of pipe break for a given postulated piping failure. However, depending upon the type and location of a postulated pipe break, certain safety equipment may not be classified as essential for that particular event (e.g., the containment spray chemical addition system is not required to mitigate the consequences of a break in high energy, secondary side, pressure boundary piping).

The essential systems which are to be protected from the effects of postulated piping failures are identified below. These essential systems were selected for each postulated break to satisfy the protection criteria given in the introduction to section 3.6.

A. The following systems, or portions of these systems, are required to mitigate the consequences of postulated breaks of high energy reactor coolant pressure boundary piping that will result in a LOCA assuming a loss of offsite power:

   1. Reactor protective system

   2. Engineered safety features actuation system

   3. Safety injection system (HPSI and LPSI, including hot leg injection lines and refueling water tank)

Table 3.6-1

HIGH ENERGY LINES[a] WITHIN CONTAINMENT (Sheet 1 of 9)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure Number/P&ID Reference	Size (in.)	Comments
Main Steam						
SG-033	From S/G No. 1	Yes	Yes	3.6-6/ 13-M-SGP-002	28	
SG-036	From S/G No. 1	Yes	Yes	3.6-6/ 13-M-SGP-002	28	
SG-042	From S/G No. 1	Yes	Yes	3.6-7/ 13-M-SGP-002	28	
SG-045	From S/G No. 2	Yes	Yes	3.6-7/ 13-M-SGP-002	28	
SG-053	S/G No. 1 Blowdown	Yes	Yes	3.6-4/ 13-M-SGP-002	6	
SG-039	S/G No. 1 Blowdown	Yes	Yes	3.6-4/ 13-M-SGP-002	6	
SG-522	S/G No. 1 Downcomer Blowdown	Yes	Yes	3.6-4/ 02-M-SGP-002 01-M-SGP-002	4[b]	
SG-052	S/G No. 2 Blowdown	Yes	Yes	3.6-5/ 13-M-SGP-002	6	
SG-048	S/G No. 2 Blowdown	Yes	Yes	3.6-5/ 13-M-SGP-002	6	
SG-523	S/G No. 2 Downcomer Blowdown	Yes	Yes	3.6-5/ 02-M-SGP-002 01-M-SGP-002	4[b]	

a. Greater than 1-inch diameter (per BTP 3-1 and BTP ASB 3-1)
b. Unit 2 only is 6”

Table 3.6-1

HIGH ENERGY LINES[(a)] WITHIN CONTAINMENT (Sheet 2 of 9)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure Number/P&ID Reference	Size (in.)	Comments
Feedwater						
SG-005	To S/G No. 2	Yes	Yes	3.6-3/ 13-M-SGP-002	14/16/24	
SG-014	To S/G No. 2	Yes	Yes	3.6-3/ 13-M-SGP-002	14/16	
SG-011	To S/G No. 2	Yes	Yes	3.6-9/	6/8	
SG-519	To S/G No. 2	Yes	Yes	3.6-9/ 02-M-SGP-002 01-M-SGP-002	4	
SG-002	To S/G No. 1	Yes	Yes	3.6-2/ 13-M-SGP-002	14/16/24	
SG-013	To S/G No. 1	Yes	Yes	3.6-2/ 13-M-SGP-002	14/16	
SG-008	To S/G No. 1	Yes	Yes	3.6-8 13-M-SGP-002	6/8	
SG-518	To S/G No. 1	Yes	Yes	3.6-9/ 02-M-SGP-002 01-M-SGP-002	4	
Reactor Coolant						
RC-032	Loop 1 Hot Leg	Yes	Yes	3.6-10/ 13-M-RCP-001	42	Covered in CESSAR
RC-031	Loop 1B Pump Disch	Yes	Yes	3.6-10/ 13-M-RCP-001	30	Covered in CESSAR

Table 3.6-1

HIGH ENERGY LINES[a] WITHIN CONTAINMENT (Sheet 3 of 9)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure Number/P&ID Reference	Size (in.)	Comments
Reactor Coolant (continued)						
RC-034	Loop 1A Pump Disch	Yes	Yes	3.6-10/ 13-M-RCP-001	30	Covered in CESSAR
RC-030	Loop 1B Pump Suct	Yes	Yes	3.6-10/ 13-M-RCP-001	30	Covered in CESSAR
RC-033	Loop 1A Pump Suct	Yes	Yes	3.6-10/ 13-M-RCP-001	30	Covered in CESSAR
RC-063	Loop 2 Hot Leg	Yes	Yes	3.6-10/ 13-M-RCP-001	42	Covered in CESSAR
RC-079	Loop 2 Pump Disch	Yes	Yes	3.6-10/ 13-M-RCP-001	30	Covered in CESSAR
RC-093	Loop 2 Pump Disch	Yes	Yes	3.6-10/ 13-M-RCP-001	30	Covered in CESSAR
RC-073	Loop 2 Pump Suct	Yes	Yes	3.6-10/ 13-M-RCP-001	30	Covered in CESSAR
RC-084	Loop 2 Pump Suct	Yes	Yes	3.6-10/ 13-M-RCP-001	30	Covered in CESSAR
RC-062	Pressurizer Spray	Yes	Yes	3.6-11/ 13-M-RCP-001	3	

Table 3.6-1

HIGH ENERGY LINES[a] WITHIN CONTAINMENT (Sheet 4 of 9)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure Number/P&ID Reference	Size (in.)	Comments
Reactor Coolant (continued)						
RC-016	Pressurizer Spray	Yes	Yes	3.6-11/ 13-M-RCP-001	3	
RC-017	Pressurizer Spray	Yes	Yes	3.6-11/ 13-M-RCP-001	3	
RC-018	Pressurizer Spray	Yes	Yes	3.6-11/ 13-M-RCP-001	3	
RC-028	Pressurizer Surge	Yes	Yes	3.6-13/ 13-M-RCP-001	12	
RC-001	Pressurizer Reliefs	Yes	Yes	3.6-12/ 13-M-RCP-001	6	
RC-003	Pressurizer Reliefs	Yes	Yes	3.6-12/ 13-M-RCP-001	6	
RC-005	Pressurizer Reliefs	Yes	Yes	3.6-12 13-M-RCP-001	6	
RC-007	Pressurizer Reliefs	Yes	Yes	3.6-12/ 13-M-RCP-001	6	
RC-058	Loop 1B Drain	Yes	Yes	3.6-22/ 13-M-RCP-001	2	

Table 3.6-1

HIGH ENERGY LINES[a] WITHIN CONTAINMENT (Sheet 5 of 9)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure Number/P&ID) Reference	Size (in.)	Comments
Reactor Coolant (continued)						
RC-060	Loop 1A Drain	Yes	Yes	3.6-22/ 13-M-RCP-001	2	
RC-051	Loop 1 Shutdown Cooling	Yes	Yes	3.6-14/ 13-M-RCP-001	16	
RC-070	Loop 1 Shutdown Cooling Drain (b)	Yes	Yes	3.6-14/ 13-M-RCP-001	2	
RC-068	Loop 2 Shutdown Cooling	Yes	Yes	3.6-15/ 13-M-RCP-001	16	
RC-089	Loop 2B Drain	Yes	Yes	3.6-22/ 13-M-RCP-001	2	
RC-091	Loop 2B Letdown	Yes	Yes	3.6-22/ 13-M-RCP-001	2	
RC-096	Loop 2A Drain	Yes	Yes	3.6-22/ 13-M-RCP-001	2	

b. This drain line has been cut and capped. Table entry is still valid for remnant (stub).

Table 3.6-1

HIGH ENERGY LINES[a] WITHIN CONTAINMENT (Sheet 6 of 9)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure Number/P&ID) Reference	Size (in.)	Comments
Chemical & Volume Control						
CH-001	Loop 2B Letdown	Yes	Yes	3.6-21/ 13-M-CHP-001	2	
CH-002	Loop 2B Reg HX	Yes	Yes	3.6-21/ 13-M-CHP-001	2	
CH-008	Aux Spray	Yes	Yes	3.6-23/ 13-M-CHP-001	2	
CH-009	Aux Spray	Yes	Yes	3.6-23/ 13-M-CHP-001	2	
CH-003	To Regen HX	Yes	No	3.6-27/ 13-M-CHP-001	3	
CH-004	To Loop 2A	Yes	Yes	3.6-27/ 13-M-CHP-001	3	
CH-005	To Loop 2A	Yes	Yes	3.6-27/ 13-M-CHP-001	3	
Safety Injection						
SI-207	To Loop 1A	Yes	No	3.6-16/ 13-M-SIP-002	14	

Table 3.6-1

HIGH ENERGY LINES[a] WITHIN CONTAINMENT (Sheet 7 of 9)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure Number/P&ID) Reference	Size (in.)	Comments
Safety Injection (continued)						
SI-206	To Loop 1A	Yes	No	3.6-16/ 13-M-SIP-002	14	
SI-203	To Loop 1A	Yes	No	3.6-16/ 13-M-SIP-002	12	
SI-223	To Loop 1B	Yes	No	3.6-17/ 13-M-SIP-002	14	
SI-222	To Loop 1B	Yes	No	3.6-17/ 13-M-SIP-002	14	
SI-221	To Loop 1B	Yes	No	3.6-17/ 13-M-SIP-002	12	
SI-160	To Loop 2A	Yes	No	3.6-18/ 13-M-SIP-002	14	
SI-159	To Loop 2A	Yes	No	3.6-18/ 13-M-SIP-002	14	
SI-156	To Loop 2A	Yes	No	3.6-18/ 13-M-SIP-002	12	

Table 3.6-1

HIGH ENERGY LINES[a] WITHIN CONTAINMENT (Sheet 8 of 9)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure Number/P&ID) Reference	Size (in.)	Comments
Safety Injection (continued)						
SI-179	To Loop 2B	Yes	No	3.6-19/ 13-M-SIP-002	14	
SI-178	To Loop 2B	Yes	No	3.6-19/ 13-M-SIP-002	14	
SI-175	To Loop 2B	Yes	No	3.6-19/ 13-M-SIP-002	12	
SI-240	Loop 1 Shutdown Cooling	Yes	Yes	3.6-14/ 13-M-SIP-002	16	
SI-248	Loop 1 Shutdown Cooling	Yes	Yes	3.6-14/ 13-M-SIP-002	3	
SI-193	Loop 2 Shutdown Cooling	Yes	Yes	3.6-15/ 13-M-SIP-002	16	
SI-199	Loop 2 Shutdown Cooling	Yes	Yes	3.6-15/ 13-M-SIP-002	3	

Table 3.6-1

HIGH ENERGY LINES[a] WITHIN CONTAINMENT (Sheet 9 of 9)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure Number/P&ID) Reference	Size (in.)	Comments
Safety Injection (continued)						
SI-303	SI Tank Drain 1B	Yes	No	3.6-17/ 13-M-SIP-002	2	Pressurized by Nitrogen
SI-304	SI Tank Drain 1A	Yes	No	3.6-16/ 13-M-SIP-002	2	Pressurized by Nitrogen
SI-305	SI Tank Drain 2B	Yes	No	3.6-19/ 13-M-SIP-002	2	Pressurized by Nitrogen
SI-306	SI Tank Drain 2A	Yes	No	3.6-18/ 13-M-SIP-002	2	Pressurized by Nitrogen

Table 3.6-2

HIGH ENERGY LINES[a] OUTSIDE CONTAINMENT
(Sheet 1 of 7)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure/P&ID	Size (in.)	Building	Comments
Main Steam							
SG-095	MSIV Bypass	Yes	Yes	3.6-20/13-M-SGP-001	4	MSSS	(b)
SG-100	MSIV Bypass	Yes	Yes	3.6-20/13-M-SGP-001	4	MSSS	(b)
SG-059	Steam Dump	Yes	Yes	3.6-20/13-M-SGP-001	12	MSSS	(c)
SG-070	Steam Dump	Yes	Yes	3.6-20/13-M-SGP-001	12	MSSS	(c)
SG-084	Steam Dump	Yes	Yes	3.6-20/13-M-SGP-001	12	MSSS	(c)
SG-103	Steam Dump	Yes	Yes	3.6-20/13-M-SGP-001	12	MSSS	(c)
SG-206	From SG-033	Yes	Yes	3.6-20/13-M-SGP-001	28	MSSS	
SG-065	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-066	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-067	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-068	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-069	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-207	From SG-036	Yes	Yes	3.6-20/13-M-SGP-001	28	MSSS	
SG-076	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)

a. Greater than 1-inch diameter (per BTP MEB 3-1 and BTP ASB 3-1).
b. No pipe breaks between isolation valves.
c. No break zone; high energy only up to dump valve.
d. No break zone; high energy only up to relief valve.

Table 3.6-2

HIGH ENERGY LINES[a] OUTSIDE CONTAINMENT
(Sheet 2 of 7)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure/P&ID	Size (in.)	Building	Comments
Main Steam (continued)							
SG-077	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-078	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-079	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-080	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-208	From SG-042	Yes	Yes	3.6-20/13-M-SGP-001	28	MSSS	
SG-090	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-091	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-092	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-093	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-094	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-209	From SG-045	Yes	Yes	3.6-20/13-M-SGP-001	28	MSSS	
SG-109	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-110	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-111	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-112	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)
SG-113	Safety Relief	Yes	Yes	3.6-20/13-M-SGP-001	24	MSSS	(d)

Table 3.6-2

HIGH ENERGY LINES[(a)] OUTSIDE CONTAINMENT
(Sheet 3 of 7)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure/P&ID	Size (in.)	Building	Comments
Main Steam (continued)							
SG-041	S/G No. 1 Blowdown	Yes	Yes	3.6-29/13-M-SGP-002	6	MSSS/ Turbine	
SG-050	S/G No. 2 Blowdown	Yes	Yes	3.6-29/13-M-SGP-002	6	MSSS/ Turbine	
SG-035	To Turbine	Yes	Yes	3.6-28/13-M-SGP-001	28	Turbine	
SG-038	To Turbine	Yes	Yes	3.6-28/13-M-SGP-001	28	Turbine	
SG-044	To Turbine	Yes	Yes	3.6-28/13-M-SGP-001	28	Turbine	
SG-047	To Turbine	Yes	Yes	3.6-28/13-M-SGP-001	28	Turbine	
Feedwater							
SG-004	S/G No. 2 Main Feed	Yes	Yes	3.6-30/13-M-SGP-002	24	Turbine	
SG-010	Downcomer Feed	Yes	Yes	3.6-30/13-M-SGP-002	8	Turbine	
SG-149	S/G No. 2 Aux Feed	Yes	Yes	3.6-30/13-M-SGP-002	6	Turbine	
SG-001	S/G No. 1 Main Feed	Yes	Yes	3.6-30/13-M-SGP-002	24	Turbine	
SG-007	Downcomer Feed	Yes	Yes	3.6-30/13-M-SGP-002	8	Turbine	
SG-147	S/G No. 1 Aux Feed	Yes	Yes	3.6-30/13-M-SGP-002	6	Turbine	
AF-024	Aux Feed	Yes	No	3.6-30/13-M-AFP-001	6	Turbine	
AF-025	Aux Feed	Yes	No	3.6-30/13-M-AFP-001	6	Turbine	

Table 3.6-2

HIGH ENERGY LINES[a] OUTSIDE CONTAINMENT
(Sheet 4 of 7)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure/P&ID	Size (in.)	Building	Comments
Safety Injection							
SI-A-009	Supply to Cont Spray Pump A	Yes	Yes	3.6-26/13-M-SIP-001	18/14	AUX	(e)
SI-A-307	Supply to L.P. SI Pump A	Yes	Yes	3.6-26/13-M-SIP-001	24/20/14	AUX	(e)
SI-A-087	From L.P. SI Pump A	Yes	Yes	3.6-26/13-M-SIP-001	10	AUX	(e)
SI-A-078	To S/D HX	Yes	Yes	3.6-26/13-M-SIP-001	10/20	AUX	(e)
SI-A-070	From S/D HX	Yes	Yes	3.6-26/13-M-SIP-001	20/12	AUX	(e)
SI-A-202	Cont Penetration	Yes	Yes	3.6-26/13-M-SIP-002	12	AUX	(e)
SI-A-079	From Cont Spray Pump A	Yes	Yes	3.6-26/13-M-SIP-001	10	AUX	(e)
SI-A-089	To Spray Header No. 1	Yes	Yes	3.6-26/13-M-SIP-001	10	AUX	(e)
SI-A-082	From Cont Spray Pump A	Yes	No	3.6-26/13-M-SIP-001	10	AUX	(e)
SI-A-088	Cont Penetration	Yes	No	3.6-26/13-M-SIP-002	10	AUX	(e)
SI-A-071	To RC Loop 1B	Yes	Yes	3.6-26/13-M-SIP-001	12	AUX	(e)
SI-A-220	Cont Penetration	Yes	Yes	3.6-26/13-M-SIP-002	12	AUX	(e)
SI-B-033	Supply to Cont Spray Pump B	Yes	Yes	3.6-26/13-M-SIP-001	18/14	AUX	(e)

e. Operates at high pressure <2% of time—considered moderate energy line.

Table 3.6-2

HIGH ENERGY LINES(a) OUTSIDE CONTAINMENT
(Sheet 5 of 7)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure/P&ID	Size (in.)	Building	Comments
Safety Injection (continued)							
SI-B-308	Supply to L.P. SI Pump B	Yes	Yes	3.6-26/13-M-SIP-001	24/20/14	AUX	(e)
SI-B-129	From L.P. SI Pump B	Yes	Yes	3.6-26/13-M-SIP-001	10	AUX	(e)
SI-B-123	To S/D HX	Yes	Yes	3.6-26/13-M-SIP-001	10/20	AUX	(e)
SI-B-072	From S/D HX	Yes	Yes	3.6-26/13-M-SIP-001	20/12	AUX	(e)
SI-B-155	Cont Penetration	Yes	Yes	3.6-26/13-M-SIP-002	12	AUX	(e)
SI-B-119	From Cont Spray Pump B	Yes	Yes	3.6-26/13-M-SIP-001	10	AUX	(e)
SI-B-134	To Spray Header No. 2	Yes	Yes	3.6-26/13-M-SIP-001	10	AUX	(e)
SI-B-147	From Cont Spray Pump B	Yes	No	3.6-26/13-M-SIP-001	10	AUX	(e)
SI-B-130	Cont Penetration	Yes	No	3.6-26/13-M-SIP-002	10	AUX	(e)
SI-B-073	To RC Loop 2B	Yes	Yes	3.6-26/13-M-SIP-001	12	AUX	(e)
SI-B-174	Cont Penetration	Yes	Yes	3.6-26/13-M-SIP-002	12	AUX	
Chemical and Volume Control							
CH-E-254	To Regen HX	Yes	No	13-M-CHP-002	2	AUX	
CH-E-256	To HPSI Header	Yes	No	13-M-CHP-002	2	AUX	
CH-E-255	To HPSI Header	Yes	No	13-M-CHP-002	2	AUX	

Table 3.6-2

HIGH ENERGY LINES[(a)] OUTSIDE CONTAINMENT
(Sheet 6 of 7)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure/P&ID	Size (in.)	Building	Comments
Chemical and Volume Control (continued)							
CH-A-258	Chg. Pump No. 1	Yes	No	13-M-CHP-002	2	AUX	
CH-B-259	Chg. Pump No. 2	Yes	No	13-M-CHP-002	2	AUX	
CH-E-260	Chg. Pump No. 3	Yes	No	13-M-CHP-002	2	AUX	
CH-E-516	Seal Injection Heat Exchanger	Yes	No	13-M-CHP-001	1-1/2	AUX	
CH-E-003	To Regen HX	Yes	No	13-M-CHP-002	2/3	AUX	
CH-N-027	Letdown Heat Exchanger	Yes	Yes	3.6-32/13-M-CHP-001	2	AUX	
CH-N-028	Letdown Heat Exchanger	Yes	Yes	3.6-32/13-M-CHP-001	2	AUX	
CH-N-029	Letdown Heat Exchanger	Yes	Yes	3.6-32/13-M-CHP-001	2	AUX	
CH-N-030	Letdown Heat Exchanger	Yes	Yes	3.6-32/13-M-CHP-001	2	AUX	
CH-N-036	Letdown Heat Exchanger	Yes	No	3.6-32/13-M-CHP-001	3	AUX	
CH-N-037	To Relief	Yes	Yes	3.6-32/13-M-CHP-001	2	AUX	
CH-N-039	Backflush Filter	Yes	No	13-M-CHP-001	2	AUX	

Table 3.6-2

HIGH ENERGY LINES[(a)] OUTSIDE CONTAINMENT
(Sheet 7 of 7)

Line Number	Line Function	Operating Pressure (>275 psig)	Operating Temperature (>200F)	Figure/P&ID	Size (in.)	Building	Comments
Auxiliary Steam in Auxiliary Building							
AS-N-013	Gas Stripper	No	Yes	3.6-31/13-M-ASP-001	6	AUX	
AS-N-013	Gas Stripper	No	Yes	3.6-31/13-M-ASP-001	10	AUX	
AS-N-014	LRS Evaporator	No	Yes	3.6-31/13-M-ASP-001	8	AUX	
AS-N-021	Cond. Rec. Tank	No	Yes	3.6-31/13-M-ASP-001	6	AUX	
AS-N-025	Gas Stripper Stm.	No	Yes	3.6-31/13-M-ASP-001	3	AUX	
AS-N-032	AS Cond. Tfr. Pumps	No	Yes	3.6-31/13-M-ASP-001	3	AUX	
AS-N-035	AS Cond. Tfr. Pumps	No	Yes	3.6-31/13-M-ASP-001	3	AUX	
AS-N-081	Auxiliary Bldg. Vent	No	Yes	3.6-31/13-M-ASP-001	3	AUX	
AS-N-117	AS Cond. Receiver	No	Yes	3.6-31/13-M-ASP-001	2	AUX	
AS-N-118	Seal Inj. H. Exch	No	Yes	3.6-31/13-M-ASP-001	4	AUX	
AS-N-119	AS Cond. Receiver	No	Yes	3.6-31/13-M-ASP-001	3	AUX	
AS-N-119	AS Cond. Receiver	No	Yes	3.6-31/13-M-ASP-001	4	AUX	
CH-N-596	Cond. Return	No	Yes	3.6-31/13-M-CHP-001	2	AUX	
Auxiliary Feedwater in Auxiliary Building							
AF-N-103	AF Turbine Exh. Stack Drain	No	Yes	3.6-33/13-M-AFP-001	3	AUX	(f)
AF-N-105	Drain Pot to Floor Drain	No	Yes	3.6-33/13-M-AFP-001	3	AUX	(f)

(f) Conservatively evaluated for breaks even though the lines are exempt per UFSAR 3.6.2.1.1.1.

4. Containment spray system
5. Auxiliary feedwater system (including safety-related condensate transfer and storage system and condensate storage tank)
6. Class 1E electrical systems, ac and dc (including switchgear, batteries, and distribution systems)
7. Diesel generator system, including diesel generator starting, lubrication, and combustion air intake and exhaust systems
8. Diesel fuel oil storage and transfer system
9. Hydrogen recombiner systems
10. Control building HVAC system
11. Essential cooling water system (portions required for operation of other listed systems)
12. Essential spray pond system
13. Fuel building HVAC system
14. Diesel generator building HVAC system
15. Main control board (see tables 7.3-2 and 7.3-14 for systems required)
16. Containment isolation systems:
    a. Penetration assemblies
    b. Isolation valves
    c. Equipment hatch

d. Emergency personnel hatch

e. Personnel lock

f. Liner plate

g. Test connections

h. Piping between penetration assemblies and isolation valves

17. Excore neutron monitoring system

18. Safety-related radiation monitors (refer to section 11.5)

19. Chemical and volume control systems (piping associated with sampling of the reactor coolant)

20. Shutdown cooling system

21. Essential chilled water system.

B. The following systems, or portions of these systems, are required to mitigate the consequences of postulated breaks in high energy secondary pressure boundary piping (main steam, main feedwater, blowdown, or auxiliary feedwater) assuming a loss of offsite power:

1. Reactor protective system

2. Engineered safety features actuation system

3. Auxiliary feedwater system (including safety-related condensate transfer and storage system and condensate storage tank)

4. Safety injection system (HPSI and LPSI, including refueling water tank)

5. Containment spray system (for breaks inside the containment only)

6. Chemical and volume control system (charging portion including boric acid makeup pumps, charging pumps, interconnecting piping, and reactor coolant sampling portion)

7. Main steam and feedwater system (from unaffected steam generator out to the containment isolation valves, including the atmospheric steam dump, steam supply to the turbine-driven auxiliary feedwater pump, and the steam generator blowdown line)

8. Shutdown cooling system

9. Class 1E electrical systems, ac and dc (including switchgear, batteries, and distribution systems)

10. Diesel generator system, including diesel generator starting, lubrication, and combustion air intake and exhaust systems

11. Diesel fuel oil storage and transfer system

12. Essential cooling water system (portions required for operation of other listed systems)

13. Essential spray pond system

14. Control building HVAC system

15. Main control board (see tables 7.3-2 and 7.3-14 for systems required)

16. Essential chilled water system

17. Containment isolation systems:

    a. Penetration assemblies

    b. Isolation valves

    c. Equipment hatch

    d. Emergency personnel hatch

    e. Personnel lock

    f. Liner plate

    g. Test connections

    h. Piping between penetration assemblies and isolation valves

18. Fuel building HVAC system

19. Diesel generator building HVAC system.

C. For other postulated breaks not included in items A. and B. above, systems must not be affected such that any break, evaluated on a case-by-case basis, violates the following criteria:

1. The pipe break must not cause a reactor coolant, steam, or feedwater line break.

2. The function of safety systems required to perform protective actions to mitigate the consequences of the postulated break must be maintained.

3. The ability to place the plant in a safe shutdown condition must be maintained.

PVNGS utilized a three-dimensional scale model for design and layout of equipment. A systematic approach of multidiscipline analyses of safety-related and associated systems was initiated to verify compliance with design criteria, interface requirements, and safety design bases. Ongoing reviews of the model identified potential hazards and highlighted susceptibility of essential equipment from common mode failure, as well as provided an independent method of verification of the availability of essential equipment required to mitigate the consequences of postulated accident scenarios. The resolution of comments raised during these reviews resulted in changes to equipment layout, design of pipe whip and jet impingement restraints, upgrading some non-seismic supports to seismic, and the addition of curbs, drains, and other flood mitigation measures. Figures 3.6-2 through 3.6-31 depict the resulting pipe routing.

The potential effects of flooding as a consequence of a pipe break or critical crack were analyzed on a case-by-case basis to ensure that the operability of safety-related equipment would not be impaired.

For areas outside the containment, flooding calculations utilizing the worst case flow from high or moderate energy piping systems provided the basis for sizing the floor drains. Compartmentation as shown in Engineering drawings 13-P-OOB-002 through -006 was utilized to minimize the potential for common safety features to be affected by a hazard-producing event. A table identifying means of protection of safety-related systems from effects of high and moderate energy pipe breaks is provided as table 3.6-3.

An analysis of the potential effects of missiles is discussed in section 3.5.

The design bases for the protection of individual safety-related equipment follows the guidance of BTP ASB 3-1. One of the following methods is utilized (listed in decreasing order of preference):

- Separation of fluid piping systems from essential systems and components
- Enclosure of essential components such that they can withstand effects of postulated piping failure
- Addition of pipe whip restraints and/or jet impingement restraints and barriers
- Addition of active features for automatic isolation of the blowdown from the ruptured pipe

Internal flooding due to high energy pipe breaks and moderate energy pipe cracks was considered (on a room-by-room basis) to

result from a postulated break of the worst case fluid piping within a room, discharging for one-half hour at normal operating temperature and pressure. Only passive means for allowing water to leave the room (i.e., drains whose check valves are inspected under the Pump and Valve Inservice Testing Program and whose valves and piping are covered by the Maintenance Rule, doorways) were considered to mitigate the break effects during that time interval. The maximum flood levels were then calculated. Safety-related equipment was located so as to be unaffected.

Jet impingement due to high energy line break (HELB) was postulated using the Moody expansion model. Where impingement on safety-related equipment was found, operability was assured by damage assessment analysis (e.g., stress analysis of impinged piping systems) or addition of jet impingement restraints/barriers.

The potential environmental effects of steam on essential systems are discussed in section 3.11. In general, because of the protective measures of redundancy and separation between systems and trains, the consequential effect of the transport of steam will not be sufficient to impair the ability of the essential system to shut down the plant and/or mitigate the consequences of the given accident of interest. Environmental parameters due to postulated high and moderate energy breaks are addressed in Appendix A of the Equipment Qualification Program Manual.

Table 3.6-3

METHODS OF PROTECTION OF SAFETY-RELATED SYSTEMS

FROM HIGH AND MODERATE ENERGY LINE BREAKS (Sheet 1 of 6)

System	Separation[(a)]	Floor Drains and Curbs	Jet Impingement (JI) Barriers/Rest[(b)]	Pipe Whip Restraints[(b)]	Other
Reactor coolant (incl PZR spray and surge lines) (RCS)	E	N/A	Yes (SG, SDC)	Yes (SG, SDC)	Plastic analysis on surge line for JI effects.
Steam generating (incl main steam and main feed) (SG)	L,E	Yes (in MSSS)	No (f)	No (f)	No break zone in MSSS (augmented inservice inspection)
Safety injection (SI)	L,E,R	Yes (in aux bldg)	No (Unit 1)	Yes (SDC)[(f)]	Plastic analysis on SI lines for JI effects.
Shutdown cooling (SDC)	L,E,R	Yes (in aux bldg)	Yes (f)(g) (RCS)	Yes (f)(g) (RCS)	Plastic analyses on SDC lines for JI effects.
Containment Spray (CS)	E,R	Yes (in aux bldg)	Yes (SG)	Yes (SG)	

Table 3.6-3

METHODS OF PROTECTION OF SAFETY-RELATED SYSTEMS

FROM HIGH AND MODERATE ENERGY LINE BREAKS (Sheet 2 of 6)

System	Separation[a]	Floor Drains and Curbs	Jet Impingement (JI) Barriers/Rest [b]	Pipe Whip Restraints[b]	Other
Auxiliary feed (AF)	L,E,R	Yes (MSSS)	N/A	N/A	
CVCS (charging) (CH)	R[c]	Yes (in aux bldg)	No	No	
Nuclear sampling (SS)	L,E,R	Yes (in aux bldg)	No	No	
Radiation monitors (PAPA'S only)	L[d]	Yes (in aux bldg)	No	No	
Hydrogen control	L[d]	Yes (in aux bldg)	No	No	

Table 3.6-3

METHODS OF PROTECTION OF SAFETY-RELATED SYSTEMS

FROM HIGH AND MODERATE ENERGY LINE BREAKS (Sheet 3 of 6)

System	Separation[a]	Floor Drains and Curbs	Jet Impingement (JI) Barriers/Rest [b]	Pipe Whip Restraints[b]	Other
Ess cooling water (EW)	L,R	Yes (in aux bldg)	N/A	N/A	
Ess chill water (EC)	L,R	Yes (in aux bldg)	N/A	N/A	
Ess spray pond (ES)	L,R	Yes (in aux bldg)	N/A	N/A	
Control bldg HVAC	L,E,R	Yes	N/A	N/A	
Fuel bldg HVAC	L,E,R	Yes	N/A	N/A	
Diesel gen bldg HVAC	L,E,R	Yes	N/A	N/A	
Diesel gen	L,E,R	Yes	N/A	N/A	

Table 3.6-3

METHODS OF PROTECTION OF SAFETY-RELATED SYSTEMS

FROM HIGH AND MODERATE ENERGY LINE BREAKS (Sheet 4 of 6)

System	Separation[a]	Floor Drains and Curbs	Jet Impingement (JI) Barriers/Rest [b]	Pipe Whip Restraints[b]	Other
Diesel fuel oil and transfer	L,E,R	Yes	N/A	N/A	
Class 1E electrical power	L	Yes (in aux bldg)	Yes (SG, CH, SI, SDC, AS) (f)	N/A	
ESFAS (incl post-accident monitoring)	L	Yes (in aux bldg)	Yes (SG, CH, SI, SDC, AS) (f)	N/A	
Reactor protective	L,E	N/A	N/A	N/A	
Excore monitors	L	N/A	N/A	N/A	
Main control board	L,E,R	Yes	N/A	N/A	

Table 3.6-3

METHODS OF PROTECTION OF SAFETY-RELATED SYSTEMS

FROM HIGH AND MODERATE ENERGY LINE BREAKS (Sheet 5 of 6)

System	Separation[a]	Floor Drains and Curbs	Jet Impingement (JI) Barriers/Rest [b]	Pipe Whip Restraints[b]	Other
Containment isolation					
• Penetration assemblies	L	N/A	N/A	N/A	
• Isloation valves	L	N/A	N/A	N/A	No break zone in MSSS (SG)
• Equipment hatch	L	N/A	N/A	N/A	
• Emergency personnel hatch	L	N/A	N/A	N/A	
• Personnel lock	L	N/A	N/A	N/A	
• Liner plate	L[e]	N/A	Yes (SG)	Yes (SG)	No break zone in MSSS (SG)
• Test connections	L	N/A	N/A	N/A	
• Piping between penetration assy’s and iso-lation valves	L	N/A	N/A	N/A	

Table 3.6-3

METHODS OF PROTECTION OF SAFETY-RELATED SYSTEMS

FROM HIGH AND MODERATE ENERGY LINE BREAKS (Sheet 6 of 6)

Notes:

a. Separation from high or moderate energy break effects is accomplished by the following methods in decreasing order of preference:

   - Layout (L)
   - Enclosure (E)
   - Redundancy (R)

b. Protection is provided from break effects originating in system listed in parentheses.

c. CVCS (charging) is required for nonaccident forced shutdown only. (SI provides reactor inventory for MS line break and LOCA.)

d. Monitors are separated from LOCA-induced jet impingement or pipe whip effects. Not required for any other design basis pipe break scenario.

e. Liner plate is separated from LOCA-induced jet impingement or pipe whip effects and is protected from MSLD whip and impingement effects by restraints or barriers. Not required for any other HELB scenario.

f. Except as noted, the jet impingement and pipe whip restraints constructed to alleviate the effects of an RCS pipe break are no longer required. However, the restraints are not removed.

g. Jet impingement barrier and pipe whip restraint protection are provided for valve SI-656.

The auxiliary steam system contains two redundant air operated isolation valves. These valves will fail closed upon the loss of either instrument air or a site loss of offsite power (LOOP).

The consequences of an unlimited auxiliary steam line HELB located in the auxiliary building, which continues until steady state conditions are reached, have been evaluated. This evaluation is predicated upon the existence of an atmospheric vent path for the steam through the building's HVAC exhaust duct.

It was determined that the resultant auxiliary building pressures from an unlimited HELB accident would not exceed the design pressure loading for the walls. Additionally, the environmental conditions were acceptable from an Equipment Qualification perspective. Therefore, no safe shutdown equipment is subject to failure due to the effects of an auxiliary steam HELB.

Pressure-temperature analyses of the chemical and volume control system (CVCS) letdown line indicated the worst case break resulted in pressure and temperatures that were within the allowable range for structural loading and for safe shutdown equipment environmental qualification, respectively.

No other safety-related structures, outside of the containment and the main steam support structure, enclose high energy lines. Therefore, pressure-temperature analyses of additional structures are not required.

There are no high energy lines in the vicinity of the control room. As such, there are no effects upon the habitability of the control room by pipe break either from pipe whip, jet impingement, or transport of steam. Further discussion on control room habitability systems is provided in section 6.4.

3.6.1.3 Safety Evaluation

By means of design features such as separation, barriers, and pipe whip and jet impingement restraints, all of which are discussed below, the effects of pipe break will not damage essential systems to an extent that would impair their design function nor affect necessary component operability.

Specific design features used for protecting the essential systems listed in paragraph 3.6.1.2 are identified in figures 3.6-1 through 3.6-30.

The ability of specific safety-related systems to withstand a single active failure concurrent with a postulated event is discussed in the failure modes and effects analyses provided in sections 6.2, 6.5, 7.2, 7.3, 8.3, 9.2, and 10.4.

A. Separation

The plant arrangement provides separation to the extent practical between redundant safety systems in order to prevent loss of safety function as a result of hazards different from those for which the system is required to function, as well as for the specific event for which the system is required to be functional.

Separation between redundant safety systems with their related auxiliary supporting features is the basic protective measure.

In general, layout of the facility followed a multistep process to ensure adequate separation.

1. Safety-related systems are located away from most high energy piping.
2. Redundant (e.g., A and B trains) safety systems and subsystems are located in separate compartments.
3. As necessary, specific components are enclosed to maintain the redundancy required for those systems that must function as a consequence of specific piping failure events.

B. Barriers-Shields and Enclosures

In many cases, protection requirements are met through the protection afforded by the walls, floors, columns, abutments, and foundations. Where adequate protection does not already exist due to separation, additional barriers, deflectors, or shields are provided as necessary to meet the functional protection requirements. Where compartments, barriers, and structures are required to provide the necessary protection, they are designed to withstand the combined effects of the postulated failure plus normal operating loads plus operating basis earthquake (OBE) loadings.

C. Piping Restraint Protection

Where adequate protection does not already exist due to separation, barriers, or shields, piping restraints are provided as necessary to meet the functional protection requirements. Restraints are not provided when it can be shown that the pipe break would not cause unacceptable damage to essential systems or components.

Typical pipe whip and jet impingement restraints are shown in figure 3.6-1.

The design criteria for pipe whip restraints are given in paragraph 3.6.2.3.2.

D. Facility Response Analyses

An analysis of postulated pipe break events was performed to identify those safety-related systems and components that provide protective actions required to mitigate, to acceptable limits, the consequences of the postulated pipe break event.

Whenever the separation inherent in the plant design is shown to assure the functional capability of the safety systems required following a postulated pipe break event, no additional protective measures are required for that event, and additional considerations of break type, location, orientation, restraints, and other protective measures are not required. When necessary, additional protective measures are incorporated into the design, as required, to assure the functional

capability of safety systems required following the postulated pipe break event.

In conducting the facility response analyses, the following criteria are utilized to establish the integrity of systems and components necessary for safe reactor shutdown and maintenance of the shutdown condition:

1. Offsite power is assumed to be unavailable if an automatic turbine generator trip or automatic reactor trip is a direct consequence of a postulated piping failure.

2. In addition to the postulated pipe failure and its accompanying effects, a single active component failure is assumed in the systems required to mitigate the consequences of the postulated piping failure.

   The single active component failure is assumed, except as noted in paragraph 3.6.1.3.D.4.

3. Each high or moderate energy fluid system pipe failure is considered separately as a single postulated initial event occurring during normal plant conditions.

4. Where a postulated piping failure is assumed in one of two redundant trains of a dual purpose system that is required to operate during normal plant conditions as well as to shut down the

reactor, single failures that prevent the functioning of the other train or trains of that system are not assumed, provided the system is designed to Seismic Category I standards, is powered from offsite and onsite sources, and is designed, constructed, operated, and inspected to quality assurance, testing, and inservice inspection standards appropriate for nuclear safety class systems.

5. All available systems and components, including non-Seismic Category I and those actuated by operator actions, may be employed to mitigate the consequences of a postulated piping failure. In judging the availability of such systems and components, account is taken of the postulated failure and its direct consequences, such as unit trip and loss of offsite power, and of the assumed single active component failure and its direct consequences. The feasibility of carrying out operator actions is based on a minimum of 30 minutes delay responding to alarm indication and adequate access to equipment being available for the proposed actions. (Access to the containment post-LOCA is not assumed.)

6. Piping systems containing high energy fluids are designed so that the effects of a single postulated pipe break cannot, in turn, cause

failures of other pipes or components with unacceptable consequences.

7. For a postulated pipe failure, the escape of steam, water, and heat from structures enclosing the high energy fluid containing piping does not preclude:

   a. Accessibility to surrounding areas important to the safe control of reactor operations.

   b. Habitability of the control room.

   c. Ability of instrumentation, electric power supplies, and components and controls to initiate, actuate, and complete a safety action. (A loss of redundancy is permissible, but not the loss of function.)

The design criteria define acceptable types of isolation for safety-related elements and for high energy lines from similar elements of the redundant train. Separation is accomplished by:

- Routing the two groups through separate compartments, or
- Physically separating the two groups by a specified minimum distance, or
- Separating the two groups by structural barriers.

The design criteria assure that a postulated failure of a high energy line or a safety-related element cannot take more than one safety-related train out of service. The failure of a component or subsystem of one train may cause failure of another of the same train; for example, a B train high energy pipe may cause failure of a B train electrical tray, but not failure of an A train electrical tray. The capability of shutting the plant down safely under such a failure will, therefore, remain intact.

Given the separation criteria above and the pipe break criteria in paragraph 3.6.2.1.1, the effects of high energy pipe breaks are not analyzed where it is determined that all essential systems, components, and structures are sufficiently physically remote from a postulated break in that piping run.

3.6.2 DETERMINATION OF BREAK LOCATIONS AND DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

This section describes the design bases for locating postulated breaks in high energy piping inside and outside of containment, the procedures used to define the jet thrust reaction at the break location, and the procedures used to define the jet impingement loading on adjacent essential structures, systems, and components.

3.6.2.1 Criteria Used to Define Break and Crack Locations and Configuration

The criteria for postulating break locations in high energy piping are described below.

3.6.2.1.1 High Energy Piping Other Than RCS Main Loop

3.6.2.1.1.1 High Energy Piping. Piping is considered high energy if, during normal plant conditions, it is either in operation or is maintained pressurized under conditions where either (or both) of the following conditions are met:

- Maximum operating temperature exceeds 200F, or
- Maximum operating pressure exceeds 275 psig.

Piping is not considered to be high energy if the piping run or branch run operates for less than 2% of the time that the system qualifies as a moderate energy system (as defined in paragraph 3.6.2.1.2). Also, auxiliary feedwater system leakages, from boundary SG system isolation valves between high and low/moderate energy lines located in rooms C-A09 and C-A10, is allowed as long as the maximum surface temperature of downsteam process piping would not exceed 212 degrees fahrenheit at atmospheric conditions.

3.6.2.1.1.2 Break Locations. In any given piping system, there are a limited number of locations which are more susceptible to failure by virtue of stress or fatigue than the remainder of the system. In determining the rupture locations,

system parameters are based on those associated with specified seismic events and operational plant conditions. The specified seismic event is the OBE; the operational plant conditions include normal reactor operation, upset conditions, and testing conditions. Where required, postulated pipe breaks are selected as described below and are analyzed to demonstrate the capability to place the plant in a safe shutdown condition.

A. ASME Section III, Code Class 1 Piping Within Containment (NRC Generic Letter 87-11 has been implemented)

For ASME Section III, Code Class 1 piping, breaks are postulated to occur at the following locations (i.e., at weld joints where the piping incorporates a fitting, valve, or welded attachment) in each piping run or branch run:

1. The terminal ends

2. At intermediate locations where the following are met:

   a. the stress range S_n exceeds 2.4 S_m, where S_m is the design stress intensity as defined in Section III of the ASME Code, or

   b. the stress range S_n as calculated by Equation 10 of Paragraph NB-3653 exceeds 2.4 S_m and the stresses computed by

Equations 12 and 13 of Paragraph NB-3653 are greater than 2.4 S_m, or

c. If fatigue analysis is performed, any intermediate location between terminal ends where the cumulative usage factor under loading associated with operational plant conditions and an OBE exceed 0.1 of the Code allowable.

In the absence of a Class 1 stress analysis, breaks are conservatively postulated at terminal ends and at all fittings, valves, or welded attachments.

B. ASME Section III, Code Class 2 and 3 Piping Within Containment (NRC Generic Letter 87-11 has been implemented)

For ASME Section III, Code Class 2 and 3 piping, breaks are postulated to occur at the following locations (i.e., at weld joints where the piping incorporates a fitting, valve, or welded attachment) in each piping run or branch run:

1. The terminal ends

2. The maximum stress as calculated by the sum of Equations 9 and 10 in Paragraph NC-3652 of the ASME Code, Section III, considering normal and upset plant conditions (i.e., sustained loads, occasional loads and thermal expansion) including

an OBE event are less than 0.8 (1.2 S_h + S_A), where S_h and S_A are the allowable stress at maximum (hot) temperature and the allowable stress for thermal expansion, respectively, as defined in Article NC-3600 of ASME Code, Section III.

3. If fatigue analysis is performed, any intermediate location between terminal ends where the cumulative usage factor exceeds 0.1 under loading associated with the normal and upset plant condition and an OBE

C. Fluid System Piping Penetrating Containment

Pipe breaks are not postulated in portions of ASME Code, Section III, Class 2 high energy fluid system piping between containment isolation valves or, where no isolation valve is used inside containment, between the first rigid pipe connection to the containment penetration or the first pipe whip restraint inside containment and the outside isolation valve, provided that the piping meets the following requirements:

1. The piping is designed to meet the requirements of NE-1120 of ASME Code, Section III.

2. The maximum stress as calculated by the sum of Equations (9) and (10) in subarticle NC-3600, ASME Code, Section III, considering those loads and conditions thereof for which level A and level B stress limits have been specified in the system’s

Design Specification (i.e., sustained loads, occasional loads, and thermal expansion) including an OBE event should not exceed 0.8 (1.8 S_h + S_A). The S_h and S_A are allowable stresses at maximum (hot) temperature and allowable stress range for thermal expansion, respectively, as defined in subarticle NC-3600 of the ASME Code, Section III.

3. The maximum stress as calculated by Equation (9) in NC-3600 under the loadings resulting from a postulated piping failure of fluid system piping beyond these portions of piping should not exceed the lesser of 2.25 S_h and 1.8 S_y except that following a failure outside containment, the pipe between the outboard isolation valve and the first restraint may be permitted higher stresses provided a plastic hinge is not formed and operability of the valves with such stresses is assured in accordance with the requirements specified in SRP section 3.9.3. This exception may be applied provided that when the piping between the outboard isolation valve and the restraint is constructed in accordance with the Power Piping Code ANSI B31.1 (see ASB 3-1 B.2.c(4)), the piping shall either be of seamless construction with full radiography of all circumferential welds, or all longitudinal and circumferential welds shall be fully radiographed.

Primary loads include those which are deflection limited by whip restraints.

4. Welded attachments to portions of piping or direct welding to the outer surface of the piping for pipe supports or pipe restraint are avoided, except where detailed stress analyses or tests are performed.

5. The number of circumferential or longitudinal welds in piping and branch connections is minimized.

6. The length of the piping run is minimized.

7. The augmented inservice inspection of the circumferential and longitudinal welds will be performed in accordance with section 6.6.

8. Geometric discontinuities such as pipe-to-valve section transitions, branch connections, and changes in pipe wall thicknesses are designed to minimize discontinuity stresses.

9. The piping run beyond the isolation valve outside the containment is restrained such that excessive pipe loads following a postulated pipe break are no transmitted to the isolation valve, which would impair the ability of the valve to perform its required function; or the piping run can be shown to have insufficient energy to cause damage to the isolation valve; or the break can be shown not to

result in unacceptable consequences, as described in the protection criteria of section 3.6.

10. Penetration is designed to withstand loadings resulting from a postulated piping failure inside the containment so that neither isolation valve operability nor, in the case of a main steam line break, the leaktight integrity of the containment is impaired.

Pressure-temperature analyses, assuming a one square foot nonmechanistic break of the main steam and feedwater lines in the MSSS, were performed to establish both the structural and the environmental design parameters for components installed in the MSSS. The original design analysis was performed using the COPDA(2) code and an eleven node model. Updates to this analysis have been performed using the PCFLUD[3] code. Evaluations have been conducted for a core power level of 3990 MWt.

Flow formulations between compartments included ideal gas, incompressible liquid, and Moody two-phase blowdowns. The pressure and temperature profiles obtained were used to establish or evaluate design loadings and environmental parameters for the main steam support structure above ground level.

A revision to the computer code used to calculate MSLB blowdown in the MSSS has been made to better represent

the secondary side. This improved model was applied for the current evaluation of the units. The revised code provides a more detailed modeling of the four main steam lines versus the original analysis which modeled only two main steam lines, the closing of the MSIVs and the steam flow through the main steam line cross header path following the closure of MSIVs. The improved secondary model provides a better representation of the post – MSIS M&E release.

A reduction in some conservative input values selected in the analysis of the original plant configuration and a revised reactor trip methodology have also been implemented. The current analysis evaluates all reasonable reactor trips and identifies the most conservative trip.

A main steam line pipe rupture is neither postulated to occur between the containment penetration and the MSSS wall nor between the double wall (designed as a pipe whip restraint) downstream from the MSIVs.

Inservice inspection requirements of Code Class 2 and 3 components are discussed in section 6.6.

D. High Energy Fluid Systems Outside Containment

1. ASME Code, Section III, Class 2 and 3 Piping

Design basis breaks in ASME Code, Section III, Class 2 and 3 high energy fluid system piping are postulated at the following locations in each

piping and branch run, except those portions of fluid system piping identified in paragraph 3.6.2.1.1.2, listing C:

a. At terminal ends

b. At intermediate locations where combined stresses associated with normal and upset plant conditions and an OBE event calculated by Equations 9 and 10, Paragraph NC-3652 or Paragraph ND-3652 of the ASME Code, Section III, exceed 0.8 (1.2 S_h + S_A) but at not less than two separate locations chosen on the basis of highest stress. In the case of a straight run without any pipe fittings or welded attachments and all stresses below 0.8 (1.2 S_h + S_A), a minimum of one location will be chosen on the basis of highest stress.

   In the absence of a Class 2 or 3 stress analysis, breaks are conservatively postulated at terminal ends and at all fittings, valves, or welded attachments.

2. Nonnuclear Class Piping

   Breaks in nonnuclear class high energy piping are postulated at the following locations in each piping and branch run:

a. At terminal ends of the pressurized portions of the run

b. At each intermediate location where combined stresses, as calculated by Equations 12 and 13, Paragraph 104.8 of ANSI B31.1, Power Piping Code, exceed 0.8 (1.2 S_h + S_A), or at each intermediate pipe fitting and welded attachment if detailed stress analyses are not performed.

Pressure-temperature analyses, assuming a single area break of the auxiliary steam (AS) line, were performed to evaluate the design of the internal structure of the auxiliary building under pipe break.

Version 3.7 of computer program PCFLUD(4) was used with the individual sub-compartments containing AS line considered as nodes.

The pressure and temperature profiles obtained were used for comparison against design loadings and environmental parameters for the auxiliary building both above and below ground level.

For the purpose of the analysis, the AS line rupture was postulated to occur at any single location along the pipe routing.

3.6.2.1.1.3 Type of Breaks in Fluid High Energy System Piping. At locations where breaks are postulated to occur, the following breaks are considered:

A. Full cross-sectional area circumferential breaks with at least one pipe diameter displacement, in piping greater than 1 inch, unless the separation is physically limited by piping restraint, structural members, or piping stiffness, as may be demonstrated by inelastic limit analysis. Circumferential breaks are not postulated at locations where circumferential stress range is at least 1.5 times the axial stress range.

   Circumferential breaks are perpendicular to the pipe axis and the break area is equivalent to the pipe flow area exposed by the separation of the two sections of pipe. Dynamic forces resulting from such breaks are assumed to separate the piping axially and cause the pipe to move in the direction of the thrust force. Pipe whipping is assumed to occur in the plane defined by the piping geometry and configuration, and to cause pipe movement in the direction of the jet reaction.

B. Single cross-sectional area longitudinal breaks in piping 4 inches and greater except at locations where axial stress range is at least 1.5 times the circumferential stress range. Longitudinal breaks are not postulated at:

1. The terminal ends, or

2. Intermediate locations where break locations are selected only to satisfy the minimum number criterion.

Longitudinal breaks are assumed to result in an axial split without pipe severance, causing piping deflections to occur in the direction of the jet reaction unless limited by structural members, piping restraints, or piping stiffness, as demonstrated by inelastic limit analysis. The break area is based on a circular break area equal to the effective cross-sectional flow area of the pipe.

3.6.2.1.2 Moderate Energy Piping

A fluid system is considered moderate energy if, during normal plant conditions, it is either in operation or maintained pressurized under conditions where both of the following are met:

- Maximum operating temperature is 200F or less, and
- Maximum operating pressure is 275 psig or less.

3.6.2.1.2.1 Postulating Criteria. The criteria for postulating break locations in moderate energy piping are described below:

A. Moderate energy fluid system pipe leakage cracks are only postulated if all of the following conditions are met:

   1. The moderate energy fluid system is not adequately separated from essential system active components such that the effects of a postulated leakage crack could impair the operability of such components.

   2. The system or portion of a system sustaining the leakage crack operates during normal plant operational modes 1, 2, and 3 defined in Table 1.1-1 of the Technical Specifications.

   3. The failed line is greater than 1 inch in diameter.

B. Where a postulated leakage crack occurs in one train of a Seismic Category I, dual-purpose, moderate energy piping system, single active component failures are not assumed in the other train (refer to Branch Technical Position APCSB 3-1, B.3.b.3). The postulated leakage crack must not adversely affect active components of both trains.

C. Through-wall leakage cracks are not postulated in portions of ASME Code, Section III, Class 2 moderate energy fluid system piping passing through the containment penetrations and extending to the first outside isolation valves if they meet the requirements

of NE-1120 of ASME Code, Section III, and the combined stresses, as calculated by Equations 9 and 10, Paragraph NC-3652 of the ASME Code, Section III, do not exceed 0.4 (1.2 S_h + S_A).

D. In portions of ASME Code, Section III, Class 2 and 3 piping and nonnuclear piping located within, or outside, and adjacent to protective structures containing safety-related systems or components, through-wall leakage cracks are postulated where combined stresses, as defined previously, exceed 0.4 (1.2 S_h + S_A) except as exempted in paragraph 3.6.2.1.2.1, listings C and E. The cracks are postulated to occur individually at locations that result in the maximum effects from fluid spraying and flooding, and the consequent hazards or environmental conditions developed.

E. Cracks are not postulated in moderate energy fluid system piping located in an area in which a break in high energy fluid system piping is postulated, provided such cracks do not result in more limiting environmental conditions than the high energy piping break. Where a postulated piping leakage crack in the moderate energy fluid system piping results in more limiting environmental conditions than the break in the proximate high energy fluid system piping, the

provisions of paragraph 3.6.2.1.2.1, listing D will be applied.

F. Through-wall leakage cracks instead of breaks are postulated in the piping of those fluid systems that qualify as high energy fluid systems for only short operational periods but qualify as moderate energy fluid systems for the major operational period. An operational period will be considered "short" if the fraction of time that the system operates within the pressure-temperature conditions specified for high energy fluid systems is less than 2% of the time that the system operates as a moderate energy fluid system.

3.6.2.1.2.2 Type of Break in Moderate Energy Piping. Moderate energy leakage cracks are based on an area equal to that of a rectangle one-half pipe diameter in length and one half pipe wall thickness in width.

3.6.2.1.3 Protection Requirements

Measures for protection against pipe whipping as a result of the breaks postulated by the above criteria are not provided for piping where any one of the following applies:

A. The piping is physically separated (or isolated) by protective barriers from any essential safety-related structure, system, or component required to place the plant in a safe shutdown condition following the

postulated rupture or is restrained from whipping by plant design features such as concrete encasement.

B. Following a single break, the unrestrained pipe movement of either end of the ruptured pipe cannot damage, to an unacceptable level, any essential safety-related structure, system, or component required to place the plant in a safe shutdown condition following the postulated rupture.

C. The energy associated with the whipping pipe can be demonstrated to be insufficient to impair, to an unacceptable level, the safety function of any essential structure, system, or component required to place the plant in a safe shutdown condition following the postulated rupture (a whipping pipe is considered insufficient to rupture an impacted pipe of equal or larger nominal pipe size and equal or heavier wall thickness).

For moderate energy systems, design measures are included that provide protection from the effects of the resulting water spray and flooding for each postulated leakage.

3.6.2.1.4 Definition of Operating Plant Conditions

For the purpose of calculating the pipe stresses, the following definitions apply:

A. Normal Plant Conditions are defined in the ASME Boiler and Pressure Vessel Code, Section III, and include

reactor startup, operation at power, hot standby, and reactor cool down to cold shutdown. The operational plant conditions do not include hydrostatic testing (however, the hydrostatic testing condition will be considered in calculating the cumulative usage factor).

B. Upset Plant Conditions are defined in the ASME Boiler and Pressure Vessel Code, Section III, and include transients of moderate frequency, which are anticipated operational occurrences caused by equipment failures, operator errors, and similar occurrences, including the OBE, but not testing conditions.

3.6.2.2 Analytical Methods to Define Forcing Functions and Response Models

The analytical methods used to define forcing functions and the response models used in paragraph 3.6.1.3 are described in the following sections.

3.6.2.2.1 High Energy Piping Other Than RCS Main Loop

Analytical methods for calculation of jet thrust forces, pipe and single restraint motion under jet force, restraint characteristics, and jet impingement forces are described in reference 1.

Jet thrust force is based on the pressure and momentum differences, inside and outside the break, for single or two-phase flow from the break. Methods for calculation of pipe and

restraint dynamic behavior include the effects of pipe-to-restraint gap and elastic and plastic deformation properties, using a simplified conservative model.

3.6.2.3 Dynamic Analysis Methods to Verify Integrity and Operability

3.6.2.3.1 High Energy Piping Other Than RCS Main Loop

The criteria for performing the dynamic analyses in paragraph 3.6.1.3 are:

A. An analysis of the pipe run or branch is performed for each longitudinal and circumferential postulated rupture at the break locations determined in accordance with the criteria of paragraph 3.6.2.1.

B. The loading condition of a pipe run or branch prior to postulated rupture in terms of internal pressure, temperature, and stress state is that condition associated with the normal and upset plant conditions and an OBE.

C. For a circumferential rupture, pipe whip dynamic analyses are only performed for that end (or ends) of the pipe or branch that is connected to a contained fluid energy reservoir having sufficient capacity to develop a jet stream.

D. Dynamic analytical methods used for calculating the piping and piping/restraint system response to the jet

thrust developed after a postulated rupture adequately account for the effects of the following:

1. Elastic and inelastic deformation of piping and/or restraint.

2. Nozzle movement where applicable.

3. On specific systems where plastic analysis is performed:

   a. Translational masses (and rotational masses for major components) and stiffness properties of the piping system, restraint system, major components, and support walls.

   b. Transient forcing function(s) acting on the piping system and jet thrusts on affected structures.

E. An allowable design strain limit of 50% of ultimate uniform strain of the materials of the restraints is used.

F. A 10% increase of minimum specified design yield strength (S_y) is used to account for strain rate effects in inelastic nonlinear analyses.

3.6.2.3.2 Pipe Whip Restraint Design Criteria

3.6.2.3.2.1 High Energy Piping Restraints Other Than RCS Main Loop Piping.

A. Design Bases

The pipe break locations and orientation are determined in accordance with paragraph 3.6.2.1. For each postulated pipe break, the possible effects of the break are investigated and, if necessary (per paragraph 3.6.1.3), restraints are provided to prevent pipe whip. Two types of restraints have been used:

1. Stainless steel U-bar type restraints where energy is absorbed by elasto-plastic elongation of the bars, and

2. Rigid frames with honeycomb material which will absorb energy through crushing.

In addition, there are steel or concrete bumpers which will resist the pipe break reactions in compression. Functional requirements are discussed in listing B below.

B. Functional Requirements

High energy pipe whip restraints are designed to ensure that the pipe whip will be eliminated or minimized. The restraints are designed to permit the predicted thermal and seismic movements of the pipes.

C. Design Parameters

After the pipe restraint locations are identified, the following design parameters are determined:

1. Jet thrust force
2. Pipe seismic displacements
3. Pipe thermal displacements
4. Pipe insulation thickness
5. Maximum allowable pipe travel (if any).

The jet thrust force and maximum allowable pipe travel are used in the analysis process.

Insulation and seismic and thermal movements are used in determining the minimum gap between the restraint and pipe surfaces.

D. Analysis and Design

Analysis of, and design for, postulated pipe break effects are in accordance with reference 1. Specifically, the following criteria are adopted in analysis and design:

1. Restraints are designed based on energy absorption principles by considering the elastic-plastic, strain hardening behavior of the materials used.
2. A rebound factor of 1.1 is applied to the jet thrust force.

3. Except in cases where plastic hinge calculations are performed, the energy absorbed by the ruptured pipe is conservatively assumed to be zero (i.e., the thrust force developed goes directly into moving the broken pipe, and is not reduced by the force required to bend the pipe).

4. In elastic-plastic design, limits for strains are as follows:

   ε = Allowable strain used in design

   a. Stainless steel U bars

      $\varepsilon = 0.5\varepsilon_u$

      where:

      ε_u = ultimate uniform strain of stainless steel (strain at ultimate stress)

   b. Crushable material (honeycomb)

      $\varepsilon = 0.8\ \varepsilon_u$

      where:

      ε_u = maximum crushable height at uniform crushable strength

5. A dynamic increase factor (DIF) of 1.1 is used for steel which is designed to remain elastic.

6. Only one structural element of a restraint has been designed to yield (U-bar or honeycomb). The

remainder of the restraint is designed elastically.

7. In the design of cantilevered compression restraints, lateral supports are provided in two orthogonal directions. These lateral supports are designed for a minimum of 5% of axial load, if the compression member is intended to yield.

E. Materials

The materials used in restraint design are selected to ensure ductile behavior. The components of the restraint which are intended to yield are made of ASTM A479 type 304 or 304L stainless steel or ASTM A36 or ASTM A992 steel. Other components, such as pins, bolts, and anchors, are designed to remain within their elastic limit. The material used for pins is ASTM A193-GR. B7; other components are made of ASTM A516 GR. 70, A36 and A500 GR.B.

3.6.2.4 Guard Pipe Assembly Design Criteria

No guard pipes are used. Any possible pipe whipping is prevented by restraints. Refer to paragraph 3.6.1.3.

3.6.2.5 Material Submitted for the Operating License Review

3.6.2.5.1 RCS Main Loop Piping

Although a summary of the dynamic analyses applicable to the RCS main loop piping and component supports that determine the

loading resulting from postulated RCS pipe breaks is covered in paragraph 3.9.1.4, these analyses are no longer required by 10CFR50, Appendix A, Criterion 4.

3.6.2.5.2 High Energy Piping Other Than RCS Main Loop

This section summarizes the dynamic analyses applicable to high energy piping systems and associated supports that determine the loading resulting from postulated pipe breaks.

A. The implementation of the stress criteria in paragraph 3.6.2.1.1 is shown in figures 3.6-2 through 3.6-30 which provide the location and number of postulated breaks on which the dynamic analyses are based. Analyses performed provide the postulated break orientation, such as the circumferential and/or longitudinal breaks, for each postulated break.

B. The implementation of criteria for inservice inspection is shown in section 6.6. The design of pipe whip restraints is described in paragraph 3.6.2.3.2. Figures 3.6-2 through 3.6-30 provide the location and number of pipe whip restraints required to protect essential systems.

C. The jet thrust and impingement functions and the pipe break analysis are derived from reference 1. The resulting whip and impingement restraints are presented in figures 3.6-2 through 3.6-30.

D. To ensure that their design-intended functions will not be impaired to an unacceptable level of integrity or operability as the result of high energy pipe breaks, essential systems and components are protected by:

   1. Physical separation from high energy systems, or

   2. Enclosing either the high energy systems or the safety-related features in protective structures, or

   3. Where neither 1. nor 2. above is practical, providing pipe restraints or protective barriers to ensure the operability of the safety-related features.

E. Protective assembly design and locations are shown in figures 3.6-2 through 3.6-30. Examination of all process piping welds required by the inservice inspection program can be accomplished without additional access openings.

3.6.2.5.2.1 Elimination of RCS Guillotine Breaks

Based upon the elimination of the double ended guillotine breaks on the RCS main loop piping (refer to GDC 4 response section 3.1.4 as approved under CESSAR SER 3, section 3.6.2), the dynamic effects of these breaks may be removed from the analyses of mechanical components and supports.

3.6.3 REFERENCES

1. "Design for Pipe Break Effects," Bechtel Power Corporation Topical Report - BN-TOP-2, Revision 2, May 1974.

2. "Subcompartment Pressure and Temperature Transient Analysis," Bechtel Power Corporation Topical Report - BN-TOP-4, Revision 1, October 1977.

3. PCFLUD (MAP-120), Version 4.0, "User's Manual," Revision 2, Dated July, 1993.

4. PCFLUD (MAP-120), Version 3.7, "User's Manual," Revision 1, Dated July, 1991.

3.7 SEISMIC DESIGN

Structures, systems, equipment, and components related to plant safety feature systems are required to have the ability to withstand potential earthquakes.

Structures, systems, and components are placed in the applicable seismic category, depending on their function. A two-level system is used for the seismic classification of structures, systems, and components:

- Seismic Category I structures, systems, and components
- Non-Category I structures, systems, and components

A definition of the seismic categories and a listing of those structures, systems, and components included in each category are given in subsection 3.2.1.

The design basis safe shutdown earthquake (SSE) and the operating basis earthquake (OBE) peak ground acceleration values are 0.25g and 0.13g, respectively. These values were chosen to provide additional conservatism beyond the 10CFR100, Appendix A, required values determined in section 2.5

Non-Category I structures and equipment are designed in such a manner that failure would not cause loss of function of Category I structures, systems, or components under SSE conditions.

A complete dynamic analysis for Seismic Category I structures is accomplished by developing mathematical models using a multilumped mass system. Dynamic soil properties and damping

coefficients are determined, and models representing the structures are used to obtain natural frequencies, mode shapes, internal forces, and floor equipment response spectra. The design spectrum or the free-field, time-history motion is used as the input for the models.

The time-history response analysis is used to obtain the in-structure response spectra. These floor response spectra provide the earthquake environment for the design of internal equipment, systems, and components.

3.7.1 SEISMIC INPUT

3.7.1.1 Design Response Spectra

The site design response spectra are provided in figures 3.7-1 and 3.7-2 for the horizontal and vertical components of the SSE and in figures 3.7-3 and 3.7-4 for horizontal and vertical components of the OBE.

The shape of the design spectra is in accordance with Regulatory Guide 1.60 and is discussed in Section 2.5.1(b) of BC-TOP-4-A. Discussion of the effects of earthquake duration, epicentral distance, and amplification is provided in paragraph 2.5.2.6.

3.7.1.2 Design Time-History

A synthetic earthquake time-history is generated because the response spectra of a recorded earthquake motion does not necessarily envelop the site design spectra. A 24-second earthquake duration is used which is comparable to the strong motion duration of the earthquake records used, and is, therefore, considered to be adequate for the time-history type

of analysis of structures and equipment. Comparison between the free-field, time-history response spectra and the design spectra for both horizontal and vertical motions, and the basis for the generation of the synthetic time-history are discussed in Section 2.5 of BC-TOP-4-A. The time-history of the design earthquake is assumed to be the free-field motion at the base of the foundation for each Category I structure.

3.7.1.3 Critical Damping Values

The damping values (percent of critical damping) used for seismic design of Category I structures are listed in table 3.7-1, and are the same as those specified in Regulatory Guide 1.61. Alternative damping values, allowed by ASME Code Case-N-411, may be used for reconciliation of as-built design, for support optimization, and for design of plant systems in accordance with conditions outlined in Regulatory Guide 1.84. Strain-corrected damping values for the foundation materials were developed using the computer program SHAKE[1] and soil properties from field and laboratory test results. The average strain-dependent damping ratios for clay and sand are shown in figures 3.7-5 and 3.7-6, respectively.

Frequency-dependent soil damping values were obtained using the LUCON computer program[2] and the strain-dependent relationships for use in the time-history analysis of lumped-mass models of structure-foundation systems. For the design response spectrum method of analysis, soil damping values for the structure-foundation system were computed using the expressions given in Table 3-2 of BC-TOP-4-A.

Refer to appendix 3A, Question 3A.4, for additional discussion. The applicable allowable design levels are given in section 3.8 for the various loading combinations which include seismic loadings.

Table 3.7-1
DAMPING VALUES (PERCENT OF CRITICAL DAMPING)

Structure or Component	Operating Basis Earthquake	Safe Shutdown Earthquake
Equipment and large-diameter piping system, pipe diameter greater than 12 inches	2	3
Small-diameter piping system, diameter equal to or less than 12 inches	1	2
Welded steel structures	2	4
Bolted steel structures	4	7
Prestressed concrete structures	2	5
Reinforced concrete structures	4	7

3.7.1.4 Supporting Media for Seismic Category I Structures

For purposes of the seismic analysis, the site is assumed to be a multilayer system consisting of soil over bedrock. The approximate depth of soil deposit over bedrock for each unit at the site is as follows:

	Unit 1	Unit 2	Unit 3
Depth of Soil, feet	400	360	310

The upper layers (soil) are relatively uniform, both at each unit and between units. A composite soil profile is formed by

averaging the thickness and properties of each layer in the soil profile at the three units. This composite design soil profile is shown in figure 3.7-7. The strain-dependent relationships for shear moduli for clay and sand are shown in figures 3.7-8 and 3.7-9, respectively.

The foundation embedment depth, width of structural foundation, and total structural height for each Category I structure are provided in table 3.7-2.

3.7.2 SEISMIC SYSTEM ANALYSIS

3.7.2.1 Seismic Analysis Methods

3.7.2.1.1 NSSS Seismic Systems

The major components of the reactor coolant system (reactor vessel, steam generators, reactor coolant pumps, pressurizer, and reactor coolant piping) are designed to the appropriate stress and deformation criteria of the ASME Code, Section III, for the loading criteria included in the component design specification. The adequacy of seismic loadings used for the design of the major components are confirmed by dynamic analysis methods, employing time-history modal analysis techniques.

A composite three-dimensional, lumped-mass model of the reactor vessel, the two steam generators, the four reactor coolant pumps, and the interconnecting piping is coupled with a three-dimensional, lumped-mass model of the containment building and foundation springs for performing the analysis of these dynamically coupled components of the reactor coolant system. In addition, the representation of the reactor vessel assembly used in this coupled model includes sufficient detail

of the reactor internals to account for possible dynamic interaction between the reactor coolant system and internals. The seismic input excitation is the free-field acceleration time-history.

The results of this analysis include appropriate time-history forcing functions for use in separate analyses of the pressurizer and of a more detailed model of the reactor internals.

A model of the coupled components of the reactor coolant system is shown in Figure 3.7-9, and is similar to CESSAR Figure 3.7.2-1 except that the model representation of the original steam generators (OSG) was replaced by the model representation of the current steam generators. The three-dimensional, beam-stick containment building model with foundation springs and connecting members, which is coupled with the reactor coolant system model, is developed from the planar models used for analysis of the containment building as discussed in paragraph 3.7.2.3.2. The separate pressurizer model is shown in CESSAR Figure 3.7.2-2.

The analytical methods used, the selection of significant modes, and the selection of adequate number of masses and dynamic degrees of freedom is in accordance with CESSAR Section 3.7.2.1.

Table 3.7-2
EMBEDMENT DEPTHS OF CATEGORY I STRUCTURES

Structure	Foundation[(a)] Embedment Depth (ft)	Least Foundation Width (ft)	Structure Height (ft)
Containment	33	161	223
Main steam support	25	40	81
Auxiliary	35	144	123
Control	30	86	111
Fuel	7	86	95
Diesel generator	6.3	68	52
Condensate storage tank	4.5	50	56.5
Refueling water tank	13.8	50	72.5

a. Effective embedment based on a weighted average of contact conditions around the perimeter of the foundation.

3.7.2.1.2 Seismic Systems Other Than NSSS

Category I structures, systems, and components are classified in accordance with NRC Regulatory Guide 1.29 (refer to section 3.2). These structures, systems, and components are analyzed for two earthquake conditions -- the SSE and OBE.

The analysis methods utilized are based upon linear dynamic analysis techniques. In general, two separate analytical procedures are employed to perform the dynamic analysis. A time-history analysis is used to develop in-structure response spectra, and a response spectrum analysis is used to obtain force distributions within the various structures. The

mathematical idealization of the structural characteristics of the various Seismic Category I structures is accomplished by a lumped-parameter, beam stick model. Modeling techniques, such as the selection of the minimum number of mass points and the number of degrees of freedom per mass point, are described in Section 3.2 of BC-TOP-4-A. The seismic input is defined in terms of the OBE and SSE design response spectra (paragraph 3.7.1.1), the free-field acceleration time-history (paragraph 3.7.1.2), and the soil-structure interaction parameters (paragraph 3.7.2.4). Structural damping values are defined in table 3.7-1 and soil-damping characteristics are in accordance with figures 3.7-5 and 3.7-6.

The lumped-mass models used for analysis of the containment, auxiliary, control, and fuel buildings are shown in figures 3.7-10 through 3.7-13, respectively. Mathematical models developed include both horizontal and vertical planar models. The analytical methods used are in accordance with BC-TOP-4-A, and the general procedure for seismic analysis is indicated in figure 3.7-14. Following this procedure, fixed-base structural mode shapes and frequencies are calculated for the purpose of computing composite modal damping. Whenever appropriate, soil-structural interaction analyses are performed by coupling the fixed-base structure models with the foundation springs and dampers. Structural mode shapes, frequencies, and modal damping values are computed for the soil-structure models. The results of the analysis include accelerations, displacements, shears, moments, and other parameters for structural design, as well as floor response spectra for design of equipment. Section 3.8 describes design allowable stresses and loading combinations which include seismic loadings.

Table 3.7-3A
NATURAL FREQUENCIES AND DOMINANT DEGREES OF FREEDOM
FIXED SUPPORT 3800 MWt REACTOR COOLANT SYSTEM (Sheet 1 of 5)

Mode No.	Frequency (Hertz)	Dominant Degrees of Freedom		
		Joint Number	Direction	Location
1	1.74	9911	Z	Reactor internals
2	1.74	9911	X	Reactor internals
3	12.29	9916,1103,2103, etc.	Z,X	Reactor vessel, pumps
4	12.60	1103,2103,etc.,9916	X	Pumps and reactor vessel
5	13.01	2103,4103	X	Pumps 1B and 2B
6	13.01	1103,5103	X	Pumps 1A and 2A
7	13.27	1103,2103,etc.	X	Pumps
8	13.51	1103,2103,etc.,9916	X	Pumps and Reactor vessel
9	14.89	1103,2103,etc.	Z	Pumps
10	14.90	1103,2103,etc.	Z	Pumps
11	14.90	1103,2103,etc.	Z	Pumps

Table 3.7-3A
NATURAL FREQUENCIES AND DOMINANT DEGREES OF FREEDOM
FIXED SUPPORT 3800 MWt REACTOR COOLANT SYSTEM (Sheet 2 of 5)

Mode No.	Frequency (Hertz)	Dominant Degrees of Freedom		
		Joint Number	Direction	Location
12	14.90	1103,2103,etc.	Z	Pumps
13	14.99	404,3404	X	Steam generators
14	15.37	404,3404	X	Steam generators
15	17.90	408,412,3408,3412	Z	Steam generator internals
16	17.90	408,412,3408,3412	Z	Steam generators internals
17	18.00	1103,2103,etc.	Y	Pumps
18	18.01	1103,2103,etc.	Y	Pumps
19	18.04	1103,2103,etc.	Y	Pumps
20	18.04	1103,2103,etc.	Y	Pumps
21	20.22	9911	Y	Reactor vessel internals
22	20.77	9995	Z	Reactor vessel
23	21.52	2101,4101	Z	Pumps 1B and 2B

Table 3.7-3A
NATURAL FREQUENCIES AND DOMINANT DEGREES OF FREEDOM
FIXED SUPPORT 3800 MWt REACTOR COOLANT SYSTEM (Sheet 3 of 5)

Mode No.	Frequency (Hertz)	Dominant Degrees of Freedom		
		Joint Number	Direction	Location
24	21.56	2101,4101	Z	Pumps 1B and 2B
25	21.62	1101,5101	Z	Pumps 1A and 2A
26	21.63	1101,5101	Z	Pumps 1A and 2A
27	24.10	9916	X	Reactor vessel
28	24.24	408,3408	X	Steam generator internals
29	26.08	9905	X	Reactor vessel internals
30	26.78	404,3404	Y	Steam generators
31	26.79	404,3404	Y	Steam generators
32	29.51	404,3404	Z	Steam generators
33	29.51	404,3404	Z	Steam generator
34	31.57	2580,4580,2101,4104	X	Suction leg piping and pumps 1B and 2B

Table 3.7-3A
NATURAL FREQUENCIES AND DOMINANT DEGREES OF FREEDOM
FIXED SUPPORT 3800 MWt REACTOR COOLANT SYSTEM (Sheet 4 of 5)

Mode No.	Frequency (Hertz)	Dominant Degrees of Freedom		
		Joint Number	Direction	Location
35	31.72	2580,4580,2101,4104	X	Suction leg piping and pumps 1B and 2B
36	32.05	1580,5580,1101,5101	X	Suction leg piping and pumps 1A and 2A
37	32.08	1580,5580,1101,5101	X	Suction leg piping and pumps 1A and 2A
38	32.40	9911	Y	Reactor vessel internals
39	38.58	2580,4580	X,Z	Suction leg piping 1B and 2B
40	38.58	2580,4580	X,Z	Suction leg piping 1B and 2B
41	38.70	1580,5580	X,Z	Suction leg piping 1A and 2A
42	38.78	1580,5580	X,Z	Suction leg piping 1A and 2A
43	41.62	9995	Z	Reactor vessel

Table 3.7-3A
NATURAL FREQUENCIES AND DOMINANT DEGREES OF FREEDOM
FIXED SUPPORT 3800 MWt REACTOR COOLANT SYSTEM (Sheet 5 of 5)

Mode No.	Frequency (Hertz)	Dominant Degrees of Freedom		
		Joint Number	Direction	Location
44	45.94	9995	X	Reactor vessel
45	47.81	412,3412,408,3408	X	Steam generator internals
46	48.14	412,3412,408,3408	X	Steam generator internals
47	48.40	412,3412,408,3408	Z	Steam generator internals
48	48.40	412,3412,408,3408	Z	Steam generator internals

Consideration of maximum relative support displacements for Seismic Category I structures is in accordance with Section 5.3 of BC-TOP-4-A and Section 4.0 of BP-TOP-1.

Significant effects such as components and piping interaction, external structural restraints, and hydrodynamic effects are included in the analysis.

The lateral seismic earth pressures acting upon embedded walls consist of active and passive pressures. The active and passive pressures are calculated separately and each wall is designed for the most severe of the two conditions.

3.7.2.2 Natural Frequencies and Response Loads

3.7.2.2.1 NSSS Seismic Systems

Natural frequencies and dominant degrees of freedom for the fixed support coupled components of the 3800 MWt reactor coolant system and pressurizer are provided in Tables 3.7-3A and 3.7-3B, respectively. Natural frequencies, participation factors and effective mass value for the reactor coolant system coupled building models are provided in Tables 3.7-4.

The reactions (forces and moments) at all design points in the reactor coolant system, obtained from the dynamic seismic analysis, are compared with seismic loads in each component design specification. The results of this comparison are summarized in tabular form for the points of maximum calculated load in Tables 3.7-5 and 3.7-6 for the reactor coolant system.

Table 3.7-3B
NATURAL FREQUENCIES AND DOMINANT DEGREES OF FREEDOM
PRESSURIZER

Mode No.	Frequency (Hertz)	Dominant Degrees of Freedom	
		Joint Number	Direction
1	29.24	135	Z
2	29.39	135	X
3	40.90	135	Y
4	54.90	135	X
5	55.14	135	Z

Table 3.7-4
COUPLED RCS MODAL ANALYSIS RESULTS FOR SSE
(Sheet 1 of 2)

MODE	FREQ (HZ)	X DIRECTION		Y DIRECTION		Z DIRECTION	
		PARTIC .FACTOR	EFFECTIVE MASS	PARTIC FACTOR	EFFECTIVE MASS	PARTIC .FACTOR	EFFECTIVE MASS
1	1.667	0.000	0.000	0.000	0.000	462.240	213666.000
2	1.671	463.490	214820.000	0.000	0.000	0.000	0.000
3	1.739	0.000	0.000	0.000	0.000	-70.053	4907.360
4	1.740	-75.228	5659.200	0.000	0.000	0.000	0.000
5	3.263	0.000	0.000	610.710	372970.000	0.000	0.000
6	3.740	0.000	0.000	0.000	0.000	392.930	154394.000
7	3.753	390.270	152313.000	0.000	0.000	0.000	0.000
8	7.332	-14.152	200.274	0.000	0.000	0.000	0.000
9	7.416	0.000	0.000	-0.224	0.050	0.000	0.000
10	10.012	0.000	0.000	0.000	0.000	-3.536	12.506
11	10.348	0.000	0.000	0.000	0.000	0.000	0.000
12	10.603	-0.027	0.001	0.000	0.000	0.000	0.000
13	12.111	0.000	0.000	0.000	0.000	-4.067	16.538
14	12.359	2.388	5.702	0.000	0.000	0.000	0.000
15	12.925	0.000	0.000	0.118	0.014	0.000	0.000
16	12.926	0.000	0.000	0.000	0.000	0.000	0.000
17	13.076	0.000	0.000	0.000	0.000	-2.711	7.347
18	13.238	0.000	0.000	0.000	0.000	3.788	14.346
19	13.595	-4.266	18.202	0.000	0.000	0.000	0.000
20	13.608	0.000	0.000	0.000	0.000	0.000	0.000
21	14.816	-0.001	0.000	0.071	0.005	0.000	0.000
22	14.833	1.048	1.099	0.000	0.000	0.000	0.000
23	14.938	0.000	0.000	0.000	0.000	-2.499	6.246
24	15.230	0.000	0.000	0.000	0.000	0.000	0.000
25	17.715	0.000	0.000	0.000	0.000	5.324	28.340
26	17.723	-5.561	30.929	0.000	0.000	0.000	0.000
27	17.917	0.000	0.000	1.118	1.250	0.000	0.000
28	17.971	0.000	0.000	0.000	0.000	0.000	0.000
29	18.015	0.000	0.000	0.000	0.000	-3.027	9.163
30	18.029	-2.833	8.024	0.000	0.000	0.000	0.000
31	18.601	0.000	0.000	0.000	0.000	-1.764	3.113
32	18.898	0.000	0.000	0.000	0.000	0.000	0.000
33	18.947	0.000	0.000	0.000	0.000	-1.935	3.743
34	19.486	0.000	0.000	5.312	28.218	0.000	0.000
35	21.140	0.000	0.000	-8.676	75.274	0.000	0.000
36	21.487	0.001	0.000	-0.905	0.818	0.000	0.000
37	21.493	-0.769	0.592	-0.001	0.000	0.000	0.000

Table 3.7-4
COUPLED RCS MODAL ANALYSIS RESULTS FOR SSE
(Sheet 2 of 2)

MODE	FREQ (HZ)	X DIRECTION		Y DIRECTION		Z DIRECTION	
		PARTIC .FACTOR	EFFECTIVE MASS	PARTIC FACTOR	EFFECTIVE MASS	PARTIC .FACTOR	EFFECTIVE MASS
38	21.660	0.000	0.000	0.000	0.000	-1.884	3.550
39	21.740	0.000	0.000	0.000	0.000	0.000	0.000
40	22.055	-0.629	0.395	0.000	0.000	0.000	0.000
41	23.184	0.000	0.000	0.000	0.000	0.000	0.000
42	23.223	0.000	0.000	0.000	0.000	-0.442	0.195
43	24.423	0.000	0.000	0.212	0.045	0.000	0.000
44	24.584	-4.141	17.150	0.000	0.000	0.000	0.000
45	26.057	-0.499	0.249	0.000	0.000	0.000	0.000
46	26.846	0.000	0.000	0.000	0.000	3.107	9.656
47	30.701	1.091	1.191	0.000	0.000	0.000	0.000
48	31.347	0.000	0.000	0.000	0.000	-1.436	2.061
49	31.533	0.000	0.000	0.000	0.000	-1.204	1.449
50	31.576	0.000	0.000	0.000	0.000	0.000	0.000
51	31.881	0.000	0.000	-0.011	0.000	0.000	0.000
52	31.910	-0.592	0.351	0.000	0.000	0.000	0.000
53	32.290	0.000	0.000	0.391	0.153	0.000	0.000
54	34.463	-0.968	0.936	0.000	0.000	0.000	0.000
55	34.559	0.000	0.000	0.000	0.000	-1.264	1.598
56	36.572	-0.060	0.004	0.000	0.000	0.000	0.000
57	36.813	0.000	0.000	-0.855	0.731	0.000	0.000
58	37.491	0.000	0.000	0.000	0.000	0.000	0.000
59	37.512	0.000	0.000	0.000	0.000	-0.016	0.000
60	37.534	0.110	0.012	0.000	0.000	0.000	0.000
61	37.537	0.000	0.000	-0.007	0.000	0.000	0.000
62	37.634	0.000	0.000	0.000	0.000	0.024	0.001
63	37.720	0.000	0.000	0.000	0.000	0.000	0.000
64	40.926	0.000	0.000	0.000	0.000	0.131	0.017
65	43.178	-0.105	0.011	0.000	0.000	0.000	0.000
66	43.438	0.969	0.939	0.000	0.000	0.000	0.000
67	44.593	0.000	0.000	0.000	0.000	0.000	0.000
68	44.599	0.000	0.000	0.000	0.000	0.006	0.000
69	46.921	0.145	0.021	0.000	0.000	0.000	0.000
70	46.983	0.000	0.000	0.000	0.000	0.298	0.089
71	47.561	0.000	0.000	-0.002	0.000	0.000	0.000
72	48.490	-0.028	0.001	0.000	0.000	0.000	0.000
73	48.655	0.000	0.000	-0.331	0.110	0.000	0.000
74	49.327	-1.196	1.429	0.000	0.000	0.000	0.000

Table 3.7-5
LOAD TABLES FOR REACTOR COOLANT SYSTEM (Sheet 1 of 4)

Seismic Excitation – OBE	Seismic Loads, Kips and Ft-Kips		
Support Location	Reaction Component	Calculated Maximum	Design Specification
Steam generator upper key	Fz	99	1080
Steam generator snubber assembly	Fx	117	900
Steam generator vertical pad	Fy (1,3) Fy (2,4)	88 120	390 1440
Steam generator hold-down bolt	Fy (1,3) Fy (2,4)	0 0	0 0
Steam generator lower key	Fz	62	770
Reactor vessel horiz. column support	Fc	283	2300
Reactor vessel column base	Fa Fb Fc Ma Mb Mc	2 118 54 189 93 14	11 825 106 46 174 150
Pump vertical column	Fy	12	175
Pump snubber	Fa	34	425
Pump upper horizontal column	Fa	20	180
Pump lower horizontal column	Fa	11	120

Table 3.7-5
LOAD TABLES FOR REACTOR COOLANT SYSTEM (Sheet 2 of 4)

Seismic Excitation – OBE	Seismic Loads, Kips and Ft-Kips		
Support Location	Reaction Component	Calculated Maximum	Design Specification
Pressurizer Key	Fk	10	12
Pressurizer support skirt	Fv	45	45
	Fh	34	42
	Mt	0	0
	Mb	273	385
Reactor vessel inlet nozzle	Fa	13	297
	Fb	4	50
	Fc	15	270
	Ma	25	289
	Mb	82	358
	Mc	27	206
Reactor vessel outlet nozzle	Fa	126	550
	Fb	38	165
	Fc	6	69
	Ma	7	270
	Mb	44	523
	Mc	260	1045
Reactor vessel column upper flange	Fa	2	11
	Fb	118	825
	Fc	4	47
	Ma	64	578
	Mb	6	58
	Mc	14	80
Reactor vessel lower key	Fc	57	109
Steam generator inlet nozzle	Fa	123	1000
	Fb	5.3	600
	Fc	47	600
	Ma	20	700
	Mb	194	1000
	Mc	37	1000

Table 3.7-5
LOAD TABLES FOR REACTOR COOLANT SYSTEM (Sheet 3 of 4)

Seismic Excitation – OBE	Seismic Loads, Kips and Ft-Kips		
Support Location	Reaction Component	Calculated Maximum	Design Specification
Steam generator support skirt	Fx	6	0
	Fy	256	2400
	Fz	113	1120
	Mx	127	2880
	My	49	550
	Mz	497	1000
Steam generator outlet nozzle	Fa	2	70
	Fb	6	130
	Fc	30	130
	Ma	27	235
	Mb	25	600
	Mc		600
Pump inlet nozzle	Fx	7	70
	Fy	2	40
	Fz	7	60
	Mx	28	280
	My	12	350
	Mz	25	340
Pump outlet nozzle	Fa	18	350
	Fb	3	70
	Fc	3	50
	Ma	11	200
	Mb	8	220
	Mc	38	850
Pump skirt/casing interface	Fx	11	120
	Fy	44	330
	Fz	18	160
	Mx	7	320
	My	4	100
	Mz	14	480

Table 3.7-5
LOAD TABLES FOR REACTOR COOLANT SYSTEM (Sheet 4 of 4)

Seismic Excitation – OBE	Seismic Loads, Kips and Ft-Kips		
Support Location	Reaction Component	Calculated Maximum	Design Specification
Pump motor support upper flange	Fx	17	400
	Fy	17	150
	Fz	14	350
	Mx	150	2480
	My	12	130
	Mz	161	2840
Pump motor support lower flange	Fx	17	180
	Fy	17	150
	Fz	14	180
	Mx	52	2000
	My	12	130
	Mz	38	2600
Piping at reactor vessel inlet nozzle	M max	87	1000
Piping at reactor vessel outlet nozzle	M max	260	2417
Piping at steam generator inlet nozzle	M max	194	2417
Piping at steam generator outlet nozzle	M max	45	1000
Piping at pump inlet nozzle	M max	87	1000
Piping at pump outlet nozzle	M max	45	1000
Piping at suction leg elbow	M max	87	1000

Table 3.7-6
LOAD TABLES FOR REACTOR COOLANT SYSTEM (Sheet 1 of 4)

Seismic Excitation – SSE	Seismic Loads, Kips and Ft-Kips		
Support Location	Reaction Component	Calculated Maximum	Design Specification
Steam generator upper key	Fz	167	1800
Steam generator snubber assembly	Fx	206	1500
Steam generator vertical pad	Fy (1,3) Fy (2,4)	0;156 201	560 2060
Steam generator hold-down bolt	Fy (1,3) Fy (2,4)	0 0	0 0
Steam generator lower key	Fz	101	1100
Reactor vessel horiz. column support	Fc	480.6	3000
Reactor vessel column base	Fa Fb Fc Ma Mb Mc	3 224 90 33 157 23	25 2000 175 79 283 200
Pump vertical column	Fy	20	275
Pump snubber	Fa	65	650
Pump upper horizontal column	Fa	35	300
Pump lower horizontal column	Fa	19	190
Pressurizer key	Fk	17	23

Table 3.7-6
LOAD TABLES FOR REACTOR COOLANT (Sheet 2 of 4)

Seismic Excitation – SSE	Seismic Loads, Kips and Ft-Kips		
Support Location	Reaction Component	Calculated Maximum	Design Specification
Pressurizer support skirt	Fv	84	100
	Fh	58	84
	Mt	0	0
	Mb	480	769
Reactor vessel inlet nozzle	Fa	24	720
	Fb	7	120
	Fc	25	650
	Ma	50	700
	Mb	136	800
	Mc	44	500
Reactor vessel outlet nozzle	Fa	221	1300
	Fb	70	400
	Fc	9	165
	Ma	10	650
	Mb	62	1250
	Mc	482	2500
Reactor vessel column upper flange	Fa	3	25
	Fb	224	2000
	Fc	8	110
	Ma	115	1400
	Mb	10	140
	Mc	24	200
Reactor vessel lower key	Fc	96	175
Steam generator inlet nozzle	Fa	219	1700
	Fb	78	950
	Fc	78	950
	Ma	32	1100
	Mb	348	1700
	Mc	49	1700

Table 3.7-6
LOAD TABLES FOR REACTOR COOLANT SYSTEM (Sheet 3 of 4)

Seismic Excitation – SSE	Seismic Loads, Kips and Ft-Kips		
Support Location	Reaction Component	Calculated Maximum	Design Specification
Steam generator support skirt	Fz	10	0
	Fy	429	4000
	Fz	190	1860
	Mx	218	4800
	My	79	900
	Mz	876	1650
Steam generator outlet nozzle	Fa	4	100
	Fb	10	190
	Fc	9	190
	Ma	45	370
	Mb	43	1000
	Mc	44	1000
Pump inlet nozzle	Fx	11	110
	Fy	3	60
	Fz	12	100
	Mx	45	420
	My	18	520
	Mz	35	520
Pump outlet nozzle	Fa	325	550
	Fb	6	110
	Fc	56	80
	Ma	20	300
	Mb	12	350
	Mc	62	1280
Pump skirt/casing interface	Fx	19	190
	Fy	71	540
	Fz	31	280
	Mx	11	500
	My	68	170
	Mz	25	750

Table 3.7-6
LOAD TABLES FOR REACTOR COOLANT (Sheet 4 of 4)

Seismic Excitation – SSE	Seismic Loads, Kips and Ft-Kips		
Support Location	Reaction Component	Calculated Maximum	Design Specification
Pump motor support upper flange	Fx	28	600
	Fy	27	240
	Fz	23	530
	Mx	257	3750
	My	18	210
	Mz	254	4250
Pump motor support lower flange	Fx	28	280
	Fy	27	240
	Fz	23	280
	Mx	767	2625
	My	189	210
	Mz	66	4100
Piping at reactor vessel inlet nozzle	M max	149	2000
Piping at reactor vessel outlet nozzle	M max	482	4834
Piping at steam generator inlet nozzle	M max	349	4834
Piping at steam generator outlet nozzle	M max	65	2000
Piping at pump inlet nozzle	M max	149	2000
Piping at pump outlet nozzle	M max	65	2000
Piping at suction leg elbow	M max	149	2000

The maximum seismic loads calculated by the time-history techniques are the result of a search and comparison over the entire time domain of each individual component of load. The maximum calculated components of load for each design location do not in general occur at the same time and therefore use of these results constitute a conservative worst case.

3.7.2.2.2 Seismic Systems Other Than NSSS

A summary of significant natural frequencies for the major Category I structures is provided in tables 3.7-7 through 3.7-10 and includes the effects of soil-structure interaction. Since the soil impedance functions utilized in the analyses of the Category I structures are strain-dependent, they are different for the OBE and SSE. This change in soil impedance functions accounts for the difference in frequencies for the Category I structures for the OBE and SSE. Mode shapes and participation factors are provided in figures 3.7-21 through 3.7-23. The solution of the equations of motion for the containment structure was carried out by the method ascribed to Foss[3]. A detailed discussion of the method is given by Hurty and Rubinstein[4]. This method is adopted so that proper consideration can be given to the radiation damping effects during soil-structure interaction analysis. Because of the relatively different energy dissipation characteristics of the structure and the soil, the resulting damping matrix is nonproportional and, hence, a solution as given by Foss properly takes this into account.

The solution of the eigenvalue problem with nonproportional damping results in complex eigenvectors (mode shapes). Thus,

in the strict sense, classical normal modes do not exist and no direct account can be taken of the classical participation factor associated with proportional damping. The interpretation of complex eigenvectors is not simple since the components of the vectors differ in phase as well as in amplitude. The vectors could be plotted in the complex plane showing amplitude and phase (see, for example, Meirovitch,[5] pp. 415-419); however, a direct interpretation of such a plot would not be practical. The solution is analogous to the direct integration technique that does not explicitly consider mode shapes.

The mode shapes and participation factors for the auxiliary building corresponding to the natural frequencies listed in table 3.7-8 are shown in amended figure 3.7-21.

The mode shapes and participation factors for the control building corresponding to the natural frequencies listed in table 3.7-9 are shown in amended figure 3.7-22.

The mode shapes and participation factors for the fuel building corresponding to the natural frequencies listed in table 3.7-10 are shown in amended figure 3.7-23.

Response loads for major Category I structures, including accelerations, shears, moments, and displacements are provided in figures 3.7-15 through 3.7-19. Horizontal and vertical response spectra are calculated at major Seismic Category I structure elevations and equipment support points for the OBE and SSE earthquakes. The response spectra at selected plant elevations with major equipment and equipment support points for each structure are given in appendix 3D.

Table 3.7-7

CONTAINMENT BUILDING NATURAL FREQUENCIES

		Mode	Frequency (Hz)
Horizontal (N-S)	OBE	1	2.00
		2	3.27
		3	8.79
		4	13.43
		5	14.51
	SSE	1	1.79
		2	2.85
		3	8.80
		4	13.42
		5	14.51
Horizontal (E-W)	OBE	1	1.99
		2	3.29
		3	7.99
		4	8.15
		5	12.51
	SSE	1	1.79
		2	2.87
		3	8.00
		4	8.15
		5	12.83
Vertical	OBE	1	3.25
	SSE	1	3.25

3.7.2.3 Procedure Used for Modeling

3.7.2.3.1 General

The lumped-mass modeling technique is used for the seismic analysis of Seismic Category I structures and equipment. A description of the procedures used to locate lumped masses and for decoupling of systems and subsystems is provided in Section 3.2 of BC-TOP-4-A.

3.7.2.3.2 Containment Building Model

Four, two-dimensional, lumped-parameter coupled models (E-W horizontal and vertical, N-S horizontal and vertical) of the containment structure and the NSSS were used for the time-history analyses. Response characteristics and in-structure response spectra along the two principal axes of the containment structure and the NSSS were obtained using these models. Each model consists of four separate subsystems: soil, containment shell, internal structure, and the NSSS.

Simplified models of the NSSS were developed and provided by the NSSS supplier. The NSSS models consist of 72 nodal points with six mass points for horizontal analyses and three mass points for the vertical analyses. This model development is an adequate representation of the mass and stiffness of the subsystem. The containment beam-stick model is coupled with the simplified NSSS model as shown in figure 3.7-10. For horizontal motion analysis, each nodal point of the containment interior and exterior structure is assigned translational as well as rotational degrees of freedom. However, for vertical analysis, only a translational degree of freedom is assigned. The local stiffness characteristics of each interface between

the NSSS and the interior structure are obtained and then incorporated into the coupled model with appropriate member properties and member end releases. An example of this is the steam generator snubber support. This support is located on a wall panel that has local deflection characteristics. A horizontal spring is used to include this effect. The spring constant is determined from a static analysis of a three-dimensional, fixed-base, finite-element model of the interior structure.

Kinematic condensation is used to eliminate the dependent coordinates and the Householder-Ortega-Wilkinson method(6) is used to effectively extract eigenvalues and eigenvectors for the fixed-base cases. Structural damping values of the superstructure are incorporated into the analysis by observing the predominate individual fixed-base response characteristics of a given mode. For example, if the predominate response in a given mode is due to the containment shell, the modal damping ratio is closely related to the damping value for pre-stressed concrete. Modal damping values given in table 3.7-1 along with the fixed-base frequency and mode shapes are used to evaluate the damping matrix for the superstructure.

The effects of soil-structure interaction are investigated by coupling the fixed-base model to foundation springs and dampers. Since the soil impedance is a function of frequency for a layered site(7), the governing equations of motion for a soil-structure interaction system are relatively complex. The FOSIN computer program(8) which is an extension of the Foss

Table 3.7-8
AUXILIARY BUILDING NATURAL FREQUENCIES[a]

		Mode	Frequency (Hz)
Horizontal (N-S)	OBE	1	3.6
		2	7.9
		3	18.8
		4	26.1
		5	37.6
	SSE	1	3.2
		2	4.0
		3	18.4
		4	26.3
		5	37.9
Horizontal (E-W)	OBE	1	3.9
		2	7.9
		3	16.1
		4	28.0
		5	39.7
	SSE	1	3.5
		2	7.0
		3	15.9
		4	28.1
		5	40.0
Vertical	OBE	1	5.2
		2	33.5
	SSE	1	4.6
		2	33.5

a. See figure 3.7-21 for mode shapes and participation factors.

Table 3.7-9
CONTROL BUILDING NATURAL FREQUENCIES[a]

		Mode	Frequency (Hz)
Horizontal (N-S)	OBE	1	4.0
		2	11.6
		3	21.1
	SSE	1	3.7
		2	10.4
		3	20.6
Horizontal (E-W)	OBE	1	4.4
		2	12.2
		3	23.6
	SSE	1	4.0
		2	10.9
		3	23.1
Vertical	OBE	1	7.1
		2	10.3
		3	11.7
	SSE	1	6.5
		2	10.0
		3	11.8

a. See figure 3.7-22 for mode shapes and participation factors.

Table 3.7-10
FUEL BUILDING NATURAL FREQUENCIES[b] (Sheet 1 of 2)

		Mode	Frequency (Hz)
Horizontal (N-S)	OBE	1	0.26[a]
		2	2.77
		3	4.81
		4	5.42
		5	5.77
		6	6.34
		7	17.26
		8	29.92
		9	34.03
	SSE	1	0.26[a]
		2	2.52
		3	4.36
		4	5.38
		5	5.51
		6	5.99
		7	16.95
		8	29.83
		9	33.01

a. Fluid oscillation mode

b. See figure 3.7-23 for mode shapes an participation

Table 3.7-10

FUEL BUILDING NATURAL FREQUENCIES[b] (Sheet 2 of 2)

		Mode	Frequency (Hz)
Horizontal (E-W)	OBE	1	0.26[a]
		2	2.73
		3	3.46
		4	5.47
		5	5.60
		6	6.13
		7	7.81
		8	14.66
		9	20.84
	SSE	1	0.26[a]
		2	2.59
		3	3.36
		4	4.97
		5	5.40
		6	5.76
		7	7.77
		8	14.66
		9	20.63
Vertical	OBE	1	4.61
		2	36.77
	SSE	1	3.87
		2	36.73

method[9] is used to perform the time-history analyses. The FOSIN computer program has the capability of generating relative displacement, relative velocity, and relative and absolute acceleration time-histories.

The relative response displacement time-histories are used as input for the STICK program[10] to obtain the seismic shear force and bending moment for each lumped mass point in the containment structure. The absolute response acceleration time histories are used to generate in-structure response spectra. Due to geometric coupling within the structure, rocking and horizontal motion will create a vertical response component. Therefore, the vertical response spectra are obtained from the square-root-of-the-sum-of-the-squares (SRSS) combination of the responses produced by the vertical excitation and two horizontal rocking components. Response spectra for representative mass points of the containment and other Category I structures are presented in appendix 3D.

3.7.2.3.3 Other Category I Structure Models

Structures are modeled as systems of lumped masses located at floor elevations and other mass concentrations. The mathematical models used for seismic analysis of the auxiliary, control, and fuel buildings are shown in figures 3.7-11, 3.7-12, and 3.7-13, respectively. The basemat has both translational and rotational degrees of freedom. For excitation in the horizontal direction each mass point of the superstructure is assigned both translational as well as rotational degrees of freedom. For the vertical excitation however, only a

translational degree of freedom is assigned in the direction of motion.

A time history analysis is used to develop in-structure response spectra, and a response spectrum analysis is used to obtain force distributions within the various structures except for the auxiliary building. Force distributions for the auxiliary building are obtained using an equivalent static method employing zero period accelerations (ZPAs) from the response spectra.

The effect of the foundation medium is considered by providing springs at the base of the model. The spring values are evaluated using the provisions of BC-TOP-4-A. Strain-corrected soil properties were developed using the computer program SHAKE with the soil properties and strain correction factors shown in figures 3.7-7 through 3.7-9.

Essential spray pond walls and their connection to the slab are designed to withstand the loading combinations of static soil pressure, surcharge, and dynamic forces under OBE and SSE conditions. The analysis conservatively assumed that the spray ponds were empty of water. A separate analysis was performed to demonstrate that the spray pond walls can withstand the effects of the static water pressure, plus the hydrodynamic forces under OBE and SSE conditions. In this analysis, the presence of a soil embankment was conservatively ignored.

A dynamic analysis of the essential spray pond pump house was performed by using a stick model with lumped masses at each floor and by performing a spectral response analysis using, as input, the PVNGS free-field response spectra.

3.7.2.3.4 Reactor Coolant System

The major components of the reactor coolant system are analyzed using a coupled model of the reactor coolant system and containment building with foundation springs which accounts for dynamic interaction effects with the internal building support structure. The 3800 MWt Unit coupled model was developed and analyzed in the STRUDL environment. For the 3990 MWt Unit reactor coolant system analysis, the 3800 MWt Unit STRUDL coupled model was converted to ANSYS, the coupled ANSYS model was benchmarked against the STRUDL model, and then the OSG representation was replaced with the RSG representation in the ANSYS coupled model. Procedures used for modeling the major components of the reactor coolant system are given CESSAR. Procedures used for modeling the major components of the reactor coolant system are given in CESSAR Section 3.7.2.1.2. All other NSSS vendor supplied systems and components are analyzed as decoupled "seismic subsystems".

3.7.2.4 Soil-Structure Interaction

The effect of soil-structure interaction is taken into account by coupling the structural model with the foundation media. The lumped parameter representation, which uses impedances to represent the dynamic effects of the soil, was employed in the formation of analytical models. The impedance functions are represented by equivalent spring stiffnesses and radiation damping coefficients. In general, the foundation impedances are complex functions of basemat configuration, embedment depth, elastic properties of the foundation medium, and forcing frequencies. Whether or not frequency dependent, they can always be represented by a mechanical analog composed of

equivalent springs and dampers. The equivalent dampers represent the radiation effect of the seismic wave energy away from the structural base. The material damping of the foundation medium is neglected in the lumped-parameter representation since it is small compared with radiation damping.

Figure 3.7-20 shows a schematic lumped-parameter model of the soil-structure system with the equivalent translational and rotation foundation springs, k_x and k_ψ, and radiation dampers, c_x and c_ψ, representing the foundation impedances for horizontal seismic excitation. The foundation is represented by translational springs and dampers, k_z and c_z, respectively, for vertical motion, and k_t and c_t respectively, for torsion. These impedance functions are the superposition of the effect due to the foundation medium below the base slab elevation and the effect due to the structural embedment. Various tests indicate that embedment has the effect of increasing both the equivalent spring stiffnesses and the radiation damping[11][12]. For simplicity of analysis, only the additional spring stiffnesses due to the embedment are considered and the additional damping due to embedment is conservatively neglected.

Accordingly,

$$k_x = k_x^{'} = k_x^{''}$$
$$k_\psi = k_\psi^{'} + k_\psi^{''}$$
$$k_z = k_z^{'} + k_z^{''}$$
$$c_x = c_x^{'}$$
$$c_\psi = c_\psi^{'}$$
$$c_z = c_z^{'}$$

in which $k'_x \ldots, c'_z$ are due to the material below the base slab elevation and k''_x, k''_ψ, and k'_z are due to structural embedment. The embedment effects are based on the embedment depths and minimum foundation dimensions given in table 3.7-2. If the material below the base slab elevation is uniform, the impedance functions are independent of frequency(13)(14). Table 3-2 of BC-TOP-4-A gives the expressions for equivalent stiffnesses and radiation damping coefficients,. $k'_x, \ldots, C'_z$ for circular and rectangular bases. If the material below the base slab consists of a layered media resting on an elastic half-space, the appropriate frequency-dependent foundation impedances are obtained using the LUCON computer program(2)(15) which considers not only radiation damping, but also the additional damping due to energy dissipation in the soil material. Since the site consists of alternating layers of sand and clay over bedrock as shown in figure 3.7-7, the latter approach for a layered media is used in the seismic analysis of Seismic Category I structures.

With the foundation impedances specified, the soil-structure system is formulated by coupling the fixed-base structure with the foundation medium through the basemat. The method of coupling, in terms of the equations of motion, is described in Appendix D of BC-TOP-4-A, with the structure represented by its fixed-base normal modes. The equations of motion for the interaction system are a mathematically coupled system. However, when frequency-independent impedances are used, it is usually sufficient to represent this coupled system by normal modes. Appendix D of BC-TOP-4-A shows one technique to determine the composite modal damping of the interaction system

in this case. This is accomplished by requiring that, at predetermined locations of the structural model, the dynamic amplification functions of both the coupled and uncoupled systems match each other at the natural frequencies of interest[16]. For structures supported on a layered medium resting on an elastic half-space, the frequency-dependent impedances are obtained using the LUCON computer program. The response of the soil-structure interaction system is obtained using the computer program FOSIN[8] which is an extension of the Foss method[9]. The complex eigenvalues and eigenvectors corresponding to the frequency-dependent interaction stiffness and damping must be obtained by an iterative process since the Foss method is applicable only to equations with constant coefficients[17].

A comparative study was made for the structural responses by two different approaches of soil modeling. A finite-element soil-structure interaction analysis was performed for SSE and OBE using the computer program LUSH[a]. In-structure response spectra for Category I structures were calculated.

These spectra were then compared to those spectra generated by the impedance method at corresponding locations. Figures 3.7-24 through 3.7-39 show the comparison of these spectra for the selected structures and locations.

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a. Lysmer, J., Udaka, T., Seed, H. B., and Huang, R., "LUSH-A Computer Program for Complex Response Analysis at Soil-Structure System," Earthquake Engineering Research Center, University of California, Berkeley, California, Report No. 74-4, April 1974.

It can be seen that response spectra from LUSH analysis are, in general, lower than those spectra generated by the analysis using the impedance method. The impedance method is thus the more conservative method for generation spectra. Based on the commitment in the PSAR to use the more conservative method to generate spectra (paragraph 3.7.1.6), the spectra from the impedance method were used for the design of the plant.

Input motions used in the LUSH analysis were applied at the "fixed boundary" of the soil medium. The fixed boundary can be the surface of bedrock or an arbitrary boundary at a great depth. The PVNGS LUSH models had a fixed boundary at 334 feet below grade level. To obtain these input motions, the computer program SHAKE was used to deconvolve the surface motions that were defined in paragraphs 3.7.1.1 and 3.7.1.2. The resulting motions at the structure foundation level, in general, meet the requirement of the Standard Review Plan, Section 3.7.1, Seismic Input, Paragraph II.2.

3.7.2.5 Development of Floor Response Spectra

A modal time-history analysis of the structural model established for each of the two horizontal and vertical directions is performed. Time-history motion is obtained at each floor for each independent direction considered and then used to compute the response spectra for that direction. The method is described in detail in Sections 4.2 and 5.2 of BC-TOP-4-A.

3.7.2.6 Three Components of Earthquake Motion

3.7.2.6.1 NSSS Seismic Systems

Procedures for considering the effects of three components of earthquake motion in determining the seismic response of NSSS vendor-supplied systems, components, and supports are in accordance with Regulatory Guide 1.92. Detailed procedures used for the reactor coolant system are described in CESSAR Section 3.7.2.1.

3.7.2.6.2 Seismic Systems Other Than NSSS

Procedures for considering the three components of earthquake motion in determining the seismic response of structures, systems, and components follow the recommendations of Regulatory Guide 1.92 and are described in Section 4.3 of BC-TOP-4-A for structures and in Section 5.1 of BP-TOP-1 for piping systems.

In addition to the SRSS method for combining responses of three components of earthquake motion as recommended in Regulatory Guide 1.92, the component factor method[15] has also been used as discussed in paragraph 3.7.3.6.

3.7.2.7 Combination of Modal Responses

The square root of the sum of the squares method is the procedure normally used to combine the modal responses when the modal analysis response spectrum method of analysis is employed. The procedure is modified only in two cases:

A. In the analysis of simple system where three or less dynamic degrees-of-freedom are involved, the modal

responses are combined by the summation of the absolute values method;

B. In the analysis of complex systems where closely spaced modal frequencies are encountered, the responses of the closely spaced modes are combined by the summation of the absolute values method and, in turn, combined with the responses of the remaining significant modes by the square root of the sum of the squares method. Modal frequencies are considered closely spaced when their difference is less than ±10 percent of the lower frequency.

Sections 4.2 and 5.3 of BC-TOP-4-A describe the techniques used to combine modal responses for structures and equipment. Sections 5.1 and 5.2 of BP-TOP-1 describe the criteria used for piping systems.

Individual modal responses are combined by the SRSS summation method. However, when modal frequencies are closely spaced (within 10% of each other), the contribution from these modes are first summed using the sum of their absolute values. Then the results from each group of closely spaced frequencies are considered in the SRSS modal summation. This is the grouping method using Equation 4 of Regulatory Guide 1.92.

3.7.2.8 Interaction of Non-Category I Structures With Seismic Category I Structures

The failure of any non-Category I structure will not impair the safety function of Seismic Category I structures or components.

Section 3.4 of BP-TOP-1 describes the techniques used to consider the interaction of Seismic Category I piping with non-Category I piping.

3.7.2.9 Effects of Parameter Variations on Floor Response Spectra

The procedures used to transform calculated floor response spectra into design floor response spectra are specified in Section 5.2 of BC-TOP-4-A. The floor response spectra computed from the floor time-history are smoothed and the peaks broadened to account for variations in the structural frequencies owing to uncertainties in such parameters as the material properties of the structure and soil, damping values, soil-structure interaction techniques, and the approximations in the modeling techniques used in seismic analysis. The peaks associated with each of the structural frequencies are broadened by a frequency $\pm 0.15\ f_j$ where f_j is the jth modal structural frequency.

3.7.2.10 Use of Constant Vertical Static Factors

Constant vertical load factors are not used for Seismic Category I structures, equipment, and piping. The methodology for vertical seismic analysis of structures is discussed in Sections 3.0, 4.0, and 5.0 of BC-TOP-4-A, and for piping in Section 2.3.2 and Appendix D of BP-TOP-1. The methodology for vertical seismic considerations for equipment is in accordance with IEEE 344, as stated in section 3.10.

3.7.2.11 Method Used to Account for Torsional Effects

The mathematical models used in seismic analysis of Category I systems, components, and piping systems include sufficient mass points and corresponding dynamic degrees-of-freedom to provide a three-dimensional representation of the dynamic characteristics of the system. The distribution of mass and the selected location of mass points account for torsional effects of valves and other eccentric masses.

Torsional effects were found insignificant, and therefore were excluded from the horizontal models at locations of mass and/or structure eccentricity. Section 3.2 and Appendix C of BC-TOP-4-A describe the techniques used to account for torsional effects.

3.7.2.12 Comparison of Responses

A comparison of maximum structural response accelerations for the control building calculated using the time-history analysis and the response spectrum method is presented in tables 3.7-11 and 3.7-12. These results indicate that both methods gave essentially the same response in terms of total lateral force and overturning moment.

3.7.2.13 Methods of Seismic Analysis of Seismic Category I Dams

There are no Seismic Category I dams at PVNGS.

3.7.2.14 Determination of Seismic Category I Structure Overturning Moments

The method used to compute structural overturning is given in Section 4.4.1 of BC-TOP-4-A. The effects of embedment, groundwater, and buoyancy are considered in the overturning analysis. Maximum soil pressure underneath structural basemats is computed as described in Section 4.4.2 of BC-TOP-4-A.

3.7.2.15 Analysis Procedure for Damping

Refer to CESSAR Section 3.7.2.1.1 for NSSS seismic systems.

The analysis procedure employed to account for damping in different elements of the model of a coupled system and the criteria used to account for composite damping in a coupled system with different elements are described in Sections 3.2 and 3.3 of BC-TOP-4-A. The analysis is based on the use of Category I structural models which include a simplified version of the NSSS model provided by the NSSS supplier.

3.7.3 SEISMIC SUBSYSTEM ANALYSIS

3.7.3.1 Seismic Analysis Methods

Seismic Category I subsystems other than piping are analyzed by use of the response spectrum method as discussed in Sections 1.0 through 6.0 of BC-TOP-4-A.

3.7.3.2 Determination of Number of Earthquake Cycles

For the NSSS Seismic Subsystems, the procedure used to account for the fatigue effect of cyclic motion associated with the OBE recognizes that the actual motion experienced during a seismic event consists of a single maximum or peak motion, and some

number of cycles of lesser magnitude. The total or cumulative fatigue effect of all cycles of different magnitude will result in an equivalent cumulative usage factor. The equivalent cumulative usage factor can also be specified in terms of a finite number of cycles of the maximum or peak motion. Based on this consideration, NSSS Seismic Category I subsystems, components, and equipment are designed for total of 200 full-load cycles about a mean value of zero and with an amplitude equal to the maximum response produced during the entire OBE event.

Procedures to determine the number of earthquake cycles for piping during seismic events are discussed in Section 6.2 of BP-TOP-1. Structures and equipment are designed on the basis of analytical results. In general, the design of structures and the majority of the equipment is not fatigue controlled since most stress and strain reversals occur only a small number of times. The occurrence of earthquake and design basis accident full-design strains occurs too infrequently and with too few cycles to generally require fatigue design of structures.

The number of earthquake cycles to be used in the design of subsystems is dependent upon three parameters:

- The significant frequency characteristics of the subsystem and/or supporting media
- The duration of the postulated seismic event
- The number of seismic events to which the plant might be subjected

Table 3.7-11

COMPARISON OF RESPONSES CONTROL BUILDING (OBE)

	Elevation (ft)	Time-History Analysis (g)	Response Spectrum Analysis (g)
Horizontal (E-W)	180	0.36	0.41
	160	0.33	0.37
	140	0.31	0.30
	120	0.27	0.24
	100	0.22	0.19
	74	0.18	0.13
Horizontal (N-S)	180	0.50	0.50
	160	0.41	0.44
	140	0.35	0.36
	120	0.31	0.29
	100	0.23	0.21
	74	0.18	0.13
Vertical[a]	180	1.01	0.98
	160	0.62	0.63
	140	0.58	0.53
	120	0.53	0.51
	100	0.43	0.36
	74	0.19	0.14

a. Maximum vertical acceleration at floor beams.

Table 3.7-12

COMPARISON OF RESPONSES CONTROL BUILDING (SSE)

	Elevation (ft)	Time-History Analysis (g)	Response Spectrum Analysis (g)
Horizontal (E-W)	180	0.67	0.82
	160	0.63	0.73
	140	0.57	0.60
	120	0.54	0.49
	100	0.41	0.38
	74	0.33	0.27
Horizontal (N-S)	180	0.81	0.87
	160	0.75	0.75
	140	0.61	0.63
	120	0.53	0.49
	100	0.41	0.38
	74	0.36	0.26
Vertical[a]	180	1.50	1.48
	160	0.90	1.05
	140	0.79	0.90
	120	0.76	0.87
	100	0.56	0.67
	74	0.37	0.29

a. Maximum vertical acceleration at floor beams.

The number of earthquake cycles used in the fatigue design for ASME, Section III, Class 1 piping is 960 cycles, obtained from the product of these three parameters:

$$N = n \times f \times d$$

where:

N = number of earthquake cycles

n = number of seismic events to be considered (= 2)

f = significant frequency characteristic of the subsystem and/or supporting media (= 20 Hz)

d = duration of the postulated seismic event (= 24 seconds)

Further conservatism is introduced by applying the resulting number of design cycles to the maximum stress range even though most of the actual stress cycles are well below the maximum stress range. In the application of this relation, two occurrences of the OBE are assumed to occur during the life of the plant.

3.7.3.3 Procedure Used for Modeling

Modeling of reactor internals, core, and control element drive mechanisms is described in section 3.7.3.14. Modeling procedures used for analysis of NSSS vendor supplied auxiliary components are given in section 3.9.3.

General modeling techniques used are in accordance with the criteria specified in Section 3 of BC-TOP-4-A. The modeling incorporates either a multidegree of freedom lumped-parameter technique or a finite-element approach. The degree of

complexity of the individual models is sufficient to define the dynamic behavior characteristics of the specific subsystem. Modeling of the attachment interface is consistent with the method of mounting the subsystem in its installed condition. Sections 2.0 and 3.0 of BP-TOP-1 discuss the techniques and procedures used to model Seismic Category I piping other than buried piping.

3.7.3.4 Basis for Selection of Frequencies

The basis for acceptability of the seismic design of equipment and subsystems is that the stresses and deformations produced by vibratory motion of the postulated seismic events, in combination with other coincident loadings, be within the limits established by applicable codes and standards in section 3.9.3.

Within practical limitations, the seismic design is accomplished in a manner to maintain the resonant frequencies well above the range which is significantly excited by the forcing frequencies. If the stresses and deformations resulting from analysis of the preliminary design exceed the established acceptable limits the stiffness of the restraint and supports system is modified as required to maintain the fundamental frequencies of equipment and subsystems sufficiently removed from the resonant range and, thereby, maintain the seismic response within the loads given in the component design specifications. The subsystem supports design is sufficiently adaptable that, dependent on the quantitative change in frequency required and the subsystem involved, modifications can be made either by changing the stiffness of existing support assembly components or by adding additional

support system restraints to the subsystems or components whose response otherwise exceeds the established limits.

If, during the analysis of the preliminary design, frequencies of the reactor coolant system were found to be in the range of resonance with those of the building, the supports for each of the components could be modified to increase their natural frequencies.

Specifically, the fundamental frequencies of the reactor vessel can be increased in both horizontal directions by the welding of a set of keys to the RV to further restrain lateral motion or rotation of the vessel. The keys would be laterally restrained by a structure supported by the primary shield wall.

The RCP moves in all three directions when seismically excited in any one direction. The fundamental frequency of the RCP can be raised by relocating the snubber from the top of the motor mount to the top of the motor. The orientation of the snubber would remain unchanged.

The SG frequency can be raised in the direction parallel to the axis of the RV outlet piping by the addition of a second set of snubbers and levers and in the direction perpendicular to the axis of the RV outlet piping by an additional set of keys above the original set.

See section 3.9.3 for auxiliary components.

Wherever practicable, Seismic Category I subsystems are designed to have fundamental frequencies well above the range of the forcing frequencies included within the response peak of the support spectra. When natural frequencies are not well separated from the critical forcing frequencies or are not

known, a dynamic analysis is made and subsystems designed for calculated response loads.

3.7.3.5 Use of Equivalent Static Load Method of Analysis

The equivalent static load method involves the multiplication of the total weight of the equipment or component member by the specified seismic acceleration coefficient. The magnitude of the seismic acceleration coefficient is established on the basis of the expected dynamic response characteristics of the component. Components that can be adequately characterized as a single degree of freedom system are considered to have a modal participation factor of one. Seismic acceleration coefficients for multidegree of freedom systems, which may be in the resonance region of the amplified response spectra curves, are increased by 50% to account conservatively for the increased modal participation. When increases of less than 50% are used for specific multidegree of freedom systems they are individually justified by comparative analysis or parametric evaluations.

For piping, refer to BP-TOP-1.

3.7.3.6 Three Components of Earthquake Motion

Procedures for considering the three components of earthquake motion in determining the seismic response of structures, subsystems, and components follow the recommendations of Regulatory Guide 1.92 and are described in BC-TOP-4-A for structures and equipment, and in BP-TOP-1 for piping systems.

Section 3.7.3.14 discusses the procedures used in the analysis of reactor internals, fuel assemblies, and control element

drive mechanisms. Procedures for considering the effects of three components of earthquake motion for auxiliary components are provided in section 3.9.3.

In addition to the SRSS method, the component factor method[15] has also been used for combining the three components of earthquake motion. The component factor method is discussed in the appendix 3A response to Question 3A.9.

3.7.3.7 Combination of Modal Responses

Refer to section 3.7.2.7 for NSSS seismic subsystems.

For structures, equipment, and piping systems, modal responses are combined using one of the methods recommended in Regulatory Guide 1.92.

3.7.3.8 Analytical Procedures for Piping

The design criteria and analytical techniques applicable to piping systems are discussed in BP-TOP-1. The effects of relative displacements between piping supports are considered.

3.7.3.9 Multiple-Supported Equipment Components with Distinct Inputs

The criteria and procedures used for seismic analysis of the multiply supported major components of the reactor coolant system are described in section 3.7.2; analysis methods used for the reactor internals and fuel assemblies are given in section 3.7.3.14.

Other seismic subsystems supported at two or more locations are analyzed using an upper bound envelope of all individual

support response spectra to calculate maximum inertial responses. Responses due to relative support displacements, imposed on the supported subsystem in the most unfavorable combination, are then combined with the responses due to inertial effects by the absolute sum method.

Section 5.3 of BC-TOP-4-A describes the approaches used for multiple-supported systems. Section 4.0 of BP-TOP-1 discusses the methods for piping systems.

3.7.3.10 Use of Constant Vertical Static Factors

A constant seismic vertical load factor is not used for the seismic design of Seismic Category I structures, components, and equipment. (Refer to paragraph 3.7.2.10. Also refer to Section 2.3.2 and Appendix D of BP-TOP-1).

3.7.3.11 Torsional Effects of Eccentric Masses

Refer to section 3.7.2.11 for NSSS seismic subsystems.

The significant torsional effects of valves and other eccentric masses are taken into account in the seismic piping analysis by the techniques discussed in BP-TOP-1.

Torsional effects are accounted for directly in the modeling for other subsystem analysis similar to the approach discussed in subsection 3.7.2 and in Appendix C of BC-TOP-4-A.

3.7.3.12 Buried Seismic Category I Piping Systems and Tunnels

Appendix 3G discusses the techniques used to calculate the stresses from seismic loadings for buried seismic piping. The buried Seismic Category I piping is designed to remain

functional when subjected to seismic loads. This is accomplished by limiting the calculated stresses in the pipe material under loading combinations, including earthquake.

3.7.3.13 Interaction of Other Piping with Seismic Category I Piping

The techniques used to consider the interaction of Seismic Category I piping with non-Category I piping are described in BP-TOP-1.

3.7.3.14 Seismic Analyses for Reactor Internals

The seismic analysis of the reactor internals and core was performed on a plant-specific basis. For Palo Verde, the seismic response necessitated the use of the vertical nonlinear analytical method and the results of the analysis are acceptable. The methodology is described below:

3.7.3.14.1 Reactor Internals and Core

The seismic analyses of the reactor internals and core consists of two phases. In the first phase, linear lumped-parameter models are formulated, natural frequencies and mode shapes for the models are determined, and the response is obtained utilizing the modal analysis response spectrum method. The response spectra used are based upon the acceleration of the reactor vessel flange. The response spectrum analysis is used to obtain preliminary design seismic loads and displacements in the vertical and horizontal directions.

In the second phase, because the relative displacements between the core and core shroud and between the core-support barrel

and pressure-vessel snubbers are sufficiently large to close the gaps that exist between these components, a nonlinear horizontal time history analysis is performed. The horizontal nonlinear analysis is divided into two parts. In the first part, the internals and core are analyzed to obtain the internals response and the proper dynamic input for the reactor core model. In the second part, the core plate motion from the first part is applied to a more detailed nonlinear model of the reactor core.

The input excitation to the internals model is the response time-history of the reactor vessel at the ledge and snubber elevations determined from the RCS analysis. Coupling effects between the internals and reactor vessel are accounted for by including a simplified representation of the internals within the RCS model. This is discussed in subsection 3.7.2. Since the linear vertical analysis indicates that the response of the core may be sufficiently large to cause it to lift off the core plate, a vertical nonlinear analysis of the internals was also performed. If this method is used a statement will be provided that a nonlinear analysis was performed and that the results were acceptable.

In these analyses, two horizontal components and one vertical component of the seismic excitation are considered and the maximum responses for the three components are combined by the method of square root of the sum of the squares.

Closely spaced modes are considered in accordance with Regulatory Guide 1.92.

3.7.3.14.1.1 Mathematical Models

Equivalent multimass mathematical models are developed to represent the reactor internals and core. The linear mathematical models of the internals are constructed in terms of lumped masses and elastic-beam elements. At appropriate locations within the internals and core, points (nodes) are chosen to lump the weights of the structure. A sketch of the internals and core showing the relative node locations for the horizontal model is presented in Figure 3.7.40-1. Figures 3.7.40-2 and 3.7.40-3 show the idealized linear horizontal and linear vertical models. The criterion for choosing the number and location of mass concentration is to provide for accurate representation of the dynamically significant modes of vibration of each of the internals components. Between the nodes properties are calculated for moments of inertia, cross-section areas, effective shear areas, and lengths. Separate horizontal and vertical models of the internals and core are formulated to more efficiently account for structural differences in these directions. In the horizontal nonlinear lumped mass representation of the internals and core, shown in Figure 3.7.40-4, gap and spring fuel assemblies and the peripheral row assemblies with the adjacent core shroud. Lumped-mass nodes in the core are positioned to coincide with fuel-spacer grid locations. To simulate the nonlinear motion of the fuel, nonlinear spring couplings are used to connect corresponding nodes to the fuel assemblies and core shroud. Incorporated into these nonlinear springs is the spacer grid impact stiffness derived from test results. The core is modeled by subdividing it into fuel assembly groupings and choosing stiffness values to adequately

characterize its beam response and contacting under dynamic loading.

The horizontal nonlinear reactor core model consisting of one row of 17 individual fuel assemblies is depicted in Figure 3.7.40-5A. In this model each fuel assembly is represented with mass points located at spacer grid locations. To simulate the gaps in the core, nonlinear spring couplings are used to connect corresponding nodes on adjacent fuel assemblies and core shroud. The impact stiffness and impact damping (coefficient of restitution) parameters for the gap elements are derived from the impact tests which are described in section 4.2. The spacer grid impact representation used for the analysis is capable of representing two types of fuel assembly impact situations. In the first type, only one side of the spacer grid is loaded. This type of impact occurs when the peripheral fuel assembly hits the core shroud, or when two fuel assemblies strike one another. The second type of impact loading occurs typically when the fuel assemblies pile up on one side of the core. In this case, the spacer grids are subjected to a through-grid compressive loading.

The fuel assemblies in the coupled core/internals model and the detailed core model are modeled with beam elements to represent the horizontal stiffness between mass points and rotational springs at each end to simulate the end fixity existing at the top and bottom of the core. The value used for fuel horizontal stiffness and end fixity are based upon a parametric study in which analytic predictions are correlated with fuel assembly static and dynamic test data. Fuel assembly structural damping as a function of vibrational amplitude was derived from fuel

assembly forced vibration and pluck tests defined in section 4.2. The damping values used in the seismic analysis of the reactor internals are in accordance with the values in Table 3.7-1.

The vertical nonlinear model incorporates nonlinear spring couplings to account for the nonlinear behavior of the internals in the vertical direction. The vertical nonlinear model is shown in Figure 3.7.40-8A.

Additional salient details of the internals and core models are discussed in the following paragraphs.

A. Hydrodynamic Effects

It has been shown both analytically and experimentally[9] that immersion of a body in a dense-fluid medium lowers its natural frequency and significantly alters its vibratory response as compared to that in air. The effect is more pronounced where the confining boundaries of the fluid are in close proximity to the vibrating body as in the case for the reactor internals. The method of accounting for the effects of a surrounding fluid on a vibrating system has been to ascribe to the system additional or "hydrodynamic mass".

The hydrodynamic mass of an immersed system is a function of the dimensions of the real mass and the space between the real mass and confining boundary.

Hydrodynamic mass effects for moving cylinders in a water annulus are discussed in Reference 22 and 23. The results of these references are applied to the

internals structures to obtain the total (structural plus hydrodynamic) mass matrix that is then used in the evaluation of the natural frequencies and mode shapes.

B. Core Support Barrel

The core support barrel is modeled as a beam with shear deformation. It has been shown that the use of beam theory for cylindrical shells gives sufficiently accurate results when shear deformation is included.(11)(12)

C. Fuel Assemblies

The fuel assemblies are modeled as uniform beams with rotational springs at each end to represent the proper end condition. The member properties for the beam elements representing the fuel assemblies are derived from the results of experimental tests of the fuel-assembly load deflection characteristics and fundamental natural frequency.

D. Support-Barrel Flanges

To obtain accurate lateral and vertical stiffness of the upper and lower core-support barrel flanges and the upper guide structure support barrel upper flange, finite-element analyses of these regions are performed. As shown in Figure 3.7.40-6 these areas are modeled with quadrilateral and triangular ring elements. Unit deflections and rotations are applied in the lateral and axial directions, and the resulting reaction forces are calculated. These

results are then used to derive the equivalent member properties for the flanges.

E. Upper Guide Structure

For the horizontal model, the upper guide structure including CEA shrouds, connecting plates and tie rods are modeled as contilever beams. A separate member is modeled to account for the connection between the tie rods and the upper guide structure support plate.

F. Lower Support Structure

To obtain vertical stiffnesses for the lower support structure grid beams and cylinder, a finite element analysis is performed. A top view of the finite element model is shown in Figure 3.7.40-7. Displacements due to vertical (out-of-plane) loads applied at the beam junctions are calculated through the use of a computer program[(13)]. Average stiffness values based on these results yield an equivalent member cross-section area for the vertical model.

3.7.3.14.1.1.1 Mathematical Models applicable to the 3990 MWt

The reactor internals horizontal direction internals and fuel model used in the 3990 MWt Unit seismic evaluations is shown in Figure 3.7.40-4A, and the vertical direction model is shown in Figure 3.7.40-8A. These models are the same as used for the structural evaluations of the 3800 MWt Units except that the fuel assembly weights and rotary inertias were increased to account for the weight of the value added fuel. The vertical direction model was used to obtain the fuel response loads.

Detailed horizontal direction core models of the longest row with 17 assemblies (3.7.40-5A) and the shortest row with 7 assemblies were to obtain the fuel assembly deflected shapes at times of maximum response loadings and the maximum one-sided and through-grid response loads.

3.7.3.14.1.2 Analytical Techniques

A. Natural Frequencies and Mode Shapes

The mass- and beam-element properties of the models are utilized in a computer program to obtain the natural frequencies and mode shapes. This computer code is described in section 3.9.1.2.3.7. The program utilizes the stiffness-matrix method of structural analysis. The natural frequencies and mode shapes are extracted from the system of equations:

$$(\underline{K} - W_n^2 \underline{M}) \phi_n = 0 \qquad (12)$$

where:

$\underline{K}$ = model stiffness matrix

$\underline{M}$ = model mass matrix

W_n = natural circular frequency for the n^{th} mode

ϕ_n = normal mode shape matrix for n^{th} mode

The mass matrix, $\underline{M}$, includes the hydrodynamic and structural masses.

B. Response Calculations Methods

1. Response Spectra Method

The response spectrum analysis is performed using the modal extraction data and the following relationships for each mode:

a. Nodal Accelerations

$$\ddot{X}_{in} = \gamma_n A_n \phi_{in} \qquad (13)$$

where:

$\ddot{X}_{in}$ = absolute acceleration at node "i" for node "n"

γ_n = modal participation factor

A_n = modal acceleration from response spectrum

ϕ_{in} = mode shape factor at node "i" for node "n"

b. Nodal Displacement

$$Y_{in} = \frac{\ddot{X}_{in}}{W_n{}^2} \qquad (14)$$

where:

Y_{in} = displacement at node "i" for mode "n" relative to base

W_n = natural circular frequency for n^{th} mode

c. Member Forces and Moments

$$F_n = \frac{(\gamma_n A_n)}{W_n^2} \bar{F}_n \qquad (15)$$

where:

F_n = actual member force for mode "n"

$\bar{F}_n$ = modal member force for mode "n"

The effect of the fluid environment is accounted for by defining the modal participation as follows:

$$\gamma_n = \frac{\sum_{j=1}^{M} W_{si} \phi_{in}}{\sum_{i=1}^{M} \sum_{j=1}^{M} \phi_{in} W_{ij} \phi_{jn}} \qquad (16)$$

where:

W_{si} = structural weight of node "i"

W_{ij} = structural + hydrodynamic weight terms

M = number of masses

The SRSS method is normally used to combine the modal responses. Where modal frequencies are closely spaced, the responses of these modes are combined by the sum of their absolute values. The modal damping factors are obtained by the method of "mass mode weighting", which gives:

$$B_n = \frac{\sum M_i\ \phi_{in}\ B_i}{\sum M_i\ \phi_{in}} \tag{17}$$

where:

B_n = modal damping factor

M_i = structural mass of mass node "i"

ϕ_{in} = absolute value of the mode shape at mass node "i"

B_i = damping associated with mass point "i"

C. Nonlinear Analysis

The nonlinear seismic response and impact forces for the internals and fuel are determined using the CESHOCK computer program (refer section 3.9.1.2.3-5). The computer program provides the numerical solution to transient dynamic problems by step-by-step integration of the differential equations of motion. The input excitation for the model is the time-history accelogram of the reactor vessel.

Input to the CESHOCK computer program consists of lumped masses, linear-spring stiffnesses, mass moments of inertia, nonlinear spring loads vs. deflection curves, and the acceleration time-histories. The output from the CESHOCK computer program consists of displacements, translational and angular accelerations, impact forces, shears, and moments.

D. Non-linear Analysis Applicable to Units with Core Power of 3990 MWt.

The methodology provided in Section 3.7.3.14.1.2C is also applicable to the 3990 MWt Unit.

3.7.3.14.1.3 Results

The nonlinear response loads for the internals, including impacting if any exist, are determined for the vertical and horizontal directions. Loads for the fuel are determined in a separate reactor core nonlinear analysis. The results are determined for the Safe Shutdown Earthquake (SSE) and the Operational Basis Earthquake (OBE).

Section 3.7.3.14.1.3 results applicable to the 3990 MWt Unit.

The above results also apply to the 3990 MWt Unit.

3.7.3.14.2 Control Element Drive Mechanisms (CEDM)

The pressure-retaining components of the CEDM are designed to the appropriate stress criteria of ASME Code Section III for all loadings specified. The structural integrity of the CEDM when subjected to seismic loadings is verified by combination of test and analysis. Methods of modal dynamic analysis

employing response spectrum techniques or time history analysis are supported with experimentally obtained information.

3.7.3.14.2.1 Input Excitation Data

For the dynamic analyses, a response spectra or time history definition of the excitation at the base of the CEDM nozzle is obtained from the seismic analysis of the RCS. The excitation is applied simultaneously in three mutually perpendicular directions (2 horizontal and 1 vertical).

3.7.3.14.2.2 Analysis

A dynamic analysis of the mathematical structural model is performed utilizing one or more of the computer programs discussed in section 3.9.1.2.

3.7.3.14.2.3 Tests

A functional test utilizing a minimum drop weight is performed to verify that drop characteristics meet the input design requirements. Results from this test are compared to the calculated CEDM deflections under seismic loading for the individual site. Verification of the proper function is thus established based on both analytical and test results.

3.7.3.15 Analysis Procedure for Damping

3.7.3.15.1 NSSS Seismic Systems

Composite modal damping values are used in analyzing the major components of the reactor coolant system using a reactor coolant system model coupled with a model of the containment building with foundation springs.

The composite modal damping values are obtained in three steps. In the first step, the equivalent modal damping values for the fixed-base model that consists of containment building and reactor coolant system are calculated by the mass weighting technique as described in Section 3.2 of BC-TOP-4A. In the second step, the complete coupled system damping matrix is formed by coupling the fixed-base damping matrix and the soil impedances.(16) Finally, the composite modal damping values for the coupled system are then calculated by assuming that normal modes exist in the classical sense, which is equivalent to retaining the diagonal terms in the coupled system damping matrix in generalized coordinates.(17)(18) The actual damping values used are contained in table 3.7-13.

3.7.3.15.2 Systems Other Than NSSS

The analysis procedure for damping of Seismic Category I subsystems is given in Section 3.2.1 of BC-TOP-4-A. The damping used in the analysis of piping systems is described in BP-TOP-1.

3.7.4 SEISMIC INSTRUMENTATION

3.7.4.1 Comparison with Regulatory Guide 1.12, Revision 2

Seismic instrumentation is provided on the basis of architect-engineer experience with seismic instrumentation used on other nuclear power plants and on the basis of currently available technology of equipment testing and qualification. In conformance with Regulatory Guide 1.12, Revision 2, Section B, only one complete set of seismic instrumentation as described below is provided for the site. Since the expected seismic

response is the same for all units, one set of seismic instrumentation installed on Unit 1 meets the requirements of Regulatory Guide 1.12, Revision 2, except as noted in section 1.8. The instrumentation program complies with Regulatory Guide 1.12, Revision 2, except as noted in section 1.8.

3.7.4.2 Location and Description of Instrumentation

The following instrumentation and associated equipment are used to measure plant response to earthquake motion:

- Six (6) – Force Balance Accelerometer (FBA) Units
- Six (6) – Recorders
- Alarm Panel
- Central Controller
- UPS (uninterruptible power supply)
- Control Panel

Table 3.7-13
FREQUENCIES AND COMPOSITE MODAL DAMPING VALUES [(a)]
(Sheet 1 of 3)

Mode No.	Operating Basis Earthquake (OBE)		Safe Shutdown Earthquake (SSE)	
	Frequency (Hz)	Composite Modal Damping Value	Frequency (Hz)	Composite Modal Damping Value
1	1.74	1.98	1.67	11.50
2	1.74	1.98	1.67	11.50
3	1.88	10.4	1.74	2.90
4	1.88	10.5	1.74	2.89
5	3.9	63.8	3.26	63.80
6	4.23	50.1	3.74	56.50
7	4.24	49.8	3.75	56.30
8	7.34	3.18	7.33	5.47
9	7.42	3.25	7.42	5.50
10	10.09	2.15	10.01	4.85
11	10.69	2.07	10.35	36.40
12	11.18	32.6	10.6	4.77
13	12.11	2.09	12.11	3.25
14	12.36	2.06	12.36	3.13
15	12.93	2.03	12.93	3.07
16	12.93	2.03	12.93	3.07
17	13.08	2.7	13.08	4.56
18	13.24	2.16	13.24	3.37
19	13.6	2.05	13.59	3.20
20	13.97	1.9	13.61	3.72
21	14.82	2.02	14.82	3.04
22	14.83	2.02	14.83	3.06
23	14.94	2.08	14.94	3.23
24	15.54	1.72	15.23	3.05
25	17.73	2.05	17.72	4.63
26	17.74	2.04	17.72	4.70
27	17.92	2.02	17.92	3.16
28	17.97	2.02	17.97	3.04

Table 3.7-13
FREQUENCIES AND COMPOSITE MODAL DAMPING VALUES [(a)]
(Sheet 2 of 3)

Mode No.	Operating Basis Earthquake (OBE)		Safe Shutdown Earthquake (SSE)	
	Frequency (Hz)	Composite Modal Damping Value	Frequency (Hz)	Composite Modal Damping Value
29	18.02	2.02	18.01	3.37
30	18.03	2.01	18.03	3.32
31	18.6	2.87	18.6	4.82
32	18.9	2.89	18.9	4.78
33	18.95	2.07	18.95	3.18
34	19.5	2.03	19.49	3.77
35	21.18	2.04	21.14	4.16
36	21.49	2.01	21.49	3.03
37	21.5	2.01	21.5	3.02
38	21.66	2.14	21.66	3.31
39	21.77	2.12	21.74	3.27
40	22.06	2.07	22.06	3.15
41	23.19	2.46	23.19	3.92
42	23.22	2.45	23.22	3.91
43	24.42	2	24.42	3.00
44	24.61	3.49	24.58	6.40
45	26.06	2.01	26.06	3.02
46	26.86	3.17	26.85	6.03
47	30.71	2.22	30.7	5.14
48	31.36	2.3	31.35	4.62
49	31.54	2.19	31.53	3.84
50	31.58	2.02	31.58	3.04
51	31.88	2.01	31.88	3.02
52	31.91	2.02	31.91	3.10
53	32.29	2.02	32.29	3.03
54	34.46	2.03	34.46	5.01
55	34.56	2.04	34.56	5.03

Table 3.7-13
FREQUENCIES AND COMPOSITE MODAL DAMPING VALUES [(a)]
(Sheet 3 of 3)

Mode No.	Operating Basis Earthquake (OBE)		Safe Shutdown Earthquake (SSE)	
	Frequency (Hz)	Composite Modal Damping Value	Frequency (Hz)	Composite Modal Damping Value
56	36.57	2.53	36.57	4.08
57	36.81	2.56	36.81	4.13
58	37.49	2.29	37.49	3.58
59	37.52	2.22	37.52	3.44
60	37.55	2	37.55	3.01
61	37.55	2	37.55	3.00
62	37.64	2.14	37.64	3.28
63	37.73	2.08	37.73	3.16
64	40.93	2.01	40.93	3.02
65	43.18	2.01	43.18	3.02
66	43.44	3.84	43.44	6.82
67	44.59	2.2	44.59	3.39
68	44.6	2.2	44.6	3.39
69	46.92	2.39	46.92	5.38
70	46.98	2.05	46.98	5.05
71	47.56	2	47.56	3.01
72	48.49	2.01	48.49	3.03
73	48.66	2.48	48.66	5.48
74	49.34	3.66	49.33	6.64
75	53.12	3.79	53.11	6.78

a. Composite modal damping values are expressed as a percentage of critical modal damping.

3.7.4.2.1 Force Balance Accelerometer (FBA) Unit

The FBA unit is used to measure the time varying acceleration input from an earthquake, and relaying the information to its corresponding recorder for information storing. Each FBA unit houses three (3) orthogonally mounted force balance accelerometers. Each force balance accelerometer measures a different axial acceleration (longitudinal, transverse, and vertical) of an earthquake. The measured data of an earthquake is used to produce a response spectrum, which is used for analysis and comparison with that of the plant's design. The FBA unit is positioned with its main horizontal axis in parallel with the major horizontal axis assumed in the seismic analysis. The location of each FBA unit is provided in Table 3.7.4.2.1-1.

Table 3.7.4.2.1-1
ACCELEROMETER UNIT LOCATION:

Motion Sensor Accelerometer Units (6)	**Location**
1	55' (Containment Bldg. – Tendon Gallery)
1	80' (Containment Bldg. – Floor)
1	140' (Containment Bldg. – Floor)
1	74' (Control Bldg. – Base Slab)
1	160' (Control Bldg. – Floor)
1	Free Field (South side of OSB Bldg., referencing Plant North)

3.7.4.2.2 Recorder

The recorders are housed in the control panel, which is located at the 140' level of the Control building in Unit 1. The main

function of the recorder is to record the acceleration input of an earthquake sent from its corresponding FBA unit.

The recorder consists basically of an ADC (analog to digital converter), MCU (main control unit), PCMCIA (Personal Computer Memory Card International Association) flash memory card, power supply charger, and an internal battery backup.

The analog acceleration data of an earthquake, sent from the FBA unit to its corresponding recorder, is converted to digital form by the ADC. The digital data is processed and sent to the MCU for examination. The MCU examines the digital data and determines if the acceleration exceeds the set trigger threshold. If the trigger threshold is exceeded, the recorder initiates and starts recording the digitized acceleration of the earthquake on the PCMCIA flash memory card. All the recorders will automatically activate and start recording when the set trigger threshold for a recorder is exceeded.

The recorder operates on direct current (DC) power provided by the power supply charger, which converts the local AC power to DC power. The power supply charger also keeps the internal battery fully charged. The internal battery provides DC power to the recorder during a loss of local AC power for up to 30 hours.

3.7.4.2.3 Central Controller

The central controller is a standard personal computer (motherboard, central processing unit, and hard drive). The central controller takes the recorded digital data stored on the PCMCIA flash memory cards, and through application software computes the response spectrum of an earthquake. The computed

response spectrum is stored on the local hard drive. A hard copy of the response spectrum can be printed out on the printer at the control panel.

3.7.4.2.4 UPS (Uninterruptible Power Supply)

The main function of the UPS is to provide backup power to the central controller, visual display, and printer during the loss of local AC power. The UPS provides 1 hour of battery backup power. If the loss of AC power should occur during an earthquake, the response spectrum can still be computed, stored on the hard drive, and retrieved for analysis.

3.7.4.2.5 Alarm Panel

The alarm panel is linked to the plant’s annunciator system in Unit 1. The audible and visual annunciation in the control room is activated if an anomaly has occurred. The anomaly can be a seismic event (exceedance of a trigger threshold setpoint), an OBE exceedance, or a health problem with the seismic monitoring system. The exact cause of the annunciation is displayed at the control panel.

3.7.4.2.6 System Control Panel

The control panel is located on the 140' level of Control building in Unit 1. The control panel houses the alarm panel, recorders, display screen, keyboard terminal, central controller, printer, and the UPS. The seismic instrumentation is controlled and monitored through the use of a custom graphical user interfSace software, along with the display screen for viewing, and the keyboard terminal/mouse for input.

The central controller in conjunction with recorders, and FBA units produce a time-history record of an earthquake. The time-history of an earthquake is stored on the local hard drive and printed in hard copy form by the printer. Each recorder has an internal trigger which can be set to activate the recorder for recording. The trigger threshold for the recorder is set at the control panel through the graphical user interface software, and the keyboard terminal/mouse.

3.7.4.3 Control Room Operator Notification

The activation of the audible and visual alarm in the Unit 1 control room will signify an anomaly has occurred. The anomaly can be a seismic event (exceedance of a trigger threshold setpoint), an OBE exceedance, or a health problem with the seismic monitoring system. The exact cause of the annunciation is displayed at the control panel. If a seismic event has occurred, notification to the control rooms of Unit 2 and Unit 3 will be done administratively by the control room of Unit 1.

Exceeding the trigger threshold setpoint causes an audible and visual annunciation in the control room, alerting the plant operator that an earthquake has occurred. The annunciation of a seismic event is initially set to occur at 0.01g horizontal and/or vertical acceleration for the free-field, Containment tendon gallery (55'), Control building foundation (74'). Annunciation is also set to occur at 0.02g horizontal and/or vertical acceleration for the Containment floor (80'), for the Containment operating floor (140') and the upper cable spreading room of the Control building (160'). These levels cause initiation of the recording system at horizontal or vertical acceleration levels slightly higher than the expected

background level; including induced vibrations from sources such as traffic, elevators, people, and machinery. These setpoints are based on experience at PVNGS and in existing plants and may be changed once significant plant operating data have been obtained which indicate that a different setpoint would provide better FBA system operation.

The peak acceleration level experienced at the free-field is available immediately following the earthquake. The information is obtained by retrieving the stored data from the free-field location, using the graphical user interface software and the keyboard terminal/mouse. The peak value is displayed on the visual display screen for viewing. A hardcopy of the peak value is produced by the printer.

3.7.4.4 Comparison of Measured and Predicted Responses

Initial determination of the earthquake level is performed immediately after the earthquake by performing a OBE (operating basis earthquake) response spectrum check and a cumulative absolute velocity (CAV) check for the free field. (Reg. Guide 1.166, (4.1), (4.2), March '97).

If the OBE response spectrum check and the CAV check were exceeded, the OBE was exceeded and plant shutdown is required. (Reg. Guide 1.166, (5.1), March '97).

After the earthquake, the acceleration data from the recorders are retrieved for each location of the FBA units. The acceleration data is used to compute the response spectra. The response spectra are compared with those used in the plant design, to determine whether the containment structure, or other Seismic Category I structures, system, and components is

still adequate for future use. The structure, system, or components is considered adequate for future operations if the measured responses are less that the values used in the design and qualification of the Seismic Category I structures, systems, and components; otherwise a new analysis is made to check the adequacy of these items for future use.

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3.8 DESIGN OF CATEGORY I STRUCTURES

This section provides information on the containment building, its internal structure, other Category I structures, and their foundations and supports. Refer to section 3A.12 for additional discussion.

3.8.1 CONCRETE CONTAINMENT

The containment structure is designed to house the reactor coolant system (RCS) and is referred to as the containment. The containment is part of the containment system whose functional requirements are summarized by the following criteria:

A. The containment must withstand the peak pressure and time-varying thermal gradient resulting from a hypothetical failure of the RCS or main steam system as discussed in subsection 6.2.1.

B. The containment must provide biological shielding during normal operation and following a postulated loss-of-coolant accident (LOCA) to minimize radiation exposure.

C. The containment must be leaktight in order to minimize leakage of airborne radioactive materials.

D. The containment must provide approximately 150 penetrations for piping and electrical cabling, as well as personnel and equipment access, and provides rigid anchor points for piping entering or leaving the containment.

This section describes the structural design considerations for the containment. Further information relative to the containment is covered in Topical Report BC-TOP-5A which provides the bases for design, construction, testing, and surveillance for the prestressed concrete containment.

3.8.1.1 Description of the Containment

3.8.1.1.1 Containment Basic Configuration

The containment consists of three basic parts:

- Flat base slab with a central cavity and an instrumentation tunnel
- Right circular cylinder
- Hemispherical dome

Principal nominal dimensions of the containment are as follows:

Interior diameter	146 feet
Interior height (above filler slab)	206 feet 6 inches
Cylindrical wall thickness	4 feet 0 inch
Dome thickness	3 feet 6 inches at dome apex 4 feet 0 inch at wall springline
Basemat thickness	10 feet 6 inches
Liner plate thickness	1/4 inch
Internal free volume	2,600,000 cubic feet net

Typical sections and details are shown in engineering drawings 13-P-OOB-002 through –011.

The containment is constructed of reinforced concrete pre-stressed by post-tensioned tendons in the cylinder and the dome. The basemat is designed and constructed of conventionally reinforced concrete (engineering drawings 13-C-ZCS-102 and -104). Special reinforcing details are provided at discontinuities and at openings in the shell. Typical shell wall and dome reinforcing steel details are shown in engineering drawings 13-C-ZCS-108, -111, -114, -115, -123 and –124.

A welded steel liner attached to the inside face of the concrete limits the release of radioactivity from the containment. The base liner is installed on the top of the basemat and is covered by a 2-foot 9-inch-thick concrete slab. The containment building provides biological shielding during normal operation and following a LOCA. It also functions as a leak-tight barrier following an accident inside the containment.

3.8.1.1.2 Post-Tensioning System

The tendon system is shown in figures 3.8-1, 3.8-2 and engineering drawings 13-C-ZCS-175, -177 and -181. High strength wires are used with buttonhead anchorage techniques. There are 186 1/4-inch diameter wires per tendon.

Each tendon assembly consists of wires together with end anchor heads and ring nuts. The tendons transfer load to the structure through shims and a bearing plate.

Tendons are installed in sheaths that form ducts through the concrete between anchorage points. Trumpets, which are enlarged ducts attached to the bearing plate, allow the wires to spread out at the anchorage to suit buttonhead spacing requirements. Further, trumpets facilitate field buttonheading of wires.

Tendon sheathing provides an enclosed space surrounding each tendon. A valved vent at the highest points of curvature permits release of entrapped air during greasing operations. Drains are provided at the lowest points of curvature to remove accumulated water prior to installing tendons. After the greasing operation, the vents and drains are closed and sealed.

The prestressing tendons are protected against atmospheric corrosion during shipment and installation, and during the life of the containment. Prior to shipment, the tendons are coated with a thin film of petrolatum containing rust inhibitors. The sheathing filler material used for permanent corrosion protection is a modified, refined petroleum-base product. The material is pumped into the sheathing after stressing.

Prestressing of the cylindrical wall is achieved by a post-tensioning system consisting of both vertical inverted U-shaped and circumferential (hoop) tendons. Vertical tendons are anchored at the base slab and extend up and over the dome to form an inverted U-shape. Three buttresses are equally spaced

at 120° around the cylinder and extend over the dome, joining together at the crown. The hoop tendons are anchored at buttresses located at 240° apart. The successive hoop tendons are anchored at alternate buttresses so that two complete horizontal loops are achieved by three consecutive horizontal tendons. Refer to figure 3.8-2 for buttress arrangement and schematic arrangement of hoop tendons.

Prestressing of the hemispherical dome is achieved by a two-way pattern of tendons, which are an extension of the continuous vertical tendons and are anchored at the base slab. They are arranged to produce two families of tendons mutually intersecting each other at 90° on the horizontal projected plane. Hoop tendons extend into the hemispherical region to provide a two-way pattern up to the 90° solid angle of the dome. Refer to engineering drawing 13-C-ZCS-177 for schematic arrangement of dome tendons.

3.8.1.1.3 Liner Plate System

3.8.1.1.3.1 Liner Plate and Anchors. A welded steel liner plate covers the entire inside surface of the containment (excluding penetrations) to satisfy the leaktight criteria. The liner is typically 1/4 inch thick and is thickened locally around penetration sleeves, large brackets, and attachments to the basemat and shell wall. The stability of the liner plate, including the thickened plate, is controlled by anchoring it to the concrete structure. The shell wall and dome liner plate system is also used as a form for construction. Typical details of the liner plate system and anchors are shown in

engineering drawings 13-C-ZCS-200, -201, -205, -206, -207, -211, -212, -213, -215 and -217.

3.8.1.1.3.2 Equipment and Personnel Penetration Assemblies. A circular equipment hatch and two personnel airlock assemblies penetrate the concrete cylinder walls. Penetration assemblies consist of steel sleeves or nozzles, reinforcing plates, and anchors. They are anchored to the concrete walls and are welded to the steel liner. Hatch and air lock doors are provided with double-gasketed flanges with provisions for leak testing the flange-gasket combinations.

One of the two personnel air locks is for emergency access. Each personnel air lock has a door at each end and is an ASME Code-stamped pressure vessel. A quick-acting equalizing valve connects the personnel air lock with the interior or exterior of the containment to equalize pressure in the two systems.

During plant operation, the two doors of each personnel air lock are interlocked to prevent both being opened simultaneously.

Provision is made to bypass the interlock system during plant cold shutdown. Equipment hatch and personnel airlock liner plate penetration details are shown in engineering drawings 13-C-ZCS-206, -207 and –212.

3.8.1.1.3.3 Process Pipe Penetration Assemblies. Single barrier piping penetrations are provided for all piping passing through the containment walls. The closure for process piping

to the liner plate is accomplished with a special flued head welded into the piping system and to the penetration sleeve which is, in turn, welded to a reinforced section of the liner plate. In the case of piping carrying hot fluid, the pipe is insulated to prevent excessive concrete temperatures and to prevent excessive heat loss from the fluid. Closures to these penetration assemblies are provided by the piping systems that are served by the penetrations. For typical details of the pipe penetration assemblies used in the shell wall, refer to engineering drawings 13-C-ZCS-205, -206 and –213.

3.8.1.1.3.4 Electrical Penetration Assemblies. Electrical penetration assemblies provide means for carrying one or more electric circuits through a single aperture (nozzle) in the containment pressure barrier while maintaining the integrity of the pressure barrier.

Medium voltage power penetrations are configured in the form of a tubular canister slightly shorter than the containment structure nozzle into which it will be installed. The penetration assemblies are installed in 24-inch diameter nozzles. The canister is used as a pressure chamber to monitor penetration leakage rate by pressurizing the interior space with nitrogen and measuring the leak rate with a pressure gauge. The medium voltage power penetration is flange-mounted to the outside containment wall with nuts, bolts, washers, and lock-washers. The aperture seal is formed between the header plate and the flange with two concentric Viton O-rings.

The low voltage power, control, and instrumentation penetrations are also flange-mounted to the outside containment wall in the manner described for the medium voltage power penetrations. Each penetration in this category has a stainless steel header plate at the outside containment end. Stainless steel feed-through subassemblies, containing electrical conductors, pass through the header plate and are secured and sealed with special stainless steel compression fittings. The interstices between the seals and feed-through subassemblies provide a pressure chamber which is used to monitor the leakage rate. These penetrations are installed in 12- or 18-inch diameter nozzles.

For locations of electrical penetration sleeves, refer to engineering drawings 13-C-ZCS-205 and -206.

3.8.1.1.3.5 Fuel Transfer Tube. A fuel transfer tube penetration is provided for refueling. An inner pipe acts as the refueling tube with an outer pipe as the housing. The tube is fitted with a double-gasketed blind flange in the refueling canal and a standard gate valve in the spent fuel pool. This arrangement prevents leakage through the refueling tube. Outer sleeves permit the transfer tube to penetrate the refueling canal wall, the containment shell, and the exterior wall of the fuel handling building, while maintaining a pressure-tight boundary at each wall. The sleeves are anchored into each wall respectively and welded to each wall's liner plate. The housing is supported by the sleeves in the vertical and horizontal directions. Bellows at both the interior and

exterior faces of the containment shell and of the fuel handling building permit thermal expansion of the transfer tube and of the housing. The same expansion bellows permit differential movement between structures. Details are shown in engineering drawings 13-C-ZCS-206 and -211.

3.8.1.1.3.6 Attachments and Brackets. Attachments to the shell wall are brackets for support of the polar crane, electrical conduit and cable tray, spray piping, lighting and ventilation. The polar crane support brackets consist of built-up steel plate, the top flange penetrating the thickened liner plate, and are anchored in the concrete of the shell wall. For details, see engineering drawings 13-C-ZCS-205, -206, -207 and -215.

Attachments to the basemat include anchor bolts for columns that support floors and reinforcing steel for internal structures support. Attachment of the reinforcing steel is accomplished by B-series cadweld connectors welded to the top and bottom of the thickened liner plate.

3.8.1.1.4 Shell Discontinuities

Significant discontinuities in the shell structure are at the wall-to-basemat connection, the buttresses, and the large penetration openings.

3.8.1.1.4.1 Wall-to-Basemat Connection. The shell wall interface at the basemat is designed to accommodate axial

forces, moments, and shears. Refer to engineering drawing 13-C-ZCS-104 for details.

3.8.1.1.4.2 Buttresses. Buttresses project out from the shell wall and dome surface to provide adequate space for hoop tendon anchorage and tendon stressing equipment. The anchorage surfaces of the buttress are normal to the tangent line of hoop tendons anchored. Details are shown in engineering drawings 13-C-ZCS-114 and -115.

3.8.1.1.4.3 Large Penetration Openings. The concrete shell around the equipment hatch opening and around the penetrations for the main steam and feedwater pipes is thickened as shown in engineering drawing 13-C-ZCS-117.

3.8.1.2 Applicable Codes, Standards, and Specifications

The following codes, standards, regulations, specifications, design criteria, and NRC Regulatory Guides constitute the basis for the design, fabrication, construction, testing, and inservice inspection of the containment structures. Modifications to these codes, standards, etc., are made when necessary to meet the specific requirements of the structure. These modifications are indicated in the sections where references to the codes and standards are made. Later editions of certain baseline standards as noted in subsequent sections are acceptable provided they are identified in applicable design calculations or specifications for fabrication, construction, testing, or inspection.

3.8.1.2.1 Regulations

The following regulations apply to containment design:

- Code of Federal Regulations, Title 10-Atomic Energy, Part 50, Domestic Licensing of Production and Utilization Facilities, 1972
- Code of Federal Regulations, Title 29-Labor, Part 1910, Occupational Safety and Health Standards, 1972

3.8.1.2.2 Codes and Standard Specifications

The following codes and standards are applicable to containment design:

- American Concrete Institute, Building Code Requirements for Reinforced Concrete (ACI 318-71).
  - In the containment design, portions of this Code, particularly Chapters 18, 19, and Appendix A, are superseded by the other provisions described in subsection 3.8.1.
- American Institute for Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, adopted February 12, 1969 and Supplement Nos. 1, 2, and 3, or later edition.
- American Institute of Steel Construction (AISC), Specification for Structural Joints Using ASTM A325 or A490 Bolts Approved by the Research Council on Riveted

and Bolted Structural Joints of the Engineering Foundation, May 8, 1974, or later.

- American Society of Mechanical Engineers (ASME), Boiler and Pressure Vessel (B&PV) Code, Section II, 1974 Edition and Addenda through Winter 1974; Section III, Division 1, 1974 Edition and Addenda through Winter 1974; Section III, Division 2, Article CC-3000, 1975 Edition and Addenda through Winter 1975; Section V, 1974 Edition and Addenda through Summer 1974; Section VIII, Division 1, 1974 Edition and Addenda through Winter 1975; Section IX, 1974 Edition and Addenda through Winter 1974; Section XI, Subsections IWE and IWL, 1992 Edition with the 1992 Addenda.

- American Welding Society (AWS), Structural Welding Code (AWS D1.1-72, Rev. 1-1973 or later version) except as noted in paragraph 3.8.1.6.6.1, listing A.

- Crane Manufacturers Association of America Inc., CMAA Specification No. 70, 1971.

- American National Standards Institute (ANSI), Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel during the Construction Phase of Nuclear Power Plants (ANSI N45.2.5-1974) except as noted in paragraph 3.8.1.6.1.2, listings A and H, and paragraph 3.8.1.6.6.1, listing D.

3.8.1.2.3 General Design Criteria, Industry Standards, and Topical Reports

The following general design criteria, industry standards, and topical reports apply to containment design:

- NRC Regulatory Guides (applicable revisions and dates are provided in section 1.8)
  - Regulatory Guide 1.10, Mechanical (Cadweld) Splices in Reinforcing Bars of Category I Concrete Structures
  - Regulatory Guide 1.15, Testing of Reinforcing Bars for Category I Concrete Structures
  - Regulatory Guide 1.18, Structural Acceptance Test for Concrete Primary Reactor Containments
  - Regulatory Guide 1.19, Nondestructive Examination of Primary Containment Liner Welds
  - Regulatory Guide 1.29, Seismic Design Classification
  - Regulatory Guide 1.35, Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures
  - Regulatory Guide 1.46, Protection Against Pipe Whip Inside Containment

- Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants
- Regulatory Guide 1.55, Concrete Placement in Category I Structures
- Regulatory Guide 1.59, Design Basis Floods for Nuclear Power Plants
- Regulatory Guide 1.60, Design Response Spectra for Seismic Design of Nuclear Power Plants
- Regulatory Guide 1.61, Damping Values for Seismic Design of Nuclear Power Plants
- Regulatory Guide 1.63, Electrical Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants
- Regulatory Guide 1.64, Quality Assurance Requirements for the Design of Nuclear Power Plants
- Regulatory Guide 1.69, Concrete Radiation Shields for Nuclear Power Plants
- Regulatory Guide 1.76, Design Basis Tornado for Nuclear Power Plants
- Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural

Steel During the Construction Phase of Nuclear Power Plants.

Exceptions to and interpretations of these regulatory guides are given in section 1.8. In addition, inservice inspection of the containment liner plate, exterior concrete surface, and tendon post-tensioned system shall be per the requirements of ASME Section XI, Subsections IWE and IWL, 1992 Edition with the 1992 Addenda, as modified and supplemented by 10 CFR 50.55a.

- NRC (AEC) Publication TID 25021, Nuclear Reactors and Earthquakes, is used for computing hydrodynamic loads imposed on the refueling canal walls.

- Industry Standards

  Nationally recognized industry standards, such as those published by American Society for Testing and Materials (ASTM), are used whenever possible to describe material properties, testing procedures, fabrication, and construction methods.

- Bechtel Power Corporation Topical Reports (applicable titles, dates, and revisions are provided in section 1.6.

  - BC-TOP-1
  - BC-TOP-3-A
  - BC-TOP-4-A
  - BC-TOP-5-A

- BC-TOP-7
- BC-TOP-8
- BC-TOP-9-A

3.8.1.2.4 Project Design and Construction Specifications

Project design and construction specifications are prepared to cover the areas related to design and construction of the containments. These specifications, prepared specifically for PVNGS, emphasize important points of the industry standards for the design and construction of the containment, and reduce options that otherwise would be permitted by the industry standards. Unless specifically noted otherwise, these specifications do not deviate from the applicable industry standards. They cover the following subject areas:

- Excavation and backfill
- Concrete placement
- Inspection of concrete production
- Reinforcement steel placement
- Structural steel erection
- Miscellaneous metalwork installation
- Stainless steel liner plate system installation
- Post-tensioning system embedded items installation
- Concrete and concrete products

- Reinforcing steel and associated products
- Prestressing steel and related accessories
- Structural steel
- Miscellaneous steel and embedded materials
- Stainless steel liner plate
- Containment polar cranes
- Containment liner plate system including locks and hatches
- Fuel transfer tube

3.8.1.3 Loads and Load Combinations

Applicable loads and load combinations used and the load factors selected for each load component are listed in ASME B&PV Code, Section III, Division 2, Article CC-3000 (Subarticle CC-3200). These loads and load combinations are used in the design and analysis of the overall structure, as well as in the design and analysis of components and localized areas. Wind and tornado loads, flood design bases, and the seismic loads are given in sections 3.3, 3.4, and 3.7, respectively. Pressure transients resulting from the LOCA and MSLB serve as the design basis for the containment design pressure of 60 psig. The prestressing forces (F) are related to P_a as discussed in Section 6.2.1 of BC-TOP-5-A. Missile effects and postulated pipe rupture effects are discussed in sections 3.5 and 3.6, respectively.

Upon completion of construction, the containment and its penetrations are tested at 115% of the design pressure as discussed in paragraph 3.8.1.7.

The design pressure will not be exceeded during any subsequent long-term pressure transient caused by the combined effects of heat sources. These effects are overcome by the combination of safety features and heat sinks.

The temperature gradient through a typical PWR containment wall during operating conditions and during LOCA is shown in Figure 7-5 of BC-TOP-5-A. The variation of temperature with time and the expansion of the liner plate with temperature are considered in determining the thermal stresses.

3.8.1.4 Design and Analyses Procedures

3.8.1.4.1 Analytical Methods

The analysis of the containment structure complies with the requirements of ASME Section III, Division 2, Article CC-3000. Classical theory, empirical equations, and numerical methods were applied as necessary for the analysis of structural elements. They are described in BC-TOP-5-A.

3.8.1.4.2 Design Methods

The design of the containment structure complies with the requirements of ASME Section III, Division 2, Article CC-3000, supplemented by the design methods described in BC-TOP-5-A, Sections 6.2 and 6.3. They involved the initial proportioning of structures using the results of preliminary analyses.

Experience based on complete design, as well as parametric studies of other structures of a similar nature, was used.

The final design phase incorporated and refined information gained in earlier phases. It also incorporated closer approximations of the equipment and piping and related loads based on completion of detailed engineering design.

The containment is considered an axisymmetric structure for the overall analysis (BC-TOP-5-A, Section 7.2.1). Although there are deviations from this ideal shape (such as major penetrations), these deviations are localized and are handled by special analyses; hence, axisymmetric analyses are considered acceptable.

The overall analysis of the containment, given the application of axisymmetric loads, is performed by Bechtel's nonlinear FINEL finite-element computer program (BC-TOP-5-A, Section 7.1.2). A detailed description of this program is provided in appendix 3B, section 3B.13. The entire containment is modeled with one finite-element mesh consisting of the shellwall, basemat, internal structure, and soil.

The entire concrete structure is modeled by continuously interconnected elements. The geometry of the mesh allows the representation of reinforcing steel superimposed on the corresponding concrete elements.

The finite-element mesh of the structure is extended into the soil to account for the elastic nature of the soil material and its effect on the behavior of the basemat. The tendon access gallery is analyzed as a separate structure.

The use of the nonlinear finite-element analysis permits accurate determination of the stress pattern at any location of the structure.

Analysis and design of tendon anchorage zones and reinforcement in buttresses are discussed in BC-TOP-7, BC-TOP-8, and BC-TOP-5-A, Section 6.6. The method of analyzing the effect of the penetrations, the thickening, the reinforcements, and the embedments, is discussed in BC-TOP-5-A, Section 7.3. The design of the liner and its anchorage system are covered in BC-TOP-1 and BC-TOP-5-A, Section 7.5.

Information on analyses for computation of seismic loads is provided in section 3.7. The overall analysis of the containment for the application of nonaxisymmetric loads is performed by Bechtel's linear elastic ASHSD finite-element computer program. A detailed description of this program is provided in appendix 3B, section 3B.2. Comparisons of predictions were made, as appropriate, within allowable values of stresses, strains, deformations, and capacities. This procedure was used for both preliminary and final phases of design.

3.8.1.4.3 Computer Programs

The programs used in the computer analyses and design of the containment for static and dynamic loads are discussed in appendix 3B. The verification of these programs is also provided in appendix 3B.

3.8.1.4.4 Tendon Anchorage Zones

The design of tendon anchorage zones is based on results of tests presented in BC-TOP-7 and BC-TOP-8 and conforms to the requirements of ASME Section III, Division 2, Paragraph CC-3543.

For a discussion on the design method, refer to BC-TOP-5-A, Section 6. Refer to figures 3.8-1 and 3.8-2 for details of tendon anchorage.

3.8.1.4.5 Reinforcing Steel Design Requirements

The reinforcing steel requirements in the critical areas of the containment shell dome and basemat are described in BC-TOP-5-A.

3.8.1.4.6 Liner Plate Leaktight Barrier

The details which depict the typical liner plate system and stiffeners are shown in BC-TOP-5-A, Figure 6-24.

The design of the liner and its anchorage system is covered in BC-TOP-1 and conforms to the requirements of ASME Section III, Division 2, Article CC-3000.

The relative strength of the liner plate against buckling as compared with its anchor and anchor welds is discussed in BC-TOP-1. BC-TOP-1 provides sample calculations that demonstrate that the strength of the anchor and the anchor welds is sufficient to preclude any possibility of overall buckling failure as a result of anchor pullout.

The elastic and plastic solutions are used to analyze the stresses in the anchors and concrete resulting from a buckled panel of the liner. The panel and anchors are modeled as a series of springs. Using the strains from all loads being considered, equilibrium of forces and compatibility of deformations, the stresses in the anchor and concrete are obtained. BC-TOP-1 provides details and further discussions.

The containment structure has a 1/4-inch liner plate in accordance with the requirements of table 3.8-1.

The liner plate above the spring line of the containment has the shape of a hemispherical dome that is self-supporting during placement of the dome concrete. It is stiffened in two directions. Details of the dome are shown in BC-TOP-5-A, Figure 6-24.

3.8.1.4.7 Brackets and Attachments

For details of the polar crane bracket and thickened liner plate assembly, refer to engineering drawings 13-C-ZCS-115 and -215. The crane bracket is completely shop-fabricated, including the thickened liner plate portion. The crane bracket top flange penetrates the thickened liner plate and is welded to the plate using full penetration welds.

The entire bracket and plate assembly is attached to the 1/4-inch thick liner plate with full penetration welds. In following established procedures, 2% of thickened liner plate perimeter welds are radiographed and 100% vacuum box-tested for

Table 3.8-1

ASTM, ASME, AND AISI MATERIAL SPECIFICATIONS FOR
CONTAINMENT LINER PLATE SYSTEM

Liner plate	SA-285 Grade A A285 Grade C A515 Grade 70
Thickened plates[a]	SA-516 Grade 70, A516 Grade 70
Penetration sleeves[a][b][c]	SA-333 Grade 1 or 6; SA-516 Grade 70
Leak-chase piping	SA-106 Grade B
Liner anchors, leak-chase	SA-36, A36
Cable ground-penetration	A36
Unistruts	A570 Grade A; A611 Grade A
Shear studs	A108
Cadweld connectors	AISI C 1026, ASTM A519
Bolts	A307, SA-325, A490, SA-105 Bar Stock, SA-193 Grade B7 with SA-194 Grade 7 nuts

a. Shall be Charpy V-notch tested for thicknesses over 5/8 inch.

b. Penetration sleeve assemblies are post-weld heat-treated in accordance with ASME Section III.

c. The energy requirements shall be 15 and 20 for SA-333, Grades 1 and 6, respectively.

leaktightness. The thickened plate to 1/4-inch plate weld does not carry the crane loads (refer to paragraph 3.8.3.4.7).

The polar crane box beam bracket is cantilevered from the containment shell. The bracket is designed to resist vertical, radial, tangential loads, torque, and bending moments in vertical and tangential (to the radius) directions. Vertical shear is transferred from the webs of the box beam bracket to the liner reinforcing plate ribs, which, in turn, transfer it to the embedded baseplate and into the concrete. Anchored bearing plates are provided at ends of the top and bottom flange. The top flange is a tension member, embedded in the concrete to develop the shear strength of concrete to prevent trapezoidal type pullout failure.

The bottom flange, in compression, is embedded in the concrete so that it can resist punchout shear due to pyramid type failure on the exterior shell face. Vertical and horizontal reinforcing bars in the vicinity of brackets are provided to resist moments induced by the critical crane loads including earthquake, dead load, live load, and impact loads.

The crane support bracket supports a circumferential crane girder which provides the support for the crane rails. The top of the rail elevation is 207 feet 6 inches and the radius to the centerline of the 171 pounds per yard crane rail is 70 feet 0 inch plus or minus 1/4 inch. The rated capacity of the polar crane is 225 tons.

3.8.1.5 Structural Acceptance Criteria

The structural acceptance criteria complies with ASME Section III, Division 2, Article CC-3000. The fundamental acceptance criteria for the complete containment are successful completion of the structural integrity test with measured responses within the limits predicted by analyses. Prediction of limits are based on test load combinations and code values for stress, strain, or gross deformation for the range of material properties and construction tolerances specified.

The structural integrity test is planned to yield information on both the overall response of the containment and the response of localized areas, such as major penetrations or buttresses, which are important to its design functions. This information, together with the test information documented in BC-TOP-7 and BC-TOP-8, makes possible the assessment of the margins of safety available locally.

The design and analysis methods, as well as the type of construction and construction materials, are chosen to allow assessment of the structure's capability throughout its service life. Additionally, surveillance testing, and inservice inspections provides further assurances of the structure's continuing ability to meet its design functions.

Table 3.8-2 lists the loading combinations used for the design and final analysis of the containment structure.

Table 3.8-3 shows the calculated stresses and strains, as well as the allowables, taken from critical sections of the containment structure as indicated in figure 3.8-3.

Table 3.8-2

LOADING COMBINATION FOR DESIGN AND FINAL ANALYSIS OF CONTAINMENT SHELL (Sheet 1 of 2)

Reference Loading (RLC)	PVNGS Project Criteria: Category	PVNGS Project Criteria: Loading Combination	ASME Sect III, Div. 2	BC-TOP-5A R-3	Final Analysis Performed	Remarks
1	Test	$D + L + F_i + P_t + T_t$	Same	Same	Yes	T_t is considered same as T_o; initial prestress is more critical
2	Construction	$D + L + F_i + T_o$	Same	Same	Yes	Initial prestress case is more critical
3	Normal Operating Loads	$D + L + F + T_o + R_o + P_v$	Same	Same	Yes	R_o is a local load
4	Severe Environment	$D + L + F + T_o + E_o + R_o + P_v$	Same	Same	Yes	R_o is a local load, P_a is omitted conservatively
5	Severe Environment	$D + L + F + T_o + W + R_o$	None	Same	No	Less severe than loading Combination No. 4
6	Severe Environment	$D + L + F + T_o + W + R_o + P_v$	Same	None	No	Less severe than loading Combination No. 5
7	Severe Environment	$D + 1.3L + F + T_o + 1.5E_o + R_o$	None	Same	No	Less severe than loading Combination No. 11
8	Severe Environment	$D + 1.3L + F + T_o + 1.5W + R_o$	None	Same	No	Less Severe than loading Combination No. 7
9	Severe Environment	$D + 1.3L + F + T_o + 1.5E_o + R_o + P_v$	Same	None	No	Less severe than loading Combination No. 7
10	Severe Environment	$D + 1.3L + F + T_o + 1.5W + R_o + P_v$	Same	None	No	Less severe than loading Combination No. 8
11	Extreme Environment	$D + L + F + T_o + E_{ss} + R_o + P_v$	None	Same	Yes	R_o is a local load; P_v is omitted conservatively
12	Extreme Environment	$D + L + F + T_o + W_t + R_o + P_v$	None	Same	No	Less severe than loading Combination No. 11

Notation

D = Dead load

L = Live Load

F_i = Initial prestress

F = Final prestress

T_o = Normal operating temperature

P_a = Design accident pressure

W = Wind Load

R_o = Pipe reactions during normal operating or shutdown conditions

R_a = Pipe reactions due to postulated break (including R_o)

T_a = Design accident temperature

P_t = Test pressure(=1.15 P_a)

T_t = Test temperature (assumed equal to T_o)

P_v = Design external pressure (vacuum)

E_o = Operating basis earthquake

E_{ss} = Safe shutdown earthquake

W_t = Tornado Loads (including differential pressure and tornado missiles)

R_r = Local effects of containment due to postulated pipe breaks

Table 3.8-2

LOADING COMBINATION FOR DESIGN ANAD FINAL ANALYSIS

OF CONTAINMENT SHELL (Sheet 2 of 2)

Reference Loading (RLC)	PVNGS Project Criteria		ASME Sect III, Div. 2	BC-TOP-5A R-3	Final Analysis Performed	Remarks
	Category	Loading Combination				
13	Extreme Environment	$D + L + F + T_o + E_{ss} + P_v$	Same	None	No	Less severe than loading Combination No. 11
14	Extreme Environment	$D + L + F + T_o + W_t + P_v$	Same	None	No	Less Severe than loading Combination No. 12
15	Abnormal	$D + L + F + 1.5P_a + T_a + R_a$	Same	Same	Yes	R_a is a local load
16	Abnormal	$D + L + F + P_a + 1.25R_a$	None	Same	No	Less critical than loading Combination No. 17 in local analysis
17	Abnormal	$D + L + F + P_a + T_a + 1.25R_a$	Same	None	No	R_a is a local load, less severe than loading Combination No. 15
18	Abnormal with Severe Environment	$D + L + F + 1.25P_a + T_a + 1.25E_o + R_a + R_r$	None	Same	Yes	R_a and R_r are local loads
19	Abnormal with Severe Environment	$D + L + F + 1.25P_a + T_a + 1.25W + R_a + R_r$	None	Same	No	Less severe than loading Combination No. 18
20	Abnormal with Severe Environment	$D + L + F + 1.25P_a + T_a + 1.25E_o + R_a$	Same	None	No	Same as loading Combination No. 18 without local loads
21	Abnormal with Severe Environment	$D + L + F + 1.25P_a + T_a + 1.25W + R_a$	Same	None	No	Less severe than loading Combination No. 19
22	Abnormal with Severe Environment	$D + L + F + T_o + E_o$	Same	None	No	Less severe than loading Combination No. 13
23	Abnormal with Severe Environment	$D + L + F + T_o + W$	Same	None	No	Less severe than loading Combination No. 14
24	Abnormal with Extreme Environment	$D + L + F + P_a + T_a + E_{ss} + R_a + R_r$	Same	Same	Yes	R_a and R_r are local loads

Notation

D = Dead load

L = Live Load

F_i = Initial prestress

F = Final prestress

T_o = Normal operating temperature

P_a = Design accident pressure

W = Wind Load

R_o = Pipe reactions during normal operating or shutdown conditions

R_a = Pipe reactions due to postulated break (including [illegible])

T_a = Design accident temperature

P_t = Test pressure(=1.15 P_a)

T_t = Test temperature (assumed equal to T_o)

P_v = Design external pressure (vacuum)

E_o = Operating basis earthquake

E_{ss} = Safe shutdown earthquake

W_t = Tornado Loads (including differential pressure and tornado missiles)

R_r = Local effects of containment due to postulated pipe breaks

Note: Local loads are not considered in the overall analysis but are taken into account in local design. Also the live load has a negligible effect on the pressure boundary and thus is not included in the final analysis.

Table 3.8-3[a]

STRESS ANALYSIS RESULTS (Sheet 1 of 9)

Reference Loading Combination: $D + F_i + P_t\ T_t$ (No. 1 from table 3.8-2)

Portion	Section (Shown in Figure 3.8.3)	Concrete Stresses								Reinforcement Stresses								Liner Strains[b]		Deflection[c] (Primary Loads) (in)
		Meridional				Hoop				Meridional				Hoop						
		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary				
		MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Meridional $\times 10^{-6}$ in/in	Hoop $\times 10^{-6}$ in/in	
Allowable	Shell	-1800	-2700	-2700	-3600	-1800	-2700	-2700	-3600	±30	±30	±40	±40	±30	±30	±40	±40	±4000	±4000	-
	Basemat	-1500	-2250	-2250	-3000	-1500	-2250	-2250	-3000											
Dome	2	-338	-327	-315	-916	-328	-330	-320	-906	-1.5	-1.7	-2.7	6.3	-1.5	-1.7	-2.6	6.3	-376	-366	-0.24
	7	-592	-627	-585	-1360	-365	-403	-384	-1085	-2.4	-1.9	-3.7	2.8	-1.6	-1.5	-3.0	6.6	-284	-428	-0.16
Wall	16	-549	-554	-549	-1401	-467	-424	-451	-1211	-2.9	-2.6	-5.2	4.4	-1.9	-1.8	-3.8	5.5	-440	-449	-0.06
	18	-594	-564	-594	-1408	-342	-326	-336	-1064	-3.2	-3.2	-5.6	3.7	-1.3	-1.2	-2.9	6.4	-429	-448	-0.04
	20	-639	-680	-639	-1315	-387	-362	-357	-1048	-3.1	-4.0	-5.7	1.6	-1.5	-1.4	-2.9	6.4	-358	-452	-0.05
	21	-650	-1049	-650	-1069	-303	-358	-196	-814	-2.2	-6.4	-5.2	-0.3	-1.0	-1.0	-1.7	7.5	-238	-450	-0.03
	22[e]	-676	-2214	-658	-941	-218	-527	-135	-560	0.1	-13.0	-4.1	-5.3	-0.5	-0.3	-1.6	6.0	636	-368	-0.01
Basemat Slab	23	27	-244	-37	-333	-6	-152	-29	-352	12.6	-0.5	2.0	0.5	-0.9	3.9	-3.4	8.3	516	-462	-0.01
	25	-40	-769	-129	-1212	-16	-336	-58	-605	-3.8	11.1	-7.6	14.5	-1.0	3.7	-3.2	8.3	-869	-450	-0.37
	26	-11	-380	-73	-705	16	-159	-29	-355	-2.4	7.5	-5.6	11.0	-0.5	1.0	-2.5	6.3	-650	-348	-0.48
Reactor Cavity	27	-177	-195	-98	-132	5	-13	79	(d)	-1.0	-1.3	-1.1	-1.0	0.3	0.2	2.7	4.9	13	-90	0.00
	28	92	-83	67	-104	92	91	107	(d)	0.6	0.7	2.8	10.4	0.6	0.6	0.8	9.6	-320	-372	-0.48

Table 3.8-3

STRESS ANALYSIS RESULTS (Sheet 2 of 9)

Footnotes:

a. Sign Conventions are:

Stresses and strains . . . . (+) tensile . . . . (-) compressive

Deflections . . . . (+) outward . . . . (-) inward

b. Allowable liner strains shown are based on the lowest values from the ASME Code, Section III, division 2.

c. All deflections shown are normal to the given surface.

d. Completely cracked sections; partially cracked sections are not indicated.

e. The stresses for section 22 were determined from a more detailed analysis, in addition to the FINEL analysis.

f. The stresses were obtained from OPTCON computer output.

g. Membrane stress is greater than 200 psi and thus the section is assumed cracked.

h. Reinforcement is assumed to yield at 54 ksi, the calculated strain is 0.00200 in/in.

Table 3.8-3[a]

STRESS ANALYSIS RESULTS (Sheet 3 of 9)

Reference Loading Combination: $D + F_i + T_o$ (No. 2 from table 3.8-2)

Portion	Section (Shown in Figure 3.8.3)	Concrete Stresses								Reinforcement Stresses								Liner Strains(b)		Deflection(c) (Primary Loads)
		Meridional				Hoop				Meridional				Hoop						
		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary				
		MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Merid-ional $x\ 10^{-6}$ in/in	Hoop $x\ 10^{-6}$ in/in	(in)
Allowable	Shell	-1800	-2700	-2700	-3600	-1800	-2700	-2700	-3600	±30	±30	±40	±40	±30	±30	±40	±40	±4000	±4000	-
	Basemat	-1500	-2250	-2250	-3000	-1500	-2250	-2250	-3000											
Dome	2	-1062	-990	-1050	-1831	-1040	-1005	-1039	-1830	-5.1	-5.1	-7.4	1.7	-5.2	-5.2	-7.5	1.6	-382	-373	-0.67
	7	-1234	-1259	-1232	-2154	-1000	-1053	-996	-1946	-4.7	-4.2	-6.5	.5	-5.1	-4.8	-7.6	2.0	-309	-430	-0.49
Wall	16	-1161	-1128	-1161	-2092	-1469	-1276	-1464	-2265	-5.6	-5.3	-8.6	.9	-6.8	-6.5	-9.8	-.3	-432	-462	-0.21
	18	-1207	-1150	-1207	-2130	-1604	-1459	-1598	-2446	-5.6	-5.6	-8.6	.8	-7.9	-7.6	-11.0	-1.4	-429	-463	-0.24
	20	-1252	-1365	-1252	-1795	-1054	-960	-895	-1704	-5.8	-7.7	-8.6	-2.4	-4.8	-4.5	-6.6	2.9	-299	-460	-0.16
	21	-1264	-1535	-1263	-2261	-497	-560	-332	-1152	-8.1	-4.4	-11.4	4.7	-1.6	-1.5	-1.9	7.4	-778	-451	-0.05
	22[e]	-1247	-1978	-1237	-3356	-401	-592	-348	-1298	-6.3	-5.0	-8.6	11.7	-.6	-.6	-1.5	6.1	-981	-366	-0.02
Basemat Slab	23	-23	-365	-116	-468	-57	-134	-121	-444	-.9	3.8	-3.6	7.5	-.5	.4	-3.5	4.2	-434	-300	-0.16
	25	-28	-225	-155	-777	-28	-111	-90	-464	-1.1	.7	-5.5	4.3	-.4	.2	-3.1	4.1	-383	-283	-0.21
	26	-19	-93	-129	-542	-21	-56	-40	-328	-.6	.5	-4.5	4.1	-.3	.1	-2.7	4.2	-339	-271	-0.22
Reactor Cavity	27	-80	-84	40	-42	-19	-22	63	(d)	-.5	-.5	-.2	.5	-.1	-.1	2.0	4.2	-30	-88	0.00
	28	13	-48	58	-87	11	13	31	27	.1	.2	-.4	9.2	.1	.1	-.9	7.2	-401	-340	-0.22

Table 3.8-3[a]

STRESS ANALYSIS RESULTS (Sheet 4 of 9)

Reference Loading Combination: $D + F + T_o + P_v$ (No. 3 from table 3.8-2)

Portion	Section (Shown in Figure 3.8.3)	Concrete Stresses								Reinforcement Stresses								Liner Strains[b]		Deflection[c] (Primary Loads)
		Meridional				Hoop				Meridional				Hoop						
		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary				
		MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Merid-ional $x 10^{-6}$ in/in	Hoop $x 10^{-6}$ in/in	(in)
Allowable	Shell	-1800	-2700	-2700	-3600	-1800	-2700	-2700	-3600	±30	±30	±40	±40	±30	±30	±40	±40	±4000	±4000	-
	Basemat	-1500	-2250	-2250	-3000	-1500	-2250	-2250	-3000											
Dome	2	-947	-903	-916	-1777	-926	-921	-888	-1762	-4.7	-4.7	-7.0	2.6	-4.8	-4.8	-7.1	2.0	-403	-375	-0.63
	7	-1088	-1145	-1085	-2086	-877	-949	-899	-1875	-4.3	-3.8	-6.3	8.6	-4.6	-4.3	-7.2	2.3	-651	-429	-0.46
Wall	16	-1030	-1027	-1030	-2030	-1264	-1127	-1259	-2153	-5.2	-4.8	-8.3	1.1	-5.9	-5.7	-9.2	0.3	-433	-460	-0.18
	18	-1075	-1048	-1075	-2065	-1383	-1291	-1375	-2317	-5.2	-5.2	-8.4	1.0	-7.0	-6.7	-10.2	-0.7	-429	-462	-0.21
	20	-1120	-1241	-1120	-1769	-921	-860	-797	-1667	-5.3	-7.0	-8.3	-1.7	-4.2	-4.0	-6.4	3.0	-321	-460	-0.14
	21	-1131	-1432	-1131	-2636	-451	-518	-377	-1210	-7.6	-4.1	-11.1	5.0	-1.5	-1.4	-2.3	7.0	-784	-452	-0.05
	22[e]	-1136	-2147	-1136	-3660	-388	-601	-399	-1427	-5.9	-4.6	-8.5	12.3	-0.6	-0.6	-2.1	5.4	-1005	-367	-0.02
Basemat Slab	23	-15	-329	-88	-442	-67	-134	-191	-534	-0.6	1.3	-3.3	6.1	-0.5	0.2	-4.2	3.0	-372	-286	-0.16
	25	-6	-57	-70	-377	-55	-112	-176	-604	-0.1	0.2	-2.9	2.0	-0.7	0.1	-4.9	3.2	-193	-316	-0.20
	26	6	-46	-34	-316	-73	-142	-200	-712	-0.1	0.6	-2.3	4.8	-1.0	-0.1	-5.8	3.0	-279	-343	-0.22
Reactor Cavity	27	-57	-117	-68	-217	-23	-29	96	189	-0.6	-0.1	-1.9	0.5	-0.1	-0.1	0.5	2.9	-97	-99	0.00
	28	20	-54	-75	-361	17	31	-57	-331	-0.1	0.4	-3.1	5.3	0.1	0.2	-2.9	2.7	-355	-232	-0.24

Table 3.8-3[a]

STRESS ANALYSIS RESULTS (Sheet 5 of 9)[f]

Reference Loading Combination: $D + F + T_o + E_o$ (No. 4 from table 3.8-2)

Portion	Section (Shown in Figure 3.8.3)	Concrete Stresses								Reinforcement Stresses								Liner Strains[b]		Deflection[c] (Primary Loads)
		Meridional				Hoop				Meridional				Hoop						
		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Meridional X 10^{-6} in/in	Hoop X 10^{-6} in/in	
		MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi			(in)
Allowable	Shell	-1800	-2700	-2700	-3600	-1800	-2700	-2700	-3600	±30	±30	±40	±40	±30	±30	±40	±40	±4000	±4000	–
	Basemat	-1500	-2250	-2250	-3000	-1500	-2250	-2250	-3000											
Dome	2	-907	-930	-869	-1859	-887	-880	-869	-1868	-5.1	-5.5	-9.6	.6	-5.1	-5.2	-9.9	.3	-425	-419	–
	7	-1049	-1065	-1045	-2054	-826	-858	-844	-1814	-6.3	-6.0	-10.5	-.6	-5.0	-4.6	-8.6	.6	-433	-416	–
Wall	16	-969	-986	-969	-2167	-1179	-1091	-1174	-2274	-5.8	-5.6	-10.6	-.1	-6.5	-6.4	-10.7	-.5	-480	-496	–
	18	-925	-942	-925	-2107	-1309	-1279	-1302	-2448	-5.4	-5.6	-10.2	.2	-7.7	-7.5	-12.0	-1.7	-473	-500	–
	20	-899	-1062	-889	-1694	-882	-870	-757	-1808	-4.6	-6.0	-8.0	-1.6	-5.0	-5.2	-7.7	1.3	-312	-439	–
	21	-880	-1211	-880	-2839	-425	-489	-307	-1439	-6.3	-3.6	-11.1	9.5	-2.6	-1.9	-4.0	8.0	-995	-580	–
	22[e]	-877	-1346	-877	-3617	-347	-465	-354	-1526	-6.7	-3.0	-12.2	23.7	-2.3	-1.3	-4.5	7.6	-1740	-587	–
Basemat Slab	23	9	-295	-69	-723	-49	-233	-177	-782	-1.1	5.8	-3.6	7.8	-1.2	1.5	-4.4	4.6	-448	-351	–
	25	24	-329	-48	-824	-38	-254	-161	-908	-1.2	6.7	-4.0	10.0	-1.3	1.8	-5.1	5.8	-548	-426	–
	26	31	-337	-14	-673	-57	-272	-191	-1085	-1.2	7.4	-3.0	9.6	-1.5	1.3	-6.1	7.1	-495	-518	–
Reactor Cavity	27	-34	-249	-44	-448	-1	-25	105	(d)	-1.1	2.5	-1.8	5.6	-.1	.4	6.5	4.9	-302	63	–
	28	48	-174	-36	-687	61	(d)	-39	-526	.9	10.6	-1.8	12.1	4.5	8.1	-1.6	8.2	-584	-410	–

Table 3.8-3[a]

STRESS ANALYSIS RESULTS (Sheet 6 of 9)[f]

Reference Loading Combination: $D + F + T_o + E_{ss}$ (No. 11 from table 3.8-2)

Portion	Section (Shown in Figure 3.8.3)	Concrete Stresses								Reinforcement Stresses								Liner Strains[b]		Deflection[c] (Primary Loads)
		Meridional				Hoop				Meridional				Hoop						
		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary				
		MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Merid-ional X 10^{-6} in/in	Hoop X 10^{-6} in/in	(in)
Allowable	Shell	-3600	-4500	-4500	-5100	-3600	-4500	-4500	-5100	±54	±54	±54	±54	±54	±54	±54	±54	±10000	±10000	-
	Basemat	-3000	-3750	-3750	-4250	-3000	-3750	-3750	-4250											
Dome	2	-901	-924	-863	-1855	-879	-873	-861	-1862	-5.1	-5.5	-9.5	.6	-5.1	-5.2	-9.9	.4	-426	-420	-
	7	-1040	-1056	-1036	-2046	-810	-841	-828	-1803	-6.3	-5.9	-10.4	-.5	-4.9	-4.5	-8.6	.8	-434	-418	-
Wall	16	-943	-965	-943	-2158	-1151	-1065	-1146	-2254	-5.7	-5.5	-10.4	.2	-6.4	-6.2	-10.6	-.3	-489	-497	-
	18	-840	-859	-840	-2068	-1299	-1269	-1292	-2438	-4.8	-5.1	-9.7	1.2	-7.7	-7.5	-12.0	-1.6	-499	-499	-
	20	-747	-1010	-747	-1475	-870	-856	-745	-1807	-3.4	-5.5	-6.8	-1.1	-4.9	-5.1	-7.6	1.5	-276	-445	-
	21	-727	-1064	-727	-3225	-405	-474	-286	-1460	-5.3	-2.7	-9.5	23.6	-2.5	-1.8	-3.8	9.0	-1600	-621	-
	22[e]	-717	-1192	-717	-3950	-321	-442	-328	-1544	-5.7	-2.1	-10.1	40.0	-2.2	-1.1	-4.3	8.7	-2430	-630	-
Basemat Slab	23	19	-267	-59	-706	-44	-281	-171	-827	-.9	6.3	-3.4	8.2	-1.4	2.7	-4.5	5.6	-456	-399	-
	25	38	-480	-33	-977	-32	-313	-155	-966	-1.7	10.1	-4.6	13.3	-1.6	3.0	-5.3	6.9	-703	-478	-
	26	43	-431	-2	-770	-52	-328	-187	-1137	-1.5	9.7	-3.4	11.9	-1.7	2.2	-6.4	8.0	-600	-565	-
Reactor Cavity	27	-12	-342	-22	-538	2	-30	109	(d)	-1.1	5.9	-1.8	9.0	-.1	.7	6.5	5.2	-441	53	-
	28	63	-258	-22	-784	86	(d)	-14	-555	1.1	14.4	-1.8	15.8	6.6	11.2	-1.2	11.2	-738	-521	-

Table 3.8-3[a]

STRESS ANALYSIS RESULTS (Sheet 7 of 9)

Reference Loading Combination: $D + F + 1.5P_a + T_a$ (No. 15 from table 3.8-2)

Portion	Section (Shown in Figure 3.8.3)	Concrete Stresses								Reinforcement Stresses								Liner Strains(b)		Deflection(c) (Primary Loads)
		Meridional				Hoop				Meridional				Hoop						
		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary				
		MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Meridional X 10^{-6} in/in	Hoop X 10^{-6} in/in	(in)
Allowable	Shell	-3600	-4500	-4500	-5100	-3600	-4500	-4500	-5100	±54	±54	±54	±54	±54	±54	±54	±54	±10000	±10000	-
	Basemat	-3000	-3750	-3750	-4250	-3000	-3750	-3750	-4250											
Dome	2	29	-88	178	-120	31	60	120	82	.3	.1	15.0	20.5	.3	.1	19.5	31.6	-232	-498	0.96
	7	-222	-277	-218	-1519	-22	-49	-99	-770	-1.1	-.6	5.3	11.1	.2	.3	14.3	23.7	-255	-422	0.71
Wall	16	-204	-249	-204	-1572	123	(d)	-281	-1055	-1.0	-1.6	8.3	16.4	4.1	4.0	12.2	21.0	-370	-425	0.12
	18	-250	-359	-250	-1731	(g)	(d)	(g)	-404	-1.8	-.8	6.8	17.3	16.9	16.4	16.7	25.3	-481	-418	0.52
	20	-295	-319	-295	-2079	77	(d)	-138	-1768	-1.9	-1.5	7.2	20.9	4.2	4.1	8.3	17.2	-661	-435	0.15
	21	-305	-1301	-305	-907	-226	-386	-439	-2702	9.7	-7.9	8.5	-3.0	-.9	.9	.7	10.0	852	-453	-0.02
	22[e]	-310	-3410	-310	-2678	-454	-1019	-559	-2835	42.4	-10.9	35.6	-13.9	-2.0	-1.4	-1.4	6.5	3820	-385	-0.06
Basemat Slab	23	22	-570	5	-579	-51	-403	-72	-484	29.5	.7	26.4	4.6	-2.7	10.6	-4.6	12.8	1131	-681	0.88
	25	11	-817	-9	-869	-119	-913	-142	-1108	-4.4	18.2	-5.6	18.3	-5.2	9.6	-7.7	12.5	940	-790	-0.16
	26	18	-822	4	-883	-219	-946	-270	-1213	-4.4	18.2	-5.5	18.4	-5.5	5.9	-8.4	9.8	-939	-718	-0.63
Reactor Cavity	27	-323	-558	-309	-605	49	(d)	107	(d)	-3.8	4.9	-4.5	5.6	2.4	2.9	4.5	7.1	-413	-105	0.02
	28	114	-118	72	-140	112	114	71	134	.7	.9	-.1	8.0	.7	.8	-.1	7.8	-343	-333	-0.69

Table 3.8-3[a]

STRESS ANALYSIS RESULTS (Sheet 8 of 9)[f]

Reference Loading Combination: $D + F + 1.25P_a + T_a + 1.25E_o$ (No. 18 from table 3.8-2)

Portion	Section (Shown in Figure 3.8.3)	Concrete Stresses								Reinforcement Stresses								Liner Strains[b]		Deflection[c] (Primary Loads)
		Meridional				Hoop				Meridional				Hoop						
		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary				
		MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Meridional $X 10^{-6}$ in/in	Hoop $X 10^{-6}$ in/in	(in)
Allowable	Shell	-3600	-4500	-4500	-5100	-3600	-4500	-4500	-5100	±54	±54	±54	±54	±54	±54	±54	±54	±10000	±10000	-
	Basemat	-3000	-3750	-3750	-4250	-3000	-3750	-3750	-4250											
Dome	2	-119	-145	18	-1334	-113	-133	-52	-1162	-.6	-.8	2.4	50.8	-.5	-.7	-1.4	28.6	-2034	-1227	-
	7	-350	-404	-344	-2173	-130	-166	-203	-1642	-2.2	-1.7	-5.8	24.6	-.9	-.6	-2.5	23.3	-1332	-1155	-
Wall	16	-293	-345	-293	-2762	-76	-97	80	-1722	-1.9	-1.5	-3.2	44.1	-.5	-.3	.4	28.2	-2167	-1345	-
	18	-227	-258	-227	-2639	64	(d)	73	-1611	-1.2	-1.4	-2.4	35.5	10.3	4.9	3.1	35.7	-1734	-1578	-
	20	-170	-238	-170	-3144	-215	-135	-260	-2434	-1.2	-.7	-.6	52.3	-.7	-.5	-2.3	31.1	-2566	-1627	-
	21	-160	-1331	-160	-1748	-229	-296	-464	-2527	12.5	-3.9	1.3	31.6	-1.0	-1.6	-6.5	18.5	-1467	-1217	-
	22[e]	-153	-3264	-153	-1397	-236	-429	-517	-2486	50.8	-8.1	14.3	-3.9	-.7	-2.2	-7.1	15.7	2854	-1110	-
Basemat Slab	23	54	-450	33	-354	-19	-532	-55	-825	17.3	1.9	12.4	1.2	-1.9	11.2	-3.4	14.7	606	-711	-
	25	36	-1088	11	-1261	-84	-892	-112	-1270	-4.6	19.6	-5.7	20.8	-4.6	9.0	-6.6	13.6	-1041	-794	-
	26	46	-1082	22	-1194	-172	-854	-208	-1351	-4.5	20.2	-5.2	20.5	-4.8	4.6	-7.6	10.3	-1011	-703	-
Reactor Cavity	27	-228	-512	-223	-686	145	(d)	91	(d)	-3.0	.3	-3.8	2.0	7.3	8.3	3.8	6.1	-239	-94	-
	28	117	(d)	77	-175	135	(d)	84	(d)	5.1	19.2	1.8	15.4	11.3	16.8	4.5	13.0	-590	-356	-

Table 3.8-3[a]

STRESS ANALYSIS RESULTS (Sheet 9 of 9)[f]

Reference Loading Combination: $D + F + P_a + T_a + E_{ss}$ (No. 24 from table 3.8-2)

Portion	Section (Shown in Figure 3.8.3)	Concrete Stresses								Reinforcement Stresses								Liner Strains[b]		Deflection[c] (Primary Loads)
		Meridional				Hoop				Meridional				Hoop						
		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary				
		MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	MEM (psi)	MEM & BEN (psi)	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Meridional $\times 10^{-6}$ in/in	Hoop $\times 10^{-6}$ in/in	(in)
Allowable	Shell	-3600	-4500	-4500	-5120	-3600	-4500	-4500	-5100	±54	±54	±54	±54	±54	±54	±54	±54	±10000	±10000	-
	Basemat	-3000	-3750	-3750	-4250	-3000	-3750	-3750	-4250											
Dome	2	-272	-298	-153	-1977	-262	-279	-210	-1735	-1.4	-1.7	-3.1	40.3	-1.4	-1.6	-5.3	24.5	-1826	-1219	-
	7	-482	-528	-476	-2476	-257	-292	-324	-2066	-3.0	-2.5	-8.1	22.6	-1.6	-1.3	-4.7	23.7	-1344	-1275	-
Wall	16	-410	-459	-410	-3168	-278	-278	-153	-2195	-2.5	-2.1	-5.8	44.2	-1.5	-1.4	-3.3	24.1	-2292	-1320	-
	18	-307	-337	-307	-3165	-203	-214	-196	-2304	-1.6	-1.9	-3.8	41.9	-1.2	-1.0	-2.6	28.5	-2094	-1500	-
	20	-214	-294	-214	-3468	-241	-247	-377	-2713	-1.0	-1.6	-1.2	54.0[h]	-1.4	-1.3	-4.4	29.4	-2676	-1647	-
	21	-194	-617	-194	-2984	-214	-241	-495	-2677	.7	-2.7	-.1	50.7	-1.0	-1.3	-7.0	19.7	-2460	-1302	-
	22[e]	-184	-2610	-184	-347	-172	-315	-540	-2612	38.9	-6.0	-1.5	-.4	-.5	-1.6	-7.5	16.9	2174	-1186	-
Basemat Slab	23	57	-439	32	-219	-23	-471	-87	-797	17.5	2.0	9.1	1.1	-1.8	9.1	-3.7	10.8	609	-569	-
	25	46	-834	18	-1135	-38	-693	-101	-1125	-3.3	16.2	-5.0	19.2	-3.3	8.4	-5.8	11.8	-950	-693	-
	26	45	-830	35	-1109	-89	-848	-160	-1238	-3.3	16.1	-4.7	19.9	-4.4	8.1	-6.7	10.7	-968	-686	-
Reactor Cavity	27	-163	-430	-156	-764	63	(d)	78	(d)	-2.4	.7	-3.8	5.4	2.7	4.1	3.1	5.3	-376	-92	-
	28	111	-130	56	-434	135	(d)	108	(d)	3.0	20.5	.6	16.9	10.4	17.5	5.3	17.1	-739	-496	-

3.8.1.5.1 Factors of Safety and Margin of Safety

The concrete portions of the containment are designed according to the requirements specified in this section. The structure is designed for the factored loads and load combinations given in ASME B&PV Code, Section III, Division 2, Article CC-3000 (Subarticle CC-3200) supplemented by additional load combinations and load factors which are included in BC-TOP-5-A, Appendix C, Table CC-32001. The load factors used to compute ultimate loads provide factors of safety against variation in loads, assumptions in structural analysis, simplifications in calculations, and effects of construction sequence and methods. The load factors are the ratio by which loads are multiplied for design purposes to assure that the load/deformation behavior of the structure is one of elastic, low-strain behavior. The load factor approach is used to make a rational evaluation of the isolated factors that must be considered to assure an adequate safety margin for the structure. This approach places the greatest conservatism on those loads most subject to variation and which most directly control the overall safety of the structure. It also places minimum emphasis on the fixed gravity loads and maximum emphasis on accident and earthquake or wind loads.

Load factors for the abnormal category demonstrate that the containment has the capacity to withstand pressure loadings at least 50% greater than those calculated for the postulated LOCA or MSLB (refer to subsection 6.2.1). The abnormal/severe environmental category demonstrates that the containment has

the capacity to withstand loadings at least 25% greater than those calculated for the postulated LOCA or MSLB with a coincident OBE; the abnormal/extreme environmental category demonstrates that the containment has the capacity to withstand the rupture of any attached piping coincident with the safe shutdown earthquake; and the extreme environmental category demonstrates that the containment has the capacity to withstand a tornado loading.

Tendon anchorage zones and buttresses are designed in accordance with BC-TOP-5-A, Section 6. The reinforcing steel is designed based on BC-TOP-7 and BC-TOP-8. These reports conclude that there is adequate margin of safety of the tendon anchorage and buttress design when subjected to the maximum condition of loading.

3.8.1.5.2 Allowable Stresses

The allowable stresses for factored loads and service loads in concrete, reinforcing steel, and the tendon system are as specified in ASME Section III, Division 2, Article CC-3000 (Subarticle CC-3400). The liner plate allowables are as specified in ASME Section III, Division 2, Article CC-3000 (Subarticle CC-3700).

3.8.1.5.3 Design of Shear Reinforcement

Methods used for radial shear design are as specified in ASME B&PV Code, Section III, Division 2, Article CC-3000. Methods

used for tangential shear design are as specified in appendix 3F.

3.8.1.5.4 Liner Plate System

The steel liner plate and anchorage are designed in accordance with ASME B&PV Code, Section III, Division 2, Article CC-3000, supplemented by the design methods and criteria of BC-TOP-1 and BC-TOP-5-A.

The basic information is described as follows:

A. Design Criteria

The design criteria applied to the containment liner to meet the specified leak rate under operating and accident conditions are as follows:

1. The liner plate is protected against damage by missiles generated from a LOCA.

2. The liner plate strains are limited to those values that have been shown by past experience to result in leaktight pressure vessels and are in conformance with the requirements of ASME Section III, Division 2, Article CC-3000 (Subarticle CC-3700).

3. The liner plate is prevented from developing distortions sufficient to impair leak tightness.

4. Criteria for protection against dynamic effects associated with the postulated rupture of piping are included in section 3.6.

B. Loads

The loads and load combinations required in paragraph 3.8.1.3 are considered in the analysis.

The following loads are considered in liner design:

1. Thermal cycling due to annual outdoor temperature variations where:

    a. Daily temperature variations do not penetrate a significant distance into the concrete shell to appreciably change the average temperature of the shell relative to the liner plate

    b. The number of cycles for this loading was 40 cycles for plant life of 40 years and was increased to 60 cycles for extended plant life of 60 years.

2. Thermal cycling due to variation in the interior temperature of the containment during the heatup and cooldown of the reactor system in which the number of cycles was assumed to be 500* cycles for plant life of 40 years. Five hundred (500) “assumed” interior operational heatup/cooldown cycles corresponds to an average of 8-1/3 cycles/year for a 60-year plant life (reactor system operational cooldown/heatup approximately every 6 weeks) which

* The reactor vessel studs shall be limited to 250 cycles

is adequately conservative to accommodate 60-year extended plant life.

3. Thermal cycling due to the LOCA is assumed to be one cycle, in which:

   a. Thermal load cycles in the piping systems are somewhat isolated from the penetration sleeve by the concentric sleeves between the pipe and the liner plate

   b. Attachments are designed in accordance with ASME B&PV Code, Section III, Division 2, Article CC-3000 fatigue considerations

   c. All penetration sleeves are reviewed for a conservative number of cycles expected during plant life

   d. Typical containment temperatures as a function of time are shown in Figure 7-5 of BC-TOP-5-A.

4. Other loads considered are the following:

   a. Local thermal loads, i.e., at hot process penetrations

   b. Construction loads, particularly those applied to the liner before the concrete is placed and after concrete has been placed but prior to time concrete has attained design strength

   c. Local loads, such as those due to restraint of support of equipment

C. Stresses and Permissible Strains

Due to the nature of the loads and other effects together with the types of components, the allowable capacities of the components are specified in terms of stress, strain, force, or displacement, whichever is applicable.

1. Liner plate

   a. The load combinations shown in ASME B&PV Code, Section III, Division 2, Article CC-3000 (Table CC-3230-1) are applicable to the liner plate except that load factors for all load cases may be taken equal to 1.0.

   b. The calculated strains and stresses for the liner plate are not to exceed the values given in ASME B&PV Code, Section III, Division 2, Article CC-3000 (Table CC-3720-1).

2. Liner plate anchors

   a. The liner plate is anchored to the concrete containment so that the liner strains do not exceed the strain allowables listed in the ASME B&PV Code, Section III, Division 2, (Subsubarticle CC-3720). The anchor size and spacing is chosen so that the response of the liner is predictable for all loads and load combinations given in paragraph 3.8.1.3. The anchorage system is designed so that it can

accommodate the design in-plane (shear) loads or deformations exerted by the liner plate and loads applied normal to the liner surface.

b. The allowable force and displacement capacity is given in ASME B&PV Code, Section III, Division 2, Article CC-3000 (Table 3730-1). Mechanical loads are those which are not self-limiting or self-relieving with load application. Displacement limited loads are those resulting from constraint of the structure or constraint of adjacent material and are self-limiting or self-relieving.

c. A nil ductility transition temperature requirement is not specified for liner plate material less than 5/8 inch thick (refer to paragraph 3.8.1.6.4). Failure by brittle fracture or cleavage mode of failure is precluded by the absence of significant tensile stresses.

3. Weld design

ASME Code, Section VIII, Subsection B, Paragraphs UW-8 to UW-19 are used as a guide in design of welds. Particular attention is given in the design of welds to the anticipated behavior of the structure under accident conditions.

3.8.1.6 Materials, Quality Control, and Special Construction Techniques

Materials used in the construction of the containment conform to the requirements of ACI 301, 318, and 211.1 for concrete and to ASTM 615 for reinforcing steel.

The containment is constructed of concrete and steel using proven methods common to heavy, industrial construction. The typical range of properties assumed in design is listed in tables 3.8-1, 3.8-4, and 3.8-5.

In instances where a particular property is not defined in tables 3.8-1 and 3.8-5, the range assumed for design is identified by standard industry specifications (paragraph 3.8.1.2.3).

3.8.1.6.1 Concrete

The compressive strength of concrete used for the containment is as follows:

- Basemat and gallery - f_c' = 5000 psi
- Cylinder and dome - f_c' = 6000 psi at 91 days

Table 3.8-4

TYPICAL RANGE OF PROPERTIES FOR CONCRETE CONTAINMENT STRUCTURES

Maximum aggregate size, in.	3/4 to 1-1/2
Unit weight, lb/ft^3	141 to 155
Predicted creep + autogenous length change at 40 years, millionths[(a)]	113 to 375
Predicted creep + autogenous + elastic length change at 40 years, millionths[(a)]	283 to 735
Modulus of elasticity at 28 days, 73F, psi x 10^6	3.6 to 7.3
Poisson's ratio at 28 d, 73F	0.16 to 0.28
Diffusivity at 28 days, 73F, ft^2/h	0.029 to 0.067
Coefficient of thermal expansion, millionths/F at 28 d, 73F	5.1 to 7.4

a. Loaded at age 180 days, 73F, 1530 psi

Table 3.8-5

LINER PLATE MATERIAL PROPERTIES AND CHARACTERISTICS

AS USED IN CONSTRUCTION

Material and Specification	Properties and Characteristics Used									
	Ultimate Strength (fu, ksi) Nominal	Ultimate Strength (fu, ksi) Range	Defined Yield (fy, ksi) Nominal	Ultimate Strain (ult, %) Nominal	E ($x10^3$ ksi) Range	Poisson's Ratio Range	Thermal Conductivity Btu / ft^3 ^oF hr Nominal	Coefficient of Linear expansion ($10^{-6}/^oF$) Nominal	Heat Capacity (Btu lb/^oF) Range	Unit Weight (lb/ft^3) Range
Liner Plate										
ASME SA-285 grade A	45	45-65	24	30	29-30	0.27-0.30	27	6.5	0.10-0.11	485-490
ASTM A 285 grade C	55	55-75	30	27	29-30	0.27-0.30	27	6.5	0.10-0.11	485-490
ASTM A 515 grade 70	70	70-90	38	21	29-30	0.27-0.30	27	6.5	0.10-0.11	485-490
ASME SA-516, grade 70	70	70-90	38	21	29-30	0.27-0.30	27	6.5	0.10-0.11	485-490
Penetration assemblies, locks, hatches, etc.										
ASME SA-516, grade 70	70	70-90	38	21	29-30	0.27-0.30	27	6.5	0.10-0.11	485-490
ASME SA-333										
grade 1	55		30	20	29-30	0.27-0.30	27	6.5	0.10-0.11	485-490
grade 6	60		35	12	29-30	0.27-0.30	27	6.5	0.10-0.11	485-490
ASME SA-240 type 304	75		30	40	29-30	0.25-0.30	27	6.5	0.10-0.11	485-490

The test age of concrete using pozzolan in the concrete mix is designated as 91 days. The test age of concrete without pozzolan in the concrete mix is designated as the normal 28 days. These strength designations are in accordance with ACI 301.

Structural concrete is batched and placed in accordance with Specifications for Structural Concrete for Buildings (ACI 301-72) and Building Code Requirements for Reinforced Concrete (ACI 318-71) with additional specific information and exceptions as noted in paragraph 3.8.1.6.1.2.

A. Cement

Cement is type II conforming to Specification for Portland Cement (ASTM C150-74). The cement does not contain more than 0.60% by weight of alkalies calculated as Na_20 plus 0.658 K_20 nor more than 58% by weight of tricalcium silicate and tricalcium aluminate. Certified copies of mill test reports showing the chemical composition and physical properties are obtained for each load of cement delivered.

In addition, the in-process tests are performed on cement used, in accordance with ANSI N45.2.5.

The purpose of these in process tests is to ascertain conformance to ASTM C150. An additional test, STM C109-73, is repeated periodically during construction to check storage environmental effects on cement

characteristics. The tests supplement visual inspection and material storage procedures.

B. Aggregates

All aggregates conform to Standard Specifications for Concrete Aggregate (ASTM C33-74). In addition to the specified gradation, the fine aggregate (sand) has a fineness modulus of not less than 2.5 nor more than 3.1 during normal operations. At least four of five successive test samples should not vary in fineness modulus more than 0.20 from the average.

Coarse aggregate may be rejected if the loss, when subjected to the Los Angeles abrasion test, ASTM C131-69, using grading A, exceeds 40% by weight at 500 revolutions.

Source acceptance of aggregates is based on the following tests:

ASTM No.	Name
D75-71	Sampling
C131-69	Los Angeles Abrasion
C142-71	Clay Lumps and Friable Particles
C117-69	Material Finer than No. 200 Sieve
C123-69	Lightweight Pieces
C40-73	Organic Impurities
C235-68	Soft Particles
C289-71	Potential Reactivity (Chemical)
C136-71	Sieve Analysis
C88-73	Soundness
C295-65	Petrographic Examination (Reapproved 1973)

In addition to the foregoing initial source tests, in-process tests are performed on the aggregate in accordance with Table B of ANSI N45.2.5.

C. Water

Water used in mixing concrete is free of injurious amounts of oil, acid, alkali, organic matter, or other deleterious substances as determined by the following tests:

C109-73	Standard Method of Test for Compressive Strength of Hydraulic Cement Mortars (using 2-inch, 50 mm, cube specimen)
C151	Standard Method of Test for Autoclave Expansion of Portland Cement
C191-74	Standard Method of Test for Time of Setting of Hydraulic Cement by Vicat Needle

Water shall not contain impurities in amounts that will cause either:

- A change in the time of setting of cement by more than 25%
- A reduction in the compressive strength of mortar by more than 5% compared with results obtained with distilled water

- A change in the results of soundness by more than 0.10%

The pH range shall be 6.0 to 8.5.

When ice is used in the concrete and it is made from a water source different from concrete mixing water, the source is tested in the same manner as the source for the concrete mixing water.

D. Admixtures

The concrete may also contain an air entraining admixture and/or a water reducing admixture. The air entraining admixture is in accordance with Specification of Air Entraining Admixtures for Concrete (ASTM C260). It is capable of entraining 3 to 6% air, is completely water soluble, and is completely dissolved when it enters the batch. The water reducing and retarding admixture conforms to Standard Specification for Chemical Admixtures for Concrete (ASTM C494-71), Types A and D. Type A is used when average ambient temperature for the daylight period is below 70F. Type D is used when average ambient air temperature for the daylight period is 70F and above. Pozzolans, if used, conform to Specifications for Fly Ash and Raw or Calcined Natural Pozzolans for use in Portland Cement Concrete (ASTM C618-73). Admixtures containing chloride ions added in the manufacturing process are not used. In-process tests for admixtures are according to Table B of ANSI N45.2.5.

E. Concrete Mix Design and Testing

Concrete mixes are designed in accordance with ACI 211.1-74, Recommended Practice for Selection Proportions for Normal and Heavy Weight Concrete, using materials qualified and accepted for this work. Only mixes meeting the design requirements specified for concrete are used.

An independent testing laboratory at the site designs and tests the concrete mixes. To maintain the quality of the concrete, workability and other characteristics of the concrete mixes are ascertained by the testing laboratory before placement.

Bechtel's concrete technologist participates in the preparation of concrete specifications, mix design, placement procedures, field quality control, and testing programs and visits the site periodically during construction.

For the concrete used in the post-tensioned containment, uniaxial creep, modulus of elasticity and Poisson's ratio, autogenous shrinkage, thermal diffusivity, thermal coefficient of expansion, and compressive strength are determined.

3.8.1.6.1.1 Construction Joints. Where horizontal shear keys are not used, the concrete surface of construction joint is prepared by a sandblasting, chipping, or airwater cutting to remove laitance and other foreign materials. The surface of

the concrete is then washed thoroughly to remove loose material. Concrete surfaces to receive new concrete shall be in a saturated condition but essentially free of standing water. Small puddles of water covering less than 10% of the area are acceptable.

In cases where shear of significant magnitude exists, in horizontal and vertical joints, shear keys are provided to transfer the shear. The same surface preparation described above applies to the keyed construction joint as well.

3.8.1.6.1.2 Concrete Construction. Standards applied to concrete construction include the following:

A. Specifications for Structural Concrete for Buildings ACI 301-72, Revised 1973) -- Used except as noted below:

   1. Chapter 3, Proportioning, Section 3.2, Strength -- The compressive strength test age of concrete using pozzolan in the concrete mix is designated as 91 days. The compressive strength test age of concrete not using pozzolan in the concrete mix is designated as the normal 28 days.

   2. Chapter 4, Formwork, Section 4.5, Removal of Forms -- The following requirements apply in place of requirements specified in Section 4.5.4:

      a. Forms for columns, walls, sides of beams, slabs and girders, and other parts not supporting the weight of the concrete are

removed as soon as practicable in order to avoid delay in curing and repairing surface imperfections.

b. Wood forms or insulated steel forms for members 2-1/2 feet or greater in thickness are stripped within 24 hours or the forms are kept in place for a minimum of 7 days. If forms are stripped within 24 hours, the surface is cured by moist curing or membrane curing as specified in Chapter 12.

3. Section 4.3, Tolerances for Formed Surfaces -- Changed to the following:

a. Variation from plumb:

(1) In the lines and surfaces of columns, piers, and walls:

- In any 10 feet of length, 1/2 inch
- Maximum for the entire length, 1-1/2 inches

(2) For exposed corner columns, control-joint grooves, and other conspicuous lines:

- In any 20 feet of length, 1/2 inch
- Maximum for the entire length, 1 inch

b. Variation from the level or from the grades specified in the contract documents:

(1) In slab soffits, ceilings, beam soffits, and arrises, measured before removal of supporting shores:

- In any 10 feet of length, 1/2 inch
- In any bay or any 20 feet of length, 5/8 inch
- Maximum for the entire length, 1 inch

(2) In exposed lintels, sills, parapets, horizontal grooves, and other conspicuous lines:

- In any bay or any 20 feet of length, 3/8 inch
- Maximum for the entire length, 1 inch

c. Variation of the linear building lines from established position in plan and related position of columns, walls, and partitions:

- In any bay, 1/2 inch
- In any 20 feet of length, 1/2 inch
- Maximum for the entire length, 1 inch

- Jump form of containment shell, horizontal deviation of ±2 inches from design radius in 120° arc
- Jump form of containment shell, ±1 inch vertical deviation in 80 feet
- Jump form of containment shell, ±1/4 inch for local deviation in 5 feet in any direction
- For each 30° section of containment shell form, with the midpoint held to the erection tolerance, each end may deviate plus 1 inch from the design radius, in addition to other tolerances allowed for containment forms
- Minimum thickness of containment wall shall be 3 feet 8 inches regardless of tolerance allowance

d. Variation in size of sleeves, floor, and wall openings:

- -1/4 inch, +1/2 inch

Variation in location of sleeves, floor and wall openings:

- ±1/2 inch

e. Variation in cross-sectional dimensions of columns and beams and in the thickness of slabs and walls:

- -1/2 inch
- +1 inch
- For containment shell wall, the variation of thickness shall not exceed -4 inches, or +5 inches

f. Footings:

(1) Variations in dimensions in the plan:

- -1/2 inch
- +6 inches

(2) Misplacement or eccentricity:

- 2% of the footing width in direction of misplacement, but not more than 2 inches

(3) Thickness:

- Decrease in specified thickness, 5%
- Increase in specified thickness, no limit

4. Section 12.3.1, Cold Weather -- The requirements of ACI 306-66 were used subject to the exceptions given elsewhere in this section.

5. Chapter 14, Massive Concrete, Section 14.4, Placing -- The following requirements apply:

   a. Section 14.4.1:

      (1) The average slump of the concrete at the point of transport discharge is 4 inches or less. Slump is specified in the construction specification for the particular location and degree of congestion.

      (2) An inadvertency margin for maximum slump of +1 inch is used.

   b. Section 14.4.3 -- The permissible placing depth of individual layers within a concrete placement is 24 inches. Placing depth may exceed 24 inches when required to obtain sufficient hydrostatic pressure to force concrete around penetrations.

6. Chapter 14, Massive Concrete, Section 14.5, Curing and Protection -- The following requirements apply:

   a. If moist curing is used, the minimum curing period is 7 days or the time necessary to attain 70% of the specified design strength, whichever time is less. For other curing methods, the minimum curing period is 7 days.

b. Liquid membrane curing of concrete may be used during the first 48 hours under winter conditions in lieu of moist curing.

7. Chapter 15, Prestressed Concrete, Section 15.4.4 -- Tendon sheathing and trumpet extensions shall be fabricated in a manner which ensures the final specified function and load capacity of the complete tendon system. Tolerances shall ensure consistent installation to $\pm 3/4$ inch. Tendon sheathing and trumpet extensions will be accurately installed at the location shown on the plans to a tolerance of $\pm 3/4$ inch.

8. Chapter 16, Testing, Section 16.3.4.3

   a. Concrete strengths for the containment cylinder and dome are specified as 91-day strengths.

   b. For large structural concrete placements (placements greater than 1000 cubic yards), where placing of concrete is a continuous operation, cylinders are made for each 100 cubic yards for the first 500 cubic yards placed and for each 250 cubic yards for the remaining concrete placed (applicable to FSAR subsections 3.8.4 and 3.8.5 only).

   c. For the containment building, cylinders are taken for each 100 cubic yards placed.

B. Recommended Practice for Cold-Weather Concreting (ACI 306-66) -- Used with the following exceptions:

1. In heating the water and aggregate, the resulting temperature of the mixed concrete will not be more than 10F higher than the temperatures indicated in the following table. The temperature of the concrete, when delivered to the forms, will not be more than 5F below the temperatures indicated in the following table:

Air Temp. (°F)	Concrete Sections Less than 2-1/2 ft in Least Dimension (°F)	Concrete Sections 2-1/2 ft or more in Least Dimension (°F)
30 to 45	55	45
0 to 30	60	50
Below 0	65	55

C. Building Code Requirements for Reinforced Concrete (ACI 318-71) -- Used with the following exceptions:

1. Section 5.5, Curing -- The following requirements apply:

a. During summer conditions the concrete is moist cured for 7 days or the time necessary to attain 70% of the design strength, whichever time is less. Liquid membrane curing of concrete may be used during the first 48 hours under winter conditions in lieu of moist curing. If liquid membrane

curing is used, the minimum curing period is 7 days.

b. The methods used in liquid membrane curing will be in accordance with ACI 306-66 and the manufacturer's instructions.

2. Section 6.3.2.4, Conduits and Pipes Embedded in Concrete -- ASME Boiler and Pressure Vessel Code, Section III, Division 1, provisions apply to nuclear piping and ANSI B31.1 apply to nonnuclear power piping. Test provisions of state and local plumbing codes apply in all cases. The following provisions of this section apply only where the above are inapplicable:

   a. Magnitude of test pressure

   b. Duration of test

   c. Timing of test

3. Section 7.3.2, Tolerances -- Tolerances for placing reinforcing, pre-stressing steel, and prestressing steel ducts are determined by the engineer based upon the structure geometry, bar size, and degree of congestion and are as follows:

   a. For containment portions other than walls and dome and for other Seismic Category I structures, the following tolerances are used for clear concrete protection and for depth (d) in flexural members, walls, and

compression members, but the cover is not reduced by more than one-third of the specified cover:

- 8 inches or less, +1/2 inch
- More than 8 inches but less than 24 inches, ±1/2 inch
- 24 inches or more, +1 inch

For floors with drains, reinforcing is placed the proper distance measured from the drain, and installed to the drain elevation throughout the floor.

b. For containment exterior walls and dome reinforcement, the concrete cover over any point on the outer curtain of reinforcing steel shall be:

- 4 ±1-1/2 inches for No. 14 and No. 18 bars
- 3 ±1 inch for all other bars

The minimum cover on the inner curtain of reinforcing steel shall be 2 inches. Cadwelds or other connectors shall not be considered as reinforcing steel. The minimum cover for ties shall be 1-1/2 inches. The minimum cover for welded wire fabric, when required, shall be 1 inch.

c. Inside face reinforcing steel (when required): The design drawings show the minimum effective depth, d, from the external concrete face to the inside face reinforcing steel.

d. For longitudinal location of bends and ends of bars: ± 3 inches, provided that specified cover at the ends of members shall not be reduced by more than 1/2 inch.

4. Chapter 4, Concrete Quality, Section 4.3.1 -- See exception 7 to ACI 301.

D. Recommended Practice for Concrete Formwork (ACI 347-68) -- Used without exception.

E. Recommended Practice for Hot-Weather Concreting (ACI 305-72) -- Used in its entirety. Since the climate in the region of the site is typical of a desert regime and there is possibly a diurnal temperature change of 30 to 50F which may effect concrete placed or concrete being placed, additional controls are provided for the PVNGS site to supplement the requirements of ACI 305, Section 2.2, "temperature of concrete as placed", and Section 4.4, "curing and protection". A summary of these measures follows:

- Minimize mixing time by utilization of stationary mixing equipment.
- Minimize transporting distance by locating stationary mixing equipment at the jobsite.

- Concrete ingredients used minimize heat of hydration problems.
- Water-reducing agent is adjusted to control setting time.
- Concrete temperature as batched is reduced by addition of ice and cooling of aggregates, as required.
- Dispatching of trucks is closely coordinated with rate of concrete placement.
- As applicable, subgrade is dampened or forms wetted prior to concrete placement.
- A fog spray procedure, judiciously used, is applied on exposed areas, when necessary, prior to final finishing and start of curing.
- Exposed surfaces of slabs are entirely covered and kept wet or sealed until firm enough to permit walking without damage.
- Mats used for initial curing period may be left in place and kept saturated for completing the curing, or may be removed at the end of the initial curing period and the concrete surface cured with one of the following methods:
  - Liquid membrane forming curing compounds
  - Polyethylene sheathing

- Waterproof paper
- Absorbent fabric
- Ponding

- For vertical and other formed surfaces, after concrete is hardened and while the forms are still in place, water may be applied to run down the inside of the form to keep the concrete wet. Except in specific approved instances, the forms may be left in place without loosening where the concrete is placed in two or more placements to obtain the total thickness. The exposed surface is moist cured and the forms have the exterior surfaces protected from the direct sun and wind.

- For construction joints, curing is continued until resumption of concrete placement or until required curing is complete.

- If, for any reason, it becomes necessary to remove supporting forms before the concrete has attained the required strength, provisions are made for additional curing under controlled conditions by water spray or water saturated fabric.

- Curing procedures are continued for a period of 7 days or the time necessary to attain 70% of the specified design strength.

- Procedures are adopted to ensure that saturated cover materials do not dry out and absorb water from the concrete.

- Concrete members 30 inches or more in the least dimension are moist cured, except that the exterior walls (shell) of the containment structure above the foundation are either form cured or liquid membrane cured.

F. Ready-Mixed Concrete (ASTM C94-74) -- Used without exception.

G. NRC Regulatory Guide 1.55 is used for concrete placement as interpreted in section 1.8.

H. Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel during the Construction Phase of Nuclear Power Plants (ANSI N45.2.5) -- Used except as noted below:

1. Section 1.4, Definitions -- The definition of in-process tests as applied to reinforcing steel is interpreted to allow taking the rebar test specimen from a heat or fraction thereof at the fabrication shop, prior to start of fabrication of the rebar.

2. Section 4.8, In-Process Tests on Concrete and Reinforcing Steel -- The following methods of sampling fresh concrete apply:

a. Samples for in-process tests of concrete are taken from the discharge of the batch plant stationary mixer.

b. For the containment building, the frequency for air content, temperature, and slump testing shall be once for the first batch placed each day and once for every 50 cubic yards placed thereafter, for each class of concrete.

c. For all other structures, the frequency for air content, temperature, and slump testing shall be once for the first batch placed each day and once for every 100 cubic yards placed thereafter, for each class of concrete (applicable to subsections 3.8.4 and 3.8.5 only).

d. Slump correlation tests are established between the batch plant and the transport discharge. Slump taken at the batch plant is the slump at the transport discharge plus an allowance for slump loss in transit.

e. After slump is established at the batch plant for each class of concrete to be placed, correlation slumps are taken at the transport discharge at intervals not to exceed every 300 cubic yards for each class of concrete placed. A minimum of one correlation slump

is taken each day for each class of concrete placed. Air content is taken when each correlation slump is made if an air entraining agent is used.

3. Table A, Required Qualification Tests, and Table B, Required In-process Tests -- Used except as noted below:

   a. Grout is not tested daily.

   b. Physical properties of reinforcing are not tested as per ASTM A615. This standard is used for mechanical property tests.

   c. Slump, air content, and temperature test frequencies are as provided in paragraph 3.8.1.6.1.2, listings H.2.b and c (applicable to FSAR subsections 3.8.4 and 3.8.5 only).

   d. Same as paragraph 3.8.1.6.1.2, listings A.7.a and b.

4. Section 4.5, Concrete Placement -- ACI Standards 305-72 and 306-66 are used subject to the exceptions and interpretations given elsewhere in this section.

5. Section 4.9, Mechanical (Cadweld) Splice Testing -- Used subject to the related interpretations given for NRC Regulatory Guide 1.10 in section 1.8.

A sister splice may be substituted for a production splice when:

a. Cadwelding to dowels which are too short to take a production splice

b. The responsible quality control engineer, in conjunction with engineering, determines that the area of reinforcing is too congested to take a production splice.

3.8.1.6.2 Reinforcing Steel

Reinforcing bars for concrete are deformed bars meeting requirements of Specification for Deformed and Plain Billet Steel Bars for Concrete Reinforcement (ASTM A615-74a), Grade 60. Splicing of bars is in accordance with ASME B&PV Code, Section III, Division 2, Article CC-3000 (Subsubarticle CC-3530) and placing of bars is in accordance with the Building Code Requirements for Reinforced Concrete (ACI 318-71) except as noted in paragraph 3.8.1.6.7.2. Mill test reports, in accordance with ASTM A615, are obtained from the reinforcing steel supplier to substantiate specification requirements.

In addition, tonnage of reinforcing steel of each size and grade for user tests on full diameter specimens is in accordance with NRC Regulatory Guide 1.15.

The test procedures are in accordance with ASTM A370-71b and acceptance standards are in accordance with ASTM A615-74a.

Lap splices are used for bar sizes No. 11 and smaller, except in areas of membrane tension perpendicular to the spliced bars. Mechanical splicing, as described in paragraph 3.8.1.6.7.2, is used for the remainder of the splices.

3.8.1.6.3 Prestressing System

A description of the types of materials used in the prestressing system is given in paragraph 3.8.1.1. Additional material properties for each component of the prestressing system are described as follows:

A. Prestressing Steel

Wires used are low relaxation type, 1/4-inch nominal diameter conforming to ASTM A421 Type BA. Tests quantifying wire relaxation are performed and results are documented. The quantity (in number of coils) of finished prestressing wires in each production lot represented by each test specimen is in accordance with ASTM A421-65 (reapproved 1972), ASTM A421-74, or ASTM A421-76. For these systems, the prestressing system supplier is required to assign an individual lot number and a tag for each size of wire from each manufactured reel in such a manner that each lot can be accurately identified.

B. Bearing Plates, Anchor Heads, Shims, Sheathing and Filler Material

The testing requirements for evaluating the quality of material and machined end anchorage hardware are discussed in paragraph 3.8.1.6.7.3.

3.8.1.6.3.1 Post-Tensioning Procedures. Post-tensioning installation work is inspected. Measuring equipment used for installation is calibrated and certified by an approved independent testing laboratory. During tensioning operations, records are kept for comparing force measurements with elongation for tendons. The resultant cross-reference provides a final check on measurement accuracy.

The tensioning sequence is based on the design requirements to limit the predicted membrane tension in the concrete and to minimize unbalanced loads and differential stresses in the structure. The procedure for prestressing is coordinated with the post-tensioning vendor. Procedures are subject to the engineer's approval.

A detailed typical prestressing sequence is shown in Figure 6-4 of BC-TOP-5-A.

3.8.1.6.4 Containment Liner

The containment structure is lined with 1/4-inch thick welded steel plate, except in limited areas where thickened plate is utilized, conforming to the requirements of ASME SA-285, Low and Intermediate Tensile Strength Carbon Steel Plates for

Pressure Vessels, Grade A, to ensure a leaktight membrane. This steel has a minimum yield strength of 24,000 psi and a minimum elongations in an 8-inch specimen of 27%. The ASME SA-285 material was chosen because it has sufficient strength, low yield point, and ductility to resist the expected stresses from design criteria loading, limit forces due to thermal differentials and, at the same time, to preserve all required leaktightness of the containment. It is readily weldable by all of the commercially available arc and gas welding processes. ASTM A285 Grade C and A515 Grade 70 are other materials of quite similar characteristics which were used for liner material. All thickened steel plate conforms to the requirements of ASME SA-516 Grade 70 or ASTM A516 Grade 70.

Design of the liner plate is subject to the provisions of C-TOP-1. Construction, inspection, and testing of the liner plate were performed using the applicable sections of the ASME B&PV Code, Section III, Division 2, as a guide only.

The equipment hatch and personnel and escape locks must resist the full design pressure and are designed in accordance with the ASME B&PV Code, Section III, Division 1, Subsection NE, Class MC components with the following exceptions:

A. Article NE-4232, Maximum Offset of Aligned Section:

   Misalignment in completed butt-welded joints shall not exceed 10% of the plate thickness or 1/16 inch, whichever is greater.

B. Article NE-4426, Reinforcement of Welds:

1. The finished surface of the reinforcement of all manually-welded butt joints may be flush with the base material or may have reasonably uniform crowns, the maximum on each side not to exceed: 3/32 inch in thickness for material thickness 1/2 inch or less; 1/8 inch in thickness for material thickness over 1/2 inch to 1 inch; 3/16 inch in thickness for material thickness over 1 inch to 2 inches.

2. The finished surface of the reinforcement of automatic machine-welded butt joints may be flush with the base material or may have reasonably uniform crowns, the maximum on each side not to exceed 5/32 inch in thickness.

Materials used for equipment hatch and personnel air locks conform to the requirements of ASME B&PV Code, Section III, Division 1, Article NE-2000.

The interior projections of all penetration assemblies must resist the full design pressure. The design of all penetration assemblies is controlled by the provisions of BC-TOP-1.

The liner plate is designed to function only as a leaktight membrane. It is not designed to resist the tension stresses from internally applied pressure, which may result from any credible accident conditions. Structural integrity of the containment is maintained by the post-tensioned concrete. Since the principal applied stress to the liner plate membrane

is in compression from shrinkage and creep of the concrete, there is no need to apply special nil ductility transition temperature criteria to the liner plate material. On the other hand, all material for containment parts that resists applied internal pressure stresses, such as penetrations, is impact tested in accordance with the requirements of ASME B&PV Code, Section III, Division I, Article NE-2320.

For stud welding to nonpressure-retaining parts of the containment liner system (i.e., the containment liner plate), welding procedures and welding operators are qualified as specified in AWS D1.1-72, Revision 1, 1973, Section 5.

For all other welding of the containment liner system, all welding procedures and welding operators are qualified by tests, as specified in ASME B&PV Code, Section IX. This Code requires testing of welded transverse root and face bend samples in order to verify adequate weld metal ductility.

Specifically, Section IX of the Code requires that the transverse root and face bend samples be capable of being bent cold 180° to an inside radius equal to twice the thickness of the test sample. Satisfactory completion of these bend tests is accepted as adequate evidence of required weld metal and plate material compatibility.

Welding materials used to join various parts of the liner plate system are as follows:

A. E6010 is general purpose welding rod for liner seam welds and pressure-retaining parts.

B. E7018 is a low hydrogen rod used for the following conditions:

1. For welds made with gas tungsten-arc root passes

2. For design temperatures below 0F

3. For steels having a specified minimum tensile strength of 70,000 psi and greater in thicknesses over 1 inch

4. Where stress relieving by post-weld heat treatment is required

C. EM12K (SFA 5.17) wire and flux is used for submerged arc welding of the 1/4-inch horizontal liner plate welds.

D. E70T-G (AWS A5.20/SFA 5.20) is used for flux core arc welding of liner plate and dome liner plate.

E. E70S-3 (SFA 5.18) is used for attachment fillet welds.

F. F74-EF2-F2 (SFA 5.23) is used for equipment hatches (exception to F2 analysis is manganese less than 1.5%).

G. E7024 is used in nonpressure-retaining fillet welds.

Mill test reports are obtained on all material giving heat numbers and material analysis. This information is traceable to the in-place penetration for all material except welding filler metal (weld rod).

3.8.1.6.4.1 Liner Plate Erection. Vertical and dome liner plates are used as forms and erection precedes the concrete

placements. Tolerances for erection of the liner plate and the penetration assemblies are specified as follows and in the event of conflict shall prevail over tolerances listed in BC-TOP-1, Section 1.3.8:

A. Liner Plate

1. The radial location of any point on the wall liner plate does not vary from the design radius, referred to the vertical centerline of the containment structure, by more than ±3 inches. At any given elevation, the maximum diameter minus the minimum diameter does not exceed 6 inches.

   Measurements are made at 30° spacing for each 10 feet of height.

2. Plates to be joined by butt welding are matched accurately and retained in position during the welding operation. Misalignment in completed joints does not exceed 10% of the plate thickness or 1/16 inch, whichever is greater.

3. A 15-foot long template curved to the required radius does not show deviations of more than 1 inch when placed against the completed surface of the shell within a single plate section and not closer than 12 inches to a welded seam. When the template is placed across one or more welded seams, the deviation does not exceed 1-1/2 inches. The effect of change in plate thickness or of weld

reinforcement is excluded when determining deviations.

4. A 15-inch long template curved to the required radius does not show deviations of more than 1/8 inch inward and 3/8 inch outward when placed against the completed surface of the shell within a single plate section. Where the deviation exceeds these limits, remedial action is taken to correct the deficiency.

5. The slope of any 10-foot section of cylindrical liner plate, referred to true vertical, does not exceed 1:120. The shell is not out of plumb in excess of 3 inches overall.

6. A 10-foot straight edge does not show deviations greater than ±1 inch in the vertical direction between seam welds.

7. Sharp bends are not permitted unless provision has been made for them in the design. A sharp bend is defined as any local bend that deviates from the design radius or a vertical straight edge by an offset of more than 1/2 inch in 1 foot. The template used to measure the local deviations is only 1 to 2 feet longer than the area of the deviation itself.

8. The maximum allowable overall as-built dome profile shall be within +8-1/2 inches and -13 inches of the design location.

3.8.1.6.4.2 Cathodic Protection. Cathodic protection is not provided for corrosion protection of the containment steel liner, reinforcing steel, or tendon sheathing.

Permanent reference electrodes are installed below the containment basemat to monitor the structure-to-earth potential.

3.8.1.6.4.3 Containment Liner Plate Coating. To prevent corrosion and to increase the visibility required for safe conditions during inspection and maintenance, the inside face of the liner plate is coated with a coating system that meets the intent of ANSI N101.2-1972 for LOCA environment conditions for pressurized water reactors and Regulatory Guide 1.54, as clarified by section 1.8.

3.8.1.6.5 Containment Liner Plate Attachments and Associated Hardware

Material for penetration sleeves conforms to the requirements of the three specifications listed below. The lowest service metal temperature is 40F and the maximum impact test temperature is 10F.

A. Penetration sleeves - Seamless and Welded Steel Pipe for Low-Temperature Service, ASME SA-333, Grade 1 or 6, and ASME SA-516, Grade 70.

B. Penetration sleeve reinforcing - ASME SA-516, Grade 70

C. Anchor rings and plates - ASME SA-516, Grade 70

Material for bolts, nuts, studs, cadwelds, and unistruts conforms to the requirements of the specifications listed below:

A. Machine bolts - ASME SA-307, Low-Carbon Steel Externally and Internally Threaded Standard Fasteners

B. Nelson studs - ASTM A108, Cold-Finished Carbon Steel Bars and Shafting

C. Cadweld connectors - AISI C 1026 or AISI C 1018

D. Unistruts - Hot-Rolled Carbon Steel Sheet and Strip, Structural Quality, ASTM A570, Grade A and steel, Cold-Rolled Sheet, Carbon, Structural, ASTM A611, Grade A.

E. High strength bolts - ASME SA-325, High Strength Bolts for Structural Steel Joints Including Suitable Nuts and Plane Hardened Washers.

F. Anchor bolts or studs - ASME SA-36, Structural Steel, ASME SA-105 (bar stock), Carbon Steel Forgings for Piping Components, ASME SA-193 (Grade B7), Alloy-Steel and Stainless Steel Bolting Materials for High Temperature Services, ASME SA-194 (Grade 7), Carbon and Alloy-Steel Nuts for Bolts for High Pressure and High Temperature Service.

Tolerances for erection of penetration assemblies are specified as follows and in the event of conflict shall prevail over tolerances listed in BC-TOP-1, Section 1.3.8:

A. Penetration assemblies

1. Paragraph 3.8.1.6.4.1, listings A.2, 3, and 5 also control the tolerance requirements for penetrations.

2. A 30-inch long template curved to the required radius does not show deviations of more than 3/4 inch when placed against the completed surface of the shell within a single plate section.

3. Alignment of the axis of penetrations greater than 12-inch nominal pipe size, as erected, does not vary by more than 1° from the alignment shown. Alignment of the axis of penetrations 12 inch or smaller nominal pipe size as erected shall not vary by more than 2° from the alignment shown. Individual penetrations and penetrations in common reinforcing plates other than main steam and feedwater penetrations are located within ±1 inch of their design elevations and circumferential locations. Main steam and feedwater penetrations shall be located within ±1/2 inch of their design elevations and circumferential locations.

4. The location of penetrations in a common reinforcing late is within ±1/4 inch of the

dimensions shown on the design drawings relative to each other.

3.8.1.6.6 Structural and Miscellaneous Steel

Detailing, fabrication, and erection of the structural and miscellaneous steel are in accordance with the AISC specifications referenced in paragraph 3.8.1.2.2.

Mill test reports of structural and miscellaneous steel are obtained for all materials used with the exceptions of hand rails, toe plates, kick plates, stairs, ladders, and for nuts, bolts, and anchors including anchor bolts less than 1-1/4 inches diameter. Handrails, toe plates, etc., are not highly stressed but require certificates of compliance as documentation.

Materials conform to the following specific designations:

Material	ASTM Designations
Structural steel shapes, plates, and bars	A36, A516 Grade 70, A992
High strength structural steel shapes, plates, and bars	A441, A514, A588
Anchor bolts	A36, A307, A540, A449, A354 Grade BD
High strength bolts (steel connections)	A325, A354 Grade BD, A490, A540
Other bolts	A36, A307
Stainless steel plate	A167 or A240, type 304 with 0.05% maximum carbon or type 304L

Welding and the acceptance criteria for visual inspection of welding are in accordance with AWS Dl.1-72, Revision 1, 1973 with clarifications and changes identified in paragraphs 3.8.1.6.6.1, listing A.

3.8.1.6.6.1 Structural Steel Construction. For steel construction, procedures are as follows:

A. Welding and acceptance criteria for visual inspection of welding are per the Structural Welding Code (AWS Dl.1-72, Revision 1, 1973) with the following clarifications and changes:

   1. Weld joint classification is based upon suitability for service in accordance with the following categories:

      a. Category A joints are part of the main building frame and carry principal design loads.

      b. Category B joints are connections between main building frame and miscellaneous metal.

      c. Category C joints are not part of the main building frame, but rather provide auxiliary support or framing for systems, components, and equipment. These joints are within the miscellaneous metal category, and shall include, but are not limited to, pipe supports (beyond the scope of ASME codes), stairways, embedments, HVAC duct supports, instrument supports, and electrical raceway and supports.

d. Category D joints are not part of the building frame, or auxiliary support system, but rather perform a passive or inactive function. These joints are within the miscellaneous metal category and shall include, but are not limited to, doors, windows, hatch covers and frames, ledger angles, handrails, and gratings.

e. Category E joints are limited to welds, used in ductwork welding of thin-walled gauge steel, whose classification is not specifically covered by the Structural Welding Code.

2. The acceptance criteria for visual inspection of Category A, B, C, and D joints are per Nuclear Construction Issues Group Document, NCIG-01, Revision 2.

3. For Category E joints, Paragraph 3.1.4 is clarified as follows:

   a. Weld sizes specified in the drawings are considered nominal. Deviations of up to -1/32 inch for the entire weld length are considered as meeting the weld size requirement.

   b. The fillet leg dimension may not underrun the specified weld size by more than 1/16 inch for more than 10% of the weld length. For flange-to-web joints, the undersize may not be within two flange thicknesses of the weld end.

c. Fillet welds exceeding the specified size are acceptable, as long as the oversized weld does not interfere with mating parts and there is no evidence of excessive distortion.

d. Fillet weld lengths in excess of those shown on the design drawings are acceptable.

e. Where intermittent fillet welds are specified on the design drawings, a continuous weld of the same size is acceptable.

4. Paragraph 4.9.2 is replaced as follows:

All electrodes having low-hydrogen coverings conforming to AWS A5.1 are purchased in hermetically-sealed containers. If the hermetically-sealed container shows evidence of damage, the electrodes are dried prior to use. Immediately after the opening of the hermetically-sealed containers, electrodes are stored in ovens held at a temperature of 200F minimum. The E70XX electrodes that are not used within 12 hours, E80XX within 2 hours, E90XX within 1 hour, E100XX and E110XX within 1/2 hour after the opening of the hermetically-sealed container or removal of the electrodes from a drying or storage oven are redried for 8 hours at a temperature of 200F minimum prior to reissue. Electrodes which have been wet are not used. Heated rod cans are not required when rod is used within the specified time.

5. In Table 4.2, the governing thickness to determine preheat requirements for fillet welds shall be the weld throat thickness. The preheat for fillet welds is based on the weld throat dimension, and the justification is based on the following engineering analysis:

   a. The structural steels used at PVNGS that utilize the fillet weld throat approach to preheating the plain carbon steels (principally A36, A992, and A500) and are essentially nonhardenable. Preheat is important for plain carbon, nonhardenable steels to counteract high restraint and shrinkage strains. The fillet welds at PVNGS are not considered to be highly restrained. Since the shrinkage strain is proportional to the weld throat, it is a rational basis for preheating. This fillet weld throat approach to preheating is not used for high strength or alloy steels. High strength and alloy steels used at PVNGS are governed by other codes and specifications.

   b. The principal welding filler metal used for the structural steel is E7018, which produces a tough ductile deposit and has minimal preheat requirements due to its low hydrogen characteristic. The NRC has reviewed and approved a test report from PVNGS, qualification of an Alternative Electrode Control Program for AWS D1.1

(including the electrode control procedure WFMC-1, Revision 6), dated March 15, 1978, which reported on the control of E7018 electrodes. The test coupons used in that program were welded without preheat. Several coupons were 1-inch thick circular patch tests which represent the maximum restraint. As the circular patch test coupons welded without preheat were acceptable, fillet welding without preheat is justifiable. In addition to these tests, other procedure qualification test coupons have been welded without preheat. Any of these tests can serve to qualify deviations from the requirements of AWS D1.1, Table 4.2.

c. The inspection requirements of AWS D1.1 are supplemented with nondestructive examinations as appropriate to the design and function of the components.

6. For Category E joints, Paragraph 3.6.4 is replaced as follows:

   Undercut shall not exceed 50% of the material thickness.

7. For Category E joints, Paragraph 3.6.6 is replaced as follows:

   Overlap/rollover may not exceed 1/8 inch.

8. For Category E joints, Paragraph 3.6.1 is replaced as follows:

   The face of fillet welds may be slightly convex, flat, or slightly concave. The convexity height shall not exceed 1/8 inch. Concavity shall not reduce the weld throat beyond that required for weld size.

9. Paragraph 8.15.1.5 is replaced as follows:

   a. For Category E joints, the welds may contain a maximum of 5%, by surface area, unaligned, unclustered porosity.

10. Welding shall be performed only by welders or welding operators who have been qualified in accordance with AWS D1.1 1972, Revision 1, 1973, or ASME Section IX, Welding and Brazing Qualifications, 1974 Edition or later. The groove plate test in the 3G and 4G positions, or any 6G position pipe, shall qualify a welder to perform the following additional operations:

    a. Welding of handrails in all positions.

    b. To make fillet welds of any size, in all positions, on base metals in all thicknesses for structural tubing.

B. AISC, Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, as referenced in paragraph 3.8.1.2.2, is used.

C. AISC, Specification for Structural Joints Using ASTM A325 or A490 Bolts, is used.

D. Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (ANSI N45.2.5-1974) is used except as noted below:

1. Section 5.4, High Strength Bolting -- Used except AISC Specification for Structural Joints Using ASTM A325 or A490 Bolts shall govern the proper length of bolts.

2. Section 5.5, Welding -- Used with exceptions as noted in paragraph 3.8.1.6.6.1, listing A.

NOTE

Work accomplished prior to the adoption of NCIG-01 shall conform to the commitments established in the PVNGS FSAR prior to NCIG-01 adoption.

3.8.1.6.7 Quality Control

Quality control procedures are established and implemented during construction and inspection as specified in Chapter 17. The quality control procedures covering the fabrication, furnishing, and installation of each structural component provide inspection and documentation to assure that the codes and construction practices are met.

3.8.1.6.7.1 Control Tests for Concrete. Concrete for the containment structure is tested in accordance with ACI 301-72,

except as noted in paragraph 3.8.1.6.1. Concrete placement is accomplished in accordance with NRC Regulatory Guide 1.55 as discussed in section 1.8.

3.8.1.6.7.2 Control Tests for Reinforcing Steel. Reinforcing steel is tested in accordance with NRC Regulatory Guide 1.15. Control of mechanical splices for reinforcement utilizing filler metal and an enclosing sleeve (cadweld-type splices) is in accordance with NRC Regulatory Guide 1.10 with exceptions as noted in section 1.8.

3.8.1.6.7.3 Control Tests and Inspection of Prestressing System. The following quality control procedures are used:

A. Prestressing Wires

1. Each tendon is individually identified and traceable to the heat numbers of the wire utilized in its buildup. Chemical and physical test reports supporting the integrity of each heat of material are reviewed as a condition of acceptance.

2. Specimens are cut from each reel of wire and tension tested to assure compliance to specifications.

3. Wires are examined for quality prior to fabrication of the tendon.

B. Bearing Plates and Trumpets

1. Verify that the bearing plate material complies with that specified on the drawings. Compliance is evidenced by mill test reports traceable to the heat number by serial numbers permanently marked on each bearing plate.

2. A full scale ultimate tensile strength test on a representative tendon sample is conducted with the anchorage, bearing plate, and supporting concrete maintained at a temperature at least 30F below the lowest anticipated service temperature. This service temperature is 20F and the test is conducted at a maximum of -10F.

3. Plates are examined for workmanship and quality. Cracks, burrs, corrosion, and other defects are not acceptable.

C. Anchor Head

1. Raw material is accompanied by mill certificates and subjected to receiving inspection.

2. Parts are coated with a preservative prior to shipment.

D. Physical Tests

1. Load Test

Typical anchorage and tendon details are tested to show that the anchorage develops the minimum

guaranteed ultimate strength of the tendon and that the elongation of the assembly will not be less than specified.

2. Cyclic Test

   Failure must not result based on test results on reduced size anchorage assemblies subjected to 500 cycles of rapid loading from stress level 0.70 f_s' to stress level 0.75 f_s' and return to 0.70 f_s'. One complete cycle shall take place in 0.1 second.

3. Cold Environment Test

   Documentary evidence or certified testing at temperatures below the lowest anticipated service temperature shall substantiate that the anchorage assembly, including the bearing plate, is capable of transmitting the ultimate load of the tendon into the structure. Reference 1 is an example of accepted documentation for the cold environment test.

3.8.1.6.7.4 Quality Control Procedures for the Liner Plate. The nondestructive examination of the liner plate is in accordance with NRC Regulatory Guide 1.19 with exceptions noted in section 1.8.

The materials which are used in the liner plate system fabrication and construction are listed in table 3.8-1.

Properties and characteristics of the liner plate are given in table 3.8-5.

A. Liner and Thickened Plate

The liner plate is 1/4 inch thick. Thickened plates are used as penetration reinforcing plates and as part of the bracket and attachment assemblies. Thickened floor plate shall be ultrasonically inspected in accordance with ASME SA-435, except that inspection shall cover 100% of the plate area. Thickened plates over 5/8 inch in thickness require Charpy V-notch impact tests in accordance with ASTM A593. Testing is specified at 30F below service temperature and the average energy requirement for 3 specimens shall be greater than 15 ft-lbs while the minimum requirement for any one specimen shall be greater than 10 ft-lbs. Structural steel members and electrical ground rods are not classified as thickened plate.

B. Penetration Nozzles

Nozzles over 5/8 inch in thickness require the same Charpy V-notch impact tests as for thickened plates in paragraph 3.8.1.6.7.4, listing A. except see note c of table 3.8-1 for minimum requirements of ASME SA-333, Grades 1 and 6.

C. Welding Materials

Welding materials used to join various parts of the liner plate system are described in paragraph 3.8.1.6.4.

The quality assurance procedures that assure the suitability of the steel plate material for field-welded brackets and attachments that are not continuous through the liner plate are discussed as follows:

A. The liner plate shall be ultrasonically examined for delaminations in an area that extends an additional liner plate thickness from the attachment weld. Any delaminated plates are repaired.

B. The strength in the through the thickness direction is taken as one-half of that in the transverse direction unless tests are performed to justify higher values.

Ultrasonic examination shall be required only for plate 3/8 inch and greater thickness.

3.8.1.6.7.5 Quality Control Procedures for the Containment Liner Plate Attachments. The quality control procedures associated with penetrations, attachments, and hardware are incorporated in the quality control procedures for the liner plate.

3.8.1.6.7.6 Quality Control Procedures for Structural and Miscellaneous Steel. Quality control procedures for structural

and miscellaneous steel and the associated structural welding conform to the requirements specified in paragraph 3.8.1.6.6.

3.8.1.7 Testing and Inservice Surveillance Requirements

3.8.1.7.1 Structural Integrity Pressure Test

Following construction, the containment is proof-tested at 115% of the design pressure. During this test, deflection measurements and concrete crack inspections are made to determine that the actual structural response is within the limits predicted by the design analyses.

The test procedure complies with the requirements of NRC Regulatory Guide 1.18 except as noted in section 1.8. Section 9 of BC-TOP-5-A also describes test results obtained using a typical procedure as well as those obtained from early tests where a substantial amount of strain information was collected.

3.8.1.7.2 Long-Term Surveillance

The long-term surveillance program consists of evaluating the general condition of the post-tensioning system. Data on wire corrosion level and tendon lift-off forces are obtained and analyzed. The surveillance tendons and surveillance frequency are designated by the engineer as explained in BC-TOP-5-A, Section 9.3. Except as noted in section 1.8, the surveillance program complies with ASME Section IX, Subsection IWL, 1992 Edition with the 1992 Addenda, as modified and supplemented by 10 CFR 50.55a.

The inservice inspection program for the containment liner plate and exterior concrete surface consist of visual examinations, tracking, monitoring, reporting, and repair/replacement/rework of applicable degraded conditions. The inservice inspection program for the containment liner plate and exterior concrete surface complies with ASME Section XI, Subsection IWE and IWL, 1992 Edition with the 1992 Addenda, as modified and supplemented by 10 CFR 50.55a. The surveillance and inservice inspection programs provide assurances of the continuing ability of the structure to meet the design functions as stated in paragraph 3.8.1.5.

3.8.2 STEEL CONTAINMENT

As described in subsection 3.8.1, the containment is a prestressed, reinforced concrete structure; therefore, this section does not apply.

3.8.3 CONCRETE AND STEEL INTERNAL STRUCTURES OF STEEL OR CONCRETE CONTAINMENTS

3.8.3.1 Description of the Internal Structures

The internal structures located in the containment consist of the reactor supports, steam generator supports, reactor coolant pipe restraints, primary shield wall and reactor cavity, secondary shield walls, pressurizer supports, refueling pool walls, and the operating and intermediate floors.

3.8.3.1.1 Reactor Vessel Supports

The reactor vessel is supported by four columns under the cold leg nozzles discussed in section 5.4.14 which interface with anchor bolts embedded in the primary shield. Lateral supports are provided for the reactor vessel to resist the horizontal loads. These lateral supports transmit the loads to the reactor cavity wall, which houses the reactor. In addition, shear keys at the lower part of the reactor vessel fit into the keyways, located in the base plate, of the column supports. These keyways (which are described in section 5.4.14) transmit the horizontal loads to the cavity wall through shear bars attached to the bottom of the base plate. Both the lateral supports and shear keys are designed to allow movement due to thermal growth of the reactor vessel in the radial and vertical directions. Details of the lateral and vertical reactor vessel supports are shown in engineering drawings 13-C-ZCS-600 and -601.

3.8.3.1.2 Steam Generator Supports

The steam generator is mounted on thick, heavily reinforced, concrete supports. The loads are transmitted to the supports by means of high-strength bolts, bearing plates, and shear keys. The supports, in turn, transmit these loads to the containment basemat. The upper part of the steam generator is restrained by means of shear keys and snubbers that are attached to the refueling pool walls and secondary shield walls. The steam generator supports are shown in engineering drawings 13-C-ZCS-605 and –606.

3.8.3.1.3 Reactor Coolant Pump Supports and Stops

The reactor coolant pumps are supported by four vertical columns, four horizontal columns, and two horizontal snubber supports. The horizontal columns and snubbers and a portion of the vertical columns are considered to be part of the NSSS as discussed in section 5.4.14. The vertical columns transmit the vertical loads to the containment basemat. The horizontal columns and the snubber supports, attached to the secondary shield wall, transmit the lateral loads to the refueling pool walls and to the secondary shield walls. All of the columns are hinged to permit radial (defined as an axis passing through the center of the reactor and the pump) movement of the pumps due to thermal growth.

Additionally, one stop is provided for each reactor coolant pump. This stop is a horizontal column designed to resist lateral loads in the radial direction due to a postulated LOCA. The resisted loads are transmitted to the secondary shield walls. Details of the reactor pump supports and stop are shown in engineering drawings 13-C-ZCS-602 and –603.

3.8.3.1.4 Pressurizer Supports

The pressurizer vessel is located in a pressurizer compartment which is supported by concrete beams at elevation 110 feet. The pressurizer compartment has a floor space approximately 18 feet square and a height of 50 feet. It is attached to one of the secondary shield structures and is covered by a three-section removable reinforced concrete missile shield at the top of the

compartment. The pressurizer support skirt, which is described in section 5.4.14, is attached to the concrete beams by anchor bolts. The beams and anchor bolts are designed for vertical and lateral loads as well as for moments due to dead loads, thermal loads, seismic loads, and loads due to surge line and other pipeline breaks.

In addition, the pressurizer is restrained near the top by means of keys which fit into keyways. Four keyway supports are located 90° apart and are designed to transmit the lateral loads due to seismic excitation and due to sub-compartment pressures by pipe breaks to the pressurizer compartment walls. These keyways are also designed to permit vertical and radial movement of the pressurizer due to thermal growth. Details of the pressurizer supports are shown in engineering drawing 13-C-ZCS-604.

3.8.3.1.5 Reactor Coolant System Pipe Restraints

The RCS restraints are provided to restrict the displacement of the reactor coolant piping. Section 3.1.4 states that dynamic effects associated with postulated pipe ruptures of primary coolant loop piping in PWRs may be excluded from the design basis when analysis demonstrates the probability of rupturing piping is extremely low. The reactions from the restraints are transmitted to the basemat or various heavily reinforced members which transmit the loads to the basemat or to the primary or secondary shield walls.

All the restraints are provided with a gap to permit movement of the pipes due to thermal growth and seismic displacements.

3.8.3.1.6 Primary Shield Wall and Reactor Cavity

The primary shield is a heavily reinforced concrete structure that houses the reactor, provides the primary radiation shielding, and is an integral part of the internal structures. It is anchored to the containment basemat through the use of cadwelds welded to both sides of the thickened liner plate.

The massive primary shield walls provide a support for the refueling pool walls above the reactor cavity. In plan, the primary shield walls form a monolithic ring, housing the reactor vessel. Penetrations in the primary shield walls are provided for the primary loop and cavity ventilation system.

Details of the primary shield walls are shown in engineering drawings 13-C-ZCS-345 through -348.

3.8.3.1.7 Refueling Canal

The refueling canal is a reinforced concrete structure that is flooded during the reactor refueling operation. The pool walls are partially supported by the primary shield and partially by the containment basemat.

The refueling canal is lined with stainless steel plate and is connected with the spent fuel pool, in the fuel handling building, through the fuel transfer tube.

3.8.3.1.8 Fuel Transfer Tube

A detailed description of the fuel transfer tube is provided in paragraph 3.8.1.1.3.5.

3.8.3.1.9 Secondary Shield Walls

The secondary shield is a heavily reinforced concrete structure enclosing (together with the refueling pool walls) the steam generators. The massive secondary shield walls are anchored into the basemat of the containment in a manner similar to the primary shield walls, in order to allow for load transfer to the foundation. Each of the two enclosed secondary shield compartments houses a steam generator and two reactor coolant pumps.

Steel embedments in the secondary shield walls transmit loads from various equipment, pipe supports, operating and intermediate floors, and platforms to the walls.

Details of the secondary shield walls are shown in engineering drawings 13-C-ZCS-366 and -358.

3.8.3.1.10 Operating and Intermediate Floors

The floors inside the containment consist of both concrete slab construction and steel grating supported by structural steel framing. The steel framing is supported by perimeter steel columns just inside the exterior shell. The internal structure, including attachments, is separated from the liner plate and its attachments by a nominal 3-inch gap for seismic displacement allowances. Smaller gaps may be permitted, based

on an engineering evaluation, on a case-by-case basis. The steel grating is vertically supported by ledger angles welded to the containment liner plate but is free to move horizontally.

Details of the operating floor are shown in engineering drawings 13-C-ZCS-306 and -307.

3.8.3.2 Applicable Codes, Standards, and Specifications

3.8.3.2.1 Codes and Standard Specifications

The codes and standard specifications listed below apply to internal structures. Later editions of certain baseline standards as noted below are acceptable provided they are identified in applicable design calculations or specifications for fabrication, construction, testing, or inspection.

- American Concrete Institute, Building Code Requirements for Reinforced Concrete (ACI 318-71, or later edition)
- American Institute for Steel Construction, Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, adopted February 12, 1969 and Supplement Nos. 1, 2, and 3, or later edition
- American Institute for Steel Construction, Specification for Structural Joints Using ASTM A325 or A490 Bolts Approved by Research Council on Riveted and Bolted Structural Joints of the Engineering Foundation, May 8, 1974, or later

- American Welding Society, Structural Welding Code (AWSD1.1-72, Revision 1, 1973 or later edition) except as noted in paragraph 3.8.1.6.6.1, listing A
- American Welding Society, Structural Welding Code Sheet Steel (AWS D1.3-1989) In addition to AWS D1.1 may be used for welding of structures inside containment.
- Crane Manufacturers Association of America Inc. CMAA Specification No. 70, 1971
- American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code
  - Section II, 1974 Edition and Addenda through Winter 1974
  - Section III, Division 1, 1974 Edition and Addenda through Winter 1974
  - Section V, 1974 Edition and Addenda through Summer 1974
  - Section VIII, Division 1, 1974 Edition and Addenda through Winter 1975
  - Section IX, 1974 Edition and Addenda through Winter 1974
- American National Standards Institute (ANSI), Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (ANSI N45.2.5-1974) except

as noted in paragraph 3.8.1.6.1.2, listings A and H, and paragraph 3.8.1.6.6.1, listing D.

3.8.3.2.2 General Design Criteria and Industry Standards

General design criteria and industry standards applicable to internal structures are listed below:

- NRC Regulatory Guides (applicable revisions and dates are provided in section 1.8)
  - Regulatory Guide 1.10, Mechanical (Cadweld) Splices in Reinforcing Bars of Category I Concrete Structures
  - Regulatory Guide 1.15, Testing of Reinforcing Bars for Category I Concrete Structures
  - Regulatory Guide 1.29, Seismic Design

  Classification
  - Regulatory Guide 1.46, Protection Against Pipe Whip Inside Containment
  - Regulatory Guide 1.55, Concrete Placement in Category I Structures
  - Regulatory Guide 1.60, Design Response Spectra for Seismic Design of Nuclear Power Plants
  - Regulatory Guide 1.61, Damping Values for Seismic Design of Nuclear Power Plants
  - Regulatory Guide 1.69, Concrete Radiation Shields for Nuclear Power Plants

Exceptions to and interpretations of these regulatory guides are given in section 1.8.

- Industry Standards
  - Nationally recognized industry standards, such as those published by ASTM, are used whenever possible to describe material properties, testing procedures, fabrication, and construction methods.

3.8.3.2.3 Project Design and Construction Specifications

Project design and construction specifications are provided in paragraph 3.8.1.2.4.

3.8.3.3 Loads and Load Combinations

The internal structures are designed for loads and loading combinations described in paragraphs 3.8.3.3.1 through 3.8.3.3.3. The loading combinations involving extreme wind, tornado, or flood forces are not applicable to the containment internal structures.

3.8.3.3.1 Loads, Definitions, and Nomenclature

3.8.3.3.1.1 Normal Loads. Normal loads are those loads to be encountered during normal plant operation and shutdown. They include the following:

D = Dead loads or their related internal moments and forces, including any permanent equipment loads and hydrostatic loads

L = Live loads or their related internal moments and forces, including any movable equipment loads and other loads which vary with intensity and occurrence, such as soil pressure

T_o = Thermal effects and loads during normal operating or shutdown conditions, based on the most critical transient or steady state condition

R_o = Pipe reactions during normal operating or shutdown conditions, based on the most critical transient or steady state condition

3.8.3.3.1.2 Severe Environmental Loads. Severe environmental loads are those loads that could infrequently be encountered during the plant life. Included in this category are:

E = Loads generated by the operating basis earthquake (OBE)

W = Loads generated by the design wind specified for the plant (not applicable to subsection 3.8.3)

3.8.3.3.1.3 Extreme Environmental Loads. Extreme environmental loads are those loads which are credible but are highly improbable. They include:

E' = Loads generated by the safe shutdown earthquake (SSE)

W_t = Loads generated by the design basis tornado specified for the plant. They include loads due to the tornado wind pressure, loads due to the tornado-created

differential pressures, and loads due to the tornado-generated missiles (not applicable to subsection 3.8.3)

3.8.3.3.1.4 Abnormal Loads. Abnormal loads are those loads generated by a postulated high energy pipe break accident within a building and/or compartment thereof. Included in this category are the following:

P_a = Pressure equivalent static load within or across a compartment and/or building, generated by the postulated break, and including an appropriate dynamic load factor to account for the dynamic nature of the load

T_a = Thermal loads under thermal conditions generated by the postulated break and including T_o

R_a = Pipe reactions under thermal conditions generated by the postulated break and including R_o

Y_r = Equivalent static load on the structure generated by the reaction on the broken high energy pipe during the postulated break, and including an appropriate dynamic load factor to account for the dynamic nature of the load

Y_j = Jet impingement equivalent static load on a structure generated by the postulated break, and including an appropriate dynamic load factor to account for the dynamic nature of the load

Y_m = Missile impact equivalent static load on a structure generated by or during the postulated break, as from pipe whipping, and including an appropriate dynamic load factor to account for the dynamic nature of the load

In determining an appropriate equivalent static load for Y_r, Y_j, and Y_m, elasto-plastic behavior may be assumed with appropriate ductility ratios provided excessive deflections will not result in loss of function of any safety-related system.

3.8.3.3.1.5 Other Definitions. Additional pertinent definitions are as follows:

S = For concrete structures, S is the required section strength based on the working stress design methods and the allowable stresses defined in Section 8.10 of ACI 318-71.

For structural steel, S is the required section strength based on the elastic design methods and the allowable stresses defined in Part 1 of the AISC

Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, February 12, 1969.

The 33% increase in allowable stresses for concrete and steel due to seismic or wind loadings is not permitted.

U = For concrete structures, U is the section strength required to resist design loads and is based on methods described in ACI 318-71.

Y = For structural steel, Y is the section strength required to resist design loads and is based on plastic design methods described in Part 2 of AISC Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, February 12, 1969.

3.8.3.3.2 Load Combinations for Concrete Structures

The following presents a set of load combinations and allowable design limits for Seismic Category I concrete structures. To assure that the structural integrity will be maintained, limits on the resulting stresses and the required section strength capacities are defined for service loads, including earthquake (OBE) and wind loads, and for factored loads, including earthquake (OBE or SSE), tornado, and pipe break effects and various combinations thereof.

A. Load Combinations for Service Load Conditions

Either the working stress design (WSD) method or the strength design method will be used.

(1) If the WSD method is used, the following load combinations are considered:

1. S = D + L

2. S = D + L + E

3. S = D + L + W (not applicable to subsubsection 3.8.3)

If thermal stresses due to T_o and R_o are present, the following combinations are also considered:

1a. $1.3S = D + L + T_o + R_o$

2a. $1.3S = D + L + T_o + R_o + E$

3a. $1.3S = D + L + T_o + R_o + W$ (not applicable to subsection 3.8.3)

Cases of L having its full value or being completely absent are both checked.

(2) If the strength design method is used, the following load combinations are considered:

1. $U = 1.4\ D + 1.7\ L$

2. $U = 1.4\ D + 1.7\ L +1.9\ E$

3. $U = 1.4\ D + 1.7\ L + 1.7\ W$ (not applicable to subsection 3.8.3)

If thermal stresses due to T_o and R_o are present, the following combinations are also considered:

1b. $U = (0.75)\ (1.4\ D + 1.7\ L + 1.7\ T_o + 1.7\ R_o)$

2b. $U = (0.75)\ (1.4\ D + 1.7\ L + 1.9\ E + 1.7\ T_o + 1.7\ Ro)$

3b. $U = (0.75)\ (1.4\ D + 1.7\ L + 1.7\ W + 1.7\ T_o + 1.7\ R_o)$ (not applicable to subsection 3.8.3)

Cases of L having its full value or being completely absent are both checked and the following combinations are also satisfied:

1c. $U = 1.2\ D + 1.9\ E$

2c. $U = 1.2\ D + 1.7\ W$ (not applicable to subsection 3.8.3)

Where soil and/or hydrostatic pressures are present, in addition to all the above combinations where they have been included in L and D, respectively, the requirements of Sections 9.3.4 and 9.3.5 of ACI 318-71 will also be satisfied.

B. Load Combinations for Factored Load Conditions

For these conditions, which represent extreme environmental, abnormal, abnormal/severe environmental and abnormal/extreme environmental conditions, respectively, the strength design method is used and the following load combinations are considered:

1. $U = D + L + T_o + R_o + E'$

2. $U = D + L + T_o + R_o + W_t$ (not applicable to subsection 3.8.3)

3. $U = D + L + T_a + R_a + 1.5\ P_a$

4. $U = D + L + T_a + R_a + 1.25\ P_a + 1.0\ (Y_r + Y_j + Y_m) + 1.25\ E$

5. $U = D + L + T_a + R_a + 1.0\ P_a + 1.0\ (Y_r + Y_j + Y_m) + 1.0\ E'$

In load combinations 3, 4, and 5, the maximum values of P_a, T_a, R_a, Y_j, Y_r, and Y_m, including an appropriate dynamic load

factor, are considered unless a time-history analysis is performed to justify otherwise. Combinations 2, 4, and 5 will be satisfied first without the tornado missile load in 2 and without Y_r, Y_j, and Y_m in 4 and 5. When considering these loads, however, local section strength capacities may be exceeded under these concentrated loads, provided there will be no loss of function of any safety-related system.

Cases of L having its full value or being completely absent are both checked.

3.8.3.3.3 Load Combinations for Steel Structures

The following presents a set of load combinations and allowable design limits for Seismic Category I steel structures. To assure that the structural integrity will be maintained, limits on the resulting stresses and the required section strength capacities are considered for service loads, including OBE and wind loads, and for factored loads, including OBE or SSE, tornado, and pipe break effects and various combinations thereof.

A. Load Combinations for Service Load Conditions

Either the elastic working stress design methods of Part 1 or the plastic design methods of Part 2 of AISC, will be used.

(1) If the elastic working stress design methods are used, the following load combinations are considered.

1. S = D + L

2. $S = D + L + E$

3. $S = D + L + W$ (not applicable to subsection 3.8.3)

If thermal stresses due to T_o and R_o are present, the following combinations are also considered:

1a. $1.5\ S = D + L + T_o + R_o$

2a. $1.5\ S = D + L + T_o + R_o + E$

3a. $1.5\ S = D + L + T_o + R_o + W$ (not applicable to subsection 3.8.3)

Cases of L having its full value or being completely absent are both checked.

(2) If plastic design methods are used, the following load combinations are considered:

1. $Y = 1.7\ D + 1.7\ L$

2. $Y = 1.7\ D + 1.7\ L + 1.7\ E$

3. $Y = 1.7\ D + 1.7\ L + 1.7\ W$ (not applicable to subsection 3.8.3)

If thermal stresses due to T_o and R_o are present, the following combinations are also considered:

1b. $Y = 1.3\ (D + L + T_o + R_o)$

2b. $Y = 1.3\ (D + L + E + T_o + R_o)$

3b. $Y = 1.3\ (D + L + W + T_o + R_o)$ (not applicable to subsection 3.8.3)

Cases of L having its full value or being completely absent are both checked.

B. Load Combinations for Factored Load Conditions

The following load combinations are considered:

(1) If elastic working stress design methods are used, the applicable load combinations are:

1. $1.6\ S = D + L + T_o + R_o + E'$

2. $1.6\ S = D + L + T_o + R_o + W_t$ (not applicable to subsection 3.8.3)

3. $1.6\ S = D + L + T_a + R_a + P_a$

4. $1.6\ S = D + L + T_a + R_a + P_a + 1.0\ (Y_j + Y_r + Y_m) + E$

5. $1.7\ S = D + L + T_a + R_a + P_a + 1.0\ (Y_j + Y_r + Y_m) + E'$

For combinations 4 and 5 of this paragraph, the plastic section modulus of steel shapes will be used in computing the required section strengths.

(2) If plastic design methods are used, the applicable load combinations are:

1. $0.90\ Y = D + L + T_o + R_o + E'$

2. $0.90\ Y = D + L + T_o + R_o + W_t$ (not applicable to subsection 3.8.3)

3. $0.90\ Y = D + L + T_a + R_a + 1.5\ P_a$

4. $0.90\ Y = D + L + T_a + R_a + 1.25\ P_a + 1.0\ (Y_j + Y_r + Y_m) + 1.25\ E$

5. $0.90\ Y = D + L + T_a + R_a + 1.0\ P_a + 1.0\ (Y_j + Y_r + Y_m) + 1.0\ E'$

For elastic and plastic design method combinations 1 and 2, thermal loads can be neglected when it can be shown that they are secondary and self-limiting in nature and where the material is ductile.

In combinations 3, 4, and 5, the maximum values of P_a, T_a, R_a, Y_j, Y_r, and Y_m, including an appropriate dynamic load factor, are used unless a time-history analysis is performed to justify otherwise.

Combinations 2, 4, and 5 will be first satisfied without the tornado missile load in 2 and without Y_r, Y_j, and Y_m in 4 and 5. When considering these loads, however, local section strengths may be exceeded under the effect of these concentrated loads, provided there will be no loss of function of any safety-related system.

3.8.3.3.4 Procedures for Determination of the Effect of Missile Impact on Concrete and Steel Structures

Missile barriers, whether concrete or steel, are designed with sufficient strength and thickness to stop the postulated missiles and to prevent generation of secondary missiles or spalling that may damage safety-related systems. To accomplish

this objective, prediction of local and overall damage due to the missile impact is necessary.

Local damage prediction, in the immediate vicinity of the impacted area, includes estimation of the depth of penetration and whether secondary missiles might be generated by spalling in case of concrete targets. Overall damage prediction includes estimation of the structural response of the target to the missile impact, including structural stability and deformations.

In general, missiles are characterized by impact velocity, missile mass, and impact area. Procedures used in determining these parameters are discussed in section 3.5.

3.8.3.3.4.1 Local Damage Prediction. Estimated missile penetration, perforation, and spalling effects are investigated using the procedures outlined in BC-TOP-9-A.

3.8.3.3.4.2 Overall Damage Prediction. The response of a structure to missile impact depends largely on the location of impact (midspan of a slab or near the support), on the dynamic properties of the target and missile, and on the kinetic energy of the missile.

Energy losses due to missile deformation, local penetration, and type of impact are accounted for. The techniques given in appendix 3C are used to determine an analytical approach, ductility factors, strength increase due to high strain rates, and methods for determining yield displacement.

3.8.3.4 Design and Analysis Procedures

Design of the interior structure evolves around four basic systems: the reactor coolant system, the main steam system, the engineered safeguards system, and the fuel handling system supply.

The structures that house or support the basic systems are designed to sustain the factored loads described in paragraph 3.8.3.3.

The design bases to be applied are given as follows:

A. Operating loads, seismic loads, and the thermal deformations at the levels indicated in paragraph 3.8.3.3.

B. Loads and deformations resulting from a LOCA and its associated effects.

C. Environmental effects resulting from a postulated high-energy line break such as temperature, pressure, humidity, or flooding. The magnitude of thrust forces and pressure buildup resulting from a pipe break is determined from appropriate blowdown values.

D. Jet impingement equivalent static loads on a structure generated by a postulated high energy line break.

E. Missile impact equivalent static loads on a structure generated by or during a postulated high energy line break, like pipe whipping.

F. Missiles as described in section 3.5.

The containment interior structure is designed to provide structural supporting elements for the entire NSSS, as well as required shielding. Basic supporting components are designed using both reinforced concrete and structural steel as appropriate. Design aspects are integrated with the design criteria of the nuclear steam supply system vendor and include particular attention to the combined thermal and dynamic effects particularly evident during earthquake conditions. Thrusts are taken by rigid members and by shock suppressors. Design loads and loading combinations for the interior structure are listed and described in paragraph 3.8.3.3.

The main considerations in establishing the structural design criteria for the internal structures are to provide a structure that will withstand the differential pressure within the reactor cavity and across the secondary shield walls in the event of an accident, and to minimize the effects of the pipe rupture force and seismic loadings utilizing supports and restraints. Loads and deformations resulting from a LOCA and its associated effects on any one of the basic systems are restricted so that propagation of the failure to any other system is prevented.

In addition, a failure in one loop of the NSSS is restricted, so that propagation of the failure to the other loop is prevented. Localized concrete yielding is permitted, when it is demonstrated that the yield capacity of the component is not affected, and that this small localized yielding does not generate missiles that could damage the structure. Full

recognition is given to the time increments associated with these postulated failure conditions. The walls are also designed to provide adequate protection for potential missile generation that could damage the containment liner.

The effect of radiation-generated heat on the internal structures was considered in the design of the primary and secondary shield walls. The shield wall thicknesses were determined on the basis of the radiation shielding requirements and, therefore, are greater than those required for structural purposes. This additional thickness provides a reserve strength greater than required to offset minor damages to the structures due to a LOCA. Since high temperatures are damaging to concrete, a thorough ventilation at a constant temperature is maintained within the containment to cool the area surrounding the shield walls and to prevent any appreciable loss of structural strength due to gamma and neutron heating.

The final design of the interior structure and equipment supports is reviewed to assure that they can withstand applicable pressure loads, jet impingement forces, pipe reactions, and earthquake loads without loss of function. The deflections or deformations of the structures and supports are checked to ensure that the functions of the containment and safety feature systems are not impaired.

The computer programs employed in the analysis of the various internal structure components perform linear, elastic analysis. The information contained in the computer runs includes forces, shears, moments, reactions, and displacements as a result of

various loading conditions considered. Table 3.8-6 lists the computer programs used for analysis. The verification of the computer programs is shown in appendix 3B.

Seismic analyses for the interior structures conform to the appropriate procedures outlined in section 3.7.

The mathematical model used includes equipment of significant mass values as discrete masses at the appropriate elevation. The seismic loads are determined using the procedures of the design response spectrum technique of analysis. Bending moments and forces resulting from appropriate earthquake loads are combined according to the load combinations described in paragraph 3.8.3.3. The equipment seismic shear is resisted by the anchorage system, anchor bolts, and by additional shear studs.

Strength design methods given in the ACI 318 Code are used for concrete and the AISC Code is used for steel. The internal structures are provided with connections capable of transmitting axial and lateral loads to the containment base slab.

The proportioning of reinforcing steel in concrete structures is based upon the specified codes of practice and it is distributed according to common detailing methods. Likewise, the selection of structural steel sections and the methods of fabrication and connections are in accordance with engineering codes and accepted industry practices.

Table 3.8-6

METHODS AND COMPUTER PROGRAMS FOR USE ON CATEGORY I STRUCTURES OTHER THAN CONTAINMENT

Code No.	Name	Documentation Traceability	Remarks
None	Classical Methods	Roark, Formulas for Stress and Strain, McGraw-Hill M. Heteny, Beams on Elastic Foundation, The University of Michigan Press, 1946 AISC, Steel Construction Manual, 1969 Davis, H., "Thermal Consid-eration in Design of Con-crete Shield," ASCE Pro-ceedings, Sept. 1958	The classical methods are for use in analyses of beams, plates, frames and shells. They are given in the standard text book and reference handbooks as used in universities and engineering practice.
CE299	FOSIN	Bechtel Power Corporation (BPC)	Time-history response with frequency dependent soil springs.
CE800	SAP	BPC	General static and dynamic analy-ses using finite-element.
CE802	SPECTRA	BPC	Development and plotting of response spectra.
CE970	LUCON	BPC	Impedance functions for layered soils.
CE029	GTSTRUDL	BPC	General static and dynamic analyses using finite elements

3.8.3.4.1 Reactor Coolant System Equipment Supports

The steel and concrete supports for the reactor, the reactor coolant pumps, the steam generators, safety injection tanks, the pressurizer, and the reactor drain tank are designed for dead loads, seismic loads, and nozzle reaction loads. These loads include the maximum forces on a support due to accident loads (e.g., pipe rupture) with a dynamic load factor, operating loads, and seismic loads. The directions of the seismic forces are chosen to give the largest load at each support.

The loads are combined using the maximum seismic forces and the maximum accident forces simultaneously. This combination ensures the worst possible design condition that could occur for each support.

The RCS equipment supports are designed using conventional design techniques.

A combination of hot gaps, keyways, and snubbers is provided between the above mentioned equipment and their supports to ensure that minimal thermal loads from the expansion of the equipment are transmitted to the supports.

3.8.3.4.2 Primary Shield Wall and Reactor Cavity

For the hypothetical LOCA condition, the cavity wall is designed to withstand jet impingement forces and internal pressurization combined with seismic and LOCA loads on the reactor vessel and coolant pipeline without gross damage to the cavity structure.

The reactor cavity is designed to withstand an internal pressure load and the reactor support loads due to a LOCA. A three-dimensional, finite-element model is used for the analysis of the portion of the primary shield wall affected by the asymmetric loadings (accident pressure and support reaction due to LOCA). The pressure loading is applied statically using an appropriate dynamic load factor. Peak differential pressures for each compartment as determined by the nodal analysis described in paragraph 6.2.1.2.2.1 are used. The applied pressures ranged between 99.8 and 8 psid. The reactor support loadings are determined by C-E using the support stiffnesses provided by Bechtel. These LOCA loads are combined with the accident pressure, dead load, seismic, etc., using the load combinations in paragraph 3.8.3.3. The rebar is designed using the OPTCON computer code (see appendix 3B). A summary of the reinforcing requirements is contained in table 3.8-7. The maximum stress level in the rebar under the worst loading combination is limited to 90% of the yield strength of the rebar.

For the normal operating condition, the reactor cavity is designed to withstand the stresses due to dead loads, live loads, and seismic loads. Under this condition, the stresses in the concrete and the reinforcing steel are significantly below working stress levels. In the stress analysis, flexure tensile cracking is permitted but is controlled by the bonded reinforcing steel.

3.8.3.4.3 Secondary Shield Wall and Steam Generator Compartments

The secondary shield walls and the refueling pool walls enclosing the steam generator compartments are designed for the effects of a LOCA condition. Specifically, accident pressures with the normal operating loads of dead, live, thermal, and seismic in the design of the steam generator compartment walls. A three-dimensional, finite-element model is used for the analysis of the secondary shield wall and internal structure. Peak pressures as determined by the nodal analysis described in paragraph 6.2.1.2.2.2 are applied statically with an appropriate dynamic load factor. The magnitude of these pressures varies between 29.4 and 5.0 psid due to any of the postulated pipe breaks listed in subsection 6.2.1.

The equipment support LOCA loadings (steam generator and reactor coolant pumps) are determined by C-E using the support stiffnesses provided by Bechtel. These asymmetric loads are conservatively applied in the analysis. The maximum support loads from all load cases for one steam generator and two reactor coolant pumps are applied simultaneously in one steam generator compartment to determine the moments and forces in the secondary shield wall. All forces are applied in a direction that would cause axial tension in the wall. This is a conservative approach since not all supports have maximums occurring under the same loading condition or accident. These LOCA loads are combined together with the dead and live loads, etc., using the load combinations listed in paragraph 3.8.3.3.

The reinforcing steel is sized using the OPTCON computer code. The reinforcing requirements are shown in table 3.8-7.

The compartments are also designed for jet forces on localized areas of the walls resulting from the impingement of escaping fluid. In addition, the affect of pipe rupture loadings at various restraints on the walls has been considered with local analysis of the walls.

3.8.3.4.4 Refueling Canal

For the refueling condition, the walls are designed for the maximum hydrostatic head due to 47.5 feet of water and including the effect of hydrodynamic pressure due to OBE and SSE. The steam generator compartment pressure loads due to postulated pipe rupture and hydrostatic head are not considered to occur simultaneously.

3.8.3.4.5 Pressurizer Compartment

The pressurizer compartment is located outside of the secondary shield structure; therefore, the LOCA load due to the rupture of a reactor coolant pipe is not considered in the design of the pressurizer compartment. Instead, the pipe rupture loads due to various pipelines within the pressurizer compartment are used for the design.

The design basis and approach for such pipe rupture loads are similar to that of the primary shield wall as described in paragraph 3.8.3.4.2.

Other major loading conditions considered in the pressurizer compartment design are:

- Reactions from the pressurizer support for operating conditions
- Seismic load due to equipment and structure itself
- Construction load for erection of pressurizer

3.8.3.4.6 Floors

Concrete floor slabs and peripheral structural steel beams supporting the slabs are designed for dead load, live load, equipment load, laydown load for refueling, and pressure differential across floor slab due to LOCA or MSLB. The slabs and the supporting beams are designed by conventional methods. Grating floors are designed for dead load, live load, laydown load for refueling, and pressure differential across floor due to LOCA or MSLB: structural steel framings are designed for equipment load and piping loads in addition to loads designed for grating floors.

3.8.3.4.7 Polar Crane Support Design

The polar crane support consists of single span steel girders which span between the polar crane support brackets. The runway rail is attached to the top of the girders. The top flange is curved on the inside to accommodate a seismic lug attached to the polar crane girders. The seismic lug serves a dual purpose. It limits the seismic motion of the crane, and it also acts as a retainer which prevents any dislodging of the

crane during a seismic event. The crane being derailed during a seismic event will not affect the safe shutdown of the plant. See figure 3.8-4.

The steel runway girders are designed, fabricated, and tested per AISC standards. The details are shown in engineering drawing 13-C-ZCS-520.

3.8.3.5 Structural Acceptance Criteria

The limiting values of stress, strain, and gross deformations are established by the following criteria:

A. To maintain the structural integrity when subjected to the worst load combinations

B. To prevent structural deformations from displacing the equipment to the extent that the equipment suffers a loss of function

The allowable stresses are those specified in the applicable codes. The stress contributions due to earthquakes are included in the load combinations described in paragraph 3.8.3.3.

Table 7 summarizes the governing load interactions and maximum capacity of principal reinforced concrete members. Table 3.8-8 summarizes the governing combined stress ratios from the beam/column interaction equation for principal structural steel members. Table 3.8-9 summarizes the ductility ratios for pipe whip restraints.

Table 3.8-7

CONTAINMENT INTERNAL STRUCTURES SUMMARY OF GOVERNING LOAD INTERACTIONS FOR PRINCIPAL REINFORCED CONCRETE MEMBERS (Sheet 1 of 3)

Description of Principal Member	Location of Principal Member	Governing Load Combination Number (a)(d)	Calculated Axial Load (P_u) and Flexural Load (M_u)		Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u) (b)(c)	Calculated Shear Load (V_u) (b)	Maximum Shear Capacity (V_u) (b)
			P_u (b)	M_u (c)			
Wall - horizontal reinforcement	North primary shield wall from El. 77.25' to El. 94'	8	29	45	520	- (e)	- (f)
Wall - horizontal reinforcement	North primary shield wall from El. 94' to El. 119'	8	117	160	170	-	-
Wall - horizontal reinforcement	North primary shield wall from El. 119' to El. 144'	8	100	102	179	-	-
Wall - horizontal reinforcement	North primary shield wall from El. 144' to El. 160'	8	-53	527	1500	-	-
Wall - vertical reinforcement	North primary shield wall from El. 77.25' to El. 94'	8	279	113	148	-	-
Wall - vertical reinforcement	North primary shield wall from El. 94' to El. 119'	8	138	60	200	-	-
Wall - vertical reinforcement	North primary shield wall from El. 119' to El. 144'	8	-4	170	440	-	-
Wall - vertical reinforcement	North secondary shield wall from El. 77.25' to El. 94'	2	174	281	596	-	-

a. Refer to paragraph 3.8.3.3.2, listing B for description of load combination number.

b. P_u and V_u are in kips; Sign convention for P_u: Compression (-), Tension (+).

c. M_u is in ft-k/ft.

d. Refer to paragraph 3.8.3.3.2, listing A(2) for description of load combination number.

e. Negligible.

f. Not calculated since shear load is negligible.

Table 3.8-7

CONTAINMENT INTERNAL STRUCTURES SUMMARY OF GOVERNING LOAD INTERACTIONS

FOR PRINCIPAL REINFORCED CONCRETE MEMBERS (Sheet 2 of 3)

Description of Principal Member	Location of Principal Member	Governing Load Combination Number (a) (d)	Calculated Axial Load (P_u) and Flexural Load (M_u)		Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u) (b) (c)	Calculated Shear Load (V_u) (b)	Maximum Shear Capacity (V_u) (b)
			P_u (b)	M_u (c)			
Wall - vertical reinforcement	North secondary shield wall from El. 94' to El. 119'	8	-16	-288	-860	-	-
Wall - vertical reinforcement	North secondary shield wall from El. 119' to El. 160'	8	41	-650	-990	-	-
Wall - horizontal reinforcement	Primary shield wall from El. 77.25' to El. 99'	6	894	1168	1308	-	-
Wall - horizontal reinforcement	Primary shield wall from El. 99' to El. 119'	7	-10	743	3608	-	-
Wall - horizontal reinforcement	Pressurizer wall from El. 94' to El. 125'	8	69	36	140	-	-
Wall - horizontal reinforcement	Pressurizer wall from El. 125' and above	7	52	47	157	-	-
Wall - vertical reinforcement	Pressurizer wall from El. 99' to El. 125'	2	159	-45	-87	-	-
Slab reinforcement north-south	6.5' slab at El. 94'	8	172	300	558	-	-
Wall-vertical reinforcement	Primary shield wall from El. 77.25' to El. 99'	6	457	-154	-207	-	-
	Primary shield wall from El. 99' to El. 114'	7	-599	871	3031	-	-

Table 3.8-7

CONTAINMENT INTERNAL STRUCTURES SUMMARY OF GOVERNING LOAD INTERACTIONS FOR PRINCIPAL REINFORCED CONCRETE MEMBERS (Sheet 3 of 3)

Description of Principal Member	Location of Principal Member	Governing Load Combination Number (a) (d)	Calculated Axial Load (P_u) and Flexural Load (M_u)		Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u) (b) (c)	Calculated Shear Load (V_u) (b)	Maximum Shear Capacity (V_u) (b)
			P_u (b)	M_u (c)			
Slab reinforcement east-west	6.5' slab at El. 94'	8	101	139	670	-	-
Wall - horizontal reinforcement	North secondary shield wall from El. 77.25' to El. 94'	8	149	206	849	-	-
Wall - horizontal reinforcement	North secondary shield wall from El. 94' to El. 119'	8	247	269	300	-	-
Wall - horizontal reinforcement	North secondary shield wall from El. 119' to El. 160'	8	230	962	973	-	-
2'-6" slab	South-East at El. 100'	4	(e)	55.2	97	17.3	38.9
2'-6" slab	South-West at El. 100'	4	-	71	198	16.9	45.7
2'-6" slab	North-West at El. 100'	4	-	31.1	70.7	10.4	45.7
2'-6" pressurizer slab	El. 100'	3	-	177	343	80.0	80.0
2'-6" slab	North-West at El. 122'	3	-	11.8	119.6	3.0	45.7
2'-6" slab above HVAC duct	El. 120'	5	-	111	115	19.3	44
1'-6" concrete shield for main steam line	El. 120'	5	-	30.2	37	14.9	23.7
3'-0" seal table slab	El. 114'-1"	5	-	108	110.9	32.2	40.6
3'-0" slab	East half at El. 140'	2(d)	-	151	200	30.2	55.8
3'-0" slab	South-West at El. 140'	2(d)	-	30	115.6	10	55.8
2'-0" slab	North-West at El. 140'	2(d)	-	25.3	91.8	6.9	35.5

Table 3.8-8

CONTAINMENT INTERNAL STRUCTURES SUMMARY OF GOVERNING COMBINED STRESS RATIOS FROM THE BEAM/COLUMN INTERACTION EQUATION FOR PRINCIPAL STRUCTURAL STEEL MEMBERS (Sheet 1 of 2)

Description of Principal Members	Location of Principal Members	Governing Load Combination Number	Combined Stress Ratio (<1.0)
W 18 X 35 Beam	El. 100′-0″ at Column No. 1	2[a]	0.94
W 21 X 55 Beam	El. 100′-0″ between Columns No. 2 and No. 3	2[a]	0.85
W 33 X 130 Beam	El. 100′-0″ between Columns No. 3 and No. 4	2[a]	0.38
W 24 X 84 Beam	El. 100′-0″ between Columns No. 4 and No. 5	2[a]	0.99
W 21 X 55 Beam	El. 100′-0″ at Column No. 4	2[a]	0.78
W 30 X 108 Beam	El. 100′-0″ at Column No. 6	2[a]	0.69
W 30 X 108 Beam	El. 100′-0″ between Columns No. 6 and No. 7	2[a]	0.58
W 24 X 84 Beam	El. 100′-0″ at Column No. 10	2[a]	0.31
W 30 X 172 Beam	El. 100′-0″ between Columns No. 14 and No.	2[a]	0.41
W 30 X 99 Beam	El. 100′-0″ at Column No. 16	2[a]	0.68
W 36 X 135 Beam	El. 120′-0″	4[a]	0.5
W 33 X 130 Beam	El. 120′-0″	4[a]	0.41
W 36 X 300 Beam	El. 120′-0″ at Column No. 8	4[a]	0.32
W 36 X 182 Beam	El. 120′-0″ at Column No. 8	4[a]	0.28
W 36 X 182 Beam	El. 120′-0″ at Column No. 7	4[a]	0.41
W 30 X 99 Beam	El. 120′-0″ between Columns No. 6 and No. 7	2[a]	0.42
W 21 X 55 Beam	El. 120′-0″ at Column No. 5	2[a]	0.87
W 14 X 43 Beam	El. 120′-0″ at Equipment Hatch	2[a]	0.80
W 33 X 130 Beam	El. 120′-0″ between Columns No. 4 and No. 5	2[a]	0.34
W 21 X 55 Beam	El. 120′-0″ between Columns No. 2 and No. 3	2[a]	0.88
W 18 X 35 Beam	El. 120′-0″ between Columns No. 1 and No. 2	2[a]	0.78
W 21 X 55 Beam	El. 120′-0″ between Columns No. 1 and No. 2	2[a]	0.86
W 30 X 99 Beam	El. 120′-0″ at Column No. 1	2[a]	0.71

a. Refer to paragraph 3.8.3.3.3, listing A(1) for description of load combination number.

b. Refer to paragraph 3.8.3.3.3, listing B(1) for description of load combination number.

Table 3.8-8

CONTAINMENT INTERNAL STRUCTURES SUMMARY OF GOVERNING COMBINED STRESS RATIOS FROM THE BEAM/COLUMN INTERACTION EQUATION FOR PRINCIPAL STRUCTURAL STEEL MEMBERS (Sheet 2 of 2)

Description of Principal Members	Location of Principal Members	Governing Load Combination Number	Combined Stress Ratio (<1.0)
W 36 X 300 Beam	El. 140’-0” between Columns No. 8 and No. 9	2[a]	0.49
W 36 X 245 Beam	El. 140’-0” between Columns No. 9 and No. 10	4[b]	0.21
W 36 X 300 Beam	El. 140’-0” between Columns No. 7 and No. 8	2[a]	0.67
W 24 X 84 Beam	El. 140’-0” at Column No. 8	2[a]	0.96
W 24 X 55 Beam	El. 140’-0” at Column No. 6	2[a]	0.80
W 30 X 210 Beam	El. 140’-0” between Columns No. 14 and No. 15	2[a]	0.26
W 24 X 68 Beam	El. 140’-0” between Columns No. 12 and No. 13	2[a]	0.48
W 30 X 108 Beam	El. 140’-0” at Column No. 17	2[a]	0.61
W 24 X 31 Beam	El. 140’-0” between Columns No. 15 and No. 16	2[a]	0.73
W 24 X 84 Beam	El. 140’-0” at Column No. 16	2[a]	0.78
W 30 X 55 Beam	El. 140’-0” between Columns No. 17 and No. 18	2[a]	0.81
W 14 X 150 Column	Column No. 1 between El. 100’-0” and 120’-0”	2[a]	0.64
W 30 X 150 Column	Column No. 2 between El. 96’-6” and 120’-0”	2[a]	0.79

Table 3.8-9

CONTAINMENT INTERNAL STRUCTURES SUMMARY OF DUCTILITY RATIOS FOR PIPE WHIP RESTRAINTS

Description of Principal Members	Location of Principal Members	Governing Load Combination Number[(a)]	Ductility or Strain Ratio		Remarks
			Actual Used	NRC Allowable	
Stainless steel "U" bar restraints	Inside the containment structure	4	0.5*	0.5*	*Ratio of maximum design strain to minimum ultimate uniform strain tested or guaranteed for the material
Carbon steel framed restraints	Inside the containment structure	4	20	20	Flexural tension and compression ductility ratio
Framed restraints with cellular energy absorbing material	Inside the containment structure	4	0.8	0.8	Ratio of design strain to total strain tested or guaranteed. (Minimum of 50% of total thickness for the cellular material at maximum crushing strength under nearly constant stress.)

a. Refer to paragraph 3.8.3.3.3, listing B(2) for description of load combination number.

3.8.3.6 Materials, Quality Control, and Special Construction Techniques

The following basic materials are used in the construction of internal structures:

A.	Concrete		f'_c, psi	= 5000 or greater

Note: Cement with standard chemical composition per ASTM C150 was used for the steam generator replacement project.

B.	Reinforcing steel Deformed bars	ASTM A615 Grade 60	f_y, psi	= 60,000 minimum
C.	Structural and miscellaneous steel			
	Rolled shapes, bars, and plates	ASTM A36	f_y, psi	= 36,000 minimum
		ASTM A588 Grade 50	f_y, psi	= 42,000 to 50,000 (varies depending on material thickness)
		ASTM A572	f_y, psi	= 42,000 minimum
	Structural Steel Shapes	ASTM A992	f_y, psi	= 50,000 minimum
	Forgings	ASTM A237 Class C	f_y, psi	= 58,000 to 60,000 (varies depending on material thickness)
		ASTM A336 Class F5A	f_y, psi	= 50,000
	Crane rails	AISC (Bethlehem)		171 lb/yd

3.8.3.6 (cont'd)

High-strength bolts	ASTM A325	f_y, psi	= 81,000 to 92,000 (varies depending on diameter of bolts)
	ASTM A354 Grade BD	f_y, psi	= 115,000 to 130,000 (varies depending on diameter of bolts)
	ASTM A490	f_y, psi	= 130,000 minimum
	A449	f_y, psi	= 58,000 to 92,000 (varies depending on diameter of bolts)
	A540	f_y, psi	= 105,000 to 150,000 (varies depending on the diameter, grade, and class of material)
	ASTM A193, Grade B7	f_t, psi	= 75,000 to 105,000 (varies based on bolt diameter)
Other bolts	ASTM A307	f_y, psi	= 60,000 minimum

3.8.3.6 (cont'd)

Stainless steel plate, sheet and strip	ASTM A167 or ASTM A240, Type 304 with 0.05% maximum carbon or type 304L	f_y, psi = 25,000
Stainless steel bars and shapes	ASTM A276, or A479 type 304L with 0.05% maximum carbon	f_y, psi = 25,000 f_y, psi = 25,000 minimum
Anchors, Stiffeners and other non-exposed carbon steel	ASTM A36	f_y, psi = 36,000 minimum
Stainless steel bolts	ASTM A320 Grade C	f_y, psi = 30,000
Unistrut	ASTM A570 Grade C	f_y, psi = 33,000
Shear studs	ASTM A108	f_y, psi = 50,000
Square/rectangular structural tubes	ASTM A500 Grade B	f_y, psi = 46,000
Structural pipe	ASTM A53 Grade B	f_y, psi = 35,000

D. Interior coating system

Carbon steel surface

Primer - Inorganic Zinc PrimerTouchup/Repair coat - Epoxy

Concrete and masonry surfaces

First coat - Epoxy - Clear Sealer

Second coat - Epoxy (optional)

Concrete floor

First coat - Epoxy - Clear Sealer

Second coat - Epoxy Surfacer (optional)

Third coat - Epoxy

3.8.3.6.1 Stainless Steel Liner Plate

The refueling canal is lined with welded stainless steel plate conforming to the requirements of ASTM A167 or A240, type 304 with 0.05% maximum carbon or type 304L. This material covers all attachments exposed on the water side, as well as the liner plate, used for the construction of the refueling canal liner.

Stainless steel welding procedures and performance qualification tests are qualified in accordance with ASME B&PV Code, Section IX. Filler material for austenitic stainless steel welds are types 308 and 308L. Types 309 and 309L welding materials are used for welding carbon or low-alloy steel to austenitic stainless steel.

Stainless steel liner plate shall be formed cold. The minimum radius at corners shall be 1 inch. Erection tolerances of the stainless steel liner plate are as follows:

- Finished concrete floor surfaces and embedded metal in the concrete floor surfaces that receive the liner plate sections will be within 1/4 inch of the established surface level alignment shown. Embedded

metal will be flush with adjacent concrete surfaces and there will be no sharp breaks in the concrete surface.

- Variation from plumb: maximum deviations in the lines and surfaces of walls shall be 1/2 inch per 10 feet, but not more than 1-1/2 inches in the full height.
- Variation from level: maximum deviation from level shall be 1/2 inch per 10 feet, 5/8 inch per 20 feet, and 1 inch per 40 feet or more.
- Variation from lines: maximum deviation from lines in plan shall be 1/2 inch per 20 feet and 1 inch per
- 40 feet or more.
- Variation from squareness at floor plate level: maximum deviation for squareness based on the difference between the diagonal lengths shall be 1/2 inch.
- Variation for centerline locations: maximum deviation for location of embeds, sleeves, or anchor plates shall be 1/2 inch.
- Floor plates warping: no limits are applied to the floor plates with regard to warping due to temperature changes.
- Wall openings (including recessed frame around openings) for bulkhead gate shall meet the following erection tolerances prior to placement of concrete:
  - Variation of each side from the plumb: 1/2 inch

- Variation of bottom from level: 1/4 inch per 5 feet with 1/2 inch maximum
- Out of plane tolerance: 1/2 inch

Other materials and quality control procedures are described in paragraph 3.8.1.6.

3.8.3.7 Testing and Inservice Surveillance Requirements

A formal program of testing and inservice surveillance is not planned for the internal structures. The internal structures are not directly related to the functioning of the containment concept. Hence, no testing or surveillance is required.

3.8.4 OTHER CATEGORY I STRUCTURES

3.8.4.1 Description of the Structures

Seismic Category I structures other than the containment and its internal structures are listed below:

- Auxiliary building
- Fuel building
- Control building
- Diesel generator building
- Main steam support structure
- Essential spray ponds
- Condensate storage tank
- Refueling water tank

- Diesel generator fuel oil tanks

3.8.4.1.1 Auxiliary Building

The auxiliary building is a multi-story, reinforced concrete structure located adjacent to the containment structure but physically separated from it. The auxiliary building has approximate dimensions of 129 feet wide by 197 feet long. It has a four-level basement extending about 60 feet below grade. The building rises to about 60 feet above grade.

The auxiliary building primarily houses the engineered safety feature (ESF) systems for the safe shutdown of the reactor that include the following systems:

- Safety injection system
- Containment spray system
- Containment combustible gas control system
- Containment isolation system

Building plans and sections are shown in engineering drawings 13-P-OOB-002 through –011.

3.8.4.1.2 Fuel Building

The fuel building is 88 by 124 feet in plan and is a reinforced concrete structure whose roof is 94 feet above grade. It is physically separated from adjoining structures and has an independent foundation. The fuel building roof has been modified by addition of a permanent hatch to facilitate

modification of the Cask Handling Crane. When not in use, the opening is sealed with a steel plate. The building contains the new fuel storage area and spent fuel pool. The walls and the floor of the spent fuel pool are lined with stainless steel plates for leaktightness.

The new and spent fuel storage is described in section 9.1.

The fuel building has a single failure proof overhead crane capable of handling such heavy loads as a fuel cask. Travel of this crane over the main body of the spent fuel pool is prevented by design. Interlocks are provided to prevent the crane from moving over the new fuel area. A new fuel handling crane, running on rails mounted over the operating floor, is provided to handle the new fuel assemblies.

A spent fuel handling machine, running on rails mounted on the operating floor, is provided to handle spent fuel assemblies.

An aluminum honeycomb energy absorption pad, mounted on the wall in the cask decontamination pit, is provided to prevent any damage to the west wall of the spent fuel pool from fuel cask positioning.

Building plans and elevations are shown in engineering drawings 13-P-OOB-002 through -011.

3.8.4.1.3 Control Building

The control building is approximately 86 by 114 feet. It is a four-story reinforced concrete structure with a full basement below ground. The building rises to about 80 feet above grade.

It is physically separated from the auxiliary and radwaste buildings.

Facilities such as the control room, computer room, upper and lower cable spreading rooms and battery rooms form the essential features of this building.

Building plans and sections are shown in engineering drawings 13-P-OOB-002 through -011.

3.8.4.1.4 Diesel Generator Building

The diesel generator building is a reinforced concrete, box-type structure located adjacent to the control building and separated by a 6-inch space. Plan dimensions, established by equipment layout and space, are approximately 60 by 80 feet.

The building has a maximum height of approximately 48 feet above grade. The diesel generator building houses two identical diesel generators whose foundations are physically separated from each other and from the building foundation.

Building plans and sections are shown in engineering drawings 13-P-OOB-002 through -011.

3.8.4.1.5 Main Steam Support Structure

The main steam support structure is a box-type, reinforced concrete structure with two chambers shown in engineering drawings 13-P-OOB-002 through -011. The inside dimensions of each chamber are 64 feet 6 inches in height and 18 feet 3 inches in width. The length of each chamber varies from 33 to 35 feet. The main steam support structure design

strength and vent capabilities will be based on the thermal and pressure loads of a nonmechanistic break area equivalent to one full flow opening of a main steam line. Pipe whip and jet impingement loads associated with this break will not be postulated.

3.8.4.1.6 Essential Spray Ponds

The ultimate heat sink for each unit will consist of two adjacent reinforced concrete essential spray ponds. The ponds have vertical walls which extend approximately 8 feet above the adjacent finish grade. Each pond has interior plan dimensions of 345 by 172 feet and a depth of 15.5 feet which includes 1.1 feet of freeboard to contain the water during seismic or wind-wave action. Each pond has an intake structure to feed the cooling loop and a pond inlet for the return line. The ponds are interconnected to allow transfer of water from one pond to the other. Spray headers installed in the ponds are used to cool the water.

Plan and details of the ponds are shown in engineering drawing 13-C-SPS-375.

3.8.4.1.7 Condensate Storage Tank

The condensate storage tank is a reinforced concrete structure (46 feet 6 inches internal diameter, 52 feet 0 inch in height, and a capacity of 520,000 gallons, see Table 9.2-21) located approximately 175 feet northerly of the center of the containment structure. The condensate storage tank has

cylindrical walls of 21 inches nominal thickness which provide suitable missile protection to prevent penetration by the tornado missiles postulated in section 3.5. This precludes loss of the contained fluid for missile impacts on the tank exterior walls. The adjacent pump structure provides similar missile protection for the condensate transfer pumps and includes a reinforced concrete roof. The condensate storage tank has a Seismic Category I stainless steel wall and basemat liner and a non-Seismic Category I stainless steel roof liner. The roof is not designed to be tornado missile resistant. The concrete and stainless steel wall liner together will withstand the structural loads including the hydrostatic pressure of the condensate. The welded stainless steel liner attached to the inside surface of the tank also ensures the leaktight integrity of the structure.

3.8.4.1.8 Refueling Water Tank

The refueling water tank is a reinforced concrete structure (46 feet 6 inches internal diameter, 68 feet 0 inch in height, and a rated capacity of 750,000 gallons) located near the fuel building. The refueling water tank has cylindrical walls of 21 inches nominal thickness and the construction is the same as that of the condensate storage tank. The refueling water tank has a Seismic Category I stainless steel wall and basemat liner and a non-Seismic Category I stainless steel roof liner. The concrete will withstand the structural loads including the hydrostatic pressure of the refueling water without reliance upon the stainless steel liner. The welded stainless steel

liner attached to the inside surface of the tank ensures the leaktight integrity of the structure.

3.8.4.1.9 Diesel Generator Fuel Oil Tanks

The station has two diesel generator fuel oil tanks per unit, each tank has a nominal capacity of 83,000 gallons. The size of each horizontal tank is approximately 13 feet in diameter by 86 feet long. The tanks are located underground about 35 feet from the diesel generator building. The tanks have approximately 10 feet of earth cover for missile protection.

3.8.4.2 Applicable Codes, Standards, and Specifications

Other Seismic Category I structures are designed in accordance with the codes, standards, and specifications listed in paragraph 3.8.3.2

3.8.4.3 Loads and Load Combinations

Other Category I structures are designed for the loads listed in paragraph 3.8.3.3.1 and for the load combinations listed in paragraph 3.8.3.3.2.

3.8.4.4 Design and Analysis Procedures

The design and analyses procedures are similar to those discussed in paragraph 3.8.3.4 for the containment internals except that a three-dimensional, finite-element model was not used.

The behavior of the turbine and radwaste buildings was checked under the extreme environmental (tornado/SSE) loads to verify that a collapse would not occur.

The effects of a postulated collapse of the corridor building were analyzed to verify that the integrity of the auxiliary and control buildings would not be impaired.

3.8.4.5 Structural Acceptance Criteria

The limiting values of stress, strain, and gross deformations are established by the following criteria:

- Maintain the structural integrity when subjected to the worst load combinations
- Prevent structural deformation from disturbing the Seismic Category I equipment to the extent that it suffers a loss of function

The allowable stresses are those specified in the applicable codes. The stress contributions due to earthquake loading are included in the load combinations described in paragraph 3.8.3.3.

Structural deformations were not found to be a controlling criterion in the design of other Seismic Category I structures, listed in paragraph 3.8.4.1.

DESIGN OF

CATEGORY I STRUCTURES

The following table summarizes: (1) the governing load interactions and maximum capacity of principal reinforced concrete members (see category A), and (2) the governing combined stress ratios from the beam/column interaction equation for principal structural steel members (see category B).

Structure	Table Number Reference	
	Category A	Category B
Auxiliary building	3.8-10	3.8-11
Fuel building	3.8-12	3.8-13
Control building	3.8-14	3.8-15
Diesel generator building	3.8-16	3.8-17
Main steam support structure	3.8-18	3.8-19

Table 3.8-10

AUXILIARY BUILDING SUMMARY OF GOVERNING LOAD INTERACTIONS FOR PRINCIPAL REINFORCED CONCRETE MEMBERS (Sheet 1 of 2)

Description of Principal Member	Location of Principal Member	Governing Load Combination Number [a]	Calculated Axial Load (P_u) and Flexural Load (M_u)		Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u) [b] [c]	Calculated Shear Load (V_u) [b]	Maximum Shear Capacity (V_u) [b]
			P_u [b]	M_u [c]			
3'-3" x 81'-9" wall - vertical and horizontal reinforcement	Exterior west wall at El. 40'0"	2	-6,258	407,353	657,502	11,884	20,984
3'-0" x 128'-6" wall - vertical and horizontal reinforcement	Exterior south wall at El. 40'-0"	2	-11,388	351,615	1,086,580	9,464	21,291
2'-9" x 51'-0" wall - vertical and horizontal reinforcement	Interior wall at El. 51'-6"	2	-7,020	149,516	223,678	4,469	8,562
2'-0" x 26'-2" wall - vertical and horizontal reinforcement	Interior wall at El. 70'-0"	2	-1,211	77,464	117,605	1,753	2,268
2' - 2-1/2 x 19'-4" wall - vertical and horizontal reinforcement	Interior wall at El. 70'-0"	2	-722	72,295	101,702	1,119	1,742
2'-6" x 196'-6" wall - vertical and horizontal reinforcement	Exterior wall at El. 70'-0"	2	-12,454	614,810	2,026,220	10,882	26,017
1'-0" x 14'-6" wall - vertical and horizontal reinforcement	Interior wall at El. 70'-0"	2	-240	20,183	23,040	328	642
2'-0" x 138'-0" wall - vertical and horizontal reinforcement	Exterior wall at El. 88'-0"	2	-5,077	442,082	1,171,555	12,850	30,522

a. Refer to Paragraph 3.8.3.3.2, listing A(2) for description of load combination number.

b. P_u and V_u are in kips; Sign convention for P_u: Compression (-). Tension (+).

c. M_u is in ft-K/ft for slabs and ft-K for walls.

d. Negligible.

e. Not calculated since shear load is negligible.

Table 3.8-10

AUXILIARY BUILDING SUMMARY OF GOVERNING LOAD INTERACTIONS FOR PRINCIPAL REINFORCED CONCRETE MEMBERS (Sheet 2 of 2)

Description of Principal Member	Location of Principal Member	Governing Load Combination Number[a]	Calculated Axial Load (P_u) and Flexural Load (M_u)		Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u)[b] [c]	Calculated Shear Load (V_u)[b]	Maximum Shear Capacity (V_u)[b]
			P_u[b]	M_u[b]			
2' - 2-1/2" x 19'-4" wall - vertical and horizontal reinforcement	Interior wall at El. 88'-0"	2	-559	52,153	115,314	1,537	2,093
3'-0" x 22'-3" wall - vertical and horizontal reinforcement	Interior wall at El. 100'-0"		-1,554	65,440	94,008	1,706	2,417
3'-0" x 6'-9" wall - vertical and horizontal reinforcement	Exterior wall at El. 100'-0"		-301	7,258	7,702	247	686
2'-9" thick slab - N-S or E-W reinforcement	El. 70'-0"		-[d]	128	181	-[d]	-[e]
1'-6" thick slab - E-W reinforcement	El. 88'-0"		-	43	51	-	-
2'-0" thick slab - N-S reinforcement	El. 88'-0"		-	65	73	-	-
2'-9" thick slab - N-S or E-W reinforcement	El. 88'-0"		-	112	131	-	-
2'-9" thick slab - N-S reinforcement	El. 100'-0"		-	84	104	-	-
1'-3" thick slab - N-S or E-W reinforcement	El. 120'-0"		-	21	26	-	-
6'-0" thick basemat - E-W reinforcement	El. 40'-0"		-	326	544	-	-
6'-0" thick basemat - E-W reinforcement	El. 70'-0"		-	933	1,031	-	-

Table 3.8-11
AUXILIARY BUILDING SUMMARY OF GOVERNING COMBINED STRESS RATIOS FROM THE BEAM/COLUMN INTERACTION EQUATION FOR PRINCIPAL STRUCTURAL STEEL MEMBERS

Description of Principal Members	Location of Principal Members	Governing Load Combination Number[(a)]	Combined Stress Ratio ($\leq$ 1.0)
W 16 X 36	Floor beam at El. 51'-6"	1	0.88
C 10 X 25	Floor beam at El. 51'-6"	2	0.82
W 14 X 78	Floor beam at El. 51'-6"	2	0.82
W 21 X 49	Floor beam at El. 70'-0"	1	0.85
W 18 X 60	Floor beam at El. 88'-0"	1	0.94
W 12 X 27	Top chord of truss at El. 88'-0"	2	0.96
W 14 X 184	Column at El. 77'-3"	2	0.73
W 14 X 158	Column at El. 120'-0"	2	0.66
W 14 X 84	Bottom chord of truss at El. 88'-0"	2	0.83
W 27 X 177	Main girder at El. 100'-0"	2	0.80
W 21 X 73	Main girder at El. 120'-0"	2	0.94
W 16 X 64	Floor beam at El. 120'-0"	2	0.93
W 27 X 94	Floor beam at El. 140'-0"	2	0.99
W 27 X 177	Main girder at El. 140'-0"	2	0.95
W 27 X 114	Main girder at El. 140'-0"	2	0.95
W 21 X 55	Floor beam at El. 156'-4"	2	0.81
C 10 X 15.3	Staircase stringer (typ.)	2	0.71
C 10 X 15.3	Platform channel at El. 43'-6"	2	0.95
W 8 X 28	Platform beam at El. 110'-0"	2	0.98

a. Refer to paragraph 3.8.3.3.3, listing A(1) for description of load combination number.

Table 3.8-12

FUEL BUILDING SUMMARY OF GOVERNING LOAD INTERACTIONS FOR PRINCIPAL REINFORCED CONCRETE MEMBERS (Sheet 1 of 2)

Description of Principal Member	Location of Principal Member	Governing Load Combination Number[a]	Calculated Axial Load (P_u) and Flexural Load (M_u)		Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u)[b][c]	Calculated Shear Load (V_u)[b]	Maximum Shear Capacity (V_u)[b]
			P_u[b]	M_u[c]			
Basemat surrounding sump	West side of basemat El. 100'-0"	2	39	-252	-603	-[d]	-[e]
Grade beam 4'-6" thick	N-W extremity of basemat	2	125	-216	-1073	-	-
10'-6" thick area of basemat	North peripheral external strip	2	65	-46	-621	-	-
6'-2" thick area of basemat slab	Decontamination pit floor	2	66	55	132	-	-
7'-0" thick area of basemat slab	Cask loading pit floor	2	54	-3	-11	-	-
12'-0" thick area of basemat slab	Equipment area (E) floor)	2	44	52	86	-	-
1'-0" thick slab	El. 120'-0"	2	11	-2	-11	-	-
1'-0" thick slab	El. 140'-0"	2	25	3	14	-	-
1'-0" thick slab	El. 140'-0"	2	19	-3	-7	-	-
5'-0" thick wall	Exterior east wall at El. 123'-0"	2	35	89	1222	-	-

a. Refer to paragraph 3.8.3.3.2, listing A(2) for description of load combination number.

b. P_u and V_u are in kips; Sign convention for P_u: Compression (-), Tension (+).

c. M_u is in ft-k/ft.

d. Negligible.

e. Not calculated since shear load is negligible.

Table 3.8-12

FUEL BUILDING SUMMARY OF GOVERNING LOAD INTERACTIONS FOR

PRINCIPAL REINFORCED CONCRETE MEMBERS (Sheet 2 of 2)

Description of Principal Member	Location of Principal Member	Governing Load Combination Number[(a)]	Calculated Axial Load (P_u) and Flexural Load (M_u)		Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u)[(b)(c)]	Calculated Shear Load (V_u)[(b)]	Maximum Shear Capacity (V_u)[(b)]
			P_u[(b)]	M_u[(c)]			
1'-9" thick wall	Exterior south wall at El. 145'-0"	2	18	3	27	-	-
8'-0" thick wall	Exterior north wall at El. 129'-6"	2	27	318	1957	-	-
5'-0" thick wall	West wall of spent fuel pool at El. 104'-6"	2	151	3	818	-	-
5'-0" thick wall	South wall of transfer tube canal at El. 129'-6"	2a	38	76	818	-	-
2'-0" thick wall	Wall above equipment area between El. 120' and 140'-0"	2a	0.2	0.5	44	-	-

Table 3.8-13

FUEL BUILDING SUMMARY OF GOVERNING COMBINED STRESS RATIOS FROM THE BEAM/COLUMN INTERACTION EQUATION FOR PRINCIPAL STRUCTURAL STEEL MEMBERS

Description of Principal Members	Location of Principal Members	Governing Load Combination Number[(a)]	Combined Stress Ratio ($\leq$1.0)
W 14 X 202	Column at FD - F2.4	2	0.97
W 18 X 35	Floor beam at El. 120'-0"	2	0.89
W 30 X 108	Main girder at El. 120'-0"	2	0.90
W 30 X 190	Floor beam at El. 140'-0"	2	0.89
W 36 X 300	Main girder at El. 140'-0"	2	0.97
W 14 X 342	Top chord roof truss	2	0.94
W 14 X 311	Bottom chord roof truss	2	1.00
W 12 X 136	Compression member roof truss	2	0.86
W 12 X 136	Tension member roof truss	2	0.91

a. Refer to paragraph 3.8.3.3.3, listing A(1) for description of load combination number.

Table 3.8-14

CONTROL BUILDING SUMMARY OF GOVERNING LOAD INTERACTIONS FOR

PRINCIPAL REINFORCED CONCRETE MEMBERS

Description of Principal Member	Location of Principal Member	Governing Load Combination Number[(a)]	Calculated Axial Load (P_u) and Flexural Load (M_u): P_u[(b)]	Calculated Axial Load (P_u) and Flexural Load (M_u): M_u[(c)]	Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u)[(b)(c)]	Calculated Shear Load (V_u)[(b)]	Maximum Shear Capacity (V_u)[(b)]
2'-0" thick wall - vertical reinforcement	Exterior west wall at El. 74'-0"	2	-73	415	437	-[(d)]	-[(e)]
1'-0" thick wall - vertical reinforcement	Interior wall at El. 74'-0"	2	+118.5	37	45.4	-	-
1'-0" thick wall - vertical reinforcement	Exterior west wall at El. 100'-0"	2	+71	233	284	-	-
1'-9" thick wall - vertical reinforcement	Exterior south wall at El. 120'-0"	2	+53	61	118	-	-
1'-0" thick slab - E-W reinforcement	El. 100'-0"	2	-[(d)]	74	90	-	-
8" thick slab - E-W reinforcement	El. 120'-0"	2	-	9	11	-	-
4'-0" thick basemat	El. 74'-0"	2	-	1,189	1,395	-	-
4'-0" thick basemat	El. 74'-0"	2	-	899	1,132	-	-

a. Refer to paragraph 3.8.3.3.2, listing A(2) for description of load combination number.

b. P_u and V_u are in kips; Sign convention for P_u: Compression (-), Tension (+).

c. M_u is in ft-k/ft.

d. Negligible.

e. Not calculated since shear load is negligible.

Table 3.8-15

CONTROL BUILDING SUMMARY OF GOVERNING COMBINED STRESS RATIOS FROM THE BEAM/COLUMN INTERACTION EQUATION FOR PRINCIPAL STRUCTURAL STEEL MEMBERS

Description of Principal Members	Location of Principal Members	Governing Load Combination Number[(a)]	Combined Stress Ratio ($\leq$1.0)
W 27 X 84	Floor beam at El. 100'-0"	2	0.85
W 36 X 300	Main girder at El. 100'-0"	2	0.52
W 24 X 55	Floor beam at El. 100'-0"	2	0.82
W 14 X 550	Column at El. 74'-0"	2	0.55
W 27 X 84	Floor beam at El. 120'-0"	2	0.91
W 36 X 300	Main girder at El. 120'-0"	2	0.59
W 14 X 314	Column at El. 140'-0"	2	0.34
W 12 X 35	Staircase beam	2	0.76

a. Refer to paragraphs 3.8.3.3.3, listing A(1) for description of load combination number.

Table 3.8-16

DIESEL GENERATOR BUILDING SUMMARY OF GOVERNING LOAD INTERACTIONS

FOR PRINCIPAL REINFORCED CONCRETE MEMBERS

Description of Principal Member	Location of Principal Member	Governing Load Combination Number[a]	Calculated Axial Load (P_u) and Flexural Load (M_u)		Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u) [b] [c]	Calculated Shear Load (V_u) [b]	Maximum Shear Capacity (V_u) [b]
			P_u [b]	M_u [c]			
1' -9" x 60' -0" wall - vertical and horizontal reinforcement	Exterior wall at El. 100' -0"	2	-1,687	58,142	160,946	1,692	4,238
1' -9" x 19' -6" wall - vertical and horizontal reinforcement	Interior wall at El. 100' -0"	2	-497	8,323	16,869	166	1,619
1' -9" x 60' -0" wall - vertical and horizontal reinforcement	Interior wall at El. 131' -0"	2	-556	5,772	146,549	385	4,986
1' -4" thick slab - E-W reinforcement	El. 115' -0"	2	- [d]	13	34	- [d]	- [e]
1' -4" thick slab - N-S reinforcement	El. 131' -0"	2	-	16	34	--	--
4' -0" thick basemat - E-W reinforcement	El. 100' -0"	2	-	247	249	--	--
4' -0" thick basemat - E-W or NS reinforcement	El. 100' -0"	2	-	210	240	--	--

a. Refer to paragraph 3.8.3.3.2, listing A(2) for description of load combination number.
b. P_u and V_u are in kips; sign convention for P_u: Compression (-), Tension (+).
c. M_u is in ft.-k/ft. for slabs and ft.-K for walls.
d. Negligible.
e. Not calculated since shear load is negligible.

Table 3.8-17

DIESEL GENERATOR BUILDING SUMMARY OF GOVERNING COMBINED STRESS RATIOS FROM THE BEAM/COLUMN INTERACTION EQUATION FOR PRINCIPAL STRUCTURAL STEEL MEMBERS

Description of Principal Members	Location of Principal Members	Governing Load Combination Number[(a)]	Combined Stress Ratio ($\leq$1.0)
W 24 X 84	Floor beam at El. 115'-0"	2	0.47
W 12 X 45	Floor beam at El. 115'-0"	2	0.71
W 24 X 130	Main girder at El. 131'-0"	2	0.87
W 36 X 160	Main girder at El. 131'-0"	2	0.85
W 24 X 100	Floor beam at El. 146'-0"	2	0.58
S 24 X 120	Monorail beam at El. 126'-5"	1	0.98

a. Refer to paragraph 3.8.3.3.3, listing A(1) for description of load combination number.

Table 3.8-18

MAIN STEAM SUPPORT STRUCTURE SUMMARY OF GOVERNING LOAD

INTERACTIONS FOR PRINCIPAL REINFORCED CONCRETE MEMBERS

Description of Principal Member	Location of Principal Member	Governing Load Combination Number[a]	Calculated Axial Load (P_u) and Flexural Load (M_u)		Maximum Flexural Interaction Capacity (M_u), Given Axial Load (P_u)[b][c]	Calculated Shear Load (V_u)[b]	Maximum Shear Capacity (V_u)[b]
			P_u[b]	M_u[c]			
3'-6" thick wall - vertical reinforcement	Exterior north wall El. 81'-0" to 100'-0"	8	+598	96,621	1.51×10^5	2,216	6,480
3'-6" thick wall - vertical reinforcement	Exterior south wall El. 100'-0" to 156'-0"	8	+1,197	67,525	2.38×10^5	1,969	12,100
Variable wall thickness vertical reinforcement	Exterior west wall El. 100'-0" to 156'-0"	5	+545	93,460	3.08×10^6	3,536	25,400
3'-6" thick slab	El. 100'-0"	3	0	103.5	264	94.3	100.9
2'-5-1/4" thick slab	El. 166'-7"	3	0	34	100	34.7	41.4

a. Refer to paragraph 3.8.3.3.2, listing B for description of load combination number.

b. P_u and V_u are in kips; sign convention for P_u: Compression (-), Tension (+).

c. M_u is in ft-k/ft for slabs and ft-k for walls.

Table 3.8-19

MAIN STEAM SUPPORT STRUCTURE SUMMARY OF GOVERNING COMBINED STRESS RATIOS FROM THE BEAM/COLUMN INTERACTION EQUATION FOR PRINCIPAL STRUCTURAL STEEL MEMBERS

Description of Principal Members	Location of Principal Members	Governing Load Combination Number	Combined Stress Ratio (<1.0)
C 10 X 30 Beam	El. 88'-11-1/2"	2[a]	1.0
W 16 X 15.5 Column	El. 88'-11-1/2"	1[a]	1.0
W 24 X 76 Beam	El. 120'-0"	2[a]	0.94
W 12 X 31 Beam	El. 120'-0"	2[a]	0.96
W 12 X 40 Beam	El. 132'-0"	2[a]	0.89
W 18 X 77 Beam	El. 129'-8"	2[a]	0.60
W 18 X 106 Beam	El. 129'-8"	2[a]	0.42
W 18 X 97 Beam	El. 140'-0"	2[a]	0.96
W 14 X 176 Beam	El. 140'-0"	2[a]	1.0
W 12 X 40 Beam	El. 140'-0"	2[a]	0.51
W 8 X 40 Beam	El. 149'-0"	2[a]	0.87
W 16 X 77 Beam	El. 164'-6-1/4"	5[b]	0.96
W 30 X 132 Beam	El. 164'-6-1/4"	5[b]	0.96
W 16 X 40 Beam	El. 164'-6-1/4"	5[b]	0.97
W 14 X 120 Column	El. 164'-6-1/4"	5[b]	1.0

a. Refer to paragraph 3.8.3.3.3, listing A(1) for description of load combination number.

b. Refer to paragraph 3.8.3.3.3, listing B(1) for description of load combination number.

3.8.4.6 Materials, Quality Control, and Special Construction Techniques

The materials, quality control, and special construction techniques are the same as those given for the containment internals in paragraph 3.8.3.6 except for the design compressive strength of concrete. For Seismic Category I structures other than the containment and its internals, the design compressive strengths are 5000 psi for the roofs and 4000 psi for the remaining structural elements. In addition, alternate interior coating system materials which are appropriate for service outside of containment may be substituted for those listed in paragraph 3.8.3.6, listing D.

3.8.4.7 Testing and Inservice Surveillance Requirements

Testing and inservice surveillance are not required for Seismic Category I structures other than the containment structure. No formal program of testing and inservice surveillance is planned.

3.8.5 FOUNDATIONS AND CONCRETE SUPPORTS

3.8.5.1 Description of the Foundations and Supports

3.8.5.1.1 Containment

The containment building foundation is a conventional reinforced concrete mat approximately 10 feet 6 inches thick. The basemat is circular in plan with an approximate diameter of 161 feet. A circular pit and instrumentation cavity extend below the basemat, and a continuous tendon gallery at the

periphery is provided for access for installation of vertical tendons. The gallery is structurally connected below the basemat and serves as a working space for post-tensioning of tendons of the containment shell and dome, and for inspection purposes. Refer to engineering drawings 13-C-ZCS-102 and -104 for configuration of the cavities and physical features. A steel liner plate with a leak chase system covers the entire interior basemat. A concrete slab 2 feet 9 inches thick is cast in place on top of the liner plate to protect the liner against damage during erection and maintenance and to reduce the thermal effects in the basemat. The added concrete slab also provides the foundation for some small equipment and steel columns so that their anchorage does not have to penetrate the liner plate underneath.

3.8.5.1.2 Other Seismic Category I Structures

A continuous reinforced concrete slab is used as foundation for each of the other Seismic Category I structures. Foundations of Seismic Category I structures are separated from one another and from other structures, either by using an expansion joint or by providing an adequate structural gap in between. The size and thickness of foundations vary with each individual Seismic Category I structure.

3.8.5.2 Applicable Codes, Standards, and Specifications

Refer to paragraph 3.8.1.2 for the containment and to paragraph 3.8.3.2 for other Seismic Category I structures.

3.8.5.3 Loads and Load Combinations

Containment foundation loads and loading combinations are discussed in paragraph 3.8.1.3.

Foundation loads and loading combinations for other Seismic Category I structures are discussed in paragraph 3.8.4.3.

Procedures for determining lateral earth pressure loadings for all Category I foundations are presented in appendix 3H.

No special measures are required in the design and construction of foundations for Category I structures to alleviate the effects of ground subsidence. As discussed in paragraph 2.5.4 1.1, subsidence, if any, will be negligible.

3.8.5.4 Design and Analysis Procedures

3.8.5.4.1 Containment

The analysis and design of the containment basemat meets the requirements of ASME Section III, Division 2, Article CC-3000, and is supplemented by BC-TOP-5-A.

The basemat is designed to sustain design loads of the containment and interior structures. The basemat is analyzed as a slab on an elastic foundation as delineated in the computer model for the SAP program. The loadings are dead load, live load, internal pressure, thermal, post-tensioning, and earthquake loads. The earthquake loads are those resulting from the entire structure taken as a whole. The basemat is designed for moments, shears, and forces resulting from

credible combinations of loads. The effect of LOCA and SSE are considered in the design in an appropriate manner.

For the discussion of the design loadings and method of analyses employed in design of the basemat, refer to paragraph 3.8.1.3. Additional discussions of the basemat are covered in BC-TOP-5-A, Sections 6 and 7.

3.8.5.4.2 Other Seismic Category I Structures

The basic techniques for analyzing the foundations of Seismic Category I structures are by the conventional methods, involving simplified assumptions found in the theory of concrete structures practice, such as two-way slab design and flat-slab design. Stresses resulting from local moments, torques, and concentrated reactions, and from uniform loading, are computed by these methods. These methods are further discussed in paragraph 3.8.3.4.

3.8.5.5 Structural Acceptance Criteria

The foundations of Seismic Category I buildings are designed to meet the same structural acceptance criteria as the buildings themselves. These criteria are discussed in paragraphs 3.8.1.5, 3.8.3.5, and 3.8.4.5. The limiting conditions for the foundation medium, together with a comparison of actual capacity and estimated structure loads, are found in paragraphs 2.5.4.10 and 2.5.4.11. Computed factors of safety against overturning, sliding, and flotation for Category I structures are given in table 3.8-20.

3.8.5.6 Materials, Quality Control, and Special Construction Techniques

The foundations and concrete supports are constructed of concrete using proven methods common to heavy industrial construction. The design compressive strength of concrete for the containment foundation is 5000 psi as described in paragraph 3.8.1.6.1. The design compressive strength of concrete for other Category I structure foundations and supports is 4000 psi. The test frequency of compressive strength for concrete shall comply with paragraph 3.8.3.2.1. For further discussion, refer to paragraph 3.8.3.6.

Table 3.8-20

COMPUTED FACTORS OF SAFETY

Structure	Overturning		Sliding		Flotation
	OBE	SSE	OBE	SSE	
Auxiliary	3200	830	2.2	1.3	4.7
Containment	3400	1200	1.7	1.2	4.5
Control	1500	420	1.6	1.2	4.8
Diesel generator	1200	400	2.2	1.1	NA[a]
Fuel	1600	400	1.9	1.1	NA
Main steam support	340	91	1.6	1.1	NA
Condensate storage and refueling water tanks	500	150	1.7	1.4	NA

a. Not applicable

3.8.5.7 Testing and Inservice Surveillance Requirements

Testing and inservice surveillance are not required and are not planned for foundations of structures or for concrete supports.

3.8.6 REFERENCE

1. Metropolitan Edison Company, Jersey Central Power and Light, Three-Mile Island Nuclear Station, Unit 1, Final Safety Analysis Report, "Low Temperature Behavior of WCS 2.0 MEP/170-W Post Tensioning System," Docket No. 50-289, Part F, Appendix 5-B.

3.9 MECHANICAL SYSTEMS AND COMPONENTS

3.9.1 SPECIAL TOPICS FOR MECHANICAL COMPONENTS

3.9.1.1 Design Transients

The Palo Verde program specified in Technical Specification 5.5.5, Component Cyclic or Transient Limit, provides controls to track the UFSSAR Section 3.9.1.1 cyclic and transient occurrences to ensure that components are maintained within the design limits. The controls to track cyclic and transient occurrences are implemented by either counting the occurrences or by accounting for the occurrences in an assessment that ensures that components are maintained within the design limits. (LDCR 10-F031).

Prior to any transient cycles reaching their maximum allowable or UFSAR limits, a corrective action document shall be initiated to develop and implement corrective actions. Corrective actions to be considered are identified in Section A2.1 of the license renewal application FSAR supplement, which will be incorporate into the UFSAR after issuance of the renewed operating licenses. Corrective actions are to be taken prior to design limits being exceeded. Any corrective action document initiated shall also identify that ASME Section XI fatigue-related analyses, such as certain crack growth and stability analyses that are dependent on the number of occurrences of design transients, may also be impacted. The evaluation of corrective actions must also address these fatigue-related analyses and may require additional or separate corrective actions in accordance with any applicable ASME Section XI requirements

3.9.1.1.1 Design Transients for NSSS Scope

The following information identifies the transient used in the design and fatigue analysis of NSSS ASME code Class 1 components, reactor internals and component supports. Cyclic data fir the desugb if ASME Code Class 2 and 3 components, as applicable, are discussed in Section 3.9.3. All transients are classified with respect to the component operating condition categories identified as normal, upset, emergencym, faulted, and testing as defined in the ASME Code, Section III. The transients specified below represent conservative estimates for design purposes only and do not purport to be accurate representations of actual transients, or necessarily reflect actual operating procedures; nevertheless, all envisaged actual transients are accounted for, and the number and severity of the design transients exceeds those which may be anticipated during the 40 year life of the plant.

Pressure and temperature fluctuations resulting from the normal, upset, emergency and faulted transients were computed by means of computer simyulations of the reactor coolant system, pressurizer, and steam generators. Design transients were detailed in the equipment specifications. The component designer then used the specification curves as the basis for design and fatigue analysis.

In support of the design of each Code Class 1 component, a fatigue analysis of the combined effects of mechanical and thermal loads was performed in accordance with the requirements of Section III of the ASME Code. The purpose of the analysis was to demonstrate that fatigue failure would not occur when

the components are subjected to typical dynamic events which may occur at the power plant.

The fatigue analysis is based upon a series of dynamic events depicted in the respective component specifications. Associated with each dynamic event is a mechanical, thermal-hydraulic transient presentation along with an assumed number of occurrences for the event. The presentation is generally simple and straightforward, since it is meant to envelope the actual plant response. The intent is to present material for purposes of design.

Similarly, the characterization of a given dynamic event with a specific name is unimportant. Any plant dynamic occurrence with consequences which fall within the envelopes associated with one of these dynamic events is by definition represented by that dynamic event. The fundamental concept is to ensure that the consequences of the normal and upset conditions which are expected to occur in the power plant are enveloped by one or more of the dynamic event portrayals in the component specifications. The number of occurrences selected for each dynamic event is conservative, so that in the aggregate, a 40 year useful life will be provided by this design process.

Design load combinations for ASME Code Class 1, 2, and 3 components are given in subsection 3.9.3. Design loading combinations for reactor internals structures are presented in section 3.9.5.2.

The principal design bases of the reactor coolant system (RCS) and reactor internals structures are given in Section 5.2 and section 3.9.5, respectively.

Table 3.9.1-1 summarizes the transients used in the stress analysis of NSSS Code Class 1 components. Additional specific component transients for the reactor coolant pumps, steam generators, reactor coolant piping, and the pressurizer are provided in Sections 5.4.1, 5.4.2, 5.4.3, and 5.4.10 respectively. The basis for the transients is indicated, and the number of occurrences specified is to provide a system/component design that will not be limited by expected cyclic operation over the life of the plant. The number of occurrences is generally based on a once/day, once/week, once/month, etc., type of evaluation. It is expected that the frequency of cyclic transients will be greater than design at the beginning of plant life and significantly less than design after the first year of operation with cumulative occurrences less than design values. System integrity is further assured by using conservative methods of predicting the range of pressure and temperature for the transients. The list of transients is intended to include startup and shutdown operations, inservice hydrostatic tests, emergency and recovery operations, switching operations, and seismic events. An explanatory discussion of each transient is also given. The applicable operating condition category or service limit as designated by the ASME Code Section III is also indicated in each case.

The transients listed include allowance for less severe transients, such as rod withdrawal incident or boron dilution incident. The number of transients listed are believed to be far in excess of any number or severity that can be anticipated to occur during the life of the facility.

Pressure and thermal stress variations associated with the design transients are considered in the design of supports, valves, and piping within the reactor coolant pressure boundary (RCPB).

In addition to the design transients listed above and included in the fatigue analysis, the loadings produced by the OBE and DBE were also applied in the design of components and support structures of the RCS. The OBE and DBE are classified as upset and faulted condition events respectively. For the number of cycles pertaining to the OBE, refer to section 3.7.3.2.

3.9.1.1.2 Design Transients for Non-NSSS Scope

Design transients for Class 1 piping systems outside NSSS scope are provided in table 3.9-1.

3.9.1.2 Computer Programs Used in Stress Analyses

Refer to section 3.9.1.2.2 and 3.9.1.2.3 for computer programs used on equipment under the C-E scope of supply. Computer codes employed for the design of the Ansaldo Replacement Steam Generators are also listed. The following section 3.9.1.2.1 refers to computer programs used on systems and components not in the C-E or Ansaldo scope of supply.

3.9.1.2.1 Non-NSSS Systems and Components

Analysis of piping systems other than reactor coolant system (RCS) main loops is performed by using the following computer programs which are described below:

TABLE 3.9.1-1
TRANSIENTS USED IN STRESS ANALYSIS OF NSSS
CODE CLASS 1 COMPONENTS
(Sheet 1 of 3)

Normal Conditions

Occurrence	Conditions
Heatup and cooldown cycles	500 heatup and cooldown cycles during the design life of the components in the system. The rate of heating and cooling is $\leq$100F/hr between 70F and 565F except for the pressurizer which has a rate of $\leq$200F/hr between 70F and 653F. The heatup and cooldown rate of the system is administratively limited to assure that these limits will not be exceeded. This condition is based on a normal plant cycle of one heatup and cooldown per month rounded up to the next highest hundred.
Power changes	15,000 power change cycles over the range of 15% to 100% of full load at a rate of 5% of full load per minute either increasing or decreasing.
Normal cyclic variations	10^6 step changes of ±100 lb/in^2 and ±10F (±20F for surge line) when at operating conditions. This condition is selected based on 1 million-cycles approximating an infinite number of cycles so that the limiting stress is the endurance limit. Grouped together in these cycles are: pressure variations associated with fluctuation in pressurizer pressure between the setpoint for actuation of the backup heaters and the opening of the spray valves; temperature variations associated with the CEA controller deadband; and 2,000 step power changes of ±10% of full load assuming 1 cycle per week for 50 weeks of the year.

TABLE 3.9.1-1
TRANSIENTS USED IN STRESS ANALYSIS OF NSSS
CODE CLASS 1 COMPONENTS
(Sheet 2 of 3)

Upset Conditions

Occurrence	Conditions
Reactor trip, turbine trip, loss of reactor coolant flow	480 cycles are used to envelope all anticipated upset transients, (one occurrence per month for the life of the plant) which includes any combination of reactor trips, equipment malfunctions, or a total loss of reactor coolant flow (for the steam generators, the 480 cycles are limited by the following: Reactor Trip = 160 cycles; Loss of Reactor Coolant Flow = 120 cycles; Loss of Lead/Turbine Trip = 200 cycles). For design purposes, conservative temperature/pressure time histories are provided in the design specification for each Class 1 component, which reflects its unique response during these events. Further thermal transient information is specified for the nozzles on these components, when they experience additional transients due to changing flow conditions.
OBE condition	See Section 3.7.3.2 for the procedures used to determine the number of earthquake cycles during the seismic event.

Faulted Condition

1. The concurrent loading produced by normal operation at full power, plus the design basis earthquake, plus loss-of-coolant accident (pipe rupture) are used to determine the faulted plant loading condition.
2. Loss of Secondary Pressure: One cycle of a postulated loss of secondary pressure due to a complete double ended severance of one steam generator or feedwater nozzle, but not simultaneously. These are not considered credible events in forming the design basis of the reactor coolant system. However, they are included to demonstrate that the reactor coolant system components will not fail structurally in the unlikely event that one of these events occur.

TABLE 3.9.1-1
TRANSIENTS USED IN STRESS ANALYSIS OF NSSS
CODE CLASS 1 COMPONENTS
(Sheet 3 of 3)

Test Conditions

Occurrence	Conditions
Primary system hydrostatic	10 primary side cycles from 15 psia to 3,125 psia at a temperature between 120F to 400F. These cycles are based on one initial hydrostatic test plus a major repair every 4 years for 36 years which includes equipment failure and normal plant cycles. The secondary side of the steam generator is at atmospheric pressure during this test.
Primary system leak	200 cycles from 15 psia to 2250 psia at a temperature between 120F to 400F. These cycles are based on a normal plant maintenance operation involving 5 shutdowns per year for 40 years.

3.9.1.2.1.1 ME 101 Program. ME 101 is a finite-element computer program which performs linear elastic analysis of piping systems using standard beam theory techniques. The input data format is specifically designed for pipe stress engineering and the English system of units is used. A thorough checking of the input has been coordinated in the program. In addition, modifications aimed at achieving an improved model are performed automatically.

ME 101 is used for the static and seismic analysis of the piping systems. Static analysis considers one or more of the following: thermal expansion, dead weight, uniformly distributed loads, and externally applied forces, moments, displacements, and rotations. Seismic analysis is based on standard normal mode techniques and uses response spectrum data. Two methods of eigenvalue solution are available. The determinant search or subspace iteration subroutines consider all data points as mass points. Kinematic reduction and householder QR subroutines consider masses only at specified data points in designated directions.

Responses of the various modes are combined using the square-root-sum-of-the-squares (SRSS) rule. Further, the responses of x-, y-, and z-earthquakes are combined using the SRSS rule. In a response spectrum seismic analysis, if some or all of the modes are closely spaced, ME 101 combines the various modes based upon the grouping method per Equation 4 of Regulatory Guide 1.92.

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 1 of 21)

I. TRANSIENTS FOR THE REACTOR COOLANT SYSTEM

A. Events Initiated Within the Reactor Coolant System

1. Normal Events

Event	Occurrences
a. System (excluding pressurizer) heatup from 70F to hot standby conditions at a rate of 100F/hr. Pressurizer heatup from 70F to 653F at a rate of 200F/hr	500*
b. 5%/minute power ramp increase, from 15% to 100% power	15,000
c. 5%/minute power ramp decrease, from 100% to 15% power	15,000
d. System (excluding pressurizer) cooldown from hot standby conditions to 70F at a rate of 100F/hr. Pressurizer cooldown from 653F to 70F at a rate of 200F/hr	500*
e. Startup of one reactor coolant pump at hot standby conditions	1000
f. Coastdown of one reactor coolant pump at hot standby conditions	1000

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 2 of 21)

A. Events Initiated Within the Reactor Coolant System (Continued)

2. Upset Events	Occurrences
a. Coastdown of one reactor coolant pump at 100% power (no reactor trip)	10
b. Startup of one reactor coolant pump at 50% power	10
c. Inadvertent control element assembly drop, at 100% power	40
d. Inadvertent control element assembly withdrawal from 0% power	40
e. Depressurization by spurious actuation of pressurizer spray control valve(s) at 100% power (normal and auxiliary spray valves are considered)	40
f. Pressurization by spurious actuation of all pressurizer heaters at 100% power	10
g. Loss of an electrical bus supplying two reactor coolant pumps at 100% power	40

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 3 of 21)

	Occurrences
A. Events Initiated Within the Reactor Coolant System (Continued)	
2. Upset Events (Continued)	
h. Spurious reactor trips (including operator error) at 100% power	50
i. System leak due to rupture of largest instrument or sampling connection at 100% power	40
3. Emergency Events	
a. Depressurization due to inadvertent actuation of one pressurizer safety valve at 100% power	1
4. Faulted Events	
a. Control element assembly ejection at 0% power	1
b. Single reactor coolant pump shaft seizure at 100% power	1
c. Major loss of coolant incident (system operating mode dependent upon design application for worst case conditions)	1

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 4 of 21)

	Occurrences
A. Events Initiated Within the Reactor Coolant System (Continued)	
4. Faulted Events (Continued)	
d. Single reactor coolant pump sheared shaft at 100% power	1
5. Test Events	
a. System hydrostatic test	10
b. System leak test	200
B. Events Initiated With or Transferred Through the Main and Auxiliary Feedwater Systems	
1. Normal Events	
None	
2. Upset Events	
a. Inadvertent closure of one main feedwater valve at 100% power	40
b. Inadvertent trip of one main feedwater or one main condensate pump at 100% power	40
c. Inadvertent isolation of one main feedwater heater at 100% power	5

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 5 of 21)

B. Events Initiated With or Transferred Through the Main and Auxiliary Feedwater Systems (Continued)

	Occurrences
2. Upset Events (Continued)	
d. Excess feedwater flow due to control system malfunction at 100% power	40
e. Partial loss of condenser cooling at 100% power	40
f. Inadvertent closure of all main feedwater valves (due to loss of pressure in compressed air system) at 100% power	5
3. Emergency Events	
None	
4. Faulted Events	
a. Major rupture in the main feedwater piping (system operating mode dependent upon design application for worst case conditions)	1

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 6 of 21)

Event	Occurrences
B. Events Initiated With or Transferred Through the Main and Auxiliary Feedwater Systems (Continued)	
4. Faulted Events (Continued)	
b. Major rupture in the auxiliary feedwater piping (system operating mode dependent upon design application for worst case conditions)	1
5. Test Events	
a. Secondary system hydrostatic test	10
b. Secondary system leak test	200
C. Events Initiated Within or Transferred Through the Main Steam System	
1. Normal Events	
a. 10% power step increase, from 90% to 100% power	2000
b. 10% power step decrease, from 100% to 90% power	2000
c. Normal cyclic variations at 100 % power; +80 psi, +10F	10^6

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 7 of 21)

Event	Occurrences
C. Events Initiated With or Transferred Through the Main Steam System (Continued)	
1. Normal Events (Continued)	
d. Normal cyclic variations at 100% power; -80 psi, -10F	10^6
e. Turbine roll test at hot standby	10
2. Upset Events	
a. Arbitrary load rejection, from 100% to 15% power	40
b. Inadvertent actuation of one turbine bypass valve or atmospheric dump valve at 100% power	40
c. Inadvertent actuation of one main steam line isolation valve at 100% power	5
d. Turbine trip without accompanying reactor trip at 100% power	40
3. Emergency Events	
a. Depressurization due to inadvertent actuation of one secondary safety valve at 100% power	10

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 8 of 21)

C. Events Initiated With or Transferred Through the Main Steam System (Continued)	
4. Faulted Events	Occurrences
a. Major rupture in the main steam piping (system operating mode dependent upon design application for worst case conditions)	1
5. Test Events	
None	
D. Events Initiated Within or Transferred Through the Chemical and Volume Control System	
1. Normal Events	
a. Shift from normal to maximum purification flow at 100% power	1000
2. Upset Events	
a. Loss of letdown and recovery at 100% power	300
b. Loss of charging and recovery at 100% power	200
c. Inadvertent initiation of auxiliary spray at 100% power	5

Table 3.9-1
DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 9 of 21)

D.	Events Initiated Within or Transferred Through the Chemical and Volume Control System (Continued)		
	2. Upset Events (Continued)		Occurrences
		d. Low-low volume control tank/charging pump suction diversion to RWT	80
		e. Pressurizer level control, failure to full open	100
		f. Charging cycles (on/off) during an Extended loss of letdown	800
	3. Emergency Events		
	None		
	4. Faulted Events		
	None		
	5. Test Events		
	None		
E.	Events Initiated Within or Transferred Through the Safety Injection, Shutdown Cooling, and Containment Spray Systems		
	1. Normal Events		
		a. Standby to SI cold leg injection check valve stroke test to standby (using charging pumps)	160
		b. Standby to SI hot leg injection check valve stroke test to standby (using the HPSI pump)	30

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 10 of 21)

Event	Occurrences
E. Events Initiated Within or Transferred Through the Safety Injection, Shutdown Cooling, and Containment Spray Systems	
(Continued)	
2. Upset Events	
a. Standby to spurious startup of a normally secured pump/spurious stopping of a normally running pump/spurious valve opening/spurious valve closure	40
3. Emergency Events	
None	
4. Faulted Events	
None	
5. Test Events	
None	
F. Externally Initiated Events	
1. Normal Events	
None	
2. Upset Events	
a. Seismic event up to and including one-half of the safe shutdown earthquake at 100% power	2

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 11 of 21)

F. Externally Initiated Events (Continued)	
3. Emergency Events	Occurrences
a. Loss of offsite and onsite ac power, with retention of onsite emergency ac and dc power at 100% power	5
4. Faulted Events	
a. Seismic event up to and including the safe shutdown earthquake (system operating mode dependent upon design application for worst case conditions)	1
5. Test Events	
None	
II. TRANSIENTS FOR THE CHEMICAL AND VOLUME CONTROL SYSTEM	
A. Events Initiated Within the Chemical and Volume Control System	
1. Normal Events	
a. Shift from normal to maximum purification flow at 100% power	1000
b. High-pressure safety injection header check valve test	40

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 12 of 21)

A. Events Initiated With the Chemical and Volume Control System (Continued)	
1. Normal Events (Continued)	Occurrences
c. Initiation of auxiliary spray during cooldown	500
2. Upset Events	
a. Loss of letdown and recovery at 100% power	300
b. Low-low volume control tank/charging pump suction diversion to RWT	80
c. Inadvertent initiation of auxiliary spray at full power	5
d. Loss of charging and recovery at 100% power	200
e. Charging cycles (on/off) during an Extended loss of letdown	800
3. Emergency Events	
None	
4. Faulted Events	
a. Class 2 line break	1

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 13 of 21)

A.	Events Initiated With the Chemical and Volume Control System (Continued)			
	5.	Test Events		Occurrences
		a.	System hydrostatic test	40
B.	Events Affecting the CVCS but Initiated Within the Reactor Coolant System			
	1.	Normal Events		
		a.	System heatup and cooldown	500*
		b.	5%/minute power ramp increases and decreases	15,000
	2.	Upset Events		
		a.	Loss of reactor coolant system flow	40
		b.	Inadvertent CEA drop	40
		c.	Inadvertent CEA withdrawal	40
		d.	Spurious reactor trip	240
		e.	Depressurization by spurious actuation of pressurizer spray control valve(s) at 100% power	40

Table 3.9-1

DESN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 14 of 21)

B.	Events Affecting the CVCS but Initiated Within the Reactor Coolant System (Continued)	
3.	Emergency Events	Occurrences
a.	Depressurization due to inadvertent actuation of one pressurizer safety valve	5
b.	CEA ejection at 0% power	1
c.	Inadvertent actuation of pressurizer heaters	10
d.	Opening of one primary safety valve at 100%	5
4.	Faulted Events	
	None	
5.	Test Events	
a.	System hydrostatic test	10
b.	System leak test	200
C.	Events Affecting the CVCS but Initiated Within the Main Feedwater System	
1.	Normal Events	
	None	

Table 3.9-1
DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 15 of 21)

C. Events Affecting the CVCS but Initiated Within the Main Feedwater System (Continued)	
2. Upset Events	Occurrences
a. Loss of feedwater flow to the steam generators	85
b. Partial loss of condenser cooling at 100% power	40
c. Excess feedwater at 100% power	40
3. Emergency Events	
a. Main feedwater line rupture	1
b. Auxiliary feedwater line rupture	1
4. Faulted Events	
None	
5. Test Events	
None	
D. Events Affecting the CVCS but Initiated Within the Main Steam System	
1. Normal Events	
a. ±10% power step changes	2000

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 16 of 21)

D. Events Affecting the CVCS but Initiated Within the Main Steam System (Continued)	
2. Upset Events	Occurrences
a. Arbitrary load rejection from 100 to 15% power	40
b. Turbine trip without reactor trip	120
c. Inadvertent activation of main steam line isolation valve	40
d. Opening one steam bypass valve at 100% power	40
3. Emergency Events	
a. Steam line rupture accident	1
4. Faulted Events	
None	
5. Test Events	
None	
E. Externally Initiated Events Affecting the CVCS	
1. Normal Events	
None	

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 17 of 21)

E. Externally Initiated Events Affecting the CVCS (Continued)	
2. Upset Events	Occurrences
a. Seismic event up to and including one-half of the safe shutdown earthquake at 100% power	2
3. Emergency Events	
a. Loss of all site electrical power	5
4. Fault Events	
a. Seismic event up to and including the safe shutdown earthquake (system operating mode dependent upon design application for worst case conditions)	1
III. TRANSIENTS FOR THE SAFETY INJECTION SYSTEM	
A. Events Initiated Within the Safety Injection System	
Plant operation is divided into five categories; namely, normal, upset, emergency, faulted and test conditions, as defined in Article NB-3000, Section III, Division I, Subsection NB. Events occurring within each of these categories are listed below.	

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 18 of 21)

A. Events Initiated Within the Safety Injection System (Continued)

1. Normal (Condition I) Events	Occurrences
a. Startup of safety injection system from standby to injection to short-term recirculation to long term recirculation to shutdown cooling to standby	10 (Note 4)
b. Startup of SDC system from standby to shutdown cooling (RCS >200F) to shutdown cooling (RCS <200F) to standby	500 (Note 1)
c. Standby to HPSI pump test to standby	500 (Note 3)
d. Standby to LPSI pump test to standby	500 (Note 3)
e. Standby to SI cold leg injection check valve stroke test to standby (using charging pumps)	160 (Note 2)
f. Standby to SI hot leg injection check valve stroke test to standby (using the HPSI pump)	30

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 19 of 21)

A. Events Initiated Within the Safety Injection System (Continued)	
2. Upset (Condition II) Events	Occurrences
a. Standby to spurious startup of a normally secured pump/spurious stopping of a normally running pump/spurious valve opening/spurious valve closure	40
3. Emergency (Condition III) Events	
a. Depressurization of the SIS, CSS, SCS by full opening of a safety or relief valve without reseating	5
4. Faulted (Condition IV) Events	
a. Major rupture of the safety injection system at the highest system pressure encountered during a normal operating mode; namely, rupture during the first phase of the preoperational hydrostatic test	1

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 20 of 21)

A. Events Initiated Within the Safety Injection System (Continued)

5. Test Events	Occurrences
a. Standby to preoperational hydrostatic test to standby	10
b. Standby to inservice hydrostatic test to standby	10

NOTES

(1) SIS event III-A-2 is caused by RCS event III-A-4, namely, RCS cooldown from hot standby to standby at a rate not to exceed 100F/hour. CESSAR Section 5.0 gives the frequency of occurrences for this event.

(2) Based on the test being conducted quarterly.

(3) Based on the test being conducted monthly.

(4) SIS event III-A-1, totaling 10 occurrences, is caused by the following RCS events:

Table 3.9-1

DESIGN TRANSIENTS FOR CLASS 1 PIPING OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 21 of 21)

A. Events Initiated Within the Safety Injection System (Continued)

NOTES (Continued)

a) III-C-1 - RCS depressurization due to inadvertent actuation of one pressurizer safety valve at 100% power (5 occurrences)

b) III-D-1 - Control element assembly ejection at 0% power (1 occurrence)

c) 111-D-3 - Major loss of coolant accident (1 occurrence)

d) IV-D-1 - Major rupture in the main feedwater piping (1 occurrence)

e) IV-D-2 - Major rupture of the auxiliary feedwater piping (1 occurrence)

f) V-D-2 - Major rupture of the main steam piping (1 occurrence)

* The reactor vessel studs shall be limited to 250 occurrences

For verification, ME 101 results have been compared against the following:

A. ME 632, Computer Program, Seismic Analysis of Piping Systems, VERB MOD8, 1976 Bechtel International Corporation, San Francisco, California

B. Pressure Vessel and Piping 1972 Computer Programs Verification, The American Society of Mechanical Engineers

C. Hand calculations

3.9.1.2.1.2 ME 210 Program, Local Stress in Cylindrical Shells Due to External Loading. The ME 210 computes the local stresses in cylindrical shells that result from external loadings. The program is based on Welding Research Council Bulletin 107, August 1965. The program has been verified based upon hand calculations.

3.9.1.2.1.3 ME 632 Program. ME 632 performs stress analysis of three-dimensional piping systems. The effects of thermal expansion, uniform load of the pipe, pipe contents and insulation, concentrated loads, movements of the piping system supports, and other external loads, such as wind and snow, may be considered. The input data format is specifically designed for pipe stress engineering, and the English system of units is used. A thorough checking of the input has been coordinated in the program.

A response spectrum analysis is performed to analyze the effect of earthquake forces on the piping system. Time-history analysis is performed for transient effects of water hammer,

steam hammer, or other impulsive type dynamic loading are also handled by the program.

For verification, ME 632 results have been compared against the following:

A. TPIPE, Computer Program for Analysis of Piping Systems, Pregnoff, Matheu & Beebe, Inc., San Francisco, California

B. Pressure Vessel and Piping 1972 Computer Programs Verification, The American Society of Mechanical Engineers, 1972

3.9.1.2.1.4 ME 643-1, ME 643-2, and ME 643-3 Program. The purpose of this program is to determine the temperature and stress distributions within a body as a function of time when subjected to thermal and/or mechanical loads. The program is valid for axisymmetric or plane structures and typically is used for gross or local discontinuity analysis as described in Paragraphs NB-3213.2 and NB-3213.3 of the ASME Code, Section III.

The program consists of three parts, each of which can be used separately. The first part, ME 643-1, calculates steady-state or transient temperature distributions due to temperature or heat flux inputs. The method used is the finite-element technique coupled with a step-by-step time integration procedure.

The program adopts a stepwise description of environmental temperatures and heat transfer coefficients if they are time dependent. Transient temperature distributions are calculated

from the specified initial temperature and the step function heat inputs. ME 643-1 is for plane and axisymmetrical structures.

The second part of the program, ME 643-2, is built on the displacement method of the matrix theory of structures which calculates the displacements and stresses within the solids with orthotropic, temperature-dependent, nonlinear material properties. ME 643-2 is also used for plane and axisymmetrical structures.

The third part of the program, ME 643-3, calculates the steady-state or transient temperature distribution due to temperature or heat flux inputs. The output of this program gives the code-required parameters; i.e., Δt_1, Δt_2, T_a and T_b, where Δt_1 is the linear thermal gradient, Δt_2 is the nonlinear thermal gradient, and T_a and T_b are the average temperature on side a and b of a gross discontinuity. ME 643-3 is for straight pipe only.

The user has the option of saving the results from part 1 on an external tape. After reviewing the printout, the user can specify the transient states for the stress evaluations; part 2 then picks up the necessary information from the tape and performs the calculations.

The program was verified by comparing the results of ME 643-1-2-3 program with the solution of an identical problem obtained by hand calculation. The results of these calculations agreed.

3.9.1.2.1.5 ME 913 Program. The ME 913 program consists of numerical calculations of stress intensity levels for Class 1 nuclear power piping components to validate their design adequacy.

The program determines the stress intensity levels of Class 1 nuclear power piping components for Equations 9 through 14 of Subarticle NB-3650, Analysis of Piping Components of Section III, ASME Boiler and Pressure Vessel (B&PV) Code.

Prior to running this program, the user analyzes the piping system using flexibility analysis program ME 101 and heat transfer program ME 643. The inputs to this program are the following:

A. Design pressure and temperature

B. Specified conditions

C. Design cycles

D. Piping configuration

E. Piping and piping component properties

F. Moment reactions due to:

   1. Thermal expansion loads

   2. Weight loads

   3. Earthquake loads

   4. Anchor movements

G. The thermal response of the piping system due to the specified transients: Δt_1, Δt_1, T_a and T_b values for the selected points in the system

The verification of ME 913 is performed in two phases:

A. Phase I: Comparison of Results Between ASME Sample Problem (1) and ME 913

A comparison of stresses for ME 913 and ASME sample problem is shown in table 3.9-2. The results obtained from ME 913 are different from those of the ASME sample problem but the difference is acceptable due to the high conservatism built into ME 913. The higher stresses calculated by ME 913 are due to the change of stress indices in the 1974 version as compared with the sample problem which adopts the 1971 version of ASME Section III.

B. Phase II: Hand Calculated Verification of the Computer Output

The main feedwater piping system inside the containment on the Grand Gulf project was analyzed using the ME 913 program. A comparison of the tabulated stresses shown in table 3.9-3 indicates almost identical results.

The comparison between ME 913 outputs and hand calculated results demonstrates the correct application of code equations. The slight numerical difference is mainly due to round-off errors in the desk calculator multiplications as compared with the numerical accuracy of the digital computer.

Table 3.9-2

COMPARISON OF RESULTS BETWEEN ME 913 AND ASME SAMPLE PROBLEM

Components	Programs	Equations						
		Eq 9 Stress[(a)]	Eq 10 Stress	Eq 11 Stress	Eq 12 Stress	Eq 13 Stress	Eq 14 Stress	Total Usage Factor
Girth butt weld	ME 913	25,950	63,112	111,833	6,563	49,526	55,917	0.0555
(Location 19)	Sample Problem	23,400	52,549	80,677	(b)	(b)	40,338	0.0126
Butt weld tee	ME 913	24,600	65,567	128,920	39,536	23,152	135,937	0.2511
(Location 10)	Sample Problem	23,400	65,596	128,950	39,564	23,155	135,977	0.3699

a. All stresses are in psi.

b. Because S_n , calculated by Equation 10, is less than $3S_m$, (52,800 psi for type 304 at 400F), Equations 12 and 13 are satisfied.

3.9.1.2.1.6 ME 912 Program. ME 912 is a quasi-two-dimensional pipe thermal transient analysis program. It calculates axial and radial pipe-wall thermal transients at piping locations specified by the user. ME 912 allows nonuniform initial temperature distribution and time dependent temperature inputs. The program results give the code-required parameters; i.e., ΔT_1, ΔT_2, T_a and T_b where ΔT_1 is the linear thermal gradient, ΔT_2 is the nonlinear thermal gradient, and T_a and T_b are the average temperatures on side a and b of a gross discontinuity.

The program was verified by comparing the results of ME 912 with the solution of an identical problem obtained by hand calculation.

3.9.1.2.1.7 ME 916 Program. The ME 916 program calculates nuclear Class 1 and 2 piping stresses at lug type integral attachments. The program has been verified based upon hand calculations.

3.9.1.2.1.8 ANSYS. The ANSYS computer program is a large-scale general purpose computer program. Analysis capabilities include static and dynamic; elastic, plastic, creep and swelling; small and large deflections; steady-state and transient heat transfer and fluid flow. The program has been verified by comparison with known theoretical solutions, experimental results, and by other calculated solutions.

Table 3.9-3

HAND-CALCULATED RESULTS COMPARED WITH ME 913 OUTPUTS

Components	Programs	Equations						
		Eq 9 Stress[a]	Eq 10 Stress	Eq 11 Stress	Eq 12 Stress	Eq 13 Stress	Eq 14 Stress	Total Usage Factor
Tee	ME 913 outputs	23,650	87,446	154,318	27,805	20,433	164,256	0.7745
(Location 115)	Hand-calculated results	23,646	87,358	154,270	27,789	20,419	164,220	(b)

a. All stresses are in psi.

b. The total usage factor in hand calculated column is left empty because of large involvements in hand computations.

3.9.1.2.1.9 WAVENET. WAVENET provides solutions of the plane wave equation in complex networks of ducts or pipes containing a homogeneous compressible fluid. A series of simple criteria were established to enable the program verification by hand calculations.

3.9.1.2.1.10 PIPERUP. The PIPERUP computer program performs nonlinear elastic-plastic analysis of three dimensional piping systems subjected to concentrated static or dynamic time-history forcing functions. The program solutions have been verified by test results, closed form solutions, and/or independent computer programs.

3.9.1.2.1.11 General Frame Analysis Program. This program solves two-dimensional structural frames. It is used for the analysis of pipe supports and their supporting structures. This program has been verified using hand calculations and by comparison to results from the computer program STRUDL.

3.9.1.2.1.12 Bechtel Structural Analysis Program (BSAP). For program description and verification, refer to appendix 3B, section 3B.12.

3.9.1.2.1.13 TMRPIPE. The TMRPIPE program consists of numerical calculations of stress intensity levels for Class 1 nuclear piping components to validate their design adequacy. The program determines stress intensity levels of Class 1 nuclear piping components for Equations 9 through 14 of Subarticle NB-3650, Analysis of Piping components of Section III, ASME B&PV Code. This part of TMRPIPE has been

verified against the ASME sample problem for Class 1 analysis. Another option of the program calculates the steady-state or transient temperature distribution due to temperature or heat flux inputs. The output of this option gives the required code parameters; i.e., ΔT_1, ΔT_2, T_a and T_b defined in paragraph 3.9.1.2.1.4.

The output of the temperature distribution option of TMRPIPE has been verified with the solution of an identical problem obtained by hand calculation.

3.9.1.2.1.14 NE458 (RELAP5). The RELAP5 program is an advanced thermal hydraulics program intended for the analysis of complex transients in nuclear reactors and piping networks. Equations of conservation of mass, energy, and momentum are solved in one dimension for steam and/or water flow. The equations assume a non-homogenous mixture of steam and liquid, and non-equilibrium between phases can be modeled. The effects of non-condensable gas on steam/liquid flow are considered in the equations. Models are available to simulate pump, valve, and heat exchanger components, as well as complex control systems. RELAP5 is expressly written for the analysis of both small and large break reactor loss-of-coolant accidents, but can be used to analyze many power plant operational transients. The program is frequently coupled with the post-processor REPIPE or NE457 (R5FORCE) to generate hydrodynamic loads on power plant piping. Bechtel maintains the verification and validation for this program.

3.9.1.2.1.15 NE457(R5FORCE). The R5FORCE program is a post-processor to RELAP5. R5FORCE uses hydrodynamic output and fluid state point qualities from the RELAP5 program output to comput piping and hydraulic force/time histories for input into various structural and stress analysis codes such as ME101. The hydraulic response of power plant piping to postulated transients is calculated using the programs in combination. Bechtel maintains the verification and validation for this program.

3.9.1.2.1.16 FAPPS™ (ME150). FAPPS™ (Frame Analysis Program for Pipe Supports) is an interactive frame analysis program specifically developed for the analysis and design of pipe support frames, associated welds, base plates, embedments and local effects such as punching shear, web crippling and local flange bending; all in one run. The program performs the code check for AISC, ASME III Subsection NF codes for normal, upset, emergency and faulted load conditions. FAPPS™ accommodates unique project criteria, standard baseplates and embedments. FAPPS™ auto-generates the input for about 30 standard frame configurations. FAPPS™ allows an automatic input of loadings from ME101 or external file. FAPPS™ allows use of various load sets to allow algebraic, absolute and/or SRSS combination of results due to each vector within a load set as well as each load set that is to be combined in one load set. The program provides margin factors for structural members, welds, base plates with anchors and embedments. Bechtel maintains the verification and validation reports for this program.

3.9.1.2.1.17 BASEPLATE (ME035). ME035 is a non-linear base plate analysis program intended for analyzing/designing base plates for pipe supports. ME035 is a combination of pre-processor, SAP and post-processor. It has capability of analyzing flexible base plates on a geometrically non-linear foundation. The pre-processor performs geometry calculations to generate the finite element model and data sets for SAP. The SAP performs analysis execution. Post processing reformats the results into report tables. ME035 has a library of standard attachments, accepts any non-standard attachments as well as multiple attachments. It accommodates welded and/or bolted conditions of the base plate. Bechtel maintains the verification and validation for this program.

3.9.1.2.1.18 PIPESTRESS Program

PIPESTRESS is a finite-element computer program which performs linear elastic analysis of piping systems. The input data is entered in a free format style, which is internally converted to fixed format for performing the actual analyses. This process is transparent to the user. PIPESTRESS is specifically designed for pipe stress engineering, and is capable of producing reports to aid the analyst in documenting the stress analyses performed. Either the metric or English system of units can be used. PIPESTRESS also has a restart option. A thorough checking of the input has been coordinated in the program.

PIPESTRESS is used for the static, response spectrum, and/or dynamic analysis of piping systems. Static analysis considers one or more of the following: thermal expansion, dead weight,

uniformly distributed loads, and externally applied forces, moments, displacements, and rotations.

In a response spectrum analysis, digitized acceleration versus frequency inputs are analyzed. Results for the various modes are combined using the square root-sum-of-the-squares (SRSS) rule. If some or all of the modes are closely spaced, PIPESTRESS has the capability of combining the various modes based upon the requirements of Regulatory Guide 1.92.

Piping systems may be subject to loadings that vary rapidly in time. In PIPESTRESS, dynamic time history analysis results may be determined for two types of loadings - forces acting at mass points, or accelerations acting at support levels. In most cases, an envelope of the instantaneous system response is required. Usually, this envelope must be combined with solutions for other loadings. In some cases, detailed information for instantaneous response is required. The PIPESTRESS package is capable of calculating either instantaneous or enveloped system response.

In either case, the mathematical model used to describe these types of problems is a system of ordinary, linear second order differential equations. The solution to two forms of these equations has been programmed into PIPESTRESS. The first form is the most general form, which calculates the external forces at piping system nodes due to vector forcing functions (e.g., pipe break loadings). The second form is a special case used for determining the primary (inertial) portion of the solution for support movement loadings, typically for earthquakes.

Finally, PIPESTRESS has the capability of combining the results of static, response spectrum, and time history load case results in any number of ways (i.e., absolute sum, algebraic sum, positive and negative envelopes, SRSS, etc.), and presenting the detailed stress and support load results in report form.

For verification, PIPESTRESS is supplied with a suite of test cases that are executed as part of any installation process.

3.9.1.2.2 Computer Programs Used in Stress Analyses for C-E Scope of Supply

3.9.1.2.2.1 Reactor Coolant System

The following paragraphs provide a summary of the applicable computer programs used in the structural analyses for ASME Code Class 1 systems, components, and supports in the CESSAR scope. The summaries include individual descriptions and applicability data. The computer codes employed in these analyses have been verified in conformance with design control methods, consistent with Chapter 17.

3.9.1.2.2.1.1 ICES/STRUDL-II. The ICES/STRUDL-II computer program provides the ability to specify characteristics of framed structure and three-dimensional solid structure problems, perform static and dynamic analyses, and reduce and combine results.

Analytic procedures in the pertinent portions of ICES/STRUDL-II apply to framed structures. Framed structures are two- or three-dimensional structures composed of slender, linear

members that can be represented by properties along a centroidal axis. Such a structure is modeled with joints, including support joints, and members connecting the joints. A variety of force conditions on members or joints can be specified. The member stiffness matrix is computed from beam theory. The total stiffness matrix of the modeled structures is obtained by appropriately combining the individual member stiffness.

The stiffness analysis method of solution treats the joint displacements as unknowns. The solution procedure provides results for joints and members. Joint results include displacements and reactions and joint loads as calculated from member end forces. Member results are member end forces and distortions. The assumptions governing the beam element representation of the structure are as follows: linear, elastic, homogeneous, and isotopic behavior, small deformation, plane sections remain plane, and no coupling of axial, torque, and bending.

The program is used to define the dynamic characteristics of the structural models used in the dynamic seismic analyses of the reactor coolant system components. The natural frequencies and mode shapes of the structural models and the influence coefficients which relate member end forces and moments and support reactions to unit displacements are calculated. The influence coefficients are calculated for each dynamic degree-of-freedom of each mass point and for each degree-of-freedom of each support point at which relative motion is imposed. In addition, stiffness coefficients are calculated which relate the forces corresponding to those joint

degrees-of-freedom for which mass is specified to the imposed displacements corresponding to those (support) joint degrees-of-freedom at which relative motion will be specified during subsequent seismic response calculations. As appropriate, these data are stored for later use in response spectra or time-history seismic response calculations.

ICES/STRUDL-II is a program which is in the public domain and has had sufficient use to justify its applicability and validity. Extensive verification of the C-E version has been performed to supplement the public documentation. The version of the program in use at C-E was developed by the McDonnell Automation Company/Engineering Computer International and is run on the IBM-360 computer system. STRUDL is described in more detail in Reference 1.

3.9.1.2.2.1.2 MARC. The MARC program is a general purpose nonlinear finite element program with structural and heat transfer capabilities. It is described in detail in Reference 2.

MARC is used for stress analysis of regions of vessels, piping or supports which may deform plastically under prescribed loadings. It is also used for elastic analyses of complex geometries where the graphics capability enables a well defined solution. The thermal capabilities of MARC are used for complex geometries where simplification of input and graphical output are preferred.

MARC is in the public domain and has had sufficient use to justify its applicability and validity. Extensive verification

of the C-E version has been performed to supplement the public documentation.

3.9.1.2.2.1.3 LION. LION is a finite difference heat transfer program for computing temperature distributions in a three dimensional field. It is described in detail in Reference 3.

LION is used for solution of heat conduction in structural elements, forced convection, free convection and radiation problems. The computed temperature distributions are used as input to the stress analysis programs.

LION is in the public domain and has had sufficient use to justify its applicability and validity. Extensive verification of the C-E version has been performed to supplement the public documentation.

3.9.1.2.2.1.4 TMCALC. The C-E program TMCALC solves the differential equations of motion for a singly or multiply excited multi-degree-of-freedom linear structural system. The program accepts separate, independent, time-varying inputs at each boundary point in the system at which motions due to a seismic event may be imposed, or where a load forcing function may be imposed. The input excitations are provided in digitized form and are assumed to vary linearly between input time steps. The solution of the equations of motion in normal mode coordinates employs a closed form integration process.

The output from TMCALC consists of digitized time history records of the absolute accelerations and relative

displacements for each mass point and boundary point dynamic degree-of-freedom of the structural system.

The program is used to calculate the dynamic response of structural models used in the dynamic seismic analysis of the reactor coolant system major components, and in the dynamic analysis of linear structural systems subjected to time varying load forcing functions, such as thrust from postulated pipe ruptures.

To demonstrate the applicability and validity of the TMCALC program, the solutions to test problems were obtained and shown to be substantially identical to the results obtained by hand calculations. Details of verification are found in Appendix 3.9A.

3.9.1.2.2.1.5 FORCE. The computer code program FORCE calculates the internal forces and moments at designated locations in a piecewise linear structural system, at each time step, due to the time history of relative displacements of the system mass points and boundary points. The program also selects the maximum value of each component of force or moment at each designated location, and the times at which they occur, over the entire duration of the specified dynamic event. The program forms appropriate linear combinations of the relative displacements at each time step and performs a complete loads analysis of the deformed shape of the structure at each time step over the entire duration of the specified dynamic event.

The program is used to calculate the time dependent reactions in structural models subjected to dynamic excitation which are analyzed by the TMCALC and DAGS programs.

To demonstrate the validity of the FORCE program, results for test cases were obtained and shown to be substantially identical to those obtained for an equivalent analysis using the public domain program ICES/STRUDL-II. Details of verification are found in Appendix 3.9A.

3.9.1.2.2.1.6 AXEL. The AXEL program allows the solution of axisymmetric problems using either triangular or general isoparametric finite elements. The isoparametric element is an 8-noded quadrilateral where the midside nodes can be used to model second order curved boundaries and to provide increased accuracy in regions of high stress. The program was verified by comparison of numerous classical examples with results from AXEL. Details of verification are found in Appendix 3.9A.

3.9.1.2.2.1.7 DAGS. The computer program DAGS (Dynamic Analysis of Gapped Structure) performs a piecewise linear direct integration solution of the coupled equations of motion of a three dimensional structure which may have clearances or gaps between the structure and any of its supports or restraints (boundary gaps) or between points within the structure (internal gaps). The contacted boundary points may be oriented in any selected direction and may respond rigidly, elastically, or plastically. The structure may be subjected to applied dynamic loads or boundary motions.

The DAGS program is used to calculate the dynamic response of piecewise linear structural systems subjected to time varying load forcing functions resulting from postulated LOCA conditions.

To demonstrate the applicability and validity of the DAGS program, the solutions to an extensive series of tests problems were obtained and shown to be substantially identical to results obtained by hand calculations or alternate computer solutions. Details of verification are found in Appendix 3.9A.

3.9.1.2.2.1.8 NFATIG. NFATIG is a digital computer program used to analyze nuclear Class 1 piping components in accordance with the ASME Code Section III NB-3650[4]. Input to this program consists of a geometry, material properties, and the various indices for a given section of piping, the loadings and number of cycles of each, the material fatigue curve, and allowable Sm stresses. The output includes the stresses Sn and Salt, and the usage factor for each load set as well as the cumulative usage factor for all cases. NFTIG also incorporates the capability to calculate the stress indices for various standard piping component shapes including tangents, elbows, tees, branches, tapered joints, fillet welds, and reducers.

The NFATIG program was developed in 1973 and updated as required in accordance with subsequent revisions of Section III, ASME Code.

Verification of NFATIG was by example problems and comparison with hand calculations. Details of verification are found in Appendix 3.9A.

3.9.1.2.2.1.9 Bottom Head Penetration Reinforcement Program. This program calculates reinforcement available and reinforcement required for penetrations in hemispherical heads.

The technique described in paragraph NB-3332 of the ASME Code, Section III is used.

This program is used to perform preliminary sizing and reinforcement calculations for hemispherical heads in the reactor vessel. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.10 Flange Fatigue Program. This program computes the redundant reactions, forces, moments, stresses, and fatigue usage factors in a reactor vessel head, head flange, closure studs, vessel flange, and upper vessel wall for pressure and thermal loadings. Classical shell equations are used in the interaction analysis.

This program is used to perform the fatigue analysis of the reactor vessel closure head and vessel flange assembly. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.11 Nozzle Fatigue Program. This program computes the redundant reactions forces, moments, and fatigue usage factors for nozzles in cylindrical shells.

This program is used to perform the fatigue analysis of reactor vessel nozzles and steam generator feedwater nozzle. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.12 Edge Coefficients Program. This code calculates the coefficients for edge deformations of conical

cylinders and tapered cylinders when subjected to axisymmetric unit shears and moments applied at the edges.

This program is used to perform the fatigue analysis of reactor vessel wall transition. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.13 Generalized 4 x 4 Program. This program computes the redundant reactions, forces, moments, stresses, and fatigue usage factors for the reactor vessel wall at the transition from a thick to thinner section and at the bottom head juncture.

This program is used to perform fatigue analysis of reactor vessel bottom head juncture. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.14 ANSYS. Large-scale, general-purpose, finite element program for linear and nonlinear structural and thermal analysis. This program is in the public domain. Additional descriptive information on this code is provided in section 3.9.1.2.3.3.

This program is used for numerous applications for all components in the areas of structural, fatigue, thermal and eigenvalue analysis. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.15 Mare Island Computer Program. This program is used for flexibility analysis of the main loop piping and components. This program is in the public domain and has had sufficient use to justify its applicability and validity. Extensive verification of the C-E version has been performed to supplement the public documentation. MEC-21 is described in more detail in Reference 4.

3.9.1.2.2.1.16 The Structural Analysis for Partial Penetration Nozzles, Heater Tube Plug Welds, and the Water Level Boundary of the Pressurizer Shell Program. This program computes various analytical parameters, primary plus secondary stresses and stress intensities, peak stresses and stress intensities, and the cyclic fatigue analysis with usage factors at cuts of interest. This program is utilized to satisfy the requirements of Section III, of the ASME Code.

This program is used in the fatigue analysis of partial penetration nozzles in the pressurizer and piping. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.17 Seal-Shell II Code. This code computes stresses and deformations of axisymmetric shells for pressure and thermal loads.

This program is used in the fatigue analysis of various nozzles in the pressurizer, piping, and steam generator. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.18 Primary Structure Interaction Program. This code calculates redundant loads, stresses, and fatigue usage factors in the primary head, tubesheet, secondary shell, and stay cylinder for pressure and thermal loadings.

This program is used in the fatigue analysis of the steam generator primary structure. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.19 Tube-To-Tubesheet Weld Program. This code performs a three body interaction analysis of the tube-to-tubesheet weld juncture. The code calculates primary, secondary, and peak stresses and computes range of stress and fatigue usage factors.

This program is used in the fatigue analysis of steam generator tube-to-tubesheet weld. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.20 Support Skirt Loading Program. This code calculates the stresses in the conical support skirt of the steam generator for external loads.

This program is used in the structural analysis of steam generator support skirt. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.21 Principal Stress Program. This code sums stresses for three load conditions and computes principal

stress intensity, stress intensity range, and fatigue usage factor.

This program is used in the fatigue analysis of steam generator components. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.22 OUTRND Program. This code calculates the bending stresses in an out-of-round cylinder subjected to internal pressure. The application of this code is limited to evaluation of secondary shell out-of-round deviation exceeding the ASME Code allowables.

This program is used for fabrication deviations on steam generator shells. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.23 Nozzle Load Resolution Program. A special purpose code, used to calculate stresses in nozzles produced by piping loads in combination with internal pressure.

This program is used in the fatigue analysis of steam generator nozzles. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.24 Zipper, CDC Timesharing Zipper, Siddon Program. These codes are used to determine the neutral axis in bending for the bolted flange of the steam generator support skirt.

These programs are used in the structural analysis of the steam generator support skirt. Program was verified by comparisons

of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.25 CHAT Program. A general purpose finite difference heat transfer program. This program is used for steady state and transient thermal analysis.

This program is used in numerous thermal relaxation analysis for all components. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.26 CEFLASH-4A. A code used to calculate transient conditions resulting from a flow line rupture in a water/steam flow system. The program is used to calculate steam generator internal loadings following a postulated main steam line break.

This program is used in a steam line break accident structural analysis. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.27 CRIBE. A one dimensional, two phase thermal hydraulic code, utilizing a momentum integral model of the secondary flow. This code was used to establish the recirculation ratio and fluid mass inventories as a function of power level. The code is in the public domain and further verification is not required.

This program is used for determining steam generator performance. Program was verified by comparisons of program results and hand calculated solutions of classical problems.

3.9.1.2.2.1.28 RANGE. This program was used for the steam generator analysis. It takes six stress components given as output by ANSYS and computes the maximum stress intensity range for axisymmetric shells and nozzles.

The program has been verified by comparison of program results with hand calculated solutions of classical problems.

3.9.1.2.2.1.29 RANGETS. This special purpose program has been used for evaluation of the stress intensity range for the steam generator tubesheet, considering the procedure of ASME III, Appendix A-8000.

This program has built-in the curve of Fig. A-8142-1 (stress multiplier K vs. biaxiality ratio β). The program requires also as input the hole pattern geometry (pitch, ligament). Stress results from ANSYS are used to evaluate β, get K, then calculate the stress range.

The program has been verified by comparison of program results with hand calculated solutions of classical problems.

3.9.1.2.2.1.30 FATIGTS. This program is used in the fatigue analysis of the steam generator tubesheet.

This program has built-in the curves of Figs. A-8142-3 to 5 (stress multipliers Y1, Y2 vs. ligament efficiency and angle ϕ). The program requires also as input the hole pattern geometry (pitch, ligament) and the Young modulus. Stress results from ANSYS are used to evaluate the peak stress intensity at different angles, based on Y1, Y2 values read on the curves. Also the fatigue curve of Table I-9.1 of ASME III

89 Edition (related to Fig. I-9.1 UTS < 80 ksi) is built into the program, to allow for the fatigue evaluation. The program has been verified by comparison of program results with hand calculated solutions of classical problems.

3.9.1.2.2.1.31 Head PR Program

This program calculates reinforcement available and reinforcement required for penetrations in hemispherical heads. The technique in paragraph NB-3332 of ASME Code, Section III is used. This program is used to perform preliminary sizing and reinforcement calculations for hemispherical heads in the reactor vessel. Program was verified by comparison of program results and hand calculated solutions of classical problem.

3.9.1.2.2.1.32 AFP2D Program

This program utilizes the thermal stresses of two dimensional axisymmetric structure resulting from ANSYS code run. This program combines thermal stresses calculated for transient load steps with stresses due to pressure and external mechanical loads, calculates primary plus secondary stresses, peak stresses and their ranges of stress intensities and fatigue usage factors.

Program was verified by comparison of the results from the program run and the hand-calculation for a test problem.

3.9.1.2.2.1.33 AFPOST Program

This program utilizes the thermal stresses of two and three dimensional structural resulting from ANSYS code run. This program combines thermal stresses calculated for transient load

steps with stresses due to pressure and external mechanical loads, calculates primary plus secondary stresses, peak stresses and their ranges of stress intensities and fatigue usage factors.

Program was verified by comparison of the results from the program run and the hand-calculation for a test problem.

3.9.1.2.2.1.34 TEMPOST Program

TEMPOST is a post processor for temperature data generated by the ANSYS finite element program. The program is used to examine thermal gradients at defined cuts and bodies in the ANSYS model. A mean temperature, equivalent linear gradient and nonlinear or skin gradients are calculated from model temperatures. The program was verified by comparison of results from the program run and hand calculations.

3.9.1.2.2.1.35 APP-GP Program

APP-GP applies the procedures of Appendix G of the ASME Code, Section III and the supplemental procedures in Welding Research Council Bulletin 175 to evaluate non-ductile fracture in pressure vessels. The program calculates the allowable internal pressure as a function of crack size. RT_{NDT}, and thermal conditions which are input by the user. Program was verified by comparison of program results and hand calculated solutions of classical problem.

3.9.1.2.3 Reactor Internals, Fuel and CEDMS

The following computer programs are used in the static and dynamic analyses of reactor internals, fuel, and CEDMs.

3.9.1.2.3.1 ICES/STRUDL-II. The ICES/STRUDL-II computer program provides the ability to specify characteristics of programs, framed structures and three-dimensional solid structures; perform analyses, static and dynamic, and reduce and combine results.

Analytic procedures in the pertinent portions of ICES/STRUDL-II apply to framed structures. Framed structures are two or three dimensional structures composed of slender, linear members and/or plate elements. Such a structure is modeled with joints (including support joints) and members connecting the joints. A variety of force conditions on members or joints can be specified. The member stiffness matrix is computed from beam and/or plate theory. The total stiffness matrix of the modeled structure is obtained by appropriately combining the individual member stiffnesses.

The stiffness analysis method of solution treats the joint displacements as unknowns. The solution procedure provides results for joints and members. Joint results include displacements and reactions and joint loads as calculated from member end forces. Member results are member end forces and distortions. The assumptions governing the element representation of the structure are as follows: linear, elastic, homogenous, and isotropic behavior, small deformations, plane sections remain plane, and no coupling of

axial, torque, and bending. Further description is provided in reference (1).

The ICES/STRUDL-II code is used for the Normal Operations thermal stress analysis of the lower support structure grid beams, and for the stiffness evaluation and stress analysis of the bottom plates and the instrument nozzle support plate.

ICES/STRUDLL-II is in the public domain and has had sufficient use to justify its applicability and validity. Extensive verification of the C-E version has been performed to supplement the public documentation.

3.9.1.2.3.2 MRI/STARDYNE. The MRI/STARDYNE program uses the finite-element method for the static and dynamic analysis of two and three dimensional solid structures subjected to any arbitrary static or dynamic loading or base acceleration. In addition, initial displacements and velocities may be considered. The physical structure to be analyzed is modeled with finite elements that are interconnected by nodes. Each element is constrained to deform in accordance with an assumed displacement field that is required to satisfy continuity across element interfaces. The displacement shapes are evaluated at nodal points. The equations relating the nodal point displacements and their associated forces are called the element stiffness relations and are a function of the element geometry and its mechanical properties. The stiffness relations for an element are developed on the basis of the theorem of minimum potential energy. Masses and external forces are assigned to the nodes. The general solution

procedure of the program is to formulate the total following equations:

$$[K] \cdot \{\delta\} = \{P\} \qquad (1)$$

$$\omega^2[m]\{q\} - [K]\{q\} = 0 \qquad (2)$$

where:

$\{\delta\}$ = the nodal displacement vector

$\{P\}$ = the applied nodal forces

$[m]$ = the mass matrix

ω = the natural frequencies

$\{q\}$ = the normal modes

Equation (1) applies during a static analysis which yields the nodal displacements and finite elements internal forces. Equation (2) applies during an eigenvalue/eigenvector analysis, which yields the natural frequencies and normal modes of the structural system. Using the natural frequencies and normal modes together with related mass and stiffness characteristics of the structure, appropriate equations of motion may be evaluated to determine structural response to a predescribed dynamic load.

The finite elements used to date in CE analyses are the elastic beam, plate and ground support spring members. The assumptions governing their use are as follows: small deformation, linear-elastic behavior, plane sections remain plane, no coupling of axial, torque and bending, geometric and elastic properties constant along length of element.

Further description is provided in reference (5).

The MRI/STARDYNE code is used in the analysis of reactor internals. The program is used to obtain the mode shapes, frequencies and response of the internals to predescribed static and dynamic loading. The structural components are modeled with beam and plate elements. Ground support spring elements are used, at times, to represent the effects of surrounding structures. The geometric and elastic properties of these elements are calculated such that they are dynamically equivalent to the original structures. The response analysis is then conducted using both modal response spectra and modal time history techniques. Both methods are compatible with the program.

The program is also used to perform a static finite element analysis of the lower support structure to determine its structural stiffness.

MRI/STARDYNE is in the public domain and has had sufficient use to justify its applicability and validity. Extensive verification of the C-E version has been performed to supplement the public documentation.

3.9.1.2.3.3 ANSYS. ANSYS is a general purpose nonlinear finite element program with structural and heat transfer capabilities. It is described in reference (6).

ANSYS is used to perform detailed stress analyses of the fuel assembly due to combined lateral and vertical dynamic loads resulting from postulated seismic and loss-of-coolant-accident conditions.

Static finite element analyses of reactor internal structures such as flanges, expansion compensating ring and core shroud are performed with ANSYS to determine vertical and lateral stiffnesses and thermal stresses.

ANSYS is a proprietary code in the public domain. The developers, Swanson Analysis Systems, Incorporated have published an ANSYS verification manual with numerous examples of its usage.

3.9.1.2.3.4 ASHSD. The ASHSD program uses a finite-element technique for the dynamic analysis of complex axisymmetric structures subjected to any arbitrary static or dynamic loading or base acceleration. The three-dimensional axisymmetric continuum is represented as an axisymmetric thin shell. The axisymmetric shell is discretized as a series of frustums of cones.

Hamilton's variational principle is used to derive the equations of motion for these discrete structures. This leads to a mass matrix, stiffness matrix, and load vectors which are all consistent with the assumed displacement field. To minimize computer storage and execution time, the non-diagonal "consistent" mass matrix is diagonalized by adding off-diagonal terms to the appropriate diagonal terms. These equations of motion are solved numerically in the time by a direct step-by-step integration procedure.

The assumptions governing the axisymmetric thin shell finite element representation of the structure are those consistent with linear orthotropic thin elastic shell theory. Further description is provided in reference (7).

ASHSD is used to obtain the dynamic response of the core support barrel under Normal Operating Conditions and due to a LOCA. An axisymmetric thin shell model of the structure is developed. The spatial Fourier series components of the time varying normal operating hydraulic pressure or LOCA loads are applied to the modeled structure. The program yields the dynamic shell and beam mode response of the structural system.

ASHSD has been verified by demonstration that its solutions are substantially identical to those obtained by hand calculations or from accepted experimental tests or analytical results. The details of these comparisons may be found in references (7) and (8).

3.9.1.2.3.5 CESHOCK. The computer program CESHOCK solves for the response of structures which can be represented by lumped-mass and spring systems and are subjected to a variety of arbitrary type loadings. This is done by numerically solving the differential equations of motion of an n^{th} degree of freedom system using the Runge-Kutta-Gill technique. The equations of motion can represent an axially responding system or a laterally responding system; i.e., an axial motion, or a coupled lateral and rotational motion. The program is designed to handle a large number of options for describing load environments and includes such transient conditions as time-dependent forces and moments, initial displacements and rotations, and initial velocities. Options are also available for describing steady-state loads, preloads, accelerations, gaps, nonlinear elements, hydrodynamic mass, friction, and hysteresis.

The output from the code consists of minimum and maximum values of translational and angular accelerations, forces, shears, and moments for the problem time range. In addition, the above quantities are presented for all printout times requested. Plots can also be obtained for displacements, velocities and accelerations as desired. Further description is provided in Reference (9).

The CESHOCK program is used to obtain the transient response of the reactor vessel internals and fuel assemblies due to LOCA and seismic loads.

Lateral and vertical lumped-mass and spring models of the internals are formulated. Various types of springs; linear, compression only, tension only, or nonlinear springs are used to represent the structural components. Thus, judicious use of load-deflection characteristics enables effects of components impacting to be predicted. Transient loading appropriate to the horizontal and vertical directions is applied at mass points and a dynamic response (displacements and internals forces) is obtained.

CESHOCK has been verified by demonstration that its solutions are substantially identical to those obtained by hand calculations or from accepted analytical results via an independent computer code. The details of these comparisons may be found in References (8) and (9).

3.9.1.2.3.6 SAMMSOR/DYNASOR. SAMMSOR/DYNASOR provides the ability to perform nonlinear dynamic analyses of shell structures represented by axisymmetric finite-elements and subjected to arbitrarily varying load configurations.

The program employs the matrix displacement method of structural analysis, utilizing a curved shell element. Geometrically nonlinear dynamic analyses can be conducted using this code.

Stiffness and mass matrices for shells of revolution are generated utilizing the SAMMSOR part of this code. This program accepts a description of the structure in terms of the coordinates and slopes of the nodes, and the properties of the elements joining the nodes. Utilizing the element properties, the structural stiffness and mass matrices are generated for as many as twenty harmonics and stored on magnetic tape. The DYNASOR portion of the program utilizes the output tape generated by SAMMSOR as input data for the respective analyses.

The equations of motion of the shell are solved in DYNASOR using Houbolt's numerical procedure with the nonlinear terms being moved to the right-hand side of the equilibrium equations and treated as generalized pseudo-loads. The displacements and stress resultants can be determined for both symmetrical and asymmetrical loading conditions. Asymmetrical dynamic buckling can be investigated using this program. Solutions can be obtained for highly nonlinear problems utilizing as many as five circumferential Fourier harmonics. Further description is provided in references (10) and (11).

This program is used to analyze the dynamic buckling characteristic of the core support barrel during a LOCA hot-leg break. The program's nonlinear characteristics provide this capability.

A finite element model of the CSB is formulated which is consistent with the computer program. Taking into account the initial deviation of the structure and the shell mode which is most likely to give the minimum critical pressure, the time-dependent pressure load is applied to the barrel. The maximum displacement occurring in the barrel is obtained.

SAMMSOR/DYNASOR has been verified by demonstration that its solutions are substantially identical to those obtained by hand calculations, accepted experimental test or analytical results, and results obtained with a similar independently written program in the public domain. The details of these comparisons may be found in reference (8).

3.9.1.2.3.7 MODSK. MODSK is a CE computer program which solves for the natural frequencies and mode shapes of a structural system. The natural frequencies and mode shapes are extracted from the system of equations:

$$(K - W_n^2 M)\,\phi_n = 0$$

where

K = model stiffness matrix

M = model mass matrix

W_n = natural circular frequency for the n^{th} mode

ϕ_n = normal mode shape matrix for the n^{th} mode

The solution to the general eigenvalue problem is obtained using the dual Jacobi rotation method.

The MODSK code is used in the analyses of reactor internals to obtain frequencies and mode shapes, and damping parameters. The results of these analyses are incorporated into overall reactor vessel internals models, which calculates dynamic response due to seismic and LOCA conditions.

The MODSK program was developed by CE and is used on the CDC 7600 computer. To demonstrate the validity of the MODSK program, results from lateral and vertical test problems were obtained and shown to be substantially identical to those obtained from an equivalent analysis using the public domain program ANSYS (Refer to section 3.9.1.2.3.3).

3.9.1.2.3.8 SAPIV. The SAP IV computer code is a structural analysis program capable of analyzing two and three dimensional linear complex structures subjected to any arbitrary static and dynamic loading or base acceleration. The analysis technique is based on the finite element displacement method. The structure to be analyzed can be represented using bars, beams, plates, membranes and three dimensional finite elements.

Structural stiffness and load vectors are assembled from the element matrices which are derived assuming various displacement functions within each element whereas lumped mass matrices are used to represent inertia characteristics of the structure. In the static analysis, the assembled equations of equilibrium are solved by using a linear equation solver. Dynamic analysis capabilities include modal analysis, modal superposition and direct integration methods of computing dynamic response and response spectrum techniques.

SAPIV has been applied to the eigenvalue and response spectra analyses of spent fuel storage racks and lifting rig structures.

The SAPIV code is used in the computation of dynamic response of control element drive mechanisms under mechanical and seismic loads. Both modal analysis and response spectrum capabilities of the code are used to find the natural frequencies and mode shapes and the dynamic loads in CEDM components.

SAPIV is in the public domain and has had sufficient use to justify its applicability and validity. Extensive verification of the C-E version has been performed to supplement the public documentation.

3.9.1.2.3.9 CEFLASH-4B. The CEFLASH-4B computer code (Reference 15) predicts the reactor pressure vessel pressure and flow distribution during the subcooled and saturated portion of the blowdown period of a Loss-of-Coolant-Accident (LOCA). The equations for conservation of mass, energy and momentum along with a representation of the equation of state are solved simultaneously in a node and flow path network representation of the primary reactor coolant system.

CEFLASH-4B provides transient pressures, flow rates and densities throughout the primary system following a postulated pipe break in the reactor coolant system.

The CEFLASH-4B computer code is a modified version of the CEFLASH-4A code (References 16-18). The CEFLASH-4A computer code has been approved by the NRC (References 19 and 20). The

capability of CEFLASH-4B to predict experimental blowdown data is presented in Reference 15.

3.9.1.2.3.10 LOAD 2. LOAD 2 calculates the applied forces of the axial internals model which is contained within water control volumes using results from the CEFLASH-4B blowdown loads analysis as input. The fluid momentum equation is applied to each volume and a resultant force is calculated. Each force is then apportioned to the various structural nodes contained within the volume. Use of the fluid momentum equation takes into account pressure forces, fluid friction, water weight, and momentum changes within each volume. The resultant forces are combined with the reactor vessel motions obtained from the reactor coolant system analysis before the structural responses are determined. The LOAD 2 code has been verified by demonstrating that its solutions are substantially identical to those obtained from hand calculations.

3.9.1.2.4 REFERENCES FOR SECTION 3.9.1.2.2 and 3.9.1.2.3

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F. M. Stern, Vice President of Projects (C-E), June 1, 1975.

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3.9.1.3 Experimental Stress Analyses

3.9.1.3.1 NSSS Items

Requirements for experimental stress analysis have not been imposed on any equipment in the CESSAR scope.

3.9.1.3.2 Non-NSSS Items

Most stress analyses have been computer simulated. Experimental stress analysis has not generally been performed on non-C-E scope components. However, experimental stress analysis has been utilized on the following components:

A. Essential Air Cooling Units, Auxiliary Building Pump Rooms

   Two units of different sizes were tested to verify the analytical method.

B. Essential Ducting

   The experimental analysis of essential HVAC ducting was performed on 17 groups of various sized ducts. These samples were subjected to pressure loading, equivalent seismic loads, and live loads (e.g., a concentrated weight was applied along the duct to simulate the live load of a man walking on the duct).

The test loads causing failure were compared to the theoretical load to failure in order to justify the design procedure.

3.9.1.4 Consideration for the Evaluation of the Faulted Condition

3.9.1.4.1 Seismic Category I NSSS Items

Analyses of the reactor coolant system components (reactor vessel, steam generator, reactor coolant pump, pressurizer, and reactor coolant piping) and their supports have been performed in accordance with the methods described in CESSAR Section 3.9.1.4.1. However, due to analyses submitted on the CESSAR docket under the requirements of 10CFR50, Appendix A, Criterion 4, loads resulting from postulated pipe breaks of the RCS MAIN Loop piping are no longer required for consideration. For each component and support member, the calculated loads, in combination with the seismic loads, are below the loads specified for design and the stresses (pipe rupture in combination with SSE) are below those listed in Table 3.9.3-2.

No components or supports of the reactor coolant system main loop for PVNGS were designed using the inelastic methods defined in Section III of the ASME Code as plastic instability or limit analysis methods.

The reactor vessel lower key horizontal supports include load limiting devices in accordance with section 5.4.14.2(e). These load limiters are designed to remain elastic for all normal, upset, and SSE loadings, and elastic system analyses are used to establish or confirm the loads specified for design of the

components and supports for these conditions. For loads resulting from postulated pipe breaks, the load limiter devices are designed to deflect plastically, and nonlinear system analyses are used accordingly for proper calculation of the distribution of the loads among the system of supports.

Figure 3.9-1 illustrates the performance requirements specified for the reactor vessel lower support key load limiters. The dashed lines represent the stiffness and load ranges evaluated in the overall system analyses. All test data points were within the envelope indicated by the solid lines. All testing was performed on samples extracted from the heat specific material used in construction.

Twenty-one tests were run at various temperatures and at crush velocities representative of performance requirements. The test results were within the specified load deflection limits.

3.9.1.4.2 Seismic Category I Non-NSSS Items

Dynamic loads for components loaded in the elastic range are calculated using dynamic load factors, time-history analysis, or any other method that assumes elastic behavior of the component. A component is assumed to be in the elastic range if yielding across a section does not occur. The limits of the elastic range are defined in Paragraph F-1323 of Appendix F for code components. Local yielding due to stress concentration is assumed not to affect the validity of the assumptions of elastic behavior. The stress allowables of Appendix F for elastically analyzed components are used for code components. For noncode components, allowables are based on tests or

accepted material standards consistent with those in Appendix F for elastically analyzed components.

3.9.1.4.3 Control Element Drive Mechanisms

The pressure boundary portions of the control element drive mechanisms (CEDMs), including the nozzle attached to the reactor vessel head, have been analyzed in accordance with the methods described in section 3.9.1.4.3.1 below. The calculated moments and/or stresses for both pipe rupture only and for the combined effects of pipe rupture and the SSE are below those allowed by Section III of the ASME B&PV Code for service level D.

The capability of the control element drive mechanisms (CEDMs) to withstand the effects of design basis pipe breaks in combination with safe shutdown seismic (SSE) loadings is evaluated by analysis. This dynamic loading is experienced by the CEDMs via the motion of the reactor vessel head. The reactor vessel head/CEDM motions due to pipe rupture and seismic loadings are calculated as described in sections 3.7.2 and 3.9.1.4.1.

3.9.1.4.3.1 Method of Analysis

Prior to implementation of leak before-break, studies on other C-E plants (Reference 1) indicated that the reactor vessel asymmetric load aspects of a hypothetical main coolant loop guillotine break produce motions which result in stresses which exceed the ASME Code Level D allowable stresses for elastic calculation. Elastic plastic dynamic analyses have demonstrated for those plants that the structural integrity of

the CEDMs is not impaired by these loadings and that the ASME Code Level D allowable limits for elastic plastic calculation are not exceeded. In order to demonstrate that the integrity of the CEDMs were not impaired by main coolant loop pipe break and SSE loads, elastic plastic dynamic analyses of the CEDM's were originally performed.

In the elastic plastic analysis, the motions of the RV were input to the finite element model of the CEDM. Moments and deformation were computed as a function of time during the event. The moment to cause plastic instability of the most severely loaded section was computed by elastic plastic static analysis. The actual moments during the dynamic event were then compared to the plastic instability moment in order to evaluate integrity.

REFERENCE

1. "Reactor Coolant System Asymmetric Loads Evaluation Program Final Report", Combustion Engineering, Inc., July 1, 1980.

3.9.1.4.3.2 Models

Dynamic analysis finite element models were prepared for CEDMs near the center of the RV head and near the outer edge. The models were made up of beam type elements.

The model for the calculation of the plastic instability load was made up of shell elements in order to consider the effects of ovalization of the cylindrical section. The nozzle at the RV head is usually the most severely loaded section.

3.9.1.4.3.3 Material Properties

The material properties necessary for elastic plastic analysis were developed by the C-E Metallurgical and Materials Laboratory. These properties are available for all of the materials at all of the temperatures that the CEDM normally experiences.

3.9.1.4.3.4 Loading

The effects of pipe break and SSE are transmitted to the CEDM by the motion of the reactor vessel head resulting from the analyses of sections 3.7.2 and 3.9.1.4.1.

A response spectrum is calculated for the motion of the reactor vessel head resulting from the primary system dynamic analysis for pipe break loads. This response spectrum is combined with the SSE response spectrum by taking the square root of the sum of the squares (RSS) of the ordinates of the two spectra. An artificial time history of motion is then developed from the combined acceleration spectrum and used as the input to the dynamic CEDM analysis.

Acceleration spectra resulting from pipe rupture at the RV inlet nozzle, the RV outlet nozzle, and at the steam generator inlet nozzle will be compared in order to determine the most severe loading condition. If one loading condition can be identified as the most severe case, only that loading condition will be used in the dynamic CEDM analysis. Other loadings will also be used if they are not clearly enveloped by the most severe one.

3.9.1.4.3.5 Response

The models, material properties and RV head motion history are used in the MARC finite element program (Section 3.9.1.2.2.1.2) for analysis. The ANSYS program (3.9.1.2.2.1.14) may also be used. The results of the dynamic analysis include moments, strains, stresses and deformation as a function of time. These results are presented graphically for critical regions of the CEDM. The same material properties will be used in the static analysis for the plastic instability moment.

3.9.1.4.3.6 Evaluation

3.9.1.4.3.6.1 Acceptance Criteria

The CEDMs are not required to operate for safe shutdown after a loss of coolant event resulting from the design basis pipe breaks. In order to comply with existing ECCS analysis methods, however, the integrity of the CEDMs must be maintained and leakage must be prevented. The ASME Boiler and Pressure Vessel Code Section III Division 1 Appendix F lists a number of criteria which assure that the pressure boundary will not be violated. These criteria include an instability limit for comparison to elastic plastic analysis results. The integrity of the pressure boundary is assured if the applied loads do not exceed 70% of the plastic instability load.

3.9.1.4.3.6.2 Evaluation of Integrity

The results of each dynamic analysis are compared to the results of the static plastic instability moment analysis.

Integrity of the CEDMs is assured if the acceptance criteria are satisfied.

3.9.1.4.3.7 CEDMs Evaluation

Evaluations of the CEDMs for loadings were performed. Linear response spectrum analyses specific to the current plant configuration were used for both seismic and BLPB excitations to calculate response loads in the CEDM nozzles and CEDM components. A three-dimensional beam finite element ANSYS 5.5 model, with all spatial degrees of freedom, was developed and used for these analyses. This model uses a sufficient number of nodes to accurately represent the dynamic characteristics of the nozzle components and to provide a detailed load response distribution throughout the CEDM structure. The mathematical model was used for dead weight, seismic and BLPB analyses.

The seismic and BLPB loads were applied to the CEDM with the longest nozzle length (37.63 inches) and the shortest nozzle length (8.31 inches). The longest nozzle produces conservative results for seismic loads, while the shortest nozzle produces conservative results for BLPB loads. However, the governing load for the Faulted Condition combined loadings are the seismic loads; therefore stresses evaluated for the CEDM with the longest nozzle are limiting, and these results are applicable and conservative for all CEDM locations.

Seismic loads were generated by performing response spectrum analyses of the mathematical model using response spectra at the RV closure head from the RCS seismic analysis. The OBE analysis was performed using structural damping of 2.5% for the first mode and 2% for all other modes, conforming to RG 1.61

and test results without introducing over-conservatism. Although RG 1.61 allows 4% damping for welded steel structures for the SSE event, 2% damping was used in the CEDM SSE analysis. For the seismic analyses, each set of spectra for three orthogonal directions were broadened by ±15%. Since the effect of closely spaced modes for the CEDM structure is insignificant, modal responses were combined using the SRSS rule. The values of structural responses to each of three orthogonal components of motion were combined using the SRSS rule.

For BLPB analysis, input response spectra were generated from RV closure head acceleration response time histories from the BLPB analysis of the RCS. Damping of 4% was used to generate the RV closure head response spectra due to BLPB. The values of structural responses to each of three orthogonal components of motion were combined using the SRSS rule.

It was demonstrated that CEDM loads due to Service Levels A, B and D are within the allowable limits and that CEDM stresses for Service Levels A and B are addressed, CEDM and RV head thermal stresses are acceptable.

It was also demonstrated that during seismic and BLPB, the maximum displacement at the top of the CEDMs is within acceptable limits, that CEDMs retain their ability to scram within the 3 second time period, that the CEDMs will not impact, and that the RSPTs remain operable.

3.9.1.4.4 Emergency Core Cooling System Piping

The emergency core cooling system (ECCS) piping, inside containment, is comprised of the high- and low-pressure piping of the safety injection system.

The capability of the ECCS piping to withstand the effects of design basis pipe breaks is evaluated by analysis. The capability of the ECCS piping to withstand the combined effects of pipe break and SSE seismic loadings is also evaluated. Pipe rupture loadings are experienced by the ECCS piping via the motion of the primary system piping and the SSE loadings are experienced by the ECCS piping via the motion of the primary system piping and the ECCS piping supports.

The primary piping motions due to pipe rupture loadings are calculated as described in section 3.9.1.4.1. Each ECCS pipeline is evaluated by dynamic elastic or dynamic elastic/plastic analysis for these primary piping motions.

The effects of primary system pipe breaks are transmitted to the ECCS piping by the motion of the primary piping. For the evaluation of pipe break loads, the displacement time-history of the primary piping (at the ECCS injection nozzle) is applied directly to each dynamic ECCS pipeline analysis.

The analysis results in motions and stresses in the piping. The analysis also results in pipe support motions and loading.

For ECCS piping attached to the broken primary pipe, pressure boundary integrity is assumed by meeting the faulted condition limits found in Appendix F of ASME B&PV Code, Section III, Division 1.

For ECCS piping attached to the unbroken loops of the primary pipes, function ability can be assumed:

A. by meeting the level B (upset condition) limits of ASME B&PV Code, Section III, Division 1 with fatigue considerations excluded, or

B. by meeting the criteria found in GE Topical Report "Functional Capability Criteria for Essential Mark II Piping," NGDO-21985 dated September 1978 (refer to NRC memorandum for R. L. Tedesco, Assistant Director for Licensing, from J. P. Knight, Assistant Director for Components and Structures Engineering, dated July 17, 1980), or

C. by demonstrating that the deformations of the piping do not significantly affect ECCS flow.

3.9.2 DYNAMIC SYSTEM ANALYSIS AND TESTING

3.9.2.1 Piping Vibration Thermal Expansion and Dynamic Effects

Safety-related piping systems are designed in accordance with the ASME Code, Section III. Each system is designed to maintain dynamic effects within acceptable limits. A preoperational test program is implemented as required by NB-3622.3, NC-3622.3, and ND-3622.3 of Section III of the ASME B&PV Code to verify that the piping and piping restraints will withstand dynamic effects due to transients such as pump trips and valve trips, and that piping vibrations are within acceptable levels.

The preoperational test program for the Class 1, 2, and 3 piping systems is to simulate actual operating modes to demonstrate that the appurtenances comprising these systems meet functional design requirements and that piping vibrations are within acceptable levels.

Piping systems are checked in three sequential series of tests and inspections. Construction acceptance, the first step, entails inspection of components for correct installation. During this phase, pipe and equipment supports are checked for correct assembly and setting. The cold locations of RCS components, such as steam generators and reactor coolant pumps, are recorded.

During the second step of testing, plant heatup, the plant is heated to normal operating temperatures. During the heatup, systems are observed periodically to verify proper expansion and expansion data is recorded at the end of heatup.

During the third step of testing, performance testing, systems are operated and performance of critical pumps, valves, controls, and auxiliary equipment is checked. This phase of testing includes transient tests such as reactor trip or turbine trip and relief valve testing. During this phase of testing, the piping and piping restraints are observed for acceptable dynamic response. System tests include critical valve operation during transient system modes.

Vibratory dynamic loadings can be placed in two categories: transient-induced vibrations and steady-state vibrations. The first is a dynamic system response to a transient, time-

dependent forcing function, such as fast valve closure, while the second is a constant vibration, usually flow-induced.

A. Transient Response

1. Dynamic events falling in this category are anticipated operational occurrences. The systems and the transients to be included in the preoperational test program will be identified in test procedures.

2. For these transients, a time-dependent dynamic analysis is performed on the system. The stresses thus obtained are combined with system stresses resulting from other operating conditions in accordance with the criteria provided in subsections 3.9.1 and 3.9.3.

   Details of the program, including the criteria for evaluation of data gained, are provided in the test procedures.

B. Steady-State Vibration

1. System vibration resulting from flow disturbances fall into this category. Positive displacement pumps may cause such flow variation and vibrations.

   In these situations, pipe supports are spaced so the natural frequency of the piping system is at least 50% higher than the pulsation frequency of the pumps. Pulsation dampeners are also provided

on the suction and discharge sides of the pumps to reduce the pressure pulsations.

2. Since the exact nature of the flow disturbance is not known prior to pump operation, no analysis is performed. If excessive system vibration is evidenced during initial operation, appropriate measures will be taken to reduce the vibration.

3.9.2.2 Seismic Qualification Testing of Safety-Related Mechanical Equipment

3.9.2.2.1 Safety-Related Mechanical Equipment in the C-E Scope of Supply

The operability of all active safety related mechanical equipment within CE's scope of supply is demonstrated by analysis and/or testing. The methods and procedures used and the results of tests and analyses that confirm implementation of the design criteria for safety-related mechanical equipment, including supports, are provided in section 3.9.3.2.

3.9.2.2.2 Safety-Related Mechanical Equipment Not in the C-E Scope of Supply

The criteria used to decide whether dynamic testing or analysis will be used to qualify Seismic Category I mechanical equipment are as follows (refer to section 3.10):

A. Analysis Without Testing

1. Structural analysis without testing will be used if structural integrity alone can assure the

intended design function. Equipment which falls into this category includes:

- Piping
- Ductwork
- Tanks and vessels
- Heat exchangers
- Filters

The seismic analysis of piping is described in section 3.7.

2. Rotational analysis without testing will be used to qualify heavy rotating machinery items where it must be verified that deformations due to seismic loadings will not cause binding of the rotating element to the extent that the component cannot perform its required safety function.

   The seismic qualification of pumps is discussed more fully in paragraph 3.9.3.2. The procedure discussed therein applies with some variations to other items in this category.

B. Dynamic Testing

Dynamic testing is used for components with mechanisms that must change position or maintain position in order to perform their required safety function and which, because of their complexity, do not lend themselves to analysis. Such components include:

- Electric motor valve operators

- Valve limit switches
- Similar appurtenances for other active mechanical equipment

The seismic qualification of Seismic Category I electrical equipment is discussed in section 3.10.

C. Combinations of Analysis with Testing

A combination of analysis, static testing, and dynamic testing is used for seismic qualification of active valves whereby:

1. The manufacturer determines the first natural frequency of the valve assembly by analysis.
2. It is verified by static test that deformation due to seismic loadings will not cause binding of internal valve parts, which prevents valve operations within specified time limits.
3. The motor operator and other electrical appurtenances are qualified by dynamic testing.

The seismic qualification of active valves is discussed in paragraph 3.9.3.2.

The acceptance criteria which are used are as follows:

1. Tests, when used, demonstrate that the component is not prevented from performing its required safety function during and after the test.
2. Analysis, when used, verifies that stresses do not exceed the allowables specified in tables 3.9-4, 3.9-5, 3.9-6, 3.9-7, 3.9-9, and

3.9-11 for the loading combinations shown in tables 3.9-8, 3.9-10, and 3.9-12 and that deformations do not exceed those that will permit the component to perform its design intended function.

3.9.2.3 Dynamic Response Analysis of Reactor Internals Under Operational Flow Transients and Steady-State Conditions

3.9.2.3.1 Introduction

The flow-induced vibration of the reactor internals components during normal operation can be characterized as a forced response to both deterministic (periodic and transient) and random pressure fluctuations in the coolant. Methods have been developed to predict the various components of the hydraulic forcing function and the response of the reactor internals to such excitation.

This analytical methodology is summarized in Figure 3.9.2-1. The method separates the response calculations into two groups in accordance with the physical nature of the loading; i.e., deterministic or random. Methods for developing the deterministic component of the hydraulic forcing function are discussed in section 3.9.2.3.2, while those relating to the random component are discussed in section 3.9.2.3.3. Where complex flow path configurations or wide variations in pressure distribution are involved, the hydraulic forcing functions are formulated using a test-analysis combination method utilizing data obtained from plant tests and/or scaled model tests.

The response of the reactor internals components (to include Core Support Barrel Assembly, Upper Guide Structure Assembly and Lower Support Structure Assembly) to the normal operating hydraulic loads are calculated by finite-element techniques. The mathematical models used in these response analyses are described in section 3.9.2.3.4. The methods used in calculating the structural responses are discussed in section 3.9.2.3.5.

3.9.2.3.2 Periodic Forcing Function

3.9.2.3.2.1 Core Support Barrel Assembly

An analysis based on an idealized hydrodynamic model is employed to obtain the relationship between reactor coolant pump pulsations in the inlet ducts and the periodic pressure fluctuations on the core support barrel. A detailed description of this model and subsequent solution are given in References 7-13. The model represents the annulus of coolant between the core support barrel and the reactor vessel. In deriving the governing hydrodynamic differential equation for the above model, the fluid is taken to be compressible and inviscide. Linearized versions of the equations of motion and continuity are used. The excitation on the hydraulic model is harmonic with the frequencies of excitation corresponding to pump rotational speeds and blade passing frequencies. The result of the hydraulic analysis is a system of equations which define the forced response, natural frequencies and natural modes of the hydrodynamic model. The forced response equations define the spatial distributions of pressure on the core support barrel system as a function of time.

3.9.2.3.2.2 Upper Guide Structure

The dynamic force on the upper guide structure assembly is due to flow induced forces on the tube bank. The periodic components of these forces are caused by pressure pulsations at harmonics of the pump rotor and blade passing frequencies, and vortex shedding due to crossflow over the tubes.

A series of tests on full size tubes at reactor pressure and temperature indicated no evidence of periodic vortex shedding at the Reynolds Number and turbulence levels expected in the tube bank (Ref. 23). Thus, the only significant periodic force is that due to pump pulsations. Data from this same test series was utilized to determine the magnitude of these pulsations at the pump rotor, twice the rotor, blade passing, and twice blade passing frequencies.

3.9.2.3.2.3 Lower Support Structure Assembly

The ICI nozzles and the skewed beam supports for the ICI support plate are excited by periodic and/or random, flow induced forces.

The periodic component of this loading is due to pump related pressure fluctuations and vortex shedding due to crossflow. High turbulence intensity caused by jetting through the flow skirt makes it unlikely that regular vortex shedding will occur (Refs. 18, 19). If it were assumed to occur, the maximum shedding frequency would be well below the lowest structural frequency for both the ICI support nozzles and skewed beams. The magnitude and frequency of this periodic force are accounted for based on data in the literature for crossflow

over both vertical (Ref. 17, 22) and skewed (Ref. 21) isolated tubes.

Derivation of pump frequency related loads is accomplished by assuming that these periodic pressure variations are propagated undiminished through the flow skirt from the lower portion of the core barrel - reactor vessel annulus. The magnitude of these pulsations is based on a combination of analytical predictions, based on Reference 7, and data from previous precritical programs (Refs. 9, 10).

3.9.2.3.3 Random Forcing Function

3.9.2.3.3.1 Core Support Barrel Assembly

The random hydraulic forcing function is developed by analytical and experimental methods. An analytical expression is developed to define the turbulent pressure fluctuation for fully developed flow (Ref. 12). This expression is modified, based upon the result of scale model testing (Refs. 15 and 16), to account for the fact that flow in the downcomer is not fully developed. Based upon tests results, an expression is developed to define the spatial dependency of the turbulent pressure fluctuations. In addition, experimentally adjusted analytical expressions are developed to define the peak value of the pressure spectral density associated with the turbulence and the maximum area of coherence, in terms of the boundary layer displacement, across which the random pressure fluctuations are in phase (Refs. 11, 12, 13). The transient behavior of the random fluctuations during loop startup and shutdown is assumed to be identical to that of the periodic excitations.

3.9.2.3.3.2 Upper Guide Structure

Results of the full size tube tests (Ref. 23) showed that at normal operating conditions the shroud tubes are excited by upstream and wake produced turbulent buffeting (Ref. 23, 24, 25). The forcing function for this type of loading can be represented as a band limited white noise power spectrum (Ref. 23). The magnitude of this spectrum is computed based on data from these tests. The resultant velocity dependent force is combined with static drag loads to compute the amplitude response and stress levels.

3.9.2.3.3.3 Lower Support Structure Assembly

The ICI nozzles and ICI support plate support beams are both subject to turbulent buffeting by the flow skirt jets. The outermost ICI nozzles and beams receive full impact of the jets before the jets decay due to fluid entrainment and the presence of inner tube rows. The force spectrum of these jets is assumed to be represented as wide band white noise. The magnitude of this spectrum is based on data in the literature for impingement of turbulent jets (Ref. 20, 26). This velocity dependent magnitude is applied to each tube, assuming no change in jet characteristics, between the outermost and inner tubes. The approach velocity for each tube is calculated from an analytical expression based on experimental data on the velocity distribution in the lower portion of the reactor vessel-core barrel annulus and the flow skirt.

3.9.2.3.4 Mathematical Models

A finite element analysis is performed on each of the reactor internals components using mathematical models. These models are designed to provide the most efficient analysis under the most significant loading condition to which each structure is exposed. The core support barrel assembly is modeled as a shell using the ASHSD computer code (Ref. 29) (Figure 3.9.2-2). The structure is fixed at the upper flange to determine the beam modes and frequencies. The shell modes and frequencies are found by considering the upper flange fixed and the lower flange pinned. These analyses include hydrodynamic mass effects. All significant mode shapes and frequencies are used in combination to perform the normal operating deterministic response analysis. A simplified finite-element model of the barrel assembly is generated on the STARDYNE computer code (Ref. 30) for use in the random response analysis.

The control element shroud tubes in the upper guide structure assembly are modeled as beams supported at the ends by plate elements. The end plates are in turn supported by spring elements which represent the stiffness of additional surrounding structure. A typical model of this configuration is shown in Figure 3.9.2-3. The STARDYNE computer code (Ref. 30) is employed to allow the same models to be utilized for modal analysis as well as deterministic and random response analysis.

The lower support structure assembly is modeled in several ways. Beam and plate elements are assembled in a comparatively coarse mesh to model the entire Instrument Nozzle Assembly

(Figure 3.9.2-4). This representation of the structure is used on the STARDYNE computer code (Ref. 30) to determine the modes, frequencies and response actions of the assembly as a system. The reaction points in this model are taken at the bottom plate level of the LSS Assembly. Typical ICI nozzles (Figure 3.9.2-5) and Skewed Beams (Figure 3.9.2-6) are modeled as fine mesh beam elements reacted at the support points by spring elements representing the surrounding structure flexibility. These component models are used on the STARDYNE computer code (Ref. 30) to provide the individual structural modes, frequencies and responses within the system. The results of both individual and system analysis are combined to provide the total response.

3.9.2.3.5 Response Analysis

3.9.2.3.5.1 Deterministic Response

The normal mode method (Reference 27) is used to obtain the structural response of the reactor internals to the deterministic forcing functions developed in section 3.9.2.3.2. The method is applied to the appropriate finite-element models described in section 3.9.2.3.4. Generalized masses based on mode shapes and the mass matrices from the finite-element computer programs are calculated for each component's modes of vibration. Modal force participation factors are based on the mode shapes and the predicted periodic forcing functions are calculated for each mode and forcing function. The generalized coordinate response for each mode is then obtained through solution of the corresponding set of independent second order single-degree of freedom equations. Utilizing displacement and

stress mode shapes from the finite-element computer programs, the modal responses of the reactor internals are obtained by means of the appropriate coordinate transformations. Response to any specific forcing function is obtained through summation of the component modes for that forcing function.

3.9.2.3.5.2 Random Response

The normal mode method (Ref. 27) is used to obtain the structural response of the reactor internals subjected to random forcing functions. The random forcing functions are assumed to be of both the band limited and wide band white noise varieties as described in section 3.9.2.3.3. Experimental and analytical expressions are used to define the force power spectral density associated with flow related turbulence and jet impact. The appropriate mathematical models described in section 3.9.2.3.4 are used in the STARDYNE computer code (Ref. 28). This code computes the response RMS displacements, loads and stresses in a multi-degree-of-freedom linear elastic structural model subjected to stationary random dynamic loadings, such as those described in section 3.9.2.3.3.

The largest response of the Core Support Barrel is expected to be in the "beam" mode. The simplified finite-element model of this structure, described in section 3.9.2.3.4, is used to compute these displacements.

The Upper Guide Structure and Lower Support Structure will not respond to random excitation as complete assemblies but rather will experience local disturbances of individual components within the assemblies. The modal analyses from the finite-element models of these components, (Figures 3.9.2-3,

3.9.2-4 and 3.9.2-6) already used for deterministic analysis, are once again utilized to determine the random responses via the normal mode procedure.

3.9.2.4 Preoperational Flow-Induced Vibration Testing of Reactor Internals

PVNGS Unit 1 is the proto-type System 80 plant for the purposes of the precritical vibration monitoring program (PVMP). PVNGS Units 2 and 3 are nonprototype plants.

In accordance with NRC Regulatory Guide 1.20, a preoperation vibration monitoring program has been developed for the prototype System 80 plant. The first System 80 unit that will go on-line will be the lead plant and will be used as the System 80 prototype. Subsequent System 80 plants will fall under a non-prototype designation as defined in Regulatory Guide 1.20. Precritical program guidelines on these plants are as defined in Regulatory Guide 1.20 for non prototype plants. The precritical test program described in this section is a prototype program.

Precritical test programs have been run on previous CE plants (References 9, 10 and 31). The System 80 program utilizes the experience from these earlier plants. The System 80 program includes predictions, measurements and evaluation of the core support barrel, lower support structure and upper guide structure assemblies consistent with the guidelines reflected by Regulatory Guide 1.20. The developed program will be incorporated into the precritical testing of the lead System 80 plant. The program is made up of four distinct, yet closely

interrelated phases. These phases are designed to satisfy the guidelines of Regulatory Guide 1.20 and are described below.

3.9.2.4.1 Vibration Analysis Phase

Analytical and test-analysis methods are used to estimate the normal operating steady state and transient forcing functions. Dynamic response of the reactor internals components are then analytically determined for those forcing functions which correspond to preoperational and initial startup test and normal operating conditions. The methods employed in these analyses are described in sections 3.9.2.3.1 through 3.9.2.3.5. The final results of this phase of the program will be issued in a prediction report prior to the initiation of the second phase of the PVMP program. Included in the prediction report will be theoretical estimates of the forcing functions and associated structural responses, definitions of criteria, and the bases for the establishment of the criteria.

3.9.2.4.2 Vibration Measurement Phase

This experimental program will incorporate internal and external accelerometers, pressure transducers and strain gages, which will permit the recording of time-dependent accelerations, pressures and strains at specific locations. The type, number and position of the instrumentation is based upon the results of the phase one analysis and will be summarized in the instrumentation report to be issued prior to startup of the prototype plant. Measurements will be made during precritical testing. A general outline of the measurement program instrumentation is shown in Figures 3.9.2-7

to 3.9.2-9. Data collection will be done on a time history basis for subsequent reduction using methods of random data analysis (Ref. 32). Testing will be of sufficient duration to assure satisfaction of the NRC Regulatory Guide 1.20 requirement.

3.9.2.4.3 Inspection Phase

A visual inspection program, including photographic documentation, will be undertaken in accordance with Regulatory Guide 1.20 at the start and conclusion of the vibration measurement phase. Critical locations identified in phase one will all be inspected to establish the effects of vibration. These locations will include contact and potential contact surfaces between all major load bearing reactor internal components, lateral, vertical and torsional restraints, locking and bolting components.

3.9.2.4.4 Evaluation & Documentation Phase

A final report will be issued to summarize the results of the experimental PVMP program. This report (see section 3.9.2.6) will include a comparison between the measured and analytically determined responses and excitation to demonstrate the validity of the analytical techniques. An evaluation of the PVMP results with respect to design and test criteria will also be made to determine the margins associated with normal steady-state and anticipated transient operation.

3.9.2.5 Dynamic System Analysis of the Reactor Internals Under Faulted Condition

The analysis of reactor internals has been performed in accordance with the methods described in CESSAR Section 3.9.2.5. The calculated stresses are below the allowable stresses for faulted conditions of the ASME B&PV Code, Section III, Appendix F. (See Table 3.9.27A)

Dynamic analyses are performed to determine blowdown loads and structural responses of the reactor internals and fuel to postulated LOCA loadings and to verify the adequacy of their design. A brief description of these methods is provided below.

The LOCA maximum stress intensities in the reactor internals will be determined using the combinations of lateral and vertical LOCA time-dependent loadings which result in maximum stress intensities. The maximum LOCA stresses and the maximum stresses resulting from the SSE will then be combined using the root sum square method to obtain the total stress intensities.

3.9.2.5.1 Dynamic Analysis Forcing Functions

The hydrodynamic forcing functions during a postulated LOCA consist of transient pressure, flow rate, and density distributions throughout the primary reactor coolant system.

3.9.2.5.1.1 Hydraulic Pressure Loads

The transient pressure, flow rate and density distributions are computed for the subcooled and saturated portions of the blowdown period during a LOCA. The computer code utilized is

based on a node-flowpath concept in which control volumes (nodes) are connected in any desired manner by flow areas (flowpaths). A complex node-flow path network is used to model the Reactor Coolant System (RCS). The modeling procedure has been compared to a large scale experimental blowdown test with excellent agreement.

The laws of conservation of mass, energy and momentum along with a representation of the equation of state are solved simultaneously. The hydraulic transient of the reactor is coupled to the thermal response of the core by analytically solving the one dimensional radial heat conduction equation in each core node.

Pre-blowdown steady state conditions in the RCS are established through the use of specified input quantities.

The blowdown loads model uses a nonequilibrium critical flow correlation for computing the subcooled and saturated critical fluid discharge through the break.

3.9.2.5.1.2 Drag Loads

A break in the primary coolant system will result in large local pressure differences across various reactor vessel internal components and an acceleration of the local fluid velocity in various regions. The acceleration of the local fluid velocity can result in higher component drag loads than occur during steady state reactor operation.

3.9.2.5.1.3 Core Loads

The total instantaneous load across the core is given by the summation of the pressure forces acting in the direction of the pressure gradient and the drag forces acting parallel to the flow. The loads are obtained using a control volume approach utilizing an integrated fluid momentum equation. The drag forces are represented by the fluid shear term in this equation and consist of both frictional and form drag.

3.9.2.5.1.4 Control Element Tube Loads

During normal operation, the reactor coolant flows axially through the core into the upper guide structure. Within the upper guide structure, the coolant flow changes direction so that it exits radially through the hot leg nozzles. During a LOCA, the transverse flow of the coolant across the control element shroud tube gives rise to loads which induce deflections in these shrouds.

The transverse drag forces were determined from flow model experiments which were geometrically and dynamically similar to the full scale upper guide structure design. The measured experimental model forces were scaled up to represent the actual forces on the System 80 upper guide structure using the computed transient flow rate and density information.

3.9.2.5.1.5 Results of Blowdown Loads Analysis

Analysis was performed of a postulated pipe break at the reactor vessel inlet nozzle. The transient pressure differences throughout the vessel are evaluated and used in the

structural response calculation described below. The pressure difference across the core is also evaluated for the break.

A postulated pipe break occurring at the reactor vessel outlet nozzle was also analyzed. The pressure difference throughout the vessel is calculated. The decompression in the annulus is symmetric early in the transient because the pressure wave must travel through the core barrel internals to reach the lower plenum from where the wave propagates uniformly up through the downcomer. The axial pressure difference across the core was also calculated.

3.9.2.5.2 Structural Response Analyses

The dynamic LOCA analyses of the reactor internals and core determine the shell, beam and rigid body motions of the internals, using established computerized structural response techniques. The analyses consist basically of three parts. In the first part, the time-dependent shell response of the core support barrel to the transient loading is calculated using the finite-element computer code, ASHSD (section 3.9.1.2.3.4). The second part of the analysis evaluates the buckling potential of the core support barrel for hot leg break conditions using the finite-element computer code, SAMMSOR-DYNASOR (section 3.9.1.2.3.6). In the third part, the non-linear dynamic time history responses of the reactor internals and core to vertical and horizontal loads resulting from hot and cold leg breaks are determined with the CESHOCK code (paragraph 3.9.1.2.3.5).

3.9.2.5.2.1 Shell Response of the Core Support Barrel (CSB)

A cold leg break causes a pressure transient on the core support barrel that varies circumferentially as well as longitudinally. The ASHSD finite element computer code is used to analyze the shell response of the CSB to the pressure transient from a cold leg break.

The CSB is modeled as a series of shell elements joined at their nodal point circles as shown in Figure 3.9.2-2. The length of the elements in each model is selected to be a fraction of the shell attenuation length.

A damped equation of motion is formulated for each degree of freedom of the system. Four degrees of freedom, radial displacement, circumferential displacement, vertical displacement, and meridional rotation are considered in the analysis. The differential equations of motion are solved numerically using a step-by-step integration procedure.

The circumferential variation of the pressure time-history is considered by representing the pressure as a Fourier expansion. The pressure at each node in the model is determined by linear interpolation. Thus a complete spatial time load distribution compatible with the ASHSD computer program is obtained. Each load harmonic is considered separately by ASHSD. The results for each harmonic are then added to obtain the nodal displacements, resultant shell forces and shell stresses as a function of time.

3.9.2.5.2.2 Dynamic Stability Analysis of CSB

A hot leg break causes net external radial pressure on the core support barrel. A stability analysis of the CSB is performed using the finite-element computer code, SAMMSOR-DYNASOR. The effects of an initially imperfect shape based on the out-of-roundness tolerances are included in the analysis.

The CSB is modeled as a series of shell elements, as shown in Figure 3.9.2-10. Stiffness and mass matrices for the barrel are generated utilizing the SAMMSOR part of the code. The equations of motion of the shell are solved in DYNASOR using the Houbolt numerical procedure.

An initial imperfection is applied to the core support barrel by means of a pseudoload for each circumferential harmonic considered. The actual pressure transient loading generated by the outlet break is uniform circumferentially but varies longitudinally. The response is obtained for each of the imperfection harmonics.

Appendix F, Section III of the ASME Boiler and Pressure Vessel Code requires that permissible dynamic external pressure loads be limited to 75% of the dynamic instability pressure loads, or alternately, the dynamic instability load must be greater than 1.33 times the actual loads. Consequently, this analysis is repeated with the imperfection applied in the critical harmonic and the pressure loading is increased beyond 1.33 times the actual loads in order to demonstrate the stability of the core support barrel.

3.9.2.5.2.3 Dynamic System Analysis of the Reactor Internals

Dynamic analyses are performed to determine the structural response of the reactor internals to postulated asymmetric LOCA loading (including reactor vessel motion effects) and to verify the adequacy of their structural design. The postulated pipe breaks result in horizontal and vertical forcing functions which cause the internals to respond to both beam and shell modes.

Detailed structural mathematical models of the reactor internals are developed based on the geometrical design. These models are constructed in terms of lumped masses connected by beam or bar elements, and include non-linear effects such as impacting and friction. The models are developed for input to the CESHOCK code which solves the differential equations of motion for lumped parameter models by a direct step-by-step numerical integration procedure. The model definitions employ the procedures established in Combustion Engineering Topical Report CENPD-42 and, in addition, include hydrodynamic coupling effects and a detailed representation of the core support barrel to upper guide structure to reactor vessel interfaces. Separate models are formulated for the horizontal (Figure 3.9.2-11) and vertical (Figure 3.9.2-12) directions to more efficiently account for structural and response differences in those directions.

A revised horizontal model is used for the analysis of BLPB effects (Figure 3.9.2-11A).

The models for the horizontal directions are developed in terms of lumped masses connected by beam elements. The stiffness

values for the beam elements are generally evaluated using beam characteristic equations. The lumped-mass weights are based upon the mass distribution of the internals structures. Local masses such as plates and snubber blocks are included at appropriate nodes. The effect of the surrounding water on the dynamics of the internals for horizontal motion is accounted for by hydrodynamically coupling the components separated by a narrow annulus - the vessel, core barrel, and core shroud. The clearance between the core support barrel and the reactor vessel snubbers, as well as the clearance between the core shroud, guide lugs and the fuel alignment plate is simulated by non-linear springs which account for the loads generated when impacting occurs. A representation of the core is included in the internals models which provides appropriate inertial and impact feedback effects on the internals response.

The vertical model stiffness values are generally calculated using bar characteristic equations. Non-linear couplings are included between components to account for structural interactions such as those between the fuel and core support plate, and between the core support barrel and upper guide structure upper flanges. Pre-loads, which are caused by the combined action of applied external forces, dead weights, and holddowns are also included. Friction elements are used to simulate the coupling between the fuel rods and spacer grids.

A reduced model of the reactor vessel internals (Fig. 3.9.2-13) is developed for incorporation into the reactor coolant system model. The detailed non-linear horizontal and vertical internals (plus core) models are condensed and combined into a three-dimensional model compatible with the reactor coolant

system model and the computer programs through which the latter model is analyzed. The purpose of this reduced internals model is to account for the effects of the internals LOCA loads on the reactor vessel support motion and the structural loading interaction between the internals and the vessel. The reduced internals model is developed so as to produce reactor vessel support motions and loadings equivalent to those produced by the detailed internals models.

The dynamic responses of the reactor internals to the postulated pipe breaks are determined with the CESHOCK code utilizing the detailed models. Horizontal and vertical analyses are performed for both hot and cold leg breaks to determine the lateral and axial responses of the internals to the simultaneous internal fluid forces and vessel motion excitation.

The vertical excitation of the internals is calculated by the LOAD2 computer code (section 3.9.1.2.3.10) using a control volume method of analysis. In this method, the reactor internals are subsectioned and enclosed within volumes of solid plus fluid. The momentum equation is then applied to each volume, and a resultant force is calculated which is assigned to the structural node within the volume. This method takes into consideration pressure, fluid friction, momentum changes, and gravitational forces acting on each volume. The resulting load time histories are in a form consistent for CESHOCK code input.

In order to achieve an initial (prior to the pipe break) equilibrium, the initial static deflections and gaps are

calculated. The resulting initial conditions and load time histories are input to the CESHOCK code and the dynamic response of the model is calculated.

The horizontal input excitation resulting from a cold leg break are the core support barrel force time history and the vessel motion time history determined from the reactor coolant system analysis. The core support barrel forces are obtained by representing the asymmetric pressure distribution time history as a Fourier expansion. The two terms (sin θ and cos θ) which excite the beam mode of vibration are then integrated over the core support barrel and transformed into nodal force time histories.

The horizontal input excitation resulting from a hot leg break are the CEA shroud crossflow load time histories and the vessel motion time history determined from the reactor coolant system analysis. The forces applied to the shroud mass points are determined directly from the blowdown pressure time history and include the drag force and forces due to the pressure differential on the shrouds.

The results from these analyses consist of time dependent member forces, and nodal displacements, velocities, and accelerations. The load and displacement responses are used in the detailed stress analyses of the internals.

3.9.2.5.2.3.1 Dynamic System BLPB Analysis of the Reactor Internals

Dynamic BLPB analyses are performed to determine the structural responses of the reactor internals considering the effects of

the steam generator and value added fuel. The methodology used is the same as described in Section 3.9.2.5.2.3 except that the horizontal direction reactor internals model uses a single grouping to represent all of the fuel assemblies. This is done because the BLPB responses of the core boundary in the internals evaluation are low and no impacting of the peripheral assemblies occurs. The fuel assembly deflected shapes at times of peak relative displacement, shear and bending moments are determined using the results of a detailed core analysis of the shortest (7 assemblies) row across the core.

3.9.2.6 Correlations of Reactor Internals Vibration Tests with the Analytical Results

Comparison of analytical predictions with data obtained from precritical program will be addressed in an evaluation report, to be submitted shortly after completion of testing.

Table 3.9-4

DESIGN STRESS LIMITS FOR CLASS 2 AND 3 VESSELS, PUMPS, AND VALVES

(Sheet 1 of 2)

Component \ Plant Condition	Design[(a)] and Normal	Upset[(a)]	Emergency[(a)]	Faulted[(a)]
ASME Code Class 2 and 3 vessels	ASME Section VIII Division 1	$\sigma_m \leq 1.1S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 1.65S$	$\sigma_m \leq 1.5S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 1.80S$	$\sigma_m \leq 2.0S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 2.4S$
ASME Code Class 2 and 3 inactive pumps	ASME Section III NC-3400 or ND-3400	$\sigma_m \leq 1.1S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 1.65S$ $P_{max} \leq 1.1$ PD	$\sigma_m \leq 1.5S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 1.80S$ $P_{max} \leq 1.2$ PD	$\sigma_m \leq 2.0S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 2.4S$ $P_{max} \leq 1.5$ PD
ASME Code Class 2 and 3 active pumps	ASME Section III NC-3400 or ND-3400	$\sigma_m \leq 1.0S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 1.5S$ $P_{max} \leq 1.1$ PD	$\sigma_m \leq 1.1S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 1.65S$ $P_{max} \leq 1.2$ PD	$\sigma_m \leq 1.2S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 1.8S$ $P_{max} \leq 1.5$ PD
ASME Code Class 2 and 3 active and inactive valves (See notes 1 to 5 and 7)	Valve bodies shall conform to the requirements of ASME Section III NC-3500 or ND-3500	$\sigma_m \leq 1.1S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 1.65S$ $P_{max} \leq 1.1$ PD or rated pressure (see note 6)	$\sigma_m \leq 1.5S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 1.80S$ $P_{max} \leq 1.2$ PD or rated pressure (see note 6)	$\sigma_m \leq 2.0S$ $(\sigma_m$ or $\sigma_L) + \sigma_b \leq 2.4S$ $P_{max} \leq 1.5$ PD or rated pressure (see note 6 and 7)

a. Stress limits are found in the applicable code cases as discussed in UFSAR section 1.8, Regulatory Guide 1.48 Response B.

Table 3.9-4
DESIGN STRESS LIMITS FOR CLASS 2 AND 3 VESSELS, PUMPS, AND VALVES
(Sheet 2 of 2)

Definitions

σ_m = general membrane stress. This stress is equal to the average stress across the solid section under consideration. It excludes discontinuities and concentrations and is produced only by mechanical loads.

σ_L = local membrane stress. This stress is the same as σ_m except that it includes the effect of discontinuities.

σ_b = bending stress. This stress is equal to the linearly varying portion of the stress across the solid section under consideration. It excludes discontinuities and concentrations and is caused by mechanical loads only.

S = allowable stress values given in Tables I-7.1, I-7.2 and I-7.3 of Appendix I of the Section III Code. The allowable stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

P_{max} = maximum pressure resulting from upset, emergency, or faulted conditions.

The term "stress" in above definitions means maximum normal stress.

Notes pertaining to ASME Code Class 2 and 3 valves (active and inactive)

1. Valve nozzle (piping load) stress analysis is not required when both of the following conditions are satisfied by calculation:
   a. Section modulus and area of a plane, normal to the flow, through the region of valve body crotch is at least 10% greater than the piping connected (or joined) to the valve body inlet and outlet nozzles.
   b. Code allowable stress, S, for valve body material is equal to or greater than the code allowable stress, S, of connected piping material.

   If the valve body material allowable stress is less than that of the connected piping, the valve section modulus and area as calculated in a. above shall be multiplied by the ratio of S_{pipe}/S_{valve}. If unable to comply with this requirement, the design by analysis procedure of NB-3545.2 is an acceptable alternate method.
2. Casting quality factor of 1.0 shall be used.
3. These stress limits are applicable to the pressure retaining boundary, and include the effects of loads transmitted by the extended structures, when applicable.
4. Design requirements listed in this table are not applicable to valve discs, stems, seat rings, or other parts of valves that are contained within the confines of the body and bonnet, or otherwise are not part of the pressure boundary.
5. These rules do not apply to Class 2 and 3 safety relief valves. Safety relief valves will be designed in accordance with ASME Section III requirements.
6. Maximum pressure should not exceed the rated pressure of valve at the applicable plant conditions.
7. The PVNGS 120 day response to NRC Generic Letter 96-06, was transmitted to the NRC under APS Letter 102-03855-JML/AKK/JRP dated January 28, 1997. This response stated that the as built penetration configurations which do not have installed relief valves were evaluated and accepted by the NRC during initial PVNGS licensing and documented by reference in the PVNGS Safety Evaluation Report. PVNGS response to a request for additional information from the NRC provided, under APS Letter 102-04130-JML/SAB/RMW, dated June 4, 1998, detailed information on the methodology utilized to predict the response of the containment penetrations to thermally induced over-pressurization due to a LOCA. This response identified the use of ASME B&PV Code, Section III, Division 1-1974 Edition with Winter 1975 Addenda, Appendix F-1000 in the evaluation of the containment penetration piping and valve components as well as the reduction of fastener torque in the body to bonnet joint for some of the containment isolation valves. The maximum internal pressure that the valves are allowed to withstand was determined based on the elastic faulted stress method of ASME Code Section III, Division 1 – 1974 Edition, with Winter 1975 Addenda, paragraphs NB-3221, NB-3545.2 and Appendix F-1000, Subsection F1323.1(b).

Table 3.9-5

DESIGN CRITERIA FOR ASME CODE CLASS 1

BECHTEL-SUPPLIED PIPING

Condition	Stress Limits[a]
Normal	NB-3653
Upset	NB-3654
Emergency	NB-3655
Faulted	NB-3656

a. As specified by ASME Section III, including the Winter 1975 addenda (Summer 1979 addenda for Subsections NB 3650 through NB 3680)

Table 3.9-6
DESIGN CRITERIA FOR ASME CODE CLASS 2 AND 3
BECHTEL-SUPPLIED PIPING

Condition	Stress Limits
Normal, Upset, and Emergency	The piping shall conform to the requirements of Section III, Paragraphs NC-3600 and ND-3600
Faulted	The piping shall conform to the requirements of ASME Code Case 1606

Table 3.9-7
DESIGN CRITERIA FOR BOLTED SUPPORTS OF
ASME SECTION III COMPONENTS

	STRESS LIMITS[(a)]	
Plant Condition	Tension	Shear
Normal	$F_{tb} = \frac{S_u}{2}$	$F_{vb} = \frac{0.62\ S_u}{3}$
Upset	$F_{tb} = \frac{S_u}{2}$	$F_{vb} = \frac{0.62\ S_u}{3}$
Emergency	$F_{tb} = \frac{2}{3} S_u$	$F_{vb} = \frac{4}{3} \quad \frac{0.62\ S_u}{3}$
Faulted	$F_{tb} = 0.7\ S_u$ or $0.9\ S_y$ whichever is less	$F_{vb} = 0.5\ S_y$

a. F_{tb} = Allowable tensile stress

F_{vb} = Allowable shear stress

S_u = Ultimate tensile stress of bolting material

S_y = Yield stress of bolting material

Table 3.9-8
DESIGN LOADING COMBINATIONS FOR ASME SECTION III
CODE CLASS 1 PIPING AND SUPPORTS OUTSIDE THE
COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 1 of 2)

Plant Condition	Piping	Supports
Design	PD	DW
Normal	PO + DW	DW + TH
Upset[(a)]	[(a)]PO + DW + OBE + RVC	DW + TH + OBE + Eq + RVC
	[(a)]PO + DW + DU PO + DW + RVC	DW + TH + DU DW + TH + RVC
Emergency	PO + DW + OBE + RVC	DW + TH + OBE + Eq + RVC
Faulted	PO + DW + SSE + RVC	DW + TH + SSE + Eq sse + RVC
	PO + DW + SSE + DF	DW + TH + SSE + Eq sse + DF

a. As required by the appropriate subsection, i.e., NB or NF, of ASME Section III, Division I, other loads, such as thermal transient, thermal gradients, and anchor point displacement portion of the OBE, may require additional consideration in addition to those primary stress-producing loads listed.

b. Thermal plant condition -- This condition is associated with thermal expansion stresses and stresses associated with earthquake anchor point displacement (piping only).

c. Load combination based on a linear elastic analysis.

d. Absolute value combination method for stresses and loading derived from an elastic/plastic analysis.

e. LOCA includes jet impingement, pipe whip, and LOCA-induced motion when applicable.

f. Load combination may be used for safety injection lines.

Table 3.9-8

DESIGN LOADING COMBINATIONS FOR ASME SECTION III CODE CLASS 1 PIPING AND SUPPORTS OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 2 of 2)

Plant Condition	Piping	Supports
	(c) $PO + DW + [(LOCA^{(e)})^2 + (SSE)^2]^{1/2}$	(c) $DW + TH + [(LOCA^{(e)})^2 + (SSE + Eq\ sse)^2]^{1/2}$ (f) $DW + TH + [(LOCA^{(e)})^2 + (SSE)^2 + (Eq\ sse)^2]^{1/2}$
	(d) $PO + DW + LOCA^{(e)} + SSE$	(d) $DW + TH + LOCA^{(e)} + SSE + Eq\ sse$ (f) $DW + TH + [(LOCA^{(e)})^2 + (SSE)^2 + (Eq\ sse)^2]^{1/2}$
Thermal	(b) Se + Eq	

Loads:

PD = Design pressure

PO = Operating pressure

DW = Piping dead weight

OBE = Operating basis earthquake (inertia portion)

SSE = Safe shutdown earthquake (inertia portion)

FV = Fast valve closure

Se = Thermal expansion stress

Eq = Earthquake (anchor point displacement OBE)

Eq sse = Earthquake (anchor point displacement SSE)

DF = Dynamic events associated with the faulted condition

RVC = Relief valve -- closed system (transient)

RVO = Relief valve -- open system (sustained)

DU = Other transient dynamic events associated with the upset plant condition

TH = Loading resulting from piping system thermal expansion

Note: Stresses from the above loading conditions are directly additive.

Table 3.9-9

DESIGN CRITERIA FOR ASME CODE CLASS 1
BECHTEL-SUPPLIED SUPPORTS

	Conditions[a]				
Support Type	Design	Normal	Upset	Emergency	Faulted
Plate and shell design by analysis	NF-3221	NF-3222	NF-3223	NF-3224	NF-3225
Linear type supports by analysis	NF-3231	NF-3231	NF-3231	NF-3231	NF-3231
Component standard supports design by analysis	NF-3240	NF-3240	NF-3240	NF-3240	NF-3240
Component supports design by load rating	NF-3260	NF-3260	NF-3260	NF-3260	NF-3260

a. Refer to ASME Code, Section III, Subsection NF.

Table 3.9-10

DESIGN LOADING COMBINATIONS FOR ASME SECTION III
CODE CLASS 2 AND 3 COMPONENTS AND SUPPORTS OUTSIDE THE
COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 1 of 3)

Plant Condition	Piping	Supports
Design	PD	DW
Normal	PO + DW	DW + TH
Upset	PO + DW + OBE	DW + TH + OBE + Eq
	PO + DW + FV	DW + TH + FV
	PO + DW + RVO + OBE	DW + TH + OBE + Eq + RVO
	PO + DW + DU	DW + TH + DU
Emergency	PO + DW + OBE + FV	DW + TH + OBE + Eq + FV
Faulted	PO + DW + SSE + RVO	DW + TH + SSE + Eq sse + RVO
	PO + DW + SSE + FV	DW + TH + SSE + Eq sse + FV
	PO + DW + SSE + [(g)] DF	DW + TH + SSE + Eq sse + [(g)] DF
	PO + DW + SSE + [(g)] DF	[(e)] $DW + TH + [(SSE)^2 + (Eq\ sse)^2]^{1/2}$ + [(g)] DF

a. Thermal plant condition -- This condition is associated with thermal expansion stresses and stresses associated with earthquake anchor point displacement (piping only).

b. Load combination based on a linear elastic analysis.

c. Absolute value combination method for stresses and loading derived from an elastic/plastic analysis.

d. LOCA includes jet impingement, pipe whip, and LOCA-induced motion when applicable.

e. Load combination may be used only in determining acceptability of unrestrained piping uplift at support locations.

Table 3.9-10

DESIGN LOADING COMBINATIONS FOR ASME SECTION III CODE CLASS 2 AND 3 COMPONENTS AND SUPPORTS OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 2 of 3)

f. The PVNGS 120 day response to NRC Generic Letter 96-06, was transmitted to the NRC under APS Letter 102-03855-JML/AKK/JRP dated January 28, 1997. This response stated that the as built containment penetration configurations which do not have installed relief valves were evaluated and accepted by the NRC during initial PVNGS licensing and documented by reference in the PVNGS Safety Evaluation Report. PVNGS response to a request for additional information from the NRC provided, under APS Letter 102-04130-JML/SAB/RMW, dated June 4, 1998, detailed information on the methodology utilized to predict the response of the containment penetrations to thermally induced over-pressurization due to a LOCA. This response identified the use of ASME B&PV Code, Section III, Division 1-1974 Edition with Winter 1975 Addenda, Appendix F-1000 in the evaluation of the containment penetration piping and valve components as well as the reduction of fastener torque in the body to bonnet joint for some of the containment isolation valves. The maximum internal pressure that the piping is allowed to withstand was determined based on the ASME Code Section III, Division 1-1974 Edition, with Winter 1975 Addenda, Appendix F-1000, Subsection F1321.1(e) and F1324.4, which provide a maximum allowable of 70% of the Plastic Instability Load.

g. Dynamic events associated with the faulted condition (DF) loads do not include water hammer (WH) loads caused by voiding in normally filled lines (i.e., - WH loads used for the purpose of determining allowable void sizes in accordance with Generic Letter 2008-01).

Table 3.9-10

DESIGN LOADING COMBINATIONS FOR ASME SECTION III CODE CLASS 2 AND 3 COMPONENTS AND SUPPORTS OUTSIDE THE COMBUSTION ENGINEERING SCOPE OF SUPPLY (Sheet 3 of 3)

Plant Condition	Piping	Supports
	(b) PO + DW + $[(\text{LOCA}^{(d)})^2 + (\text{SSE})^2]^{1/2}$	(b) DW + TH + $[(\text{LOCA}^{(d)})^2 + (\text{SSE + Eq sse})^2]^{1/2}$
	(c) PO + DW + LOCA(d) + SSE	(c) DW + TH + LOCA(d) + SSE + Eq sse
Thermal(a)	Se + Eq	
Thermally induced over-pressurization	(see item f)	

<u>Loads</u>:

PD	=	Design pressure
PO	=	Operating pressure
DW	=	Piping dead weight
OBE	=	Operating basis earthquake (inertia portion)
SSE	=	Safe shutdown earthquake (inertia portion)
FV	=	Fast valve closure
Se	=	Thermal expansion stress
Eq	=	Earthquake (anchor point displacement OBE)
Eq sse	=	Earthquake (anchor point displacement SSE)
DF	=	Dynamic events associated with the faulted condition
RVC	=	Relief valve -- closed system (transient)
RVO	=	Relief valve -- open system (sustained)
DU	=	Other transient dynamic events associated with the upset plant condition
TH	=	Loading resulting from piping system thermal expansion

Note: Stresses from the above loading conditions are directly additive.

MECHANICAL SYSTEMS AND COMPONENTS

3.9-11
DESIGN CRITERIA FOR ASME CODE CLASS 2 AND 3
BECHTEL-SUPPLIED SUPPORTS

Support Type	Conditions[a]				
	Design	Normal	Upset	Emergency	Faulted
Plate and shell design by analysis	NF-3221	NF-3321	NF-3321	$\sigma 1 \leq 1.25^{(b)}$ σ_1 the lesser of and 1.5 S or $0.4S_{\mu}^{(c)}$ $\sigma 1 + \sigma 2 \leq 1.85$ $\sigma 1 + \sigma 2 \leq$ the lesser of 2.555 or $0.6S_{\mu}$	
Linear	NF-3231	NF-3231	NF-3231	NF-3231	NF-3231
Component standard supports design by analysis	NF-3221 or NF-3231	NF-3222 or NF-3231	NF-3223 or NF-3231	NF-3224 or NF-3231	NF-3225 or NF-3231
Component supports design by load rating[a]	NF-3260	NF-3260	NF-3260	NF-3260	NF-3260

a. Refer to ASME Code, Section III, Subsection NF.

b. $\sigma 1$ and $\sigma 2$ are defined in NF-3321.1.

c. S_{μ} = minimum ultimate tensile strength of material from Table I-12.1.

Table 3.9-12
DESIGN LOADING COMBINATIONS FOR BOLTED SUPPORTS
OF ASME SECTION III COMPONENTS

Plant Condition	Design Loading Combinations
Normal	$D + T_o + R_o$
Upset	$D + T_o + R_o + E$
Emergency	$D + T_o + R_o + E'$
Faulted	$D + P_a + T_a + R_a$
	$D + P_a + T_a + R_a + E' + Y_r + Y_j + Y_m$

Loads:

D = Dead load
T_o = Operating thermal load
R_o = Pipe reactions (operating or shutdown)
E = OBE
E' = SSE
P_a = Accident pressure load
R_a = Pipe reactions due to postulated break
Y_r = Pipe whip load
Y_j = Jet impingement load
Y_m = Missile impact load

3.9.3 ASME CODE CLASS 1, 2, AND 3 COMPONENTS, COMPONENT SUPPORTS, AND CORE SUPPORT STRUCTURE.

Refer to section 3.9.3.5 and 3.9.3.6 for components in the C-E scope of supply, except that the following valves are added to the list of NSSS Seismic I Active Valves in Table 3.9.3-3, sheet 7 of 8:

Valve No.	System Name (Safety Function)	Line Size	Valve Type	ASME Section III Code Class	Actuator Type
CH 501	Volume Control Tank Discharge Isolation (Close)	4	Gate	2	Motor
CH 536	RWT Gravity Feed to Charging Pump Suction (Open)	4	Gate	3	Motor

The subsections 3.9.3.1 through 3.9.3.4 apply to all components not in the C-E scope of supply.

For plant conditions and loading combinations, the requirements of Regulatory Guide 1.48 are met except as noted in section 1.8.

3.9.3.1 Loading Combinations, Design Transients, and Stress Limits

Non-NSSS ASME Class 2 and 3 components and supports and ASME Class 1 piping are designed to an appropriate combination of plant conditions and design loadings. The plant conditions are design, normal, upset, emergency, faulted, and thermal conditions. The design loadings are pressure, temperature, dead weight, seismic, and dynamic loads.

The plant conditions and design loading combinations for ASME Code Class 1 piping outside the C-E scope of supply are indicated in table 3.9-8. Stress limits for Class 1 supports, bolting, and piping outside the C-E scope of supply are indicated in tables 3.9-9, 3.9-7, and 3.9-4, respectively.

The plant conditions and design loading combinations for ASME Code Class 2 and 3 components and supports outside the C-E scope of supply are indicated in table 3.9-10. Stress limits for Class 2 and 3 supports, bolting, piping and vessels, pumps, and valves are indicated in tables 3.9-11, 3.9-7, 3.9-6, and 3.9-4, respectively.

The methodology used for combining responses meets the requirements of NUREG-0408, Revision 1.

Piping components in essential ASME Code Class 1, 2, and 3 piping systems designed to level C or D service limits were shown to retain functionability for emergency and faulted plant conditions by meeting the screening criteria found in GE Topical Report, "Functional Capability Criteria for Essential Mark II Piping," (NEDO-21985), dated September 1978 (reference NRC memorandum to R. L. Tedesco, Assistant Director for Licensing, from J. P. Knight, Assistant Director for Components and Structures Engineering, dated July 17, 1980).

3.9.3.1.1 Design Load Combinations and the Associated Operating Plant Condition

3.9.3.1.1.1 Design and Normal Conditions. The design and normal conditions are as defined in NB-3112 and NB-3113 of ASME B&PV Code, Section III.

3.9.3.1.1.2 Upset Condition. Loads that are considered in upset plant operating conditions (defined in ASME Section III as those having a high probability of occurrence) include the following:

- Operating pressure
- Operating temperature
- Deadweight
- Open relief valve thrust
- Transient pressure effects
  - Fast valve closure
  - Closed relief valve discharges
- Earthquake (OBE)

Although the occurrence of an earthquake cannot be considered highly probable, the number of cycles associated with a seismic event are considered with the low stress allowables of the upset plant condition.

It should be noted that two different types of relief valves are categorized, open discharge and closed discharge, as described in paragraph 3.9.3.3.

The open discharge relief valve has a continuous blowdown thrust that can occur for a period of tens of seconds to minutes. The associated piping must be designed for this thrust. Since the maximum stress due to the relief valve thrust occurs over a significant period of time, coincident earthquake and relief stresses are assumed.

The case, however, for a closed discharge system is much different. During the long-term blowdown following the establishment of steady-state flow, the reactions on the discharge piping, relief valve, and inlet piping are balanced and no stresses are introduced as a result of relief valve blowdown. The time duration for the stresses induced during the transient preceding steady-state flow is approximately 500 milliseconds. After this period of time, the effects from valve blowdowns are damped out.

The results of time-history dynamic analysis, using very conservative damping ratios (0.5%), show that 3 to 10 stress cycles occur before steady-state blowdown.

It may be argued that an earthquake can cause a plant trip and consequential relief valve actuation. However, the probability of the maximum stresses from these transients (in a time sense) occurring at the same location, at the same instant in time and in place, is extremely low.

Further, the number of cycles (3 to 10) during which both are occurring also is extremely low.

Therefore, it is concluded that the combination of loads resulting from the OBE and the transient induced by relief valve actuation in a closed discharge system is not an upset plant condition. The same argument is made for the fast valve closure event. An example of this is the trip of the main steam turbine stop valves.

3.9.3.1.1.3 Emergency Conditions. Load combinations falling into this category are of low probability of occurrence.

Therefore, a higher design stress is allowed since the number of cycles is low. The coincident effects of OBE and transient pressures (discussed under upset) are evaluated as an emergency plant condition.

3.9.3.1.1.4 Faulted Condition. For the faulted condition, ASME piping, vessels, pumps, and valves are analyzed to the three design loading combinations shown in tables 3.9-8 and 3.9-10.

3.9.3.1.2 Design Stress Limits

3.9.3.1.2.1 ASME Code Class 2 and 3 Components. Stress limits on valves, pumps, and vessels are given in table 3.9-4.

3.9.3.1.2.2 ASME Code Class 2 and 3 Piping. Stress limits on piping are given in the subsequent listing:

A. Normal Conditions

Calculated stresses due to sustained loads and thermal expansion shall conform to the requirements of ASME Section III, NC-3600 or ND-3600. For calculated stresses due to occasional loads, the following shall be used.

B. Upset Conditions

The sum of stresses produced by loading combinations shown in table 3.9-10 for upset condition shall not exceed 1.2 times the allowable stress values given in Tables I-7.1, 1-7.2, and 1-7.3 of Appendix I of the ASME Code Section III or ND-3600. Under upset

conditions, Equation 9 of NC-3650 or ND-3650 shall be met (permissible pressure $\leq$1.1p).

C. Emergency Conditions

The sum of the stresses produced by the loading combinations shown in table 3.9-10 for emergency conditions shall not exceed 1.8 times the allowable stress values given in Tables I-7.1, I-7.2, and I-7.3 of Appendix I of the ASME Code, Section III. Under emergency conditions, Equation 9 of NC-3650 or ND-3650 shall be met using a stress limit of 1.8 S_h. Equations 8, 10, and 11 shall not be considered.

The permissible pressure shall not exceed 1.5 times the design pressure (P) calculated in accordance with Equation 4 of NC-3641.1.

D. Faulted Conditions (Code Case 1606)

The sum of the stresses produced by the loading combinations shown in table 3.9-10 for faulted condition shall not exceed 2.4 times the allowable stress values given in Tables I-7.1, I-7.2, and I-7.3 of ASME Code, Section III, Appendix I. Under faulted conditions, Equation 9 of NC-3650 shall be met using a stress limit of 2.4 S_h. Equations 8, 10, and 11 shall not be considered.

The permissible pressure shall not exceed 2.0 times the design pressure (P) calculated in accordance with Equation 4 of NC-3641.1.

3.9.3.1.2.3 ASME Code Class 1 Piping. Stress limits on ASME Code Class 1 piping not provided by C-E are given in table 3.9-5.

3.9.3.2 Pump and Valve Operability Assurance

3.9.3.2.1 Non-C-E-Supplied Active ASME Code Class 2 and 3 Pumps and Class 1, 2, and 3 Valves.

3.9.3.2.1.1 Pumps. Non-C-E-supplied, safety-related active pumps are subjected to in-shop tests which include hydrostatic tests of casing to 150% of the design pressure, and performance tests to determine total developed head, minimum and maximum head, net positive suction head (NPSH) requirements except as noted below, and other pump/motor characteristics. Where applicable, bearing temperature and vibration are monitored during the performance tests. For the diesel fuel oil transfer pumps, the NPSH data were developed by actual developmental testing of pumps of the same size. For the essential spray pond pumps, submergence is the relative parameter used to satisfy the NPSH requirement.

In addition to the required testing, the pumps are designed and supplied in accordance with the following specified criteria:

A. In order to ensure that the active pump will not be damaged during the seismic event, test or analysis is required to show that the lowest natural frequency of the pump is greater than 33 Hz. If the natural frequency is found to be above 33 Hz, the pump will be considered essentially rigid. This frequency is considered sufficiently high to avoid problems with

amplification between the component and structure for all seismic areas. A static shaft deflection analysis of the rotor is performed. The natural frequency of the support is determined and used in conjunction with the project seismic response spectra. The deflection determined from the static shaft analysis is compared to the allowable rotor clearances.

If the natural frequency is found to be below 33 Hz, an analysis is performed to determine the amplified input accelerations necessary to perform the static analysis. The static deflection analyses are performed using the adjusted accelerations.

B. The maximum seismic nozzle loads are also considered in an analysis of the pump supports to assure that unacceptable system misalignment cannot occur.

C. To complete the seismic qualification procedures, the pump motor and appurtenances vital to the operation of the pump are independently qualified for operation during the maximum seismic event in accordance with IEEE Standard 344-1975. If the testing option is chosen, sine-beat or sweep testing for the electrical equipment is justified by satisfying one or more of the following requirements to demonstrate that multifrequency response is negligible or the sine-beat or sine-sweep input is of sufficient magnitude to conservatively account for this effect:

1. The equipment response is basically due to one mode.

2. The sine-beat response spectra envelops the floor response spectra in the region of significant response.

3. The floor response spectra consists of one dominant mode and has a narrow peak at this frequency.

The degree of coupling in the equipment, in general, determines if a single or multiaxis test is required. Multiaxis testing is required if there is considerable cross-coupling. If coupling is very light, then single-axis testing is justified. Or, if the degree of coupling can be determined, then single-axis testing can be used with the input sufficiently increased to include the effect of coupling on the response of the equipment.

From this, it is concluded that the safety-related pump/motor assemblies will not be damaged and will continue operating under SSE loadings, and will perform their intended functions. These proposed requirements take into account the complex characteristics of the pump and are sufficient to demonstrate and assure the seismic operability of the active pumps. Results of these analyses are contained in the following paragraphs. For the results of pump motor seismic operability analyses refer to section 3.10.

3.9.3.2.1.1.1 Essential Cooling Water Pumps. A structural integrity and operability analysis of the essential cooling water pump (Ingersoll-Rand Model 16 x 23 S pump) was performed.

The components analyzed are those that comprise the pressure boundary, the rotating member, and the attachment of the pump/motor to the floor.

Tables 3.9-13 and 3.9-14 list the most important stresses and deflections. The upset condition was not analyzed as the emergency condition was more significant. The calculated stresses were within the allowable stress limits.

Two sets of figures for the shaft deflections are listed in table 3.9-14. The first numbers are the maximum sums of weight, g loads, and hydraulic loads, all assumed to act in the same direction. The numbers in parentheses represent expected normal or maximum deflections based on the following considerations: the normal deflection at the coupling, in reality, becomes zero when the pump and motor is aligned in the field; the shaft deflection relative values are reduced when the pump rotor is aligned. The impeller to casing ring clearance is equalized for 360 degrees during pump alignment and the bearing housing is pinned to the casing to prevent movement. The shaft deflection at the casing ring cannot exceed one-half of the ring clearance. Beyond this point, the casing ring acts as a bearing, during which time a hydrodynamic film is generated, maintaining a finite clearance between the rotor and casing.

MECHANICAL SYSTEMS AND COMPONENTS

Table 3.9-13
ESSENTIAL COOLING WATER PUMP SUMMARY OF STRESSES
(Sheet 1 of 2)

Part	Condition	Category[a]	Stress (KSI) Calculated	Stress (KSI) Allowable
Casing	Normal	S_m	11.5	14.0
Casing bolts	Normal	S_t	11.6	25.0
Gland bolts	Normal	S_t	1.7	25.0
Shaft	Normal	S_b	1.9	13.4[b]
	Normal	S_s	3.1	6.0[b]
	Normal	S_{tp}	4.3	13.4[b]
	Normal	S_{sp}	3.2	6.0[b]
	Faulted	S_{tp}	6.8	20.1[b][c]
	Fatigue	S_t	7.6	10.5
Wear ring	3g	S_c	0.7	44.0
Suction nozzle flange	Normal	S_t	16.3	21.0
	Faulted	S_t	22.0	25.2
Discharge nozzle flange	Normal	S_t	10.9	21.0
	Faulted	S_t	16.2	25.2
Motor bolt	Faulted	S_t	11.4	35.6

a. S_m membrane; S_b bending; S_t tension; S_s shear; S_{tp} principal tension; S_{sp} principal shear; S_c Bearing; S_1 Local

b. Suppliers allowable

c. 1.8 (13.4) = 24.1

Table 3.9-13
ESSENTIAL COOLING WATER PUMP SUMMARY OF STRESSES
(Sheet 2 of 2)

Part	Condition	Category[a]	Stress (KSI)	
			Calculated	Allowable
Motor pin	Faulted	S_s	25.0	25.2
Motor mtg pl bolt	Faulted	S_t	2.8	22.0
Motor mtg pl weld	Faulted	S_s	1.7	18.0
Pump bolt	Faulted	S_t	33.5	40.5
Pump pin	Faulted	S_s	24.9	27.3
Pump mtg pl bolt	Faulted	S_t	16.8	22.0
Pump mtg pl weld	Faulted	S_s	2.5	18.0
Pump foot	Normal	S_t	1.5	21.0
Pump foot	Faulted	S_t	6.1	21.0
Mounting plate	Faulted	S_t	6.6	21.6

Table 3.9-14
ESSENTIAL COOLING WATER PUMP SUMMARY OF DEFLECTIONS

Location	Condition	Shaft Deflection (in.)
Impeller	Normal	0.0071 (0.0052)[a]
Casing rings	Normal	0.0066 (0.0047)[a]
Casing rings	3g	0.0188 (0.0169)[a]
Coupling	Normal	0.0061 (0)[b]
Coupling	3g	0.0170 (0.0109)[b]

a. After pump rotor alignment - relative values

b. After field alignment of pump + motor - relative values

Holddown bolting and shear pin loads are analyzed using a computer program to calculate the reactions at the pump/supporting structure interface. These reactions are then used to determine bolt stresses, shear pin stress, and the stresses in the pump casing feet.

The reactions are obtained by applying the external forces and moments along with the deadweight, seismic accelerations, driving torque, and, using the principles of statics, individual forces are determined. Maximum values are summed for a conservative analysis.

The program was checked by an independent reviewer and verified by a hand calculation.

Nozzle flange stresses are analyzed using a computer program to calculate the longitudinal hub stress, radial flange stress, and tangential flange stress in accordance with the ASME B&PV

Code, Section III, Subsection NA, Appendix XI and Subsection NC, Paragraph 3647.1.

This procedure incorporates the contribution of the external nozzle loads and internal pressure in the form of an equivalent pressure.

The program was checked by an independent reviewer and verified by hand calculation.

The natural frequency of vibration of the pump-motor assembly is shown to be above 33 Hz based on the detailed analysis of two directly comparable pumps. This detailed analysis is based on multidegree of freedom mathematical model and a structural mechanics computer program. The numerical value of the important parameters that determine the natural frequency of vibration are listed in table 3.9-15 for the essential cooling water pump.

Based on this comparison of the parameters, the natural frequency of vibration of the 16X23S pump-motor assembly will be above 33 Hz.

Past inservice experience with other pumps of this type indicates that the pump is capable of operating in a safe manner. The pump meets the performance criteria for structural integrity and operability in accordance with the design specification.

Table 3.9-15
COMPARISON OF LEADING PARAMETERS USED IN THE DETERMINATION OF EQUIPMENT NATURAL FREQUENCY OF VIBRATION - ESSENTIAL COOLING WATER PUMP

Pump Report No.	6X18SE EAS-TR-7720-PSI	14X23S EAS-TR-7535-N	16X23S EAS-TR-7722-GN
1. Calculated equipment W_n using ANSYS, Hz	77.8	59.0	--
2. Shaft lateral W_n, Hz	106.5	67.18	53.2
3. Distance between bearing C, in.	30.0	46.87	50.0
4. Average shaft diameter, in.	2.47	3.5	3.88
5. Rotor weight, lb.	130	357	550
6. Pump weight, lb	1500	3950	4400
7. Average pump casing thickness, in.	0.625	0.625	0.75
8. Bearing housing overhang, in.	3.5	3.75	4.0
9. Height of shaft from ground, in.	37.0	41.5	44.0
10. Overall pump width, in.	37.0	52.0	60.0
11. Overall pump height, in.	39.0	51.5	61.56
12. Overall pump length, in.	39.0	59.0	63.0

3.9.3.2.1.1.2 Essential Chilled Water Pumps. A structural integrity and operability analysis of the essential chilled water pump (Ingersoll-Rand Model 4X10AN) was performed.

The fundamental frequency of pump-motor-support frame is demonstrated to be above 33 Hz. Accordingly, a static analysis was performed.

The components analyzed are those that comprise the pressure boundary, the rotating member, and the attachment of the pump/motor to the floor.

Table 3.9-16 lists the most important stresses. Shaft deflections are calculated as 0.0012 inch under normal loading and 0.0023 inch with a 3g static load imposed. These deflections are less than the minimum clearance of 0.0085 inch between impeller and casing wear ring.

The ANSYS computer program was used to perform the structural analysis.

The nozzle flanges were analyzed in accordance with ASME B&PV Code, Section III, Subsection NA, Appendix XI, Article NC-3647. Internal pressure, axial force and bending moments are used. Visual factor is 0.8 as per ASME Table 1-7.1, footnote 4.

The stuffing box extension is a Class 3 component, and ASME B&PV Code, Division 1, ND-3325-2 (b), 1977 Edition was applied for analyzing the flange thickness. An Ingersoll-Rand verified computer program EAS-1-13 was used to calculate the maximum reaction at each pedestal bolt.

Table 3.9-16

ESSENTIAL CHILLED WATER PUMP SUMMARY OF STRESSES
(Sheet 1 of 3)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Suction flange	Normal	Longitudinal	7,150	21,000
		Radial	2,038	21,000
		Tangential	2,453	21,000
	OBE	Longitudinal	11,038	23,100
		Radial	3,181	23,100
		Tangential	3,829	23,100
	SSE	Longitudinal	11,636	25,200
		Radial	3,356	25,200
		Tangential	4,040	25,200
Discharge flange	Normal	Longitudinal	7,847	21,000
		Radial	3,148	21,000
		Tangential	3,045	21,000
	OBE	Longitudinal	10,140	23,100
		Radial	4,109	23,100
		Tangential	3,975	23,100
	SSE	Longitudinal	10,515	25,200
		Radial	4,267	25,200
		Tangential	4,127	25,200

Table 3.9-16

ESSENTIAL CHILLED WATER PUMP SUMMARY OF STRESSES
(Sheet 2 of 3)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Stuffing box bolts	Normal	Tensile	5,006	25,000
Gland bolts	Normal	Tensile	643	25,000
Pedestal bolts	Normal	Tensile	3,742	35,600
	OBE	Tensile	9,423	39,200
	SSE	Tensile	10,566	42,800
Pump pins	Normal	Shear	2,125	25,200
	OBE	Shear	5,944	27,700
	SSE	Shear	7,011	30,200
Mounting foot	Normal	Max Prin	6,227	21,000
	OBE	Max Prin	15,748	23,100
	SSE	Max Prin	17,698	25,200
Bedplate top-plate	OBE	Tensile	2,553	19,800
	SSE	Tensile	3,658	21,600
Bedplate pedestal	Normal	Tensile	1,254	18,000
		Shear	70	18,000
	OBE	Tensile	3576	19,800
		Shear	197	19,800

Table 3.9-16

ESSENTIAL CHILLED WATER PUMP SUMMARY OF STRESSES
(Sheet 3 of 3)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Bedplate pedestal (cont)	SSE	Tensile	4,204	21,600
		Shear	232	21,600
Pedestal/top-plate weld	Normal	Tensile	1,253	18,000
	OBE	Tensile	3,482	19,800
	SSE	Tensile	4,085	21,600
Motor holddown bolts	Normal	Tensile	327	15,840
	OBE	Tensile	2,227	17,400
	SSE	Tensile	3,373	19,000
Motor pins	OBE	Shear	217	27,700
	SSE	Shear	347	30,200
Anchor bolts	Normal	Tensile	2,976	20,000
		Shear	1,587	10,800
	OBE	Tensile	13,365	21,986
		Shear	6,111	11,880
	SSE	Tensile	17,032	21,790
		Shear	7,913	12,960
Shaft	--	Torsional	517	7,500

The pump was modeled and analyzed using the ANSYS computer program to determine the natural frequencies and mode shapes for the pump and motor assembly.

The pump stand, pump, and shaft were modeled as beams with distributed mass. Mass elements were added in the pump and motor areas to account for the total mass of these items.

The shaft was conservatively considered unsupported at the stuffing box and no credit was taken for the effects of the grouting. The actual grouting effects would stiffen the bedplate and raise the natural frequency, so this model is conservative.

A reduced modal analysis was performed. No rotational dynamic degrees of freedom were specified since the mode shapes at the lower natural frequencies are dominated by translation rather than rotation.

A static analysis with a 1g vertical acceleration was made first, followed by a natural frequencies and mode shapes run.

The first vibration mode has a natural frequency of 48.5 Hz. This mode is characterized by lateral displacement of the whole pump.

Natural frequencies for this pump assembly are sufficiently high such that the pump assembly may be treated as a rigid component for seismic analyses.

3.9.3.2.1.1.3 Condensate Transfer Pumps. The condensate transfer pump is a horizontal, single-stage, end-suction, frame-mounted-type unit, Ingersoll-Rand Model 2X10AN. The driver is an electric motor, with a nominal rating of 5 hp at

1750 revolutions per minute. The motor is coupled directly to the pump using a flexible type steel coupling. Both pump and motor are mounted on a common bedplate.

The fundamental frequency of pump-motor-support frame is demonstrated to be above 33 Hz. Static analysis techniques are therefore employed in evaluating the structural integrity and operability.

Pressure vessel and support structure components are analyzed in accordance with applicable methods and allowable stresses of the ASME B&PV Code, Section III.

A. Pressure Boundary

The pump casing and cover are analyzed by ASME Code design procedures to assure that the casting thicknesses of the parts are equal to or above the minimum requirements.

Material is SA-351 CF8M, for which the allowable stress is 17,500 psi. A casting quality factor of 0.8 is used. Stresses evaluated are the result of combined membrane and bending loads. The allowable stresses for the various operating modes, therefore, are:

Normal	(1.5)	(0.8)	(17,500)	=	21,000	psi
OBE	(1.65)	(0.8)	(17,500)	=	23,100	psi
SSE	(1.8)	(0.8)	(17,500)	=	25,200	psi

Pressure bolting is also analyzed for both the main flange and the shaft seal gland. Bolting material is SA-193 Grade B7, for which the allowable stress is 25,000 psi under normal load conditions. Seismic loads

do not contribute significantly to the stresses in these bolts.

B. Nozzle Flanges

The pump casing flanges are analyzed in accordance with the procedures of Section III, Subsection NA, Appendix XI, Subarticle NC-3647. Internal pressure and externally applied axial force and bending moments are applied. Allowable stresses are the same as those defined for the casing. Detailed calculations are performed using a verified computer program which utilizes the equations given in the Code procedures. Nozzle loads are given in table 3.9-17.

C. Anchor Bolts

Anchor bolts are used along the edges of the bedplate to fasten the entire pump assembly to the floor. The loads and stresses are analyzed. No credit is taken for restraining effects of the grout which is to be used at the final installation.

D. Shaft

The natural frequency of the shaft is determined, to assure that there is a safe margin above 33 Hz.

To assure that operability requirements are satisfied, the shaft deflection at the impeller under the maximum anticipated seismic load and radial thrust (hydraulic) load is determined and compared to the minimum running clearances designed into the pump.

Table 3.9-17
PRIMARY LOADS ON CONDENSATE TRANSFER PUMP NOZZLES

Plant Condition	Suction and Discharge Nozzles	
	Moment, M (Lb-In.)	Force, F (Lb-In.)
Primary		
Normal, N_n	1,800	150
Upset, N_u	2,270	190
Emergency, N_e (DBE)	2,570	215
Faulted, N_f (SSE)	5,440	450
Primary and Secondary		
	6,030	500

Notes:

1. Attached piping for both nozzles is 3 inches Schedule 40.

2. All forces F_x, F_y and F_z and all moments M_x, M_y, and M_z act concurrently.

   Magnitudes: $F_x = F_y = F_z = F$ $M_x = M_y = M_z = M$

Seismic Loading

OBE: 1.0g

SSE: 1.6g

Notes:

1. Analysis established that the pumps are rigid equipment; hence, the listed values are for zero period acceleration (ZPA), floor-mounted devices.
2. The seismic components are applied in the two horizontal and the vertical direction simultaneously.

Table 3.9-18

CONDENSATE TRANSFER PUMPS
DETAILED STRESS ANALYSES (Sheet 1 of 4)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Suction flange	Normal	Longitudinal	2,461	21,000
		Radial	874	21,000
		Tangential	1,221	21,000
	OBE	Longitudinal	2,953	23,100
		Radial	1,058	23,100
		Tangential	1,477	23,100
	SSE	Longitudinal	4,784	25,200
		Radial	1,739	25,200
		Tangential	2,429	25,200
Discharge flange	Normal	Longitudinal	4,261	21,000
		Radial	3,526	21,000
		Tangential	2,678	21,000
	OBE	Longitudinal	5,688	23,100
		Radial	4,725	23,100
		Tangential	3,588	23,100
	SSE	Longitudinal	11,002	25,200
		Radial	9,188	25,200
		Tangential	6,977	25,200
Casing flange bolts	Normal	Tensile	2,248	25,000
Gland bolts	Normal	Tensile	403	25,000

Table 3.9-18

CONDENSATE TRANSFER PUMPS
DETAILED STRESS ANALYSES (Sheet 2 of 4)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Pump holddown bolts	Normal	Tensile	976	46,200
	OBE	Tensile	2,541	50,800
	SSE	Tensile	5,943	55,400
Pump pins	Normal	Shear	1,128	25,200
	OBE	Shear	3,570	27,700
	SSE	Shear	6,314	30,240
Mounting foot	Normal	Max. Prin.	1,777	21,000
	OBE	Max. Prin.	4,445	23,100
	SSE	Max. Prin.	10,091	25,200
Bedplate top-plate	Normal	Tensile	658	18,000
	OBE	Tensile	1,132	19,800
	SSE	Tensile	3,268	21,600
Pump pedestal	Normal	Tensile	513	18,000
		Shear	36	12,000
	OBE	Tensile	1,624	19,800
		Shear	116	13,200
	SSE	Tensile	3,016	21,600
		Shear	206	14,400

Table 3.9-18

CONDENSATE TRANSFER PUMPS
DETAILED STRESS ANALYSES (Sheet 3 of 4)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Pedestal upper weld	Normal	Tensile	391	18,000
		Shear	192	12,000
	OBE	Tensile	1,019	19,800
		Shear	608	13,200
	SSE	Tensile	2,383	21,600
		Shear	1,074	14,400
Pedestal/top-plate weld	Normal	Tensile	413	18,000
		Shear	20	12,000
	OBE	Tensile	1,353	19,800
		Shear	120	13,200
	SSE	Tensile	2,508	21,600
		Shear	212	14,400
Motor hold-down bolts	Normal	Tensile	3,804	46,200
	OBE	Tensile	5,717	50,820
	SSE	Tensile	7,128	55,440
Anchor bolts	Normal	Tensile	1,310	20,000
		Shear	992	10,800
	OBE	Tensile	5,222	22,000
		Shear	3,008	11,800
	SSE	Tensile	10,627	23,040
		Shear	5,508	12,960

Table 3.9-18

CONDENSATE TRANSFER PUMPS
DETAILED STRESS ANALYSES (Sheet 4 of 4)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Shaft	-	Torsional	469	7,500
Shaft natural frequency		10,713 rpm		
Running speed		1,750 rpm		
Pump rotor deflection at wear rings (SSE)			0.0038 in.	
Radial clearance at wear rings			0.008 in.	
Drive Motor				
First critical of shaft/rotor assembly is			155.3 Hz	
Maximum rotor deflection (SSE)			0.0036 in.	
Radial clearance			0.0148 in.	

E. Results

The lowest natural frequency of the pump-driver-bedplate assembly was established by analysis to be 61.3 Hz.

The wall thickness of the casing is found to be well above the required minimum, by code. When seismic acceleration and externally applied nozzle loads were superimposed on the pressure load, stresses are still found to be within prescribed limits.

Pump and motor holddown bolts, anchor bolts, and the most highly loaded portions of the bedplate were also analyzed and deemed acceptable.

Operability considerations addressed were shaft natural frequency and the running clearances within the pump. The first critical was found to be well above running speed, and maximum deflection at the impeller ring fits will be less than the running clearance provided.

Results of the detailed stress analyses are given in table 3.9-18.

3.9.3.2.1.1.4 Fuel Pool Cooling Pumps. The 8X17A horizontal centrifugal pump is used for fuel pool cooling. The pump is of the single-stage, end-suction volute type and is driven by a Westinghouse motor of 100 hp at 1180 revolutions per minute.

The first natural frequency of the assembly has been demonstrated to be 59 Hz, and the pump is thus a rigid structure.

The analysis is done according to ASME B&PV Code, Section III, Subsection NA, Appendix XI, Article NC-3647.

Flange material is ASME SA-351 CF8M, and the visual qualification factor is 0.8. The material allowable stresses are 19,800 psi, 21,780 psi, and 23,760 psi for the three load cases, respectively.

The reaction of each pedestal bolt is conservatively calculated. Since there is one pin to each foot, the pin will take up twice the bolt shear load. Stresses of the bolting and foot are calculated and compared.

Results of detailed stress analyses are given in table 3.9-19.

3.9.3.2.1.1.5 Auxiliary Feedwater Turbine-Driven Pump. A seismic, stress, and deflection analysis of the auxiliary feedwater turbine-driven pump (Bingham-Willamette Model 4 x 6 x 10-1/2 MSD 8 stage) was performed. The components analyzed are those that comprise the pressure boundary, the rotating member, the pump/turbine sole plate, and attachments to the floor. The turbine driver was analyzed separately.

Table 3.9-20 lists the more important stresses and deflections.

A dynamic model of the pump was developed and a computer frequency analysis made. The frequency analysis of the assembly shows that the pump and bedplate are rigid. The turbine was analyzed separately and found to be flexible.

A static analysis was made of the assembly, with 1.5 times the peak of the response spectra curve applied to the turbine center of gravity to account for the effect of the turbine on the bedplate and pump.

Table 3.9-19
FUEL POOL COOLING PUMPS
DETAILED STRESS ANALYSES (Sheet 1 of 3)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Stuffing box stud	--	Tensile	7,150	25,000
Gland stud	--	Tensile	1,185	25,000
Discharge flange	Normal	Longitudinal	5,298	19,800
		Radial	3,484	19,800
		Tangential	2,439	19,800
	OBE	Longitudinal	5,940	21,780
		Radial	3,942	21,780
		Tangential	2,759	21,780
	SSE	Longitudinal	8,255	23,760
		Radial	5,591	23,760
		Tangential	3,913	23,760
Suction flange	Normal	Longitudinal	2,604	19,800
		Radial	1,506	19,800
		Tangential	1,904	19,800
	OBE	Longitudinal	3,204	21,780
		Radial	1,876	21,780
		Tangential	2,372	21,780
	SSE	Longitudinal	5,346	23,760
		Radial	3,199	23,760
		Tangential	4,046	23,760

Table 3.9-19
FUEL POOL COOLING PUMPS
DETAILED STRESS ANALYSES (Sheet 2 of 3)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Pump shear pin	Normal	Shear	3,050	25,200
	OBE	Shear	6,657	27,720
	SSE	Shear	12,895	30,240
Pedestal bolt	Normal	Tensile	7,200	35,640
	OBE	Tensile	11,883	39,204
	SSE	Tensile	24,466	42,768
Mounting foot	Normal	Prin. Tensile	5,485	19,800
	OBE	Prin. Tensile	9,162	21,800
	SSE	Prin. Tensile	18,810	23,800
Motor holddown bolts	Normal	Tensile	656	30,000
	OBE	Tensile	6,831	30,000
		Shear	2,340	16,200
	SSE	Tensile	10,536	30,000
		Shear	3,737	16,200
Anchor bolt	Normal	Tensile	2,931	30,000
		Shear	1,476	16,200
	OBE	Tensile	10,686	30,000
		Shear	4,392	16,200
	SSE	Tensile	20,626	30,000
		Shear	8,108	16,200

Table 3.9-19
FUEL POOL COOLING PUMPS
DETAILED STRESS ANALYSES (Sheet 3 of 3)

Part	Load Case	Stress	Calculated (psi)	Allowable (psi)
Bedplate pedestal	Normal	Tensile	1,073	27,000
		Shear	65	18,000
	OBE	Tensile	2,196	27,000
		Shear	142	18,000
	SSE	Tensile	4,310	27,000
		Shear	275	18,000
Pedestal/top-plate weld	Normal	Tensile	1,441	18,000
		Shear	90	12,000
	OBE	Tensile	2,944	18,000
		Shear	194	12,000
	SSE	Tensile	5,783	18,000
		Shear	376	12,000
Top-plate	OBE	Bending	2,460	19,800
	SSE	Bending	6,880	21,600

First natural frequency of bedplate-motor-pump assembly = 59 Hz

Minimum allowable casing thickness = 0.25 in. < 13/16 in.

Minimum allowable SBE flange thickness = 1.07 in. < 1.75 in.

Shaft frequency = 4200 r/min > 1180 r/min

Maximum shaft deflection at wear ring = 0.005 in.< 0.013 in.

Table 3.9-20
AUXILIARY FEEDWATER TURBINE-DRIVEN PUMP
SUMMARY OF STRESSES AND DEFLECTIONS (Sheet 1 of 2)

Components	Faulted		Upset	
	Actual	Allowable	Actual	Allowable
Sole plate holddown bolt stress - Shear, psi	30,130	30,600	19,208	25,500
- Tensile, psi	27,853	73,800	17,346	61,500
Pump holddown bolt stress - Shear, psi	14,971	22,680	12,949	18,900
- Tensile, psi	24,159	54,180	22,315	45,150
Anchor bolt stress - Shear, psi	26,785	27,360	17,066	22,800
- Tensile, psi	27,388	66,240	16,971	55,200
Frame stress, psi	24,982	25,920	15,869	21,600
Pump pedestal stress, psi	15,599	25,920	13,827	21,600
Pedestal weld stress, psi	12,289	12,960	10,474	10,800
Nozzle stress - Discharge, psi	31,403	39,600	31,403	33,000
- Suction, psi	25,800	39,600	25,800	33,000
Nozzle flange pressure - Discharge psig	2,611	3,580	2,611	3,580
- Suction, psig	931	2,148	931	2,148
Bearing housing to frame bolt stress - Shear, psi	490	10,000	490	12,000
- Tensile, psi	13,045	20,000	13,045	24,000
Shaft stress, psi	15,531	26,250	15,531	26,250

Table 3.9-20
AUXILIARY FEEDWATER TURBINE-DRIVEN PUMP
SUMMARY OF STRESSES AND DEFLECTIONS (Sheet 2 of 2)

Components	Faulted		Upset	
	Actual	Allowable	Actual	Allowable
Pump bearing loads - Inboard, psi	67	200	67	200
- Outboard, lb	8,248	36,283	8,248	36,283
Impeller key stress - Shear, psi	6,225	10,500	6,225	10,500
Thrust retainer bolt stress - Tensile, psi	4,646	20,000	4,696	20,000
Flexible coupling misalignment, radians	0.00076	0.017	0.00076	0.017
Impeller relative deflection, inches	0.00512	0.007	0.00512	0.007
Cooling water piping stress, psi	14,992	18,600	14,992	18,600
Sealing liquid piping stress, psi	15,550	18,600	15,550	18,600

The pump and turbine nozzle loads, normal loads, and seismic loads are imposed on the same model used for the frequency analysis and a stress and deflection analysis of the pump and plate was made.

The pump nozzle discontinuity stresses are calculated by the method of the ASME Code, ND-3652, where the pump casing/discharge nozzle intersection is treated as an equivalent tee in a conservative manner. The pump suction nozzle is treated as an equivalent tee.

The pump discharge and suction flanges are treated by the method of the ASME Code, ND-3647, for the normal loads and external forces and moments caused by weight and thermal. Seismic loads were also considered.

The pump rotor/shaft was analyzed separately in accordance with the design specification.

The computer analysis for the frequencies is performed by use of the ICES-STRUDL computer program operating on an IBM 370/158 computer. Certain assumptions are made in developing the model.

These assumptions are made such that the model would be more flexible than the actual assembly. Thus, the frequencies predicted by the model will be lower than the actual frequencies.

Some of these assumptions are:

A. The bedplate is assumed to be supported only at the foundation bolts. This is true for upward forces, but for downward forces the bedplate channel flanges are continuously supported.

B. The turbine could help restrain the pump in the direction parallel to the shaft centerline by transmitting forces through the coupling. This is not included in the model since the coupling connection is not positive in that direction. This is also not desirable since this would impose thrust loads on the pump and turbine bearings.

The local flexibility of the turbine is not included in the model, but the effect of the turbine upon the pump/bedplate is included.

To account for the turbine flexibility, 1.5 x the peak of the spectra curve loads are applied for the turbine frame only. The turbine sole plate is rigid.

The turbine (Terry Turbine Model Number G5-2N) is analyzed separately. A similar turbine assembly has been shake tested and the results of this test are used for seismic qualification of the auxiliary feedwater pump turbine. The turbine tested was the same model turbine but differed in the configuration of the mounting plate.

A supplementary analysis was performed to qualify parts not subject to heat. Table 3.9-21 itemizes the type of qualification. Results of the seismic test were reviewed and an analysis made of deviations observed during testing. Minor modifications were incorporated into the turbine design as a result of seismic testing. It was concluded that turbine seismic operability was satisfactorily demonstrated.

3.9.3.2.1.1.6 Auxiliary Feedwater Motor-Driven Pump. A seismic, stress, and deflection analysis of the auxiliary

feedwater motor-driven pump (Bingham-Willamette Model 4 x 6 x 10-1/2 MSD 8 stage) was performed.

Table 3.9-22 lists the more important stresses and deflections.

A dynamic model of the pump was developed and a computer frequency analysis made. The lowest frequency of the pump was shown to be 40 Hz, and thus it can be treated statically.

The nozzle loads, seismic loads, and normal loads were imposed on the computer model and a stress and deflection analysis of the entire assembly was made.

The nozzle discontinuity stresses were calculated by the method of the ASME Code, ND-3652, where the pump casing/discharge nozzle intersection is treated as an equivalent tee in a conservative manner. The suction nozzle was treated as an equivalent tee.

The discharge and suction flanges were treated by the method of the ASME Code, ND-3647, for the normal loads and external forces and moments caused by weight and thermal. Seismic loads were also considered.

The pump rotor/shaft was analyzed separately in accordance with the design specification.

The motor holddown bolt stresses for the upset/emergency case are 5406 psi tensile and 7270 psi shear compared with allowable stresses of 16,368 psi tensile and 10,000 psi shear.

Table 3.9-21
AUXILIARY FEEDWATER PUMP TURBINE QUALIFICATION

	Analysis	Test	Qualification
Turbine case		X	
Pedestal-gov end		X	
Holddown		X	
Guide blocks	X	X	
Pedestal-coupl end		X	
Holddown	X	X	
Taper pins	X	X	
Bearing-radial	X	X	
Bearing-thrust	X	X	
Flanges-loads		X	
Rotor	X	X	
Trip and throttle valve		X	
Motor operators		X	
Solenoid trip		X	
Limit switches		X	
Spring support			X
Governor valve		X	
Valve body		X	
Flanges		X	
Servo		X	
Valve linkage		X	
Limit switches		X	
Oil cooler		X	
Tube		X	
Shell		X	
Head		X	
Baffles		X	
Support			X
Piping			X
Oil piping			
Drain side		X	
Feed side	X		
Control	X		
Supports			X
Panel-electric	X		
Panel-junction box			
Support		X	
Base-support	X		

Table 3.9-22
AUXILIARY FEEDWATER MOTOR-DRIVEN PUMP
SUMMARY OF STRESSES AND DEFLECTIONS UNDER SSE LOADS

Components	Actual	Normal Allowable
Motor holddown bolt stress[a]		
- Shear, psi	11,626	12,000
- Tensile, psi	10,496	11,278
Pump holddown bolt stress		
- Shear, psi	15,971	18,900
- Tensile, psi	24,589	45,150
Anchor bolt stress - Shear, psi	9,772	10,000
- Tensile, psi	8,593	12,365
Frame stress, psi	17,203	21,600
Pump pedestal stress, psi	12,139	21,600
Pedestal weld stress, psi	10,077	10,800
Nozzle stress - Discharge, psi	31,403	33,000
- Suction, psi	25,800	33,000
Nozzle flange pressure		
- Discharge, psig	2,611	3,580
- Suction, psig	931	2,148
Bearing housing to frame bolt stress,		
- Shear, psi	442	10,000
- Tensile, psi	12,660	20,000
Shaft stress, psi	18,017	26,250
Pump bearing loads - Inboard, psi	73	200
- Outboard, lbs	6,636	36,283
Impeller key stress - Shear, psi	7,341	10,500
Thrust retainer bolt stress		
- Tensile, psi	4,646	20,000
Flexible coupling misalignment, radians	0.00819	0.017
Impeller relative deflection, in.	0.00512	0.007
Cooling water piping stress, psi	14,992	18,600
Sealing liquid piping stress, psi	15,550	18,600

a. These are faulted case stresses and allowable.

The computer analysis for the frequency analysis was performed by use of the ICES-STRUDL computer operating on an IBM 370/158 computer. Certain assumptions were made in developing the model. These assumptions were made such that the model would be more flexible than the actual assembly. Thus, the frequencies predicted by the model will be lower than the actual frequencies.

Some of these assumptions are:

A. The bedplate is assumed to be supported only at the foundation bolts. This is true for upward forces but for downward forces the bedplate channel flanges are continuously supported.

B. The motor could help restrain the pump in the direction parallel to the shaft centerline by transmitting forces through the coupling. This is not included in the model since the coupling connection is not positive in that direction. This is also not desirable since this would impose thrust loads on the pump and motor bearings.

3.9.3.2.1.1.7 Diesel Fuel Oil Transfer Pump. A static analysis shows the pump to have a natural frequency greater than 33 Hz. Accordingly, a 3g horizontal and vertical seismic load is applied. Calculated values of stresses and deflections are listed in table 3.9-23.

Table 3.9-23
DIESEL FUEL OIL TRANSFER PUMP STRESSES AND DEFLECTIONS
COMPARISON OF CALCULATED AND ALLOWABLE VALUES

Component	Calculated Value	Allowable Parameter or Actual Thickness
Deflection, in.		
Impeller	0.000277	0.013200
Rotor	0.000036	0.019600
Stress, psi		
Bearings	31,580	150,000
Shaft	904	18,800
Support	3,299	12,600
Retainer	3,930	12,600
Cover	-3,998	12,600
Natural frequency, Hz		
Support	34.94	Greater than 33
Loads, lb		
Anchor bolts		
Tensile	425.6	N.A.
Horizontal	219.3	N.A.
Foundation		
Vertical	7,652.4	N.A.
Horizontal	4,386	N.A.
Weld thickness, in.		
Stiffeners	0.106	0.125
Discharge pipe	0.234	0.3125
Retainer	0.105	0.25

Calculations are performed for this pump in the dry condition. This is considered the most severe condition since the affect of the fluid would be to dampen or cushion the acceleration forces. One exception is taken to this; the radial thrust force is taken into consideration for impeller calculations.

The affect that various loadings have relative to the analysis are discussed below.

The only operating load considered critical, other than seismic conditions, is radial thrust. This force affects the deflection of the rotor and impeller.

As the discharge pipe is fixed to the coverplate, the nozzle loads are not transmitted to the pump or the support. They do have an effect on the coverplate, the discharge pipe weld and on the anchor bolts. The effects are investigated in this analysis using the maximum loading combinations for a faulted condition.

The calculated stresses in this report have been compared to the working stress limits as specified by the ASME Code, Section III. A study of the cross-section of the pump suggests that seismic forces would have little or no effect. This is due to the general compactness and relative mass of the component parts. Horizontal and vertical forces are assumed to act through the center of gravity of the pump being analyzed. For calculation purposes, the center of gravity can be considered to be located on the axes of the pump, with little or no effect on the final results.

Temperature is not considered to have any critical effect. The allowable stresses for the materials of construction are based

on values shown in Section III of the Code for a design temperature of 200F.

The calculated rotor and impeller deflections are compared to the value of the corresponding deflection which would cause rubbing or interference of the pump's operation. The calculated bearing load will be compared to the design bearing load.

3.9.3.2.1.1.8 Essential Spray Pond Pump. A structural integrity and operability analysis of the essential spray pond pump (Bingham-Willamette Model Number 24 x 38 BVTM) was performed.

A dynamic computer model of the pump was developed and the masses lumped at appropriate places. The ANSYS structural program was employed for the study and the lowest natural frequency of the system was found to be 32.26 Hz. Hence, a seismic analysis was conducted using the SSE spectra from which the stresses and deflections were obtained. The same computer model was used to conduct static analyses for nozzle loads and dead weight. The pump structure was analyzed for 150 psi internal pressure loading. The faulted condition combining these load cases is the critical condition. The component stresses for individual load cases are added algebraically to obtain the maximum stress values. These stresses are found to be within the specified allowables. Table 3.9-24 lists a summary of the stresses.

The effect of hydraulic thrust on the suction bell, impeller, bowl, and shaft has been included to obtain maximum stresses in these components. The highest temperature of 200F that the

pumped fluid attains is considered and, accordingly, the allowables at that temperature are used for the analysis.

The SSE response spectrum (acceleration vs. frequency) for the floor-mounted device was applied in X, Y, and Z directions individually and the stresses in each element of the computer model for the first six mode shapes obtained through computer runs. For each excitation (in X, Y, and Z directions) the individual element stresses due to modal responses are obtained by using the SRSS method. The total stresses are obtained by summing the SRSS stresses due to individual X, Y, and Z excitations. These stress values are used to analyze the faulted condition.

Appendix 1, by the specified factor of 1.8 for faulted condition.

3.9.3.2.1.2 Valves. Refer to section 3.9.3.6 for testing criteria of NSSS and containment spray system. Non-C-E scope safety-related active valves, 2 inches and larger nominal pipe size, are listed in table 3.9-25. Combustion Engineering scope safety-related active valves, 2 inches and larger nominal pipe size, which are plant specific to PVNGS and not provided in section 3.9.3.6, are listed in table 3.9-26. Safety-related active valves are subjected to the following tests: hydrostatic test in accordance with ASME Section III requirements, main seat leakage tests, functional tests that verify that the valve will open and close within the specified time limits when subjected to the maximum expected differential pressure, and operability qualification of motor operators for the environmental conditions over the installed life (i.e.,

Table 3.9-24
ESSENTIAL SPRAY POND PUMP - SUMMARY OF
MAXIMUM STRESSES AND ALLOWABLES

Item	Max Stress[a] (psi)	Allowable Stress[a] (psi)
Suction bell	12,114	33,660
Suction nozzle	3,041	33,660
Discharge column	30,447	31,500
Discharge shell lower section	4,479	31,500
Tube	5,088	31,500
Discharge nozzle	8,515	31,500
Pump shaft	3,613	174,780
Bolts (axial)	8,642	14,220
(shear)	4,561	11,376
Shaft keys	17,461	52,434
Driver stand	2,615	31,500

a. The allowable stresses given above are obtained by multiplying the values given in ASME Section III, Division 1, Appendix 1, by the specified factor of 1.8 for faulted condition.

aging, radiation, accident environment simulation, etc.) in accordance with the general format and qualification procedure of IEEE 382-1972, IEEE 323-1974, and IEEE 344-1975. Normal and abnormal conditions to which the valves are subjected are discussed in section 3.11.

Periodic inservice testing is performed to verify and assure the functional ability of the valve. These tests enhance reliability of the valve for the design life of the plant. Note that the lists of active valves in Tables 3.9-25, 3.9-26, and 3.9-27 are not necessarily identical to the list of valves in the Pump and Valve Inservice Testing Program, because these lists serve different purposes. Refer to UFSAR Section 3.9.6.2 for additional information on inservice testing of valves.

The valves are designed using either stress analysis (described by ASME Section III) or standard design rules for minimum wall thickness requirements. On active valves with extended top works, an analysis is also performed for static equivalent SSE loads applied at the center of gravity of the extended structure.

The maximum stress limits allowed in the analyses are those recommended by the ASME for the particular ASME class of valve analyzed.

In addition to these tests and analyses, the operability of the valve during an SSE is demonstrated by satisfying the following criteria:

A. The active valves with extended top works are designed to have a first natural frequency greater than 33 Hz. This may be shown by test or analysis. Valves with a

first natural frequency less than 33 Hz are discussed below.

B. The structural integrity of the valve is qualified by requirements that the nozzle loads due to the SSE (emergency or faulted plant condition) are considered as a normal load for the active valve, including supports when required to operate after SSE.

C. The motor operators and other electrical appurtenances necessary for operation are qualified for operability during SSE as described in section 3.10.

D. The complete valve assembly is qualified by test or analysis or both for operability during the SSE. The valve assembly is only qualified by analysis in cases where structural integrity alone is sufficient to assure operability.

For the seismic operability test, the valve is mounted in a manner that conservatively represents a typical plant installation. The valve includes the actuator and appurtenances normally attached to the valve when in service.

The extended top works of the valve are subjected to a statically applied equivalent seismic load of 1.6g horizontally and vertically for floor-mounted valves and 3g horizontally and vertically for line-mounted valves. Vertical load in the static test may be excluded when it is not a contributing factor.

Table 3.9-25
LISTING OF NON-C-E SCOPE ACTIVE VALVES ASME CLASS 2 AND 3[(c)(d)]
(Sheet 1 of 6)

Valve No.	System Name[(a)]	Valve Size (in.)	Valve Type	ASME Section III Code Class	Active Function	Actuator Type[(b)]
UV34 UV35 UV36 UV37	Auxiliary feedwater	6	Gate	2	Auxiliary feedwater supply	MO
UV61 UV62 UV63	Normal chilled water	10	Gate	2	Containment isolation	MO
UV134 UV138	Main steam	6	Gate	2	Auxiliary feedwater turbine steam supply	MO
UV169 UV183	Main steam	4	Globe	2	MS isolation	D
UV500P UV500Q UV500R UV500S	Main steam	6	Gate	2	MS isolation	P

a. See Appendix A of the Equipment Qualification Program Manual for environmental qualification parameters.

b. Actuator Types

D - Diaphragm   E - Electrohydraulic   P - Piston   MO - Motor-Operated   S - Solenoid

c. Also see the table included in each system section for additional active valves.

d. For application of the single failure rule to check valves, refer to Section 3.1.30.

e. In units where DEC-00649 has been implemented, this valve has been removed.

Table 3.9-25
LISTING OF NON-C-E SCOPE ACTIVE VALVES ASME CLASS 2 AND 3[c][d]
(Sheet 2 of 6)

Valve No.	System Name[a]	Valve Size (in.)	Valve Type	ASME Section III Code Class	Active Function	Actuator Type[b]
UV172 UV130 UV175 UV135	Main steam	8	Gate	2	MS isolation	P
UV1 UV2 UV3 UV4 UV5 UV6	Containment hydrogen	2	Globe	2	Containment isolation	MO
HV8A HV8B	Containment hydrogen	2	Solenoid	2	Containment isolation	S
UV170 UV180 UV171 UV181	Main steam	28	Gate	2	MS isolation	P
UV174 UV132 UV177 UV137	Main steam	24	Gate	2	Feedwater isolation	P

Table 3.9-25
LISTING OF NON-C-E SCOPE ACTIVE VALVES ASME CLASS 2 AND 3[c][d]
(Sheet 3 of 6)

Valve No.	System Name[a]	Valve Size (in.)	Valve Type	ASME Section III Code Class	Active Function	Actuator Type[b]
UV2A UV2B	Containment purge	42	Butterfly	2	Containment isolation	MO
UV3A UV3B	Containment purge	42	Butterfly	2	Containment isolation	MO
UV4A UV4B	Containment purge	8	Butterfly	2	Containment isolation	P
UV5A UV5B	Containment purge	8	Butterfly	2	Containment isolation	P
UV401 UV402 UV403	Nuclear cooling water	10	Butterfly	3	Containment isolation	MO
HV1 HV4	Condensate transfer	10	Butterfly	3	Auxiliary Feedwater	MO
HV-178 HV-179 HV-184 HV-185	Main steam	12	Globe	2	Atmospheric dump	P
HV-30 HV-31 HV-32 HV-33	Auxiliary feedwater	4	Globe	3	Auxiliary Feedwater	MO
HV-75[1] HV-76[1]	Spray Pond	14	Butterfly	3	Spray Pond Flow Control	MO

[1] DMWO 3304346 adds the capability to vary SP flow rates. This note applies to units and trains where this DMWO has been installed.

Table 3.9-25
LISTING OF NON-C-E SCOPE ACTIVE VALVES ASME CLASS 2 AND 3[c][d]
(Sheet 4 of 6)

Valve No.	System Name[a]	Valve Size (in.)	Valve Type	ASME Section III Code Class	Active Function	Actuator Type[b]
TV-29 TV-30	Essential chilled water	2-½	3-way	3	Control room S.O. temperature control	E
PSV-103 PSV-104	Essential cooling water	2	Safety relief	3	Pressure relief ECW system	Process fluid
EWA PCV-173	Essential Cooling Water	4”	Pilot	3	Maintain min. chiller cond. pressure	Process fluid
EWB PCV-174	Essential Cooling Water	4”	Pilot	3	Maintain min. chiller cond. pressure	Process fluid
UV-23 UV-24	Radioactive waste drains	3	Gate	2	Containment isolation	MO P
UV-2	Instrument and service air	2	Globe	2	Containment isolation	S
LV-91 LV-92	Essential cooling water	2	Solenoid	3	EW system surge tank level	S
PSV-137[e]	Essential spray pond	2-½	Safety relief	3	Diesel generator A fuel oil cooler	Process fluid
PSV-138	Essential spray pond	2-½	Safety relief	3	Diesel generator B lube oil cooler	Process fluid

Table 3.9-25
LISTING OF NON-C-E SCOPE ACTIVE VALVES ASME CLASS 2 AND 3[c][d]
(Sheet 5 of 6)

Valve No.	System Name[a]	Valve Size (in.)	Valve Type	ASME Section III Code Class	Active Function	Actuator Type[b]
PSV-139	Essential spray pond	2-½	Safety relief	3	Diesel generator A jacket wtr cooler	Process fluid
PSV-140	Essential spray pond	2-½	Safety relief	3	Diesel generator B air intercooler	Process fluid
PSV-141	Essential spray pond	2-½	Safety relief	3	Diesel generator A air intercooler	Process fluid
PSV-142	Essential spray pond	2-½	Safety relief	3	Diesel generator B jacket wtr cooler	Process fluid
PSV-143	Essential spray pond	2-½	Safety relief	3	Diesel generator A lube oil cooler	Process fluid
PSV-144[e]	Essential spray pond	2-½	Safety relief	3	Diesel generator B fuel oil cooler	Process fluid
PSV-105	Essential cooling water	2	Vacuum relief	3	Surge tank A	Atmosphere

Table 3.9-25
LISTING OF NON-C-E SCOPE ACTIVE VALVES ASME CLASS 2 AND 3[c][d]
(Sheet 6 of 6)

Valve No.	System Name[a]	Valve Size (in.)	Valve Type	ASME Section III Code Class	Active Function	Actuator Type[b]
PSV-106	Essential cooling water	2	Vacuum relief	3	Surge tank B	Atmosphere
HV-54	Auxiliary feedwater	4	Globe	3	Turbine trip	MO
UV-65	Essential cooling water	14	Butterfly	3	Crosstie from NCWS	MO
UV-145	Essential cooling water	14	Butterfly	3	Crosstie from NCWS	MO
V-215	Fuel pool cooling	3	Diaphragm	3	Fuel pool makeup	Manual
V-018 V-019	Condensate transfer	3	Gate	3	Fuel pool makeup	Manual

Table 3.9-26
NSSS SEISMIC I ACTIVE VALVES[b] FOR PVNGS SPECIFIC EQUIPMENT

Valve No.	System Name[a]	Valve Size (in.)	Valve Type	ASME Section III Code Class	Active Function
V-540 V-541 V-542 V-543	Safety injection	12	Check	1	SI to RC loop 2A SI to RC loop 2B SI to RC loop 1A SI to RC loop 1B
HV-239	Chemical volume and control	2	Globe	2	Auxiliary spray to pressurizer
VM-70	Chemical volume and control	3	Check	2	Regenerative heat exchanger
PSV-554 PSV-555 PSV-556 PSV-557 PSV-558 PSV-559 PSV-560 PSV-561 PSV-572 PSV-573 PSV-574 PSV-575 PSV-576 PSV-577 PSV-578 PSV-579 PSV-691 PSV-692 PSV-694 PSV-695	Main steam	10	Safety relief	2	Pressure relief SG system

a. See Appendix A of the Equipment Qualification Program Manual for environmental qualification parameters.

b. For application of the single failure rule to check valves, refer to Section 3.1.30.

The load is applied at the center of gravity of the operator in the direction of the weakest axis of the yoke. The design pressure of the valve is simultaneously applied to the valve during the static load tests.

The valve is then operated while the equivalent seismic static load is applied; i.e., from the normal operating status to the faulted operating status. The valve must perform its safety-related function within the specified operating time limits. Three minutes testing is required.

If the frequency of the valve, by test or analysis, is less than 33 Hz, a dynamic analysis of the valve is performed to determine the equivalent acceleration, considering the natural frequency of the valve and the frequency content of the applicable plant floor response spectra. The equivalent acceleration is then used in the static analysis and the valve seismic operability test.

The seismic operability test applies only to valves with overhanging structures; i.e., the motor operator. The valves are tested with appropriate external loads and seismic excitation as a unit and qualified using input motion which develops test response spectra equal to or greater than the required floor response spectra. The testing is conducted on a representative number of valves. Valves from each of the primary safety-related design types; e.g., motor-operated control valve, are tested. Valve sizes that envelop the range of sizes in service are qualified by the tests and the results are used to qualify all valve sizes within the envelope.

Stress and deformation analyses are used to support the interpolation.

Valves without extended structural features that are safety-related but can be classified as not having an overhanging structure, such as check valves, are considered below. Refer to table 3.9-27 for safety-related check valves 2 inches and larger. Check valves are characteristically simple in design. The effects from seismic accelerations or the maximum applied nozzle loads on their operation are negligible. The check valve design is compact and there are no extended structures or masses whose motion can cause distortions that can restrict operation of the valve. The nozzle loads due to maximum seismic excitation will not affect the functional ability of the valve since the valve disc is designed to be isolated from the casing wall. The clearance supplied around the disc by the design will prevent the disc from becoming bound or restricted due to any casing distortions caused by nozzle loads. Therefore, the design of these valves is assured, using standard design or analysis methods, and the ability of the valve to operate is assured by the design features. In addition to these design considerations, the valve also undergoes the following tests and analyses:

- Stress analysis as a part of the piping system including the SSE loads
- In-shop hydrostatic test
- In-shop seat leakage test

- Periodic in situ valve exercising and inspection to assure the functional ability of the valve

3.9.3.2.1.2.1 Anchor/Darling Gate Valves -- Limitorque Actuators. Natural frequency of each valve assembly (valve plus actuator) was determined by a multimass finite-element model analysis to be greater than 33 Hz. A static stress analysis was performed using a static seismic loading of 3g. The maximum stresses and deflections were calculated. A static operability test was conducted on a representative group of valves to verify operability during a safe shutdown earthquake condition. The Limitorque motor actuators were environmentally and seismically qualified by the manufacturer, Limitorque. Nonmetallic parts of the valve, such as packing and gaskets, were environmentally qualified by analysis.

3.9.3.2.1.2.2 Anchor/Darling Main Steam and Feedwater Isolation Valves. A hydraulic actuator for the main steam and feedwater isolation valves was subject to seismic testing.

Testing was performed using a shake table. Nonmetallic components, such as seals, and electrical equipment were subjected to irradiation and temperature aging prior to the seismic test program.

Table 3.9-27
LISTING OF NON-C-E SCOPE ACTIVE CHECK VALVES[b] ASME CLASS 2 and 3
(Sheet 1 of 4)

Valve No.	System Name[a]	Valve Size (in.)	ASME Section III Code Class	Active Function
V002 V004	Containment hydrogen control	2	2	Containment isolation
V002 V003 V006 V011 V012 V015	Diesel generator	2	3	Cooling water supplies to diesel generator
V012 V019	Diesel fuel	2	3	Diesel fuel oil supply
V096	Auxiliary feedwater	4	3	Auxiliary steam supply to AFW turbine

a. See Appendix A of the Equipment Qualification Program Manual for environmental qualification parameters.

b. For application of the single failure rule to check valves, refer to Section 3.1.30.

Table 3.9-27
LISTING OF NON-C-E SCOPE ACTIVE CHECK VALVES[b] ASME CLASS 2 and 3
(Sheet 2 of 4)

Valve No.	System Name[a]	Valve Size (in.)	ASME Section III Code Class	Active Function
V015 V024	Auxiliary feedwater	6	3	Auxiliary feedwater supply
V079 V080	Auxiliary feedwater	6	2	Auxiliary feedwater supply
V003 V005 V006 V007	Main steam	24	2	Main feedwater supply to SG
V642 V652 V653 V693	Main steam	8	2	Auxiliary feedwater supply to SG
V043 V044	Main steam	6	3	Steam supply to AFW turbine
V020 V021 V022 V040 V041 V042	Radioactive drains	4	3	Drains to ESF sumps A and B

Table 3.9-27
LISTING OF NON-C-E SCOPE ACTIVE CHECK VALVES[b] ASME CLASS 2 and 3
(Sheet 3 of 4)

Valve No.	System Name[a]	Valve Size (in.)	ASME Section III Code Class	Active Function
V016 V020	Condensate transfer	3	3	Condensate makeup to essential cooling system surge tanks
V037 V038	Condensate transfer	3	3	Condensate makeup to fuel pool
V007 V022	Auxiliary feedwater	8	3	Condensate supply to auxiliary feedwater
V005 V009	Auxiliary feedwater	8	3	Reactor makeup supply to auxiliary feedwater
V013 V017	Fuel pool cooling	8	3	Pool cooling flow
V090	Fire protection	6	2	Containment isolation
V039	Chilled water	10	2	Containment isolation
V012 V041	Essential spray pond	24	3	Spray pond circulation

Table 3.9-27
LISTING OF NON-C-E SCOPE ACTIVE CHECK VALVES[b] ASME CLASS 2 and 3
(Sheet 4 of 4)

Valve No.	System Name[a]	Valve Size (in.)	ASME Section III Code Class	Active Function
V137 V138	Auxiliary feedwater	6	3	Auxiliary feedwater pump discharge
V021	Instrument and service air	2	2	Instrument and service air supply
V118	Nuclear cooling water	10	2	NCWS to RC pumps
V887 V888	Main steam	2	3	SG supply to auxiliary feed pump turbine
XCV15A XCV15B XCV16A XCV16B	Essential chilled water	2	3	Excess flow valve for expansion tank bridle
XCV89A XCV89B XCV90A XCV90B	Essential cooling water	2	3	Excess flow valve for surge tank bridle

3.9.3.2.1.2.3 Dresser Globe Valves -- Rotork Actuators. Natural frequency of each valve assembly (valve plus actuator) was determined by a one degree of freedom, mass-spring model analysis to be greater than 33 Hz. A static stress analysis was performed using a static seismic loading of 3g. The maximum stresses and deformations were calculated. A static operability test was conducted on a representative group of valves to verify operability during a safe shutdown earthquake condition. The Rotork motor actuators were environmentally qualified by the manufacturer, Rotork. Nonmetallic parts of the valve, such as packing and gaskets, were environmentally qualified by analysis.

3.9.3.2.1.2.4 Henry Pratt Butterfly Valves -- Limitorque Actuators. A type test was performed on these valve sizes, and the other valve sizes are qualified by comparison and analysis. The valves tested were subject to leakage test, cold cycling, static seismic loading, hot cycling, and dynamic seismic testing. The valve actuators were qualified separately by the manufacturer, Limitorque.

3.9.3.2.1.2.5 Anchor/Darling Gate Valves -- Parker-Hannifin, Miller Fluid Power, and Chicago Fluid Power Pneumatic Actuators. Natural frequency of each valve assembly (valve plus actuator) was determined by a multimass, finite-element model analysis. The qualification of these valves was performed either by static or dynamic analysis based on the valve assembly's natural frequency. The stress analysis was performed using a seismic loading of 3g. The maximum stresses and deflections were calculated. A static operability test was

conducted on a representative group of valves to verify operability during a safe shutdown earthquake condition. The pneumatic actuator Class 1E parts (limit switches-Namco, solenoid valves-Asco and Valcor) were qualified separately by the individual suppliers. Environmental qualification of the air cylinder consisted of identifying and analyzing the non-metallic degradable parts which, if they failed, would prevent the actuator from closing the valve. Nonmetallic parts of the valve, such as packing and gaskets, were environmentally qualified by analysis.

3.9.3.2.1.2.6 Henry Pratt Butterfly Valves -- Bettis Pneumatic Actuators. The containment purge isolation valves were qualified by analysis. The valve actuator type test was performed and qualified separately by the manufacturer, GH Bettis Corporation. The test valve assembly (valve plus actuator) was subjected to operability testing; e.g., leakage, cold cyclic, hot cyclic temperature-pressure, seismic, and vibration testing.

3.9.3.2.2 C-E-Supplied Active ASME Code Class 2 and 3 Pumps and Class 1, 2, and 3 Valves

Refer to section 3.9.3.6 and Table 3.9.3-3 as augmented for PVNGS specific equipment.

3.9.3.2.2.1 Pumps for PVNGS Specific Equipment.

Active Components	Active Safety Function
Containment spray pumps	Operate

3.9.3.2.2.1.1 Containment Spray Pumps. Operability of the containment spray (CS) pumps under faulted conditions has been demonstrated by analyses of the assemblies and by analyses and tests of the motors in accordance with the recommendations of Regulatory Guide 1.48.

A. Structural Integrity[2]

Component		Calculated (psi)	Allowable (psi)
Casing foot attachment		15,913	28,050
Casing discharge nozzle attachment		7,849	28,050
Casing suction nozzle attachment		17,800	28,050
Main flange bolting		22,225	37,500
Foot		20,720	24,300
Foot weld		20,054	24,300
Anchor bolting	Tension	17,143	40,000
	Shear	6,202	15,390
Support head		1,029	18,900
Motor attachment bolting		9,845	37,500

B. Operational Deflection[2]

Description	Calculated (in.)	Allowable (in.)
Rotor/stator deflection (motor air gap)	0.0020	0.0500
Impeller/ring deflection	0.0055	0.0115
Shaft/cover deflection at mechanical seal	0.0023	0.0100

C. Operability was demonstrated under the following loads[2]

CS Pump

Horizontal seismic, (g)	1.1
Vertical seismic, (g)	1.1
Design pressure (psig)	710
Suction nozzle resultant force, (lb)	10,607
Suction nozzle resultant bending moment, (ft-lb)	50,000
Discharge nozzle resultant force, (lb)	6,500
Discharge nozzle resultant bending moment, (ft-lb)	16,000

To complete the operability demonstration, the motors were qualified to IEEE 323-1974 and IEEE 344-1975[3].

3.9.3.2.2.1.2 Spray Chemical Addition Pumps - Abandoned in Place

3.9.3.2.2.2 Valves for PVNGS Specific Equipment. Table 3.9-26 provides a listing of C-E-supplied Seismic I active valves for PVNGS specific equipment.

3.9.3.2.2.3 PVNGS Exceptions to CESSAR Table 3.9.3-3, NSSS Seismic I Active Valves (CE Scope).

A. Tag Number Changes:

CESSAR Valve Number	PVNGS Valve Number
CH-639	CH-429

B. Deletions:

C. Additions:

Valve Number	System Name (Safety Function)	Line Size	Valve Type	ASME Section III Code Class	Actuator Type
CH-144	CVCS (Open)	3	Packless diaphragm	3	Manual
CH-164	CVCS (Open)	3	Packless diaphragm	3	Manual
CH-174	CVCS (Open)	3	Packless diaphragm	3	Manual
CH-753	CVCS (Open)	3	Packless diaphragm	3	Manual
CH-755	CVCS (Open)	3	Packless diaphragm	2	Manual
CH-756	CVCS (Open)	3	Packless diaphragm	2	Manual
CH-757	CVCS (Open)	3	Packless diaphragm	2	Manual

3.9.3.3 Design and Installation Criteria, Pressure-Relieving Devices

Pressure vessels are protected by pressure-relieving devices to meet applicable code requirements such as ASME Code, Section III, Section VIII, and ANSI B31.1.

The design of pressure-relieving devices generally can be grouped in two categories, open and closed systems.

A. Open System

An example of an open system is a relief valve discharge elbow open to the atmosphere.

1. Main Steam Lines and Relief Valve System

Each main steam line is designed to withstand the maximum possible discharge flow from any one relief valve and also from the full steam generator capacity with all valves discharging simultaneously. A stress analysis is performed to determine the effects on the main steam lines, assuming that all steam generator relief valves discharge concurrently. The design of a safety and relief valve system shall include consideration of all components of the system; safety or relief valve, upstream piping or header, downstream or vent piping, system support, and structures or buildings to which the supports are attached.

The most severe load combination is considered as follows: internal pressure, dead weight, seismic, thermal, and reaction forces of blowing valves including entrainment.

The maximum allowable internal pressure in the main steam piping or header at the safety valve inlet nozzle is 110% of the steam generator shell design pressure as specified by the ASME Code.

Relief valve connections will be spaced on the header so that there is no local interaction.

Reaction force and moment effects on the steam header, supports, and connecting nozzles for each valve blowing, and for combinations of valves blowing, shall be considered. The steady blowdown load is not transmitted to the header but is carried by the structure, using a piston type design.

The reaction force of the flowing valve is obtained from the valve manufacturer; however, the manufacturer's reaction force is verified by the total hydraulic reaction force analysis for a discharging jet of fluid, comprised of a pressure area contribution and fluid momentum contribution, referring to the outlet plane of the flow geometry.

Dynamic amplification of the reaction force is considered using a dynamic load factor of 2.0. Amplification load factor is defined as the ratio of the dynamic deflection at any time to the deflection which would have resulted from the static application of the load.

Stress analysis of the safety and relief valve system is conducted including evaluation of the header local stresses due to reaction moment when

applicable. The stresses are categorized according to the appropriate code.

Material thicknesses are selected to accommodate expected loads and maintain stresses within allowable limits.

B. Closed System

1. Pressurizer and Relief Valve Systems

The pressurizer in the RCS is provided with four spring-loaded ASME Code, Section III, Class 1 safety valves connected to the top of the pressurizer for overpressure protection and transient pressure control and is designed in accordance with ASME B&PV Code, Section III, Class 1. These valves discharge through a closed piping system to the reactor drain tank, where the steam is condensed and cooled by mixing with water. The system arrangement is shown schematically in engineering drawings 01, 02, 03-M-RCP-001, -002 and –003.

The transient force is included in the analysis to assure that the pressurizer nozzle, the safety valve, and the connecting piping (Safety Class 1) will not fail when the valve operates.

2. Hydraulic Forces

The pressurizer safety valve discharge piping system is a closed system so that no sustained reaction force from a free discharging jet of fluid can exist. However, transient hydraulic forces can be imposed at various points in the piping system from

the time a safety valve begins to pop open until steady flow is completely developed. In order to evaluate these transient forces, an analytical model is developed which incorporates technology applied from existing analyses of the blowdown during LOCA. The analytical model and its application is estimated to be a conservative representation of the transient forces.

3. Load Combinations

   One of the most important considerations related to the mechanical design and analysis is the identification and calculation of the loads and load combinations imposed on the system. The following is considered in determining the most severe combinations: internal pressure; dead weight; seismic, thermal, transient hydraulic forces in closed piping system.

4. Internal Pressure

   The maximum design pressure in relief lines has been incorporated in the stress analysis of pressure-relieving devices.

5. Safety Valve Flow

   The rated flow of the safety valves is based on the total relieving capacity required to prevent pressurizer pressure from exceeding the maximum stated in item 4 above. However, based on ASME Code, the rated flow of a safety valve is no more than 90% of the actual flow-relieving capacity. In

the development of the hydraulic forces on the discharge piping, maximum flow capacity is applied.

6. Thermal

   The design of the safety valve system considers the differential thermal growth and expansion loads, as well as the local effects of reinforcing and supports. The design also considers the differential thermal growth and expansion loads existing after any combination of safety valves (one valve to all valves) operates, raising the temperature of the discharge piping.

7. Safety Valve Cycling

   Pressurizer safety valves are full-life, pop-type valves, and are essentially full-flow devices, with no capability for flow modulation. In actual pressure transients, the steam relief flow required to prevent overpressure is a varying quantity, from zero to the full rated capacity of the safety valves. As a result, the valves will be required to open and close a number of times during the transient. Since each opening and closing produces a reaction force, consideration is given to the effect of multiple valve operations on the piping system, including supports. For design purposes, it is assumed that each safety valve will experience 80 occurrences of valve operation transients and each occurrence will include 20 cycles of individual safety valve operations, for a 40-year plant life.

C. Supports

The following support system criteria apply:

1. A support is provided on the discharge piping as close as possible to each safety valve discharge nozzle so that forces and moments will not jeopardize the integrity of the valves, the inlet lines to the valves, or the nozzles on the pressurizer.

2. Each straight leg of discharge piping has a support to take the force along that leg. Where the support is not on the leg itself, it is as near as possible on an adjacent leg.

3. Where a large portion of the system lies in a plane, the piping is supported normal to that plane even though static calculations do not identify a direct force requiring restraint in that direction. Dynamic analyses of these systems have shown that out-of-plane motions can occur.

4. Either hydraulic snubbers or rigid supports may be applied, consistent with the requirements for thermal expansion and seismic support.

D. Stress Analysis

Open discharge systems are analyzed using a static method of analysis. To ensure consideration of the effects of fast valve opening, a dynamic load factor (DLF) of 2.0 is applied to the steady-state forces and moments. This method of analysis is conservative, and follows the guidance of Regulatory Guide 1.67. Closed

discharge systems are dynamically analyzed considering the transient hydraulic forces imposed on the structural piping system. If a static analysis is performed on closed discharge systems, additional justification will be provided.

3.9.3.4 Component Supports

3.9.3.4.1 NSSS Supports

Supports for ASME Section III Code Class 1 components in the CESSAR scope are specified for design in accordance with the loads and loading combinations discussed in section 3.9.3.5.

In addition to the normal operating and seismic supports, component stops are employed to limit displacements for postulated pipe breaks. Where a component stop is designed solely to control movement following a postulated pipe break, only the design loading combination (d) of section 3.9.3.5 is specified.

Component supports which are loaded during normal operation, seismic and following a pipe break are specified for design for loading combinations (a) through (d) of section 3.9.3.5. Component stops which are loaded only following a pipe break are specified for design for loading combination (d). Design stress limits applied in evaluating loading combinations (a), (b), and (c) of section 3.9.3.5 are consistent with the ASME Code, section III. The design stress limits applied in evaluating loading combination (d) of section 3.9.3.5 are in accordance with the ASME Code, Section III. Loads in compression members are limited to 2/3 of the critical buckling load.

To insure that pipe restraints and component stops do function independently of the normal support system, the motions of the intact pipe due to all normal and upset plant conditions and vibratory motion of the SSE are calculated and used to specify a minimum clearance between the pipe and the restraint. Wherever possible, gaps between pipes and restraints are maximized to avoid possible contact during plant operation. Where a particular location requires minimizing a gap, special features are provided to permit adjustment of the gap size during hot functional testing in order to decrease the uncertainty in the calculated pipe motion in the vicinity of the restraint.

3.9.3.4.2 Non-NSSS Supports

Refer to subsection 3.6.2 for a description of supports required to absorb loads due to the dynamic effects of piping ruptures.

Loading combinations, design transients, and stress limits for the design of Code Class 1, 2, and 3 component supports are provided in paragraph 3.9.3.1. The analysis for such supports complies with Subsection NF of Section III of the ASME B&PV Code as indicated within the design specification.

Supports for active pumps and valves are included in the overall design and qualification of the component. Refer to subsection 3.9.3 for test and analysis of components and supports for active components.

3.9.3.5 Loading Combinations, Design Transients, and Stress Limits for CE Scope

ASME Section III Code Class 1, components, supports and piping in the CESSAR licensing scope are limited to the reactor coolant system main loop and the pressurizer. The loading combinations specified for the design of CESSAR Code Class 1 components, supports, and piping are categorized as normal, upset, emergency and faulted. The following specific loading combinations are specified for design:

A. The concurrent loadings associated with the normal plant conditions of dead weight, pressure and the thermal and expansion effects during startup, hot standby, power operation and normal shutdown to cold shutdown conditions.

B. The concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of the Operational Basis Earthquake (OBE).

C. The concurrent loadings associated with the plant emergency condition.

D. The concurrent loadings associated with the normal plant condition, the vibratory motion of the SSE, and the dynamic system loadings associated with the plant faulted condition (postulated pipe rupture). The SSE and pipe rupture loadings are combined by the SRSS method or a more conservative method.

The specific design transient specified for design are discussed in section 3.9.1.1.

3.9.3.5.1 ASME Code Class 1 Components and Supports

Design transients for ASME Code Class 1 components, supports and piping are discussed in subsection 3.9.1. Loading combinations for ASME Code Class 1 components are described in Table 3.9.3-1. Stress limits for ASME Code Class I components, supports and piping are described in Table 3.9.3-2. The operating pressures of Code Class 1 active valves are limited to the pressures taken from the applicable primary pressure class pressure-temperature rating of the ASME Code, Section III, for the maximum temperature for the applicable condition.

3.9.3.5.2 Reactor Internals Structures

Design transients for reactor internals structures are discussed in section 3.9.1.1. Loading combinations and stress limits are presented in section 3.9.5.

3.9.3.5.3 ASME Code Class 2 and 3 Components and Supports

Loading combinations applicable to Code Class 2 and 3 components and supports are described in Table 3.9.3-1. System operating conditions due to the design transients defined in Table 3.9.1-1, as well as any other auxiliary system specific conditions, are reviewed to determine the appropriate operating parameters to be used in the design of Code Class 2 and 3 components.

3.9.3.5.3.1 <u>Tanks, Heat Exchangers, and Filters</u>

Pressure vessels supplied for the auxiliary systems are:

A. Letdown heat exchanger

B. Shutdown cooling heat exchanger

C. Regenerative heat exchanger

D. Seal injection heat exchanger

E. Safety injection tanks

F. Volume control tank

G. Spray chemical storage tank

H. Equipment drain tank

I. Preholdup ion exchanger

J. Purification ion exchangers

K. Deborating ion exchanger

L. Purification filters

M. Seal injection filters

N. Reactor drain filter

O. Boric acid filter

Vessel assemblies, including supports, support attachment welds, and anchor bolts, are capable of withstanding specified horizontal and vertical seismic accelerations. The seismic accelerations are applied separately at the center of gravity acting in each of two orthogonal horizontal directions and either vertical direction. The stresses or reaction loads at a given point, due to the three separate analyses, are combined by the SRSS method to define a total seismic design condition. The design allowable nozzle forces and moments act in directions that yield the highest stress which combined with the seismic loads, as determined above, and other concurrent loads.

For Class 2 and 3 pressure retaining parts under the concurrent loadings of the OBE and normal operation (upset conditions), the primary membrane stress is less than 1.1S, and the primary membrance plus bending stress is less than 1.65S. No emergency condition that has been identified for the applicable components is more severe than the upset condition; therefore, no appropriate stress criteria are provided. Under the concurrent loadings of the normal operating condition and the SSE, the primary membrane stress is less than 2.0S, and the primary membrane plus bending stress is less than 2.4S. Where:

S = Allowable value of ASME Code, Section III.

Vessel components not subject to fluid pressure, such as supports, attachment welds, and anchor bolts, were designed to the stress criteria of ASME Code, Section III for the loading conditions defined above.

In cases where the natural frequency could not be increased to avoid amplification of the floor response of the postulated seismic input for a specific plant, the components were modeled as multi-mass systems, and their modal frequencies and maximum reactions were determined from the floor response spectra for the plant, using the ICES STRUDL II computer program. The maximum damping values used were 2% for OBE and 3% for SSE. The design point reactions due to each modal loading were combined by the STRUDL computer program as the sum of the absolute values or by root sum square of the modal reactions, as appropriate per recommendation of Regulatory Guide 1.92.

3.9.3.5.3.2 Valves

ASME Class 2 and 3 valves are designed by analysis to standard rules. Valve operating pressures are consistent with the recommendations of Regulatory Guide 1.48. For active valves, the design pressure rating is not exceeded, for nonactive valves the ratio of 1.1 Pr for upset and emergency conditions is not exceeded and 1.2 Pr for faulted conditions is not exceeded. Loading combinations are in accordance with Table 3.9.3-1. Stress limits are in accordance with Table 3.9.3-2 for active values and ASME Section III paragraphs NC 3522 or ND 3522 for non-active values.

3.9.3.5.3.3 Pumps

Pumps supplied for the Auxiliary Systems are:

A. Boric Acid Makeup (non-active) Code Class 3

B. Reactor Drain (non-active) Code Class 3

C. Spray Chemical Addition (active) Code Class 2 (abandoned in place)

D. Charging (active) Code Class 2

E. High Pressure Safety Injection (active) (Safeguard) Code Class 2

F. Low Pressure Safety Injection (active) (Safeguard) Code Class 2

G. Containment Spray (active) (Safeguard) Code Class 2

The design result and associated design stress limits applied in the design of ASME Code Class 2 and 3 pumps are in accordance with the ASME Code, Section III, respectively. The

results are supplemented in a manner consistent with Regulatory Guide 1.48, May 1973, as described herein.

Pump assemblies, including supports, support attachment welds, and bolts, are capable of withstanding specified horizontal and vertical seismic accelerations. The seismic accelerations are applied separately at the center of gravity acting in each of two orthogonal horizontal directions and either vertical direction. The stresses or reaction loads at a given point, due to the three separate analyses, are combined by the SRSS method to define a total seismic design condition. The design allowable nozzle forces and moments act in directions that yield the highest stress when combined with the seismic loads, as determined above, and other concurrent loads.

For Class 2 and 3 pressure retaining parts of non active pumps under the concurrent loadings of the OBE and normal operating (upset conditions), the primary membrane stress is less than 1.1S, and the primary membrane plus bending stress is less than 1.65S. No emergency condition that has been identified for the applicable components is more severe than the upset condition; therefore, no appropriate stress criteria are provided. Under the concurrent loadings of the normal operating conditions and the SSE (faulted conditions), the primary membrane stress is less than 2.0S, and the primary membrane plus bending stress is less than 2.4S. Where:

S = Allowable value of ASME Code, Section III.

For Class 2 and 3 pressure retaining parts of active pumps, the primary membrane stress is limited to the allowable stress value S, and primary membrane plus bending stress is limited to

1.5 S for each of the loading combinations associated with the upset, emergency and faulted plant operating conditions.

The stress criteria of the ASME Code, Section III are applied in the design of component supports to the same Code Class as the pressure boundary involved within the jurisdictional boundaries defined in the code for the loading conditions defined above. Those steel support structures which are considered to be an extension of the building structure, but supplied with the pump assembly (i.e., bedplates), are designed to the stress criteria of the AISC Manual of Steel Construction.

In addition, the Safeguard Pump assemblies are required to be capable of withstanding the following thermal transients:

A. HPSI and LPSI, suction temperature increases from 40°F to 300°F in 10 seconds. After each temperature change the end point is assumed to hold until temperature equilibrium is attained. Temperature returns to 40°F in several days. This transient would be applied a minimum of 10 times during the design life of the pump.

B. LPSI shutdown cooling operation applied for 500 cycles as follows:

   1. Suction temperature increases from 70°F to 350°F in about 1 minute.

   2. Suction temperature decrease from 350°F to 70°F in several hours.

3.9.3.6 Pump and Valve Operability Assurance for CE Scope

3.9.3.6.1 NSSS Active ASME Code Class 2 and 3 Pumps and Class 1, 2 and 3 Valves

3.9.3.6.1.1 Operability Assurance Program

Active pumps and valves are defined in Regulatory Guide 1.48 as components that require a mechanical motion in performing a safety function. The operability (i.e., performance of this mechanical motion) of active components during and after exposure to design bases events is confirmed per the recommendations of Regulatory Guide 1.48 by:

A. Designing each component to be capable of performing all safety functions during and following design bases events. The design specification includes applicable loading combinations, and conservative design limits for active components, consistent with the recommendations of Regulatory Guide 1.48. The specification requires that the manufacturer demonstrate operability by analysis or test (footnotes 6 and 11 of Regulatory Guide 1.48). The results are independently reviewed by the NSSS Supplier considering the effects of postulated failure modes on operability.

B. Analysis and/or test demonstrating the operability of each design under the most severe postulated loadings which are combined in a manner consistent with the recommendations of Regulatory Guide 1.48. Methods/results of operability demonstration programs are detailed in sections 3.9.3.6.1.2 and 3.9.3.6.1.3.

C. Inspection of each component to assure compliance of critical parameters with specifications and drawings. This inspection confirms that specified materials and processes were used, that wall thicknesses met code requirements, and that fits and finishes met the manufacturer's requirements based on design clearance requirements.

D. Shop testing of each component to verify "as built" conditions as defined in sections 3.9.3.6.1.2 and 3.9.3.6.1.3.

E. Startup and periodic inservice testing in accordance with ASME OM Code to demonstrate that the active pumps and valves are in operating condition throughout the life of the plant.

NSSS active pumps are listed below with a brief description of active safety function of each. NSSS active valves are listed in Table 3.9.3-3. CENPD-161-P-A (proprietary), April 1986.

Active Components	Active Safety Function
High-pressure safety injection pumps	Operate at flowrates to runout
Low-pressure safety injection pumps	Operate at flowrates to runout
Charging pumps	Operate

3.9.3.6.1.2 Operability Assurance Program Results for Active Pumps

3.9.3.6.1.2.1 High- and Low-Pressure Safety Injection Pumps. Operability of the high- and low-pressure safety injection (HPSI and LPSI) pumps under faulted conditions has been

demonstrated by analyses of the assemblies and by analyses and tests of the motors in accordance with the recommendations of Regulatory Guide 1.48.

For the HPSI pumps, the manufacturer has shown that allowable stresses are not exceeded, that clearances are acceptable and that shaft and pedestal bolt deflections do not cause stresses to exceed the normal values indicated by past experience for other pumps of the same type.

For the LPSI pumps, the manufacturer has shown that allowable stresses are not exceeded and that clearances remain acceptable under faulted loadings.

Where necessary, lumped mass models are used with the computer programs to determine the natural frequencies and displacements. The models are conservative (i.e., simplifications tend to make them more flexible).

Operability was demonstrated under the following loads;

	HPSI Pump	LPSI Pump
Horizontal seismic, g's	1.1	1.1
Vertical seismic, g's	1.1	1.1
Design pressure, lb/in.^{2}	2050	710
Suction nozzle max, resultant force, lb	6713	22711
Suction nozzle max, resultant moment, ft-lb	12990	59225
Discharge nozzle max, resultant force, lb	2500	6611
Discharge nozzle max, resultant moment, ft-lb	2500	33237

To verify "as built" conditions the HPSI and LPSI pumps were hydrostatically tested in accordance with the ASME Boiler and Pressure Vessel Code, Section III to confirm acceptability of structural integrity of pressure retaining parts, tested for seal leakage, and tested for performance and NPSH characteristics in accordance with the Hydraulic Institute

Standard to verify operation within specified parameters. The motors were built as Class IE and were tested in accordance with IEEE Standard 112A-1964 to verify operation within specified parameters. Additionally, the motors were qualified to IEEE Standard 323-1974 and IEEE Standard 344-1975 to assure operability during and following design basis events.

3.9.3.6.1.2.2 Charging Pumps. The charging pumps have a relatively complex geometry, which is difficult to analyze. Therefore, a simplified analysis and type test were used to confirm the charging pump functionality during and following a DBE.

A sinusoidal test with simultaneous 1.5 g horizontal and vertical accelerations was conducted. The test on the pump assembly, including its supports, showed no significant natural frequencies in the 1 to 33 Hz range. The fundamental linear natural frequency of the rotating parts of the pump was shown to be greater than 73 Hz. The base of the test pump had a fundamental natural frequency above 33 Hz. Therefore, the System 80 pumps are rigid to postulated seismic input.

The test pump was vibration tested with 2410 psig internal pressure, 1825-pound axial force and 610 ft-lb moment on the suction nozzle, and 1650-pound axial force and 550 ft-lb moment on the discharge nozzle. Simultaneous 1.5g accelerations is applied to the horizontal and vertical axes by driving the assembly in a 45 degree plane. The test was run with the horizontal input parallel to the motor axis. It was repeated with the horizontal input directed 90, 180, and then 270 degrees from the direction for the first test.

The pump was subjected to two sinusoidal sweeps at 1/2 octave per minute in each direction with 1.0g peak accelerations, limited to 12-inch double amplitude, from 1 to 35 Hz. One of the sweeps in each direction was with the pump operating and one with the pump idle. The test shows that no resonances applicable to functionality are in the range of concern, and the unit is therefore rigid to the postulated seismic input. The assembly, both operating and non-operating, was exposed to a 1.5g horizontal and vertical 30-second sinusoidal dwell at 2.5, 10, 12.25, 20, 23.8 and 33 Hz. The pump was shown to operate normally, and no evidence of damage or deterioration to critical parts exists. The 1.5g horizontal and vertical accelerations exceed the applicable response spectra. The successful test on these pumps demonstrates that the System 80 pumps operate during and following the postulated seismic event.

To verify "as built" conditions the charging pumps were hydrostatically tested in accordance with the ASME Boiler and Pressure Vessel Code, Section III to confirm acceptability of structural integrity of pressure retaining parts, tested for seal leakage, and tested for performance and NPSH characteristics in accordance with the Hydraulic Institute Standards to verify operation within specified parameters. The motors were built as Class IE and were tested in accordance with IEEE Standard 112A-1964 to verify operation within specified parameters. Additionally, the motors were qualified to IEEE Standard 323-1974 and IEEE Standard 344-1975 to assure functionality during and following design basis events.

3.9.3.6.1.3 Operability Assurance Program for Active Valves

Safety related active valves must perform their mechanical motion in times of an accident. The qualification program assures that these valves will operate during a seismic event. Qualification tests and/or analyses are conducted for all active valves.

Class 1, 2 and 3 valves are designed/analyzed according to the rules of the ASME Boiler and Pressure Vessel Code, Section III, Section NB-3500, NC-3500, and ND-3500 respectively.

Procurement specifications for safety related active valves stipulate that vendor shall submit either detailed calculations and/or test data to demonstrate operability when subjected to the specification loading and stress criteria (normal through faulted conditions). The decision to accept actual or prototype test data, or analysis for operability assurance is made during the normal design and procurement process. The decision to test is based on (1) whether the component is amenable to analysis, (2) whether proven analytical methods are available, and (3) whether applicable prototype test data is available. If analysis or prototype test data is not sufficient, testing is conducted to qualify the component or to verify the analytical technique.

Where appropriate, valve stem deflection calculations are performed to determine deflections due to short term seismic and other applicable loadings. Deflections so determined are compared to allowable clearances. It must be noted that seismic events are of short duration; thus, contact (if it occurs) does not demonstrate that operability is adversely

affected. Cases where contact occurs are reviewed on a case by case basis to determine acceptability.

The operability of active Code Class 1, 2 and 3 components is assured through an extensive program of design verification, qualification testing and thorough surveillance of the manufacturing, assembly and shop testing of each active component. Each aspect of the design related to pressure boundary integrity and operability is either tested or verified by calculations. Procedures for testing are developed by component manufacturers and reviewed and approved by the NSSS supplier before the tests are conducted. The design analyses of the component take into consideration environmental conditions including loadings developed from seismic, operational effects, and pipe loads. Where necessary and feasible, the conclusions of these analyses are confirmed by test.

On all active valves, an analysis of the extended structure is also performed for static equivalent seismic SSE loads supplied at the center of gravity of the extended structure. The maximum stress limits allowed in these analyses show that structural integrity is within the limits developed and accepted by the ASME Code.

The safety-related valves are subjected to a series of tests prior to service and during the plant life. Prior to installation, the following tests are performed; shell hydrostatic test to ASME Sections III requirements, backseat and main seat leakage tests, disc hydrostatic test, functional tests to verify that the valve will open and close within the specified time limits, operability qualification of motor

operators for the environmental conditions over the installed life (i.e., aging, radiation, accident environment simulation, etc.) according to IEEE 382. Cold hydro qualification tests, hot functional qualification tests, periodic inservice inspections, and periodic inservices operation are performed in-situ to verify and assure the functional ability of the valves. These tests ensure the reliability of the valve for the design life of the plant. The valves are designed using either stress analyses or the pressure containing minimum wall thickness requirements.

All the active valves shall be designed to have a first natural frequency which is greater than 33 Hz. This is shown by suitable test or analysis.

The above outlines in general the methods used to assure valve operability. Each vendor's specific program is described in Section 3.9.3.2.

In addition to the above, the following specific operability assurances are provided for the various type valves:

3.9.3.6.1.3.1 Pneumatically Operated Valves

Pneumatic operated valves are furnished by several vendors in CE System 80 Nuclear Power Plants. Methods of operability demonstration are discussed in general and discussed in detail in Section 3.9.3.2.1.2 subject to the vendor(s) utilized. Spring actuation of the valve is the required active safety function. Loss of electric power or supply air will result in venting of the actuator and return of the valve to the safe position. Each vendor provides their own method to demonstrate valve operability. The operability for these valves is

demonstrated by analysis, test or by a combination of analysis and test. The vendor considers concurrent loads including seismic, design pressure and pipe loads.

The three-way solenoid valve was qualified by test to IEEE-382-1972, IEEE-323-1974 and IEEE-344-1975. Testing included thermal aging, radiation aging, wear aging, vibration endurance, seismic event simulation, and loss of coolant accident. All test results provided satisfactory evidence of air solenoid valve operability.

Limit switches, used to determine valve position, were qualified by testing to IEEE-323-1974, IEEE-344-1975 and IEEE-382-1972. Switches were successfully performance tested for aging simulation, wear aging, radiation exposure, seismic qualification, and design basis event environmental conditions. For valves outside of containment and utilizing EA-170 limit switches, the switches were seismically qualified to IEEE-344-1975 and were tested to sustain radiation dosages up to 2×10^8 rads.

3.9.3.6.1.3.2 Motor Operated Valves

Motor operated valves are qualified by analysis as a minimum as described above. The analysis for each valve assembly considers the effects of seismic loads, design pressure, and piping reaction forces to provide assurance of operability.

To provide full qualification of the motor operated valve actuator, environmental and seismic qualification tests were conducted to simulate the following conditions:

A. Inside Containment (LOCA)

B. Outside Containment

C. Seismic Qualification

D. Steam Line Break Accident

Mid-size valve actuators were subjected to complete environmental qualification consisting of inside containment and outside containment. Each qualification exposed the actuator to thermal and mechanical aging, radiation aging, seismic aging, environmental transient profile test, and steam line break. For the steam line break test an actuator was subjected to a very high superheated temperature to demonstrate that the electrical components of the actuator never exceeded the saturated temperature corresponding to the ambient pressure for the short duration of the test. This short term test proves the existing qualification envelopes the steam line break for superheated temperatures as high as 492°F for a few minutes.

The qualification of the mid-size valve actuator was used to generically qualify all sizes of mid-size valve actuator operators for the environmental test conditions in accordance with IEEE-382-1972. All sizes are constructed of the same materials with components designed to equivalent stress levels, and to the same clearances and tolerances with the only difference being in physical size which varies corresponding to the differences in unit rating.

All the qualifications were conducted per IEEE 382-1972 and meet the requirements of IEEE 323-1974 and IEEE 344-1975 as they apply to valve motor actuators. Further, since the actuators performed satisfactorily without maintenance

throughout the various qualifications, the valve actuators are fully qualified for use in CE Nuclear Power Generating Plants.

3.9.3.6.1.3.3 Pressurizer Safety Valves

Pressurizer Safety valves are 6 x 8 valves. Operability has been successfully demonstrated by a combination of dynamic testing and analysis or by static testing. Operability was successfully demonstrated with a 6g seismic load by one vendor or with a 7.1g seismic load by another vendor. Dynamic testing has demonstrated that the natural frequency of both valves was greater than 33 Hz. A summary of the test programs follows:

A. Vendor A Safety Valves

1. Natural Frequency Demonstration

   Vibration input was in a single, horizontal direction. It was established by previous experience that the horizontal direction was more significant than the vertical direction, and that there was no material difference between the various horizontal directions. The frequency of vibration was increased from 5 to 75 Hz at a rate of 1 octave per minute. Accelerometers were mounted on the valve assembly. The actual natural frequency under test conditions was 38 Hz.

2. Operability Demonstration

   A series of tests demonstrated that the valve would fully open and reseat during and after a seismic acceleration. Vibration input ranged from 3 to 6g and 10 to 33 Hz. The tests were performed using

saturated steam. In addition, analysis was used to establish the significance of nozzle loading. The results indicated that deformation was significantly less than the internal clearances. This loading was therefore neglected in the seismic operability tests.

B. Vendor B Safety Valves

1. Natural Frequency Demonstration

A resonance survey was performed along three orthogonal axes with one axis being the centerline of the outlet port. (Valve mounted on inlet port.) No resonant frequencies were detected in the range of 1-50 Hz on any axis.

2. Operability Demonstration

A series of tests demonstrated that the valve would fully open and reseat during and after applying the following loading combinations: Static seismic loads up to 7.1g were applied to the valve in the direction of least bending stiffness. In addition the maximum permissible piping loads were applied concurrently. The tests were performed using saturated steam. Valve operation was satisfactory.

C. EPRI Testing of Safety Valves

One manufacturer's valve was tested in the EPRI Test Program under full pressure and full flow conditions. This testing has demonstrated that stable valve operation under these conditions is dependent upon the inlet pipe configuration, built up back pressure range

and blowdown setting. Prior to plant startup the inlet pipe configuration and built up back pressure range for each specific plant will be examined by CE and the applicable valve vendor. If necessary, the valves will be adjusted to provide blowdown settings which will result in stable valve operation. These blowdown settings will be recommended by the vendor and approved by CE. These adjustments will be based on the results obtained in the EPRI Test Program. Required adjustments to the valve to assure operability will be documented in the plant specific FSAR.

3.9.3.6.1.3.4 Check Valves. The check valves are characteristically simple in design and their operation will not be affected by seismic accelerations or the maximum applied nozzle loads. The check valve design is compact and there are no extended structures or masses whose motion could cause distortions which could restrict operation of the valve. The nozzle loads due to maximum seismic excitation will not affect the functional ability of the valve since the valve disc is designed to be isolated from the casing wall. The clearance supplied by the design around the disc will prevent the disc from becoming bound or restricted due to any casing distortions caused by nozzle load. Therefore, the design of these valves is such that once the structural integrity of the valve is assured using standard design or analysis methods, the ability of the valve to operate is assured by the design features. In addition to these design considerations, the valve will also undergo, (1) stress analysis including the SSE loads,

MECHANICAL SYSTEMS AND COMPONENTS

TABLE 3.9.3-1

LOADING COMBINATIONS ASME CODE CLASS 1, 2, AND 3 NSSS COMPONENTS

Condition	Design Loading[a] Combination
Design	PD
Normal[b]	PO+DW
Upset[b]	PO+DW+OBE
Emergency	PO+DW+DE
Faulted	PO+DW+SSE+DF

A) Legend:

PD = Design pressure

PO = Operating pressure

DW = Dead weight

OBE = Operating Basis earthquake

SSE = Safe shutdown earthquake

DE = Dynamic system loadings associated with the emergency condition

DF = Dynamic system loadings associated with a postulated pipe rupture (LOCA) for ASME Code Class 1 NSSS components. See the Applicant's SAR for the effects of postulated piping terminal end breaks for ASME Code Class 2 and 3 components.

B) As required by ASME Code Section III, other loads, such as thermal transient, thermal gradient, and anchor point displacement portions of the OBE require consideration in addition to the primary stress producing loads listed.

TABLE 3.9.3-2
STRESS LIMITS FOR ASME CODE CLASS 1
NSSS COMPONENTS, PIPING, AND COMPONENT SUPPORTS

	COMPONENT AND PIPING STRESS LIMITS (a)	COMPONENT SUPPORT STRESS LIMITS (c)
Design	NB-3221, NB-3231 and NB-3652	NF-3221 or NF-3231, and NF-3280
Normal	NB-3222, NB-3232 and NB-3653	NF-3222 or NF-3231, and NF-3280
Upset	NB-3223, NB-3233 and NB-3654	NF-3223 or NF-3231, and NF-3280
Emergency	NB-3224, NB-3234 and NB-3655	NF-3224 or NF-3231, and NF-3280
Faulted	NB-3225, NB-3235 and NB-3656 (d)	NF-3225 or NF-3231 (b)

a) Stress limits listed are used as required by ASME Section III, and applicable addenda for all components except active components. Active components are designed to the stress limits of NB-3221 and NB-3231 for Design Conditions and the stress limits of NB-3222 and NB-3232 for all other conditions for active components.

b) For faulted condition loadings, bolts in the load path connecting two members of an NF support for Class 1 components are designed in accordance with Appendix XVII of the ASME Code for friction type connections with tensile stresses limited to the lesser of 0.7 Su or Sy.

c) Stress limits used are as required by ASME Section III and applicable addenda and modified by Regulatory Guide 1.124 and 1.130. Component standard supports may be designed to the limits of NF-3260.

d) The deformation resulting from the application of a moment in excess of the maximum Level D moment, determined on an elastic basis, (56.7 x 106 in-lb) permitted by NB 3656 of Section III of the ASME Code has been calculated to demonstrate piping functionability following postulated pipe rupture. The calculated deformation is shown in Figure 3.9.3-1.

TABLE 3.9.3-3
NSSS SEISMIC I ACTIVE VALVES(4) (Sheet 1 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 134	Safety Injection Sys. (Operate)	12	Swing Check	2	None
SI 143	Safety Injection Sys. (Operate)	3	Swing Check	2	None
SI 144	Safety Injection Sys. (Operate)	12	Swing Check	2	None
SI 164	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 165	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 179	Shutdown Cooling Suction Relief (Operate)	6 x 10	Relief	2	None
SI 189		6 x 10	Relief	2	None
SI 169	Shutdown Cooling Suction Thermal Relief (Operate)	3/4 x 1	Relief	1	None
SI 469		3/4 x 1	Relief	1	None
SI 215	Safety Injection Sys. (Operate)	14	Swing Check	1	None
SI 217	Safety Injection Sys. (Operate)	14	Swing Check	1	None
SI 225	Safety Injection Sys. (Operate)	14	Swing Check	1	None
SI 227	Safety Injection Sys. (Operate)	14	Swing Check	1	None
SI 235	Safety Injection Sys. (Operate)	14	Swing Check	1	None
SI 237	Safety Injection Sys. (Operate)	14	Swing Check	1	None
SI 245	Safety Injection Sys. (Operate)	14	Swing Check	1	None
SI 247	Safety Injection Sys. (Operate)	14	Swing Check	1	None
SI 321	Safety Injection Sys. (Operate)	3	Globe	2	Motor
SI 322	Safety Injection Sys. (Close)	1	Globe	1	Pneumatic
SI 331	Safety Injection Sys. (Operate)	3	Globe	2	Motor
SI 332	Safety Injection Sys. (Close)	1	Globe	1	Pneumatic
SI 522	Safety Injection Sys. (Operate)	3	Swing Check	1	None
SI 523	Safety Injection Sys. (Operate)	3	Swing Check	1	None
SI 532	Safety Injection Sys. (Operate)	3	Swing Check	1	None
SI 533	Safety Injection Sys. (Operate)	3	Swing Check	1	None

TABLE 3.9.3-3
NSSS SEISMIC I ACTIVE VALVES(4) (Sheet 2 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 605	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 606	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 607	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 608	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 611	Safety Injection Tank Fill Valve (Close)	2	Globe	2	Pneumatic
SI 613	Safety Injection Tank Fill Vent (Operate)	1	Globe	2	Solenoid
SI 614	Safety Injection Tank Isolation (Operate)	14	Gate	1	Motor
SI 615	LPSI Header Isolation Valve (Operate)	12	Globe	2	Motor
SI 616	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 617	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 618	Leakage Return to RWT (Close)	1	Globe	1	Pneumatic
SI 621	Safety Injection Tank Fill Valve (Close)	2	Globe	2	Pneumatic
SI 623	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 624	Safety Injection Tank Isolation (Operate)	14	Gate	1	Motor
SI 625	LPSI Header Isolation Valve (Operate)	12	Globe	2	Motor
SI 626	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 627	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 628	Leakage Return to RWT (Close)	1	Globe	1	Pneumatic
SI 631	Safety Injection Tank Fill Valve (Close)	2	Globe	2	Pneumatic
SI 633	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 634	Safety Injection Tank Isolation (Operate)	14	Gate	1	Motor

TABLE 3.9.3-3
NSSS SEISMIC I ACTIVE VALVES[4] (Sheet 3 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 635	LPSI Header Isolation Valve (Operate)	12	Globe	2	Motor
SI 636	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 637	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 638	Leakage Return to RWT (Close)	1	Globe	1	Pneumatic
SI 641	Safety Injection Tank Fill Valve (Close)	2	Globe	2	Pneumatic
SI 643	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 644	Safety Injection Tank Isolation (Operate)	14	Gate	1	Motor
SI 645	LPSI Header Isolation Valve (Operate)	12	Globe	2	Motor
SI 646	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 647	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 648	Leakage Return to RWT (Close)	1	Globe	1	Pneumatic
SI 651	Shutdown Cooling Suction (Operate)	16	Gate	1	Motor
SI 652	Shutdown Cooling Suction (Operate)	16	Gate	1	Motor
SI 754	Shutdown Cooling Suction Valve Bonnet Relief (Operate)	1/2 x 1	Relief	1	None
SI 755		1/2 x 1	Relief	1	None
SI 653	Shutdown Cooling Suction (Operate)	16	Gate	1	Motor
SI 654	Shutdown Cooling Suction (Operate)	16	Gate	1	Motor
SI 997	Shutdown Cooling Suction Valve Bonnet Relief (Operate)	1	Spring-loaded Check	1	None
SI 998		1	Spring-loaded Check	1	None
SI 655	Shutdown Cooling Suction (Operate)	16	Gate	2	Motor
SI 656	Shutdown Cooling Suction (Operate)	16	Gate	2	Motor
SI 690	Safety Injection Sys. (Operate)	10	Globe	2	Motor
SI 691	Safety Injection Sys. (Operate)	10	Globe	2	Motor

TABLE 3.9.3-3
NSSS SEISMIC I ACTIVE VALVES(4) (Sheet 4 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 157	Safety Injection Sys. (Operate)	18	Swing Check	2	None
SI 158	Safety Injection Sys. (Operate)	18	Swing Check	2	None
SI 200	Safety Injection Sys. (Operate)	20	Swing Check	2	None
SI 201	Safety Injection Sys. (Operate)	20	Swing Check	2	None
SI 205	Safety Injection Sys. (Operate)	24	Swing Check	2	None
SI 206	Safety Injection Sys. (Operate)	24	Swing Check	2	None
SI 306	Safety Injection Sys. (Operate)	10	Globe	2	Motor
SI 307	Shutdown Cooling Sys. (Operate)	10	Globe	2	Motor
SI 404	Safety Injection Sys. (Operate)	4	Swing Check	2	None
SI 405	Safety Injection Sys. (Operate)	4	Swing Check	2	None
SI 424	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 426	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 434	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 446	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 448	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 451	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 484	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 485	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 486	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 487	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 604	HPSI Hot Leg Isolation (Operate)	3	Gate	2	Motor
SI 609	HPSI Hot Leg Isolation (Operate)	3	Gate	2	Motor
SI 657	Shutdown Cooling (Operate)	16	Butterfly	2	Motor
SI 658	Shutdown Cooling (Operate)	16	Butterfly	2	Motor

TABLE 3.9.3-3
NSSS SEISMIC I ACTIVE VALVES(4) (Sheet 5 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 659	Mini Flow Isolation (Operate)	4	Globe	2	Solenoid
SI 660	Mini Flow Isolation (Operate)	4	Globe	2	Solenoid
SI 664	CSP Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 665	CSP Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 666	HPSI Pump Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 667	HPSI Pump Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 668	LPSI Pump Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 669	LPSI Pump Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 671	Containment Spray Isolation Valve (Operate)	8	Gate	2	Motor
SI 672	Containment Spray Isolation Valve (Operate)	8	Gate	2	Motor
SI 673	Sump Suction Isolation (Operate)	24	Butterfly	2	Motor
SI 674	Sump Suction Isolation (Operate)	24	Butterfly	2	Motor
SI 675	Sump Suction Isolation (Operate)	24	Butterfly	2	Motor
SI 676	Sump Suction Isolation (Operate)	24	Butterfly	2	Motor
SI 678	CSP Flow Control Valve (Operate)	10	Butterfly	2	Motor
SI 679	CSP Flow Control Valve (Operate)	10	Butterfly	2	Motor
SI 682	SIT Fill Line (Close)	2	Globe	2	Pneumatic
SI 683	LPSI Pump Suction (Operate)	20	Gate	2	Motor
SI 684	CSP Discharge (Operate)	10	Gate	2	Motor
SI 685	LPSI Discharge (Operate)	10	Gate	2	Motor
SI 686	SDCHX Discharge (Operate)	20	Gate	2	Motor

TABLE 3.9.3-3
NSSS SEISMIC I ACTIVE VALVES[4] (Sheet 6 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 687	SDCHX Discharge (Operate)	10	Gate	2	Motor
SI 688	SDCHX Spray Bypass (Operate)	10	Gate	2	Motor
SI 689	CSP Discharge (Operate)	10	Gate	2	Motor
SI 692	LPSI Pump Suction (Operate)	20	Gate	2	Motor
SI 693	SDCHX Spray Bypass (Operate)	10	Gate	2	Motor
SI 694	LPSI Discharge (Operate)	10	Gate	2	Motor
SI 695	SDCHX Discharge (Operate)	10	Gate	2	Motor
SI 696	SDCHX Discharge (Operate)	20	Gate	2	Motor
SI 698	HPSI Pump Orifice Bypass (Operate)	4	Gate	2	Motor
SI 699	HPSI Pump Orifice Bypass (Operate)	4	Gate	2	Motor
SI 113	Safety Injection Sys. (Operate)	3	Check	2	None
SI 114	Safety Injection Sys. (Operate)	12	Check	2	None
SI 123	Safety Injection Sys. (Operate)	3	Check	2	None
SI 124	Safety Injection Sys. (Operate)	12	Check	2	None
SI 133	Safety Injection Sys. (Operate)	3	Check	2	None
CH 118	VCT Outlet Check (Operate)	4	Swing Check	2	None
CH 144	CVCS (Open)	3	Packless diaphragm	3	Manual
CH 164	CVCS (Open)	3	Packless diaphragm	3	Manual
CH 174	CVCS (Open)	2	Packless diaphragm	3	Manual
CH 190	Gravity Feedline Check (Operate)	3	Swing Check	2	None
CH 203	Auxiliary Spray (Operate)	2	Globe	1	Solenoid
CH 205	Auxiliary Spray (Operate)	2	Globe	1	Solenoid
CH 239	Charging Line Backpressure (Close)	2	Globe	2	Pneumatic
CH 240	Charging Line Backpressure (Close)	2	Globe	1	Pneumatic

TABLE 3.9.3-34
NSSS SEISMIC I ACTIVE VALVES[4] (Sheet 7 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
CH 255	Seal Inj. Containment Isolation (Open)	1-1/2	Globe	2	Motor
CH 305	RWT Suction Check (Operate)	20	Swing Check	2	None
CH 306	RWT Suction Check (Operate)	20	Swing Check	2	None
CH 328	Charging Line Check (Operate)	2	Lift Check	2	None
CH 331	Charging Line Check (Operate)	2	Lift Check	2	None
CH 334	Charging Line Check (Operate)	2	Lift Check	2	None
CH 431	Auxiliary Spray Check (Operate)	2	Lift Check	1	None
CH 433	Charging Line Check (Operate)	2	Lift Check	1	None
CH 435	Charging Line to Loop 2A Bypass (Operate)	2	Spring-loaded Check	1	None
CH 440	HPSI Header Check (Operate)	2	Lift Check	2	None
CH 494	RMW Supply Line to RDT Check (Operate)	1-1/2	Lift Check	2	None
CH 505	RCP Controlled Bleed-Off Containment Isolation (Close)	1	Globe	2	Pneumatic
CH 506		1	Globe	2	Pneumatic
CH 515	Letdown Isolation Valve (Close)	2	Globe	1	Pneumatic
CH 516		2	Globe	1	Pneumatic
CH 523		2	Globe	2	Pneumatic
CH 524	Charging Line Isolation Valve (Open)	2	Globe	2	Motor
CH 530	RWT Suction Isolation (Operate)	20	Gate	2	Motor
CH 531		20	Gate	2	Motor
CH 560	RDT Suction Isolation (Close)	3	Globe	2	Pneumatic
CH 561	RDT Suction Isolation (Close)	3	Globe	2	Pneumatic
CH 580	RMW Supply Isolation to RDT Iso. (Close)	1-1/2	Globe	2	Pneumatic
CH 429	Charging Line Check Valve (Operate)	2	Lift Check	2	None

TABLE 3.9.3-3
NSSS SEISMIC I ACTIVE VALVES[4] (Sheet 8 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
CH 753	CVCS (Open)	3	Packless diaphragm	3	Manual
CH 755	CVCS (Open)	3	Packless diaphragm	2	Manual
CH 756	CVCS (Open)	3	Packless diaphragm	2	Manual
CH 757	CVCS (Open)	3	Packless diaphragm	2	Manual
CH 787	Seal Injection Check (Operate)	1	Lift Check	1	None
CH 802	Seal Injection Check (Operate)	1	Lift Check	1	None
CH 807	Seal Injection Check (Operate)	1	Lift Check	1	None
CH 812	Seal Injection Check (Operate)	1	Lift Check	1	None
CH 835	Seal Injection Check (Operate)	1-1/2	Lift Check	2	None
CH 866	Seal Injection Check (Operate)	1	Lift Check	1	None
CH 867	Seal Injection Check (Operate)	1	Lift Check	1	None
CH 868	Seal Injection Check (Operate)	1	Lift Check	1	None
CH-869	Seal Injection Check (Operate)	1	Lift Check	1	None
RC 108	Pressurizer vent (Operate)	1	Globe	1	Solenoid
RC 109	Pressurizer vent (Operate)	1	Globe	1	Solenoid
RC 200	RCS (Operate)	6 x 8	Safety	1	None
RC 201	RCS (Operate)	6 x 8	Safety	1	None
RC 202	RCS (Operate)	6 x 8	Safety	1	None
RC 203	RCS (Operate)	6 x 8	Safety	1	None
RC 244	RCS (Operate)	4	Internals Removed	1	None

NOTE:

1. (Operate) is defined as valve being capable of both opening and closing.
2. (Close) is defined as valve being capable of moving to or maintaining a closed position.
3. (Open) is defined as valve being capable of moving to or maintaining an open position.
4. For application of the single failure rule to check valves, refer to Section 3.1.30.

(2) in-shop hydrostatic tests, (3) in-shop seat leakage test, and (4) periodic in-situ valve exercising and inspection to assure the functional ability of the valve.

3.9.4 CONTROL ROD DRIVE SYSTEMS

3.9.4.1 Descriptive Information of CEDM

The control element drive mechanisms (CEDMs) are magnetic jack type drives used to vertically position and indicate the position of the full-strength control element assemblies (FSCEAs) and the part-strength control element assemblies (PSCEAs) in the core. Each CEDM is capable of withdrawing, inserting, holding, or tripping the FSCEA/PSCEA from any point within its 153 inch stroke in response to operation signals.

The CEDM is designed to function during and after all normal plant transients. The FSCEA drop time for 90% insertion is 4.0 seconds maximum. The drop time is defined as the interval between the time power is removed from the CEDM coils to the time the FSCEA has reached 90% of its fully inserted position. This maximum drop time does not apply to the PSCEAs which are not considered for SDM. The CEDM pressure boundary components have a design life of 40 years. The CEDM is designed to operate without maintenance for a minimum of 1-1/2 years and without replacing components for a minimum of 3 years. The CEDM is designed to function normally during and after being subjected to the operating basis earthquake loads. The CEDM will allow for tripping of the FSCEA/PSCEA during and after a safe shutdown earthquake.

The design and construction of the CEDM pressure housing fulfill the requirements of the ASME boiler and Pressure Vessel

Code, Section III, for Class 1 vessels. The CEDM pressure housings are part of the reactor coolant pressure boundary, and they are designed to meet stress requirements consistent with those of the vessel. The pressure housings are capable of withstanding, throughout the design life, all normal operating loads, which include the steady-state and transient operating conditions specified for the vessel. Mechanical excitations are also defined and included as a normal operating load. The CEDM pressure housings are service rated at 2500 lb/in.^{2} at 650°F. The loading combinations and stress limit categories are presented in Table 3.9.4-1 and are consistent with those defined in the ASME code.

The design duty requirements for the CEDM is a total cumulative CEA travel of 100,000 feet operation without loss of function.

The test programs performed in support of the CEDM design are described in Section 3.9.4.4.

3.9.4.1.1 Control Element Drive Mechanism Design Description

The CEDMs are mounted on nozzles on top of the reactor vessel closure head. The CEDMs consist of the upper and lower CEDM pressure housings, motor assembly, coil stack assembly, reed switch assemblies, and extension shaft assembly. A typical CEDM outline drawing is shown in Figure 3.9.4-1. The drive power is supplied by the coil stack assembly, which is positioned around the CEDM housing. Two position indicating reed switch assemblies are supported by the upper pressure housing shroud, which encloses the upper pressure housing assembly.

The lifting operation consists of a series of magnetically operated step movements. Two sets of mechanical latches are utilized engaging a notched extension shaft. To prevent excessive latch wear, a means has been provided to unload the latches during the engaging operations. The magnetic force is obtained from large dc magnet coils mounted on the outside of the lower pressure housing.

Power for the electromagnets is obtained from two separate supplies. A control programmer actuates the stepping cycle and moves the FSCEA/PSCEA by a forward oreverse stepping sequence. Control element drive mechanism hold is obtained by energizing deenergized. The FSCEAs/PSCEAs are tripped upon interruption of electrical power to all coils. Each CEDM is connected to the FSCEAs/PSCEAs by an extension shaft. The weight of the CEDMs and the FSCEAs/PSCEAs is carried by the pressure vessel head. Installation, removal, and maintenance of the CEDM is possible with the reactor vessel head in place; however, the CEDM is inaccessible during operation of the plant.

The axial position of a FSCEA/PSCEA in the core is indicated by three independent signals. One counts the CEDM steps electronically, and the other two consist of magnetically actuated reed switches located at regular intervals along the CEDM. These signals are designed to indicate FSCEA/PSCEA position to within $\pm$ 2-½ inches of the true location. This accuracy requirement is based on ensuring that the axial alignment between FSCEAs/PSCEAs is maintained within acceptable limits. Refer to UFSAR Sections 7.5.1.1.4 and 7.7.1.3.2.3 for a more complete description of the three position signals.

The materials in contact with the reactor coolant used in the CEDM are listed in Section 4.5.1.

3.9.4.1.1.1 CEDM Pressure Housing

The CEDM pressure housing consists of the motor housing assembly and the upper pressure housing assembly. The motor housing assembly is attached to the reactor vessel head nozzle by means of a threaded joint and seal welded. Once the motor housing assembly is seal welded to the head nozzle, it need not be removed since all servicing of the CEDM is performed from the top of the housing. The upper pressure housing is threaded into the top of the motor housing assembly and seal welded. The upper pressure housing encloses the CEDM extension shaft and contains a vent.

3.9.4.1.1.2 Motor Assembly

The motor assembly is an integral unit which fits into the motor housing and provides the linear motion to the CEA. The motor assembly consists of a latch guide tube, upper latches and lower latches.

Both upper latches and lower latches are used to perform the stepping of the CEA and by proper sequencing perform a load transfer function to minimize latch and extension shaft wear. The upper latch also performs the holding when CEA motion is not required. Engagement of the extension shaft occurs when the appropriate set of magnetic coils is energized. This moves sliding magnets which cam a two-bar linkage moving the latches inward. The upper latches move vertically 7/16" while the lower latches move vertically 3/8" to perform both the load

transfer and stepping action. Total CEA motion per cycle is limited to 3/4".

3.9.4.1.1.3 Coil Stack Assembly

The coil stack assembly for the CEDM consists of four large DC magnet coils mounted on the outside of the motor housing assembly. The coils supply magnetic force to actuate mechanical latches for engaging and driving the CEA extension shaft. Power for the magnetic coils is supplied from two separate supplies. A CEDM control system actuates the stepping cycle and obtains the correct CEA position by a forward or reverse stepping sequence. CEDM hold is obtained by energizing the upper latch coil at a reduced current while all other coils are deenergized. The CEAs are tripped upon interruption of electrical power to all coils. Electrical pulses from the magnetic coil power programmer provide one of the means for transmitting CEA position indication.

A conduit assembly containing the lead wires for the coil stack assembly is located at the side of the upper pressure housing shroud.

3.9.4.1.1.4 Reed Switch Assembly

Two reed switch assemblies provide separate means for transmitting CEA position indication. Reed switches and voltage divider networks are used to provide two independent output voltages proportional to the CEA position. The reed switch assemblies are positioned so as to utilize the permanent magnet in the top of the extension shaft. The permanent magnet actuates the reed switches as it passes by them. The reed

switch assemblies are provided with accessible electrical connectors at the top of the upper pressure housing.

3.9.4.1.1.5 Extension Shaft Assembly

The extension shaft assemblies are used to link the CEDMs to the CEAs. The extension shaft assembly is a 304 stainless steel rod with a permanent magnet assembly at the top for actuating reed switches in the reed switch assembly, a center section called the drive shaft and a lower end with a coupling device for connection to the CEA.

The drive shaft is a long tube made of 304 stainless steel. It is threaded and pinned to the extension shaft. The drive shaft has circumferential notches in 3/4" increments along the shaft to provide the means of engagement to the control element drive mechanism.

The magnet assembly, located in the top of the extension shaft assembly, consists of a housing, magnet and plug. The magnet is made of two cylindrical Alnico-5 magnets. This magnet assembly is used to actuate the reed switch position indication and is contained in a housing which is plugged at the bottom of the housing.

3.9.4.1.2 Description of the CEDM Motor Operation

Withdrawal or insertion of the CEA is accomplished by programming current to the various coils. There are three programmed conditions for each coil; high voltage for initial gap closure, low voltage for maintaining the gap closed and zero voltage to allow opening of the gap.

3.9.4.1.2.1 Operating Sequence for the Double Stepping Mechanism

The initial condition is the hold mode. In this condition, the upper latch coil is energized at low voltage.

Withdrawal

1. The upper lift coil is energized causing the 7/16" upper lift gap to close lifting the CEA.
2. The lower latch coil is energized causing the lower latches to engage the drive shaft with 1/32" clearance.
3. The upper lift coil is deenergized allowing the upper latches to drop 7/16" and the drive shaft to lower 1/32" placing the load on the lower latches.
4. The upper latch coil is deenergized disengaging the upper latches.
5. The lower lift coil is energized lifting the drive shaft 3/8".
6. The upper latch coil is energized engaging the upper latches in the drive shaft with 1/32" clearance.
7. The lower lift coil is deenergized allowing the lower latches to drop 3/8" and causing the drive shaft to drop 1/32" applying the load on the upper latches.
8. The lower latch coil is deenergized disengaging the lower latches from the drive shaft.

Insertion

1. The lower latch coil is energized causing the lower latches to engage the drive shaft.
2. The lower lift coil is energized lifting the lower latches 3/8" and lifting the drive shaft 1/32" thus applying the load to the lower latches.
3. The upper latch coil is deenergized causing the upper latches to disengage the drive shaft.
4. The upper lift coil is energized, moving the deenergized upper latch assembly up 7/16".
5. The upper latch coil is energized engaging the latches with clearance, 11/32".
6. The lower lift coil is deenergized, allowing the lower latches to drop with the drive shaft, 3/8. The drive shaft will move down 11/32" stopping on the upper latch assembly which is energized and in its up position.
7. The lower latch coil is deenergized disengaging the lower latches.
8. The upper lift coil is deenergized lowering the upper latch assembly with the drive shaft 7/16".

3.9.4.2 Applicable CEDM Design Specifications

The pressure boundary components are designed and fabricated in accordance with the requirements for Class 1 vessels per the applicable Edition and Addendums of Section III of the ASME Boiler and Pressure Vessel Code. The pressure boundary material complies with the requirements of Section III and IX

of the ASME Boiler and Pressure Vessel Code and Code Case N-4-11.

The adequacy of the design of the non pressure boundary components have been verified by prototype accelerated life testing as discussed in Section 3.9.4.4.

The reed switch position transmitter assembly of the CEDM is designed to comply with IEEE 323-1974, standard for "Qualification of Class I Electrical Equipment for Nuclear Power Generating Stations," and IEEE 344-1975, "Recommended Practice Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations." The electrical components are external to the pressure boundary and are non-pressurized.

The test program to verify the CEDM design is discussed in Section 3.9.4.4.

3.9.4.3 Design loads, Stress Limits, and Allowable Deformations

The CEDM stress analyses consider the following loads:

A. Reactor coolant pressure and temperature

B. Reactor operating transient conditions

C. Dynamic stresses produced by seismic loading

D. Dynamic stresses produced by mechanical excitations

E. Loads produced by the operation and tripping of the mechanism

F. Loads produced by loss-of-coolant accident.

The methods used to demonstrate that the CEDMs operate properly under seismic conditions are presented in Section 3.7.3.14.

The design and fabrication of the CEDM pressure boundary components fulfills the requirements of the ASME Code, Section III, for Class I vessels. The pressure housings are capable of withstanding throughout the design life all the steady state and transient operating conditions specified in Table 3.9.4-1.

The adequacy of the design of the CEDM pressure boundary and non-pressure boundary components has been verified by prototype accelerated life testing as discussed in Section 3.9.4.4.

Clearances for thermal growth and for dimensional tolerances were investigated, and tests have proven that adequate clearances are provided for proper operation of the CEDM.

The latch locations are set by a master gage, and settings are verified by testing at reactor conditions.

A weldable seal closure, per Section III of the ASME Code, is provided for the vent valve in case of leakage.

The motor housing fasteners are mechanically positively captured, and all threaded connections are preloaded before capturing.

The coil stack assembly can be installed or removed simply by lowering or lifting the stack, relative to the CEDM pressure housing, for ease of coil replacement or maintenance.

3.9.4.4 CEDM Performance Assurance Program

3.9.4.4.1 CEDM Testing

3.9.4.4.1.1 Prototype Accelerated Life Tests

The PVNGS (System 80) CEDM is similar to and based on magnetic jack mechanisms used at other reactors such as Maine Yankee (Docket No. 50-309), Calvert Cliffs (Docket 50-317), as well as 150-inch core reactors such as Arkansas Nuclear One Unit 2 (Docket No. 50-368) and San Onofre Units 2 & 3 (Docket Nos. 50-361/362).

The significant differences between the System 80 drives and previous CEDMs are:

(1) The elimination of the pulldown coil and (2) the use of the lift coils to perform both a load transfer function and stepping action. The elimination of the pulldown coil required installation of a coil spring to ensure positive resetting of the latch assemblies. In addition, the drive shaft was modified by placing the teeth on 3/4" centerline in place of the 3/8" spacing of previous drive shafts to allow load transfer and stepping with the same coil. The safety release mechanism uses the same materials and clearances as on all previous magnetic jack mechanisms. The following describes accelerated life tests on both a pre-System 80 mechanism as well as on a prototype System 80 CEDM. Both programs provide design verification for the PVNGS CEDM.

A pre-System 80 prototype CEDM was subjected to an accelerated life test accumulating a minimum of 157,000 feet of travel on all CEDM components. In addition, the latch guide tube

bearings in the motor assembly saw an additional 50,000 feet of operation.

The prototype mechanism was installed on a test facility which was operated at a nominal temperature of 600°F and 2250 psi. After 50,000 feet of operation lifting 230 pounds at 40 inches per minute, the motor was removed from the test motor housing and the bearing surfaces inspected. During this inspection it was found that excessive wear existed on the upper gripper magnet and upper gripper housing bearings.

The gripper housing magnet bearing configuration was revised and replacement parts with this revision were incorporated into the prototype mechanism. This configuration was reinstalled into the test facility and the mechanism operated as before for an additional 157,000 feet of travel. The replacement parts showed a wear of only .001 inches while the latch guide tube bearings had a total wear of .012". The mechanism at disassembly was still operational with no abnormalities. This test constituted operation equivalent to 1.5 to 2.0 times the design duty requirements of the mechanism.

A prototype System 80 CEDM was assembled and installed in a test loop, where the accelerated wear test was conducted at 615°F and 2250 psi. The total weight attached to the CEDM was 450 pounds and this was moved at a nominal speed of 30 inches per minute. A total of thirty-four thousand (34,000) feet of travel was then completed without difficulty. Included in that test were 300 full height gravity scrams.

The mechanism motor was removed from the test facility and disassembled for inspection. The latch guide tube bearings

showed a maximum diametrical wear of .003" with negligible wear on the gripper housing to gripper magnetic bearings. Alignment tabs, which maintain orientation of the gripper with the latch guide tube, showed extensive wear but had not caused mechanism malfunctions. These alignment tabs were replaced in production units with an improved design.

Upon completion of the accelerated wear test, 300 full height light weight drops were completed utilizing a 75 lb. test weight. The maximum CEA drop time to 90% insertion was 2.93 seconds which met the 4.0 second criteria. All release times were less than .3 seconds with normal releases completed in less than .200 seconds.

3.9.4.4.1.2 First Production Test.

A qualification test program was completed on the first production C-E magnetic jack CEDM. During the course of this program, over 4000 feet of travel was accumulated and 30 full height gravity drops were made without mechanism malfunction or measurable wear on operating parts. The program included the following:

A. Operation at 40 in./min lifting 230 pounds (dry) at ambient temperature and 2300 psig pressure for 800 feet.

B. Six full-height 230 pounds dry weight gravity drops at ambient temperature.

C. Operation at simulated reactor operating condition at 40 in/min lifting 230 pounds for 1700 feet.

D. Six full-height drops at simulated reactor operating conditions with 230 pounds of weight.

E. An operational test at ambient temperature and 2300 psig pressure, lifting 335 pounds at 200 in/min. for 500 feet.

F. Six full-height drops of the 335 pound weight.

G. Operation at simulated reactor conditions for 1700 feet at 20 in/min, lifting 335 pounds.

H. Operation at ambient temperature and 2300 psig for 1100 feet and 20 full-height drops with an attached dry weight of 130 pounds.

The mechanism operated without malfunction throughout the test program and, upon final inspection, no measurable wear was found.

3.9.5 REACTOR PRESSURE VESSEL INTERNALS

3.9.5.1 <u>Design Arrangements</u>

The components of the reactor internals are divided into two major parts consisting of the core support structure and the upper guide structure assembly. The flow skirt, although functioning as an integral part of the coolant flow path, is separate from the internals and is affixed to the bottom head of the pressure vessel. The arrangement of these components is shown in Figure 3.9.5-1.

3.9.5.1.1 Core Support Structure

The major structural member of the reactor internals is the core support structure. The core support structure consists of the core support barrel and the lower support structure. The material for the assembly is Type 304 stainless steel.

TABLE 3.9.4-1

STRESS LIMITS FOR CEDM PRESSURE HOUSINGS

Operating Condition	Stress Categories and Limits of Stress Intensities[(a)]
1. Normal (level A) & Upset(Level B) : Normal Operating Loading plus Normal Operating & Upset Plant Transients plus Operating Basis Earthquake Forces.	Article NB-3222 (Normal/Level A) Article NB-3223 (Upset/Level B).
2. Faulted (Level D): Normal Operating Loadings plus Faulted Plant Transients plus Safe Shutdown Earthquake (SSE) and Branchline pipe breakloads.	Article NB-3225 (Faulted/Level D)
3. Testing: Testing Plant Transients	Article NB-3226

For the above listed operating conditions, the following limits regarding function apply:

1. Normal & Upset: The CEDMs are designed to function normally during and after exposure to these conditions.

2. Faulted: The deflections of the CEDM shall be limited, so that the CEAs can be inserted after exposure to these conditions.

a. References listed in Table 3.9.4-1 are taken from Section III, Subsection NB of the ASME Boiler and Pressure Vessel Code 1998 Edition through 2000 Addenda. Note that the ASME code replaced Normal with Level A; Upset with Level B; and Faulted with Level D.

The core support structure is supported at its upper end by the upper flange of the core support barrel, which rests on a ledge in the reactor vessel. Alignment is accomplished by means of four equally spaced keys in the flange, which fit into the keyways in the vessel lodge and closure head. The lower flange of the core support barrel supports, secures, and positions the lower support structure and is attached to the lower support structure by means of a welded flexural connection. The lower support structure provides support for the core by means of support beams that transmit the load to the core support barrel lower flange. The locating pins in the beams provide orientation for the lower ends of the fuel assemblies. The core shroud, which provides a flow path for the coolant and lateral support for the fuel assemblies, is also supported and positioned by the lower support structure. The lower end of the core support barrel is restricted from excessive radial and torsional movement by six snubbers which interface with the pressure vessel wall.

3.9.5.1.1.1 Core Support Barrel

The core support barrel is a right circular cylinder including a heavy external ring flange at the top end and an internal ring flange at the lower end. The core support barrel is supported from a ledge on the pressure vessel. The core support barrel, in turn, supports the lower support structure upon which the fuel assemblies rest. Press-fitted into the flange of the core support barrel are four alignment keys located 90 degrees apart. The reactor vessel, closure head, and upper guide structure assembly flange are slotted in

locations corresponding to the alignment key locations to provide alignment between these components in the vessel flange region. The core support barrel assembly is shown in Figure 3.9.5-2.

The upper section of the barrel contains two outlet nozzles that interface with internal projections on the vessel nozzles to minimize leakage of coolant from inlet to outlet.

Since the weight of the core support barrel is supported at its upper end, it is possible that coolant flow could induce vibrations in the structure. Therefore, amplitude limiting devices, or snubbers, are installed on the outside of the core support barrel near the bottom end. The snubbers consist of six equally-spaced lugs around the circumference of the barrel and act as a tongue-and-groove assembly with the mating lugs on the pressure vessel. Minimizing the clearance between the two mating pieces limits the amplitude of vibration. During assembly, as the internals are lowered into the pressure vessel, the pressure vessel lugs engage the core support barrel lugs in an axial direction. Radial and axial expansion of the core support barrel are accommodated, but lateral movement of the core support barrel is restricted. The pressure vessel lugs have bolted, captured Inconel X shims. The core support barrel lug mating surfaces are hardfaced with Stellite to minimize wear. The shims are machined during initial installation to provide minimum clearance. The snubber assembly is shown in Figure 3.9.5-3.

3.9.5.1.1.2 Lower Support Structure and Instrument Nozzle Assembly

The lower support structure and ICI nozzle assembly position and support the fuel assemblies, core shroud, and ICI nozzles. The structure is a welded assembly consisting of a short cylinder, support beams, a bottom plate, ICI nozzles, and an ICI nozzle support plate. The lowest support structure is made up of a short cylindrical section enclosing an assemblage of grid beams arranged in egg-crate fashion. The outer ends of these beams are welded to the cylinder. Fuel assembly locating pins are attached to the beams. The bottoms of the parallel beams in one direction are welded to an array of plates which contain flow holes to provide proper flow distribution. These plates also provide support for the ICI nozzles and, through support columns, the ICI nozzle support plate. The cylinder guides the main coolant flow and limits the core shroud bypass flow by means of holes located near the base of the cylinder. The ICI nozzle support plate provides lateral support for the nozzles. This plate is provided with flow holes for the requisite flow distribution. The lower support structure and ICI nozzle assembly is shown in Figure 3.9.5-4.

3.9.5.1.1.3 Core Shroud

The core shroud provides an envelope for the core and limits the amount of coolant bypass flow. The shroud consists of a welded vertical assembly of plates designed to channel the coolant through the core. Circumferential rings and a top and bottom end plate provide lateral support. The rings are attached to the vertical plates by means of welded ribs which

extend the full length of the core shroud. A small gap is provided between the core shroud outer perimeter and the core support barrel in order to provide upward coolant flow in the annulus, thereby minimizing thermal stresses in the core shroud. The core shroud is shown in Figure 3.9.5-5. Four hardfaced alignment lugs, spaced 90 degrees apart, protrude vertically from the top of the core shroud and engage in corresponding hardfaced slots in the upper guide structure fuel alignment plate to ensure proper alignment between the upper guide structure assembly, core shroud, and lower support structure.

3.9.5.1.2 Upper Guide Structure Assembly

The UGS assembly aligns and laterally supports the upper end of the fuel assemblies, maintains the control element spacing, holds down the fuel assemblies during operation, prevents fuel assemblies from being lifted out of position during a severe accident condition and protects the control elements from the effects of coolant cross flow in the upper plenum. The upper guide structure (UGS) assembly is handled as one unit during installation and refueling.

The UGS assembly consists of the UGS support barrel assembly and the CEA shroud assembly (Figure 3.9.5-6). The UGS support barrel assembly consists of UGS support barrel fuel alignment plate, UGS base plate and control element shroud tubes. The UGS support barrel consists of a right circular cylinder welded to a ring flange at the upper end and to a circular plate (UGS base plate) at the lower end. The flange, which is the supporting member for the entire UGS assembly, seats on its

upper side against the pressure vessel head during operation. The lower side of the flange is supported by the holddown ring, which seats on the core support barrel upper flange. The UGS flange and the holddown ring engage the core support barrel alignment keys by means of four accurately machined and located keyways equally spaced at 90 degree intervals. This system of keys and slots provides an accurate means of aligning the core with the closure head and thereby with the CEA drive mechanisms. The fuel alignment plate is positioned below the UGS base plate by cylindrical control element shroud tubes. These tubes are attached to the UGS base plate and the fuel alignment plate by rolling the tubes into the plates and welding. The fuel alignment plate is designed to align the lower ends of the control element shroud tubes which in turn locate the upper ends of the fuel assemblies. The fuel alignment plate also has four equally spaced slots on its outer edge which engage with Stellite hardfaced lugs protruding from the core shroud to provide alignment. The control element shroud tubes bear the upward force on the fuel assembly holddown devices. This force is transmitted from the alignment plate through the control element shroud tubes to the UGS barrel base plate.

The CEA shroud assembly limits cross flow and provides separation of the CEA assemblies. The assembly consists of an assemblage of large vertical tubes connected by vertical plates in a grid pattern. The shroud assembly is mounted on the UGS base plate and is held in position by eight tie rod tube assemblies which are threaded into the UGS base plate at their lower end. The tie rods are bolted against plates located at

the top of the CEA shroud assembly and are pretensioned. Guides for the CEA extension shafts are provided by the Guide Structure Support System. The tubes and connecting plates are furnished with multiple holes to permit hydraulic communication. Lateral movement of the vertical tube and plate assembly is minimized by four snubbers symmetrically located between this assembly and the top of the UGS support barrel.

The holddown ring provides axial force on the flanges of the upper guide structure assembly and the core support structure in order to prevent movement of the structures under hydraulic forces. The holddown ring is designed to accommodate the differential thermal expansion between the pressure vessel and the internals in the vessel ledge region.

3.9.5.1.3 Flow Skirt

The Inconnel flow skirt is a right circular cylinder, perforated with flow holes, and reinforced with two stiffening rings. The flow skirt is used to reduce inequalities in core inlet flow distributions and to prevent formation of large vortices in the lower plenum. The skirt is supported by nine equally spaced machined sections that are welded to the bottom head of the pressure vessel.

3.9.5.1.4 In-Core Instrumentation Support System

The complete in-core neutron flux monitoring system includes self-powered in-core detector assemblies, supporting structures and guide paths, an external movable detector drive system and an amplifier system to process detector signals. The self-powered in-core detector assemblies and the amplifier system

are described in Section 7.7. The external movable detector drive system and the instrumentation supporting structures and guide paths are described in this section and shown in Figure 3.9.5-7.

The support system begins outside the pressure vessel, penetrates the bottom of the vessel boundary and terminates in the upper end of the fuel assembly. Each in-core instrument is guided over its full length by the external guidance conduit, the pressure vessel nozzles, the lower support structure ICI nozzles and the instrument guide tube of the fuel assembly. Figure 3.9.5-4 shows the in-core instrument support structure. The in-core instrumentation support system routes the instruments so that detectors are located in selected fuel assemblies throughout the core. An equal instrument length exists for all locations. The guide tube routing outside the reactor vessel is a simple 180° bend to the seal table. The pressure boundaries for the individual instruments are at the out-of-reactor seal table, where the external electrical connections to the in-core instruments are made (Figure 3.9.5-7).

The in-core instrument assemblies contain a movable detector guide tube to allow insertion of a miniature movable flux detector. The assemblies have an integral seal plug which forms a seal at the instrument seal table and through which the signal cables and movable guide tube pass. Static O-ring seals are used to seal against operating pressure.

The movable detector drive system consists of two drive machines, two transfer machines, two drive cables with detectors and the interconnecting tubing. Because the two

halves of the system are identical with only several connections between them (leak detection and gas purge), only half of the system is described below.

A fission chamber is used as the moveable flux detection device. The detector signal cable is wound with an edgewise helical steel wrap to form the drive cable. This cable construction allows a hobbed wheel in the drive machine to drive the cable in either direction. The drive machine consists of a cable reel, a drive motor, gear reducer, hobbed drive wheel and a shaft position encoder. The detector may be positioned from the control room by use of the plant computer or a separate control box.

The detector may be shifted from any location to any other location in less than eight minutes. The detectors are shifted by the transfer machine which is mounted above the seal table. The machine consists of a geared drive motor, multiple position Geneva positioning mechanism, inlet and outlet tubes and miscellaneous limit and interlock switches. External commands control the motor to position the mechanism so that the inlet path is lined up with the correct outlet path. The transfer machine also has connections for inert gas blanketing and for guide tube leak detection. The gas connection allows an inert gas supply to blanket the transfer machine and movable detector guide tubes during machine operation.

The leak detector alarm system is a float switch mounted in a chamber which is fed from both transfer machines. Any leak which might occur in a movable detector guide tube flows to the transfer machine and then to the transfer machine sump, which exists to the leak detector. A solenoid valve past the leak

detector allows remote drainage of the leak detector sensing line.

3.9.5.2 Design Loading Conditions

The following loading conditions are considered in the design of the reactor internals.

A. Normal operating temperature differences

B. Normal operating pressure differences

C. Flow loads

D. Weights, reactions and superimposed loads

E. Vibration loads

F. Shock loads (including operating basis and safe shutdown earthquakes)

G. Anticipated transient loadings not requiring forced shutdown

H. Handling loads (not combined with other loads above)

I. Loads resulting from postulated loss-of coolant accidents

3.9.5.3 Design Loading Categories

The design loading conditions are categorized as follows:

3.9.5.3.1 Normal Operating and Upset

This category includes the combinations of design loadings consisting of normal operating temperature and pressure differences, loads due to flow, weights, reactions,

superimposed loads, vibration, shock loads including operating basis earthquake, and transient loads not requiring shutdown.

3.9.5.3.2 Faulted

This category consists of the loading combinations of Section 3.9.5.3.1 with the exception that the safe shutdown earthquake (in place of the operating basis earthquake) and the blowdown loads resulting from the loss-of-coolant accident are included.

3.9.5.4 Design Bases

3.9.5.4.1 Reactor Internals

The stress limits to which the reactor internals are designed are listed in Table 3.9-27A.

No emergency condition has been identified for the applicable components, therefore no stress criteria are provided.

The operating categories and stress limits are defined in the applicable section of the Section III of the ASME Boiler and Pressure Vessel Code.

The maximum stresses resulting from the LOCA and the SSE are combined to obtain the total stress intensities.

To properly perform their functions, the reactor internal structures are designed to meet the deformation limits listed below:

A. Under design loadings plus operating basis earthquake forces, deflection will be limited so that the control element assemblies (CEAs) can function and adequate core cooling is preserved.

B. Under normal operating loadings, plus SSE forces, plus pipe rupture loadings resulting from a break equivalent to a maximum of 0.5 square foot, deflections are limited so that the core will be held in place, adequate core cooling is preserved, and all CEAs can be inserted. Those deflections which would influence CEA movement are limited to less than 80% of the deflections required to prevent CEA insertion.

C. Under normal operating loadings, plus SSE forces, plus the maximum pipe rupture loadings resulting from the design basis pipe breaks, deflections are limited so that the core will be held in place and adequate core cooling is preserved. CEA insertion is not required for a safe and orderly shutdown for break sizes greater than 0.5 square foot, in accordance with the Safety Analysis described in 6.3.3.

The allowable deformation limits are listed in the following tabulation. Allowable limits are established as 80% of the loss-of-function deflection limits.

Location	Allowable Deflection (in)
Fuel lower end fitting, lower support structure	2.600 (Disengagement)
Fuel upper end fitting, upper guide structure	1.216 (Disengagement)
CEA Shroud (lateral)	0.209 (CEA Insertion)

In the design of critical reactor vessel internals components which are subject to fatigue, the stress analysis is performed utilizing the design fatigue curve of Figure I-9-2 of Section III of the ASME Boiler and Pressure Vessel Code. A cumulative usage factor of less than one is used as the limiting criterion.

As indicated in the preceding Sections, the stress and fatigue limits for reactor internals components are obtained from the ASME Code. Allowable deformation limits are established as 80% of the loss-of-function deflection limits. These limits provide adequate safety factors assuring that so long as calculated stresses, usage factors, or deformations do not exceed these limits, the design is conservative.

TABLE 3.9-27A

STRESS LIMITS FOR REACTOR INTERNALS

Operating Category	Limits of Stress Intensities[a]
Normal and Upset	Figure NG 3221.1 including notes.
Faulted	Appendix F, Rules for Evaluating Faulted Conditions, Section F-1380 and Table F-1322.2-1 including notes.

(a) References listed are taken from Section III of the ASME Boiler and Pressure Vessel Code. Only the stress-intensity criteria given by the ASME code are applicable to the reactor internal components.

3.9.6 INSERVICE TESTING OF PUMPS AND VALVES

The inservice testing program for Code Class 1, 2, and 3 pumps and valves will be conducted in accordance with the requirements of the ASME OM Code. This program will be implemented to assess operational readiness during preservice and inservice inspection.

3.9.6.1 Inservice Testing of Pumps

Inservice testing of pumps is limited by ASME OM Code to those pumps that are required to perform a specific function in shutting down a reactor or in mitigating the consequences of an accident, and are provided with an emergency power source. A list of the applicable Code Class 2 and 3 pumps is given in table 3.9-28. The required hydraulic and mechanical parameters will be measured by the methods and with the frequency prescribed in ASME OM Code.

3.9.6.2 Inservice Testing of Valves

Code Class 2 and 3 valves will be categorized in accordance with ASME OM Code. The valves will be tested according to the requirements of Subsection ISTC for each valve category. Certain valves will be exempt from testing in accordance with ASME OM Code.

Additionally, the RCS pressure isolation valves listed in table 3.9-29 are subject to Technical Specification 3.4.15, RCS pressure isolation valve leakage requirements.

The Class 1 to Class 2 boundary will be considered the isolation point which must be protected by redundant isolation valves.

Where pressure isolation is provided by two valves, both will be leak tested. When three or more valves provide isolation, only two of the valves will be leak tested.

Table 3.9-28
ASME CODE CLASS 2 AND 3 PUMPS SUBJECT TO
TESTING FOR OPERATIONAL READINESS PER ASME OM CODE

Equipment Tag Number	Description
M-SIA(B)-P02	HP safety injection pump
M-SIA(B)-P01	LP safety injection pump
M-DFA(B)-P01	Diesel fuel oil transfer pump
M-AFB-P01	Auxiliary feedwater pump (motor-driven)
M-AFA-P01	Auxiliary feedwater pump (turbine-driven)
M-SIA(B)-P03	Containment spray pump
M-EWA(B)-P01	Essential cooling water pump
M-SPA(B)-P01	Essential spray pond pump
M-ECA(B)-P01	Essential chilled water pump
M-CHA(B)-P01	Charging pump
M-CHE-P01	Charging pump

Table 3.9-29

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES[a] (PIVs) SUBJECT TO TECHNICAL SPECIFICATION 3.4.15 PIV LEAKAGE REQUIREMENTS

VALVE		DESCRIPTION
1)	SIE-V237	LOOP 1A RC/SI CHECK
2)	SIE-V247	LOOP 1B RC/SI CHECK
3)	SIE-V217	LOOP 2A RC/SI CHECK
4)	SIE-V227	LOOP 2B RC/SI CHECK
5)	SIE-V235	LOOP 1A SIT CHECK
6)	SIE-V245	LOOP 1B SIT CHECK
7)	SIE-V215	LOOP 2A SIT CHECK
8)	SIE-V225	LOOP 2B SIT CHECK
9)	SIE-V542	LOOP 1A SI HEADER CHECK
10)	SIE-V543	LOOP 1B SI HEADER CHECK
11)	SIE-V540	LOOP 2A SI HEADER CHECK
12)	SIE-V541	LOOP 2B SI HEADER CHECK
13)	SIA-V522	LOOP 1 HP LONG TERM RECIRCULATION CHECK
14)	SIA-V523	LOOP 1 HP LONG TERM RECIRCULATION CHECK
15)	SIB-V532	LOOP 2 HP LONG TERM RECIRCULATION CHECK
16)	SIB-V533	LOOP 2 HP LONG TERM RECIRCULATION CHECK
17)	SIA-UV651	LOOP 1 SHUTDOWN COOLING ISOLATION
18)	SIB-UV652	LOOP 2 SHUTDOWN COOLING ISOLATION
19)	SIC-UV653	LOOP 1 SHUTDOWN COOLING ISOLATION
20)	SID-UV654	LOOP 2 SHUTDOWN COOLING ISOLATION

a. For application of the single failure rule to check valves, refer to Section 3.1.30.

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APPENDIX 3.9A

COMPUTER CODE VERIFICATION

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APPENDIX 3.9A
COMPUTER CODE VERIFICATION

3.9A-1 INTRODUCTION

This Appendix provides documentary verification for those computer codes used in the analyses reported, which are not in the public domain.

Programs discussed in this Appendix include TMCALC, FORCE, NFATIG, DAGS, and AXEL.

3.9A-2 TMCALC

The C-E program TMCALC solves the differential equations of motion for a singly or multiply excited multi-degree-of-freedom linear structural system. The program accepts separate, independent, time-varying inputs at each boundary point in the system at which motions due to a seismic event may be imposed, or where a load forcing function may be imposed. The input excitations are provided in digitized form and are assumed to vary linear between input time steps. The solution of the equations of motion in normal mode coordinates employs a closed form integration process.

The inputs to TMCALC consist of:

A. Eigenvalues (natural frequencies) and eigenvectors (mode shapes).

B. A stiffness matrix which relates mass point degrees-of-freedom to boundary point degrees-of-freedom.

C. Mass and damping matrices.

D. Digitized time history records which define the excition in terms of motions at the boundary points of the structural system or forces at mass points.

The output from TMCALC consists of digitized time history records of the absolute accelerations and relative displacements for each mass point and boundary point dynamic degree-of-freedom of the structural system.

The program is used to calculate the dynamic response of structural models used in the dynamic seismic analysis of the reactor coolant system major components, and in the dynamic analysis of linear structural systems subjected to time varying load forcing functions, such as thrust from postulated pipe ruptures.

To demonstrate the applicability and validity of the TMCALC program, the solutions to test problems were obtained and shown to be substantially identical to the results obtained by hand calculations.

One such problem is shown here for the purposes of illustration. The satisfactory agreement between the program results and the theoretical solution indicates the reliability of TMCALC.

Figure 3.9A-1 is a lumped mass, shear beam representation of a uniform beam with the properties shown subjected to different, arbitrary motions at each of the two supports, as shown. The closed form solution to the equation of motion for this structure can be found using standard integration techniques (1). From this closed form solution of the

equations of motion of the multipliexcited system shown in Figure 3.9A-1 maximum values of relative displacement, velocity and acceleration were derived. These solutions are tabulated on Figure 3.9A-1 along with the corresponding results from program TMCALC. Differences can be seen to be less than 1%. The respective times at which these maxima occurred were identical.

3.9A-3 FORCE

The computer code program FORCE calculates the internal forces and moments at designated locations in a piecewise linear structural system, at each time step, due to the time history of relative displacements of the system mass points and boundary points. The program also selects the maximum value of each component of force or moment at each designated location, and the times at which they occur, over the entire duration of the specified dynamic event. The input to FORCE consists of the following:

A. A matrix of influence coefficients computed by the ICES/STRUDL-II[2] program which relate the displacements of the mass point and support point dynamic degrees-of-freedom to the reaction forces and moments or displacements at the designated locations.

B. The time history of the relative displacements of the mass point and support point dynamic degrees-of-freedom as calculated by the programs TMCALC or DAGS.

The program forms appropriate linear combinations of the relative displacements at each time step and performs a complete loads analysis of the deformed shape of the structure at each time step over the entire duration of the specified dynamic event.

The program is used to calculate the time dependent reactions in structural models subjected to dynamic excitation which are analyzed by the TMCALC and DAGS programs.

To demonstrate the validity of the FORCE program, results for test cases were obtained and shown to be substantially identical to those obtained for an equivalent analysis using the public domain program STRUDL(2). One such test case is shown here for purposes of illustration. Figure 3.9A-2 is a lumped mass multiple degree of freedom model of a uniform beam which has been defined to have mass and differential boundary excitation. The arbitrary differential support motion and mass point responses chosen for this example are tabulated on Figure 3.9A-2. The matrix of influence coefficients and the arbitrary mass point and differential support point motions are input to the program to calculate the support reactions and internal shear forces and bending moments indicated in Figure 3.9A-2. These results and those found by performing a stiffness analysis using the STRUDL(2) program are tabulated on Figure 3.9A-2. Results can be seen to be substantially identical.

3.9A-4 AXEL

The AXEL program allows the solution of axisymmetric problems using either triangular or general isoparametric finite elements. The isoparametric element is an 8-noded quadrilateral where the midside nodes can be used to model second order curved boundaries and to provide increased accuracy in regions of high stress. The AXEL program has been run at C-E since 1971 on the IBM 360 computer. The program was verified by comparison of numerous classical examples with results from AXEL. Two such cases are presented here for information.

COMPARISON #1

Two finite element models of a thick cylinder (inner radius = 1 inch, thickness = 4 inches, outer radius = 5 inches) are shown in Figure 3.9A-3. The internal pressure is 20 ksi and the axial pressure is zero. Lame is credited with the classical solution to this problem in the year 1852[3].

In the table below, the deflections and stresses reported are those at the center line of the disc.

	Model			% of Classical	
Radius	A	B	Classical	A	B
1" δ R(mils)	0.921	0.919	0.924	99	99
1" σ R(KSI)	-13.6	-18.5	-20.0	68	92
1" σ T	23.5	21.9	21.7	104	101
1" $\sigma_1 - \sigma_3$	37.1	40.4	41.7	89	97
3" σ R	0.359	0.360	0.359	100	100
3" σ R	-1.5	-1.5	-1.5	100	100
3" σ T	3.1	3.2	3.1	100	103

3" $\sigma_1 - \sigma_3$	4.6	4.7	4.6	100	102
5" δ R	0.277	0.278	0.277	100	100
5" σ R	-0.1	0	0	-	-
5" $\sigma_1 - \sigma_3$	1.7	1.6	1.6	100	100
5" $\sigma_1 - \sigma_3$	1.7	1.6	1.6	106	100

The two different models are presented to demonstrate the accuracy of the program independent of the details of modeling assumptions. It can be seen that there is excellent agreement between the classical text book solution and the program results.

COMPARISON #2

The gross dimensions are identical to the previous case, but the models are subject to a linear radial gradient of 100°F/inch, Figure 3.9A-4. Axial displacement is suppressed (σ_2 = 0) as shown in Figure 3.9A-5. Classical work in this area is attributed to Duhamel (1838) and Lorenz (1907).[3]

Deflection and stresses reported are at the center line of the disc.

	Model			% of Classical	
Radius	A	B	Classical	A	B
1" σ R(MILS)	2.65	2.67	2.69	99	99
1" σ R(KSI)	3.4	3.4	0	-	-
1" σ 2	0	1.9	0.9	-	-
1" σ T	56.6	62.9	62.9	90	100
1" $\sigma_1 - \sigma_3$	56.6	61.0	62.9	90	97
3" δ R	6.17	6.16	6.15	100	100
3" σ 2	-50.4	-50.5	-50.5	100	100
3" σ T	-2.9	-3.0	-3.0	-	-
3" $\sigma_1 - \sigma_3$	56.0	65.1	65.1	100	100

5" δ R	13.42	13.43	13.42	100	100
5" σ R	0.6	-0.6	0	-	-
5" σ 2	-101.7	-102.0	-40.0	99	101
5" $\sigma_1 - \sigma_3$	102.3	101.6	102.0	100	100

Again, two models are presented to allow independent evaluation of the code, and excellent agreement with the classical solution is observed.

3.9A-5 DESCRIPTION OF COMPUTER CODE DAGS

The computer program DAGS (Dynamic Analysis of Gapped Structure) performs a piecewise linear direct integration solution of the coupled equations of motion of a three dimensional structure which may have clearances or gaps between the structure and any of its supports or restraints (boundary gaps) or between points within the structure (internal gaps). The contacted boundary points may be oriented in any selected direction and may respond rigidly, elastically, or plastically. The structure may be subjected to applied dynamic loads or boundary motions.

3.9A-5-1 Formulation of Equations

The general matrix form of the undamped coupled equations of motion can be written as:[1]

$$M\ddot{X} + KX = F \qquad (1)$$

or in expanded form

$$\begin{matrix} M_m & 0 \\ 0 & 0 \end{matrix} \begin{matrix} \ddot{X}_m \\ \ddot{X}_s \end{matrix} + \begin{matrix} K_{mm} & K_{ms} \\ K_{sm} & K_{ss} \end{matrix} \begin{matrix} X_m \\ X_s \end{matrix} = \begin{matrix} F_m \\ F_s \end{matrix} \qquad (2)$$

Where:

K = the stiffness matrix of the system, condensed in a manner to retain only degrees of freedom at which mass is lumped (subscript m), and those massless boundary degrees of freedom which move with the system until they contact an external boundary point (subscript s).

M_m = a diagonal submatrix of the lumped masses of the system.

X_m = vector of displacements of the mass degrees of freedom of the system.

X_s = vector of displacements of the boundary degrees of freedom of the system.

F_m = vector of external loads applied to the mass degrees of freedom.

F_s = vector of reaction forces applied to the boundary degrees of freedom by the boundaries which they may contact.

For each boundary degree of freedom, either the reaction force is known to be zero because the degree of freedom is not in contact with the boundary, or the position is known to be equal in magnitude to the specified gap distance necessary for contact. For each boundary degree of freedom in Equation (2), the corresponding element in either the X_s or F_s vector is known. Consequently, Equation (2) are rearranged and written as:

$$\begin{bmatrix} M_m & 0 \\ 0 & 0 \end{bmatrix} \begin{Bmatrix} \ddot{X}_m \\ \ddot{X}_s \end{Bmatrix} + \begin{bmatrix} K_{mm} & K_{ms} \\ \overline{K}_{sm} & \overline{K}_{ss} \end{bmatrix} \begin{Bmatrix} X_m \\ \overline{X}_s \end{Bmatrix} = \begin{Bmatrix} F_m \\ \overline{F}_s \end{Bmatrix} \qquad (3)$$

Where:

$\overline{X}_s$ = vector of known quantities.

$\overline{F}_s$ = vector of unknown quantities.

The first of equations (3) is written as

$$M_m \ddot{X}_m + \overline{K}_{mm} X_m = P \qquad (4)$$

where: $P = F_m - \overline{K}_{ms} X_s$ is a vector of known quantities.

Equation (4) are solved in the coupled form using the Newmark β Method[(4)] with β = 1/6 which assumes that acceleration varies linearly between integration points.

At each point in time at which Equation (4) are solved for X_m, the second of Equations (3) are solved for all boundary point unknowns F_s. The status of each boundary degree of freedom is then checked and the stiffness matrix is rearranged if necessary to reflect a change in the configuration of the structure, such as opening or closing of a gap. Time steps are adjusted by the program to insure that an integration is performed at the time of configuration change.

The stiffness matrix can be similarly manipulated to account for elasticity or bilinearity in the boundaries, contact between two internal joints, boundary excitation, and

combinations of any or all of these features. In all cases, the basic configuration changes take place as described above.

3.9A-5-2 Description of Program

The DAGS program is used to calculate the dynamic response of piecewise linear structural systems subjected to time varying load forcing functions resulting from postulated LOCA conditions. The program was developed by C-E in 1974 for use of the CDC 7600 computer.

The input to the DAGS program consists of:

A. A symmetric stiffness matrix condensed as described in Equation (2).

B. Mass and damping matrices.

C. Digitized time history records of each of the externally applied forcing functions.

The output from the program consists of digitized time history records of the displacements, velocities and accelerations of all mass degrees of freedom and the displacements and reaction forces for all boundary degrees of freedom.

To demonstrate the applicability and validity of the DAGS program, the solutions to an extensive series of test problems were obtained and shown to be substantially identical to results obtained by hand calculations or alternate computer solutions. Several such problems are shown here for the purposes of illustration. The satisfactory agreement between the program results and the alternate solution indicates the reliability of DAGS.

A. Figure 3.9A-6 is a lumped mass single degree of freedom system with the given properties, subjected to a suddenly applied constant force F_o. The massless boundary degree of freedom is initially a distance of 2 inches from a rigid stop. The solution of the equation of motion for this structure for maximum displacement and reaction force can be found by standard work-energy balance principles. This solution was performed by hand calculation and by the DAGS program. Both results are shown in Table 3.9A-1 and can be seen to be virtually identical.

B. Figure 3.9A-7 is a multiple degree of freedom lumped mass shear beam representation of a beam which may contact rigid, elastic or plastic boundaries and which has a gap between two internal joints. This structure is subjected to three simultaneous applied loads chosen to insure that all gaps close. The solution to the equations of motion for this structure was found using the computer program SHOCK[5] which is in the public domain. The resulting maximum responses are shown in Table 3.9A-2 along with the corresponding results from DAGS. These results can be seen to be in a very good agreement.

C. Figure 3.9A-8 is a three dimensional multiple degree of freedom space from representation of a reactor coolant pump and cold leg piping with a gap between the pump and a pump stop. The structure is subjected to a suddenly applied constant load simulating a

postulated guillotine rupture in the pump discharge piping. This system was analyzed by a version of the C-E computer program TMCALC which uses modal solution procedures but allows the presence of a single rigid stop. The results from the analyses using TMCALC and DAGS are shown in Tables 3.9A-3a and 3.9A-3b. Table 3.9A-3a shows the maximum mass point displacements, velocities, and accelerations and the reaction force at the stop. The support reactions and internal forces and moments shown in Table 3.9A-3b were obtained using C-E computer program FORCE and the digitized time history results from the TMCALC analysis and from the DAGS analysis. All results can be seen to be in excellent agreement.

3.9A-6 NFATIG

NFATIG is a digital computer program used to analyze nuclear Class 1 piping components in accordance with the ASME B&PV code Section III NB-3650(6). Input to this program consists of a geometry, material properties, and the various indices for a given section of piping, the loadings and number of cycles of each, the material fatigue curve, and allowable Sm stresses.

The output includes the stresses Sn and Salt, and the usage factor for each load set as well as the cumulative usage factor for all cases. NFATIG also incorporates the capability to calculate the stress indices for various standard piping component shapes including tangents, elbows, tees, branches, tapered joints, fillet welds, and reducers.

The NFATIG program was developed by C-E in 1973 for use on the CDC 7600 computer, and updated as required in accordance with subsequent revision of Section III Code.

Verification of NFATIG was by example problems and comparison with hand calculations. One such example is included below for demonstration of the accuracy of the program.

Example:

The stress indices for an elbow are given in Table NB-3683.2-1 as follows:

$$C_1 = \frac{2R - r}{2(R - r)}$$

$$C_2 = \frac{1.95}{(t\,R/r^2)\;2/3}$$

C_3 = 1.0

C_3 = 0.5

K_1 = K_2 = K_3 = 1.21 (weld corrected)

For the example problem of a hot leg elbow:

R = 63.

r = 23.3125

t = 4.125

Then:

C_1 = 1.2937

C_2 = 3.1889

NFATIG computes values of 1.294 and 3.190, respectively.

Equation (10) of NB-3653 is:

$$S_n = C_1 \frac{Po\,Do}{2t} + C_2 \frac{Do}{2I} Mi + \frac{1}{2(1-v)} E\alpha\,\Delta T_1 + C_3\,Eab\,(\alpha aTa - \alpha bTb)$$

For the example problem of a hot leg elbow, considering the Hydrostatic Test - Plant Heatup Load Set:

Do = 50.75 in. (piping spec.)

Po = (3125 - 200) = 2925 psid (system spec.)

Mx = 405.

My = 7.63

Mz = 2383584. (from MEC - 21 Flexibility analysis)

E = 29.9×10^6

v = 0.3

α = 6.07×10^{-6} (material spec.)

ΔT_1 = 127. (system spec.)

ΔT_2 = 77.

Ta = 6.0 (LION thermal gradient analysis)

T_b = 0

I = 6521.1 (calculated from geometry)

The computed NFATIG result is 54822. psi versus a value of 54818. calculated by hand, showing excellent agreement within round off accuracy.

Equation (11) of NB-3653 is:

$$Sp = K_1C_1 \frac{Po\,Do}{2T} + K_2C_2 \frac{Do}{2I} Mi + \frac{1}{2(1-v)} K_3\, E\alpha\, \Delta T_1 + K_3C_3\, Eab$$

$$(\alpha a\, Ta - \alpha b\, Tb) + \frac{1}{(1-v)} E\alpha\, \Delta T_2$$

The computed NFATIG result is 86298 psi versus a hand calculated value of 86283 psi, which again shown excellent agreement.

Now, since Sn < 3 Sm, Ke = 1.0 and by Equation (14) Salt equal 1/2 Sp. NFATIG computes Salt 43149 psi versus 43147 psi by hand.

The number of allowable fatigue cycles at this Salt magnitude is computed at 6945 cycles by NFATIG versus 6950 calculated by eye from Figures 1-90.

The individual usage factor for 5 cycles specified for this load set is computed at .00072 by NFATIG and .00072 by hand.

Additional verification examples exist to verify computation of primary stress intensity by Equation (9), inclusion of seismic induced pipe moments, computation of cumulative usage factor for several loads sets, and computation of stress indices for other shapes. The above example is provided as a typical case to verify the accuracy of the NFATIG program.

TABLE 3.9A-1

COMPARISON OF HAND CALCULATION AND DAGS PROGRAM

RESPONSE	DAGS	HAND CALCULATIONS
R max	-.83108E+00	-.83043E+00
X max	.33361E+01	.33351E+01

APPENDIX 3.9A

TABLE 3.9A-2

MULTI - STOP STRUCTURE

	Max. Acceleration		Max. Reaction	
Joint	DAGS	Verification	DAGS	Verification
2	-3312.9	-3349.	--	--
3	--	--	140.5	140.9
4	-3940.1	-3853.	--	--
5	2983.8	2977.	--	--
6	--	--	.743	.753
7	-2418.9	-2382.	--	--
8	--	--	-180.4	-180.0
9	--	--	-180.4	-180.0
10	2056.0	2052.	--	--
11	-2758.2	-2687.	--	--
12	--	--	.200	.200
13	2845.0	2988.	--	--
14	4027.5	3998.	--	--

APPENDIX 3.9A

TABLE 3.9A-3a

RESPONSE COMPARISON

Joint Name	Location	Maximum Displacement DAGS	Maximum Displacement Verification	Maximum Velocity DAGS	Maximum Velocity Verification	Maximum Acceleration DAGS	Maximum Acceleration Verification
2257	X	-0.231	-0.231	32.587	32.903	-46050.	-45291.
	Y	0.119	-0.119	21.106	21.106	-24978.	-25400.
	Z	0.069	0.069	24.82	24.523	31066.	31933.
2567	X	-0.447	-0.448	36.269	36.447	32201.	32207.
	Y	0.103	0.103	-19.869	-19.985	18385.	18837.
	Z	0.114	0.114	-31.771	31.970	-35774.	-33677.
2580	X	-0.623	-0.623	50.044	49.891	42355.	42586.
	Y	-0.051	-0.051	-25.028	-24.785	-39926.	-40569.
	Z	-0.285	-0.285	-42.304	-42.499	-34237.	-35263.
2585	X	-0.732	-0.732	-60.946	-60.826	-36865.	-36824.
	Y	-0.042	-0.042	-21.824	-22.072	38753.	36691.
	Z	-0.429	-0.429	-44.849	-44.790	26956.	28681.
2597	X	-0.796	-0.796	-58.990	-59.101	38542.	37589.
	Y	-0.018	-0.018	16.354	17.744	-53548.	-48022.
	Z	-0.525	-0.525	-51.874	-51.916	-29198.	-30783.
2740	X	-0.752	-0.752	-58.213	57.171	-64757.	-67886.
	Z	-0.473	-0.474	-48.867	-49.247	-108260.	-115070.
2101	X	-0.713	-0.713	-46.135	-45.906	-11388.	-11430.
	Z	-0.447	-0.447	-34.698	-34.837	-14684.	-13470.
2749	Y	-0.079	-0.078	36.959	34.368	-92836.	-105080.
2103	X	-0.787	-0.787	-40.697	-40.721	5253.8	5285.1
	Y	0.005	0.005	-1.831	-1.845	1505.9	1550.1
	Z	-0.470	-0.471	26.175	26.145	3534.2	3583.3
2750	X	-0.889	-0.889	-164.37	157.50	318000.	318000.
	Y	-0.162	-0.163	45.898	42.797	100270.	121750.
	Z	-0.449	-0.451	-134.72	-138.23	-294420.	-289960.

TABLE 3.9A-3b

REACTION COMPARISON

Joint	Force	DAGS	Verification
2111	FY	678.4	679.2
2115	FY	446.2	437.7
2121	FY	-592.7	-595.3
2125	FY	493.0	494.9
2051	FX	-717.8	-716.4
	FZ	1172.	1179.
2061	FX	681.8	686.7
	FZ	-1114.	-1122.
2251	FX	-586.8	-589.7
	FZ	958.6	963.2
2261	FX	676.5	673.3
	FZ	-1105.	-1101.
2271	FX	1098.	1092.
	FZ	672.4	672.4

APPENDIX 3.9A

TABLE 3.9A-4a
HAND-CALCULATED STRESS INTENSITIES
(FROM STRESS COMPONENTS CALCULATED BY ANSYS, REF. 8)

Stress components – output of five LCs plus the "zero stress" LC – obtained with ANSYS are tabulated here below. LCs 1 & 4 have been imposed to be coincident to verify that the program performs correctly also when stress components are identical.

Location	**1**	**NODE**	**1379**				
	LC	**SX**	**SY**	**SZ**	**SXY**	**SYZ**	**SXZ**
	1	3291.1	-35.634	19.571	167.57	0.00E+00	0.00E+00
	2	2028.7	485.24	1300	-810.5	0.00E+00	0.00E+00
	3	2254.2	735.15	1715.6	-1146.5	0.00E+00	0.00E+00
	4	3291.1	-35.634	19.571	167.57	0.00E+00	0.00E+00
	5	2591.3	1242.2	2331	-1686.2	0.00E+00	0.00E+00
Location	**2**	**NODE**	**2935**				
	LC	**SX**	**SY**	**SZ**	**SXY**	**SYZ**	**SXZ**
	1	-2047.9	-1458.2	-2346.2	2444.5	0.00E+00	0.00E+00
	2	475.8	350.85	979.25	2469	0.00E+00	0.00E+00
	3	178.03	574.87	1256.4	2502	0.00E+00	0.00E+00
	4	-2047.9	-1458.2	-2346.2	2444.5	0.00E+00	0.00E+00
	5	-277.96	940.35	1684.5	2718.8	0.00E+00	0.00E+00

Differences between stress components and resulting S.I. are:

Node 1379

LC 1	LC 2	SX	SY	SZ	SXY	SYZ	SXZ	SI
0	1	-3291.1	35.634	-19.571	-167.57	0	0	3343.57
0	2	-2028.7	-485.24	-1300	810.5	0	0	2238.28
0	3	-2254.2	-735.15	-1715.6	1146.5	0	0	2750.52
0	4	-3291.1	35.634	-19.571	-167.57	0	0	3343.57
0	5	-2591.3	-1242.2	-2331	1686.2	0	0	3632.24
1	2	1262.4	-520.874	-1280.43	978.07	0	0	2974.69
1	3	1036.9	-770.784	-1696.03	1314.07	0	0	3423.99
1	4	0	0	0	0	0	0	0
1	5	699.8	-1277.83	-2311.43	1853.77	0	0	4202.01
2	3	-225.5	-249.91	-415.6	336	0	0	672.443
2	4	-1262.4	520.874	1280.429	-978.07	0	0	2974.69
2	5	-562.6	-756.96	-1031	875.7	0	0	1762.15
3	4	-1036.9	770.784	1696.029	-1314.07	0	0	3423.99
3	5	-337.1	-507.05	-615.4	539.7	0	0	1092.7
4	5	699.8	-1277.83	-2311.43	1853.77	0	0	4202.01

Node 2935

LC 1	LC 2	SX	SY	SZ	SXY	SYZ	SXZ	SI
0	1	2047.9	1458.2	2346.2	-2444.5	0	0	4924.44
0	2	-475.8	-350.85	-979.25	-2469	0	0	4939.58
0	3	-178.03	-574.87	-1256.4	-2502	0	0	5019.71
0	4	2047.9	1458.2	2346.2	-2444.5	0	0	4924.44
0	5	277.96	-940.35	-1684.5	-2718.8	0	0	5572.41
1	2	-475.8	-350.85	-979.25	-2469	0	0	1517.24
1	3	-178.03	-574.87	-1256.4	-2502	0	0	1585.37
1	4	2047.9	1458.2	2346.2	-2444.5	0	0	0
1	5	277.96	-940.35	-1684.5	-2718.8	0	0	2363.62
2	3	297.77	-224.02	-277.15	-33	0	0	576.999
2	4	2523.7	1809.05	3325.45	24.5	0	0	1517.24
2	5	753.76	-589.5	-705.25	-249.8	0	0	1503.96
3	4	2225.93	2033.07	3602.6	57.5	0	0	1585.37
3	5	455.99	-365.48	-428.1	-216.8	0	0	937.796
4	5	-1769.94	-2398.55	-4030.7	-274.3	0	0	2363.62

Maximum S.I. are:

- Node 1379 $S.I._{max}$ = **4,202.01** for LCs 1-5 and 4-5.
- Node 2935 $S.I._{max}$ = **5,572.41** for LC 0-5.

TABLE 3.9A-4b
MAX STRESS INTENSITIES (OUTPUT of RANGE)

```
*** INNER NODE 1379 ***
 FIRST LOAD STEP     1
 SECOND LOAD STEP    5
STRESS RANGE   0.42020E+04


*** OUTER NODE 2935 ***
 FIRST LOAD STEP     0
 SECOND LOAD STEP    5
STRESS RANGE   0.55724E+04
```

Hand-calculated results (Table 3.9A-4a) match perfectly the numbers obtained by running RANGE (Table 3.9A-4b).

APPENDIX 3.9A

TABLE 3.9A-5a
HAND-CALCULATED STRESS INTENSITIES
(FROM STRESS COMPONENTS CALCULATED BY ANSYS, REF. 8)

Stress components – output of five LCs plus the "zero stress" LC – obtained with ANSYS are tabulated here below. LCs 1 & 4 have been imposed to be coincident to verify that the program performs correctly also when stress components are identical.

Location 1	**NODE 1379**		**Location 2**	**NODE 2935**	
LC	**SX**	**SZ**	**LC**	**SX**	**SZ**
1	3291.1	19.571	1	-2047.9	-2346.2
2	2028.7	1300	2	475.8	979.25
3	2254.2	1715.6	3	178.03	1256.4
4	3291.1	19.571	4	-2047.9	-2346.2
5	2591.3	2331	5	-277.96	-1684.5

Stress components to account for T/S holes and internal pressure are:

	NODE 1379			**NODE 2935**	
LC	**SX**	**SZ**	**LC**	**SX**	**SZ**
1	1.80E+04	4.46E+03	1	-4.08E+03	-5.31E+03
2	1.28E+04	9.75E+03	2	6.35E+03	8.43E+03
3	1.37E+04	1.15E+04	3	5.12E+03	9.57E+03
4	1.80E+04	4.46E+03	4	-4.08E+03	-5.31E+03
5	1.47E+04	1.36E+04	5	2.84E+03	1.10E+04

The stress ranges for radial and tangential components are:

		NODE 1379				**NODE 2935**	
LC 1	**LC 2**	**SX**	**SZ**	**LC 1**	**LC 2**	**SX**	**SZ**
0	1	-1.08E+04	-4.46E+03	0	1	4.08E+03	5.31E+03
0	2	-1.28E+04	-9.75E+03	0	2	-6.35E+03	-8.43E+03
0	3	-1.37E+04	-1.15E+04	0	3	-5.12E+03	-9.57E+03
0	4	-1.80E+04	-4.46E+03	0	4	4.08E+03	5.31E+03
0	5	-1.47E+04	-1.36E+04	0	5	-2.84E+03	-1.10E+04
1	2	5.22E+03	-5.29E+03	1	2	-1.04E+04	-1.37E+04
1	3	4.28E+03	-7.01E+03	1	3	-9.20E+03	-1.49E+04
1	4	0.00E+00	0.00E+00	1	4	0.00E+00	0.00E+00
1	5	3.28E+03	-9.16E+03	1	5	-6.92E+03	-1.63E+04
2	3	-9.32E+02	-1.72E+03	2	3	1.23E+03	-1.15E+03
2	4	-5.22E+03	5.29E+03	2	4	1.04E+04	1.37E+04
2	5	-1.94E+03	-3.87E+03	2	5	3.50E+03	-2.52E+03
3	4	-4.28E+03	7.01E+03	3	4	9.20E+03	1.49E+04
3	5	-1.00E+03	-2.15E+03	3	5	2.27E+03	-1.38E+03
4	5	3.28E+03	-9.16E+03	4	5	-6.92E+03	-1.63E+04

At node 1379, the max stress range occurs for the radial stress between LCs 0 & 1 and is -1.80E4.

The corresponding biaxiality ratio β is 0.248 and the stress multiplier factor is 1.06 (from fig. A-8142-1 of Ref. 7). The corresponding stress range results then Dσ = **19,058.**

At node 2935, the max stress range occurs for the tangential stress between LCs 1 & 5 and is -1.63E4.

The corresponding biaxiality ratio β is 0.425 and the stress multiplier factor is 1.03 (from fig. A-8142-1 of Ref. 7). The corresponding stress range results then Dσ = **16,754.**

TABLE 3.9A-5b
MAX STRESS INTENSITIES (OUTPUT of RANGETS)

NODE 1379
FIRST LOAD STEP = 0
SECOND LOAD STEP = 1
BETA = 0.24821E+00
KAPPA = 0.10604E+01
STRESS RANGE = **0.19067E+05**

NODE 2935
FIRST LOAD STEP = 1
SECOND LOAD STEP = 5
BETA = 0.42568E+00
KAPPA = 0.10289E+01
STRESS RANGE = **0.16737E+05**

Hand-calculated results (Table 3.9A-5a) match those obtained by running the RANGETS program (Table 3.9A-5b) except for the small differences caused by rounding off in hand calculations.

TABLE 3.9A-6a
HAND-CALCULATED FATIGUE USAGE FACTORS
(FROM STRESS COMPONENTS CALCULATED BY ANSYS, REF. 8)

Stress components – output of five LCs from ANSYS – are tabulated below. LCs 1 & 4 were imposed coincident to verify that the program performs correctly also when stress components are identical. The 5 LCs were grouped within two events, the first containing LCs 1, 2, 3, the second one LCs 3 and 4. The associated number of cycles were 500 and 100,000, respectively.

LOCATION	**1**	**NODE**	**1379**	**LOCATION**	**2**	**NODE**	**2935**
Event	**LC**	**SX**	**SZ**	**Event**	**LC**	**SX**	**SZ**
1	1	10669	4569.7	1	1	1219.1	-1260.6
1	2	4106.7	1984.1	1	2	2879.2	1235.7
1	3	4721.1	2485.5	1	3	2605.8	1467.7
2	1	10669	4569.7	2	1	1219.1	-1260.6
2	2	6100.7	3344.2	2	2	2532	1947.7

By performing hand-calculation following the sequence identified at points a) thru k) of Section 3.9A-9, the cumulative fatigue usage factors at selected locations/orientations of the nodes being analyzed result:

Node **1379** (two locations/orientations selected):

1. T/S angular orientation: **0°** - orientation through the hole: **40°**.

Max total stress range occurs between Event 1, LC 1 and Event 1, LC 2.

Max absolute value of the stress range is 36,048.
Corresponding S_{alt} is 18,024.
Number of allowable cycles is 145,480
Usage factor is 500/145480 = 0.0034.
Event 1 is eliminated. The 100,000 cycles of Event 2 remain.
Max absolute value of the stress range is 25,718.
Corresponding S_{alt} is 12,859.
Number of allowable cycles is 774,900
Usage factor is 0.129.
100,000 cycles of Event 2 eliminated. No other events remain.
The cumulative usage factor is then **0.1324.**

2. T/S angular orientation: 15° - orientation through the hole: 120°.

Max total stress range occurs between Event 1, LC 1 and Event 1, LC 2.

Max absolute value of the stress range is 52,490.
Corresponding S_{alt} is 26,245.

Number of allowable cycles is 33,344

TABLE 3.9A-6a (Cont'd)
HAND-CALCULATED FATIGUE USAGE FACTORS
(FROM STRESS COMPONENTS CALCULATED BY ANSYS, REF. 8)

Usage factor is 500/145,480 = 0.015.
Event 1 is eliminated. The 100,000 cycles of Event 2 remain.
Max absolute value of the stress range is 40,384.
Corresponding S_{alt} is 20,192.
Number of allowable cycles is 95,372.
Usage factor is 1.048.
Cycles of Event 2 eliminated. No other events remain.
The cumulative usage factor is then **1.063**.
Node **2935** (two orientations/locations selected):

1. T/S angular orientation: 0° - orientation through the hole: 0°.

   The max total stress range occurs either between Event 1, LC 1 and Event 2, LC 2 (or between Event 2, LC 1 and Event 2, LC 2, being LCs 1 and 4 imposed to be coincident).

   Max absolute value of the stress range is 27,724.
   Corresponding S_{alt} is 13,862.
   Number of allowable cycles is 443,090
   Usage factor is 500/443090 = 0.0011.
   Event 1 is eliminated. The 99,500 cycles of Event 2 remain.
   Max absolute value of the stress range is 27,724 (this cycle too).
   Corresponding S_{alt} is 13,862.
   Number of allowable cycles is 443,090
   Usage factor is 99,500/443,090 = 0.225.
   Cycles of Event 2 eliminated. No other events remain.
   The cumulative usage factor is then **0.226**

[If the first cycle reported above between (…..) was used, the first usage factor (for 100,000 cycles) would have resulted 0.226, whereas the second usage factor (for 500 cycles) would have resulted 0.0011 giving a cumulative usage factor of 0.227.]

TABLE 3.9A-6a (Cont'd)
HAND-CALCULATED FATIGUE USAGE FACTORS
(FROM STRESS COMPONENTS CALCULATED BY ANSYS, REF. 8)

1. T/S angular orientation: 15° - orientation through the hole: 180°.

   The max total stress range occurs between Event 1, LC 1 and Event 2, LC 2 (or between Event 2, LC 1 and Event 2, LC 2, being LCs 1 and 4 imposed to be coincident).

   Max absolute value of the stress range is 25,345.
   Corresponding S_{alt} is 12,673.
   Number of allowable cycles is 883,560.
   Usage factor is 500/883,560 = 0.001.
   Event 1 is eliminated. The 99,500 cycles of Event 2 remain.
   Max absolute value of the stress range is 25,345 (this cycle too).
   Corresponding S_{alt} is 12,673.
   Number of allowable cycles is 883,560.
   Usage factor is 99,500/883,560 = 0.112.
   Cycles of Event 2 eliminated. No other events remain.
   The cumulative usage factor is then **0.113**

   [If the first cycle reported above between (…..) was used, the first usage factor (for 100,000 cycles) would have resulted 0.113, whereas the second usage factor (for 500 cycles) would have resulted 0.001 giving a cumulative usage factor of 0.114.]

TABLE 3.9A-6b
FATIGUE USAGE FACTORS (OUTPUT OF FATIGTS)
(Excerpt from the complete tabulation
for all orientations/locations)

*** TUBESHEET FATIGUE VERIFICATION ***

NODE 1379

TUBESHEET ANGULAR ORIENTATION = 0 DEGREES
ORIENTATION THROUGH THE HOLE = 40 DEGREES

EVENT	LOAD STEP	EVENT	LOAD STEP	$S_{ALTERNATE}$	N	$N_{ALLOWABLE}$	USAGE FACTOR
1	1	1	2	0.180E+05	500.	0.14548E+06	0.0034
2	1	2	2	0.129E+05	100000.	0.77502E+06	0.1290

CUMULATIVE USAGE FACTOR = **0.13247**

NODE 1379

TUBESHEET ANGULAR ORIENTATION = 15 DEGREES
ORIENTATION THROUGH THE HOLE = 120 DEGREES

EVENT	LOAD STEP	EVENT	LOAD STEP	$S_{ALTERNATE}$	N	$N_{ALLOWABLE}$	USAGE FACTOR
1	1	1	2	0.262E+05	500.	0.33344E+05	0.0150
2	1	2	2	0.202E+05	100000.	0.95369E+05	1.0486

CUMULATIVE USAGE FACTOR = **1.06355**

NODE 2935

TUBESHEET ANGULAR ORIENTATION = 0 DEGREES
ORIENTATION THROUGH THE HOLE = 0 DEGREES

EVENT	LOAD STEP	EVENT	LOAD STEP	$S_{ALTERNATE}$	N	$N_{ALLOWABLE}$	USAGE FACTOR
1	1	2	2	0.139E+05	500.	0.44310E+06	0.0011
2	1	2	2	0.139E+05	99500.	0.44310E+06	0.2246

CUMULATIVE USAGE FACTOR = **0.22568**

NODE 2935

TUBESHEET ANGULAR ORIENTATION = 15 DEGREES
ORIENTATION THROUGH THE HOLE = 180 DEGREES

EVENT	LOAD STEP	EVENT	LOAD STEP	$S_{ALTERNATE}$	N	$N_{ALLOWABLE}$	USAGE FACTOR
1	1	2	2	0.127E+05	500.	0.88393E+06	0.0006
2	1	2	2	0.127E+05	99500.	0.88393E+06	0.1126

CUMULATIVE USAGE FACTOR = **0.11313**

3.9A-7 RANGE

The RANGE program calculates the primary membrane plus bending stress range at two nodes of a stress line for "n" load cases (LCs), based on the rules of NB-3222-2 (Ref. 7). Specifically:

a) calculates the difference of the six membrane plus bending stress components between each LC and the other "n-1" LCs;

b) calculates the resulting stress intensity (S.I.) from the stress differences above;

c) for the two LCs which give the maximum S.I., results are recorded and printed.

As an example, for 6 LCs identified as "1", "2",..., "6", the difference between each stress component (membrane + bending) is computed according to the following scheme ("0" indicates the "zero-stress" case):

0-1	0-2	0-3	0-4	0-5	0-6
1-2	1-3	1-4	1-5	1-6	
2-3	2-4	2-5	2-6		
3-4	3-5	3-6			
4-5	4-6				
5-6					

For each of the 21 combinations, the maximum S.I. is computed starting from the difference between corresponding stress components (i.e., $\sigma_{x(0)} - \sigma_{x(1)}$, $\sigma_{y(0)} - \sigma_{y(1)}$, etc.).

For the two LCs giving the maximum S.I., results are recorded and printed.

The difference between hand-calculated numbers and output from RANGE are summarized in Tables 3.9A-4a and 3.9A-4b, respectively. The results can be observed to be perfectly coincident.

3.9A-8 RANGETS

RANGETS calculates the stress range at two nodes of a stress line in a perforated region of a tubesheet (T/S), analyzed according to the rules established in A-8000 (Ref. 7). The stress range is computed for "n" load cases (LCs) – including the "zero stress" – as per NB-3222-2 (Ref. 7), starting from the ANSYS (Ref. 8) output for a homogeneous T/S analysis.

Namely:

a) for each LC, the program calculates the radial and tangential stress components. The contribution due to the primary pressure inside the T/S holes is taken into account as defined in A-8000;

b) the difference between the radial and tangential stress components (membrane + bending + peak) for each LC (including the "zero stress") is calculated;

c) the maximum stress range ($D\sigma$) is selected, regardless the direction (either radial or tangential);

d) for the maximum $D\sigma$ identified at point c), the biaxiality ratio σ_r/σ_t is calculated;

e) the stress multiplier factor K is determined (from Figure A-8142-1) and the max S.I. is calculated multiplying the stress range of point c) by the K factor;

f) for each node of the stress line, and for each LC, operations c) thru e) are performed and results recorded and printed.

Following the rules of A-8000, the stress due to the internal pressure on tubes is evaluated as follows:

$S = (p-h-2 * t) * [h+2 (E_t/E)t]$

$\sigma_{rt} = \sigma_{\Theta t} = s * Pr$, where:

s = stress for unitary pressure, p = pitch, h = nominal width of ligament

t = tube thickness, Pr = internal pressure on tubes,

E_t = Young's modulus of tubes, E = Young's modulus of T/S,

σ_{rt} = radial stress due to internal pressure,

$\sigma_{\Theta t}$ = tangential stress due to internal pressure.

Total stresses are then evaluated with the following formulas:

$\sigma_r = (p/h) * \sigma_{ra} + \sigma_{rt}$

$\sigma_{\Theta} = (p/h) * \sigma_{\Theta a} + \sigma_{\Theta t}$

where:

σ_r = total radial stress, σ_{ra} = radial stress from ANSYS (Ref. 8),

σ_θ = total tangential stress, $\sigma_{\theta a}$ = tangential stress from ANSYS (Ref. 8).

The difference between hand-calculated results and output results as generated by RANGETS are summarized in Tables 3.9A-5a and 3.9A-5b, respectively, and show excellent agreement within round off accuracy.

3.9A-9 FATIGTS

The FATIGTS program calculates the maximum fatigue usage factor at two nodes of a stress line in a perforated region of a tubesheet (T/S), analyzed per rules of A-8000 (Ref. 7). The fatigue usage factors are calculated for "m" events of "n" load cases (LCs) each (including the "zero stress"), as per NB-3222-4 (Ref. 7). Stresses are calculated with ANSYS for a homogeneous T/S model. The stress intensity (S.I.) range is computed per rules of A-8142-2 (Ref. 7), at various angular orientations of the T/S and through the holes. Namely, FATIGTS includes three angular orientations along the T/S and ten orientations along the holes. The orientations along the T/S are 0°, 15° and 30°, whereas the orientations along the holes are evenly distributed between 0° and 90° per the T/S angular orientations at 0° and 30°; between 0° and 180° per the T/S angular orientation at 15°. The three angular orientations above cover all the T/S surface with an approximation of 7.5°.

Angular orientations refer to a coordinate system X-Y with the origin at the center of the T/S and the axes parallel and perpendicular to the tube-lane, respectively. Moreover, the Y-axis is located such that the distance between two adjacent tubes, measured along the Y-axis, corresponds to the nominal ligament. Angular orientations along the T/S holes are measured starting from the y-axis of a coordinate system with the origin at the center of the hole and the axes oriented according to Fig's A-8142-3, A-8142-4 and A-8142-5 of A-8000 (Ref. 7).

The fatigue usage factors at each node of a stress line and at each angular orientation as described above are computed as follows:

a) for each LC of a specified event, the radial and tangential stress components are evaluated per rules of A-8000. Contribution due to the primary pressure inside the T/S holes is taken into account;

b) radial and tangential components are multiplied by Y1 and Y2 (stress multipliers), derived from Fig's A-8142-3, A-8142-4, A-8142-5, as a function of the ratio between ligament and pitch to account for the effective angular orientations along the T/S and along the holes;

c) for each LC, the total stress obtained by summing the radial, the tangential and the pressure on the

surface where the stress is being computed (either primary or secondary) is evaluated;

d) the range of the total stress is then computed as a difference between each LC (including the "zero stress") and the others;

e) the (two) LCs, and the events to which they belong, producing the maximum range of point d) are identified;

f) the smaller – between the number of cycles associated at the events of point e) – is identified;

g) the corresponding S_{alt}, half of the maximum stress range of point e) is computed;

h) the fatigue usage factor produced by the two events identified at point e) is computed. The allowable number of cycles is derived from the fatigue curve for S_{alt} * (E/E_{act}), being E the Young's modulus of the fatigue curve used and E_{act} the actual Young's modulus at the location being examined;

i) the event to which corresponds the smaller number of cycles is then eliminated. The number of cycles of the other event is reduced by an equivalent amount of cycles;

j) calculations of points d) to i) above are repeated until all the events are eliminated;

k) the total fatigue usage factor is then computed by summing each single contribution computed at point h) for all the iterations required.

The stress contribution due to the tube internal pressure is computed as described in previous Section 3.9A-8 for the program RANGETS.

According to the rules of A-8000, the total stresses are:

$\sigma = Y1*\sigma_r + Y2*\sigma_\theta + Ps$, where:

σ = total stress,

$\sigma_r = (p/h) * \sigma_{ra} + \sigma_{rt}$,

$\sigma_\theta = (p/h) * \sigma_{\theta a} + \sigma_{\theta t}$,

Ps = pressure on the surface where the stress is being computed,

σ_{rt} = radial stress due to tubes internal pressure,

$\sigma_{\theta t}$ = tangential stress due to tubes internal pressure,

σ_r = total radial stress,

σ_{ra} = radial stress from ANSYS (Ref. 8),

σ_θ = total tangential stress,

$\sigma_{\theta a}$ = tangential stress from ANSYS (Ref. 8),

p = pitch; h = ligament,

Y1, Y2 = stress multipliers, from Tables A-8142-3, A-8142-4, A-8142-5 of Ref. 7.

The difference between hand-calculated results and output results as generated by FATIGTS are summarized in Tables 3.9A-6a and 3.9A-6b, respectively. Excellent matching can be observed, except for small differences caused by rounding off to hand calculations.

3.9A-10 REFERENCES

(1) Thomson, W. T., "Vibration Theory and Applications," Chapter 3, Prentice Hall, Inc. Englewood, Cliffs, New Jersey, 1965.

(2) ICES STRUDL-II, "The Structural Design Language Engineers Users Manual", MIT Press, Cambridge, Mass., 1968.

(3) Przemieniecky, J. S., "Theory of Matric Structural Analysis," Chapter 13, McGraw Hill Book Co., New York, 1968

(4) Newmark, N. M., "A Method of Computation for Structural Dynamics," Volume 3, Journal of Engineering Mechanics Division, A.S.C.E., July, 1959.

(5) Gabrielson, V. K., "SHOCK - A Computer Code for Solving Lumped - Mass Dynamic Systems," SCL-DR-65-34, January 1966

(6) ASME Boiler and Pressure Vessel Code, Section III, subsection NB, 1974 Edition.

(7) ASME Boiler & Pressure Vessel Code, Section III, Subsection NB, 1989 Edition, No Addenda

(8) Computer Code, ANSYS, Revision 5.4 – ANSYS Engineering Analysis System User’s Manual, Revision 5.4, by G.J. De Salvo and J.A. Swanson

3.10 SEISMIC QUALIFICATION OF SEISMIC CATEGORY I INSTRUMENTATION AND ELECTRICAL EQUIPMENT

Refer to section 3.10.5 through 3.10.7 for the seismic qualification of Seismic Category I instrumentation and electrical equipment in the C-E scope of supply. The following sections 3.10.1 through 3.10.4 applies to Seismic Category I instrumentation and electrical equipment not in the C-E scope of supply.

3.10.1 SEISMIC QUALIFICATION CRITERIA

General Design Criterion 2 (GDC-2) of Appendix A to Code of Federal Regulations, 10CFR50 requires that "Structures, systems and components important to safety shall be designed to withstand the effects of earthquakes without loss of capability to perform their safety functions. The integrity of the safety-related Seismic Category I instrumentation of nuclear power plants must be assured in the event that earthquakes occur at nuclear plant sites. This assurance is provided by designing the plant to withstand the seismic responses that would be experienced during a postulated earthquake."

3.10.1.1 General

Seismic Category I instrumentation and electrical equipment are qualified to withstand the effects of the safe shutdown earthquake (SSE) and remain functional.

10CFR100 defines Safe Shutdown Earthquake as an earthquake which produces maximum vibratory ground motion for which structures, systems and components, important to safety, are designed to remain functional.

The parameters used to develop seismic loadings and criteria for Seismic Category I structures, systems, and components are described in section 3.7.

Seismic Category I instrumentation and electrical equipment important to safety are divided into three categories:

A. Equipment which has been designed and qualified to maintain its functional capability during and after an SSE

B. Equipment which has been qualified to remain functional after an SSE

C. Equipment which has been designed and qualified to maintain the pressure boundary integrity of the system of which it is a part during and after an SSE

The structural requirements for instrumentation equipment and systems that were qualified to maintain pressure boundary integrity are in accordance with ASME Section III.

3.10.1.2 Standby Power System and Category I Instrumentation and Electrical Equipment

In addition to the general qualifications of paragraph 3.10.1.1, the standby power system and Seismic Category I instrumentation and electrical equipment associated with engineered safety features are qualified to withstand seismic disturbances of the intensity of an SSE during post-accident operation.

3.10.2 METHODS AND PROCEDURES FOR QUALIFYING ELECTRICAL EQUIPMENT AND INSTRUMENTATION

3.10.2.1 Means of Qualification

IEEE Standard 344-1975, Recommended Practices for Seismic Qualification for Class IE Equipment (classified as Seismic Category I) for Nuclear Power Generating Stations, was used for all seismic qualifications.

The applicable seismic input data in the form of a specification was provided to the equipment supplier with appropriate response spectrum curves for the various floor elevations (or one curve that envelops all locations). The supplier was also provided with minimum acceptance criteria for all equipment and/or systems to determine their compliance with the seismic specifications.

An analysis of seismic design adequacy of equipment, including supports such as cable tray supports, battery racks, instrument racks, control consoles and switchgear, was performed according to the response spectrum techniques (see section 3.7).

3.10.2.2 Seismic Qualification

Seismic qualification plans were prepared by the equipment suppliers and submitted for review prior to qualification. Subsequent seismic qualifications were performed by the equipment suppliers.

The seismic qualification reports demonstrate the equipment's ability to perform its required function during and after (in accordance with paragraph 3.10.1.1) the time it would be

subjected to the force resulting from one SSE preceded by the effects of the equivalent of two operating basis earthquakes (OBEs).

Qualification and documentation procedures used for Seismic Category I equipment and/or systems meet the requirements of IEEE 344-1975 and Regulatory Guide 1.100 (refer to section 1.8).

The methods for seismic qualification are:

- Analysis
- Test
- Combination of analysis and test.

3.10.2.2.1 Analysis

Mathematical analyses without testing were acceptable only where it could be demonstrated that structural integrity alone ensured the intended design function. The procedures used were in accordance with Section 5 of IEEE 344-1975. Justification for the use of any static coefficient was provided by the supplier. In the case of electrical motors used as pump drivers where it was shown that the motors had no resonances in the frequency range below the high frequency asymptote (ZPA) of the required response spectrum (RRS), they were considered rigid and were analyzed statically without testing.

3.10.2.2.2 Testing

Seismic tests were performed by subjecting equipment to vibratory motions that conservatively simulated the Required

Response Spectra (RRS) or the required input motion (RIM) at the equipment mounting. The requirements of testing were in accordance with Section 6 of IEEE 344-1975. The tests were performed using one of the following techniques:

- Proof testing
- Fragility testing
- Device testing
- Assembly testing
- Generic testing

If the equipment was not tested to its ultimate capability (fragility testing), then proof or generic testing was acceptable based on limits imposed by system design requirements.

3.10.2.2.3 Test Methods

Test methods were in accordance with Section 6 of IEEE 344-1975 for qualification testing. Selection and justification for any static coefficients or test methods used was provided by the supplier (refer to paragraph 3.10.2.1).

3.10.2.2.4 Combined Analysis and Testing

When the equipment could not be qualified practically by analysis or testing because of its size and complexity, combined analysis and testing were utilized.

Combined analysis and testing methods were in accordance with Section 7 of IEEE 344-1975.

3.10.3 METHODS AND PROCEDURES OF ANALYSIS OR TESTING OF SUPPORTS OF ELECTRICAL EQUIPMENT AND INSTRUMENTATION

Analyses or tests were performed for all supports of electrical and instrumentation equipment to ensure their structural capability to withstand seismic excitation. The following bases were used in the design and analysis of cable tray supports and instrument tubing supports:

A. All cable tray supports and instrument tubing supports were designed by the response spectrum method.

B. Analysis and seismic restraint measures for tray supports and tubing supports were based on combined limiting values for static load, span length, and computed seismic response.

C. All Class 1E cable tray supports were designed to meet the requirements by dynamic analysis using the appropriate seismic response spectra generated for 20% damping during SSE loading. The damping value is expressed as a percentage of critical damping.

D. The Seismic Category I instrument tubing systems are supported such that the allowable stresses permitted by Section III of ASME Boiler and Pressure Vessel (B&PV) Code are not exceeded when the tubing is subjected to the loads specified in section 3.9 and Regulatory Guide 1.48 for Class 2 and 3 piping.

   For field-mounted instruments, the stress level in the mounting structure does not exceed the material allowable stress when subjected to the maximum

acceleration level of the mounting location. The weight of the instrument is included.

Supports were tested and/or analyzed with equipment installed. If the equipment was inoperative during the support test, the response at the equipment mounting location was monitored. In such a case, equipment was tested separately. Where it was necessary to test individual devices (e.g., relays or instruments) separate from the panels to which they are mounted, the accelerations of the panel at the device locations were checked to ensure that they were equal to or lower than the level to which the devices were qualified.

3.10.4 OPERATING LICENSE REVIEW

3.10.4.1 Qualification and Documentation Procedures

Qualification and documentation procedures for Seismic Category I equipment were in accordance with the recommendations contained in IEEE Standard 344-1975.

3.10.5 SEISMIC DESIGN OF CATEGORY I INSTRUMENTATION AND ELECTRICAL EQUIPMENT IN THE CE SCOPE OF SUPPLY

This section describes the seismic design criteria and analyses, tests, procedures, and acceptance criteria applied to seismic Category I instrumentation, electrical equipment, except for valve and pump motors, and their supports. The information applicable to instrumentation and control equipment is contained in Combustion Engineering's Topical Report CENPD-182 "Seismic Qualification of C-E Instrumentation

Equipment." Valve and pump motors are discussed in Section 3.9.2.2.

3.10.5.1 Seismic Qualification Criteria

Instrumentation and electrical equipment used for Post-Accident Monitoring (PAM), the Reactor Protective System (RPS), the Supplementary Protection System (SPS), the Engineered Safety Features Actuation System (ESFAS), the actuation devices for ESF Systems actuated components, and the emergency power system are designed as Seismic Category I requirements to ensure the ability to initiate required protective actions during, and following, a Safe Shutdown Earthquake (SSE); and to supply power, following an SSE, to components required to mitigate the consequences of events which require safety system operation. The criteria chosen, tests or analyses to be used, and the general methodology are discussed in CENPD-182.

3.10.6 METHODS AND PROCEDURES FOR QUALIFYING ELECTRICAL EQUIPMENT AND INSTRUMENTATION

Seismic Category I instrumentation and electrical equipment required to perform a safety action during a seismic event, after a seismic event, or both is qualified (with appropriate documentation) in accordance with the requirements of the equipment specifications. These requirements are consistent with the requirements of IEEE 344-1971 "IEEE Guide For Seismic Qualification of Class 1 Electrical Equipment for Nuclear Power Generating Stations" and the following additional requirements.

A. The appropriate seismic excitation for which the equipment must qualify will be determined based on location in the plant.

B. The equipment will be required to be designed against failure to perform its intended function during and after an earthquake of the intensity of the Safe Shutdown Earthquake.

C. The vendor is required to substantiate the adequacy of the design by analysis, or testing and/or operating experience depending on the type of equipment under consideration and its intended safety function. The choice of the qualification method will be approved by Combustion Engineering.

D. The quality assurance program as described in CENPD-210A "Description of the C-E Nuclear Steam Supply System Quality Assurance Program" illustrates the procedures used in assuring the implementation of the requirements by equipment suppliers.

The tests and analyses used to implement IEEE 344-1971 and the additional requirements are discussed in Combustion Engineering's Topical Report CENPD-182. The documentation of these tests and analyses will appear in Part Two of CENPD-182 as they are performed. See table 3.2-1 for Seismic Category I principal components. The test program will provide the following:

E. A test program is required to confirm the functional operability of all Seismic Category I electrical and

associated mechanical equipment and instrumentation during and after an earthquake of magnitude up to and including the SSE.

F. The characteristics of the required input motion shall be specified by one of the following:

1. response spectrum

2. power spectral density function

3. time history

Such characteristics, as derived for the structures or systems seismic analysis, shall be representative of the input motion at the equipment mounting locations.

G. Equipment shall be tested in the operational condition. Operability shall be verified during and after the testing.

*H. The actual input motion shall be characterized in the same manner as the required input motion, and the conservatism in amplitude and frequency content shall be demonstrated.

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* Item H is supplemented as follows: In applying this item to the electrical equipment, the frequency spectrum used shall cover the range from 1 through 33 hz.

I. Seismic excitations generally have a broad frequency content. Random vibration input motion shall be used. However, single frequency input, such as sine beats, may be utilized provided one of the following conditions are met:

1. The characteristics of the required input motion indicate that the motion is dominated by one frequency (i.e., by structural filtering effects).

2. The anticipated response of the equipment is adequately represented by one mode.

3. The input has sufficient intensity and duration to excite all modes to the required magnitude, such that the testing response spectra will envelop the corresponding response spectra of the individual modes.

J. The input motion shall be applied to one vertical and one principal (or two orthogonal) horizontal axes simultaneously unless it can be demonstrated that the equipment response along the vertical direction is not sensitive to the vibratory motion along the horizontal direction, and vice versa. The time phasing of the inputs in the vertical and horizontal direction, and vice versa. The time phasing of the inputs in the vertical and horizontal directions will be such that a purely rectilinear resultant input is avoided. The acceptable alternative is to have vertical and horizontal inputs in-phase, and then repeated with inputs 180 degrees out-of-phase. In addition, the test

will be repeated with the equipment rotated 90 degrees horizontally.

K. The fixture design shall meet the following requirements:

   1. Simulate the actual service mounting

   2. Cause no dynamic coupling to the test item.

L. The in-situ application of vibratory devices to superimpose the seismic vibratory loadings on the complex active device for operability testing is acceptable when application is justifiable.

M. The test program may be based upon selectively testing a representative number of mechanical components according to type, load, level, size, etc. on a prototype basis.

3.10.7 METHODS AND PROCEDURES OF ANALYSIS OR TESTING OF SUPPORTS OF ELECTRICAL EQUIPMENT AND INSTRUMENTATION

To insure qualification for the required forces, acceleration requirements are included in equipment specifications as design parameters. Vendors will use this information as the basis for analysis or testing depending on the type, size, shape, or complexity of equipment to be qualified.

The equipment specification include, as a minimum, the following seismic requirements:

A. The appropriate seismic excitation for which the equipment must qualify will be determined based on location in the plant.

B. The equipment is required to perform its intended function during and after a Safe Shutdown Earthquake;

C. The vendor is required to substantiate the adequacy of the design by analysis, testing, past qualifications, or a combination of these depending on the type of equipment and its intended safety function; and

D. The quality assurance program used in assuring the implementation of the requirements of CENPD-182 are discussed in CENPD-210A.

The seismic qualification program, as described in CENPD-182 meets the specified requirements for seismic category I equipment.

E. Analyses or tests shall be performed for all supports of electrical and associated mechanical equipment and instrumentation to ensure their structural capability to withstand seismic excitation.

F. The analytical results will include the following:

   1. The required input motions to the mounted equipment shall be obtained and characterized in the manner as stated in Section 3.10.6 item F.

   2. The combined stresses of the support structures shall be within the allowable limits found in recognized mechanical handbooks.

G. Supports shall be tested with either equipment or dynamically equivalent models installed. If the equipment is not operating or not installed during the support test, the response at the equipment mounting

locations shall be monitored and characterized in the manner as stated in Section 3.10.6 item F. In such a case, equipment shall be tested separately and the actual input to the equipment shall be more conservative in amplitude and frequency content than the monitored response.

H. The requirements of Section 3.10.6 items F, H, I, J, and K are applicable when tests are conducted on the equipment supports.

Specifically, cabinet and support test requirements will be conducted as follows:

The design seismic environment of equipment located within support-structures (cabinets) will be determined by either test or analysis.

I. Testing will consist of one of the following procedures:

1. Fully Operational Cabinet Test

The cabinet, fully loaded with equipment, will be tested in its operating state. During testing, a sample of safety-related functions will be monitored. This test will demonstrate both structural integrity and functional operability.

2. Weighted Cabinet Test With Subsequent Equipment Tests

a. The cabinet will be tested with simulated equipment in place of the actual equipment. The simulated equipment will be equal in mass, mass distribution, and mounting to the actual

equipment such that the dynamic response of the weighted cabinet is equal to that of the fully loaded cabinet. During testing the motions present at the equipment mounting points will be recorded. This test will demonstrate the cabinet structural integrity and determine the local seismic environment of the actual equipment.

b. The actual equipment will be independently tested or analyzed to those motions determined by the weighted cabinet test. The equipment will be operational and all safety related functions will be monitored during the test. This test will demonstrate functional operability of the equipment.

3. <u>Equipment Test</u>

Equipment which is not mounted in a cabinet will be tested or analyzed in its operating state in a configuration which simulates its intended mounting.

J. For structures which can be modeled a dynamic analysis may be substituted for the weighted cabinet test to determine the motions at the enclosed equipment mounting points.

For both testing and analysis, the input motions to the cabinet shall be derived from the building motions at the cabinet's intended location.

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3.11 ENVIRONMENTAL DESIGN OF ELECTRICAL EQUIPMENT

Environmental design criteria for the facilities conform to 10CFR50, Appendix A, General Design Criterion 4, Environmental and Missile Design Bases. Compatibility of safety-related equipment with environmental conditions is provided to fulfill the following design criteria:

A. For normal operation, systems and components required to mitigate the consequences of a design basis accident (DBA) or for safe shutdown are designed to remain functional during and after exposure to the following environmental conditions:

   1. Winter and summer design temperatures maintained at the equipment location during normal operation by the ventilating and cooling system described in section 9.4.

   2. Relative humidity conditions at the equipment location during normal operation.

   3. Pressure conditions at the equipment location during normal operation.

   4. Maximum expected integrated radiation exposures for 40 years at the equipment location during normal operation.

B. In addition to the normal operation environmental requirements given in listing A above, the safety-related systems and components required to mitigate the consequences of a DBA, or to attain a safe

shutdown of the reactor, are designed to remain functional after exposure to the environmental conditions anticipated following the specific DBA which they are intended to mitigate. Anticipated environmental conditions and requirements are as listed below:

1. Components inside containment -- The temperature, pressure, humidity, and chemical environment inside containment after a design basis loss-of-coolant accident (LOCA) or main steam line break (MSLB) accident.

2. Components inside containment which are required after a design basis LOCA -- In addition to the requirements set forth in listing B.1, the time integrated post-LOCA radiation doses.

3. Components outside containment -- The expected pressure temperature and humidity environmental conditions at the equipment location.

4. Components outside the containment that are required to mitigate the consequences of a design basis LOCA -- The expected integrated accident radiation doses at the equipment locations in addition to the requirements set forth in listing B.3. In computing such doses for equipment in contact with or in proximity to recirculation water, it is assumed that 50% of the core halogen inventory and 1% of the core solid fission product

inventory are in the recirculation water after a design basis LOCA. For equipment located remotely from recirculation water, the containment leakage plume or other appropriate accidental release is assumed. These other accidental releases may be from a fuel handling accident or waste gas decay tank rupture in the fuel building or radwaste building, respectively.

3.11.1 EQUIPMENT IDENTIFICATION AND ENVIRONMENTAL CONDITIONS

The Equipment Qualification Program provides assurance that certain safety-related (i.e. important to safety) electrical and post-accident monitoring equipment will function during the design conditions postulated for plant normal, abnormal operation, design basis accidents, and the post-accident duration, as outlined in subsections 3.11.A and 3.11.B.

Normal plant environmental conditions are defined as those temperature, pressure, humidity and radiation conditions that occur during normal plant operations, including anticipated operational occurrences. Normal conditions are those for which the plant is designed.

Anticipated operational occurrences, or abnormal plant conditions, are those transient conditions of normal operation which are expected to occur one or more times during the life of the plant and include, but are not limited to, the loss of all offsite power and the concurrent loss of non-essential HVAC systems.

The Equipment Qualification Program defines plant areas as either mild or harsh based upon their accident environments. Mild environmental parameters are the range of conditions upon which equipment design is based. Failures under mild environment conditions are not considered common mode failures and are typically random in nature. A mild environment is an environment that would at no time be significantly more severe than the environment that would occur during normal plant operation, including anticipated operational occurrences. The specific environmental qualification of equipment located in mild environment plant areas is established by the use of design/purchase specifications and maintenance/surveillance programs. Therefore, equipment located in mild environment plant areas is not within the scope of the environmental qualification program.

A harsh environment is defined as the environment in any plant area where there is a significant increase above the normal plant environmental conditions in one or more environmental parameters due to a design basis accident or high energy line break. Harsh plant conditions subject equipment to severe environmental stresses as compared to the range of conditions during the equipment design and specification process and may potentially result in common mode failures. Therefore, important to safety equipment located in harsh environment plant areas are within the scope of the environmental qualification program.

The harsh environmental parameters that occur during normal plant operation and postulated design basis accident conditions

are provided for the containment, auxiliary, and fuel buildings and the main steam support structure in Appendix A of the Equipment Qualification Program Manual. The environmental parameters in the appendix are given by EQ Zone. An EQ Zone consists of one or more rooms and/or plant areas grouped according to their similarity of environmental conditions. The values given for each zone represents the worst case for the room(s) within each zone.

3.11.2 QUALIFICATION TESTS AND ANALYSES

Qualification tests and analyses performed on instrumentation and electrical equipment located in a harsh environment fulfill the requirements of IEEE 323-1974. When data for safety-related equipment are available and proven analytical methods are known, environmental qualification may be based on analysis. If such analytical methods are not feasible, qualification is based on environmental testing.

The harsh environmental qualification design parameters are presented in Appendix A of the Equipment Qualification Program Manual.

3.11.2.1 Component Environmental Design and Qualification for Normal Operation

Environmentally qualified equipment is designed for 40 years of continuous operation in the most severe temperature, pressure, humidity, and radiation environment that exists at the equipment location during normal operation, assuming proper

routine preventive maintenance is performed, such as periodic replacement of seals and packing, and testing.

Appendix A of the Equipment Qualification Program Manual provides the design temperatures, pressures, and humidities for each harsh plant area in which the safety-related equipment is located, as well as the exposures to radiation and chemical spray.

The use of representative operating temperatures (based on actual field temperature monitoring) in lieu of design temperatures from Appendix A of the Equipment Qualification Program Manual in the calculation of qualified life of equipment is acceptable.

For most equipment, special qualification tests to verify operability at normal operating temperature, pressure, and humidity conditions are generally not required. Certification for this equipment is based on proven operating capability in similar environments in nuclear power plant applications. The preoperational and postoperational test programs for safety-related components further ensure that safety-related components will be available when required. The normal and accident integrated radiation doses are assumed to have cumulative effects. The integrated radiation dose during normal operation is discussed in paragraph 3.11.5.2.

The normal plant vibration of safety-related equipment conforms to the requirements of the following standards or requirements;

Equipment	Standard or Requirement
Diesel fuel oil transfer pumps	Hydraulic Institute Standard
Essential cooling water pump	Hydraulic Institute Standard
Fuel pool cooling pump	Hydraulic Institute Standard
Essential chilled water pump	Hydraulic Institute Standard
Condensate transfer pump	Hydraulic Institute Standard
Essential spray pond pump	Hydraulic Institute Standard
Auxiliary feedwater pump	Hydraulic Institute Standard
HVAC equipment	ASHRAE Systems Handbook
Diesel engine generators	DEMA Standard Practices for Low and Medium Speed Stationary Diesel and Gas Engines
Electric motors	NEMA MG-1

The absence of any significant plant vibration caused by piping vibration (interaction) with the above equipment is verified as discussed in subsection 3.9.2

3.11.2.2 Component Environmental Design and Qualification for Operation After a Design Basis Accident

Safety-related equipment is designed to remain functional in the most severe combination of temperature, pressure, humidity, and chemical spray environmental conditions that exist at the equipment location after a DBA. This equipment is also designed for the maximum calculated integrated radiation

exposure after the DBA, as discussed in subsection 3.11.5. The temperature, pressure, and humidity environment inside the containment after a DBA is discussed in detail in subsection 6.2.1. The containment spray characteristics are given in paragraph 6.2.2.1. The integrated post-accident radiation dose for harsh plant locations in which the equipment is located is given in Appendix A of the Equipment Qualification Program Manual. In addition, steam and feedwater line breaks outside the containment are analytically checked to ensure that no additional qualifications need be applied to components that could be affected by these breaks.

The requirements of the General Design Criteria, Appendix A to 10CFR50, are met as follows:

- Criterion 1 - Quality Standards and Records, refer to section 3.1.
- Criterion 4 - Environmental and Missile Design Basis, refer to section 3.1.
- Criterion 23 - Protection System Failure Modes, refer to sections 3.1.
- Criterion 50 - Containment Design Basis, refer to sections 3.1 and 6.2.

The requirements of Quality Assurance Criterion III, Appendix B to 10CFR50 were met in accordance with the design and procurement QA program.

The recommendations contained in the regulatory guides listed below, listings A through E, have been utilized as described in

section 1.8. Additional comments are included in listings F through I.

A. Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment.

   Standard procedures and plans are utilized. Preconstruction verification is combined with receiving inspection when components are not stored.

B. Regulatory Guide 1.40, Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants.

   Regulatory Guide 1.40 is not applicable to PVNGS as there are no safety-related continuous-duty motors installed inside the containment.

C. Regulatory Guide 1.63, Electrical Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants. Refer to section 8.3 for the discussion on this guide.

D. Regulatory Guide 1.73, Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants.

   Motor-operated valves used inside the containment are qualified for abnormal environmental conditions in accordance with the general format and qualification procedures of IEEE 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power

Generating Stations, and IEEE 382-1972, IEEE Trial-Use Guide for Type Test of Class 1 Electric Valve Operators for Nuclear Power Generating Stations.

E. Regulatory Guide 1.89, Rev 1, Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants.
The qualification methods and documentation requirements of IEEE Standard 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations, are discussed in section 1.8.

F. Type tests to ensure acceptability for use in the containment post-accident environment are performed for each type of cable in accordance with IEEE Standard 383-1974, Standard for Type Tests for Class 1 Cables, Field Splices and Connections for Nuclear Power Generating Stations. Values of environmental parameters used in such tests are given in Appendix A of the Equipment Qualification Program Manual.

G. A total (normal plus accident) integrated dose of less than 10^4 rads will not affect the strength or properties of materials used;(1) hence, further qualification analyses and tests for components which will be exposed to less than 10^4 rads are not necessary. For higher integrated doses, components are qualified either by qualification testing or by evaluation of materials used. Reliable accumulated data on radiation effects,

such as is contained in reference 1, is used to analyze the dose effects on particular materials.

H. The sources used in calculating the radiation levels following a DBA are consistent with those set forth in reference 2 and Regulatory Guide 1.4. The non-NSSS safety-related equipment located inside the containment is designed to withstand the maximum integrated doses listed in Appendix A of the Equipment Qualification Program Manual during the life of the plant. Verification of suitability of materials used are verified by test for all electrical penetration assembly materials, for an integrated dose of at least 1.1×10^8 rads.

I. The materials used in the fabrication of mechanical and structural components inside the containment are selected so as to minimize corrosion and hydrogen generation resulting from contact with chemical spray solutions. Alternately, the components may be protected from contact with the spray. The use of aluminum and zinc is minimized in these components.

Copper is used as a pressure boundary material only in the containment fan cooler coils since its corrosion rate in the spray solution is acceptably low.(3) Gaskets, when used in piping systems, are composed of material compatible with the spray solution. Gasket materials on the fuel transfer tube and on the containment equipment and personnel hatches are selected

to be compatible with the spray solution. Other pressure boundary and structural materials used are stainless and carbon steel and concrete, which do not suffer significant degradation in the spray environment.[3]

3.11.3 QUALIFICATION TEST RESULTS

The results of qualification tests for the equipment covered in subsection 3.11.2 have been provided to the NRC by letters separate from the FSAR.

3.11.4 LOSS OF VENTILATION

The HVAC design to prevent loss of essential ventilation is described in sections 6.4 and 9.4. In general, for areas containing safety-related equipment, two separate environmental control systems are provided. One system operates during normal plant conditions. The second (essential) system operates during emergency conditions.

The following plant areas contain safety-related equipment:

A. Auxiliary Building

B. Main Steam Support Structure

C. Diesel Generator Building

D. Control Building

E. Fuel Building Exhaust

F. Containment

The safety-related equipment inside containment is qualified, as a minimum, to LOCA conditions as defined in Appendix A of the Equipment Qualification Program Manual. This qualification is more severe than any temperature, humidity, or radiation conditions expected during normal operation, shutdown, or standby. Two 100% capacity normal environmental control systems are provided in containment with automatic failover from the operating system to the standby system. In addition, the containment is equipped with temperature and humidity monitors which alarm in the control room.

The following plant areas contain temperature switches which alarm in the control room:

A. Auxiliary Building

   1. HPSI pump rooms
   2. LPSI pump rooms
   3. CSS pump rooms
   4. ECW pump rooms
   5. ESF electrical penetration areas
   6. CEDM control cabinet room

B. Main Steam Support Structure

   1. Motor-driven auxiliary feed pump room
   2. Turbine-driven auxiliary feed pump room

C. Diesel Generator Building

   1. DG rooms

2. DG control areas

D. Control Building

1. Essential DC equipment rooms

The following plant areas are monitored by a temperature switch (alarmed in the control room) in the exhaust duct or exhaust plenum of the normal environmental control system:

A. Control Building

1. ESF switchgear rooms

2. Essential DC equipment rooms

3. Essential battery rooms

4. Remote shutdown panel area

B. Fuel Building Exhaust Plenum

Temperature switches located in individual rooms alarm when abnormally high temperatures exist in the room. Administrative procedures require operating personnel to respond to these alarms. Operation of either the normal or essential environmental control system will ensure control of humidity below that for which the equipment is qualified. Therefore, only temperature switches are provided in each room.

Temperature switches located in the exhaust duct or exhaust plenum of the normal environmental control system monitor for abnormally high temperature in the control building and monitor for abnormally high/low temperature in the fuel building. The equipment located in the ESF switchgear rooms, essential battery rooms, and remote shutdown area does not constitute a

large heat load. It is expected, therefore, that temperature variations during periods of operations, standby, and shutdown would be slight, making individual room alarms unnecessary. The initial quantification of the Level I Probabilistic Risk Assessment (performed as part of the Individual Plant Examination requirements in response to Generic Letter 88-20) identified the loss of all ventilation to the essential DC equipment rooms, which results in the failure of the battery chargers and vital inverters due to high temperature, as a dominant scenario in the assessed Core Damage Frequency. Subsequent quantifications, accounting for the installed local temperature indicators and the high temperature alarm in the essential DC equipment rooms allowing for operator recovery of ventilation, result in a substantial decrease in the assessed Core Damage Frequency.

Per Regulatory Guide 1.47, whenever an essential environmental control system is bypassed or inoperable, this condition will be alarmed in the control room. Administrative procedures will require operating personnel to respond to these alarms and ensure that either an environmental control system is operating or, if all systems are shut down, that portable temperature monitoring equipment is installed near the affected safety-related equipment before the environmental conditions would adversely effect equipment qualification. Administrative procedures ensure that the environmental control systems in safety related areas are always maintained in operation during periods of plant shutdown or hot standby.

The normal and essential environmental control systems are designed to maintain the conditions listed in Appendix A of the Equipment Qualification Program Manual during normal plant operation and during shutdown or standby conditions. Either the normal or the essential environmental control system is capable of maintaining these environmental conditions.

In order to assure the function of the safety-related harsh area equipment during accident conditions, the equipment is qualified to perform its safety-related function in the environmental conditions listed in Appendix A of the Equipment Qualification Program Manual.

The main steam support structure above elevation 100 feet is open to natural circulation of outside air. All safety-related equipment in this area are qualified to the conditions listed in Appendix A of the Equipment Qualification Program Manual. This qualification is sufficient to ensure that the safety-related equipment in the main steam support structure will not be exposed to environmental conditions during normal operation, shutdown or standby for which it has not been qualified.

The remote shutdown panel area is located adjacent to the ESF switchgear, ESF equipment, and essential battery rooms and utilizes the same environmental control systems as these rooms.

Cable insulation design rating is 90°C.

The actual operating temperature of a cable is affected by its current flow under load, the normal and abnormal environmental temperature(s) and routing conditions. Cable ampacity analysis

have been performed to verify that cables installed in raceway within the Licensed Facility do not exceed the 90 degree C insulation rating.

3.11.5 ESTIMATED CHEMICAL AND RADIATION ENVIRONMENT

3.11.5.1 Chemical Environment

Engineered safety feature (ESF) systems located in a harsh environment are designed to perform their safety-related functions in the temperature, pressure, and humidity conditions described in Appendix A of the Equipment Qualification Program Manual and sections 6.2 and 6.3. In addition, components of ESF systems inside the containment are designed to perform their safety-related functions in long-term contact with boric acid recirculated through the emergency core cooling system and containment spray systems.

The containment atmosphere is maintained below 4 volume % hydrogen consistent with the recommendations of Regulatory Guide 1.7 as discussed in subsection 6.2.5.

3.11.5.2 Radiation Environment

ESF systems and components are designed to perform their safety-related functions after normal operational exposure plus an accident exposure. The normal operational exposure is based on the design source terms presented in chapter 11 and subsection 12.2.1 and the equipment and shielding configurations presented in section 12.3.

Post-accident ESF system and component radiation exposures are dependent on equipment location. In the containment and control room area, exposures are due to a hypothesized LOCA. Source terms and other accident parameters are presented in subsection 12.2.1 and chapter 15, and are consistent with the recommendations of Regulatory Guides 1.4, 1.7, and Standard Review Plan Section 6.5.2 NUREG 800 Rev. 1.

In the auxiliary building, exposures are based on the assumption that 50% of the core halogen inventory and 1% of the core solid fission products are recirculated in the sump water. For a postulated intact primary degraded core event, the exposures are based on the assumption that 100% of the core noble gases, 50% of the core halogen inventory, and 1% of the core solid fission products are recirculated in the low pressure safety injection (LPSI) piping. In addition, the post-LOCA total integrated doses for the auxiliary building, fuel building, and main steam support structure are the sum of the following doses:

1. Containment shine and penetration streaming.
2. Shine from equipment and piping in or near the electrical and mechanical penetration rooms.
3. Post-LOCA airborne dose due to containment airborne penetration leakage.
4. 40 year normal dose.

In the fuel handling building, exposures are based on a fuel handling accident and LOCA. Source terms and other accident parameters are presented in chapter 15.

Normal, accident, and design (normal plus accident) radiation exposures based on the above assumptions for harsh environment locations are presented in Appendix A of the Equipment Qualification Program Manual.

3.11.6 REFERENCES

1. Kircher, J. F. and Bowman, R. E., Effects of Radiation on Materials and Components, Van Nostrand Reinhold, New York, 1964.

2. DiNunno, J. J., Baker, R. E., Anerson, F. D., and Waterfield, R. L., "Calculation of Distance Factors for Power and Test Reactor Sites," TID-14844, Division of Licensing and Regulation, AEC, Washington, D.C., 1962.

3. Griess, J. C. and Bacarella, A. L., "Design Considerations of Reactor Containment Spray Solutions," ORNL-TM 2412, Part III, Oak Ridge National Laboratory, Oak Ridge, Tennessee, December 1969.

4. Letter, Oak Ridge National Laboratory (L. T. Corbin) to Mobil Chemical Company (M. J. Masciole), March 26, 1974.

5. Franklin Institute Research Laboratories, Technical Report No. F-C3349, May 1973.

6. Equipment Qualification Program Manual, EQDF EQ-PM.

APPENDIX 3A

RESPONSES TO NRC REQUESTS FOR INFORMATION

CONTENTS

TABLES

FIGURES

ATTACHMENT

APPENDIX 3A

QUESTION 3A.1 (NRC Comment on section 3.8.3.5) (6/18/80) (3.8.3.5)

No input of allowable limits and factors of safety against structural failure.

RESPONSE: The response is given in amended paragraph 3.8.3.5.

QUESTION 3A.2 (NRC Question 460.2) (3.2.2)

Include sections for effluent radiation monitors and process radiation monitors in table 3.2-1 of the Final Safety Analysis Report (FSAR), which lists quality classification of structures, systems and components.

RESPONSE: The response is given in amended subsection 3.2.2 (table 3.2-1).

QUESTION 3A.3 (NRC Question 220.1) (3.4.2)

Provide information of underdrains and pressure-relieving systems if used in Palo Verde stations.

RESPONSE: There are no underdrains or pressure-relieving systems required for PVNGS.

QUESTION 3A.4 (NRC Question 220.2) (3.7.1)

Provide information on the strain levels of soil during an OBE and SSE, and the variations of soil strain with the depth and layering of the supporting soil media. Describe the procedure of using strain-dependent soil properties (damping and shear modulus) to model the soil-structure interaction system. To what extent the computer program SHAKE is used to develop

strain-corrected damping values for foundation materials and what is the theoretical basis for such use?

RESPONSE: The "effective strains"[a] for each layer of the soil media for SSE and OBE are shown in figures 3A-1 and 3A-2. The computer program SHAKE[b] was used to establish the strain-corrected values of shear moduli and damping values for each layer of soil during SSE and OBE. The curves relating shear moduli and damping values to shear strain are site specific. The strain-corrected values of shear moduli and damping values were then utilized to calculate the impedance functions for each foundation by means of a computer program LUCON[c]. The method for coupling soil impedance function with the structural model has been described in paragraph 3.7.2.4.

QUESTION 3A.5 (NRC Question 220.3) (3.7.2)

Explain how does each of the Category I structures (containment building, auxiliary building, control building, and fuel building) have different sets of natural frequencies for OBE and for SSE. Do the natural frequencies listed in tables 3.7-7 through 3.7-10 represent the structural modes only, or the soil- structure interaction modes as well?

RESPONSE: The response is given in amended paragraph 3.7.2.2.2

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a. Effective strain is defined as 65% of the maximum strain in "SHAKE" (see reference 1 of section 3.7).

b. The theoretical basis of the SHAKE program is given in reference 1 of section 3.7.

c. The theoretical basis for the computer program LUCON is described in appendix 3B.8.

APPENDIX 3A

<u>QUESTION 3A.6</u> (NRC Question 220.4) (3.7.2)

Supply for each mode of vibration listed in tables 3.7-3 through 3.7-6 the mode shape and its corresponding participation factor.

<u>RESPONSE</u>: The response is given in amended paragraph 3.7.2.4.

<u>QUESTION 3A.7</u> (NRC Question 220.5) (3.7.2)

Perform a comparative study of results in structural responses obtained by two different approaches of soil modeling to soil-structure interaction analyses: the half-space method (lumped parameter, compliance function, or impedance function methods) and the finite boundary method (also known as the finite-element, shear beam, or one-dimensional shear wave methods). Quantities to be compared should include floor response spectra in typical Category I structures; e.g., at the basemat, operating floor, and an upper elevation of the containment building, and at the basement and an intermediate elevation of the auxiliary building. The input ground motion or control motion should be applied at the foundation level as required by Appendix A to 10CFR100.

RESPONSE: The response is given in amended paragraph 3.7.2.4.

<u>QUESTION 3A.8</u> (NRC Question 220.6) (3.7.3)

Provide specific number of earthquake cycles used in the design of subsystems of Palo Verde Stations. The Standard Review Plan 3.7.3 states that a postulation of one safe shutdown earthquake

and five operating basis earthquake with ten stress cycles per earthquake is acceptable.

RESPONSE: The response is given in paragraph 2.5.2.7 and amended paragraph 3.7.3.2.

<u>QUESTION 3A.9</u> (NRC Question 220.7) (3.7.3)

The criteria for combining responses to three components of earthquake motion have been stipulated in Regulatory Guide 1.92. The criteria suggested in NUREG/CR-0098 are for certain operating plants only and have not been approved for use in Palo Verde stations. The applicant should either provide justification to use the NUREG/CR-0098 criteria or commit to use Regulatory Guide 1.92 criteria for Palo Verde seismic analysis.

RESPONSE: The factor method of combining responses to three components of earthquake motion is equivalent to the square-root-of-the-sum-of-the-squares (SRSS) method discussed in Regulatory Guide 1.92. The results from the component factor method are usually more conservative than the results from the SRSS method. In no case is the component factor method outcome below the SRSS value by more than 1%. The validity of the component factor method is demonstrated in attachment 3A1.

Thus, it is concluded that use of the component factor method is a valid alternative to the SRSS approach.

QUESTION 3A.10 (NRC Question 220.8) (3.8.1)

The acceptance of the Topical Report BC-TOP-5A as reference to prestressed concrete nuclear reactor containment structures excludes its applicability to Subsection 3.8.1.6, Materials, Quality Control and Special Construction Techniques. Identify all deviations from PSAR commitments and all exceptions to accepted codes. Provide explanation and justification for these deviations and exceptions.

RESPONSE:

I. Exceptions to PSAR Sections 3.8.1.6 and 3.8.3 commitments are as follows:

A. PSAR Section 3.8.1.6.3 does not take any exceptions to obtaining mill test reports (MTRs) for materials.

FSAR paragraph 3.8.1.6.6 takes exceptions as stated.

B. PSAR Section 3.8.1.6.4 states that if loads are transferred through the thickness dimension of the liner plate, tests will be made to determine the through-thickness strength of the liner materials used in these locations. FSAR paragraph 3.8.1.6.4 and project specifications do not require any tests to be performed to determine the through-thickness strength of the liner materials.

Justification: Although no tests are required, the design was based on the code requirement

that the strength in the thickness direction of the plate is one-half of the nominal yield strength.

C. FSAR paragraph 3.8.1.6.6 lists additional materials which were not listed in the PSAR.

Additional steels were required by design due to their material properties or material availability.

D. PSAR Section 3.8.1.6.6.2.A takes no exceptions to Table 4.2 of AWS Dl.1-72. FSAR paragraph 3.8.1.6.6.1 takes exceptions as stated.

E. PSAR Section 3.8.3.4.1.7 states that the polar crane is provided with mechanical guides to the rails to prevent the crane from being derailed as a result of the SSE.

FSAR paragraph 3.8.3.4.7 takes exceptions as stated.

II. All exceptions to accepted codes or regulatory guides have been previously identified in the following paragraphs of the FSAR:

A. Paragraph 3.8.1.6.1.2 for exception to the ACI Code.

B. Paragraph 3.8.1.6.6.1 for exception to the AWS Code.

C. Section 1.8 for exceptions to the Regulatory Guides.

A review of these exceptions indicates mostly minor differences between the PVNGS criteria and accepted codes and regulatory guides. These differences in no

way affect the safety margin of the containment building.

QUESTION 3A.11 (NRC Question 220.9) (3.8.4)

Identify any deviation from PSAR design criteria of Category I structures and any exception to applicable accepted codes. Provide explanation and justification for these deviations and exceptions.

RESPONSE: There are no deviations or exceptions to applicable accepted codes mentioned in subsection 3.8.3 for the design of the following Category I structures: auxiliary building, control building, diesel generator building, fuel handling building, Category I tanks. (The containment building exceptions are discussed in Question 3A.10 (NRC Question 220.8).

QUESTION 3A.12 (NRC Question 220.10) (3.8.4)

Are there any concrete masonry walls used in any of the Category I structures of the Palo Verde plant? If "yes", provide answers to the following questions:

(a) Indicate the loads and load combinations to which the walls are designed to resist. If load factors other than one (1.0) have been employed, indicate their magnitudes.

(b) In addition to complying with the applicable requirements of the SRP Sections 3.5, 3.7, and 3.8, is there any other code, such as the "Uniform Building Code" or the "Building Code Requirements for Concrete

Masonry Structures" (proposed by the American Concrete Institute) which was or is being used to guide the design of these walls? Please identify and discuss any exceptions or deviations from the SRP requirements or the aforementioned codes.

(c) Indicate the method that you used to calculate the dynamic forces in masonry walls due to earthquake, i.e., whether it is a code method such as Uniform Building Code, or a dynamic analysis. Identify the code and its effective date if the code method has been used. Indicate the input motion if a dynamic analysis has been performed.

(d) How were the masonry walls and the piping/equipment supports attached to them designed? Provide enough (numerical) examples including details of reinforcement and attachments to illustrate the methods and procedures used to analyze and design the walls and the anchors needed for supporting piping/equipment (as applicable).

(e) Provide plan and elevation views of the plant structures showing the location of all masonry walls for your facility.

RESPONSE: The project has used nonbearing, non-shear carrying concrete masonry walls in two Category I structures; namely, the control building and the auxiliary building.

The control building has a concrete masonry partition wall for fire protection which divides the building into two

halves from elevation 74 feet to elevation 100 feet. There are seven concrete masonry partition walls at elevation 100 feet which form eight compartments to house various equipment. In addition, concrete masonry walls were used to provide fire protection for a cable raceway from elevation 120 feet to elevation 140 feet.

The auxiliary building has seven concrete masonry partition walls at elevation 140 feet.

(a) The subject concrete masonry walls are classified as non-Category I, however they are required to retain their structural integrity in the event of an earthquake. Therefore, the walls were originally designed for the following governing load-factored equations:

1) 1.4 D + 1.9 E

2) 1.0 D + 1.0 E'

where D = Dead load

E = Seismic loads due to operating basis earthquake (OBE)

E' = Seismic loads due to safe shutdown earthquake (SSE)

The original concrete masonry wall design was performed using ultimate strength design methods. Because the partition walls at control building elevations 74'-0" and 100'-0" have limited Category attachments, they have also been seismically evaluated in accordance with the working stress design

requirements described in NUREG-0800, Standard Review Plan (SRP), Revision 0, July 1981, Section 3.8.4, Appendix A. The following governing load combinations were considered for the working stress analysis:

1.0 D + 1.0 E

1.0 D + 1.0 E'

(b) The concrete and masonry walls were originally designed in accordance with NUREG-75/087, Standard Review Plan (SRP), November 1975, Sections 3.7 and 3.8, and using the following codes:

1) 1974 masonry codes and specifications by Masonry Industry Advancement Committee.

2) Building code requirements for reinforced concrete (ACI 318-77).

Through subsequent evaluations, it has been established that the masonry walls of the control building at elevations 74'-0" and 100'-0" also conform to the requirements of NUREG-0800, Standard Review Plan (SRP), Revision 0, July 1981, Section 3.8.4, Appendix A. In addition, these evaluations utilized the following codes:

1) Uniform Building Codes (UBC) - 1985.

2) Building code requirements for concrete masonry structures, ACI 531-79, Revised 1983.

3) Specifications for the design, fabrication and erection of structural steel for buildings, AISC Manual of Steel Construction, 8th edition.

It should be noted that SRP Section 3.5 does not apply since these walls are not missile barriers.

(c) Seismic acceleration values corresponding to the specifically calculated wall frequencies were used to generate equivalent static loads for the initial design of the masonry walls. The accelerations were obtained from the in-structure response spectrum curves generated by performing dynamic analysis of the respective building. Subsequent evaluations utilized the same analytical methods in addition to the time history response spectrum analysis of detailed FEM models representing various concrete masonry wall sections.

(d) Project requirements prohibit the attachment of Seismic Category I piping to masonry walls.

At a few locations conduits, instrumentation tubing, bracing for equipment supports and small electrical panels are attached to the masonry walls. Two-inch and smaller non-Seismic Category I fire protection lines are also attached. In general, these attachments are made by bolting through the masonry walls. Light-weight attachments, i.e., small diameter thin wall conduits, emergency lighting fixtures, and instrumentation lines, may be attached using expansion anchors. The attachments and their effects on the

integrity of the walls are evaluated using frequency-specific or peak seismic acceleration values obtained from the in-structure response spectrum curves and equivalent static load methodology. The time history and response spectrum analyses of the control building masonry walls at elevations 74'-0" and 100'-0" include the effects of the additional weight of the attachments. Records of the wall attachments are kept to assure that wall integrity is not jeopardized.

The calculated out-of-plane deflections on the masonry block walls due to seismic OBE and SSE loading conditions will have an insignificant effect on the performance of Seismic Category I components attached to those walls. These components will retain their structural integrity without loss of operability during and following an OBE or SSE event.

(e) Figures 3A-3 through 3A-6 show plan and elevation views of all masonry walls used in Category I structures for Palo Verde Nuclear Generating Station as well as reinforcement and attachment details.

QUESTION 3A.13 (NRC Question 450.1) (3.5.1.4)

Provide the locations of all safety-related equipment not contained within reinforced concrete buildings or structures. Provide the structural composition of all walls and roofs of buildings housing safety-related equipment, as well as the building locations. Discuss the sizes and directional orientations of any openings in these buildings.

RESPONSE: The following safety-related equipment is not enclosed within reinforced concrete buildings or structures:

- Roof levels of the refueling water tank (RWT) and condensate storage tank (CST) (structural steel lined with 1/4-inch stainless steel)
- The discharge duct from the fuel building and auxiliary building exhaust essential air filtration units and the radiation monitoring equipment located in it. These items are located on the fuel building roof.
- Piping from the RWT to the auxiliary building (buried below ground level)
- Piping from the condensate storage tank (CST) to the auxiliary feedwater pumps (buried below ground level or enclosed in concrete pipe tunnel)
- Diesel fuel oil storage tank and piping (buried below ground level)
- Piping from the essential spray pond to the auxiliary building (buried below ground level)
- Essential spray pond spray headers and nozzles

The locations of this equipment are shown in engineering drawing 13-P-OOB-001.

Refer to table 3.5-9 for the structural composition of the walls and roofs of buildings housing safety-related equipment. Any openings in the buildings through which a tornado-generated missile may enter and damage the

safety-related equipment are provided with one of the following missile barriers:

1. All exterior door openings are protected by missile-proof doors.
2. Thick steel plate missile shields.
3. Concrete missile shields.
4. The space within the opening is sufficiently occupied by piping and pipe supports to preclude missile penetration.

The roof of the main steam support structure is elevated from the top of the walls to allow the escape of steam in the event of a major pipe break. The roof is cantilevered beyond the wall to provide the necessary missile protection.

Missile protection is not required for the duct or radiation monitoring equipment located on the fuel building roof because:

a) The duct is on the discharge side of the AFUs; therefore the air in this duct has already been filtered. The amount of radiation released would remain the same.

b) If a tornado-generated missile did strike the duct, it would either tear it apart [see (a) above] or pierce it. The five missiles from UFSAR table 3.5-8 that must be considered all strike end-on. The blockage caused from any of these (maximum 12 inches wide x 60 inches long) is small compared to the 60-inch diameter duct.

The velocity through this duct without a blockage is only about 305 fpm (6000 cfm, 60-inch diameter duct). Because of this extremely low velocity, the airflow change caused by one of these five missiles is negligible. The other two missiles, the utility pole and the car, do not have to be considered because the fuel building roof is higher than 30 feet above grade level (UFSAR 3.5.1.4).

c) The radiation monitors can provide a "start" signal to these AFUs but this is a redundant function. Radiation monitor J-SQA-RU-31 provides a redundant FBEVAS. The AFUs may also be started by an SIAS to keep the elevations below 100 feet in the auxiliary building negative. There is also a manual "on" switch for the AFUs.

d) The Offsite Dose Calculation Manual (ODCM) allows for manual effluent monitoring if these radiation monitors are inoperable.

e) UFSAR chapter 3 does not show a fuel handling accident or LOCA combined with a tornado as a credible scenario.

QUESTION 3A.14 (NRC Question 450.2) (3.5.1.4)

Describe the protection of the control room air intakes and diesel generator exhaust pipes from tornado-generated missiles.

RESPONSE:

- The control room air intakes are enclosed within a box structure located within the control building (see figure 3A-7). The wall sections exposed to

tornado-generated missiles are designed to withstand such impact without adverse effect upon the system.

- The diesel generator exhaust pipes are enclosed within a 1- foot 9-inch thick vertical, concrete chimney which is designed to withstand tornado-generated missile impact. A thick, steel pipe sleeve, also capable of withstanding tornado-generated missile impact, provides protection for the exhaust piping at the vent opening at the top of the chimney.

QUESTION 3A.15 (NRC Question 210.1) (3.9.6)

There are several safety systems connected to the reactor coolant pressure boundary that have design pressure below the rated reactor coolant system (RCS) pressure. There are also some systems which are rated at full reactor pressure on the discharge side of pumps but have pump suction below RCS pressure. In order to protect these systems from RCS pressure, two or more isolation valves are placed in series to form the interface between the high-pressure RCS and the low-pressure systems. The leaktight integrity of these valves must be ensured by periodic leak testing to prevent exceeding the design pressure of the low-pressure systems, thus causing an intersystem LOCA.

Pressure isolation valves are required to be Category A or AC and to meet the appropriate requirements of the ASME OM Code except as discussed below.

Limiting conditions for operation (LCO) are required to be added to the technical specifications which will require corrective action; i.e., shutdown or system isolation when the final approved leakage limits are not met. Also surveillance requirements, which will state the acceptable peak rate testing frequency, shall be provided in the Technical Specifications.

Periodic leaktesting of each pressure isolation valve is required to be performed at least once per each refueling outage, after valve maintenance prior to return to service, and for systems rated at less than 50% of RCS design pressure each time the valve has moved from its fully closed position unless justification is given. The testing interval should average to be approximately 1 year. Leaktesting should also be performed after all disturbances to the valves are complete, prior to reaching power operation following a refueling outage, maintenance, and etc.

The staff's present position on leak rate limiting conditions for operation must be equal to or less than 1 gallon per minute for each valve (gpm) to ensure the integrity of the valve, demonstrate the adequacy of the redundant pressure isolation function and give an indication of valve degradation over a finite period of time. Significant increases over this limiting valve would be an indication of valve degradation from one test to another.

Leak rates higher than 1 gpm will be considered if the leak rate changes are below 1 gpm above the previous test leak rate or system design precludes measuring 1 gpm with sufficient

accuracy. These items will be reviewed on a case-by-case basis.

The Class 1 to Class 2 boundary will be considered the isolation point which must be protected by redundant isolation valves.

In cases where pressure isolation is provided by two valves, both will be independently leaktested. When three or more valves provide isolation, only two of the valves need to be leaktested.

Provide a list of all pressure isolation valves included in your testing program along with four sets of piping and instrument diagrams which describe your reactor coolant system pressure isolation valves. Also discuss in detail how your leaktesting program will conform to the above staff position.

RESPONSE: The response is given in amended paragraph 3.9.6.2.

QUESTION 3A.16 (NRC Question 410.1) (3.5.1.2)

Your evaluation of potential missile sources inside containment is not complete. The following concerns should be addressed:

a) Verify that secondary missiles, if any, generated by impact of the primary missiles identified in FSAR table 3.5-4 inside containment will not cause damage to essential systems required to assure a safe shutdown or result in unacceptable release of radioactivity.

b) Verify that a seismic event will not result in gravity missiles within the containment which could cause damage to

essential systems required to assure a safe shutdown or result in unacceptable releases of radioactivity.

RESPONSE: The response is given in amended paragraph 3.5.1.2.2.

QUESTION 3A.17 (NRC Question 410.2) (3.5.2)

In FSAR figures 3.5-4 through 3.5-7 you have identified those areas housing equipment, systems, and components required for safe reactor shutdown as missile targets. However, you have not considered areas housing radioactive fluid such as the radwaste building as missile targets. Verify that equipment, systems, and components containing radioactive fluid are protected against tornado missile damage, or assure that failure of unprotected components will not result in an unacceptable release of radioactivity.

RESPONSE: As noted in paragraphs 15.7.3.3, 15.7.3.4, and 15.7.3.5, failures of liquid and gaseous radwaste components do not cause unacceptable releases of radioactivity; therefore, missile protection is not required. Also see amended table 3.5-9.

QUESTION 3A.18 (NRC Question 410.3) (3.5.2)

Describe the protection provided for all essential ventilation system air intakes and exhausts against damage due to multiple tornado-generated missiles assuming missiles as identified in the tornado missile spectrum for the plant. Verify that safety-related equipment and spent fuel is not affected by tornado missile impact to these openings or that openings in

structures created by failures due to a tornado will not affect the function of safety related components or cause damage to spent fuel by allowing missile entry.

RESPONSE: Essential ventilation system openings with a potential for tornado-generated missiles to enter and damage safety-related equipment are provided with missile protection, as shown in table 3A-1. This prevents tornado-generated missiles from damaging safety-related equipment or spent fuel.

Table 3A-1

MISSILE PROTECTION OF ESSENTIAL

VENTILATION SYSTEM AIR INTAKES AND EXHAUSTS

Intake/Exhaust Point	Protective Feature
Fuel building exhaust	Steel plate prevents missile passage through penetration
Main steam support structure	Steel plate prevents missile passage through penetration
Auxiliary building	
• Hydrogen recombiner cooling air intake	Steel plate prevents missile passage through penetration
• Hydrogen recombiner cooling air exhaust	Steel plate prevents missile passage through penetration
Control building intake	Concrete intake plenum designed as labyrinth
Control building exhaust	Steel louvers
Diesel generator	
• Combustion air intake	Offset concrete baffles prevent missile entry
• Combustion air exhaust	Protected by a combination of concrete and guard piping
• Cooling air intake	Offset concreted baffles prevent missile entry
• Cooling air exhaust	Concrete plenum

QUESTION 3A.19 (NRC Question 410.4) (3.6.1)

Your analysis of the consequences of high and moderate energy pipe breaks outside containment is not complete. Provide the following additional information:

a. Verify that the high and moderate energy pipe break analysis outside containment is in accordance with the guidance of Branch Technical Position (BTP) ASB 3-1.

b. Reference is made in FSAR paragraph 3.6.1.3 to specific safety-related system failure modes and effects analyses. However, these tables do not identify the capability of individual systems to mitigate the consequences of pipe breaks assuming a single failure as identified in the criteria of BTP ASB 3-1. Include such a discussion in FSAR paragraph 3.6.1.3.

c. Provide layout drawings of safety-related areas outside containment showing the routing of high and moderate energy piping systems and their relative position to safety-related equipment and components. These drawings should identify postulated break and crack locations in high and moderate energy lines. Further, provide a table which identifies the means of protection (i.e., pipe whip restraint, jet impingement barrier, separation, floor drainage, etc.) for safety-related equipment from the effects of the postulated high and moderate energy pipe breaks.

d. Expand the discussion in FSAR subsection 3.6.1 to identify the design bases for the protection of individual safety-related equipment which has been identified in

part c) above. For example, the FSAR should describe the design bases for internal flood protection (expected leakage rate), jet impingement protection (force assumed from the blowdown), worst expected environment (temperature, pressure, and humidity), etc., which result from the bounding pipe breaks in the area of the auxiliary feedwater pumps.

RESPONSE:

a. Extent of compliance with BTP ASB 3-1 (follows format of BTP ASB 3-1):

   1. In compliance.

   2a. In compliance.

   2b(1). In compliance.

   2b(2). In compliance.

   2c(1). The design of PVNGS fluid system piping in the penetration area either:

      (1) Meets the stress limits of BTP MEM 3-1 Sec. B.1.b or B.2.b, or,

      (2) Is not essential to shut down the reactor or mitigate the consequences of the postulated piping failure (at the terminal end) without offsite power.

   2c(2). Not applicable to PVNGS

   2c(3). Terminal ends of the piping are considered to originate at the penetration sleeve inside and outside containment.

2c(4). In compliance.

2d(1). In compliance.

2d(2). In compliance.

2d(3). Not applicable to PVNGS.

2d(4). In compliance.

3a. In compliance.

3b(1). In compliance.

3b(2). In compliance.

3b(3). In compliance with the clarification that the criteria have been extended to include high energy (e.g., CVCS charging system) as well as moderate energy systems.

3b(4). In compliance.

3c. In compliance.

3d. In compliance.

b. The equipment or systems required to mitigate the effects of various types of breaks are listed in paragraph 3.6.1.2. The equipment layout and/or design features are such that high or moderate energy breaks will not adversely affect either train of any system required for shutdown or mitigate the consequences of the break. Therefore, the single failure analyses (refer to paragraph 6.2.1.3) do not require addition of direct high energy or moderate energy effects since these effects are precluded by design.

c. The response is given in amended paragraph 3.6.1.2.

d. The response is given in amended paragraph 3.6.1.2.

QUESTION 3A.20 (NRC Question 410.5) (3.6.1)

It is our position that the common compartment which houses the main steam lines and feedwater lines and the isolation valves for these lines (the main steam support structure) be designed to consider the environmental effects (pressure, temperature, humidity) and potential flooding consequences from an assumed crack of 1 square foot. The essential equipment located within the main steam support structure, including the atmospheric dump valves, main steam isolation valves, and feedwater isolation valves and their operators, and the essential auxiliary feedwater pumps and associated equipment should be capable of operating in the environment resulting from the above crack. Further, if this assumed crack could cause the structural failure of this compartment, then the failure should not jeopardize the safe shutdown of the plant.

We, therefore, request that you submit a subcompartment pressure analysis to confirm that the design of the main steam support structure conforms to our position as outlined above. The evaluation should include a verification that the methods used to calculate the pressure buildup in the main steam support structure for the postulated breaks are the same as those used for subcompartments inside the containment. Also, the allowance for structural design margins (pressure) should be the same. If different methods are used, justify that your method provides adequate design margins and identify the margins that are available. When you submit the results of

your evaluation, identify the computer codes used, and the assumptions used for mass and energy release rates. The peak pressures and temperatures resulting from the postulated break of a high energy pipe located in the main steam support structure is dependent on the mass and energy flows during the time of the break. Therefore, for each pipe break or crack analyzed, provide the total blowdown time and the mechanism used to terminate or limit the time of blowdown flow so that the environmental effects will not affect safe shutdown of the facility.

Also provide a similar analysis for other compartments outside containment in the vicinity of safety-related structures, systems, and components which house high energy lines such as CVCS charging, letdown, and steam generator blowdown.

RESPONSE: A pressure-temperature analysis of the main steam support structure (MSSS) was performed as discussed in amended paragraph 3.6.2.1.1.2. For the purpose of establishing design parameters (i.e., pressure, temperature) of the enclosing structure, a one square foot break of the main steam line was conservatively assumed. The results of the analysis indicate a peak temperature of 383F, a peak pressure of less than 2.1 psig, and a steady state pressure of less than 0.2 psig, which were conservatively selected for equipment qualification and structural design.

The pressure-temperature effects resulting from cracks in the main feedwater, steam generator blowdown, and steam

generator downcomer feed lines are bounded by the results from the main steam line break analysis.

A pressure-temperature analysis of the auxiliary building was performed utilizing the building's HVAC exhaust duct as an atmospheric vent path for the steam. The resulting transient environmental parameters from the postulated failure of the CVCS let down line and auxiliary steam line do not exceed the building allowable range for structural loading nor render safe shutdown equipment unqualified from the Equipment Qualification perspective.

An auxiliary steam line HELB will initiate neither a reactor trip nor a turbine trip. Therefore, a site Loss of Offsite Power (LOOP) is not postulated to occur concurrent with the HELB, and the building's HVAC exhaust duct can provide a passive atmospheric vent path for the steam to exit the building.

Should a loss of instrument air (IA) or loss of the non class 1E control power occur concurrent with a HELB, the pneumatic dampers in the exhaust duct will fail closed, blocking the atmospheric vent path. This loss of IA or the non class 1E control power will also result in the two redundant air operated auxiliary steam isolation valves failing closed position, and thereby isolating the auxiliary steam system, which results in an atmosphere that is not as harsh as an unlimited HELB.

Blowdown of the CVCS letdown line is terminated by operator action within 10 minutes of the initiation of three alarms in the control room:

- Regenerative heat exchanger high exit temperature
- Letdown line low pressure
- Low flow in the process radiation monitor loop.

Also see Question 3A.19 (NRC Question 410.4).

APPENDIX 3A

ATTACHMENT 3A1

VALIDITY OF THE COMPONENT FACTOR METHOD

This attachment presents a demonstration of the adequacy of the component factor method expressed by equation 1 when compared to the square-root-of-the-sum-of-the-squares (SRSS) method expressed by equation 2.

$$R' = 1.0\ R_i + 0.4\ R_j + 0.4\ R_k \quad (1)$$

$$R = \left\{R_i^2 + R_j^2 + R_k^2\right\}^{1/2} \quad (2)$$

To demonstrate this, first consider a combination response, R' defined as follows:

$$R' = R_i + 0.414R_j + 0.318R_K \quad (3)$$

in which

$$R_i \geq R_j \geq R_k \geq 0 \quad (4)$$

Let

$$R_j = \overline{R}_j + R_k \ \left(\overline{R}_j = 0 \text{ if } R_j = R_k\right) \quad (5)$$

$$R_i = \overline{R}_i + R_j = \overline{R}_i + \overline{R}_j + R_k \ \left(\overline{R}_i = 0 \text{ if } R_i = R_j\right)$$

Substituting these values into equation 2, the SRSS method gives:

$$R = \left\{\left(\overline{R}_i + \overline{R}_j + R_k\right)^2 + \left(\overline{R}_j + R_k\right)^2 + R_k^2\right\}^{1/2}$$

$$= \left\{3R_k^2 + 2\overline{R}_j^2 + \overline{R}_i^2 + 2\overline{R}_i\left(\overline{R}_j + R_k\right) + 4\overline{R}_j\ R_k\right\}^{1/2} \quad (6)$$

while substituting these values into equation 3, the component factor method gives:

$$R' = \left(\bar{R}_i + \bar{R}_j + R_k\right) + 0.414\left(\bar{R}_j + R_k\right) + 0.318R_k$$

$$= 1.732R_k + 1.414\bar{R}_j + \bar{R}_i = \left\{\left[1.732R_k + 1.414\bar{R}_j + R_i\right]^2\right\}^{1/2}$$

Therefore,

$$R' = \left\{3R_k^2 + 2\bar{R}_j^2 + \bar{R}_i^2 + 2\bar{R}_i\left(1.414\bar{R}_j + 1.732R_k\right) + 4.9\bar{R}_jR_k\right\}^{1/2} \qquad (7)$$

Comparing equations 6 and 7, it is obvious that the combined response calculated according to equation 3 is always more conservative than the combined response by the SRSS method given by equation 2. In the special case that $R_i + R_j + R_k$, they become identical to each other, i.e., $R + R' + \sqrt{3R_k}$. For convenience of engineering applications, equation 3 can be simplified by replacing the factors 0.414 and 0.318 by a common factor of 0.4. This reduces equation 3 to equation 1. By inspection, the maximum probable error of equation 1 with respect to the SRSS method is less than 1%. This maximum error occurs when $R_k = 0$ and $R_i = R_j$. In this special case, the SRSS method gives $R = 1.4R_i$ and equation 1 gives $R = 1.4R_i$.

APPENDIX 3B

COMPUTER PROGRAMS USED IN

STRUCTURAL ANALYSIS

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APPENDIX 3B
COMPUTER PROGRAMS USED IN STRUCTURAL ANALYSES

3B.1 GENERAL

A number of computer programs, most of which use the finite-element numerical approach, are used in the structural analyses of the containment and other Seismic Category I structures. Each of these is described fully in sections 3B.2 through 3B.11.

There are many advantages to the finite-element method when compared to other numerical approaches. This method is completely general with respect to geometry and material properties. In addition, complex bodies composed of many different materials are easily represented. Therefore, in the analysis of the containment, concrete and foundation materials can be realistically analyzed. Also, arbitrary thermal, mechanical, and gravity loading can be analyzed.

The finite-element method assumes a compatible or semicompatible displacement field for a typical cross-sectional area (element equals cross-section of ring). The number of degrees of freedom determines the number of unknown generalized displacements of each element-nodal point, and consequently the number of generalized forces through the stiffness equation. Accuracy of results depends upon:

- Shape of element
- Assumed displacement field (linear, quadratic, or higher order)
- Number of nodal points per element
- Size of the elements

- Total number of elements and nodal points (with rounded-off computer errors in the solution of simultaneous linear equations)

Following is a listing of the computer programs which were used in the design of Palo Verde Nuclear Generating Station (PVNGS) and the section references where program descriptions may be found:

Computer Program	Section Reference
Axisymmetric Shell and Solid Computer Program (ASHSD) CE 803	3B.2
Structural Analysis Program (SAP) CE 800	3B.3
Description of Verification Problems (OPTCON MODULE) CE 201	3B.4
Dynamic Analysis Computer Program (ICES-DYNAL)	3B.5
Symbolic Matrix Interpretive System (SUPER SMIS) CE 804	3B.6
Spectra Computer Program (SPECTRA) CE 802	3B.7
LUCON Computer Program (LUCON) CE 970	3B.8
CECAP Computer Program (CECAP) CE 987	3B.9
FOSIN Computer Program (FOSIN) CE 299	3B.10
STICK Computer Program (STICK)	3B.11
Bechtel CE 800, Bechtel Structural Analysis Program (BSAP)	3B.12
Finite-Element Computer Program (FINEL)	3B.13

3B.1.1 OTHER COMPUTER PROGRAMS USED IN STRUCTURAL ANALYSES

In the course of generating structural design calculations, several programs were used to assist design efforts. These programs were limited in scope and were developed solely to assist the designer in making lengthy, repetitious calculations, thereby saving design efforts. The programs were validated by generating example problems or performing manual design checks. These validations were incorporated into the project design calculation books. These programs are not itemized here due to their simplicity and nature of use.

3B.1.2 BIBLIOGRAPHY

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3B.2 AXISYMMETRIC SHELL AND SOLID COMPUTER PROGRAM (ASHSD) CE 803

The ASHSD program is capable of both static and dynamic elastic analysis of structural systems idealized by either axisymmetric shell or axisymmetric solid finite-elements or by a combination thereof.

The ASHSD code is also capable of handling both axisymmetric and asymmetric loadings.

This program is a refinement of the original ASHSD code by S. Ghosh, developed at the University of California at Berkeley under the direction of Dr. E. L. Wilson and published for the National Science Foundation Research Project GK4395. The present program is modified by Bechtel Power Corporation for the special purpose of static and dynamic analysis of nuclear containment structures. The modified program has the following features:

A. The original shell element used by the code is entirely replaced with a new shell finite-element that uses an interaction stiffness allowing analysis of layered shells. A complete discussion of the theory is given in Theory of Anisotropic Shells by S. A. Ambartsumyan.[1]

B. Since shell layers may be bonded or unbonded from each other, it is possible to describe concrete shells in their actual geometric form. For example, it is possible to describe liner plate, concrete, reinforcing steel, and post-tensioning steel in their real spatial locations.

C. Post-tension forces may be applied to the shell by subjecting only the unbonded post-tensioning elements to a pseudo-thermal loading.

D. Isotropic and orthotropic elastic constants are possible for both shell and solid elements. For example, the orthotropic material properties may be used to describe the different stiffnesses of reinforcing steel in the hoop and meridional directions.

E. Nonuniform axisymmetric or asymmetric thermal gradients through the wall thickness may be imposed.

F. Eigenvectors and eigenvalues may be computed by the program.

G. Three dynamic response routines are available in the program. They are:

   1. Arbitrary dynamic loading or earthquake, base excitation using an uncoupled (modal) technique

   2. Arbitrary dynamic loading or earthquake, base excitation using a coupled (direct integration) technique

   3. Response spectrum nodal analysis for absolute and square-root-of-the-sum-of-the-squares displacements and element stresses

The ASHSD computer model consists of containment, internal structure of axisymmetric shell, and a soil grid of

axisymmetric solid under basemat. The reactor cavity is modeled as an axisymmetric cylinder. The tendon cavity also may be included in the model. Interior structures have been idealized as an asymmetric shell and plate that are composed of primary shield, secondary shield, refueling canal, and operating floor. The liner plate also may be modeled as a finite-element in the inside face of concrete. The soil grid is extended sufficiently below the basemat and beyond the containment wall to enable ASHSD model to take into account the effects of soil interaction in seismic analysis and eliminate the effect of boundary conditions in all loading cases.

3B.2.1 ANALYSIS OF THE CONTAINMENT STRUCTURE FOR NONAXISYMMETRIC LOADS

3B.2.1.1 Nonaxisymmetric Loads

The nonaxisymmetric loadings include the earthquake forces, forces due to rupture of any pipe, forces due to thermal expansion of pipes in operating or accident conditions, wind loadings, and such other loadings that are not assumed to be symmetric with respect to the vertical axis of the containment structure.

3B.2.1.2 Analysis

The structure is idealized as an assemblage of elastic finite-element axisymmetric solids or thin shells. The solid of revolution is simulated as an assemblage of triangular or quadrilateral constant strain toroids interconnected at nodal

points, and the axisymmetric shell is modeled as a series of frustums of cones or cylinders. The structure can be idealized even as a combination of both types of elements. The only restriction is that the resultant model has to be axisymmetric.

The ASHSD computer program uses an extended Ritz technique of seeking a stationary value of an energy integral. Hamilton's variational principle is used to derive the equations of motion such as Lagrange's equations involving the total kinetic and potential energies of the system. If the program is used for only the static analysis, the kinetic energy being absent, the problem is governed by the principle of minimum potential energy.

Any arbitrary loading is approximated by the cosine terms of a Fourier series with a finite number of terms. For each Fourier component, the stiffness and mass matrices and the corresponding load vectors are formed. These are consistent with the assumed sinusoidal displacement field. After solving for the response of all the Fourier terms, their contributions are summed up to obtain the total response.

3B.2.1.3 Program Results

Typical program outputs from the ASHSD code are:

- Complete printout of all input data
- Complete displacements of each nodal point
- Shell element stresses and member forces
- Solid element stresses and strains

3B.2.2 EXTENT OF APPLICATION OF ASHSD PROGRAM

The ASHSD program is used in performing the preliminary static analyses of the containment structure for various loads. The results of these analyses are employed in arriving at the design section parameters for the cracked section analyses performed using the FINEL program.

3B.2.3 APPLICABILITY AND VALIDITY OF ASHSD PROGRAM

Six test problems, outlined in subsection 3B.2.4, demonstrate applicability and validity of the ASHSD program. Results of the problems for various loadings demonstrate that ASHSD results are essentially identical to the results obtained by hand calculations or those obtained by the closed-form analytical results available in technical literature.

3B.2.4 ASHSD VERIFICATION (TEST PROBLEMS)

3B.2.4.1 ASHSD Example 1, Closed Cylinder Under Internal Pressure

This test example demonstrates the membrane state of stress of a closed cylinder subjected to a uniformly distributed internal pressure. Because of symmetry, a finite-element idealization of one-half of the cylinder and the appropriate boundary conditions is used. The numerical data required for the ASHSD program input also are described. Refer to figure 3B.2-1.

For the purpose of illustrating the layered shell feature of the ASHSD program, a second test case is undertaken. The thickness of the closed cylinder used in the above example is divided into three layers as shown in figure 3B.2-2.

The longitudinal and circumferential forces for all node points of the two ASHSD program runs are listed in table 3B.2-1. The theoretical values for the membrane stress resultants are calculated to be PR/2 (=27,000 pounds per inch) and PR (=54,000 pounds per inch), respectively. As noted in table 3B.2-1, the results from both analyses compare with the theoretical values.

3B.2.4.2 ASHSD Example 2, Cylindrical Shell Under Internal Pressure

This test example illustrates the use of arbitrary static loading conditions. A sketch of the cylinder and the applied pressure is shown in figure 3B.2-3. Since there is a plane of symmetry, only one-half of the cylinder need be considered. The finite-element model, boundary conditions, and the relevant input data are described in figure 3B.2-4.

Figure 3B.2-5 shows a comparison of ASHSD radial displacements and analytically obtained displacements found in Theory of Plates and Shells.[2]

A comparison of ASHSD longitudinal moments and those obtained from Theory of Plates and Shells[2] is shown in figure 3B.2-6.

Both the radial displacements and the longitudinal moments check with analytical solutions obtained from Theory of Plates and Shells.[2]

3B.2.4.3 ASHSD Example 3, Spherical Dome, Dead Load Analysis

This test example demonstrates the dead load analysis feature of the ASHSD program. It considers a spherical dome of constant thickness under its own weight, as shown in figure 3B.2-7. The axisymmetric finite-element model and pertinent shell data are described in figure 3B.2-8.

The exact analytical solutions obtained from Applied Elasticity(3) for longitudinal and circumferential forces are compared to the ASHSD finite-element results in figures 3B.2-9 and 3B.2-10, respectively.

With the exception of forces near the shell boundary, all forces away from the boundary have excellent agreement between the two solutions.

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Table 3B.2-1

TABULATION OF MEMBRANE STRESS RESULTANTS, ASHSD EXAMPLE 1

Node Point	Shell		Layered Shell	
	Longi-tudinal Force (lb/in)	Circum-ferential Force (lb/in)	Longi-tudinal Force (lb/in)	Circum-ferential Force (lb/in)
1	27,000.0	54,004.0	27.000.0	54,004.0
2	27,000.0	54,005.0	27,000.0	54,005.0
3	27,000.0	54,008.0	27,000.0	54,008.0
4	27,000.0	54,012.0	27,000.0	54,012.0
5	27,000.0	54,015.0	27,000.0	54,015.0
6	27,000.0	54,012.0	27,000.0	54,012.0
7	27,001.0	53,999.0	27,001.0	53,999.0
8	27,001.0	53,968.0	27,001.0	53,968.0
9	27,001.0	53,912.0	27,001.0	53,912.0
10	27,000.0	53,829.0	27,000.0	53,829.0
11	26,999.0	53,731.0	26,999.0	53,731.0
12[a]	26,997.0	53,654.0	26,997.0	53,654.0
13[a]	26,994.0	53,674.0	26,994.0	53,674.0
14[a]	26,989.0	53,912.0	26,989.0	53,912.0
15[a]	26,984.0	54,532.0	26,984.0	54,532.0
16[a]	27,111.0	55,724.0	27,111.0	55,724.0

a. Results for node points 12 through 16 are influenced by the boundary conditions at node point 16.

3B.2.4.4 ASHSD Example 4, Cylindrical Shell Subjected to an Internal Pressure and a Uniform Temperature Rise

This test example demonstrates the use of arbitrary static load and thermal load conditions. A short circular cylindrical shell, clamped at both ends, is subjected to an internal pressure and a uniform temperature rise, as shown in figure 3B.2-11. Because of symmetry, one-half of the cylinder is used in this finite-element model, which is shown in figure 3B.2-12. For the purpose of inputting the thermal coefficient of expansion of this isotropic shell, it is required to identify the shell material as orthotropic.

A comparison of ASHSD longitudinal moments and the theoretical solutions reported in Thin Elastic Shells,(4) is displayed in figure 3B.2-13.

The finite-element model has approximately the same complexities as the examples demonstrating membrane stresses and displacements. Inasmuch as the moment involves higher-order effects, better correlation between the finite-element result and the theoretical solution is accomplished using a larger number of elements.

3B.2.4.5 ASHSD Example 5, Asymmetric Bending of Cylindrical Shell

This test example illustrates the use of higher harmonics for asymmetric loading cases. The cylindrical shell analyzed is a short, wide cylinder, as shown in figure 3B.2-14. The finite-element idealization of the cylinder and other pertinent

data are illustrated in figure 3B.2-15. At each end of the cylinder, moments of the form M = Mo cos nθ were input for harmonics n = 0, 2, 5, 20.

Figures 3B.2-16 through 3B.2-19 show the theoretical results per Analysis of Unsymmetric Bending of Shells(5) and ASHSD results for element longitudinal bending moments and radial displacements for harmonic number n = 0, 2, 5, and 20, respectively.

As noted in figures 3B.2-16 through 3B.2-19, the results obtained from the ASHSD program are in good agreement with that reported in Analysis of Unsymmetric Bending of Shells.(5)

3B.2.4.6 ASHSD Example 6, Isotropic Disk, Axisymmetric Solids

This test example illustrates the use of the ASHSD solid elements to evaluate the stress distribution in axisymmetric structures. The structural problem consists of a 2-inch-thick isotropic disk with a 10-inch inner radius and a 20-inch outer radius supported at the outer top edge. The finite-element model and the applied load are shown in figure 3B.2-20. The disk is divided into 10 quadrilateral solid elements having 22 node points.

The radial and axial displacements for all node points, obtained from the ASHSD computer run and Finite-Element Stress Analysis of Axisymmetric Solids with Orthotropic, Temperature-Dependent Material Properties,(6) are tabulated in table 3B.2 2. The radial, axial, and tangential stresses for all elements obtained from these same sources are tabulated in table 3B.2-3.

Table 3B.2-2
TABULATION OF RADIAL AND AXIAL DISPLACEMENTS,
ASHSD EXAMPLE 6

Node Point	Radial Displacement		Axial Displacement	
	ASHSD	Analytical[a]	ASHSD	Analytical[a]
1	1.86526	1.865246	1.70644×10^{-3}	1.596941×10^{-3}
2	1.74648	1.746466	1.42706×10^{-4}	4.343421×10^{-5}
3	1.65210	1.652084	1.32770×10^{-4}	4.377285×10^{-5}
4	1.57633	1.576314	1.58635×10^{-4}	8.014718×10^{-5}
5	1.51518	1.515166	1.77255×10^{-4}	1.095182×10^{-4}
6	1.46573	1.465718	1.90285×10^{-4}	1.334706×10^{-4}
7	1.42579	1.425777	1.99601×10^{-4}	1.538637×10^{-4}
8	1.39368	1.393668	2.06398×10^{-4}	1.718854×10^{-4}
9	1.36810	1.368085	2.11214×10^{-4}	1.880642×10^{-4}
10	1.34802	1.348000	2.07829×10^{-4}	1.961813×10^{-4}
11	1.33263	1.332815	0.0	0.0
12	1.86526	1.865266	2.54113×10^{-2}	2.530175×10^{-2}
13	1.74648	1.746486	2.69750×10^{-2}	2.687561×10^{-2}
14	1.65210	1.652105	2.69850×10^{-2}	2.689533×10^{-2}
15	1.57633	1.576336	2.69591×10^{-2}	2.688047×10^{-2}
16	1.51518	1.515188	2.69405×10^{-2}	2.687260×10^{-2}
17	1.46573	1.465740	2.69275×10^{-2}	2.687051×10^{-2}
18	1.42579	1.425800	2.69181×10^{-2}	2.687228×10^{-2}
19	1.39368	1.393691	2.69113×10^{-2}	2.687674×10^{-2}
20	1.36810	1.368108	2.69065×10^{-2}	2.688331×10^{-2}
21	1.34802	1.348023	2.69099×10^{-2}	2.689816×10^{-2}
22	1.33263	1.332637	2.71177×10^{-2}	2.711740×10^{-2}

a. Finite-Element Stress Analysis of Axisymmetric Solids with Orthotropic, Temperature-Dependent Material Properties[6]

Table 3B.2-3

TABULATION OF RADIAL, AXIAL, AND TANGENTIAL STRESSES, ASHSD EXAMPLE 6

Element Number	Radial Stress		Axial Stress		Tangential Stress	
	ASHSD	Analytical[a]	ASHSD	Analytical[a]	ASHSD	Analytical[a]
1	-87.71	-88.0	0.74	1.0	154.6	154.0
2	-67.55	-68.0	-0.08	0.0	134.2	134.0
3	-52.04	-52.0	-0.08	0.0	118.7	118.0
4	-39.86	-40.0	-0.06	0.0	106.5	106.0
5	-30.10	-30.0	-0.04	0.0	96.8	97.0
6	-22.18	-22.0	-0.03	0.0	88.8	89.0
7	-15.65	-16.0	-0.03	0.0	82.3	82.0
8	-10.21	-10.0	-0.02	0.0	76.9	77.0
9	- 5.63	- 6.0	-0.02	0.0	72.3	72.0
10	- 1.74	- 2.0	-0.13	0.0	68.4	68.0

a. Finite-Element Stress Analysis of Axisymmetric Solids with Orthotropic, Temperature-Dependent Material Properties[6]

3B.2.5 REFERENCES

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3B.3 STRUCTURAL ANALYSIS PROGRAM (SAP) CE 800

The SAP program is capable of both static and dynamic analysis of large elastic, three-dimensional structural systems.

The SAP code is used primarily in the analysis of the equipment hatch penetration areas, personnel lock penetration areas, and containment basemat. It also is used in much of the analysis of the internal reactor building.

The program has the following elements available, which are used in the containment analysis:

- Three-dimensional truss (axial) elements
- Three-dimensional beam (bending) elements
- Curved beam elements
- Quadrilateral plate (membrane, plate, or shell) elements
- Triangular plate (membrane, plate, or shell) elements
- Three-dimensional, eight-point brick solid (cube) elements
- Plane strain elements
- Boundary elements
- Sixteen-node-thick shell elements
- Axisymmetric ring elements

Systems composed of a large number of joints and members may be analyzed with the SAP program. The capacity of the program depends mainly on the total number of joints in the system. There is practically no restriction on the number of elements,

number of load cases, or the bandwidth of the equations to be solved.

3B.3.1 ANALYSIS OF EQUIPMENT HATCH AND PERSONNEL LOCKS BY THE SAP PROGRAM

All structural analysis for axisymmetric and nonaxisymmetric loadings is first carried out with either the FINEL or ASHSD codes.

An idealized finite-element model then is prepared for the region of the containment shell near the opening being analyzed.

The element mesh chosen considers the expected stress gradients at and near the shell opening. Enough of the region around the opening is included in the model to adequately eliminate the effect of the opening at the models boundaries.

The stress gradients considered in the preparation of the model are those obtained from the analytical solutions obtained from reference to State of Stress in a Circular Cylindrical Shell with a Circular Hole(1) and Reinforcement of a Small Circular Hole in a Plane Sheet Under Tension.(2)

A typical SAP penetration model, which is used for analysis, may have the following features:

A. Single layer (quadrilateral or triangular shell elements are used in the low stress gradient) outer regions of the model.

B. Near the opening being examined, the shell elements branch into a minimum of three layers of solid elements.

C. In the highly stressed regions, up to five layers of solid elements or a single layer thick shell element are used.

D. The element mesh describes the shell curvature and the thickening near the opening.

E. A mesh of truss elements is used to simulate the uneven post-tensioning around the opening. The mesh is geometrically located at the actual post-tensioning locations. The post-tensioning forces are induced in the truss elements by inducing pseudo-thermal loadings.

F. The model has loads applied to its surfaces and boundaries. The boundary conditions consider both specified displacement and force loads, which are obtained from the axisymmetric and nonaxisymmetric analyses.

3B.3.2 EXTENT OF APPLICATION OF SAP PROGRAM

The SAP program is used in performing the analysis of equipment hatch penetration areas, personnel lock penetration areas, and containment basemat. Details of the SAP methodology for these analyses are covered in Section 6.4 of BC-TOP-5-A. As an

alternative to ICES-STRUDL-II, the SAP program is used to analyze the containment internal structures.

3B.3.3 APPLICABILITY AND VALIDITY OF SAP PROGRAM

Applicability and validity of the SAP program are demonstrated in the four test problems outlined in subsection 3B.3.4. In each of the test problems, solutions are obtained by using the SAP program and some other analytical or computer program technique; then the results are compared. As will be noted, in all cases the solutions compare favorably and are essentially identical. The various analytical or computer program techniques used in the comparisons are extensively referenced within the test problems; they are collectively listed in the references for this appendix.

3B.3.4 SAP VERIFICATION (TEST PROBLEMS)

3B.3.4.1 SAP Example 1, Shell Element

This problem demonstrates the ability of the SAP program to give solutions to plate bending problems that are essentially identical to the results obtained from classical analytical techniques or independent computer programs. Details of the independent analysis are contained in Finite-Element Bending Analysis for Plates.(3)

The problem is solved once using the SAP triangular shell elements, and again using the SAP quadrilateral shell elements. The plate, which has a combination of fixed, free, and simple supported edges, is subjected to a uniform normal load of

1.0 pounds per square inch. Details of the problems are as follows:

A. Property Data

E = 30.0 x 10-6 pounds per square inch

υ = 0.3

B. Geometry

The geometry of the plate is shown in figure 3B.3-1. The plate is 0.01 inch thick.

C. Boundary Conditions

As shown in figure 3B.3-1, two edges of the plate are simply supported at X = 0.0 and x = 1.6. The edge at Y = 0 is fixed, while the edge at y = 0.8 is free. Because of the symmetry of the loading, structure, and support conditions, only half of the plate is modeled with appropriate boundary conditions imposed along the plane of symmetry.

D. Results

The results obtained from the SAP analysis are compared with the classical finite-element solution in figures 3B.3-2 through 3B.3-4. The results obtained using the triangular-element mesh are essentially identical to those obtained using the quadrilateral-element mesh. The sign convention for the above figures are shown in figure 3B.3-5.

3B.3.4.2 SAP Example 2, Static Analysis of Shell Structures

This problem demonstrates the agreement of results obtained using SAP shell elements and those obtained using classical analytical techniques and computer programs found in Pressure Vessel and Piping 1972 Computer Programs Verification (ASKA),[4] Theory of Plates and Shells,[5] Analysis of Thin Shells by a Finite-Element Procedure,[6] and a Mixed Finite-Element Method for Thin Shell Analysis.[7]

A spherical shell with clamped edges is subjected to a uniform external pressure. Due to the symmetry of the structure and the applied loading, only a segment of the shell is modeled, with appropriate boundary conditions applied at the meridional planes of symmetry. Details of the problems are as follows:

A. Property Data

E = 1.0 x 106 pounds per square inch

υ = 0.17

B. Geometry

The clamped spherical shell geometry is shown in figure 3B.3-6.

C. Loading Data

Uniform external load is 1.0 pounds per square inch, acting downward.

D. Results

The displacements, forces, and bending moments obtained from the SAP program, classical analytical techniques, and other referenced computer programs are plotted together for comparison in figures 3B.3-7 through 3B.3 10. The results are in good agreement.

3B.3.4.3 SAP Example 3, Static Analysis of Shell Structures

To demonstrate the validity of the static analysis capability of the SAP program for shell structures, a hyperboloid cooling tower is modeled as an assemblage of thin shell elements and analyzed to determine the effects of wind loading. The results thus obtained are compared to the solutions obtained using ASKA program from Pressure Vessel and Piping 1972 Computer Program Verification,(4) and The Analysis of Cooling Towers by the Matrix Finite-Element Method.[8]

The cooling tower is modeled using 240 thin shell elements and 143 nodal points. Since there is a vertical plane of symmetry for both the structure and the applied load, only half of the tower is modeled by imposing appropriate boundary conditions at the plane of symmetry. The base of the tower is clamped. Details of the problem are as follows:

A. Property Data

$E = 4.32 \times 108$ pounds per square feet

$\upsilon = 0.15$

B. Geometry

The geometry of the cooling tower is shown in figure 3B.3-11.

C. Loading Data

The cooling tower is subjected to the wind pressure distribution in figure 3B.3-12.

E. Results

The displacements at the top of the cooling tower obtained from the SAP program, classical analytical techniques, and other referenced computer programs are plotted together in figure 3B.3-13. The results are in good agreement.

3B.3.4.4 SAP Example 4, Three-Dimensional Solid Element

This problem demonstrates the applicability and validity of the SAP solid element for modeling and analyzing three-dimensional structures. The problem involves determining the magnitude of stress concentrations in the vicinity of a circular penetration through a pressurized cylinder. The results of the problem are compared to the theoretical solution provided in State of Stress in a Circular Cylindrical Shell with a Circular Hole.(1)

The three-dimensional, finite-element model used for this example is provided in figure 3B.3-14. The sign convention for resultant forces and moments is provided in figure 3B.3-15. The model consists of 20 elements and 60 nodal points. Details of the problem are as follows:

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A. Property Data

E = 4.7 x 106 pounds per square inch

υ = 0.26

B. Geometry

1. Cylinder inside radius = 62 feet

2. Cylinder Thickness = 3.5 feet

3. Penetration radius = 5.17 feet

D. Loading Data

The closed-end cylinder is subjected to an internal pressure of 60 pounds per square inch. The shear force transferred from the penetration cover to the cylinder is included in the analysis.

E. Boundary Conditions

1. Symmetry

Because of the symmetry of the structure and the applied load, only one quadrant of the penetration is modeled by applying appropriate symmetry boundary conditions along two perpendicular planar boundaries.

2. Compatibility

The stress and displacement conditions at the circular boundary, which is sufficiently remote from the influence of the penetration, were required to be compatible with analytically

obtained values for a closed, thick-walled cylinder.

F. Results

The resultant forces and moments obtained from the SAP analysis are compared with the theoretical results in figures 3B.3-16 through 3B.3-19. The results are in good agreement.

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3B.4 DESCRIPTION OF VERIFICATION PROBLEMS (OPTCON MODULE) CE 201

This section presents a description of verification for all test problems. Each problem is described with a sketch showing the OPTCON model, loading, and comparison of pertinent results.

3B.4.1 OPTCON MODULE VERIFICATION (TEST PROBLEMS)

3B.4.1.1 OPTCON Module Example 1 - CE201VER0P1

A section was designed for primary loads using the ASME service load criteria (figure 3B.4-1). The results compared closely with hand calculations.

3B.4.1.2 OPTCON Module Example 2 - CE201VER0P2

A section was designed for primary loads using the ASME factored load criteria (figure 3B.4-2). The results compared closely with hand calculations.

3B.4.1.3 OPTCON Module Example 3 - CE201VER0P3

A section was designed for primary loads using ACI 318-71 ultimate strength criteria (figure 3B.4-3). The results compared closely with hand calculations.

3B.4.1.4 OPTCON Module Example 4 - CE201VER0P4

A section was designed for primary plus secondary thermal loads using the ASME service load criteria (figure 3B.4-4). The results compared closely with hand calculations.

3B.4.1.5 OPTCON Module Example 5 - CE201VER0P5

A section was designed for primary plus secondary thermal loads using the ASME factored load criteria (figure 3B.4-5). The results compared closely with hand calculations.

3B.4.1.6 OPTCON Module Example 6 - CE201VER0P6

A section with primary plus secondary thermal loads was analyzed using the ASME service load criteria (figure 3B.4-6). The results compared closely with hand calculations.

3B.4.1.7 OPTCON Module Example 7 - CE201VER0P7

A fully cracked section with reinforcing yielding under primary plus secondary thermal loads was analyzed using the ASME factored load criteria (figure 3B.4-7). The results compared closely with hand calculations.

3B.4.1.8 OPTCON Module Example 8 - CE201VER0P8

A partially cracked section with reinforcing yielding under primary plus secondary thermal loads was analyzed using the ASME factored load criteria (figure 3B.4-8). The results compared closely with hand calculations.

3B.4.1.9 OPTCON Module Example 9 - CE201VER0P9

A section was analyzed to test the input flags, ITEMP and JTEMP, which define the type of secondary thermal loading (figure 3B.4-9). The results agreed with hand calculations,

and the secondary thermal moment input flags were shown to be functional.

3B.4.1.10 OPTCON Module Example 10 - CE201VER0P10

A section was analyzed to test the input flags on the OPTIONS card; NOPTN(1), NOPTN(2) and NOPTN(3). The ASME service load criteria was used for primary plus secondary thermal loading (figure 3B.4-10). The primary loading included tangential shear (membrane shear). The results agreed with hand calculations, and the OPTIONS input flags were shown to be functional.

3B.4.1.11 OPTCON Module Example 11 - CE201VER0P11

CE201VER0P6 (load case c) was reanalyzed using metric units, scale factors, and maximum percentages of reinforcing (figure 3B.4-11). The results compared closely with hand calculations. The conversion of units, scale factors, and maximum percentages was shown to be functional.

3B.4.1.12 OPTCON Module Example 12 - CE201VER0P12

A section with a liner plate was analyzed for primary loading using the ASME factored load criteria. The section was analyzed with and without liner plate temperature and finally without liner plate using the OFF LINER card (figure 3B.4-12). The results compared closely with hand calculations and the OFF LINER card was shown to be functional.

3B.4.1.13 OPTCON Module Example 13 - CE201VER0P13

CE201VER0P12 (load cases 1 and 2) was reanalyzed with an additional moment applied to the section to simulate the zero change in curvature conditions that would exist in the hoop direction of a containment shell (figure 3B.4-13). The results agreed closely with hand calculations.

3B.4.1.14 OPTCON Module Example 14 - CE201VER0P14

A section with a liner plate was analyzed with primary plus secondary thermal gradient loading using the ASME factored load criteria. Three liner plate conditions were investigated; liner on without temperature, liner on with temperature, and finally, liner off (figure 3B.4-14). The results agreed closely with the results determined from hand calculations.

3B.4.1.15 OPTCON Module Example 15 - CE201VER0P15

CE201VER0P14 (load cases 1 and 2) was reanalyzed with an additional moment applied to the section to simulate the zero change in curvature condition that would exist in the hoop direction of a containment shell (figure 3B.4-15). The results agreed closely with hand calculations.

3B.4.1.16 OPTCON Module Example 16 - CE201VER0P16

CE201VER0P14 was redesigned with the inclusion of a hot liner plate (figure 3B.4-16). The section was shown to be adequate with the liner plate and liner plate temperature. The stress results compared closely with hand calculations.

3B.4.1.17 OPTCON Module Example 17 - CE201VER0P17

CE201VER0P5 was redesigned with the inclusion of a hot liner plate (figure 3B.4-17). The section was shown to be adequate with the hot liner plate. The stress results compared closely with hand calculations.

3B.4.1.18 OPTCON Module Example 18 - CE201VER0P18

CE201VER0P2 was rerun to test the input flags, REF1 and RPEF1, which set the maximum allowable percentages of reinforcing and allow termination of the optimization process (figure 3B.4-18). The results compared closely with hand calculations and the input flags were shown to be functional.

3B.4.1.19 OPTCON Module Example 19 - CE201VER0P19

CE201VER0P1 was rerun to test the SET OUTPUT flag equal to 0 and 2 (figure 3B.4-19). For the flag set to 0, only the optimum reinforcing and thermal moment iteration should be printed. For the flag set to 2, the results are the same as for 0 but with the iteration diagram printed and plotted. The results for 0 were the same as those in CE201VER0P1 (i.e., all information was printed). The results for 2 were also the same as those in CE201VER0P1 except that no iteration diagram was plotted.

3B.4.1.20 OPTCON Module Example 20 - CE201VER0P20

CE201VER0P1 and CE201VER0P2 were rerun for certain load combinations using the SUPPRESS option in OPTCON. Two designs

were made using both the ASME service and ASME factored load criteria. The first design suppressed the ASME factored, and the second suppressed the ASME service criteria (figure 3B.4 20). The results compared exactly with those of 0P1 and 0P2 and the suppress option flags, NOUSD and NOWSD, were shown to be functional.

3B.4.1.21 OPTCON Module Example 21 - CE201VER0P21

CE201VER0P6 (load cases 1 and 2) was rerun with thermal parameter modifications and using the OFF THERMAL card (figure 3B.4-21). The thermal parameters modified were NPARAM, which defines the maximum number of steps in the thermal moment calculations, and AKKK, which defines the step size for iteration for thermal moments. The results compared closely with hand calculations except for the stresses after thermal moment relaxation. The final thermal moment was extrapolated correctly from just five cycles, and the design section was shown to be adequate. The stresses, however, which are based on the CURV value at five cycles, are incorrect. This discrepancy was identified as item AIF08. The thermal parameters NPARAM and AKKK and the OFF THERMAL card were shown to be functional.

3B.4.1.22 OPTCON Module Example 22 - CE201VER0P22

A section was analyzed for secondary thermal gradient loading using the ASME service load criteria. The effect of tension reinforcing on the relaxed thermal moment was investigated

(figure 3B.4-22). The results compared closely to hand calculations. This test case illustrates how the final or cracked thermal moment can be greater than the uncracked thermal moment.

3B.4.1.23 OPTCON Module Example 23 - CE201VER0P23

A section was analyzed with load input from a BSAP[a] Tape 27 and cards. Primary and secondary thermal loading were applied to the section using the ASME service load criteria (figure 3B.4-23). The results compared closely with hand calculations.

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a. BSAP-POST (CE 201) is a general-purpose post-processor program for the BSAP (CE 800) finite-element analysis program. BSAP-POST can take the output from BSAP and display this data (graphically and/or on a line printer) or perform additional calculations. In addition, some of the capabilities of BSAP-POST can be used independently. For example, the concrete design module, OPTCON, can use design loads obtained from BSAP output (Tape 27) or from punched cards.

BSAP-POST consists of a number of modules that can be used independently or sequentially to display or modify the contents of a data base under the control of an executive supervisor program. The data base consists of the contents of a file (TAPE 27) created by a BSAP analysis problem. The executive supervisor ensures that each module in BSAP-POST is compatible with every other module and initiates the execution of each module when required by input data supplied by the user.

3B.5 DYNAMIC ANALYSIS COMPUTER PROGRAM (ICES-DYNAL)

The DYNAL,(1) another subsystem of ICES, is used for the dynamic analysis of Seismic Category I structures other than the containment. It analyzes the structural dynamics of the broad class of structures represented as assemblages of triangular elements, curved or straight prismatic beams and pipes, and springs. Present analysis capability consists of:

A. Computing system stiffness and mass matrices

B. Computing the structural modes (eigenvectors) and frequencies (eigenvalues)

C. Computing the structural response to:

   1. Excitation represented as a shock spectrum (used in many cases to represent earthquake and blast shocks)

   2. Harmonic (sinusoidal) forcing functions

   3. Time history (transient) forcing functions

The DYNAL uses a problem-oriented language very similar to that used in STRUDL. This is a very convenient language, and its use allows one who is familiar with STRUDL to use DYNAL with a minimum of effort.

The structural dynamic analyses available are based on the modal superposition method, which basically consists of reducing a set of second-order linear differential equations to their simplest form and solving the resulting equations. This approach is attractive because the reduced set of equations is uncoupled, and only a relatively small percentage of the total

number of equations is necessary to adequately represent the structural response.

Structural dynamic analyses by the modal superposition method invariably require three basic steps. These are:

A. Generation of mass and stiffness (or flexibility) matrices to represent the distributed mass and stiffness of the actual structure

B. Solution of the eigenvalue-eigenvector problem

C. Solution of a reduced set of uncoupled equations for response to a specified form of excitation

Some form of damping usually is included in the reduced set of equations, but sometimes is neglected depending on its magnitude and the form of excitation.

The generation of stiffness matrices follows procedures similar in many aspects to that used for STRUDL. A consistent mass matrix, as discussed by Archer(2), also may be generated. The terminology "consistent mass matrix" is used to indicate that mass matrix formulation uses deformation shapes that are consistent with the stiffness formulation. This approach provides a better representation of the kinetic energy than does the more conventional "lumping" technique, which consists of lumping the continuous mass distribution at discrete joints.

A technique called "kinematic condensation"(3) is available for reducing the size of structural mass and stiffness matrices before computing the normal modes and frequencies. The

condensation is such that the lower frequency modes of vibration are preserved.

The structural modes and frequencies are computed using any of three available methods, all of which are discussed by Wilkinson.[4] The recommended method uses Householder's transformation to tridiagonalize symmetric matrices, Ortega's bisection techniques for eigenvalues, and Weilandt inverse iteration for eigenvectors (also attributed to Wilkinson).

The other two available methods are Jacobi iteration and Francis' QR algorithm.

The response analysis computations provide joint displacements, velocities and accelerations, and member forces and moments.

The shock spectrum analysis is used in many cases for earthquake structural response. It requires, as input, a table expressing the maximum response of simple oscillators as a function of their natural frequency.

The harmonic analysis obtains the structural response to joint forces or base (support) excitations that can be expressed as cosine waves with arbitrary phasing.

The time-history (transient) analysis computes the response to joint loads or base excitations represented as tables of magnitude vs. time.

The DYNAL also may be used for shell vibration analysis. Provision has been made to read an output tape from the SABOR shell analysis program. A kinematic condensation and/or modal analysis may then be performed.

A sophisticated plotting capability is available for plotting planar and three-dimensional structural views and mode shapes.

3B.5.1 EXTENT OF APPLICATION OF ICES-DYNAL

The ICES-DYNAL program is one of the programs used in performing lumped mass dynamic analyses of Seismic Category I structures.

3B.5.2 APPLICABILITY AND VALIDITY OF ICES-DYNAL

The ICES-DYNAL program is in the public domain and has been in use since 1970. For this reason, no verification test problems are provided. However, following is a listing of the specific versions of ICES-DYNAL used:

A. McDonnell Douglas Release 3.2, dated February 5, 1973.

B. McDonnell Douglas Executive System Release 2.3, dated February 5, 1973.

The IBM 370-165 computer and applicable system programs are used in conjunction with the above programs to perform the lumped mass dynamic analyses covered herein.

3B.5.3 REFERENCES

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2. Archer, J. S., "Consistent Mass Matrix for Distributed Mass Systems," Proceedings of the ASCE, J. of Structural, Div 89, No. ST4, Part I, pp 161-178, August 1963.

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3B.6 SYMBOLIC MATRIX INTERPRETIVE SYSTEM (SUPER SMIS) CE 804

The SUPER SMIS is a general-purpose program that is used to solve practically any problem in which matrix analysis is applicable. A common application of the SUPER SMIS program is the solution of static and dynamic structural problems.

This program is a refinement of the original Symbolic Matrix Interpretive System (SMIS) program developed at the University of California at Berkeley in 1963. The present program handles about 60 operations, including:

A. General matrix manipulations such as matrix addition, multiplication, and inversion

B. General tape and card-handling manipulations (including the savings of results on magnetic tapes and card-punching capability)

C. General element stiffness routines for plate or three-dimensional beam and truss elements and for a constant-strain, triangular-plate finite-element

D. Element stiffness routine for the three-dimensional beam includes axial, torsional, bending, and shearing stiffness and computation of a consistent element mass matrix

E. Eigenvalue and eigenvector capability

F. Element stress routines for finding the forces for each of the element types

G. Acceptability of matrices generated by other programs as input to the SUPER SMIS program

H. Uncoupled (normal mode) time-history response analysis of dynamic systems

I. Coupled time-history response analysis of dynamic systems

J. Sorting of results from both uncoupled and coupled analyses into forms desired for further analyses

K. Steady-state response analysis of uncoupled systems

The coupled time-history response analyses uses a Newmark-Beta direct-integration technique, which allows the solution of coupled or uncoupled systems of equations.(1) This, for example, allows the analysis of systems using any arbitrary damping matrix. It also may be used in the analysis of systems having different excitations at different support points. The system may be treated as either having displacement boundary conditions or as a free-free system with base displacement time-history excitations. The main feature of this program is its versatility, allowing almost any type of modification to be made to a matrix. This proves to be a distinct requirement where damping matrices or dynamic matrices are being formed for arbitrary structures.

3B.6.1 EXTENT OF APPLICATION OF SUPER SMIS

The SUPER SMIS program is one of the programs used in performing lumped mass dynamic analyses of Seismic Category I structures.

3B.6.2 APPLICABILITY AND VALIDITY OF SUPER SMIS

Applicability and validity of the SUPER SMIS program are demonstrated in the three test problems outlined in subsection 3B.6.3. In each test problem, the solutions are obtained by using SUPER SMIS and ICES-DYNAL programs, and then comparing the results.

3B.6.3 SUPER SMIS VERIFICATION (TEST PROBLEMS)

3B.6.3.1 SUPER SMIS Example 1, Lumped Mass Response Spectrum Analysis

This problem demonstrates the agreement of results obtained using SUPER SMIS and ICES-DYNAL for the lumped mass response spectrum analysis.

The lumped mass model used in the demonstration is illustrated in figure 3B.6-1. Each nodal point has two degrees of freedom: horizontal and rotational.

A. Problem Parameters

   1. Elastic modulus (E = 617,000 ksf)

   2. Poisson's ratio (υ = 0.167)

   3. The spectra acceleration input is taken from typical design spectra for 2% damping.

B. Results

   The natural frequency and displacement results obtained from the SUPER SMIS and ICES-DYNAL programs are summarized in tables 3B.6-1 and 3B.6-2.

3B.6.3.2 SUPER SMIS Example 2, Lumped-Mass Time-History Analysis

This problem demonstrates the agreement of results obtained using SUPER SMIS and ICES-DYNAL for the lumped-mass time-history analysis:

A. Problem Parameters

1. Elastic modulus (E = 617,000 ksf)

2. Poisson's ratio (υ = 0.167)

Table 3B.6-1

NATURAL FREQUENCIES (Hz), SUPER SMIS EXAMPLE 1

Mode	SUPER SMIS	ICES-DYNAL
1	10.509	10.520
2	30.506	30.538
3	43.131	43.177

Table 3B.6-2

DISPLACEMENT (RMS), SUPER SMIS EXAMPLE 1

Nodal Point	Translation		Rotation	
	SUPER SMIS	ICES-DYNAL	SUPER SMIS	ICES-DYNAL
1	0.000389	0.000395	0.000022	0.000021
2	0.000732	0.000730	0.000025	0.000025
3	0.001179	0.001176	0.000028	0.000028
4	0.001690	0.001684	0.000030	0.000030
5	0.002221	0.002215	0.000032	0.000032
6	0.002714	0.002706	0.000033	0.000033
7	0.003269	0.003260	0.000034	0.000034
8	0.003748	0.003737	0.000035	0.000035

B Results

The solution using SUPER SMIS indicates a maximum absolute acceleration of 4.451 ft/s^2 at time 0.28 second; ICES-DYNAL indicates 4.444 ft/s^2 at time 0.28 second.

3. The spectra acceleration input is taken from typical design spectra for 2% damping.

3B.6.3.3 SUPER SMIS Example 3, Eigenvalue Analysis of Space Frames

This problem demonstrates the ability of SUPER SMIS in handling tridimensional elements using consistent mass. The natural frequencies are calculated using SUPER SMIS and ICES-DYNAL.

The eigenvalue analysis model used in the demonstration is illustrated in figure 3B.6-2. Each nodal point is assumed to have six degrees of freedom:

A. Problem Parameters

1. Elastic modulus (E = 617,000 ksf)
2. Poisson's ratio ($\nu = 0.167$)
3. Cross sectional area of elements ($A = 4.0\ ft^2$)
4. Shear area of elements ($A_y = A_z = 4.0\ ft^2$)
5. Moment of inertia ($I_y = I_z = 1.3\ ft^4$)
6. Mass density ($0.0045684\ ks^2/ft^4$)

B. Results

The natural frequency results obtained from SUPER SMIS and ICES-DYNAL programs are summarized in table 3B.6-3.

Table 3B.6-3

NATURAL FREQUENCIES (Hz), SUPER SMIS EXAMPLE 3

Nodal Point	SUPER SMIS	ICES-DYNAL
1	3.204	3.208
2	3.297	3.301
3	5.515	5.525
4	8.208	8.223
5	10.036	10.058
6	14.258	14.298

3B.6.4 REFERENCES

1. Chan, S. D., Cox, H. L., and Benfield, W. A., "Transient Analysis of Forced Vibrations of Complex Mechanical Systems," Journal of the Royal Aeronautical Society, London, England, 66, pp 457-960, 1962.

3B.7 SPECTRA COMPUTER PROGRAM (SPECTRA) CE 802

The SPECTRA program is a special-purpose program that is used to compute response spectra from a time-history accelerogram.

The SPECTRA program defined and used in the examples provided herein is a refinement of the original code developed at the California Institute of Technology.(1)(2) This modified program has the following additional features:

A. Cal-Comp plotting of accelerograms

B. The SC-4020 optical plots of computed response spectra. These plots are available for displacement, velocity, and acceleration spectra

The main feature of SPECTRA is its use of the closed-form recur-rence algorithm for a ramp function. This allows the exact solution of equations with the exception of machine roundoff.

3B.7.1 EXTENT OF APPLICATION OF SPECTRA

The SPECTRA program is used for Seismic Category I structures to generate floor response spectra, computed from time-history motions at various floor or other locations.

3B.7.2 APPLICABILITY AND VALIDITY OF SPECTRA

Applicability and validity of the SPECTRA program are demonstrated in the two test problems outlined in subsection 3B.7.3. In each test problem, the solutions are obtained by using SPECTRA and various analytical techniques,

and then comparing the results. In both examples the comparison of results are in good agreement.

3B.7.3 SPECTRA VERIFICATION

The two test problems described in the following paragraphs pro-vide comparisons of response spectra computed using the SPECTRA program and a classic analytical technique.

The SPECTRA program computes response spectra values from a time-history accelerogram digitized at equal time intervals using numerical analysis of closed-form recurrence equations.

In the first test problem, response spectra applicable to an undamped system are determined when subjected to a symmetrical triangular pulse load. In this example, the pulse duration is 5 seconds and various natural frequencies are used.

In the second test problem, response spectra applicable to an undamped system are determined when subjected to a sinusoidal force. As in the first example, various natural frequencies also are used in this example.

A typical undamped system is illustrated in figure 3B.7-1.

3B.7.3.1 Test Problem 1, Symmetrical Triangular Pulse

In this test problem the equation for the triangular pulse, taken from Engineering Vibrations(3) is:

$$DLF = \frac{x_m}{X_{st}} = \frac{2}{t_d}\left(t - \frac{\sin \omega t}{\omega}\right) \qquad ,0 \le t = 1/2\ t_d$$

$$DLF = \frac{2}{t_d}\left\{t_d - t + \frac{1}{\omega}\left[2 \sin \omega \left(t - \frac{t_d}{2}\right) - \sin \omega t\right]\right\},\ 1/2\ t_d \le t \le t_d$$

$$DLF = \frac{2}{\omega t_d}\left[2 \sin \omega \left(t - \frac{t_d}{2}\right) - \sin \omega t - \sin \omega \left(t - t_d\right)\right],\ t_d \le t$$

The analytical response spectra from the foregoing are plotted in figure 3B.7-2. This represents the maximum response, as a

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Table 3B.7-1

SPECTRA OUTPUT, SPECTRA EXAMPLE 1

$\frac{t_d}{T}$	Dynamic Load Factor (DLF)
0.2	$(2\pi/25)^2$ (9.624) = 0.61
0.4	$(2\pi/12.5)^2$ (4.352) = 1.10
0.6	$(2\pi/8.333)^2$ (2.448) = 1.39
0.8	$(2\pi/6.25)^2$ (1.489) = 1.50
1.0	$(2\pi/5)^2$ (0.955) = 1.51
1.2	$(2\pi/4.167)^2$ (0.636) = 1.45
1.4	$(2\pi/3.511)^2$ (0.435) = 1.35
1.6	$(2\pi/3.125)^2$ (0.304) = 1.23
1.8	$(2\pi/2.778)^2$ (0.217) = 1.11
2.0	$(2\pi/2.5)^2$ (0.158) = 0.998
2.2	$(2\pi/2.273)^2$ (0.125) = 0.955
2.4	$(2\pi/2.083)^2$ (0.112) = 1.02
2.6	$(2\pi/1.923)^2$ (0.102) = 1.09
2.8	$(2\pi/1.786)^2$ (0.092) = 1.14
3.0	$(2\pi/1.667)^2$ (0.082) = 1.165
3.2	$(2\pi/1.563)^2$ (0.072) = 1.16
3.4	$(2\pi/1.471)^2$ (0.063) = 1.15
3.6	$(2\pi/1.389)^2$ (0.054) = 1.10
3.8	$(2\pi/1.316)^2$ (0.046) = 1.05
4.0	$(2\pi/1.250)^2$ (0.040) = 1.01

function of td/T where T is the natural period. The SPECTRA response spectra, tabulated in table 3B.7-1, also are shown in figure 3B.7-2.

In this test problem, static deflection is computed using equation of motion for a free vibration state:

Where: $MX + KX = 0$

$$X + (K/M)X = 0 \qquad (\text{Let } \omega = K/M)$$

Then, the solution is:

$$X = A \sin \omega t + B \sin \omega t$$

For: $X_o = 0$ at time $t = 0$

$$X = A \sin \omega t$$

$$X = A\omega \cos \omega t$$

$$X = -A\omega^2 \sin \omega t$$

Thus, X and X are related by the relationship:

$$X = -\frac{1}{\omega^2} X$$

Therefore, for maximum static deflection

$$X = -\frac{1}{\omega^2}$$

Since maximum dynamic displacement and input acceleration are present, the input acceleration is converted to static deflection by the relationship:

$$X = \frac{-1}{\omega^2} X$$

Thus, the DLF is computed from:

$$DLF = \frac{X_{dyn}}{\frac{1}{\omega^2} X}$$

$$DLF = \omega^2 \left(\frac{X_{dyn}}{X} \right)$$

For maximum static response:

$$DLF = \omega^2 \ X_{dyn}$$

Plotting t_d/T versus $(DLF)_{max}$ as:

$$\omega = \frac{2\pi}{T}$$

$$\boxed{(DLF)_{max} = \left(\frac{2\pi}{T} \right)^2 \left(X_{dyn} \right)_{max}}$$

3B.7.3.2 Test Problem 2, Symmetrical Sinusoidal Pulse

In this test problem the equation for the sinusoidal pulse, taken from Introduction to Structural Dynamics,(4) is:

$$MX + Kx = F_1 \sin \Omega t$$

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The general solution is:

$$x = \frac{F_1}{M}\left(\frac{\sin \Omega t}{\omega^2 - \Omega^2} - \frac{\Omega}{\omega}\frac{\sin \omega t}{\omega^2 - \Omega^2}\right)$$

or:

$$DLF_{max} = \frac{1}{\left(1 - \Omega^2/\omega^2\right)}\left[\sin \Omega t - \frac{\Omega}{\omega} \sin \omega t\right]$$

The analytical response spectra derived from the foregoing are in two parts: transient (free part), and steady-state (forced part). The upper bound of free and forced parts combined, as well as forced parts only, are plotted in figure 3B.7-3. The SPECTRA response spectra, tabulated in table 3B.7-2, also are shown in figure 3B.7-3.

Table 3B.7-2

SPECTRA OUTPUT, SPECTRA EXAMPLE 2

Ω/ω	Dynamic Load Factor (DLF)
0.25	$(2\pi/0.25)^2$ (0.002) = 1.26
0.50	$(2\pi/0.50)^2$ (0.11) = 1.74
0.75	$(2\pi/0.75)^2$ (0.56) = 3.93
1.00	$(2\pi/1.0)^2$ (1.591) = 62.81
1.25	$(2\pi/1.25)^2$ (0.156) = 4.28
1.50	$(2\pi/1.50)^2$ (0.118) = 2.07
1.75	$(2\pi/1.75)^2$ (0.128) = 1.65
2.00	$(2\pi/2.0)^2$ (0.088) = 0.87
2.25	$(2\pi/2.25)^2$ (0.102) = 0.79
2.50	$(2\pi/2.50)^2$ (0.103) = 0.65
2.75	$(2\pi/2.75)^2$ (0.121) = 0.63
3.00	$(2\pi/3.0)^2$ (0.148) = 0.65

3B.7.4 REFERENCES

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3B.8 LUCON COMPUTER PROGRAM (LUCON) CE 970

This section describes the theoretical basis, verification and usage of a computer program developed to evaluate the impedance functions for a rigid circular foundation placed on a layered viscoelastic medium.

Given the characteristics of the site and the geometry of the foundation, the program computes the vertical, rocking, and horizontal impedance functions, and its reciprocals, the compliance functions, for any given set of frequencies. The foundation medium may be layered or may be a uniform elastic half-space. Two types of material damping in the soil may be considered; namely, constant hysteretic type damping and Voigt type damping. The type of damping must be the same for all layers, but the values of the damping constants may differ from layer to layer.

3B.8.1 THEORETICAL BASIS

A key step in the evaluation of the soil-structure interaction effects on the earthquake response of a structure is the computation of the force displacement relationship for the foundation. Several such relationships, expressed in terms of impedance or compliance functions, are available at the present time.(1) However, most of these studies are restricted to a model of soil corresponding to a nondissipative, purely elastic medium. In these studies, no material or internal damping is considered, and, consequently, the only source of energy dissipation corresponds to the geometric attenuation, also called radiation damping.

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The object of this study is to incorporate the effects of material damping in the analysis of the harmonic response of a rigid circular foundation placed on a layered medium. The need for incorporating the material damping in the solution of this problem arises from the important effects that internal damping has, particularly when large strains are involved or when the medium representing the soil is layered. In this study, two types of material damping are considered: viscous Voigt type damping and hysteretic type damping. Three types of harmonic excitations are investigated: vertical force, rocking moment, and horizontal force. In all cases, relaxed conditions on the contact between the circular foundation and the supporting medium are assumed.

In a previous study, Veletsos and Verbic[2] considered the harmonic response of a circular foundation placed on a visco-elastic half-space. The method of solution employed in rocking moment is approximate and does not lend itself to the analysis of layered media for which the impedance functions present strong fluctuations as a function of frequency. The studies reported in references 3, 4, and 5, although more general in regards to the incorporation of material damping, are based on an assumed stress distribution on the contact between the foundation and the soil.

The method of solution employed herein follows, except for consideration of the material damping, the procedure used by the author[6] to solve the problem for a nondissipative layered medium.

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3B.8.2 PROBLEM DESCRIPTION

3B.8.2.1 Statement of the Problem

In what follows, a study is made of the forced harmonic vibrations of a rigid circular footing of radius a placed on the surface of a layered viscoelastic medium. The layered medium consists of N-1 parallel layers resting on a viscoelastic half-space. Both the layers and the elastic half-space are assumed to be homogeneous and isotropic with densities ρ_i, shear moduli G_i, and Poisson's ratios σ_i (i = 1, 2,....N), respectively. In addition, depending on the type of internal friction considered, the relative viscosity coefficient $(G_i^{'} / G_i)$ (for Voigt type dissipation), or, the hysteretic damping coefficient $x_i = wG'_i/2G_i$ (for hysteretic type dissipation) are assumed to be known for each one of the media forming the soil deposit. The geometry of the model and the coordinate systems used are shown in figure 3B.8-1.

A welded type of contact is assumed to exist between adjacent layers. Thus, the stresses and displacements are continuous across each interface. The contact between the foundation and the surface of the top layer is assumed to be relaxed, i.e., the contact is frictionless for vertical and rocking vibrations and pressureless for horizontal vibrations.

The boundary conditions on z = 0 expressed in terms of displacement and stress components in cylindrical coordinates are the following:

A. Vertical Vibrations

$$u_z(r, \theta, 0) = D_V e^{i\omega t} \qquad 0 \leq r \leq a \tag{1.a}$$

$$\sigma_{zz}(r, \theta, 0) = 0 \qquad r > a \tag{1.b}$$

$$\sigma_{zr}(r, \theta, 0) = \sigma_{z\theta}(r, \theta, 0) = 0 \qquad 0 < r < \infty \tag{2}$$

B. Rocking Vibrations

$$u_z(r, \theta, 0) = \alpha r \cos \theta \, e^{i\omega t} \qquad 0 \leq r \leq a \tag{3.a}$$

$$\sigma_{zz}(r, \theta, 0) = 0 \qquad r > a \tag{3.b}$$

$$\sigma_{zr}(r, \theta, 0) = \sigma_{z\theta}(r, \theta, 0) = 0 \qquad 0 < r < \text{¥} \tag{4}$$

C. Horizontal Vibrations

$$\left.\begin{aligned} u_r(r, \theta, 0) &= \Delta_H \cos \theta e^{i\omega t} \\ u_\theta(r, \theta, 0) &= -\Delta_H \sin \theta e^{i\omega t} \end{aligned}\right\} \qquad 0 \leq r \leq a \tag{5}$$

$$\sigma_{zr}(r, \theta, 0) = \sigma_{z\theta}(r, \theta, 0) = 0 \qquad r > a \tag{6}$$

$$\sigma_{zz}(r, \theta, 0) = 0 \qquad 0 < r < \infty \tag{7}$$

In the equations above, Δ_V is the amplitude of the vertical displacement of the center of the rigid foundation, α is the amplitude of the rocking angle about the y-axis ($\theta = \pi/2$), Δ_H is the amplitude of the horizontal displacement of the foundation in the direction of the x-axis ($\theta = 0$), and ω is the frequency of the steady-state vibrations.

The continuity conditions at the interface z = Hi are:

$$u_r^{i}(r, \theta, H_i) = u_r^{i+1}(r, \theta, H_i) \quad (8.a)$$

$$u_\theta^{i}(r, \theta, H_i) = u_\theta^{i+1}(r, \theta, H_i) \quad (8.b)$$

$$u_z^{i}(r, \theta, H_i) = u_z^{i+1}(r, \theta, H_i), \ (i = 2, \ldots N) \quad (8.c)$$

$$\sigma_{zr}^{i}(r, \theta, H_i) = \sigma_{zr}^{i}(r, \theta, H_i) \quad (9.a)$$

$$\sigma z_\theta^{i}(r, \theta, H_i) = \sigma_{z\theta}^{i}(r, \theta, H_i) \quad (9.b)$$

$$\sigma_{zz}^{i}(r, \theta, H_i) = \sigma_{zz}^{i}(r, \theta, H_i), \ (i = 1, 2, \ldots N) \quad (9.c)$$

where, the superscript i indicates the i^{th} layer. In addition, the displacement and stress components in the underlying half-space must tend to zero as $(r^2 + z^2)$ tends to infinity.

3B.8.2.2 Types of Energy Dissipation

In this study, two types of energy dissipation are considered; namely, the Voigt viscous model and the hysteretic model.

The stress-strain relationships for harmonic vibrations of a solid with Voigt type damping are of the form[7]

$$\sigma_{zz} = (\lambda + i\omega\lambda')\,H + 2(\mu + i\omega\mu')\,\varepsilon_{zz} \quad (10.a)$$

$$\sigma_{zx} = 2(\mu + i\omega\mu')\,\varepsilon_{xz} \quad (10.b)$$

where:

$$H = \varepsilon_{xx} + \varepsilon_{yy} + \varepsilon_{zz} \quad (10.c)$$

In equations 10.a and 10.b, ω is the frequency of the excitation; λ and μ are Lame's constants, and, λ', μ' are the viscosities. It is clear from equations 10.a and 10.b that the viscoelastic problem may be solved if the solution for the corresponding purely elastic problem is known by substituting in the elastic solution λ and μ by the complex moduli:

$$\lambda * = \lambda(1 + i\omega\lambda' / \lambda) \tag{11.a}$$

$$\lambda * = \mu(1 + i\omega\mu' / \mu) \tag{11.b}$$

In order to simplify the problem it is assumed that:

$$\frac{\lambda'}{\lambda} = \frac{\mu'}{\mu} \tag{12}$$

In this case the remaining complex constants are given by:

$$E* = \frac{(3\lambda * + 2\mu *) \mu *}{\lambda * + \mu *} = E(1 + i\omega\mu' / \mu) \tag{13.a}$$

$$k* = \lambda * + \frac{2}{3} \mu * = k(1 + i\omega\mu' / \mu) \tag{13.b}$$

$$\sigma * = \frac{\lambda *}{2(\lambda * + \mu *)} = \sigma \tag{13.c}$$

where E, k, and σ are the Young's modulus, the bulk modulus, and Poisson's ratio, respectively. The assumption given by equation 12 has the advantage that the Poisson's ratio for the viscoelastic medium is real and equal to the Poisson's ratio of the corresponding elastic medium. One disadvantage, however, is the fact that the bulk modulus is complex and

consequently there are losses associated with changes of volume.

Equation 10.b indicates that for shear deformations the stress-strain relationship could be described by an ellipse. The energy loss per cycle is given by the area of the ellipse and the corresponding 'specific loss' is:

$$\frac{\Delta W}{W} = 2\pi \frac{\omega\mu'}{\mu} \qquad (14)$$

Where W is the elastic energy stored when the strain is a maximum, equation 14 indicates that for a Voigt solid the 'specific loss', or the energy loss per cycle, is proportional to the frequency of the excitation. The elliptical stress-strain loop in this case is a direct result of the viscosity of the medium.

Laboratory tests on soils indicate that the 'specific loss' $\Delta W/W$ is independent of the frequency of the excitation and that the stress-strain loop is not an ellipse[8-12]. It appears then that the mechanism of energy loss in soils is not of the viscous type but rather is a direct result of the inelastic behavior of soils. In spite of this inelastic behavior, an approximate approach is to assume that the soil may be treated in a similar way as a viscoelastic medium, except that in this case the complex shear modulus μ^* and the 'specific loss' are taken to be equal to:

$$\mu^* = \mu(1 + 2i\xi) \tag{15}$$

$$\frac{\Delta W}{W} = 4\pi\xi \tag{16}$$

Where ξ is a damping constant independent of frequency. This model of internal damping is also called constant hysteretic type damping. The damping constant ξ is analogous to the percentage of critical damping under resonant conditions, or during free vibrations[9]. The hysteretic damping constant ξ is strain dependent: values for low strain may be less than 0.02, while for high strains ξ may reach values of 0.15 or 0.20.

In what follows, the shear modulus μ is designated by G, and the shear viscosity μ' is designated by G'.

3B.8.2.3 Integral Representation

A solution of the equations of motion in cylindrical coordinates satisfying the conditions at the interface between layers, as well as the conditions at infinity, may be obtained by application of the correspondence principle to a representation derived by Sezawa and reported in references 13 and 14.

The displacement and stress components of interest on z = 0 are given by:

$$u_r(r, \theta, 0) = a\, u_r^*(r') \cos(n\theta)$$

$$u_\theta(r, \theta, 0) = a\, u^*_\theta(r') \sin(n\theta) \qquad (17)$$

$$u_z(r, \theta, 0) = a\, u^*_z(r') \cos(n\theta)$$

$$\sigma_{zr}(r, \theta, 0) = G_1 \sigma^*_{zr}(r') \cos(n\theta)$$

$$\sigma_{z\theta}(r, \theta, 0) = G_1 \sigma'_{z\theta}(r') \sin(n\theta) \qquad (18)$$

$$\sigma_{zz}(r, \theta, 0) = G_1 \sigma^*_{zz}(r') \cos(n\theta)$$

where n = 0 for vertical vibrations, n = 1 for rocking and horizontal vibrations, r' = r/a, and

$$u^*_r(r') \pm u^*_\theta(r') = \mp 2 \int_o^\infty \{k[\Delta_{11}(k)C_1(k) + \Delta_{12}(k)C_2(k)]/\Delta_R \mp \Delta_{33}C_3(k)/\Delta_L\} J_{n\pm1}(a_o kr')dk \qquad (19)$$

$$u^*_z(r') = 2\int_o^\infty k\{[\Delta_{21}(k)C_1(k) + \Delta_{22}(k)C_2(k)]/\Delta_R\} J_n(a_o kr')dk \qquad (20)$$

$$\sigma^*_{zr}(r') \pm \sigma^*_{z\theta}(r') = \pm 2a_o \int_o^\infty [kC_1(k) \mp C_3(k)]J_{n+1}(a_o kr')dk \qquad (21)$$

$$\sigma^*_{zz}(r') = 2a_o \int_o^\infty kC_2(k)J_n(a_o kr')dk \qquad (22)$$

In equations 19 through 22, $a_o = \omega a/\beta_1$ is a dimensionless frequency defined in terms of the shear wave velocity β_1 of the top layer. The functions Δ_{ij} (i, j = 1,2), Δ_R, Δ_{33}, and Δ_L

appearing in equations 19 through 22 depend on the properties of the soil column, and are given in subsection 3B.8.5. The functions $C_1(k)$, $C_2(k)$, and $C_3(k)$ are to be determined by the boundary conditions on z = 0. For vertical and rocking vibrations, equations 2 and 4, together with equation 21, imply that:

$$C_1(k) = C_3(k) = 0. \tag{23}$$

Similarly, for horizontal vibrations, equations 7 and 22 imply that:

$$C_2(k) = 0. \tag{24}$$

Before imposing the remaining boundary conditions, it is convenient to introduce the following substitutions:(6)(13)

A. Vertical Vibrations

$$C_2(k) = -\left[\frac{\Delta_v k_1^2}{\pi a(1-\sigma_1)} a_o\right] \int_o^1 \phi_V(t) \cos(a_o kt)\, dt \tag{25}$$

B. Rocking Vibrations

$$C_2(k) = -\left[\frac{2\alpha\ \kappa_1^2}{\pi(1-\alpha_1)} a_o\right] \int_o^1 \phi_R(t) \sin\ (a_o kt) dt \tag{26}$$

C. Horizontal Vibrations

$$C_1(k) = \left[\frac{2\Delta H\ \kappa 1^2}{\pi a(2-\sigma_1)} a_o\right] \int_o^1 \Big\{\phi_1(t) \cos(a_o kt)$$

$$- \phi_2(t) [\cos(a_o kt) - \sin(a_o kt)/a_o kt]\Big\} dt \tag{27}$$

$$C_3(k) = -\left[\frac{2\Delta H\ \kappa 1^2}{\pi a(2-\sigma_1)} a_o k\right] \int_o^1 \Big\{-\phi_1(t) \cos(a_o kt)$$

$$-(1-\sigma_1)\ \phi_2(t)\ [\cos(a_o kt) - \sin(a_o kt)/a_o kt]\Big\}dt \qquad (28)$$

where $\phi_V(t)$, $\phi_R(t)$, and $\phi_1(t)$, $\phi_2(t)$ are functions to be determined by equations 1, 3, and 5, respectively. Also, $\kappa_1^{\,2} = (1 + i\omega G_1'/G_1)^{-1}$ for Voigt type damping, and $\kappa_1^{\,2} = (1 + 2i\xi_1)^{-1}$ for hysteretic type damping. The substitutions indicated above satisfy directly the stress boundary conditions prescribed in equations 1, 3, and 6.

3B.8.3 INTEGRAL EQUATIONS AND IMPEDANCE FUNCTIONS

Substitution from equations 25 through 28, together with equations 23 and 24, into equations 17, 19, and 20, and imposition of the remaining displacement boundary conditions leads to the following integral equations for the unknown functions $\phi_V(t)$, $\phi_R(t)$, $\phi_1(t)$, and $\phi_2(t)$:

A. Vertical Vibrations

$$\phi_V(t) + \int_o^1 K(t, t')\ \phi_V(t')dt' = 1 \qquad (0\ £\ t\ £\ 1) \qquad (29)$$

where:

$$K(t, t') = L_1(|t - t'|) + L_1(t + t') \qquad (30)$$

$$L_1(t) = -\frac{a_o}{\pi}\int_o^\infty \left[\frac{k\Delta_{22}}{(1-\sigma_1)\ \Delta_R \kappa_1^{\,2}} + 1\right]\cos(a_o kt)dk \qquad (31)$$

B. Rocking Vibrations

$$\phi_R(t) + \int_o^1 K(t,t')\phi_R(t')dt' = t \qquad (0 \le t \le 1) \qquad (32)$$

where:

$$K(t, t') = L_1(|t-t'|) - L_1(t+t'). \qquad (33)$$

The function $L_1(t)$ in equation 33 is defined by equation 31.

C. Horizontal Vibrations

$$\phi_1(t) + \int_o^1 [K_{11}(t,t')\phi_1(t')$$

$$+ K_{12}(t,t')\phi_2(t')]dt' = 0 \qquad (0 \le t \le 1) \qquad (34)$$

$$(1 - \sigma_1)\phi_2(t) + \int_o^1 [K_{21}(t,t')\phi_1(t')$$

$$+ K_{22}(t,t')\phi_2(t')]dt' = 0 \qquad (0 \le t \le 1) \qquad (35)$$

where:

$$K_{11}(t,t') = \frac{2a_o}{\pi}\left(\frac{1}{2-\sigma_1}\right)\int_o^\infty [(1-\sigma_1)H_1(k)$$

$$+ H_2(k)]\cos(a_o kt)\cos(a_o kt')dk \qquad (36)$$

$$K_{12}(t,t') = -\frac{2a_o}{\pi}\left(\frac{1-\sigma_1}{2-\sigma_1}\right)\int_o^\infty [H_1(k)$$

$$- H_2(k)]\cos(a_o kt)\left[\cos(a_o kt')\right.$$

$$\left. - \frac{\sin(a_o kt')}{a_o kt'}\right]dk \qquad (37)$$

$$K_{21}(t, t') = -\frac{2a_o}{\pi}\left(\frac{1 - \sigma_1}{2 - \sigma_1}\right)\int_0^{\infty} [H_1(k) - H_2(k)]\left[\cos(a_o kt) - \frac{\sin(a_o kt)}{a_o kt}\right]\cos(a_o kt')dk \tag{38}$$

$$K_{22}(t, t') = \frac{2a_o}{\pi}\left(\frac{1 - \sigma_1}{2 - \sigma_1}\right)\int_0^{\infty} [H_1(k) + (1 - \sigma_1)H_2(k)]\left[\cos(a_o kt) - \frac{\sin(a_o kt)}{a_o kt}\right]\left[\cos(a_o kt') - \frac{\sin(a_o kt')}{a_o kt'}\right]dk \tag{39}$$

and,

$$H_1(k) = \frac{k}{\kappa_1^2(1-\sigma_1)}\frac{\Delta_{11}}{\Delta_R} - 1 \tag{40}$$

$$H_2(k) = \frac{k\Delta_{33}}{\kappa_1^2\Delta_L} - 1. \tag{41}$$

The integral equations 29, 32, 34, and 35 are of the Fredholm type and have a form suitable for numerical solution. Once these integral equations have been solved, the entire displacement and stress field may be evaluated by substitution from equations 25 through 28 into equations 19 through 22. In particular, the total vertical load V, the rocking moment about the y-axis M, and the total horizontal load in the x-direction H may be found to be given by:

$$V = \frac{4G_1 a\Delta_V e^{i\omega t}}{(1 - \sigma_1)\kappa_1^2} \int_o^1 \phi_V(t)dt \quad (42)$$

$$M = \frac{8G_1 a^3 \alpha e^{i\omega t}}{(1 - \sigma_1)\kappa_1^2} \int_o^1 t\Phi_R dt \quad (43)$$

$$H = \frac{8G_1 a\Delta_h e^{i\omega t}}{(2 - \sigma_1)\kappa_1^2} \int_o^1 \Phi_1(t)dt \quad (44)$$

Equations 42, 43, and 44 constitute the force-displacement relationship for the circular foundation. It should be mentioned that in deriving these equations the terms coupling the horizontal and rocking vibrations have been neglected.

It is convenient to write equations 42 through 44 in the following form:

$$V = \frac{4G_1 a}{1 - \sigma_1} \left[k_{VV}(a_o) + ia_o c_{VV}(a_o)\right]\Delta_v e^{i\omega t} \quad (45)$$

$$M = \frac{8G_1 a^3}{3(1 - \sigma_1)} \left[k_{MM}(a_o) + ia_o c_{MM}(a_o)\right]\alpha e^{i\omega t} \quad (46)$$

$$H = \frac{2G_1 a}{2 - \sigma_1} \left[k_{HH}(a_o) + ia_o c_{HH}(a_o)\right]\Delta_H e^{i\omega t} \quad (47)$$

where:

$$k_{VV}(a_o) = \int_o^1 \mathrm{Re}\left[\phi_v(t) / \kappa_1^2\right] dt,$$

$$c_{VV}(a_o) = -\frac{1}{a_o} \int_o^1 \mathrm{Im}\left[\phi_v(t) / \kappa_1^2\right] dt \quad (48)$$

$$k_{MM}(a_o) = 3\int_o^1 \mathrm{Re}\left[t\phi_R(t) / k_1^2\right] dt,$$
$$c_{MM}(a_o) = \frac{3}{a_o}\int_o^1 \mathrm{Im}\left[t\phi_R(t) / k_1^2\right] dt, \qquad (49)$$

$$k_{HH}(a_o = \int_o^1 \mathrm{Re}\,[\phi_1(t)/\kappa_1^2]\,dt,$$

$$c_{HH}(a_o = \frac{1}{a_o}\int_o^1 \mathrm{Im}\,[\phi_1(t)/\kappa_1^2]\,dt \qquad (50)$$

The terms inside the square brackets in equations 45, 46, and 47 are the normalized impedance functions for vertical, rocking, and horizontal vibrations; the factors outside the parenthesis correspond to the static values ($a_o = 0$) of the impedance functions for an elastic half-space having the properties of the top layer. The functions $k_{VV}(a_o)$, $k_{MM}(a_o)$, and $k_{HH}(a_o)$, corresponding to the real part of the impedance functions, will be called here stiffness coefficients, while the functions $c_{VV}(a_o)$, $c_{MM}(a_o)$, and $c_{HH}(a_o)$, proportional to the imaginary part of the impedance functions, will be designated here as damping coefficients. Both the stiffness and damping coefficients are functions not only of the dimensionless frequency a_o but also depend on the properties of the different media forming the soil column.

In solving the problem of the horizontal vibrations, a further approximation has been introduced by assuming that $\phi_2(t)$ is

sufficiently small so that the integral equations 34 and 35 may be reduced to:

$$\tilde{\phi}_1(t) + \int_o^1 K_{11}(t, t')\,\tilde{\phi}_1(t')\,dt' = 1 \quad (0 \leq t \leq 1) \qquad (51)$$

where the kernel $K_{11}(t, t')$ is given by equation 36. The basis for this approximation is that for the case of a uniform half-space, the function $\phi_2(t)$ is much smaller than $\phi_1(t)$, in particular, for the static case $\phi_2(t) = 0$. The above approximation is equivalent to the requirement that $\sigma_{zy} = 0$ under the foundation and thus corresponds to a further relaxation of the boundary conditions.

3B.8.4 NUMERICAL SOLUTION

The numerical procedure used to solve the integral equations 29, 32, and 51, consists in reducing these equations to a system of algebraic equations that are solved by standard methods. A key step in this procedure is the evaluation of the kernels K(t, t') given by equations 30, 33, and 36. In the case of a medium with no internal friction, the functions Δ_R and Δ_L have zeroes for real values of k and consequently the integrads in equations 31 and 36 are singular at these points. This situation complicates the numerical evaluation of the kernels. However, if there is internal friction, then the zeroes of Δ_R and Δ_L are complex and consequently the numerical evaluation of the kernels is simplified. The kernels are

evaluated numerically by use of Filon's method of integration up to a sufficiently large value of k; the rest is evaluated analytically by using the asymptotic forms of the integrads for large k.

3B.8.5 APPLICABLE EQUATIONS

The functions $\Delta_{ij}(k)$ (i, j = 1, 2) and Δ_R (k) entering in equations 19 and 20 are defined by:

$$\begin{bmatrix} \Delta_{11}(k) & \Delta_{12}(k) \\ \\ \Delta_{21}(k) & \Delta_{21}(k) \end{bmatrix} = (T^*_{11}A + T^*_{12}B)\ \mathrm{adj}(T^*_{21}A + T^*_{22}B) \tag{52}$$

and,

$$\Delta_R = \det\left(T^*_{21}A + T^*_{22}B\right) \tag{53}$$

where the matrices [A] and [B] are given by:

$$[A] = \begin{bmatrix} -k & \nu'_N \\ \\ \nu_N & -k \end{bmatrix} \tag{54}$$

$$[B] = \frac{G^*_N}{G_1}\begin{bmatrix} -2\nu_N k & \left(2k^2 - k_N^2\right) \\ \\ -\left(2k^2 - k_N^2\right) & 2\nu'_N k \end{bmatrix} \tag{55}$$

and, T^*_{ij} (i,j = 1, 2) are the submatrices of the total transfer matrix T* associated with the set of layers overlaying the base half-space. The total transfer matrix T*

$$\left[T^*\right] = \left[\begin{array}{c|c} T^*_{11} & T^*_{12} \\ \hline T^*_{21} & T^*_{22} \end{array}\right] \quad (56)$$

may be obtained in terms of the transfer matrices for each layer T_j (j = 1, N-1) by means of the following product:

$$[T^*] = [T_1][T_2]....[T_j]....[T_{N-1}] \quad (57)$$

The transfer matrix for the j^{th} layer is in turn given by:

$$\left[T_j\right] = \left[\begin{array}{c|c} T_{11}{}^j & T_{12}{}^j \\ \hline T_{21}{}^j & T_{22}{}^j \end{array}\right] \quad (58)$$

$$T^j_{11} = -\frac{1}{\kappa^2_j}\begin{bmatrix} -2k^2CH_j + (2k^2 - \kappa_j{}^2)\,CHP_j & -k(2k^2 - \kappa_j{}^2)\,SH_j + 2k\upsilon_j'^2SHP_j \\ 2k\upsilon_j{}^2SH_j - k(2k^2 - \kappa_j{}^2)\,SHP_j & (2k^2 - \kappa_j{}^2)\,CH_j - 2k^2CHP_j \end{bmatrix}$$

$$T^j_{12} = -\left(\frac{\rho_1}{\rho_j}\right)\begin{bmatrix} -k^2SH_j + \upsilon_j'^2\;SHP_j & k(CH_j - CHP_j) \\ k(CH_j - CHP_j) & -\upsilon_h{}^2SH_j + k^2SHP_j \end{bmatrix}$$

$$T^j_{21} = -\frac{1}{\kappa_j{}^4}\left(\frac{\rho_1}{\rho_j}\right)\begin{bmatrix} -4\upsilon_j{}^2k^2SH_j + (2k^2 - \kappa_j{}^2)^2\,SHP_j & -2k\,(2k^2 - \kappa_j{}^2)\,(CH_j - CHP_j) \\ -2k\,(2k^2 - \kappa_j{}^2)\,(CH_j - CHP_j) & -(2k^2 - \kappa_j{}^2)^2\,SH_j + 4\upsilon_j'^2k^2SHP_j \end{bmatrix} \quad (59)$$

$$T^j_{22} = -\frac{1}{\kappa_j{}^2}\begin{bmatrix} -2k^2CH_j + (2k^2 - \kappa_j{}^2)\,CHP_j & 2k\upsilon_j{}^2SH_j - k\,(2k^2 - \kappa_j{}^2)\,SHP_j \\ -k\,(2k^2 - \kappa_j{}^2)\,SH_j + 2\upsilon_j'^2k\;SHP_j & (2k^2 - \kappa_j{}^2)\,CH_j - 2k^2CHP_j \end{bmatrix}$$

The different terms entering in equations 54 to 59 are defined by:

$$\nu_j = (k^2 - \gamma_j^2 \kappa_j^2)^{1/2} \qquad \nu_j' = (k^2 - \kappa_h^2)^{1/2}$$

$$\gamma_j^2 = (1 - 2\sigma_j) / 2(1 - \sigma_j) \qquad k_j^2 = G_1 \rho_j / G_j^* \rho_1$$

$$G_j{*} = G_j(1 + i\omega G_j' / G_j),\ \text{or,} \qquad G_j{*} = G_j(1 + 2i\xi_j) \qquad (60)$$

$$SH_j = \sinh(a_o \nu_j \lambda_j)/\nu_j \qquad SHP_j = \sinh(a_o \nu_j' \lambda_j)/\upsilon_j'$$

$$CH_j = \cosh(a_o \nu_j \lambda_j) \qquad CHP_j = \cosh(a_o \nu_j' \lambda_j)$$

$$\lambda_j - h_j/a$$

$$a_o = \omega a/\beta_1$$

where σ_j, ρ_j, G_j, G'_j/G_j, and h_j are, respectively, the Poisson's ratio density, shear modulus, relative viscosity, and thickness of the j^{th} layer. In the last two equations of equation 60, a is the radius of the circular foundation, ω is the frequency of the steady-state vibrations and β_1 is the shear wave velocity of the top layer. The first form of G_j^* corresponds to the Voigt type damping, while the second corresponds to the hysteretic type damping, x_j being the hysteretic damping constant for the j^{th} layer.

The functions Δ_{33} (k) and Δ_L (k) entering in equation 19 are defined by

$$\Delta_{33}(k) = L_{11}^* + L_{12}^* \ \upsilon'_N G_N^*/G_1 \qquad (61)$$

$$\Delta_L(k) = L_{21}^* + L_{22}^* \ \upsilon'_N G_N^*/G_1 \qquad (62)$$

where L^*_{ij} (i, j = 1,2) are the elements of the transfer matrix L*. The transfer matrix L*

$$\left[L^*\right] = \begin{bmatrix} L^*_{11} & L^*_{12} \\ L^*_{21} & L^*_{22} \end{bmatrix} \tag{63}$$

is defined in terms of the transfer matrices for each layer by:

$$[L^*] = [L_1] \cdot [L_2]. \ . \ . \ .[L_j]. \ . \ [L_{N-1}] \tag{64}$$

in which,

$$\left[L_j\right] = \begin{bmatrix} CHP_j & \left(G_1 / G *_j\right) SHP_j \\ \left(G^*_j / G_1\right) \nu'^{\,2}_j \; SHP_j & CHP_j \end{bmatrix} \tag{65}$$

3B.8.6 VERIFICATION OF THE METHOD AND COMPUTER PROGRAM

3B.8.6.1 Introduction

The objective of this part is to test, by means of several comparisons, the adequacy of the method of solution described in subsections 3B.8.1 through 3B.8.5, and also, to verify the accuracy of the computer program developed to carry on the numerical computations.

One of the problems that appears in trying to reach this objective is the lack of "exact" solutions for the problem of forced vibrations of rigid foundations on viscoelastic layered media. There are, however, some approximate results that may be used as a basis of comparison [Veletsos and Verbic[(2)]].

Also, by considering the case of low damping values it is possible to compare results with the purely elastic case.

3B.8.6.2 Circular Foundation on a Viscoelastic Half-Space

A first test of the method of solution and associated computer program is provided by considering the harmonic response of a rigid circular foundation on a uniform viscoelastic half-space. Although this is the first time that an "exact" solution for the problem could be obtained, approximate results that can be used as a basis of comparison have been obtained by Veletsos and Verbic[2]. The approximate method used by Veletsos and Verbic is based on establishing analytical approximations to the numerically obtained solutions for the elastic problem and in extending these approximations to the viscoelastic case by use of the correspondence principle.

The vertical, rocking, and horizontal impedance functions for a rigid circular foundation on a uniform viscoelastic half-space with a Poisson's ratio of 1/3 were obtained by means of the computer program described here and the results compared with those obtained by Veletsos and Verbic. The comparisons are shown in figures 3B.8-2 through 3B.8-7. The continuous or segmented lines correspond to the results obtained by Veletsos and Verbic. The results obtained here are indicated in the figures by crosses, triangles, and circles, and are also listed in section 3B.8.6. The comparisons were made for the following six cases:

Case	Type of Damping	Damping Constant
1.a	Hysteretic	x = 0.05
2.a	Hysteretic	x = 0.15
3.a	Hysteretic	x = 0.25
1.b	Voigt	G'/G = 0.1 a/b
2.b	Voigt	G'/G = 0.3 a/b
3.b	Voigt	G'/G = 0.5 a/b

It may be seen in figures 3B.8-2 to 3B.8-7 that the results obtained here follow the same trend as those obtained by Veletsos and Verbic(2). However, some differences may be observed. These differences are in part a result of the approximate method used by the authors just mentioned. Some differences at high frequencies, i.e., for values of ao ~ 10., may be due to lack of accuracy of the computer program for these high frequencies.

3B.8.6.3 Viscoelastic Half-Space Represented by Several Layers with Equal Properties

Having verified the accuracy of the program for a uniform viscoelastic half-space, the next step is to verify that the program leads to the same results when the uniform half-space is represented by means of several layers all having the same viscoelastic properties. Six cases labeled 4.a, 4.b, 5.a, 5.b, 6.a, and 6.b, were considered. The cases indicated by the

letter a correspond to hysteretic type damping (ξ=0.05), the case designated by the letter b correspond to Voigt type damping (G'/G=0.10 a/β_1). In all cases a Poisson's ratio of 1/3 was used. The geometric properties for each case are given in the following:

Case	Geometry
4.a and 4.b	Three layers and underlying half-space $h_i = a$ (i = 1,3)
5.a and 5.b	Four layers and underlying half-space $h_1 = 0.25a$ $h_2 = 0.50a$ $h_3 = 0.75a$ $h_4 = 1.50a$
6.a and 6.b	Nine layers and underlying half-space $h_i = a$ (i = 1,9)

The results for cases 4.a, 4.b, 5.a, and 5.b match those for the viscoelastic half-space up to five significant figures (compare with cases 1.a and 1.b of the previous section). The results for case 6.b also coincide to the fifth significant figure with those for the viscoelastic half-space. The results for case 6.a are exact up to a value of a_o = 4.0; for higher frequencies the results are in error. These errors result from the combination of large number of layers (9), low damping value (χ = 0.05), and relatively high frequencies

($a_o \geq 5.0$). The important effect of damping in controlling the accuracy for high frequencies when several layers are involved is illustrated by the fact that the results for the Voigt model with the same number of layers (case 6.b) are exact. For a Voigt model damping increases with frequency and, consequently, more accurate results are obtained.

3B.8.6.4 Comparison with an Elastic Half-Space

One other test of the accuracy of the computer program is based on comparing the results obtained for a viscoelastic half-space with a low damping value with those for a purely elastic half-space. Shah[15], Veletsos and Wei,[16] and Luco and Westmann[13] have evaluated numerically the impedance or compliance functions for a rigid disc foundation on a purely elastic half-space. Comparisons with the values obtained by these authors allow the evaluation of the accuracy of the program under study for low values of the damping constant. Two cases with the following characteristics were considered:

Case	Geometry	Damping
7.a	half-space	hysteretic χ = 0.005
7.b	half-space	Voigt G'/G = 0.01 a/β

The results for these cases are shown in figures 3B.8-8, 3B.8-9, and 3B.8-10. The comparisons shown in these figures indicate a good accuracy in the evaluation of the imaginary parts of the impedance functions. The results for the real part of the impedance functions compare well for values of a_o up

to 4 or 5. For larger values of a_o some differences may be observed. These differences result in part from the effects of the damping, but they also reflect the numerical difficulties of evaluating the values of $k_{MM}(a_o)$, $k_{HH}(a_o)$, and $k_{VV}(a_o)$ for high frequencies for both the elastic and viscoelastic case.

3B.8.6.5 Comparison with an Elastic Two-Layered Medium

A computer program to evaluate the impedance functions for a rigid circular foundation placed on an elastic layer overlaying an elastic half-space is available(6). It is then possible to compare the results for a viscoelastic two-layered medium with low damping values with those for a purely elastic two-layered medium. This comparison was made for the four cases described below:

Case	Geometry	Elastic Properties
8	h = 0.5a	$\beta_1/\beta_2 = 0.8$, $\rho_1/\rho_2 = 0.85$, $\sigma_1 = \sigma_2 = 0.25$
9	h = 3a	$\beta_1/\beta_2 = 0.8$, $\rho_1/\rho_2 = 0.85$, $\sigma_1 = \sigma_2 = 0.25$
10	h = 0.5a	$\beta_1/\beta_2 = 0.2$, $\rho_1/\rho_2 = 0.85$, $\sigma_1 = 0.35$, $\sigma_2 = 0.25$
11	h = 5a	$\beta_1/\beta_2 = 0.2$, $\rho_1/\rho_2 = 0.85$, $\sigma_1 = 0.35$, $\sigma_2 = 0.25$

In all cases the viscoelastic medium was assumed to have constant hysteretic type damping. A value of $\chi = 0.05$ was used. The comparisons for cases 8 and 9 are shown in figures 3B.8-11, 3B.8-12, and 3B.8-13. It may be seen that for low frequencies the stiffness coefficients for the viscoelastic case tend to match those of the elastic case.

Similarly, for high frequencies the damping coefficients for the viscoelastic case tend to match those for the elastic case.

The comparisons for cases 10 and 11 are shown in figures 3B.8-14, 3B.8-15, and 3B.8-16. Again, the comparisons indicate the correct behavior at low and high frequencies. For values of $a_o \leq 0.2$, the stiffness coefficients for the viscoelastic case for a thin layer ($h/a = 0.5$) tend to be lower than those for the elastic case. This behavior has been corrected in the final version of the computer program.

3B.8.6.6 Conclusions

The comparisons made indicate that the computer program described here leads to results that are consistent with what is known about the response of rigid foundations on a layered viscoelastic medium. As a result of these comparisons, some limitations on the use of the program are described below:

A. In the first place the combination of very thin layers ($h/a < 0.25$) and low frequencies ($a_o < 0.2$) may lead to slightly lower values of the stiffness coefficients for these frequencies.

B. There is a loss in accuracy for a combination of high frequencies, several layers, and low damping constants.

3B.8.7 REFERENCES

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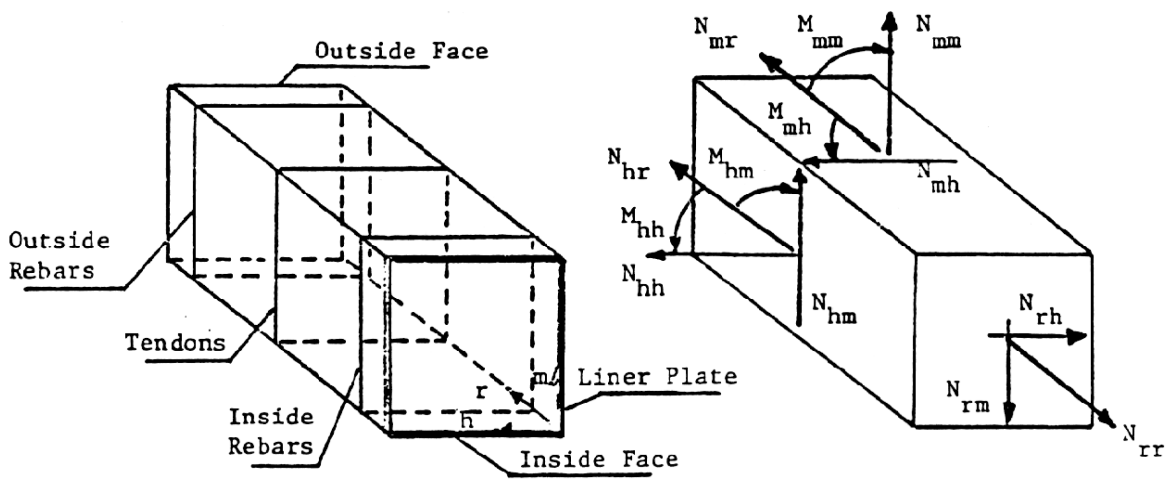
3B.9 CECAP COMPUTER PROGRAM (CECAP) CE 987

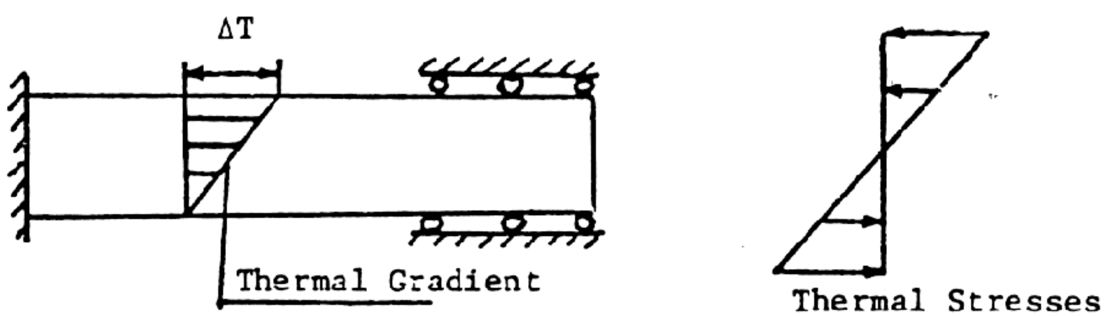
CECAP computes stresses in a concrete element under thermal and/or nonthermal (real) loads, considering effects of concrete cracking. The element represents a section of a concrete shell or slab, and may include two layers of reinforcing, transverse reinforcing, prestressing tendons, and a liner plate. The program has been developed primarily for analysis of nuclear plant containments, but may also be used for analysis of basemats, fuel pools, or other structures, providing program assumptions are valid. The configuration of the element and applied force/moment loadings are as follows:



Nonthermal force/moment loads on the element must be determined in a separate analysis of the structure containing the element, and input to the program. Thermal loads may be determined and input in similar fashion, or alternatively input as linear temperature gradients through the thickness.

CECAP assumes linear stress-strain relationships for steel and concrete in compression. Concrete is assumed to have no

tensile strength. The solution is an iterative process, whereby tensile stresses found initially in concrete are relieved (by cracking) and redistributed in the element. Equilibrium of nonthermal loads is preserved. For thermal effects, the element is assumed free to expand inplane, but fixed against rotation as shown:



The capability for expansion and cracking generally results in a reduction in thermal stresses from the initial condition.

The program will output stresses and strains at selected locations in the concrete, reinforcement, tendons, and liner plate; and resultant forces and moments for the composite concrete element.

3B.9.1 ANALYSIS OF SAMPLE PROBLEM WITH CECAP

3B.9.1.1 Introduction

The analysis of a reinforced concrete beam subjected to a linear thermal gradient was performed to test the redistribution of thermal stresses due to the relieving effect

of concrete cracking. The results were compared with hand calculations.

3B.9.1.2 Problem Description

Sample A.1 shows the reinforced concrete beam and the corresponding CECAP concrete element used in the analysis. Boundary conditions, geometry, and applied loads are illustrated.

3B.9.1.3 Problem Parameters

Concrete modulus of elasticity	$E_c = 3 \times 10^6$ psi
Rebar modulus of elasticity	$E_s = 30 \times 10^6$ psi
Concrete Poisson's ratio	$\upsilon_c = 0.22$
Concrete coefficient of thermal expansion	$\alpha_c = 6 \times 10^{-6}$ in/in/°F
Temperature difference	$\Delta T = 100F$
Rebar coefficient of thermal expansion	$\alpha_R = \alpha_c$

CECAP COMPUTER PROGRAM (CECAP)

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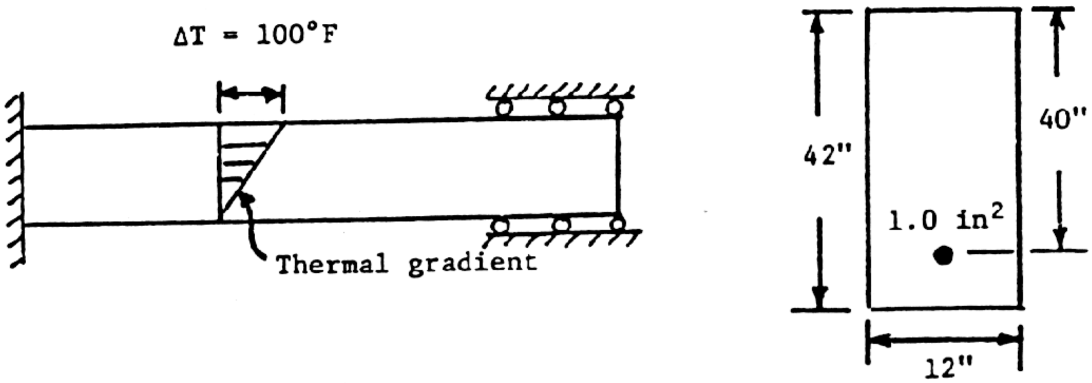
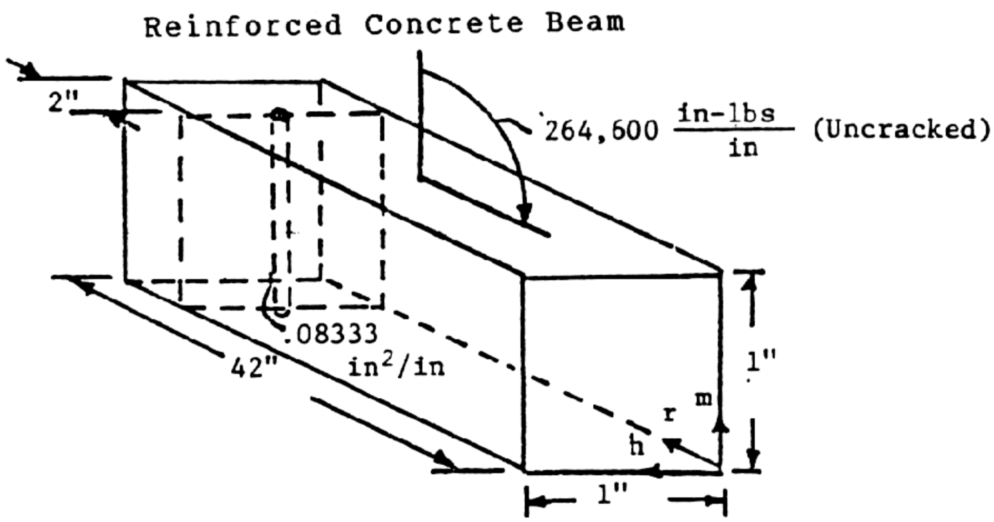




CECAP Concrete Element Model

Sample A.1 Reinforced Concrete Beam and

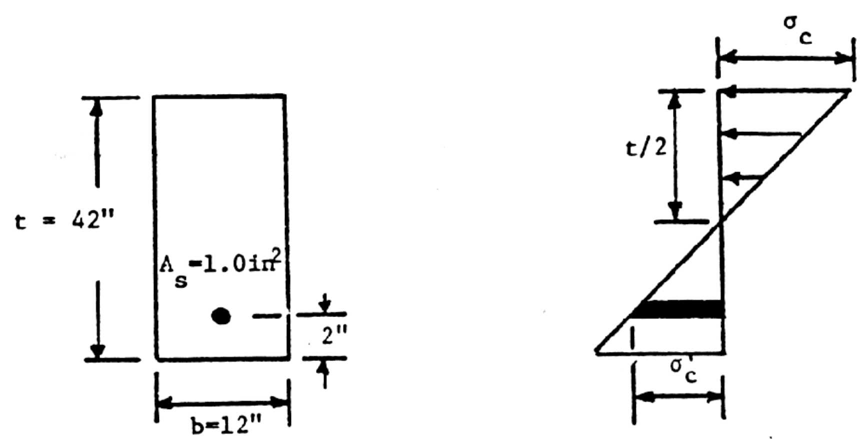
CECAP Concrete Element Model

3B.9.1.4 Hand Calculations

The following illustrates how thermal loads are treated in a cracked section analysis of a reinforced concrete beam. The main assumptions pertaining to thermal boundary conditions are:

- The beam is allowed to expand freely axially.
- There is no rotation of the initial thermal stress slope.

The beam cross-section and initial thermal stress distribution are:



where, for ΔT = 100F, the equivalent thermal moment, concrete, and rebar stresses are:

$$M = \Delta T \alpha_c E_c bt^2/12 = (100)(6 \times 10^{-6})(3 \times 10^{6})(12)(42)^2/12$$

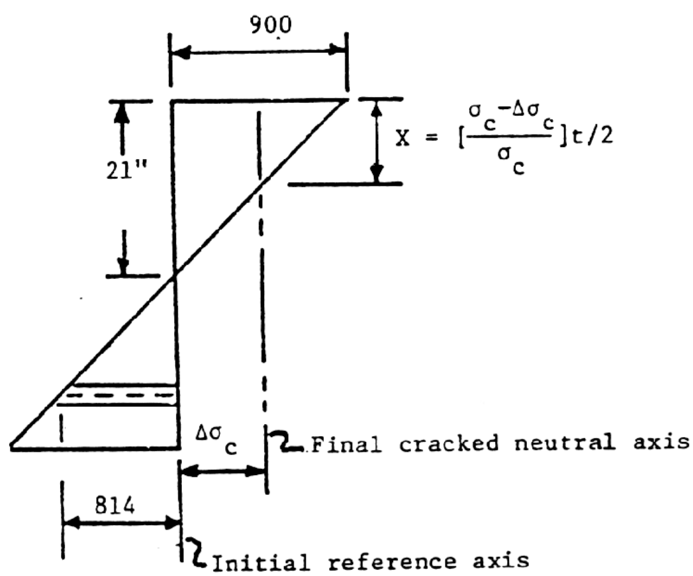
$$= 3,175,000 \text{ in-lbs}$$

$$\sigma_c = \Delta T \alpha_c E_c/2 = (100)(6 \times 10^{-6})(3 \times 10^{6})/2$$

= 900 psi (compression)

$$\sigma_c' = \frac{(t/2 - 2)}{t/2}\sigma = \frac{(21 - 2)}{21} 900 = 814 \text{ psi (tension)}$$

The stress diagram used for the cracked section analysis with thermal loading is as follows. The assumptions of free movement axially and constant thermal stress slope are maintained by a lateral translation of the initial reference axis to a final cracked position.



From Force Equilibrium:

$$F_{rebar} + F_{concrete} = 0$$

$$\underbrace{1.0(814 + \Delta\sigma_c)10}_{F_{rebar}} - \underbrace{900\left(\frac{42}{2}\right)\left(\frac{12}{2}\right) + \frac{\Delta\sigma_c(12)}{2}\left[21 + \left(\frac{900 - \Delta\sigma_c}{900}\right)21\right]}_{F_{concrete}}$$

$$= 0$$

Solving for $\Delta\sigma_c$

$$\Delta\sigma_c = 582 \text{ psi}$$

Rebar and concrete stresses are:

$$f_s = (814 + 582)10 = 13,970 \text{ psi (tension)}$$

$$f_c = 900 - 582 = 318 \text{ psi (compression)}$$

Locations of cracked neutral axis is:

$$kd = x = \left(\frac{900 - 582}{900}\right) 21 = 7.42 \text{ in.}$$

Self-relieved thermal moment is:

$$M_T = \frac{f_s A_s \left(d - \frac{x}{3}\right)}{12} = \frac{13970\,(1)\,(40 - 2.47)}{12} = 43{,}690\,\frac{\text{in} - \text{lb}}{\text{in}}$$

3B.9.1.5 Comparison of Results

The rebar and concrete stresses, self-relieved thermal moment, and neutral axis location obtained from the CECAP program are compared with the hand calculations in table 3B.9-1. It can be seen that the CECAP results compare favorably with the hand calculations.

3B.9.1.6 Conclusions

The difference in the stress results are largely due to the accuracy limit defined for the force iterations. Smaller errors would result with smaller accuracy limits, but the

trade-off would be with longer run times. The CECAP program is verified for this type of thermal loading.

Table 3B.9-1

CECAP AND HAND CALCULATION COMPARISON - THERMAL GRADIENT

	CECAP	Hand Calculations	Percent Error
f_s	13,150 psi	13,790 psi	5.9
f_c	-331 psi	-318 psi	4.1
k_d	7.55 in.	7.42 in.	1.8
M_T	43,760 in-lb/in	43,690 in-lb/in	0.2

3B.9.2 DESCRIPTION OF VERIFICATION PROBLEMS (CECAP) - CE 987

Eleven example problems were analyzed by the CECAP program and compared to hand-calculated solutions. The problems were chosen to verify the program for various combinations of thermal and nonthermal (real) loads. A list of verification problems with short descriptions follows. More detailed descriptions of the problems and their hand calculated solutions can be found in the appendices.

CECAP COMPUTER PROGRAM (CECAP)

CE 987

CECAPVER Number	Description
1	Thermal moment
2	Thermal moment and real axial load
3	Real moment
4	Real moment and real axial load
5	Thermal moment, real moment and real axial load
6	Uniaxial tension
7	Biaxial tension
8	Biaxial tension with shear
9	Uniaxial tension with liner
10	Thermal moment with liner
11	Thermal moment with tension and compression reinforcement

3B.9.2.1 Summary of Verification

The results of the CECAP analyses of the 11 verification problems and comparisons with hand-calculated solutions are summarized in figures 3B.9-1 through 3B.9-11. Each figure shows the verification problem, corresponding CECAP element model, and comparison of pertinent results. The comparisons show that the CECAP results for rebar and concrete stresses, self-relieved thermal moments, and neutral axes locations are in good agreement with hand-calculated values for all test cases. Detailed descriptions of hand-calculated solutions and

computer output results can be found in the appendices. Note that some of the stress results may be above accepted code limits for concrete or steel. CECAP is a linear program and the magnitude of the loads were chosen for illustration purposes only.

3B.10 FOSIN COMPUTER PROGRAM (FOSIN) CE 299

The FOSIN program performs a dynamic analysis on a structure foundation system by a modal analysis technique. Input consists of the structure definition in the form of mass, stiffness, and damping matrices, foundation geometry, soil impedances, and the free field time-history input motion. The program calculates modal frequencies, mode shapes, a measure of the ratio of critical damping in each mode, and the time-history record for each degree of freedom.

3B.10.1 DESCRIPTION OF VERIFICATION

Three test problems were considered in the verification of the FOSIN program.

A. Comparison with results published by Jacobo Bielak in his doctoral thesis "Earthquake Response of Building Foundation Systems," California Institute of Technology, 1971.

   Operations utilized in case 1:

   1. Input impedance table
   2. Default impedance table
   3. Determination of the frequencies and damping values
   4. Time-history analysis
   5. Base line correction of time history
   6. Unequally spaced time history

B. Comparison of the dynamic analysis of a structure; first, as a fixed-base, three-degree of freedom model, and second, as a two-degree of freedom model with frequency dependent impedances modeling the dynamic properties of the lower portion of the structure.

   Operations utilized in case 2:

   1. Input impedance table

   2. Determination of the frequencies and damping values

   3. Time-history analysis

   4. Equally digitized time-history

C. A repeat of problem 2 for a 10-degree of freedom structural model. The same operations will be utilized.

3B.10.2 SUMMARY OF THE VERIFICATION

The results of the three problems tested here show that the FOSIN program is giving very reasonable answers. Please refer to the appendices for the actual numerical comparisons for each of the three problems.

3B.10.3 FOSIN VERIFICATION (TEST PROBLEMS)

3B.10.3.1 FOSIN Example 1, Bielak Soil Structure Interaction

The following problem presents a comparison of results obtained by use of the FOSIN computer program and those published by Bielak[(1)] for a simple structure founded upon uniform soil deposits with different shear wave velocities. Bielak used the LaPlace transform method to solve the equations of motion of the dynamic system while the method employed by the FOSIN computer code is based on uncoupling the equations of motion by Foss's method.[(2)]

A. Problem Description

The superstructure is represented by a two-node model with a single horizontal degree of freedom per node. Rotation of the nodes is restrained; thereby, allowing the structure to deform only in shear between nodes. Figure 3B.10-1 shows a sketch of the model as proposed by Bielak along with the soil and structural properties. This same data was input into the FOSIN program and the resulting undamped system frequencies and modal damping values were then calculated.

The compliances, C, used by Bielak in reference 1 are listed in table 3B.10-1. These compliances must first be inverted to their corresponding impedance values, K, before they can be input into the FOSIN program. The relationship between the compliances and impedances may be expressed by the equation:

$$K = 1/C$$

where:

$$K = k_1 + ik_2$$

$$C = c_1 + ic_2$$

$$K = \frac{1}{C_1 + ic_2} \quad \frac{c_1 - ic_2}{c_1^2 + c_2^2} = \frac{c_1}{c_1^2 + c_2^2} - \frac{ic_2}{c_1^2 + c_2^2}$$

therefore:

$$k_1 = \frac{c_1}{c_1^2 + c_2^2} \text{ and } k_2 = \frac{-c_2}{c_1^2 + c_2^2}$$

The results of this data transformation are also listed in table 3B.10-1.

FOSIN COMPUTER PROGRAM (FOSIN)

CE 299

Table 3B.10-1

UNCOUPLED ELASTIC HALF-SPACE IMPEDANCES,

FOSIN EXAMPLE 1

	Horizonatal Translation				Rocking			
	Compliance*		Impedance**		Complicance*		Impedance**	
A_o	Re C_{HH}	Im C_{HH}	Re K_{HH}	Im K_{HH}	Re C_{MM}	Im C_{MM}	Re K_{MM}	Im K_{MM}
0.0	1.0000	0.0	1.0000	0.0	1.0000	0.0	1.0000	0.0
0.1	0.9969	-0.0601	0.9995	0.6026	1.0030	-0.0003	0.9970	0.0030
0.2	0.9876	-0.1194	0.9980	0.6033	1.0118	-0.0020	0.9883	0.0098
0.3	0.9724	-0.1771	0.9954	0.6043	1.0259	-0.0067	0.9747	0.0212
0.4	0.9514	-0.2324	0.9919	0.6057	1.0445	-0.0155	0.9572	0.0355
0.5	0.9251	-0.2847	0.9874	0.6078	1.0667	-0.0298	0.9367	0.0523
0.6	0.8940	-0.3331	0.9822	0.6099	1.0910	-0.0502	0.9147	0.0701
0.7	0.8587	-0.3771	0.9763	0.6125	1.1162	-0.0774	0.8916	0.0883
0.8	0.8199	-0.4162	0.9698	0.6153	1.1406	-0.1117	0.8684	0.1063
0.9	0.7784	-0.4502	0.9627	0.6186	1.1627	-0.1530	0.8454	0.1236
1.0	0.7351	-0.4786	0.9554	0.6220	1.1807	-0.2008	0.8231	0.1400
1.1	0.6908	-0.5016	0.9479	0.6257	1.1934	-0.2545	0.8015	0.1554
1.2	0.6464	-0.5193	0.9402	0.6294	1.1993	-0.3128	0.7807	0.1697
1.3	0.6026	-0.5318	0.9329	0.6333	1.1975	-0.3745	0.7607	0.1830
1.4	0.5601	-0.5397	0.9258	0.6372	1.1873	-0.4379	0.7414	0.1953
1.5	0.5195	-0.5435	0.9190	0.6410	1.1683	-0.5013	0.7229	0.2068
1.6	0.4811	-0.5436	0.9130	0.6447	1.1407	-0.5630	0.7049	0.2175
1.7	0.4453	-0.5407	0.9076	0.6482	1.1049	-0.6213	0.6876	0.2274
1.8	0.4122	-0.5354	0.9028	0.6515	1.0618	-0.6748	0.6708	0.2369
1.9	0.3819	-0.5282	0.8989	0.6544	1.0125	-0.7221	0.6547	0.2457
2.0	0.3542	-0.5196	0.8957	0.6570	0.9583	-0.7624	0.6390	0.2542
2.5	0.2507	-0.4687	0.8873	0.6636	0.6657	-0.8511	0.5702	0.2916
3.0	0.1861	-0.4215	0.8766	0.6618	0.4313	-0.7989	0.5233	0.3231
3.5	0.1401	-0.3825	0.8443	0.6586	0.2916	-0.6992	0.5081	0.3481
4.0	0.1040	-0.3470	0.7925	0.6611	0.2191	-0.6077	0.5250	0.3641
4.5	0.0775	-0.3122	0.7490	0.6705	0.1803	-0.5390	0.5582	0.3708
5.0	0.0612	-0.2802	0.7440	0.6813	0.1548	-0.4894	0.5875	0.3715
5.5	0.0523	-0.2540	0.7777	0.6867	0.1334	-0.4511	0.6028	0.3706
6.0	0.0469	-0.2337	0.8255	0.6856	0.4177	-0.4177	0.6095	0.3712
6.5	0.0425	-0.2177	0.8638	0.6807	0.0990	-0.3863	0.6225	0.3737
7.0	0.0382	-0.2041	0.8860	0.6762	0.0889	-0.3575	0.6551	0.3763
7.5	0.0342	-0.1916	0.9028	0.6744	0.0833	-0.3328	0.7078	0.3770
8.0	0.0314	-0.1795	0.9456	0.6757	0.0801	-0.3129	0.7678	0.3749
8.5	0.0301	-0.1685	1.0274	0.6766	0.2969	-0.2969	0.8203	0.3712
9.0	0.0299	-0.1590	1.1423	0.6749	0.0736	-0.2833	0.8591	0.3674
9.5	0.0302	-0.1511	1.2719	0.6699	0.0694	-0.2704	0.8905	0.3652
10.0	0.0304	-0.1440	1.4035	0.6648	0.0657	-0.2574	0.9310	0.3647

* From Reference 1

** The impedance, K is calculated from the compliance, C, as follows:

$K = K_1 + iK_2$

$C = C_1 + iC_2$

$$K = \frac{1}{C} = \frac{1}{C_1 + iC_2} = \frac{C_1 - iC_2}{(C_1)2 + (C_2)2}$$

In addition to running the cases as performed by Bielak with the uncoupled impedances, the FOSIN program was used to solve the problems by generating a set of soil impedance values by using the default impedance table contained in the program; the other parameters of the Bielak problem remained the same. The default impedance table was derived by inverting the complete coupled compliances developed by J. E. Luco for an elastic half-space.(3) It should be noted that Bielak also used the compliances developed by Luco but neglected the coupling terms which he considered insignificant.

The results of the FOSIN analysis, first using the default impedance table and then using Bielak's impedance data, will be compared to the original work of Bielak.

A comparison of the response of the system due to a "free field" acceleration was also made. The time-history acceleration record used was the N33E component of the earthquake motion recorded at the SONGS Unit 1 Power Plant, San Onofre, California on April 8, 1968. This time-history, as obtained from Caltech, was the uncorrected record; therefore, it was base line corrected internally as a portion of the computer run. The analytical model used was again that of figure 3B.10-1 with the shear wave velocity of the foundation medium taken as 1500 feet per second.

B. Problem Parameters

Symbol	Description
m_i	lumped mass parameter, kip-s^2/ft
k_i	stiffness of idealized stick between masses, kip/ft
I_t	mass moment of inertia about the base of the model, kip-s^2-ft
ρ	mass density of soil, k-s^2/ft^4
σ	Poisson's ratio
V_s	shear wave velocity, ft/s
r	radius of foundation, ft
h_i	height of mass m_i above base, ft
K_i	impedance of soil, kip/ft
C_i	compliances of soil, ft/kip
$\varnothing$	rotation at base of model, rad
v_i	horizontal displacement of mass m_i
ω	frequency of vibration, rad/s
β	% critical damping

C. Results

The computed frequencies and damping values of the two problems (one using the Bielak impedance data, and the

other using the coupled impedances from the FOSIN default table) are shown compared to the results given by Bielak in table 3B.10-2. The response of the model to the "free field" acceleration (N33E component of the SONGS 1 Power Plant) is shown in figure 3B.10-2. This may be compared to the results obtained by Bielak that are shown in figure 3B.10-3. In both figures, the horizontal displacement time-history is shown for the base and the two masses representing the super-structure. Also shown is the horizontal displacement of mass m_1 due to the rotation of the structure about m_0.

D. Solution of the Bielak Model for Fixed Base Free Vibration Conditions

$$[M]\ \{\ddot{x}\} + [K]\ \{x\} = 0$$

let:

$$\{x\} = \{A\}\ e^{i\omega t}$$

now substituting this into the equation above yields:

$$-\omega^2\ [M]\ \{A\}\ e^{i\omega t} + [K]\ \{A\}\ e^{i\omega t} = 0$$

$$\left[[K] - \omega^2\ [M]\right] \{A\}\ e^{i\omega t} = 0$$

$$[M]^{-1}\ [K] - \omega^2\ [I] = 0$$

where:

[I] = identity matrix

$$[M] = m\begin{bmatrix} \frac{1}{2} & 0 \\ 0 & 1 \end{bmatrix} => [M]^{-1} = \frac{1}{m}\begin{bmatrix} 2 & 0 \\ 0 & 1 \end{bmatrix}$$

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Table 3B.10-2

MODAL FREQUENCY AND DAMPING COMPARISON,

FOSIN EXAMPLE 1

Vs (ft/sec)	Source**	Undamped Frequency (rad/sec)				Ratio of Critical Damping (%)			
		1	2	3	4	1	2	3	4
800	B	8.87	23.86	54.84	87.73	4.26	58.69	0.88	16.14
	F-UCI	8.86	23.86	54.84	87.72	4.26	58.64	0.88	16.11
	F-D	8.49	25.12	54.90	87.19	6.56	52.50	0.82	16.32
1000	B	10.76	29.85	54.85	89.25	3.77	58.70	0.99	19.86
	F-UCI	10.76	29.84	54.86	89.21	3.77	58.66	0.99	19.85
	F-D	10.34	31.35	54.95	89.02	5.89	52.73	0.97	20.29
1200	B	12.47	35.86	54.86	90.79	3.27	58.74	1.05	23.55
	F-UCI	12.47	35.85	54.86	90.76	3.27	58.70	1.04	23.48
	F-D	12.02	35.58	54.97	90.21	5.18	53.00	1.13	24.35
1500	B	14.70	44.93	54.86	93.66	2.57	58.86	1.06	27.61
	F-UCI	14.69	44.92	54.86	93.70	2.57	58.82	1.06	27.41
	F-D	14.23	46.92	54.93	91.90	4.15	53.56	1.27	28.38
2000	B	17.54	54.82	60.14	101.6	1.65	0.90	59.27	31.53
	F-UCI	17.53	54.82	60.12	101.8	1.65	0.90	59.23	31.20
	F-D	17.12	54.80	62.29	99.1	2.73	1.13	54.93	32.18
2700	B	20.12	54.86	81.29	117.3	0.87	0.53	59.93	34.47
	F-UCI	20.12	54.86	81.26	117.5	0.87	0.53	59.90	34.01
	F-D	19.79	54.81	82.83	116.0*	1.46	0.68	56.83	34.45*
3500	B	21.83	54.97	105.2	138.4	0.44	0.27	60.43	36.03
	F-UCI	21.83	54.97	105.2	138.9	0.45	0.27	60.40	35.45
	F-D	21.60	54.93	105.4	139.6*	0.75	0.35	58.31	34.96*
5000	B	23.39	55.12	149.8	182.8	0.16	0.09	60.92	37.22
	F-UCI	23.38	55.12	149.8	183.4*	0.17	0.09	60.90	36.63*
	F-D	23.26	55.09	146.8	188.7*	0.26	0.12	59.65	35.66
8000	B	24.43	55.22	238.8	279.5	0.04	0.02	61.25	37.24
	F-UCI	24.43	55.22	238.7	279.3*	0.04	0.02	61.23	37.28*
	F-D	24.37	55.21	229.9	292.8	0.06	0.03	60.52	36.35
10,000	B	24.86	55.25	298.2	345.4	0.02	0.01	61.33	37.37
	F-UCI	24.68	55.25	298.0	345.1*	0.02	0.01	61.31	37.41*
	F-D	24.65	55.24	285.7	363.6	0.03	0.01	60.73	36.54
15,000	B	24.94	55.28	446.7	512.0	0.006	0.003	61.41	37.53
	F-UCI	24.94	55.28	446.5	511.6*	0.006	0.003	61.39	37.55*
	F-D	24.92	55.28	425.9	541.8	0.007	0.004	60.92	36.74

* Convergence limit of 0.1% on system frequency not satisfied after five iterations, fifth iteration used.

** B Results tabulated in reference 2, page 123

F-UCI Results obtained using the FOSIN program with the uncoupled impedance functions used by Bielak.

F-D Results obtained using the FOSIN program with the default coupled impedance functions.

$$[K] = \frac{k}{4}\begin{bmatrix} 3 & -3 \\ -3 & 7 \end{bmatrix}$$

$$\therefore \; [M]^{-1} \; [K] - \omega^2 \; [I] =$$

$$\begin{bmatrix} (3/2 \text{ k/m} - \omega^2) & (-3/2 \text{ k/m}) \\ (-3/4 \text{ k/m}) & (7/4 \text{ k/m} - \omega^2) \end{bmatrix} = 0$$

the determination of the above matrix yields the characteristic equation

$$\lambda^2 - \left(\frac{13k}{4m}\right)\lambda + 3/2\,(k/m)^2 = 0$$

where

$$\lambda = \omega^2$$

solving for λ yields:

$$\lambda = .56 \text{ k/m}, \; 2.69 \text{ k/m}$$

where:

$$k/m = \frac{5.394 \bullet 10^5}{.475 \bullet 10^3} = 1135.58 \text{ rad / s}^2$$

therefore,

$$\lambda_1 = 632.52 \text{ rad/s}^2 \text{ and } \omega_1 = 25.15 \text{ rad/s} = 4.00 \text{ Hz}$$

$$\lambda_2 = 3058.12 \text{ rad/s}^2 \text{ and } \omega_2 = 55.30 \text{ rad/s} = 8.80 \text{ Hz}$$

As the shear wave velocity of the soil is increased to that of a rigid material, the system frequencies should approach the fixed-base values calculated above.

E. Comparison of Results

The calculated system frequencies and modal damping values are tabulated in table 3B.10-2. The maximum percent difference between Bielak's results for the first three system frequencies, and the results of the FOSIN analysis using the uncoupled impedances, is 0.1% which corresponds well with the convergence limit of 0.001 that was specified in the FOSIN input. The frequencies calculated for the fourth mode differed by a maximum of 0.4%.

A comparison of damping values from the two sources also showed good agreement. The first mode damping values differed by a maximum of one hundredth of a percent of critical. The damping values agreed to within 1% for modes two and three, with mode four showing a maximum difference of 1.6%.

The results of the forced vibration analysis are compared on the basis of the computer response displacement time-histories. A better comparison would have been to compare the resulting response spectra for each node; however, this information from the Bielak solution is not available. The displacement time-histories obtained by Bielak are shown in figure 3B.10-3 and the corresponding results from the FOSIN program are given in figure 3B.10-2.

F. Conclusions

The FOSIN program determines the natural frequencies and modal damping characteristics by solving for an individual mode in a system where the soil parameters are compatible with that particular modal frequency. The comparison of frequencies and modal damping values obtained by use of the FOSIN program with those calculated by Bielak verify that the program is adequately representing the frequency dependence of the half-space dynamic properties.

The time-history displacement records shown in figures 3B.10-3 and 3B.10-2 do not provide sufficient detail to verify the FOSIN program for forced vibration analysis. However, the comparison of the records does tend to show a good correspondence.

G. Computer Runs

1. FOSIN frequency analysis of the Bielak model for Vs values between 800 feet per second and 1500 feet per second using the Bielak impedance table

2. FOSIN frequency analysis of the Bielak model for Vs values between 800 feet per second and 1500 feet per second using the default impedance table derived from the Luco compliances

3. FOSIN time-history analysis of the Bielak model for Vs = 1500 feet per second and using the San Onofre earthquake of 1968

3B.10.3.2 FOSIN Example 2, Comparison of a Three-Mass, Fixed Base System with an Equivalent Two-Mass Interaction System

This problem will test the FOSIN program by comparing an exact solution of a three-mass system using modal synthesis with the approximate FOSIN analysis of the system after it has been converted to a two-mass system resting on a frequency-dependent impedance foundation. The impedance foundation will be representing the remaining lower portion of the structure. See figures 3B.10-4 and 3B.10-5.

The following calculations will be performed in the process of exercising this problem.

A. Theoretical verification of the equivalence of the response for the top masses of the three-mass fixed base system and the two-mass interaction system. See paragraph 3B.10.3.2.3.

B. A hand calculation of the fixed-base, three-mass system to include:

   1. System frequencies

   2. Mode shapes

   3. Damping ratios

4. Damped frequencies of vibration

5. Modal mass

6. Participation factors

See paragraph 3B.10.3.2.4.

C. The SUPER SMIS program will be used to calculate the frequencies and eigenvectors and will also perform a time-history analysis of the three mass model.

See program "A".

D. A SUPER SMIS analysis of subsystem "A" to generate the modified base motion to be used with subsystem "B" by FOSIN.

See program "B".

E. An evaluation of the substructure impedances to be used by FOSIN to represent subsystem "A".

See paragraph 3B.10.3.2.5, program "D", table 3B.10-3.

F. A FOSIN analysis of the interaction system using sub-system "B", the modified base motion and the impedance table calculated above. The following quantities will be found:

1. The first two system frequencies of the complete three mass system

2. A measure of the damped system frequencies

3. Eigenvectors for the first two modes

4. Time-history analysis for masses m_1 and m_2.

See program "E".

3B.10.3.2.1 Problem Description

Consider a simple three-mass system having only three translational DOFF in the vertical direction which is subjected to a support motion input at its base. This basic system will

Table 3B.10-3

TABLE OF SUBSTRUCTURE IMPEDANCES, FOSIN EXAMPLE 2

A_0 (ω)	k x(10^4 k/ft)	c x$\left(10^3 \frac{K-sec}{ft}\right)$	A_0 (ω)	k x(10^4 k/ft)	c x$\left(10^3 \frac{K-sec}{ft}\right)$
0.00	5.000	1.000	14.80	3.417	1.069
1.00	4.994	1.000	14.90	3.392	1.071
2.00	4.976	1.000	15.00	3.366	1.073
3.00	4.946	1.000	15.10	3.340	1.076
4.00	4.903	1.000	15.20	3.314	1.078
5.00	4.847	1.001	15.30	3.287	1.081
6.00	4.777	1.001	15.40	3.260	1.083
7.00	4.694	1.003	15.50	3.233	1.086
8.00	4.595	1.005	15.60	3.205	1.088
8.10	4.584	1.005	15.70	3.178	1.091
8.20	4.573	1.005	15.80	3.149	1.094
8.30	4.562	1.005	15.90	3.121	1.097
8.40	4.551	1.006	16.00	3.092	1.100
8.50	4.539	1.006	17.00	2.788	1.134
8.60	4.528	1.006	18.00	2.451	1.179
8.70	4.516	1.006	19.00	2.081	1.236
8.80	4.504	1.007	20.00	1.677	1.308
8.90	4.492	1.007	21.00	1.242	1.398
9.00	4.480	1.007	22.00	0.7817	1.509
10.00	4.347	1.012	23.00	0.3055	1.646
11.00	4.196	1.018	24.00	-0.1708	1.809
12.00	4.024	1.026	25.00	-0.6250	2.000
13.00	3.829	1.038	26.00	-1.028	2.217
13.90	3.634	1.051	27.00	-1.347	2.456
14.00	3.611	1.053	28.00	-1.547	2.706
14.10	3.588	1.055	29.00	-1.601	2.956
14.20	3.564	1.057	30.00	-1.495	3.189
14.30	3.540	1.059	31.00	-1.233	3.393
14.40	3.516	1.060	32.00	-0.8372	3.556
14.50	3.492	1.062	33.00	-0.3441	3.674
14.60	3.467	1.065	34.00	0.2055	3.746
14.70	3.442	1.067	35.00	0.7727	3.776

$m_2' = 10$ K-sec ^{2}/ft $c_2 = 2000$ K-sec /ft $k_2 = 100000$ K/ft

$m_3 = 200$ $c_3 = 2000$ $k_3 = 100000$

Note: The value of R,G and p were chosen so that Ao = ω

Be modeled by two different techniques. In the first case, the complete three-DOF system will be subjected to the base acceleration input z(t) as shown in figure 3B.10-4. The response of the system in this case can be calculated exactly using mode superposition procedure and the standard time-history analysis.

In the second case, the three-DOF system is treated as an interaction system formed by coupling two subsystems, designated as subsystems "A" and "B". These subsystems will be obtained by dividing the three-DOF system into two parts by separating the middle mass into two arbitrary segments, as shown in figure 3B.10-5. Subsystem "A" may be considered to represent a two-DOF foundation model from which the foundation impedances $k^*(\omega) + i\omega c^*(\omega)$ and the modified "free-field" motion z(t) can be determined. Subsystem "B" may be considered as a single DOF structural model with a base mass supported on subsystem "A". The interaction system is thus obtained by coupling subsystem "B" with the foundation impedance that can be derived from subsystem "A". The response of this interaction system subjected to the free-field motion z(t) can then be evaluated.

Theoretically, the response of the three-DOF system as evaluated by both approaches should be identical with each other for the top and the middle masses. This is proven in paragraph 3B.10.3.2.3.

3B.10.3.2.2 Problem Parameters

The analysis was carried out using the following values for the three-DOF system:

	Mass ($k\text{-}s^2/ft$)	Damping (k-s/ft)	Stiffness (k/ft)
1	100	200	10,000
2	200	2,000	100,000
3	200	2,000	100,000

See figure 3B.10-4.

As can be seen, the damping values c_1, c_2, and c_3 were so chosen that the damping matrix of the three-DOF system is proportional to the stiffness matrix. This enables the modal superposition method to be used for an exact time-history solution; it also allows the division of the model without distorting the damping characteristics.

The interaction system in the second case was obtained by arbitrarily splitting the middle mass m_2 into two parts, m_2' (10 $k\text{-}s^2/ft$) and m_2'' (190 $k\text{-}s^2/ft$), for subsystems "A" and "B", respectively. See figure 3B.10-5.

The input acceleration time-history $\ddot{z}(t)$ is shown in figure 3B.10-6. It is the Bechtel Synthetic time-history (H1) with 4800 points sampled at every 0.005 second. The modified

"free-field" motion $\ddot{z}(t)$ calculated from $\ddot{z}(t)$ is shown in figure 3B.10-7. The impedance functions $k^*(\omega)$ and $c^*(\omega)$ of the lower structure that were computed from subsystem "A" are shown in figure 3B.10-8. See paragraphs 3B.10.3.2.3 and 3B.10.3.2.5.

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Parameters	Definition	Units
m	lumped mass	k-s^2/ft
c	damping	k-s/ft
k	stiffness	k/ft
ω	frequency	rad/s
β	damping ratio	fraction of critical
z(t)	base motion of three-DOF model	ft/s^2
$\ddot{\bar{z}}(t)$	modified base motion for two-DOF model used by FOSIN	ft/s^2
x	relative displacement of lumped masses	ft
u	absolute displacement of lumped masses	ft
[E]	$[m]^{-1}[k] - w^2[I]$	
[V]	unnormalized eigenvector	
[ϕ]	orthonormalized eigenvector	
[M]	$[f]^T[m]\ [f]$	
[K]	$[f]^T[k]\ [f]$	
[C]	$[f]^T[c]\ [f]$	

L_n participation factor

Ω_n modal mass

3B.10.3.2.3 The Interaction Analysis of a Three-DOF System (Taken from the Theoretical Manual for the Computer Program FASS, CE933, by W. S. Tseng)[4]

3B.10.3.2.3.1 Introduction. In this paragraph (3B.10.3.2), it will be shown that under the base input motion z(t), the response of the three-DOF system as a whole (figure 3B.10-4), is identical to that of an interaction system derived from splitting the three-DOF system into two subsystems, "A" and "B", as shown in figure 3B.10-5. The middle mass, m2, can be divided into and in any proportion for subsystems "A" and "B", respectively. Subsystem "A" may be considered as a two DOF foundation model from which the foundation impedances

and the response motion (t), resulting from the input motion (t) prescribed at the base, can be obtained. Subsystem "B" represents a single DOF structural system with a base mass supported on subsystem "A". By coupling the foundation impedances derived from subsystem "A" with the structural model represented by subsystem "B", an equivalent interaction system is formed and its response under the "free-field" input (t) can be calculated.

To show the equivalence of the two systems, it suffices to consider only their frequency responses.

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A. Response of the three-DOF System as a Whole

The equation of motion can be separated into two parts for subsystem "A" and subsystem "B". The equations of motion for subsystem "A" subjected to the input motion $\ddot{z}(t)$ at its base can be written as:

$$\begin{bmatrix} m_1 & & \\ & m_2 & \\ & & m_3 \end{bmatrix} \begin{Bmatrix} x_1 \\ x_2 \\ x_3 \end{Bmatrix} + \begin{bmatrix} c_1 & -c_1 & \\ -c_1 & c_1 + c_2 & -c_2 \\ & -c_2 & c_2 + c_3 \end{bmatrix} \begin{Bmatrix} x_1 \\ x_2 \\ x_3 \end{Bmatrix}$$

$$+ \begin{bmatrix} k_1 & -k_1 & \\ -k_1 & k_1+k_2 & -k_2 \\ & -k_2 & k_2+k_3 \end{bmatrix} \begin{Bmatrix} x_1 \\ x_2 \\ x_3 \end{Bmatrix} = - \begin{Bmatrix} m_1 \\ m_2 \\ m_3 \end{Bmatrix} \ddot{z}(t) \tag{1}$$

where x_i, i=1, 2, 3 is the displacement of mass point i relative to the input motion z(t). The total displacement u_i, i=1, 2, 3 is determined by the relation:

$$\begin{Bmatrix} u_1 \\ u_2 \\ u_3 \end{Bmatrix} = \begin{Bmatrix} x_1 \\ x_2 \\ x_3 \end{Bmatrix} + \begin{Bmatrix} 1 \\ 1 \\ 1 \end{Bmatrix} z(t) \tag{2}$$

The frequency response of the system can be obtained by considering the input motion $\ddot{z}(t)$ to be the linear combination of harmonic motions $e^{i\omega t}$ at each frequency, ω, i.e.,

$$\ddot{z}(t) = Z(\omega)e^{i\omega t} \qquad (3)$$

Let:

$$\begin{Bmatrix} x_1 \\ x_2 \\ x_3 \end{Bmatrix} = \begin{Bmatrix} X_1 \\ X_2 \\ X_3 \end{Bmatrix} e^{i\omega t}; \quad \begin{Bmatrix} u_1 \\ u_2 \\ u_3 \end{Bmatrix} = \begin{Bmatrix} U_1 \\ U_2 \\ U_3 \end{Bmatrix} e^{i\omega t}$$

$$\begin{Bmatrix} \ddot{x}_1 \\ \ddot{x}_2 \\ \ddot{x}_3 \end{Bmatrix} = \begin{Bmatrix} \ddot{X}_1 \\ \ddot{X}_2 \\ \ddot{X}_3 \end{Bmatrix} e^{i\omega t}; \quad \begin{Bmatrix} \ddot{u}_1 \\ \ddot{u}_2 \\ \ddot{u}_3 \end{Bmatrix} = \begin{Bmatrix} \ddot{U}_1 \\ \ddot{U}_2 \\ \ddot{U}_3 \end{Bmatrix} e^{i\omega t} \qquad (4)$$

and let:

$$\begin{aligned} s_1 &\circ\ k_1 + i\omega c_1 \\ s_2 &\circ\ k_2 + i\omega c_2 \qquad (5) \\ s_3 &\circ\ k_3 + i\omega c_3 \end{aligned}$$

The equations of motion in frequency domain become:

$$\begin{bmatrix} (s_1 - \omega^2 m_1) & -s_1 & \\ -s_1 & (s_1 + s_1 - \omega^2 m_2) & -s_2 \\ & -s_2 & (s_2 + s_3 - \omega^2 m_3) \end{bmatrix} \begin{Bmatrix} X_1 \\ X_2 \\ X_3 \end{Bmatrix}$$

$$= -\begin{Bmatrix} m_1 \\ m_2 \\ m_3 \end{Bmatrix} Z \qquad (6)$$

Solving equation 6 gives the frequency responses X_1, X_2 in the following form:

$$X_1 = \frac{-(M_1 + m_1)}{s_1 - (K_1 + \omega^2 m_1)} Z$$
$$X_2 = \frac{-\left[K_1 m_1 + M_1 (s_1 - \omega^2 m_1)\right]}{s_1(s_1 - K_1 - \omega^2 m_1)} Z \qquad (7)$$

where:

$$K_1 = \frac{s_1^2}{s_1 + s_2 - (K_2 + \omega^2 m_2)} \qquad (8)$$

$$M_1 = \frac{s_1(M_2 + m_2)}{s_1 + s_2 - (K_1 + \omega^2 m_2)}$$

and

$$K_2 = \frac{s_2^2}{s_2 + s_3 - \omega^2 m_3} \qquad (9)$$

$$M_2 = \frac{s_2 m_3}{s_2 + s_3 - \omega^2 m_3}$$

By equations 2, 4, and 7, the absolute acceleration responses $\ddot{U}_1$ and $\ddot{U}_2$ in the frequency domain can be expressed as:

$$\ddot{U}_1 = \ddot{X}_1 + Z = \frac{s_1 - K_1 + \omega^2 M_1}{s_1 - (K_1 + \omega^2 m_1)} Z \qquad (10)$$

$$\ddot{U}_2 = \ddot{X}_2 + Z =$$

$$\frac{s_1(s_1 - K_1 - \omega^2 m_1 + \omega^2 M_1) + \omega^2 m_1 (K_1 - \omega^2 M_1)}{s_1(s_1 - K_1 - \omega^2 m_1)} Z$$

B. Response of the Interaction System

The equations of motion 1 can be separated into two parts for subsystem "A" and subsystem "B". The equations of motion for subsystem "A" subjected to the input motion $\ddot{z}(t)$ at its base can be written as:

$$\begin{bmatrix} m_2' & \\ & m_3 \end{bmatrix} \begin{Bmatrix} \ddot{x}_2 \\ \ddot{x}_3 \end{Bmatrix} + \begin{bmatrix} c_2 & -c_2 \\ -c_2 & c_2+c_3 \end{bmatrix} \begin{Bmatrix} \dot{x}_2 \\ \dot{x}_3 \end{Bmatrix} \tag{11}$$

$$+ \begin{bmatrix} k_2 & -k_2 \\ -k_2 & k_2+k_3 \end{bmatrix} \begin{Bmatrix} x_2 \\ x_3 \end{Bmatrix} = -\begin{Bmatrix} m_2' \\ m_3 \end{Bmatrix} \ddot{z}(t) + \begin{Bmatrix} f_2(t) \\ 0 \end{Bmatrix}$$

where $f_2(t)$ is the interaction force acting on m_2' from subsystem "B". Using the notations introduced previously, equation 11 in the frequency domain becomes:

$$\begin{bmatrix} s_2-\omega^2 m_2' & -s_2 \\ -s_2 & s_2+s_3-\omega^2 m_3) \end{bmatrix} \begin{Bmatrix} X_2 \\ X_3 \end{Bmatrix} = -\begin{Bmatrix} m_2' \\ m_3 \end{Bmatrix} Z$$

$$+ \begin{Bmatrix} F_2(\omega) \\ 0 \end{Bmatrix} \tag{12}$$

where $F_2(\omega)$ is the harmonic component of $f_2(t)$ at frequency ω; i.e., $f_2(t) = F_2(\omega)\ e^{i\omega t}$.

By reduction of equation 12, the following expression is obtained:

$$F_2(\omega) = (s_2 - K_2 - \omega^2 m_2') X_2 + (M_2 + m_2') Z \qquad (13)$$

By definition, the impedance $K_2^*(\omega)$ of subsystem "A" can be obtained from equation 13 by putting Z = 0, i.e.,

$$F_2(\omega) = K_2^* (\omega) X_2$$

where: (14)

$$K_2^*(\omega) = s_2 - K_2 - \omega^2 m_2' = k_2^*(\omega) + i\omega c_2^*(\omega)$$

Again, by definition, the free-field motion $\ddot{z}(t)$ of subsystem "A" is the absolute acceleration response of mass m_2' when $f_2(t) = 0$. Thus putting $F_2(\omega) = 0$ in equation 13 gives:

$$X_2 = \frac{-(M_2 + m_2')}{s_2 - k_2 - \omega^2 m_2'} Z \qquad (15)$$

Let $\ddot{z}(t) = \overline{Z} e^{i\omega t}$, hence;

$$\overline{Z} = \omega^2 X_2 + Z = \frac{s_2 - k_2 + \omega^2 M_2}{s_2 - k_2 - \omega^2 m_2'} Z \qquad (16)$$

$\overline{Z}$ is the "free-field" motion in the frequency domain.

The equations of motion for the interaction system formed by coupling the impedance $K_2^*(\omega)$ with subsystem "A" subjected to the "free-field" motion $\ddot{z}(t)$ are:

$$\begin{bmatrix} m_1 & \\ & m_2'' \end{bmatrix} \begin{Bmatrix} \ddot{x}_1 \\ \ddot{x}_2 \end{Bmatrix} + \begin{bmatrix} c_1 & -c_1 \\ -c_1 & c_1 + c_2^*(\omega) \end{bmatrix} \begin{Bmatrix} \dot{x}_1 \\ \dot{x}_2 \end{Bmatrix}$$

$$+\begin{bmatrix} k_1 & -k_1 \\ -k_1 & k_1 + k_2^{*}(\omega) \end{bmatrix} \begin{Bmatrix} \bar{x}_1 \\ \bar{x}_2 \end{Bmatrix} = - \begin{Bmatrix} m_1 \\ m_2'' \end{Bmatrix} \ddot{\bar{z}}\,(t) \qquad (17)$$

where $\bar{x}_1$ and $\bar{x}_2$ are the displacements of m_1 and m_2'', respectively, relative to the free-field input motion $\ddot{\bar{z}}\,(t)$, and where $m_2'' = m_2 - m_2'$. The absolute displacements $\bar{u}_1$ and $\bar{u}_2$ of m_1 and m_2'' can be determined by:

$$\bar{u}_1 = \bar{x}_1 + \bar{z}(t) \qquad (18)$$

$$\bar{u}_2 = \bar{x}_2 + \bar{z}(t)$$

Let:

$$\begin{Bmatrix} \bar{x}_1 \\ \bar{x}_2 \end{Bmatrix} = \begin{Bmatrix} \bar{X}_1 \\ \bar{X}_2 \end{Bmatrix} e^{i\omega t} \qquad (19)$$

Thus equation 17 in the frequency domain becomes:

$$\begin{bmatrix} s_1 - \omega^2 m_1 & -s_1 \\ -s_1 & s_1 + k_2^{*}(\omega) \end{bmatrix} \begin{Bmatrix} \bar{X}_1 \\ \bar{X}_2 \end{Bmatrix} = \bar{Z} \begin{Bmatrix} m_1 \\ m_2'' \end{Bmatrix} \qquad (20)$$

Solving equation 20 for $\bar{X}_1$ and $\bar{X}_2$, and noting equation 14 gives:

$$\bar{X}_1 = \frac{-(m_1 + M_1'')}{s_1 - k_1 - \omega^2 m_1} \bar{Z} \qquad (21)$$

$$\overline{X}_2 = \frac{\omega^2(k_1 m_1 + s_1 M_1'' - \omega^2 m_1 M_1''}{s_1(s_1 - k_1 - \omega^2 m_1)} \overline{Z}$$

where:

$$M_1'' = \frac{s_1 m_2''}{s_1 + s_2 - k_2 - \omega^2 m_2} \tag{22}$$

Let:

$$\left\{\begin{matrix} \ddot{u}_1 \\ \\ \ddot{u}_2 \end{matrix}\right\} \left\{\begin{matrix} \ddot{\overline{U}}_1 \\ \\ \ddot{\overline{U}}_2 \end{matrix}\right\} e^{i\omega t}, \left\{\begin{matrix} \ddot{x}_1 \\ \\ \ddot{x}_2 \end{matrix}\right\} \left\{\begin{matrix} \ddot{\overline{X}}_1 \\ \\ \ddot{\overline{X}}_2 \end{matrix}\right\} e^{i\omega t} \tag{23}$$

Hence:

$$\begin{aligned} \ddot{\overline{U}}_1 &= \ddot{\overline{X}}_1 + \overline{Z} = \frac{s_1 - K_1 + \omega^2 m_1''}{s_1 - K_1 - \omega^2 m_1} \overline{Z} \\ \ddot{\overline{U}}_2 &= \ddot{\overline{X}}_2 + \overline{Z} = \left[\frac{\omega^2(K_1 m_1 + s_1 M_1'' - \omega^2 m_1 M_1''}{s_1(s_1 - K_1 - \omega^2 m_1)} + 1\right] \overline{Z} \end{aligned} \tag{24}$$

which, after substituting the expressions for M_1'' and $\overline{Z}$ from equations 16 and 22, become:

$$\begin{aligned} \ddot{\overline{U}} &= \frac{s_1 - K_1 - \omega^2 M_1}{s_1 - K_1 - \omega^2 m_1} Z \\ \ddot{\overline{U}}_2 &= \frac{(s_1 - \omega^2 m_1)\,(s_2 - K_2 + \omega^2 M_2)}{(s_1 - K_1 - m_1\omega_1^2)\,(s_1 + s_2 - K_2 - \omega^2 m_2)} Z \end{aligned} \tag{25}$$

By comparing $\ddot{U}_1$ and $\ddot{U}_2$ in equation 10 with $\ddot{\overline{U}}_1$ and $\ddot{\overline{U}}_2$ in equation 25, it is easily seen that:

$$\ddot{U}_1 = \dddot{U}_1$$
$$\ddot{U}_2 = \dddot{U}_2 \qquad (26)$$

Thereby, the objective of this section has been proved.

3B.10.3.2.4 Solution of the Three Degrees of Freedom, Fixed Base Model

The dynamic equation of motion is:

$$|m|\{\ddot{x}\} + |c|\{\dot{x}\} + |k|\{x\} = -\{m\}\ddot{z}(t)$$

where:

$$|m| = \begin{vmatrix} m_1 & 0 & 0 \\ 0 & m_2 & 0 \\ 0 & 0 & m_3 \end{vmatrix} = \begin{vmatrix} 100 & 0 & 0 \\ 0 & 200 & 0 \\ 0 & 0 & 200 \end{vmatrix} \frac{kip - s^2}{ft}$$

$$|m|^{-1} = \frac{1}{200}\begin{vmatrix} 2 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{vmatrix} \frac{ft}{kip - s^2}$$

$$|k| = \begin{vmatrix} k_1 & -k_1 & 0 \\ -k_1 & (k_1+k_2) & -k_2 \\ 0 & -k_2 & (k_2+k_3) \end{vmatrix} = 10^4 \begin{vmatrix} 1 & -1 & 0 \\ -1 & 11 & -10 \\ 0 & -10 & 20 \end{vmatrix} \frac{kip}{ft}$$

$$|c| = \begin{vmatrix} c_1 & -c_1 & 0 \\ -c_1 & (c_1+c_2) & -c_2 \\ 0 & -c_2 & (c_2+c_3) \end{vmatrix} = 10^2 \begin{vmatrix} 2 & -2 & 0 \\ -2 & 22 & -20 \\ 0 & -20 & 40 \end{vmatrix} \frac{kip - s}{ft}$$

$$\{m\} = \begin{Bmatrix} 100 \\ 200 \\ 200 \end{Bmatrix} \qquad \{x\} = \begin{Bmatrix} x_1 \\ x_2 \\ x_3 \end{Bmatrix}$$

For the free vibration response [c] = 0, $\ddot{z}(t) = 0$

$$[m]^{-1}\,[m]\,\{\ddot{x}\} + [m]^{-1}\,[k]\,\{x\} = 0$$

$$[I]\,\{\ddot{x}\} + [m]^{-1}\,[k]\,\{x\} = 0$$

Let $\{x\} = \{A\}e^{i\omega t}$ then:

$$-\omega^2[I]\{A\}e^{i\omega t} + [m]^{-1}[k]\{A\}e^{i\omega t} = 0$$

$$\left[[m]^{-1}\,[k] - \omega^2\,[I]\right]\{A\}e^{i\omega t} = 0$$

$$[m]^{-1}\,[k]\,-\omega^2\,[I] = 0 \text{ for } \{A\}e^{i\omega t} \neq 0$$

To solve the above equation for our particular problem, first find $[m]^{-1}$ [k]. After making the appropriate matrix operations, the result is:

$$[m]^{-1}\,[k] = 50 \begin{vmatrix} 2 & -2 & 0 \\ -1 & 11 & -10 \\ 0 & -10 & 20 \end{vmatrix}$$

Let $\lambda = \dfrac{\omega^2}{50} => \omega = \sqrt{50\lambda}$

Then:

$$50\begin{vmatrix} 2-\lambda & -2 & 0 \\ -1 & 11-\lambda & -10 \\ 0 & -10 & 20-\lambda \end{vmatrix} = [m]^{-1}\ [k] - \omega^2\ [I] = 0$$

The characteristic equation to be solved for the eigenvalues is:

$$\lambda^3 - 33\lambda^2 + 180\lambda - 200 = 0$$

The solutions for λ are:

$$\lambda_1 = 1.5100 \qquad \omega_1 = 8.68909 \text{ rad/s}$$

$$\lambda_2 = 5.0000 \quad \Rightarrow \quad \omega_2 = 15.81139$$

$$\lambda_3 = 26.4900 \qquad \omega_3 = 36.39368$$

To find the mode shapes let:

$$[m]^{-1}\ [k]\ -\omega^2\ [I] = [E] = 0$$

Now partition [E] in the following form:

$$[E] = \left|\begin{array}{c:c} E_{11}' & E_{10} \\ (1x1) & (1x2) \\ \hdashline E_{01} & E_{00} \\ 2x1 & 2x2 \end{array}\right| = 0$$

To find the mode shapes let the first unknown be 1:

$$\begin{vmatrix} E_{11} & E_{10} \\ E_{01} & E_{00} \end{vmatrix} \begin{Bmatrix} 1 \\ V_{on} \end{Bmatrix} = 0$$

Solving the second equation for $\{V_{on}\}$ yields:

$$\{V_{on}\} = -[E_{00}]^{-1} \{E_{01}\}$$

This equation will yield the eigenvectors.

For $\lambda = 1.51$:

$$[E_{00}] = \begin{bmatrix} (11-1.51) & -10 \\ -10 & (20-1.51) \end{bmatrix} = \begin{bmatrix} 9.49 & -10 \\ -10 & 18.49 \end{bmatrix}$$

$$[E_{00}]^{-1} = \frac{1}{75.47} \begin{vmatrix} 18.49 & 10 \\ 10 & 9.49 \end{vmatrix}$$

and $\{E_{01}\} = \begin{Bmatrix} -1 \\ 0 \end{Bmatrix}$

$\{V_{01}\}$ may now be found

$$\{V_{01}\} = \frac{-1}{75.49} \begin{vmatrix} 18.49 & 10.00 \\ 10.00 & 9.49 \end{vmatrix} \begin{Bmatrix} -1 \\ 0 \end{Bmatrix} = \begin{Bmatrix} 0.2450 \\ 0.1325 \end{Bmatrix}$$

The complete eigenvector may be written as:

$$\{V_1\} = \begin{Bmatrix} 1.0000 \\ 0.2450 \\ 0.1325 \end{Bmatrix}$$

In a similar manner $\{V_2\}$ and $\{V_3\}$ may be found. The results are:

$$\{V_2\} = \begin{Bmatrix} 1.0000 \\ -1.5000 \\ -1.0000 \end{Bmatrix} \qquad \{V_3\} = \begin{Bmatrix} 1.0000 \\ -12.2430 \\ 18.8644 \end{Bmatrix}$$

The matrix of mode shapes [V] is then:

$$[V] = \begin{vmatrix} 1.0000 & 1.0000 & 1.0000 \\ 0.2450 & -1.5000 & -12.2430 \\ 0.1325 & -1.0000 & 18.8644 \end{vmatrix}$$

To orthonormalize the matrix of eigenvectors, first find:

$$(M_n)^{1/2} = \left[\sum_{i-1}^{3} V_{in}^{\ 2}\ m_1\right]^{1/2}$$

Substituting the values yields:

$$(M_1)^{1/2} = \left[(1)^2(100) + (.2450)^2(200) + (.1325)^2(200)\right]^{1/2}$$

$$= 10.7480\ \text{Kips}^2/\text{ft}$$

$$(M_2)^{1/2} = \left[(1)^2(100) + (-1.5)^2(200) + (-1)^2(200)\right]^{1/2}$$

$$= 27.3861$$

$$(M_3)^{1/2} = \left[(1)^2(100) + (-12.2430)^2(200) + (18.8644)^2(200)\right]^{1/2}$$

$$= 318.2001$$

The orthonormalized mode shape matrix [ϕ] may now be found by using the relationship $\{\phi_n\} = \dfrac{1}{M_n^{1/2}}\{V_n\}$

This relationship yields the following matrix of mode shapes stored in columns:

$$[\phi] = \begin{vmatrix} 0.093041 & -0.036515 & 0.003143 \\ 0.022795 & -0.054772 & -0.038476 \\ 0.012328 & -0.036515 & 0.059285 \end{vmatrix}$$

Now by introducing the relationship $\lceil C \rfloor = [\phi]^T [c] [\phi]$ and making the indicated matrix multiplications the diagonal modal damping matrix is formed. The result is:

$$\lceil C \rfloor = \begin{vmatrix} 1.51 & 0.00 & 0.00 \\ 0.00 & 5.00 & 0.00 \\ 0.00 & 0.00 & 26.49 \end{vmatrix}$$

Note that this result could have also been obtained in a much simpler manner by making use of the knowledge that the [k] and [c] matrix are proportional.

$$\lceil C \rfloor = [\phi]^T \alpha [k] [\phi] \qquad \text{where } [c] = \alpha [k] \qquad \alpha = 1/50$$

$$= \alpha [\phi]^T [k] [\phi]$$

$$= \alpha [K] \qquad \text{where } [K] = [\phi]^T [k][\phi]$$

$$= a \lceil w^2 \rfloor [M] \qquad \text{where } [M] = [I]$$

$$[K] = \lceil \omega^2 \rfloor [M]$$

$$\lceil c \rfloor = \alpha \lceil \omega^2 \rfloor = \begin{vmatrix} 75.50/50 & 0 & 0 \\ 0 & 250/50 & 0 \\ 0 & 0 & 1324.5/50 \end{vmatrix}$$

Now that the modal damping matrix has been obtained, the damping ratio β for each mode may be found in the following manner:

$$C_n = 2\beta_n \omega_n M_n$$

Recall that $[M] = [\phi]^T [m] [\phi] = [I]$. This is due to the orthonormalization of $[\phi]$, so $M_n = 1$. Then solving for β_n yields:

$$\beta_n = \frac{C_n}{2\omega_n} = \frac{\alpha\omega_n 2}{2\omega_n} = \frac{\omega_n}{100}$$

$\beta_1 = 0.086891$ (fraction of critical)

$\beta_2 = 0.158114$

$\beta_3 = 0.363937$

An estimate of the damped frequency of vibration may be found by the approximate relationship.

$$\omega_n^D = \omega_n \sqrt{1 - \beta_n^2}$$

$$\omega_1^D = 8.68909 \sqrt{1 - (0.0868909)^2} = 8.65623 \text{ rad/s}$$

Similarly:

$$\omega_2^D = 15.61250 \text{ rad/s}$$

$$\omega_3^D = 33.89793 \text{ rad/s}$$

To complete this analysis, the modal participation factors and the modal masses will be calculated. Recall that the participation factors may be obtained by the relationship:

$$L_n \equiv \phi_n^T [m] \{1\}$$

By making the appropriate substitution for n=1

$$L_1 = \begin{Bmatrix} 0.093041 \\ 0.022795 \\ 0.012328 \end{Bmatrix}^T \begin{bmatrix} 100 & 0 & 0 \\ 0 & 200 & 0 \\ 0 & 0 & 200 \end{bmatrix} \begin{Bmatrix} 1 \\ 1 \\ 1 \end{Bmatrix}$$

$$= 9.3041 + 4.559 + 2.4656$$

$$L_1 = 16.3287$$

Similarly:

$$L_2 = -14.6059$$

$$L_3 = 4.4761$$

Now the modal masses may be found by:

$$\Omega n = L_n^2$$

so:

$$\Omega_1 = 266.63$$

$$\Omega_2 = 213.33$$

$$\Omega_3 = 20.04$$

Note that $\sum_{i=1}^{n} \Omega_n = 500$ and is equal to the total mass of the system as would be expected.

3B.10.3.2.5 The Impedance Function of Substructure "A"

The equation of motion is:

$$\begin{bmatrix} m'_2 & 0 \\ 0 & m_3 \end{bmatrix} \begin{Bmatrix} \ddot{x}_2 \\ \ddot{x}_3 \end{Bmatrix} + \begin{bmatrix} c_2 & -c_2 \\ -c_2 & c_2 - c_3 \end{bmatrix} \begin{Bmatrix} \dot{x}_2 \\ \dot{x}_3 \end{Bmatrix} + \begin{bmatrix} k_2 & -k_2 \\ -k_2 & k_2 + k_3 \end{bmatrix} \begin{Bmatrix} x_2 \\ x_3 \end{Bmatrix} = \begin{Bmatrix} e^{i\omega t} \\ 0 \end{Bmatrix}$$

let $x_2 = Ae^{i\omega t}$ and $x_3 = Be^{i\omega t}$

then $\dot{x}_2 = i\omega Ae^{i\omega t}$ $\dot{x}_3 = i\omega Be^{i\omega t}$

x defines the motion relative to the base

$\ddot{x}_2 = -\omega^2 Ae^{i\omega t}$ $\ddot{x}_3 = -\omega^2 Be^{i\omega t}$

Where “A” and “B” are complex constants. By substituting the above quantities into the equation of motion and simplifying yields :

$$\left[-\omega^2 \begin{bmatrix} m'_2 & 0 \\ 0 & m_3 \end{bmatrix} + i\omega \begin{bmatrix} c_2 & -c_2 \\ -c_2 & c_2 + c_3 \end{bmatrix} + \begin{bmatrix} k_2 & -k_2 \\ -k_2 & k_2 + k_3 \end{bmatrix} \right] \begin{Bmatrix} A \\ B \end{Bmatrix} = \begin{Bmatrix} 1 \\ 0 \end{Bmatrix}$$

Combining terms yields:

$$\begin{bmatrix} (-\omega^2 m'_2 + i\omega c_2 + k_2) & (-i\omega c_2 - k_2) \\ (i\omega c_2 - k_2) & (-\omega^2 m_3 + i\omega\ (c_2 + c_3) + k_2 + k_3) \end{bmatrix} \begin{Bmatrix} A \\ B \end{Bmatrix} = \begin{Bmatrix} 1 \\ 0 \end{Bmatrix}$$

$$\text{let } [D] = \begin{bmatrix} (-\omega^2 m'_2 + i\omega c_2 + k_2) & (-i\omega c_2 - k_2) \\ (-i\omega c_2 - k_2) & (-\omega^2 m_3 + i\omega(c_2 + c_3) + k_2 + k_3) \end{bmatrix}$$

The determinent of [D] is

$$\left| D \right| = (-\omega^2 m'_2 + k_2 + i\omega c_2)\ (-\omega^2 m_3 + k_2 + k_3 + i\omega(c_2 + c_3)$$

$$- (k_2 + i\omega c_2)^2 = (-\omega^2 m'_2 + k_2)\ (-\omega^2 m_3 + k_2$$

$$+ k_3)\ -\omega^2 c_2(c_2 + c_3)\ - k_2^2 + \omega^2 c_2^2 + i\omega c_2(-\omega^2 m_3$$

$$+ k_2 + k_3) + i\omega(c_2 + c_3)(-\omega^2 m_2' + k_2) - 2i\omega c_2 k_2$$

$$= (k_2 - \omega^2 m_2')(k_2 + k_3 - \omega^2 m_3) - \omega^2 c_2(c_2 + c_3) - k_2^2 + \omega^2 c_2^2$$

$$+ i\omega(c_2(k_2 + k_3 - \omega^2 m_3) + (c_2 + c_3)(k_2 - \omega^2 m_2') - 2c_2 k_2)$$

let $\Delta_1 = k_2 + k_3 - \omega^2 m_3$

$\Delta_2 = \omega(c_2 + c_3)$

$\Delta_3 = \Delta_1(k_2 - \omega^2 m_2') - \Delta_2 \omega c_2 - k_2^2 + \omega^2 c_2^2$

$\Delta_4 = \Delta_1 \omega c_2 + \Delta_2(k_2 - \omega^2 m_2') - 2\, k_2 \omega c_2$

The determinant of [D] can now be written:

$$|D| = \Delta_3 + i\Delta_4$$

The inverse of [D] is then:

$$[D]^{-1} = \frac{\begin{vmatrix} (\Delta_1 + 1\Delta_2) & (k_2 + i\omega c_2) \\ (k_2 + i\omega c_2) & (k_2 - \omega^2 m_2 + i\omega c_2) \end{vmatrix}}{\Delta_3 + i\Delta_4}$$

The complex constant "A" may now be determined from:

$$\begin{Bmatrix} A \\ B \end{Bmatrix} = [D]^{-1} \begin{Bmatrix} 1 \\ 0 \end{Bmatrix}$$

$$A = \frac{\Delta_1 + i\Delta_2}{\Delta_3 + i\Delta_4}$$

Note that the complex constant "B" is identically zero.

Since “A” is a compliance term and we are interested in the impedances, the inverse relation of “A” must be found.

$$I = \frac{1}{A} = \frac{\Delta_3 + i\Delta_4}{\Delta_1 + i\Delta_2} = \frac{(\Delta_3 + i\Delta_4)(\Delta_1 - i\Delta_2)}{\Delta_1^2 + \Delta_2^2}$$

$$I = \frac{\Delta_1\Delta_3 + \Delta_2\Delta_4}{\Delta_1^2 + \Delta_2^2} + i\left(\frac{\Delta_1\Delta_4 + \Delta_2\Delta_3}{\Delta_2^2 + \Delta_2^2}\right)$$

$$I_{REAL} = \frac{\Delta_1\Delta_3 - \Delta_2\Delta_4}{\Delta_1{}^2 + \Delta_2{}^2} \text{ (equivalent spring)}$$

$$I_{IM} = \frac{\Delta_1\Delta_4 - \Delta_2\Delta_3}{\Delta_1{}^2 + \Delta_2{}^2} \text{ (equivalent spring)}$$

Now all the variables but ω are known for the above relations, so ω will be varied over the frequency range of interest and a table of impedances will then be generated for use with the FOSIN analysis. See computer programs “D” and “E”. For convenience the values used are listed in table 3B.10-3.

3B.10.3.2.6 Comparison of the Results

The FOSIN impedance approach and the theoretical solutions of the complete three-mass model yielded the following frequencies.

Frequency (rad/s)

Mode	Exact	FOSIN	Error %
1	8.6891	8.6911	.02
2	15.811	15.935	.78
3	36.394	---	

A comparison of the mode shapes, time-history responses, and response spectra analysis of m1 and m2 can be found in figures 3B.10-6, 3B.10-7, and 3B.10-9 through 3B.10-14. In general, the comparisons of the mode shapes and response spectra are very good. The results obtained by comparing the two runs for the shape of the first mode and the response of the first mass were found to be almost identical. As would be expected for this small model, the results begin to deteriorate for the response of the second mass.

The pseudo damping values that were obtained by the FOSIN analysis can be found on figure 3B.10-9. The difference in the first mode damping value was found to be only 4%; however, for the second mode the difference is about 40%. So it appears that for some models the correspondence between the actual and the pseudo damping computed by FOSIN may be considerably different. This may be due to our oversimplification of the problem, in that we are only looking at one of the terms associated with the dissipation of the energy in the system while we are neglecting the effect of the phasing inherent in the real and imaginary parts of the response. The important

point to make here is that the response of the model is the same.

3B.10.3.2.7 Conclusions

While the results found here are very good, considering the severity of the modeling constraints, it was decided to rerun the analysis using the same procedure on a larger model. The new fixed-base model will consist of 10 mass points and again the second mass up from the fixed-base will be the division point to form the two substructures. This will provide an eight-mass structural model to compare the interaction impedance solution of FOSIN to the full structure solution of SUPER SMIS.

3B.10.3.2.8 List of Computer Runs

Run "A": Run SUPER SMIS to analyze the complete three-mass system of figure 3B.10-4 that will be subjected to the Bechtel Synthetic Time-History H1 and obtain the time-histories of m1.

Run "B": Run SUPER SMIS to analyze subsystem "A" of figure 3B.10-5 that will be subjected to the Bechtel Synthetic Time-History H1 and obtain the absolute acceleration z(t) of for input into run "E".

Run "C": Run SPECTRA to obtain the response spectra of the input motion H1, the time-history response of m1 from run "A".

Run "D": Run IMPEDANCE to analyze the complex impedances and for use in run "E".

Run "E": Run FOSIN to analyze subsystem "B" using z(t) from run "B" and the substructure impedances from run "D". Obtain the time-history of m1.

Run "F": Run SPECTRA to obtain the response spectra of the time-history for m1 from run "E".

3B.10.3.3 FOSIN Example 3, Comparison of a 10-Mass Base with an Equivalent Eight-Mass Interaction System

This problem is an extension of the three-mass model used in paragraph 3B.10.3.2. It may be observed that the lower portion of the 10-mass model is identical to model "A" of the three-mass model previously used. By keeping the lower portions of both models identical to each other, there will be no need to recalculate the substructure impedance properties that must be input into FOSIN. This more extensive model should provide some insight into how accurately a more realistic model is handled by FOSIN.

For a more detailed analysis of a similar problem, please refer to the analysis of the three-mass model of paragraph 3B.10.3.2.

The following calculations will be performed in the process of exercising this problem:

A. A SUPER SMIS analysis of the complete 10-mass system subjected to a vertical excitation to produce:

- The system frequencies

- Mode shapes
- Modal damping ratios
- Time-history analysis

B. A FOSIN analysis of the interaction system using the substructure impedances and modified input motion z(t) to calculate all the items of listing A above.

C. A comparison of the response spectra for the time-histories generated for each mass by both the SUPER SMIS and FOSIN programs.

3B.10.3.3.1 Problem Description

Consider a 10-mass system, having only vertical translation degrees of freedom, which is subjected to a base excitation (t). (See figure 3B.10-13.) This system will be divided into two subsystems that will be designated as subsystem "A" and subsystem "B". (See figure 3B.10-14.) Subsystem "A" will be used to model the foundation. From subsystem "A" can be derived the impedance relationships of the foundation model as well as the modified base input motion (t). Since subsystem "A" for this problem is the same as that used in paragraph 3B.10.3.2, there will be no need to recalculate these quantities.

Subsystem "B" is an eight-degree of freedom model that will represent the structural portion of the model. This subsystem will be combined with the impedances of subsystem "A" and input into FOSIN. The results of the FOSIN time-history analysis

will be compared to the time-history analysis of the complete system performed by SUPER SMIS. The equivalence of the two approaches was proven in paragraph 3B.10.3.2. Although the proof was established for a three-mass system, it could be extended to cover any lumped mass system. Refer to paragraph 3B.10.3.2 for a more detailed accounting of the formulation of the three-mass problem.

3B.10.3.3.2 Problem Parameters

The analysis was carried out using the following values for the 10-mass system:

m_1 through m_8 = 100 K-s^2/ft

m_9 , m_{10} = 200 K-s^2/ft

k_1 through k_8 = 10^4 K/ft

k_9, k_{10} = 10^5 K/ft

c_1 through c_8 = 200 K-s/ft

c_9 , c_{10} = 2000 K-s/ft

See paragraph 3B.10.3.2.2 for the specification of the remainder of the parameters of the problem.

3B.10.3.3.3 Comparison of Results

The FOSIN impedance approach and the theoretical solution of the complete 10-mass model yielded the frequencies shown in table 3B.10-4.

As can be seen by table 3B.10-4, the maximum error found in the frequency determination was less than 2%. Also note that the error involved in calculating the first five frequencies was less than 1%.

The mode shapes have been recorded in table 3B.10-5 for comparison. The mode shapes have been normalized so that the responses shown for m1 are matched identically for both cases. It may be observed that the first three modes are identical for the first three significant figures. In general all nine modes agree very well. For convenience the mode shapes have been plotted in figure 3B.10-15.

A comparison of the response spectra of each node was also made. The results may be found in figures 3B.10-16 through 3B.10-23. Note that the only differences are in the high frequency end of the spectrum, and that they are generally very minor.

Of lesser importance, but of some interest, was the comparison of the damping ratios. The comparison of these values may be seen on figure 3B.10-15. The maximum difference was found to be 14% for mode 6.

3B.10.3.3.4 Conclusions

The results shown here for the 10-mass model compare very well. The approximations used by FOSIN give very good answers, especially for the first few frequencies and mode shapes. Since, for all practical purposes, the first few modes are responsible for the majority of the response of the typical

lumped-mass structural model, it can be expected that the FOSIN program will give reasonable and accurate results.

Table 3B.10-4

COMPARISON OF FOSIN IMPEDANCE APPROACH AND THE THEORETICAL SOLUTION OF THE COMPLETE 10-MASS MODEL, FOSIN EXAMPLE 3

MODE	FREQUENCIES RAD/SEC		ERROR
	EXACT	FOSIN	%
1	1.8028	1.8025	0.02
2	5.3421	5.3344	0.14
3	8.6801	8.6473	0.38
4	11.6631	11.585	0.67
5	14.0534	13.938	0.82
6	15.7156	15.477	1.52
7	17.3009	16.976	1.88
8	18.7400	18.389	1.87
9	19.6783	19.290	1.97
10	36.3953	---	---

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Table 3B.10-5

COMPARISON OF MODE SHAPES, FOSIN EXAMPLE 3

	MODE 1		MODE 2		MODE 3	
	EXACT	FOSIN	EXACT	FOSIN	EXACT	FOSIN
1	4.774	4.774	-4.608	-4.608	4.277	4.277
2	4.619	4.619	-3.293	-3.293	1.054	1.055
3	4.314	4.313	-1.038	-1.038	-2.962	-2.965
4	3.868	3.868	1.513	1.513	-4.747	-4.750
5	3.297	3.297	3.632	3.632	-2.955	-2.955
6	2.619	2.619	4.715	4.715	1.063	1.066
7	1.855	1.855	4.453	4.452	4.281	4.284
8	1.032	1.031	2.919	2.919	4.273	4.273
9	0.174	0.174	0.553	0.553	1.046	1.043
10	0.087	---	0.284	---	0.566	---
	MODE 4		MODE 5		MODE 6	
	EXACT	FOSIN	EXACT	FOSIN	EXACT	FOSIN
1	-3.764	-3.764	2.998	2.998	-2.444	-2.444
2	1.356	1.365	-2.923	-2.994	3.592	3.600
3	4.631	4.634	-3.071	-3.009	0.756	0.782
4	1.607	1.588	2.846	2.998	-3.948	-4.050
5	-3.603	-3.623	3.143	3.028	1.098	1.121
6	-3.912	-3.899	-2.768	-3.009	3.432	3.672
7	1.101	1.140	-3.212	-3.053	-2.710	-2.943
8	4.616	4.626	2.687	3.028	-2.158	-2.449
9	1.852	1.808	3.279	3.089	3.724	4.322
10	1.072	---	2.043	---	2.473	---
	MODE 7		MODE 8		MODE 9	
	EXACT	FOSIN	EXACT	FOSIN	EXACT	FOSIN
1	2.260	2.260	-1.648	-1.647	0.853	0.853
2	-4.505	-4.397	4.138	4.100	-2.449	-2.443
3	2.214	1.886	-4.609	-4.456	3.733	3.706
4	2.306	2.648	2.830	2.528	-4.540	-4.470
5	-4.504	-4.423	0.330	0.702	4.768	4.633
6	2.168	1.521	-3.330	-3.586	-4.387	-4.172
7	2.351	3.055	4.704	4.645	3.447	3.148
8	-4.503	-4.476	-3.782	-3.328	-2.066	-1.699
9	2.122	1.161	1.014	0.293	0.421	0.019
10	1.514	---	0.781	---	0.344	---

3B.10.4 REFERENCES

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3. Luco, Juan E. and Westmann, Russell, "Dynamic Response of Circular Footings," J. Appl. Mech., ASME, Vol. 39, Series E, No. 2, June 1972, pp. 527-534.

4. Tseng, W. S., "Soil-Structure Interaction Analysis Using the Fast Fourier Transform Method, The Theoretical Manual or Computer Program CE 933 (FASS)", Technical Report, Bechtel Power Corporation, San Francisco, CA, November 974.

3B.11 STICK COMPUTER PROGRAM (STICK)

In order to evaluate the responses of structures, the effects of soil-structural interactions must be investigated. A computer program named FOSIN was developed for this purpose by LAPD of Bechtel Power Corporation. The program utilizes the FOSS method to solve the problem; the general theory upon which the program is based is explained briefly in the user's manual of FOSIN Version FO.0.

The output of FOSIN computer program consists of: relative accelerations, relative velocity, relative displacement, and/or absolute acceleration for each degree of freedom.

Relative implies relative to base, with the base considered to be fixed. While these outputs very readily provide the response spectra, they are nevertheless rather difficult to use in the design of structural members. Usual modal analysis techniques break down in the formation of soil structural interaction analysis, and SRSS criteria can no longer be applied. A post-processing computer program, STICK, was thus developed with the object of determining the critical condition on the basis of which structural members are to be designed.

In this report, the basic theory for the method of approach is explained and the procedures of solution presented. Application of the method is shown through a number of numerical examples dealing with rigid frame structural system.

STICK COMPUTER PROGRAM (STICK)

3B.11.1 BASIC THEORY AND METHOD OF APPROACH

Linear elastic analysis of structural systems is based upon two assumptions; namely, of small deformation and linear stress-strain relationship. The assumption of small deformation implies linear strain-deformation relationship. Therefore, in the case of horizontal excitation, the strains will increase linearly with horizontal displacements of floors. The assumption of linear stress-strain implies that the internal stresses (forces) of structural members increase proportionately with the increase of horizontal displacement of floors. Particularly, the internal stresses of members between any two adjacent floors will be maximum when the relative horizontal displacement between two floors becomes maximum.

FOSIN computer program will, as mentioned previously, generate the time-history of horizontal displacements of floors. Therefore, finding the critical conditions for members involves no more than establishing the instant at which absolute relative horizontal displacements between adjacent floors is maximum.

FOSIN computer program utilizes a lumped-mass model for analyzing the structural system. Thus, in the case of vertical excitation, the critical condition during whole time-history will be at an instant when relative vertical displacements between two adjacent floors is either maximum (for tension stress) or minimum (for compressive stresses).

3B.11.2 PROCEDURES OF ANALYSIS

It has been concluded that the critical conditions for a member will occur at a moment when the relative displacement between two adjacent floors becomes maximum during whole time history. Thus, in the case of member design between the $(i-1)^{th}$ and i^{th} floor due to horizontal excitation. The first step is to find out a time instant, say Ti, such that the absolute relative horizontal displacement between the $(i-1)^{th}$ and i^{th} floor becomes maximum at t = Ti.

If [Di] be a displacement vector for all floors at a time t = Ti, then the corresponding equivalent force {Fi}, acting at the floors is given by:

$$\{Fi\} = [k]\ \{Di\}$$

where [k] is the stiffness matrix.

Finally, by applying the force vector {Fi} to the actual structural system (as distinct from the lumped mass model), the internal forces in members between the $(i-1)^{th}$ and i^{th} floor can be analyzed. In general, n sets of force vectors may be obtained for an n-floor structure.

The procedure discussed so far may be summarized as follows (for a case of horizontal excitation):

A. Model the structural system as a lumped-mass system - assigning the mass point numbers in sequence starting from the base. Generate the equivalent stiffness matrix [k] of the fixed-base structure.

B. Generate the horizontal displacement time-histories of the floors using FOSIN computer program.

C. Generate displacement matrix [D] whose i^{th} column will be a displacement vector at t = Ti when the absolute relative displacement between $(i-1)^{th}$ and i^{th} floor is maximum.

D. Multiply the displacement matrix {D} by the stiffness matrix {k} and obtain the force matrix {F}. The i^{th} column of force matrix {Fi} will represent the force vector {Fi}. These are the equivalent force acting on the structural system at t = Ti.

E. Apply the force vector {Fi} one at a time to the structure and calculate the members' internal stresses. Use the highest values obtained as design stresses.

3B.11.3 NUMERICAL EXAMPLES AND DISCUSSIONS

To demonstrate the application of the method, rigid frame structures will be analyzed numerically. In the following examples, the structural systems are kept the same but girder moment of inertia is altered.

The structure is first modeled as a lumped mass system and the fixed-base equivalent stiffness matrix generated by CE 917 computer program. Kern County Earthquake (1952) is used for input in FOSIN computer program. STRUDL computer program is then used to calculate members' internal forces.

For convenience, the terms "predicted maximum" and "actual maxi-mum" will be used in the following discussions. The term "predicted maximum" implies the maximum value was obtained according to the criteria of maximum absolute relative displacement as discussed earlier. The term "actual maximum" implies the maximum values actually occurred during the earthquake excitation.

3B.11.4 STICK VERIFICATION (TEST PROBLEMS)

3B.11.4.1 STICK Example 1

Consider the rigid frame structure shown in figure 3B.11-1. The structure is then modeled as a lumped mass system as shown in figure 3B.11-2. Considering the horizontal degree of freedom only, the equivalent stiffness matrix for fixed-base system is:

(kip/ft)

The outputs of FOSIN computer program is stored on HI magnetic tape. By using the post-processing computer program, STICK, the displacement matrix [D] and the force matrix [F] are generated and tabulated in table 3B.11-1. The member forces calculated according to force matrix [F] are given in tables 3B.11-2 through 2B.11-4; the values appearing in the solid line boxes are the predicted maximum member forces. It is seen that, for most of the members, the predicted maximum bending moments and shearing forces are the maximum values stated in tables 3B.11-2 through 3B.11-4. The maximum bending moments and shearing forces for column between the first and second floor and for girders for the second and third floor are

not the predicted maximum. However, the discrepancies are less than 1%.

Members 6, 7, and 8, which are columns between first and second floor, for instance, have the maximum bending moments and shearing forces at t = 353 and the predicted maximum bending moments and shearing forces are at t = 354. The absolute relative displacement between the first and second floors is 2.355 x 10-4 feet at t = 354 and 2.344 x 10-4 feet at t = 353. The difference between these two values is less than 1%. This closeness, coupled with the effect of the interaction between the shear and flexural deformation, is in all probability the explanation for the discrepancies between the predicted and the actual maximum member forces.

In order to show whether the predicted maximum is the actual maximum for horizontal excitation, a portion of time-history between t = 401 and t = 450 has been studied. The predicted maximum member forces are tabulated in the last three columns of table 3B.11-5. On the other hand, member forces for the whole portion of time-history have been calculated, and the actual maximum shearing force and bending moments were then obtained. It is seen that, except for the column between the first and second floor (members 6, 7, and 8), the predicted maximum member forces come out to be the actual maximum. For members 6, 7, and 8, the predicted maximum occurred at t = 415 while the actual maximum occurred at t = 416, and the absolute relative displacement between floors at t = 416 is about 0.2% less than that at t = 415. Table 3B.11-6 summarizes the

predicted maximum and actual maximum for the time interval between t = 401 and t = 450.

In this example, the girders' flexural rigidity (EI/) is about 1.2 of the columns' flexural rigidity.

Table 3B.11-1

DISPLACEMENT AND FORCE VECTORS FOR MAXIMUM ABSOLUTE RELATIVE DISPLACEMENTS (FROM WHOLE TIME-HISTORY), STICK EXAMPLE 1

Mass Points	Max. Absolute Relative Displacement Between 1st Floor and Base is at t = 354		Max. Absolute Relative Displacement Between 1st and 2nd Floor is at t = 354*		Max. Absolute Relative Displacement Between 2nd and 3rd Floor is at t = 353		Max. Absolute Relative Displacement Between 3rd and Roof is at t = 355	
	Floor Disp. (10^{-4} ft)	Forces (kips)	Floor Disp. (10^{-4}ft)	Forces (kips)	Floor Disp. (10^{-4} ft)	Forces (kips)	Floor Disp.	Forces (kips)
M_1	-3.67456	-0.1066			-3.56104	-0.0791	-3.63942	-0.1257
M_2	-6.03001	-1.0276			-5.90142	-1.0474	-5.92713	-0.9729
M_3	-4.127456	-0.1431			-3.94300	-0.1020	-4.14829	-0.1761
M_4	1.80250	0.5730			7.50452	0.5486	7.78818	0.5743

*Same as previous two columns.

Table 3B.11-2

PREDICTED MAXIMUM AXIAL FORCES, STICK EXAMPLE 1

Axial

	Member	Joint	Max. Member Force for Whole Time-History Loading 1-2	Loading 3	Loading 4	Max. Member Force for T = 401 ~ T = 450 Loading 1-4	Loading 2	Loading 3
C_1	1	1	-0.0026057	-0.0035084	-0.0015702	-0.0004546	-0.0016056	-0.0047643
	1	2	0.0026057	0.0035084	0.0015702	0.0004546	0.0016056	0.0047643
	2	6	0.0000000	0.0000000	0.0000000	-0.0000000	-0.0000000	0.0000000
	2	7	-0.0000000	-0.0000000	-0.0000000	0.0000000	0.0000000	-0.0000000
	3	11	0.0026057	0.0035084	0.0015702	0.0004546	0.0016056	0.0047643
	3	12	-0.0026057	-0.0035084	-0.0015702	-0.0004546	-0.0016056	-0.0047643
B_1	4	2	0.0333035	0.0253459	0.0386318	-0.0821258	-0.0722945	0.0244732
	4	7	-0.0333035	-0.0253459	-0.0386318	0.0821258	0.0722945	-0.0244732
	5	7	-0.0333035	-0.0253459	-0.0386318	0.0821258	0.0722945	-0.0244732
	5	12	0.0333035	0.0253459	0.0386318	-0.0821258	-0.0722945	0.0244732
C_2	6	2	-0.1324598	-0.1307811	-0.1289681	0.1057482	0.1037371	-0.0833759
	6	3	0.1324598	0.1307811	0.1289681	-0.1057482	-0.1037371	0.0833759
	7	7	0.0000000	0.0000000	0.0000000	-0.0000000	-0.0000000	0.0000000
	7	8	-0.0000000	-0.0000000	-0.0000000	0.0000000	0.0000000	-0.0000000
	8	12	0.1324598	0.1307811	0.1289681	-0.1057482	-0.1037371	0.0833759
	8	13	-0.1234598	-0.1307811	-0.1289681	0.1057482	0.1037371	-0.0833759
B_2	9	3	0.2789575	0.2845378	0.2638019	-0.1552249	-0.1017534	0.1730154
	9	8	-0.2789575	-0.2845378	-0.2638019	0.1552249	0.1017534	-0.1730154
	10	8	-0.2789575	-0.2845378	-0.2638019	0.1552249	0.1017534	-0.1730155
	10	13	0.2789575	0.2845378	0.2638019	-0.1552249	-0.1617534	0.1730155
C_3	11	3	-0.1512890	-0.1482169	-0.1485232	0.1253801	0.1238968	-0.0919807
	11	4	0.1512890	0.1482169	0.1485232	-0.1253801	-0.1238968	0.0919807
	12	8	0.0000000	0.0000000	0.0000000	-0.0000000	-0.0000000	0.0000000
	12	9	-0.0000000	-0.0000000	-0.0000000	0.0000000	0.0000000	-0.0000000
	13	13	0.1512890	0.1482169	0.1485232	-0.1253801	-0.1238968	0.0919807
	13	14	-0.1512890	-0.1482169	-0.1485232	0.1253801	0.1238968	-0.0919807
B_3	14	4	0.0220168	0.0112910	0.0311900	-0.0815156	-0.0762721	0.0045700
	14	9	-0.0220168	-0.0112910	-0.0311900	0.0815156	0.0762761	-0.0045700
	15	9	-0.0220168	-0.0112910	-0.0311900	0.0815156	0.0762721	-0.0045700
	15	14	0.0220168	0.0112910	0.0311900	-0.0815156	-0.0762721	0.0045700
C_4	16	4	-0.0567014	-0.0543891	-0.0567494	0.0540837	0.0529892	-0.0334296
	16	5	0.0567014	0.0543891	0.0567494	-0.0540837	-0.0529892	0.0334296
	17	9	0.0000000	0.0000000	0.0000000	-0.0000000	-0.0000000	0.0000000
	17	10	-0.0000000	-0.0000000	-0.0000000	0.0000000	0.0000000	-0.0000000
	18	14	0.0567014	0.0543891	0.0567494	-0.0540837	-0.0529892	0.0334296
	18	15	-0.0567014	-0.0543891	-0.0567494	0.0540837	0.0529892	-0.0334296
B_4	19	5	-0.1417120	-0.1355687	-0.1421719	0.1374058	0.1344958	-0.0832309
	19	10	0.1417120	0.1355687	0.1421719	-0.1374058	-0.1344958	0.0832309
	20	10	0.1417120	0.1355687	0.1421719	-0.1374058	-0.1344958	0.0832309
	20	15	-0.1417120	-0.1355687	-0.1421719	0.1374058	0.1344958	-0.0832309

Table 3B.11-3

PREDICTED MAXIMUM SHEARING FORCES, STICK EXAMPLE 1

Shear Y

	Member	Joint	Max. Member Force for Whole Time-History Loading 1-2	Max. Member Force for Whole Time-History Loading 3	Max. Member Force for Whole Time-History Loading 4	Max. Member Force for T = 401 ~ T = 450 Loading 1-4	Max. Member Force for T = 401 ~ T = 450 Loading 2	Max. Member Force for T = 401 ~ T = 450 Loading 3
C_1	1	1	-0.1925659	-0.1856060	-0.1914520	0.1814605	0.1758242	-0.1188276
	1	2	0.1925659	0.1856060	0.1914520	-0.1814605	-0.2758242	0.1188276
	2	6	-0.3192971	-0.3082475	-0.3170459	0.2972353	0.2885100	-0.1967849
	2	7	0.3192971	0.3082475	0.3170459	-0.2972353	-0.2885100	0.1967849
	3	11	-0.1925659	-0.1856060	-0.1914520	0.1814605	0.1758242	-0.1188276
	3	12	-0.1925659	0.1856060	0.1914520	-0.1814605	-0.1758242	0.1188276
B_1	4	2	0.1298541	0.1272727	0.1273978	-0.1062028	-0.1053427	0.0786117
	4	7	-0.1298541	-0.1272727	-0.1273978	0.1062028	0.1053427	-0.0786117
	5	7	0.1298541	0.1272727	0.1273978	-0.1062028	-0.1053427	0.0786117
	5	12	-0.1298541	-0.1272727	-0.1273978	0.1062028	0.1053427	-0.0786117
C_2	6	2	-0.1592624	-0.1602601	-0.1528201	0.0993347	0.1035297	-0.0943545
	6	3	0.1592624	0.1602601	0.1528201	-0.0993347	-0.1035297	0.0943545
	7	7	-0.2792941	-0.2798793	-0.2690095	0.1821043	0.1884239	-0.1653103
	7	8	0.2792941	0.2798793	0.2690095	-0.1821043	-0.1884239	0.1653103
	8	12	-0.1592624	-0.1602601	-0.1528201	0.0993347	0.1035297	-0.0943545
	8	13	0.1592624	0.1602601	0.1528201	-0.0993347	-0.1035297	0.0943545
B_2	9	3	0.0188292	0.0174358	0.0195551	-0.0196319	-0.0201597	0.0086047
	9	8	-0.0188292	-0.0174358	-0.0195551	0.0196319	0.0201597	-0.0086047
	10	8	0.0188292	0.0174358	0.0195551	-0.0196319	-0.0201597	0.0086047
	10	13	-0.0188292	-0.0174358	-0.0195551	0.0196319	0.0201597	-0.0086047
C_3	11	3	0.1196951	0.1242777	0.1109819	-0.0558901	-0.0582237	0.0786610
	11	4	-0.1196951	-0.1242777	-0.1109819	0.0558901	0.0582237	-0.0786610
	12	8	0.1904294	0.1980444	0.1762359	-0.0873715	-0.0909895	0.1258464
	12	9	-0.1904294	-0.1980444	-0.1762359	0.0873715	0.0909895	-0.1258464
	13	13	0.1196952	0.1242777	0.1109819	-0.0558901	-0.0582237	0.0786610
	13	14	-0.1196952	-0.1242777	-0.1109819	0.0558901	0.0582237	-0.0786610
B_3	14	4	-0.0945876	0.0938278	-0.0917738	0.0712964	0.0709077	-0.0585511
	14	9	0.0945876	-0.0938278	0.0917738	-0.0712964	-0.0709077	0.0585511
	15	9	-0.0945876	-0.0938277	-0.0917738	0.0712964	0.0709077	-0.0585511
	15	14	0.0945876	0.0938277	0.0917738	-0.0712964	-0.0709077	0.0585511
C_4	16	4	0.1417120	0.1355687	0.1421719	-0.1374058	-0.1344958	0.0832309
	16	5	-0.1417120	-0.1355687	-0.1421719	0.1374058	0.1344958	-0.0832309
	17	9	0.2894758	0.2774321	0.2899457	-0.2775539	-0.2718659	0.1704342
	17	10	-0.2894758	-0.2774321	-0.2899457	0.2775539	0.2718659	-0.1704342
	18	14	0.1417120	0.1355687	0.1421719	-0.1374058	-0.1344958	0.0832309
	18	15	-0.1417120	-0.1355687	-0.1421719	0.1374058	0.1344958	-0.0832309
B_4	19	5	-0.0567014	-0.0543891	-0.0567494	0.0540837	0.0529892	-0.0334296
	19	10	0.0567014	0.0543891	0.0567494	-0.0540837	-0.0529892	0.0334296
	20	10	-0.0567014	-0.0543891	-0.0567494	0.0540837	0.0529892	-0.0334296
	20	15	0.0567014	0.0543891	0.0567494	-0.0540837	-0.0529892	0.0334296

Table 3B.11-4

PREDICTED MAXIMUM BENDING MOMENTS, STICK EXAMPLE 1

Bending Z

			Max. Member Force for Whole Time-History			Max. Member Force for T = 401 ~ T = 450		
	Member	Joint	Loading 1-2	Loading 3	Loading 4	Loading 1-4	Loading 2	Loading 3
C_1	1	1	-19.5822754	-18.9112701	-19.4392242	18.1726379	17.1758242	-12.1188276
	1	2	-15.0795927	-14.4977989	-15.0221195	14.4902449	13.2758242	-9.1188276
	2	6	-31.2030945	-30.1593475	-30.9541473	28.7685089	27.2885100	-19.1967849
	2	7	-26.2703857	-25.3252106	-26.1141052	24.7338715	23.2885100	-16.1967849
	3	11	-19.5822754	-18.9112701	-19.4392242	18.1726379	17.1758242	-12.1188276
	3	12	-15.0795927	-14.4977989	-15.0221233	14.4902449	13.1758242	-9.1188276
B_1	4	2	24.5879364	24.0997925	24.1220093	-20.1091461	-19.1053427	14.0786117
	4	7	22.1595306	21.7183838	21.7412109	-18.1238556	-17.1053427	13.0786117
	5	7	22.1595154	21.7183838	21.7412109	-18.1238556	-17.1053427	13.0786117
	5	12	24.5879364	24.0997925	24.1220093	-20.1091461	-19.1053427	14.0786117
C_2	6	2	-9.5083466	-9.6019993	-9.0998974	5.6189013	5.1035297	-5.0943545
	6	3	-13.4254398	-13.4754591	-12.9062014	8.6852999	8.1035297	-8.0943545
	7	7	-18.0486450	-18.1115417	-17.3653167	11.5138426	11.1884239	-10.1653103
	7	8	-22.1697083	-22.1910858	-21.3690491	14.7091818	15.1884239	-13.1653103
	8	12	-9.5083466	-9.6019993	-9.0998974	5.6189013	5.1035297	-5.0943545
	8	13	-13.4254398	-13.4754591	-12.9062014	8.6852999	8.1035297	-8.0943545
B_2	9	3	3.4337378	3.1753788	3.5711718	-3.5902014	-3.0201597	1.0086047
	9	8	3.3447847	3.1015186	3.4686842	-3.4772768	-3.0201597	1.0086047
	10	8	3.3447888	3.1015177	3.4686832	-3.4772768	-3.0201597	1.0086047
	10	13	3.4337387	3.1753788	3.5711718	-3.5902023	-3.0201597	1.0086047
C_3	11	3	9.9917021	10.3000813	9.3350306	-5.0950966	-5.0582237	6.0786610
	11	4	7.2444010	7.5959091	6.6463699	-2.9530811	-3.0582237	4.0786610
	12	8	15.4801512	15.9880571	14.4316902	-7.7548282	-8.0909895	10.1258464
	12	9	11.9416904	12.5303307	10.9462719	-4.8268661	-5.0909895	8.1258464
	13	13	9.9917021	10.3000813	9.3350306	-5.0950966	-5.0582237	6.0786610
	13	14	7.2444010	7.5959091	6.6463699	-2.9530821	-3.0582237	4.0786610
B_3	14	4	-17.4990387	-17.3840790	-16.9547577	13.0304518	12.0709077	-10.0585511
	14	9	-16.5524902	-16.3939056	-16.0838013	12.6362486	12.0709077	-10.0585511
	15	9	-16.5524902	-16.3939056	-16.0838013	12.6362448	12.0709077	-10.0585511
	15	14	-17.4990540	-17.3840790	-16.9547577	13.0304556	12.0709077	-10.0585511
C_4	16	4	10.2546511	9.7881823	10.3083973	-10.0773697	-9.1344958	6.0832309
	16	5	10.1518698	9.7337141	10.1643543	-9.7090540	-9.1344958	5.0832309
	17	9	21.1632843	20.2574768	21.2213287	-20.4456177	-20.2718659	12.1704342
	17	10	20.5212250	19.6927490	20.5308533	-19.5221558	-19.2718659	12.1704342
	18	14	10.2546511	9.7881823	10.3083973	10.0773697	-9.1344958	6.0832309
	18	15	10.1518698	9.7337141	10.1643581	-9.7090578	-9.1344958	5.0832309
B_4	19	5	-10.1518698	-9.7337141	-10.1643543	9.7090540	9.0529892	-5.0334296
	19	10	-10.2606163	-9.8463774	-10.2654285	9.7610807	9.0529892	-6.0334296
	20	10	-10.2606163	-9.8463736	-10.2654285	9.7610807	9.0529892	-6.0334296
	20	15	-10.1518698	-9.7337141	-10.1643581	9.7090578	9.0529892	-5.0334296

Table 3B.11-5

DISPLACEMENT AND FORCE VECTORS FOR MAXIMUM ABSOLUTE RELATIVE DISPLACEMENTS

(BETWEEN t = 401 AND t = 450), STICK EXAMPLE 1

Mass Points	Max. Absolute Relative Displacement Between 1st Floor and Base is at t = 414		Max. Absolute Relative Displacement Between 1st and 2nd Floor is at t = 415		Max. Absolute Relative Displacement Between 2nd and 3rd Floor is at t = 401		Max Absolute Relative Displacement Between 3rd and 4th Floor is at t = 414*	
	Floor Disp. (10^{-4} ft)	Forces (kips)	Floor Disp. (10^{-4} ft)	Forces (kips)	Floor Disp. (10^{-4} ft)	Forces (kips)	Floor Disp. (10^{-4} ft)	Forces (kips)
M_1	3.332704	0.27938	3.248404	0.244675	-2.252668	-0.080421		
M_2	5.016353	0.57993	4.965810	0.602921	-3.641348	-0.636719		
M_3	4.010619	0.35321	3.938708	0.333342	-2.392102	-0.0537278		
M_4	-7.343548	-0.55237	-7.187330	-0.540855	4.644617	0.336896		

*Same as first two columns.

3B.11.4.2 STICK Example 2

In order to investigate the effects of girders' bending rigidities, moment of inertia of all girders is first reduced to one half of the original values. The equivalent stiffness matrix for lumped mass model is:

$$[k] = \begin{bmatrix} 5724.6 & -3674.2 & 59.03 & -21.0 \\ -3674.2 & 5567.3 & -2650.9 & 126.7 \\ 59.03 & -2650.9 & 2615.2 & -488.8 \\ -21.0 & 126.7 & -488.8 & 380.4 \end{bmatrix} \quad \text{(kip/ft)}$$

Since the effect of soil-structure interactions is not important in these studies, the same FOSIN outputs of the previous example may be used. The members' force corresponding to the force matrix given in table 3B.11-7 is tabulated in table 3B.11-8. The predicted maximum and actual maximum member forces are summarized in table 3B.11-9. Again, the only discrepancy occurs with respect to the column members between the first and second floor. Although an error of 35% occurs at joint 2 of member 6, this error is of no practical importance. Since the load at that joint is not a design load; this, by virtue of the fact that its magnitude is less than that occurring at joint 3 where attendant error is only 3.7%.

3B.11.4.3 STICK Example 3

The moment of inertia of the girders is again reduced to one-fifth of the actual values in the structure. The force matrix is tabulated in table 3B.11-10, and the corresponding member forces are given in table 3B.11-11. The predicted maximum and actual maximum member forces are summarized in table 3B.11-12. It is seen that, in the event of predicted

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Table 3B.11-6

SUMMARY OF PREDICTED AND ACTUAL MAXIMUM OF MEMBER FORCES (BETWEEN t = 401 AND t = 450), STICK EXAMPLE 1

			Shearing Forces					Bending Moments				
			Predicted		Actual			Predicted		Actual		
Type	Member	Joints	Forces	Time	Forces	Time	Error	Moments	Time	Moments	Time	Error
C_1	1	1 2	0.1815 -0.0815	414	* *	414		18.173 14.490	414	* *	414	
	2	6 7	0.2972 -0.2973	414	* *	414		28.769 24.734	414	* *	414	
	3	11 12	0.1815 -0.1815	414	* *	414		18.173 14.490	414	* *	414	
B_1	4	2 7	-0.1062 0.1062	414	* *	414		-20.109 -18.124	414	* *	414	
	5	7 12	-0.1062 0.1062	414	* *	414		-18.124 -20.109	414	* *	414	
C_2	6	2 3	0.1035 -0.1035	415	0.1086 -0.1086	417	4.9%	5.946 8.962	415	6.565 9.205	417 416	10.4% 2.7%
	7	7 8	0.1884 -0.1884	415	0.1939 -0.1939	416	2.9%	11.993 15.140	415	12.487 15.442	416 416	4.0% 2.0%
	8	12 13	0.1035 -0.1035	415	0.1086 -0.1086	417		5.946 8.462	415	6.565 9.205	417 416	10.4% 2.7%
B_2	9	3 8	-0.0202 0.0202	415	* *	415		- 3.694 - 3.564	415	* *	415	
	10	8 13	-0.0202 0.0202	415	* *	415		- 3.564 - 3.694	415	* *	415	
C_3	11	3 4	0.0786 -0.0786	401	* *	401		6.478 4.849	401	* *	401	
	12	8 9	0.1258 -0.1258	401	* *	401		10.106 8.016	401	* *	401	
	13	13 14	0.0786 -0.0786	401	* *	401		6.478 4.849	401	* *	401	
B_3	14	4 9	0.0713 -0.0713	414	* *	414		13.031 12.636	414	* *	414	
	15	9 14	0.0713 -0.0713	414	* *	414		12.636 13.031	414	* *	414	
C_4	16	4 5	-0.1374 0.1374	414	* *	414		-10.077 - 9.709	414	* *	414	
	17	9 10	-0.2776 0.2776	414	* *	414		-20.446 -19.522	414	* *	414	
	18	14 15	-0.1374 0.1374	414	* *	414		-10.077 - 9.709	414	* *	414	
B_4	19	5 10	0.0541 -0.0541	414	* *	414		9.709 9.709	414	* *	414	
	20	10 15	0.0541 -0.0541	414	* *	414		9.709 9.709	414	* *	414	

Table 3B.11-7

DISPLACEMENT AND FORCE VECTORS FOR MAXIMUM ABSOLUTE RELATIVE DISPLACEMENTS (BETWEEN t = 401 AND t = 450), STICK EXAMPLE 2

Mass Points	Max. Absolute Relative Displacement Between 1st Floor and Base is at t = 414		Max. Absolute Relative Displacement Between 1st and 2nd Floor is at t = 415		Max. Absolute Relative Displacement Between 2nd and 3rd Floor is at t = 401		Max. Absolute Relative Displacement Between 3rd and 4th Floor is at t = 414*	
	Floor Disp (10^{-4} ft)	Forces (kips)	Floor Disp. (10^{-4} ft)	Forces (kips)	Floor Disp. (10^{-4} ft)	Forces (kips)	Floor Disp. (10^{-4} ft)	Forces (kips)
M_1	3.332704	0.31690	3.248404	0.28264	-2.252668	-0.10262		
M_2	5.016353	0.41203	4.965810	0.43591	-3.641348	-0.50660		
M_3	4.010619	0.27475	3.938708	0.25673	-2.392102	-0.20302		
M_4	-7.343548	-0.41883	-7.18733	-0.40983	4.644617	0.25220		

*Same as first two columns.

Table 3B.11-8

PREDICTED MAXIMUM BENDING MOMENTS AND SHEARING FORCES, STICK EXAMPLE 2

	Member	Joint	Bending Z			Shear Y		
			Loading 1-2	Loading 3	Loading 4	Loading 1-4	Loading 2	Loading 3
C_1	1	1	17.0384064	16.5238495	-11.1851320	0.1605406	0.1550775	-0.1029626
	1	2	11.8589010	11.3901043	-7.3481398	-0.1605406	-0.1550775	0.1029626
	2	6	26.9427338	26.1533508	-17.7972717	0.2637683	0.2552945	-0.1713945
	2	7	20.5355377	19.7996521	-13.0537291	-0.2637683	-0.2552945	0.1713945
	3	11	17.0384064	16.5238495	-11.1851320	0.1605406	0.1550775	-0.1029626
	3	12	11.8589010	11.3901043	-7.3481398	-0.1605406	-0.1550775	0.1029626
B_1	4	2	-14.6304083	-14.5031977	10.8365107	-0.0787578	-0.0780790	0.0583289
	4	7	-13.7223854	-13.6052599	10.1618929	0.0787578	0.0780790	-0.0583289
	5	7	-13.7223854	13.6052599	10.1618929	-0.0787578	-0.0780790	0.0583289
	5	12	-14.6304121	-14.5031977	10.8365107	0.0787578	0.0780790	-0.0583289
C_2	6	2	2.7715082	3.1130953	-3.4883709	0.0682938	0.0725237	-0.0724467
	6	3	7.0628080	7.3303156	-6.9439602	-0.0682938	-0.0725237	0.0724467
	7	7	6.9092293	7.4108620	-7.2700615	0.1313619	0.1377623	-0.1298063
	7	8	12.0068855	12.4269123	-11.4220495	-0.1313619	-0.1377623	0.1298063
	8	12	2.7715092	3.1130953	-3.4883718	0.0682938	0.0725237	-0.0724467
	8	13	7.0628080	7.3303194	-6.9439602	-0.0682938	-0.0725237	0.0724467
B_2	9	3	-2.6519346	-2.7272358	1.1594124	-0.0146909	-0.0150826	0.0064773
	9	8	-2.6367779	-2.7024946	1.1723976	0.0146909	0.0150826	-0.0064773
	10	8	-2.6367779	-2.7024946	1.1723976	-0.0146909	-0.0150826	0.0064773
	10	13	-2.6519356	-2.7272358	1.1594124	0.0146909	0.0150826	-0.0064773
C_3	11	3	-4.4108706	-4.6030817	5.7845459	-0.0403885	-0.0429052	0.0640249
	11	4	-1.4050674	-1.5752630	3.4350309	0.0403885	0.0429052	-0.0640249
	12	8	-6.7333307	-7.0219212	9.0772524	-0.0633031	-0.0672897	0.1038501
	12	9	-2.3823137	-2.6677933	5.8771706	0.0633031	0.0672897	-0.1038501
	13	13	-4.4108706	-4.6030817	5.7845459	-0.0403885	-0.0429052	0.0640249
	13	14	-1.4050684	-1.5752630	3.4350319	0.0403885	0.0429052	-0.0640249
B_3	14	4	9.2280884	9.2142954	-7.9482260	0.0509199	0.0507960	-0.0433203
	14	9	9.1030807	9.0722799	-7.6470728	-0.0509199	-0.0507960	0.0433203
	15	9	9.1030769	9.0722799	-7.6470728	0.0509199	0.0507960	-0.0433203
	15	14	9.2280884	9.2142954	-7.9482260	-0.0509199	-0.0507960	0.0433203
C_4	16	4	-7.8230181	-7.6390305	4.5131941	-0.1043153	-0.1020210	0.0622085
	16	5	-7.1983900	-7.0519876	4.4448195	0.1043153	0.1020210	-0.0622085
	17	9	-15.8238459	-15.4767723	9.4169750	-0.2101990	-0.2057878	0.1277829
	17	10	-14.4448147	-14.1566706	8.9837723	0.2101990	0.2057878	-0.1277829
	18	14	-7.8230181	-7.6390305	4.5131941	-0.1043153	-0.1020210	0.0622084
	18	15	-7.1983900	-7.0519876	4.4448195	0.1043153	0.1020210	-0.0622084
B_4	19	5	7.1983900	7.0519876	-4.4448195	0.0400578	0.0392509	-0.0248242
	19	10	7.2224054	7.0783310	-4.4918823	-0.0400578	-0.0392509	0.0248242
	20	10	7.2224092	7.0783348	-4.4918861	0.0400578	0.0392509	-0.0248242
	20	15	7.1983900	7.0519876	-4.4448195	-0.0400578	-0.0392509	0.0248242

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Table 3B.11-9

SUMMARY OF PREDICTED AND ACTUAL MAXIMUM OF MEMBER FORCES

(BETWEEN t = 401 AND t = 450), STICK EXAMPLE 2

			Shearing Forces				Bending Moments					
			Predicted		Actual			Predicted		Actual		
Type	Member	Joints	Forces	Time	Forces	Time	Error	Moments	Time	Moments	Time	Error
C_1	1	1 2	0.1605 -0.1605	414	* *			17.038 11.859	414	* *	414	
	2	6 7	0.2638 -0.2638	414	* *			26.943 20.536	414	* *	414	
	3	11 12	0.1605 -0.1605	414	* *			17.038 11.859	414	* *	414	
B_1	4	2 7	-0.0788 0.0788	414	* *			-14.630 -13.722	414	* *	414	
	5	7 12	0.0788 -0.0788	414	* *			-13.722 -14.630	414	* *	414	
C_2	6	2 3	0.0725 -0.0725	415	0.0825 -0.0825	417	13.7%	3.113 7.330	415	4.214 7.689	418 417	35% 4.9%
	7	7 8	0.1378 -0.1278	415	0.1488 -0.1488	417	8.0%	7.411 12.427	415	8.607 12.818	417 416	16% 3.1%
	8	12 13	0.0725 -0.0725	415	0.0825 -0.0825	417	13.7%	3.113 7.330	415	4.214 7.689	418 417	35% 4.9%
B_2	9	3 8	-0.0151 0.0151	415	* *			- 2.727 - 2.703	415	* *	415	
	10	8 13	-0.0151 0.0151	415	* *			- 2.703 - 2.727	415	* *	415	
C_3	11	3 4	0.0640 -0.0640	401	* *			5.785 3.435	401	* *	401	
	12	8 9	0.1039 -0.1039	401	* *			9.077 5.877	401	* *	401	
	13	13 14	0.0440 -0.0440	401	* *			5.877 3.435	401	* *	401	
B_3	14	4 9	0.0509 -0.0509	414	* *			9.228 9.103	414	* *	414	
	15	9 14	0.0509 -0.0509	414	* *			9.103 9.228	414	* *	414	
C_4	16	4 5	-0.1043 0.1043	414	* *			- 7.823 - 7.198	414	* *	414	
	17	9 10	-0.2102 0.2102	414	* *			-15.824 -14.445	414	* *	414	
	18	14 15	-0.1043 0.1043	414	* *			- 7.823 - 7.198	414	* *	414	
B_4	19	5 10	0.0401 -0.0401	414	* *			7.198 7.222	414	* *	414	
	20	10 15	0.0401 -0.0401	414	* *			7.222 7.398	414	* *	414	

Note: *Denotes Actual Maximum is the Same as the Predicted Maximum

maximum being different from actual maximum, the bending moments at the ends of the member becomes maximum at different instances. The predicted maximum member force may practically be used as design forces.

3B.11.5 CONCLUSION

Since the axial member forces offer no major contribution to horizontal displacements of floors, the predicted maximum axial force of the members are, in general, far removed from the actual maximum. Fortunately, stress due to axial forces are generally not important and may, therefore, be neglected in the case of horizontal excitation.

The predicted maximum values for the shear force and bending moments emerge, in general, the actual maximum for most members. The results of the numerical examples indicate that the predicted maximum is at most 5% less than actual maximum.

In case of vertical excitation, design criteria for compressive and tension members are generally different. Thus, maximum relative vertical displacement and minimum relative vertical displacement between two adjacent mass points should be considered to obtain the maximum compression and maximum tension stress.

If the rotational degree of freedom is considered in analysis, the additional criteria of maximum relative rotation between two adjacent mass points should be included. The rotation degree of freedom, however, is generally not being considered in analysis since its effect is negligible.

Table 3B.11-10

DISPLACEMENT AND FORCE VECTORS FOR MAXIMUM ABSOLUTE RELATIVE DISPLACEMENTS

(BETWEEN t = 401 AND t = 450), STICK EXAMPLE 3

Mass Points	Max. Absolute Relative Displacement Between 1st Floor and Base is at t = 414		Max. Absolute Relative Displacement Between 1st and 2nd Floor is at t = 415		Max. Absolute Relative Displacement Between 2nd and 3rd Floor is at t = 401		Max. Absolute Relative Displacement Between 3rd and 4th Floor is at t = 414*	
	Floor Disp. (10^{-4} ft)	Force (kips)	Floor Disp. (10^{-4} ft)	Force (kips)	Floor Disp. (10^{-4} ft)	Force (kips)	Floor Disp. (10^{-4} ft)	Force (kips)
M_1	3.332704	0.24499	3.248404	0.209965	-2.252668	-0.060007		
M_2	5.016353	0.73552	4.965810	0.757488	-3.641348	-0.754406		
M_3	4.010619	0.457075	3.938708	0.435080	-2.392102	-0.107418		
M_4	-7.343548	-0.69480	-7.18733	-0.680572	4.644617	0.426968		

*Same as first two columns.

Table 3B.11-11

PREDICTED MAXIMUM BENDING MOMENTS AND SHEARING FORCES, STICK EXAMPLE 3

			Bending Z			Shear Y		
	Member	Joint	Loading 1-4	Loading 2	Loading 3	Loading 1-4	Loading 2	Loading 3
	1	1	25.1728821	24.5982208	-17.1333008	0.2039388	0.1980855	-0.1354463
	1	2	11.5361004	11.0571671	-7.2740303	-0.2039388	-0.1980855	0.1354463
C_1	2	6	39.5116577	38.6274109	-26.9510193	0.3349118	0.3257885	-0.2239673
	2	7	20.7724762	20.0145111	-13.3630924	-0.3349118	-0.3257885	0.2239673
	3	11	25.1728821	24.5982208	-17.1333008	0.2039388	0.1980855	-0.1354463
	3	12	11.5361004	11.0571671	-7.2470303	-0.2039388	-0.1980855	0.1354463
	4	2	-15.9070024	-15.7967176	11.5328817	-0.0871011	-0.0865012	0.0631520
B_1	4	7	-15.4494047	-15.3437366	11.2018232	0.0871011	0.0865012	-0.0631520
	5	7	-15.4494047	-15.3437366	11.2018232	-0.0871011	-0.0865012	0.0631520
	5	12	-15.9070024	-15.7967176	11.5328817	0.0871011	0.0865012	-0.0631520
	6	2	4.3709011	4.7395496	-4.2858467	0.1313508	0.1353624	-0.1163175
	6	3	14.5436039	14.7526312	-12.4638700	-0.1313508	-0.1353624	0.1163175
C_2	7	7	10.1263266	10.6729593	-9.0405540	0.2350982	0.2412749	-0.2022150
	7	8	23.7277985	24.0706177	-20.0783997	-0.2350982	-0.2412749	0.2022150
	8	12	4.3709011	4.7395496	-4.2858467	0.1313508	0.1353624	-0.1163175
	8	13	14.5436039	14.7526312	-12.4638700	-0.1313508	-0.1353624	0.1163175
	9	3	-4.1432962	-4.2150307	2.0482006	-0.0229750	-0.0233600	0.0113698
B_2	9	8	-4.1277218	-4.1945772	2.0449257	0.0229750	0.0233600	-0.0113698
	10	8	-4.1277218	-4.1945772	2.0449257	-0.0229750	-0.0233600	0.0113698
	10	13	-4.1432962	-4.2150307	2.0482006	0.0229750	0.0233600	-0.0113698
	11	3	-10.4003038	-10.5375967	10.4156704	-0.0685097	-0.0706402	0.0892476
	11	4	0.5349091	0.3654018	2.4359961	0.0685097	0.0706402	-0.0892476
C_3	12	8	-15.4723616	-15.6814671	15.9885569	-0.1007005	-0.1042094	0.1410543
	12	9	0.9714904	0.6753068	4.3232613	0.1007005	0.1042094	-0.1410543
	13	13	-10.4003077	-10.5375967	10.4156704	-0.0685097	-0.0706402	0.0892477
	13	14	0.5349084	0.3654011	2.4359970	0.0685097	0.0706402	-0.0892477
	14	4	13.3658304	13.2287998	-10.6098156	0.0743384	0.0735524	-0.0586521
B_3	14	9	13.3959951	13.2500610	-10.5049286	-0.0743384	-0.0735524	0.0586521
	15	9	13.3959951	13.2500610	-10.5049286	0.0743384	0.0735524	-0.0586521
	15	14	13.3658304	13.2287998	-10.6098156	-0.0743384	-0.0735524	0.0586521
	16	4	-13.9007406	-13.5941982	8.1738195	-0.1737546	-0.1701487	0.1060680
	16	5	-11.1199322	-10.9072094	7.0999756	0.1737546	0.1701487	-0.1060680
C_4	17	9	-27.7634735	-27.1754303	16.6865845	-0.3472902	-0.3402722	0.2148336
	17	10	-22.2463226	-21.8237762	14.2494478	0.3472902	0.3402722	-0.2148336
	18	14	-13.9007406	-13.5941982	8.1738157	-0.1737546	-0.1701487	0.1060680
	18	15	-11.1199284	-10.9072094	7.0999718	0.1737546	0.1701487	-0.1060680
	19	5	11.1199322	10.9072094	-7.0999756	0.0617864	0.0606086	-0.0395130
B_4	19	10	11.1231585	10.9118891	-7.1247215	-0.0617864	-0.0606086	0.0395130
	20	10	11.1231632	10.9118929	-7.1247215	0.0617864	0.0606086	-0.0395131
	20	15	11.1199284	10.9072094	-7.0999718	-0.0617864	-0.0606086	0.0395131

Note: 1. Between t = 401 and t = 405
2. Girders' flexural rigidities are 1/5 of original structure

STICK COMPUTER PROGRAM (STICK)

Table 3B.11-12

SUMMARY OF PREDICTED AND ACTUAL MAXIMUM OF MEMBER FORCES

(BETWEEN t = 401 AND t = 450), STICK EXAMPLE 3

			Shearing Forces					Bending Moments				
			Predicted		Actual			Predicted		Actual		
Type	Member	Joints	Forces	Time	Forces	Time	Error	Moments	Time	Moments	Time	Error
C_1	1	1 2	0.2039 -0.2039	414	* *	414		25.173 11.536	414	* *	414	
	2	6 7	0.3349 -0.3349	414	* *	414		39.512 20.772	414	* *	414	
	3	11 12	0.2039 -0.2039	414	* *	414		25.173 11.536	414	* *	414	
B_1	4	2 7	-0.0871 0.0871	414	* *	414		-15.907 -15.449	414	* *	414	
	5	7 12	-0.0871 0.0871	414	* *	414		-15.449 -15.908	414	* *	414	
C_2	6	2 3	0.1354 0.1354	415	* *	415		4.740 14.753	415	5.542 *	417 415	16.9%
	7	7 8	0.2413 -0.2413	415	0.2440 -0.2440	416	1.2%	10.673 24.071	415	11.357 *	417 415	6.4%
	8	12 13	0.1354 -0.1354	415	* *	415		4.740 14.753	415	5.542 *	417 415	16.9%
B_2	9	3 8	-0.0234 0.0234	415	* *	415		- 4.215 - 4.195	415	* *	415	
	10	8 13	-0.0234 0.0234	415	* *	415		- 4.195 - 4.215	415	* *	415	
C_3	11	3 4	0.0892 -0.0892	401	* *	401		10.416 2.436	401	10.625 2.500	416 420	2.0% 2.6%
	12	8 9	0.0141 -0.0141	401	* *	401		15.981 4.323	401	16.171 4.434	402 420	1.2% 2.6%
	13	13 14	0.0892 -0.0892	401	* *	401		10.416 2.436	401	10.625 2.500	416 420	2.0% 2.6%
B_3	14	4 9	0.0743 -0.0743	414	* *	414		13.366 13.296	414	* *	414	
	15	9 14	0.0743 -0.0743	414	* *	414		13.296 13.366	414	* *	414	
C_4	16	4 5	-0.1738 0.1738	414	* *	414		-13.901 -11.120	414	* *	414	
	17	9 10	-0.3473 0.3473	414	* *	414		-27.763 -27.246	414	* *	414	
	18	14 15	-0.1738 0.1738	414	* *	414		-13.401 -11.120	414	* *	414	
B_4	19	5 10	0.0618 -0.0618	414	* *	414		11.120 11.123	414	* *	414	
	20	10 15	0.0618 -0.0618	414	* *	414		11.123 11.120	414	* *	414	

Note: *Denotes Actual Maximum is the Same as the Predicted Maximum

3B.12 BECHTEL CE 800, BECHTEL STRUCTURAL ANALYSIS PROGRAM (BSAP)

A. Description

The program performs the static and dynamic analyses of linear, elastic, three-dimensional structures, using the finite-element method. The finite-element library contains truss and beam elements, plane and solid elements, plate and shell elements, axisymmetric (torus) elements, and special boundary (spring) elements.

Element stresses and displacements are solved for either applied loads or temperature distributions. Concentrated loads, pressures, or gravity loads may be applied. Temperature distributions are assigned as an appropriate uniform temperature change in each element. Prestressing may be simulated by using artificial temperature changes on rod elements.

Dynamic response routines are available for solving arbitrary dynamic loads or seismic excitations, using modal superposition. The program can also perform response spectrum and time-history analyses.

B. Validation

The solutions to test problems have been demonstrated to be essentially identical to the results obtained, using the following recognized public-domain computer programs:

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1. EASE - Elastic Analysis Corporation
2. STARDYNE - Mechanics Research Incorporated
3. ANSYS - Swanson Engineering Corporation
4. ICES/STRUDL - McDonnell-Douglas Automation
5. MSC/NASTRAN - MacNeil Schwendler Corporation

Agreement has also been established between BSAP program results and the results presented in the ASME Library of Benchmark Computer problems and solutions[4] and in recognized technical journals. Document traceability is available at Bechtel Power Corporation.

C. Extent of Application

The program was used to perform structural analysis for concrete structures.

BECHTEL STRUCTURAL ANALYSIS PROGRAM

(BSAP) CE 800

3B.12.1 REFERENCES

1. Wilson, E. L., "SAP, A General Structural Analysis Pro-gram," University of California Structural Engineering Laboratory, Report No. UCSESM 70-20, September, 1970.

2. Wilson, E. L., "SOLID SAP - A Static Analysis Program for Three-Dimensional Solid Structures," University of California, Berkeley, Department of Civil Engineering, SESM Report No. 71-19, September, 1971.

3. Wilson, E. L., "SAP-IV-A Structural Analysis Program for Static and Dynamic Response of Linear Systems," University of California, Berkeley, EERC Report No. 73-11, June, 1973.

4. "Pressure Vessel and Piping - 1972 Computer Programs Verification," ASME Committee on Computer Technology, Pressure Vessel and Piping Division.

3B.13 FINITE-ELEMENT COMPUTER PROGRAM (FINEL)

3B.13.1 DESCRIPTION

FINEL is a two-dimensional, static, small displacement, bilinear-elastic, finite-element computer program. FINEL is an improved version of the original FINEL code developed under the direction of Dr. E. L. Wilson at the University of California at Berkeley in 1962 under a National Science Foundation grant G18986.

The primary purpose of this program is to perform plane or axisymmetric stress analysis of reinforced concrete structures. The program allows for concrete cracking and reinforcement yielding. This is done by a series of successive elastic iterations in which the stiffness matrix is modified to account for the nonlinear effect of cracking or yielding of each element. Loading includes concentrated, pressure, displacement (no inclined roller), thermal, inertial and, for axisymmetric problems, centrifugal forces.

In addition to analysis of reinforced concrete structures, FINEL can perform linear stress analysis on structures that can be modeled as plane stress, plane strain, or axisymmetric problems with axially symmetric material properties; i.e., isotropic in the plane (radial plane for axisymmetric problems), with the same or different properties normal to the plane.

FINEL has been used extensively to analyze reinforced concrete containment vessels.

Two types of material behavior are incorporated into FINEL:

A. Ductile

The stress-strain curve is bilinear in compression and bilinear in tension. This type of material behavior is used to model reinforcing steel and the liner plate material.

B. Brittle

The stress-strain curve is bilinear in compression and fractures (cracks) in tension. This type of material behavior is used to represent concrete and the foundation media.

3B.13.2 VALIDATION

Demonstration of the applicability and validity of the FINEL program is achieved through the comparison of the results obtained using the program with experimental and/or manually-calculated solutions.

Eight test problems, outlined in paragraphs 3B.13.2.1 through 3B.13.2.8, were used in this demonstration, the results of which show that the FINEL solutions are essentially identical to experimental and/or manually-calculated solutions.

3B.13.2.1 FINEL Example 1, Cracking Analysis of a Prestressed Concrete Reactor Vessel (PCRV)

The purpose of this test problem is to compare the results obtained from the FINEL program with the results obtained from both experimental and analytical investigation of the cracking

of a cylindrical PCRV subjected to internal pressurization. A pictorial representation of the PCRV under investigation is shown in figure 3B.13-1.

The finite-element idealization used in the FINEL analysis is shown in figure 3B.13-2. The zoning is obtained from the zoning used in reference 1 by subdividing each element into four elements. Since reference 1 used a quadratic element, while FINEL uses a linear element, the two zonings will have the same order of accuracy. Another difference between the analysis of reference 1 and the FINEL analysis is the assumed cracking criteria. Reference 1 used the following maximum strain criteria:

$$\varepsilon_{crack} = \frac{500\ \text{lb/in.}^2}{E} = 0.000116$$

(incorrectly reported as 0.00015 in reference 1).

The FINEL program used the following maximum stress criteria:

$$T_{crack} = 500\ \text{lb./in.}^2$$

Also, reference 1 reduced the shear stiffness to zero once an element cracked, while a shear stiffness reduction factor of 0.5 was used in the FINEL analysis.

The loading steps applied to the FINEL model of the PCRV are given in table 3B.13-1. Other parameters used are:

Young's Modulus = E = 4.3 x 10^6 pounds per square inch

Poisson's Ratio = ν = 1/3

Cracking Stress = T_{crack} = 500 pounds per square inch

The cracking patterns calculated by reference 1 (= 1/3) and the FINEL analysis are shown in figure 3B.13-3. Agreement is very good, taking into account the difference in the load-deformation curves, i.e., similar patterns, with the cracks from reference 1 growing more rapidly with increased load.

Load-deformation curves for a point on the PCRV from references 1 and 2 and the FINEL analysis are shown in figure 3B.13-4. The numerical results of reference 1 and the FINEL analysis as shown in figures accurately predict the load at which significant cracking begins.

However, after significant cracking occurs, both the results of reference 1 and the FINEL analysis underestimate the deformation. Therefore, it is apparent that after significant cracking has occurred, a more accurate stiffness formulation is needed to predict the deformations of a PCRV. The fact that the results of the FINEL analysis agree more closely with the results of reference 1 where = 0 than to reference 1 where = 1/3 is due to the different failure criteria assumed. Reference 1 used a maximum strain criteria and FINEL uses a maximum stress criteria.

The results of this investigation indicate that the FINEL program can accurately predict loads at which significant cracking is initiated in a PCRV. As the load is increased above the point where significant cracking occurs, the results

are only approximate. A more accurate stiffness formulation is needed to accurately predict the behavior of a PCRV after significant cracking has occurred.

Table 3B.13-1

LOADING STEPS FOR FINEL MODEL

(FINEL Example 1)

Step	Longitudinal Prestress (lbs)	Circumferential Prestress (lb/in.^{2})	Internal Pressure (lb/in.^{2})	No. of Iterations Required for Convergence
1	760,000	620	0	1
2	760,000	620	500	4
3	760,000	620	575	6
4	760,000	620	625	5
5	760,000	620	675	5
6	760,000	620	725	10

3B.13.2.2 FINEL Example 2, Analysis of a Simply Supported Beam

The purpose of this test problem is to compare the results obtained from the FINEL program with the results obtained from both experimental and analytical investigation of the cracking of a simply supported beam. A pictorial representation of the characteristics of the simply supported beam under investigation is shown in figure 3B.13-5.

The finite-element mesh used in reference 3 and in the FINEL analysis are shown in figure 3B.13-6. The FINEL analysis requires a finer mesh because it used linear displacement elements while reference 2 used quadratic displacement elements.

The material properties of the concrete and reinforcing steel, and the loading history used in the FINEL analysis are given in tables 3B.13-2 and 3B.13-3.

This problem solution was not continued beyond the yield point of the reinforcing steel due to an error in the FINEL program which has since been corrected.

The cracking patterns obtained from reference 3 and FINEL are shown in figure 3B.13-7. The load deflection curves from references 3 and 4 and the FINEL analysis are shown in figure 3B.13-8. The load deflection curve obtained from the FINEL analysis shows very good agreement with the experimental results. The cracked region grows faster in the FINEL analysis and more slowly in reference 3, since the FINEL and reference 3 load deflection curves show different gradients (stiffnesses).

Table 3B.13-2

MATERIAL PROPERTIES OF THE CONCRETE AND REINFORCING STEEL USED FOR FINEL VERIFICATION

(FINEL Example 2)

Property	Concrete	Steel
E	4.3×10^6 lb/in^2	29×10^6 lb/in.^{2}
ν	0.15	0.29
T_{yield}	-4,820 lb/in.^{2}	± 44,900 lbs/in.^{2}
E_{yield}	0.	0.
T_{crack}	+546 lb/in.^{2}	-----
E_{crack}	1.0 lb/in. ^{2}	-----
Shear stiffness reduction factor for once cracked concrete	0.5	-----

3B.13.2.3 FINEL Example 3, Analysis of an End-Loaded Cantilever

The analysis of an end-loaded cantilever prismatic beam is performed to test the constant strain finite-elements. The results are compared to theory. The beam geometry and finite-element mesh are illustrated in figure 3B.13-9. The problem is treated by a plane stress analysis, and the mesh contains 119 nodes and 96 quadrilateral constant strain elements.

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The deflections and stress results from the FINEL program are compared with the hand calculations in tables 3B.13-4 and 3B.13-5. The theoretical linear strain variation across the

Table 3B-13.3

LOADING HISTORY USED FOR THE FINEL VERIFICATION

(FINEL Example 2)

Load, P (lb)	Number of Cycles At Load for Convergence
1	1
8,700	4
20,000	4
28,000	1
31,200	4
31,300	1[a]

a. Reinforcing steel yielded

Table 3B.13-4

DEFLECTION RESULTS FROM FINEL VERIFICATION

USING AN END-LOADED CANTILEVER

(FINEL Example 3)[a]

Node	Deflections	
	FINEL	Hand Calculations
25	0.0182	0.0169
46	0.0652	0.0630
67	0.1338	0.1316
88	0.2176	0.2160
116	0.3417	0.3413

a. Flexural deflections only are computed here.

Table 3B.13-5

STRESS RESULTS FROM FINEL VERIFICATION

USING AN END-LOADED CANTILEVER

(FINEL Example 3)[a]

Section	Flexure Stress	
	FINEL	Hand Calculations
a	63.132	64.5833
b	54.048	56.2500
c	46.107	57.9170
d	38.087	39.5830
e	30.069	31.2500
f	22.050	22.9170
g	14.032	14.5830
h	6.004	6.2500

a. Computed at center of outer elements to correspond to output from computer.

depth of the beam is represented by discrete constant strain "steps" due to these finite-elements. The differences in results are largely due to this feature of the constant strain elements.

3B.13.2.4 FINEL Example 4, Analysis of an Axially Constrained Hollow Cylinder with a Distributed Pressure Loading

The purpose of this test problem is to compare the response of an axially constrained hollow cylinder to internal pressure, determined using FINEL, with an analytical solution of the same problem. The finite-element model is illustrated in figure 3B.13-10. Nodal points are free to move only in the radial direction, modeling the conditions of axisymmetry and plane strain.

The closed-form solution is based upon Roark Formulas for Stress and Strain.(5) A summary comparison between the closed form and FINEL solutions is given in table 3B.13-6.

3B.13.2.5 FINEL Example 5, Analysis of an Axially Constrained Hollow Cylinder with a Linear Temperature Gradient

The purpose of this test problem is to compare the response of an axially constrained hollow cylinder to a radially varying temperature gradient, determined using FINEL, with a closed-form solution to the same problem. The finite-element model is illustrated in figure 3B.13-11. The conditions of axisymmetry and plane strain are imposed by using the axisymmetric quadrilateral element and restraining all nodes

against axial displacement. The temperature is illustrated in figure 3B.13-12.

The closed-form solution is based on Timoshenko, Elasticity(6) and Manson, Thermal Stress.(7) A summary comparison between the closed-form and FINEL solutions is given in table 3B.13-7.

3B.13.2.6 FINEL Example 6, Analysis of an Axially Constrained Hollow Cylinder with a Nonlinear Temperature Gradient

The purpose of this test problem is to compare the response of an axially restrained hollow cylinder to a radially varying temperature gradient, determined using FINEL, with a closed-form solution to the same problem. The finite-element model is illustrated in figure 3B.13-13. The conditions of axisymmetry and plane strain are imposed by using the axisymmetric quadrilateral element and restraining all nodes against axial displacement. The bilinear temperature gradient is illustrated in figure 3B.13-14.

The closed-form solution is based on Timoshenko, Elasticity[6] and Manson, Thermal Stress[7]. A summary comparison between the closed-form and FINEL solutions is given in table 3B.13-8.

Table 3B.13-6

SUMMARY COMPARISON

(FINEL Example 4)

Element	r (ft)	Tangential Stress (k/ft^2)		Axial Stress (k/ft^2)		Radial Stress (k/ft^2)	
		Analytical[a] Solution	FINEL Solution	Analytical[a] Solution	FINEL Solution	Analytical[a] Solution	FINEL Solution
1	65.19	17.79	17.79	4.212	4.212	-0.95	-0.95
2	65.56	17.69	17.69	4.212	4.212	-0.84	-0.84
3	65.94	17.58	17.58	4.212	4.212	-0.73	-0.73
4	66.31	17.48	17.48	4.212	4.212	-0.63	-0.63
5	66.69	17.38	17.38	4.212	4.212	-0.53	-0.53
6	67.06	17.28	17.28	4.212	4.212	-0.43	-0.43
7	67.44	17.18	17.18	4.212	4.212	-0.33	-0.33
8	67.81	17.08	17.08	4.212	4.212	-0.24	-0.24
9	68.19	16.99	16.99	4.212	4.212	-0.14	-0.14
10	68.56	16.89	16.89	4.212	4.212	-0.05	-0.05

a. Based on Roark Formulas for Stress and Strain.[5]

Table 3B.13-7

SUMMARY COMPARISON

(FINEL Example 5)

Element	r (ft)	Tangential Stress (k/ft^2)		Axial Stress (k/ft^2)		Radial Stress (k/ft^2)	
		Analytical[a] Solution	FINEL Solution	Analytical[a] Solution	FINEL Solution	Analytical[a] Solution	FINEL Solution
1	65.19	-78.34	-78.33	-77.96	-77.96	-0.22	-0.23
2	65.56	-60.67	-60.66	-60.68	-60.68	-0.62	-0.62
3	65.94	-43.10	-43.09	-43.40	-43.40	-0.91	-0.91
4	66.31	-25.63	-25.62	-26.12	-26.12	-1.10	-1.10
5	66.69	-8.26	-8.25	-8.84	-8.84	-1.19	-1.19
6	67.06	9.01	9.02	-8.44	-8.44	-1.18	-1.18
7	67.44	26.19	26.20	-25.72	-25.72	-1.08	-1.08
8	67.81	43.27	43.28	-43.00	-43.00	-0.88	-0.88
9	68.19	60.26	60.27	-60.28	-60.28	-0.59	-0.59
10	68.56	77.16	77.17	-77.56	-77.56	-0.21	-0.21

a. Based on formula given in Timoshenko, Elasticity[6] and Manson, Thermal Stress.[7]

3B.13.2.7 FINEL Example 7, Analysis of a Deep Elastic Panel

The purpose of this test problem is to compare the response of a deep elastic panel subjected to a uniformly distributed load determined using FINEL with a closed-form solution to the same problem. The finite-element model is illustrated in figure 3B.13-15.

Due to the symmetry of the actual problem, only half of the panel has been modeled. Appropriate boundary conditions are applied to the nodal points along the axis of symmetry.

Boundary conditions along axis X = 0

θ rotation = 0

X displacement = 0

The closed-form solution is based on Timoshenko, Elasticity.[8] The stress results from FINEL represent the centroidal value for each plate elements. Therefore, in order to obtain stress values at locations more suitable for comparison with the theoretical solution, a graphical extrapolation of the results obtained from the FINEL analysis is necessary to establish stress values at nodal points along the axis of symmetry. Figure 3B.13-16 illustrates the approach used to establish the stress levels at nodal points 1 and 61.

Table 3B.13-8

SUMMARY COMPARISON

(FINEL Example 6)

Element	r (ft)	Tangential Stress (k/ft^2)		Axial Stress (k/ft^2)		Radial Stress (k/ft^2)	
		Analytical[a] Solution	FINEL Solution	Analytical[a] Solution	FINEL Solution	Analytical[a] Solution	FINEL Solution
1	65.19	-385.68	-383.29	-442.35	-441.72	-1.25	-1.10
2	65.56	-199.73	-197.38	-258.09	-257.47	-2.94	-2.76
3	65.93	-51.93	-68.07	-110.92	-128.89	-3.57	-3.49
4	66.31	-16.09	-13.58	-75.24	-74.61	-3.73	-3.70
5	66.68	19.54	22.06	-39.56	-38.92	-3.68	-3.66
6	67.06	54.98	57.50	-3.88	-3.24	-3.44	-3.41
7	67.43	90.22	92.75	31.80	32.45	-3.00	-2.98
8	67.81	125.27	127.81	67.47	68.14	-2.37	-2.35
9	68.19	160.14	162.68	103.15	103.82	-1.56	-1.54
10	68.56	194.82	197.37	138.83	139.51	-0.56	-0.54

a. Based on formula given in Timoshenko, Elasticity[6] and Manson, Thermal Stress.[7]

The results from the FINEL solution for the stresses at the nodal points located at the top and bottom of the panel along the axis of symmetry were compared to those from the manually-calculated solution as shown in table 3B.13-9.

The magnitude of the error reflects the use of graphical extrapolation in conjunction with a relatively coarse mesh of constant strain elements.

This verification problem demonstrates the performance of the constant strain finite-elements to solve an elasticity problem where shear effects are significant. These results confirm the known limitations of this type of element.

Table 3B.13-9

COMPARISON OF RESULTS FOR A DEEP ELASTIC PANEL

(FINEL Example 7)

Node	Stress $(k/in.)^2$ FINEL	Stress $(k/in.)^2$ Hand Calculations
Node 61	-52.0	-48.8
Node 1	146.0	126.8

3B.13.2.8 FINEL Example 8, Analysis of a Deep Elastic Panel (Finer Mesh Size)

The purpose of this test problem is to compare the response of a deep elastic panel subjected to a uniformly distributed load determined using FINEL with a closed-form solution to the same

problem. The problem is identical to the one presented in paragraph 3B.13.2.7 except that the mesh size of the finite model has been reduced. The actual mesh size of the finite-element model is shown in figure 3B.13-17.

The closed-form solution is based on Timoshenko, Elasticity.[8] For comparison purposes, the FINEL results at the nodal points located at the top and bottom of the panel along the axis of symmetry are extrapolated from the centroidal plate element results along the diagonal away from these nodal points using the following cubic polynomial curve fit algorithm.[9]

$$4 = (ao + x (a1 + x (a2 + a3x)))$$

The results from the FINEL solution for the stress at the points of interest were compared to those from the manually calculated solution as shown in table 3B.13-10.

This verification problem demonstrates the performance of the constant strain finite-elements to solve an elasticity problem where shear effects are significant. These results confirm the known limitations of this type of element.

Table 3B.13-10

COMPARISON OF RESULTS FOR THE DEEP ELASTIC PANEL

(FINEL Example 8)

Node	Stress	
	FINEL	Hand Calculations
21	-51.185	-48.8
1	137.925	126.8

3B.13.3 EXTENT OF APPLICATION

FINEL is used to perform the cracked-section analysis of the containment structure, based on an axisymmetric analysis. The program performs a design check of the structure for which all geometric and design parameters are known.

3B.13.4 REFERENCES

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2. Sozen, M. A. and Paul, S. L., "Structural Behavior of A Small-Scale Prestressed Concrete Reactor Vessel, Nuclear Engineering and Design, Vol 8, No. 403, 1968.

3. Suidan, M. and Schnobrich, W. C., "Finite-Element Analysis of Reinforced Concrete,"Journal of the Structural Division, ASCE, Vol 99, No. ST10, pp 2109 2122, October 1973.

4. Burns, N. H. and Seiss, C. P., "Load Deformation Characteristics of Beam-Column Connections in Reinforced Concrete," Structural Research Series No 234, Civil Engineering Studies, University of Illinois, Urbana-Champaign, Ill., January 1962.

5. Roark, Raymond, Formulas For Stress And Strain, Fourth Edition, McGraw-Hill, p 308, 1965.

6. Timoshenko and Goodier, Theory of Elasticity, Third Edition, McGraw-Hill, p 448, 1970.

7. Manson, Thermal Stress and Low Cycle Fatigue, McGraw-Hill, pp 28-29, 1960.

8. Timoshenko and Goodier, Theory of Elasticity, Third Edition, McGraw-Hill, pp 538-545, 1970.

9. Connor and Will, "Computer Aided Teaching Of The Finite-Element Displacement Method," MIT Research Report 69-23, p 196, February 1969.

3B.14 TENDON COMPUTER PROGRAM CE 239

A. Description

The dome tendon computer program calculates forces and pressures on a hemispherical dome of a prestressed, three-buttress concrete containment building, resulting from prestress by two orthogonal groups of vertical dome tendons and one group of horizontal hoop tendons.

The program calculates pressures at elements in the radial direction, and forces at nodes in the circumferential (hoop or azimuth) and meridional directions. Nodal forces in the hoop and meridional directions are calculated at each node point.

The pressures and forces calculated by this program are intended for use as input to a finite-element computer program to determine the stress distribution in the dome.

B. Validation

Program verification and document traceability are available at Bechtel Western Power Corporation.

3B.15 COMDAM COMPUTER PROGRAM (COMDAM)

3B.15.1 DESCRIPTION

Nuclear power plant structures are usually made up of several substructures with different dynamic characteristics. Addition-ally, the superstructure and the foundation are coupled to form the total soil-structure interaction system. In order to evaluate the structure responses due to seismic excitation, the proper modeling of the damping characteristics for the total system must be adequately treated. In general, the structure damping is usually specified by a fraction of critical viscous damping for each mode of vibration, and the soil damping represented by dashpots. Because damping varies as to magnitude and type, the classical model analysis generally is not strictly applicable to such a highly complex system. Therefore, it will be desirable to obtain the approximate composite modal damping values for the component-structure-foundation interaction system.

3B.15.2 BASIC THEORY AND METHOD OF APPROACH

The formulation of a rigorous composite damping matrix for complex systems can be derived by first obtaining the damping submatrices of the substructures as free-free systems, and then assembling these submatrices into a global matrix that represents the damping characteristics of the total system.

Given the modal damping values of a fixed base substructure, the corresponding damping matrix $[C_{fb}]$ can be obtained by:

$$[C_{fb}] = [\phi^{-1}]^T \, [{}^{\prime}2\zeta iWi_{.}] \, [\phi^{-1}]$$

where the ζi are the modal damping values and Wi and $[\phi]$ are the eigenvalues and eigenvectors of the undamped fixed-base sub-structure obtained from the solution of the eigenvalue problem:

$$[K_{fb}]\ [\phi] - \{W^2\}\ [M_{fb}]\ [\phi] = 0$$

Once the fixed-base damping matrix is known, the free-free damping matrix [Cff] of the substructure can be obtained from the following transformation:

$$[C_{ff}] = [\alpha^{-1}]^T [C_{fb}]\ [\alpha^{-1}]$$

where $[\alpha] = \begin{bmatrix} I & O \\ T & I \end{bmatrix}$ is the transformation matrix and matrix [T] is defined by the displacements of the interior freedoms due to successive unit displacement of boundary points, all other boundary points being totally constrained.

After the free-free damping matrices of each substructure are formed, these submatrices are then assembled into the global damping matrix [C].

Finally, the composite modal damping values β for the total system are then calculated by assuming that normal modes exist in the classical sense which is equivalent to neglecting the off-diagonal terms in the total system damping matrix in generalized coordinates.

$$\beta_n = \frac{\{Q\}_n^T [C]\ \{Q\}_n}{ZW_n}$$

where W_n and $\{Q\}_n$ are the eigenvalue and eigenvector of the n-th mode of the undamped total system and $[Q]^T [M] [Q] = [I]$.

3B.15.3 PROGRAM VERIFICATION

Evaluation of the adequacy of composite modal damping values obtained by the method described above may be assessed by comparing the responses using normal mode solution with the corresponding responses from the rigorous solution obtained by solving the coupled equations of motion.

The formulation of the damping matrix and the calculation of composite modal damping have been implemented into the Bechtel Standard Computer Program DAMPSI (CE 251) which has been verified. Therefore, it will be only necessary to prove that the composite modal damping values obtained by the COMDAM program code are similar to those obtained from DAMPSI program.

The structural properties and sketch of the test problem are shown in table 3B.15-1 and figure 3B.15-1, respectively; the test problem is the same as the VM-A03 model of the DAMPSI program. System frequencies and comparison of the damping results are tabulated in table 3B.15-2, and the system mode shapes are graphed in figure 3B.15-2.

From a comparison of the results, it can be concluded that the COMDAM approach is appropriate and correct.

COMDOM COMPUTER PROGRAM

(COMDAM)

Table 3B.15-1

STRUCTURE PROPERTIES OF MODEL

(Concrete Modulus $E = 6.9 \times 10^5$ KSF, $G = 2.7 \times 10^5$ KSF)

Joint Properties			Member Properties				
Mass No.	$m_i g$ (KIPS)	$I_i \times 10^{-6} xg$ (KIP-Ft^2)		Location Between Joint No.	Area (Ft^2)	Shear Area (Ft^2)	Moment of Inertia $\times 10^{-6}$ (Ft^4)
19[a]	20000	20.0	CONTAINMENT				
1	4600	9.5		19 to 1	1400	700	3.0
2	4200	8.5		1 to 2	1400	700	3.0
3	4200	8.5		2 to 3	1400	700	3.0
4	4200	8.5		3 to 4	1400	700	3.0
5	4200	8.5		4 to 5	1400	700	3.0
6	4200	8.5		5 to 6	1400	700	3.0
7	4600	9.5		6 to 7	1400	700	3.0
8	3000	6.0		7 to 8	1000	500	2.0
9	2500	4.0		8 to 9	1000	500	1.5
10	2000	2.0		9 to 10	1000	500	0.8
11	200	0.1		10 to 11	1000	500	0.2
12	2800	2.5	INTERNALS	Base to 12	2000	1300	1.1
13	2500	2.0		12 to 13	2600	1600	1.2
14	6300	5.0		13 to 14	2200	1500	1.2
15	3800	6.5		14 to 15	2000	750	1.3
16	8500	12.5		15 to 16	1750	600	1.0
17	1200	0.8		16 to 17	800	400	0.2
18	800	0.1		17 to 18	200	70	0.1

a. Base Node

COMDOM COMPUTER PROGRAM

(COMDAM)

Table 3B.15-2

SYSTEM FREQUENCY AND MODAL DAMPING PROPERTIES OF MODEL

(Sheet 1 of 2)

Mode No.	Frequency (CPS)		Modal Damping (% Critical)		
	Fixed Base	Interaction	Fixed Base	Interaction	
				DAMPSI	CONDAM
1	5.23	3.36	2.0	5.17	5.17
2	14.25	8.68	4.0	34.65	34.65
3	14.78	12.50	2.0	9.04	9.04
4	23.65	17.36	4.0	14.35	14.35
5	27.25	23.08	2.0	6.25	6.25
6	29.45	25.61	2.0	5.53	5.53
7	31.31	29.86	4.0	2.62	2.62
8	41.65	32.36	2.0	11.02	11.02
9	47.56	41.13	4.0	9.56	9.56
10	50.09	42.15	2.0	2.82	2.82
11	54.89	53.01	2.0	7.28	7.28
12	62.38	53.37	2.0	3.08	3.08
13	69.79	60.90	2.0	8.09	8.09
14	74.59	63.29	2.0	3.46	3.46
15	77.88	70.13	2.0	2.31	2.31
16	79.31	76.92	4.0	3.15	3.15
17	83.48	78.13	2.0	2.42	2.42
18	86.86	82.43	4.0	4.76	4.76
19	89.07	83.50	4.0	2.04	2.04
20	91.21	88.55	2.0	4.36	4.36
21	99.94	90.49	2.0	3.67	3.67
22	106.44	92.27	4.0	3.48	3.48
23	123.72	104.10	2.0	3.91	3.91
24	131.89	106.96	4.0	4.28	4.28
25	140.22	125.45	2.0	2.51	2.51
26	151.50	134.26	4.0	4.47	4.47
27	153.35	141.05	4.0	2.19	2.19
28	160.47	151.76	2.0	4.01	4.01

Table 3B.15-2

SYSTEM FREQUENCY AND MODAL DAMPING PROPERTIES OF MODEL

(Sheet 2 of 2)

Mode No.	Frequency (CPS)		Modal Damping (% Criteria)		
	Fixed Base	Interaction	Fixed Base	Interaction	
				DAMPSI	CONDAM
29	177.49	156.26	2.0	4.27	4.27
30	182.68	161.59	2.0	2.48	2.48
31	194.73	177.61	2.0	2.02	2.02
32	216.50	182.83	4.0	2.02	2.02
33	260.95	194.77	4.0	2.01	2.01
34	263.65	219.26	2.0	4.27	4.27
35	379.35	261.28	2.0	4.02	4.02
36	399.00	263.65	4.0	2.00	2.00
37	-	379.35	-	2.00	2.00
38	-	399.38	-	4.01	4.01

3B.16 ICES-STRUDL II COMPUTER PROGRAM CE 901

3B.16.1 DESCRIPTION

The STRUDL subsystem of ICES is designed as a structural information system, to assist the engineer throughout the design process. STRUDL is designed for application to a wide range of structural types including two and three dimensional structures consisting of truss and frame members. The program assumes, for the frame analysis, that the linear, slender, elastic members are subjected to small displacements. Member end conditions can be pinned or rigid. A wide variety of loading conditions and combinations can be considered.

For program limitations, see Appendix A in the Bechtel developed user's manual, and STRUDL news.

3B.16.2 VALIDATION

The solutions to test problems have been demonstrated to be essentially identical to the results obtained using the following recognized public-domain computer programs.

- SAP 1.9 program (Bechtel standard computer program)
- MSC/NASTRAN (MacNeil Schwendler Corporation)
- CE 800 BSAP (Bechtel standard computer program)
- CE 401 (Bechtel standard computer program; AISC computer program for steel beam and girder design)

Agreement has also been established between STRUDL program results and the results of benchmark computer problems and solutions using other independent programs available in

engineering journals. Document traceability is available at Bechtel Power Corporation.

3B.16.3 EXTENT OF APPLICATION

The program was used to perform structural analysis for pipe supports.

3B.17 SARGENT AND LUNDY PIPING ANALYSIS COMPUTER PROGRAMS

3B.17.1 INTEGRATED PIPING ANALYSIS SYSTEM COMPUTER PROGRAM (PIPSYS)

The program number for PIPSYS is 09.5.065-6.1.

3B.17.1.1 Description

PIPSYS analyzes piping systems of power plants for static and dynamic loadings, and computes the combined stresses. The following analyses are performed.

A. Static: Analysis of thermal, displacement, distributed, and concentrated weight loadings on piping systems.

B. Dynamic: Analysis of piping system response to seismic and fluid transient loads.

C. Stress Combination: Computation of the combined stresses in the piping components in accordance with the ASME Boiler and Pressure Vessel Code, Section III.(1)

The static, dynamic, and stress combination analyses can be performed independently or in sequence. Results of the static and dynamic analyses can be stored on magnetic tape for use at a later date to perform the stress combination analysis. The piping configuration can be plotted on a CalComp plotter.

The input consists of the piping system geometry, material properties, and static and dynamic loading. Various options exist to control the length of the output. The default option generally prints only the summary of input data and final results.

SARGENT AND LUNDY PIPING ANALYSIS

COMPUTER PROGRAM

PIPSYS was developed at Sargent and Lundy in 1972. It is currently maintained on a UNIVAC 1106 operating under EXEC-8.

3B.17.1.2 Validation

To demonstrate the validity of the PIPSYS program, the following three examples are presented.

To illustrate the validity of the static portion of PIPSYS, the problem shown in figure 3B.17-1 was analyzed and the results compared to those given in reference 2. Table 3B.17-1 shows the comparison of member end moments. As shown, the results from PIPSYS and reference 2 are in good agreement.

Table 3B.17-1

COMPARISON OF MOMENTS FOR SELECTED MEMBERS

	Moments From Reference 2 (kip-ft)	Moments From PIPSYS (kip-ft)
M_{AB}	106.0	102.8
M_{BA}	72.0	72.5
M_{BC}	133.0	131.8
M_{CB}	133.0	131.8
M_{CD}	-133.0	-131.8
M_{DC}	-133.0	-131.8
M_{DE}	133.0	131.8
M_{ED}	86.0	84.2
M_{BE}	-158.0	-156.6
M_{EB}	-158.0	-156.6
M_{FE}	106.0	102.8
M_{EF}	72.0	72.5

To illustrate the validity of the stress combination analysis portion of PIPSYS, the problem outlined in reference 3 was reanalyzed on the PIPSYS program. The layout of the piping system is shown in figure 3B.17-2. The stress analysis is performed at location 19. The summary of loads sets and descriptions are presented in table 3B.17-2. The results of the stress analysis are presented in tables 3B.17-3 and 3B.17-4. The notations and equation numbers correspond to the ASME Boiler and Pressure Vessel Code.(1)

It is observed that the PIPSYS results are very close to those presented in reference 3.

To illustrate the validity of the dynamic analysis portion of PIPSYS, a problem was analyzed and the results obtained from PIPSYS were compared with those from two public domain computer programs, DYNAL(4) AND NASTRAN.(5)(6)

Figure 3B.17-3 shows a schematic representation of the piping system analyzed. The system is modeled with simple beam elements with a total of 136 degrees-of-freedom. Figure 3B.17 4 shows the time-dependent blowdown forces at the relief valves' locations. Results of PIPSYS are compared with DYNAL and NASTRAN in table 3B.17-5 and figure 3B.17-5. The results from all three programs are quite close.

3B.17.2 INTEGRATED PIPING ANALYSIS SYSTEM FOR MICROCOMPUTERS (PIPSYS/PC)

The program number for PIPSYS/PC is 03.7.026-1.20 and the authors are J. A. Stirk, S. A. Keller, and N. A. Holmes.

Table 3B.17-2

SUMMARY OF LOAD SETS AT GIRTH BUTT WELD WITH CHANGE
IN MATERIAL AND WALL THICKNESS

Load Set No.	Load Set Description	No. of Transients	P	M_x	M_y	M_z	DT_1	T_a (Valve)	T_b (Pipe)	DT_2
1	Zero	5	0	0	0	0	0	70	70	0
2	Cold Hydro Test		3590	0	0	0	0	70	70	0
3	Hot Hydro Test, Up	40	2200	251.7	141.6	-7.1	2.4	400	400	0.3
4	Hot Hydro Test, Down		0	0	0	0	-2.4	70	94	-0.3
5	Plant Startup	100	2200	337.2	184.9	-936.0	0	70	70	0
6	Plant Shutdown		0	0	0	0	0	70	70	0
7	Plant Loading	18300	2200	381.6	204.4	-1169.6	0	70	70	0
8	Plant Unloading		2200	337.2	184.9	-936.0	0	70	70	0
9	Loss of Load, 4.1	80	2515	384.2	204.4	-1183.4	0	70	70	0
10	Loss of Load, 4.2		1500	345.7	186.4	-1011.4	0	70	70	0
11	N.O. + Earthquake	50	2200	408.6	463.3	-1134.1	0	70	70	0
12	N.O. - Earthquake		2200	265.8	-93.5	-737.9	0	70	70	0

Table 3B.17-3

SIX HIGHEST VALUES OF STRESS INTENSITY, FOR GIRTH BUTT WELD WITH CHANGE IN MATERIAL AND WALL THICKNESS

Load Set Pair		Values From Reference 5				PIPSYS Program			
		S_n	Eq.(12)	Eq.(13)	K_e	S_n	Eq.(12)	Eq.(12)	K_e
3	4	52549	(a)	(a)	1,000	52600	(a)	(a)	1,000
3	9	49883	(a)	(a)	1,000	49900	(a)	(a)	1,000
3	10	49620	(a)	(a)	1,000	49600	(a)	(a)	1,000
3	6	48013	(a)	(a)	1,000	48000	(a)	(a)	1,000
1	3	48013	(a)	(a)	1,000	48000	(a)	(a)	1,000
3	11	47728	(a)	(a)	1,000	47700	(a)	(a)	1,000

a. Because S_n, calculated by Equation (10), is less than $3S_m$, Equations (12) and (13) are satisfied.

Table 3B.17-4

SUMMARY OF CALCULATIONS OF CUMULATIVE USAGE FACTOR,

FOR GIRTH BUTT WELD

WITH CHANGE IN MATERIAL AND WALL THICKNESS

Load Set Pair		Values Based On Reference 5		Values From PIPSYS Program	
i	j	$\frac{S_p K_e}{2}$	Usage Factor	$\frac{S_p K_e}{2}$	Usage Factor
3	9	40338	0.0050	40300	0.005
4	9	34400	0.0029	34400	0.003
1	11	29806	0.0002	29800	0.000
6	11	29806	0.0020	29800	0.002
6	7	29163	0.0023	29200	0.002
2	10	26254	0.0002	26300	0.000
10	12	93170	0.0000	93200	0.000
Cumulative Usage Factor			0.0126		0.124

3B.17.2.1 General Description

PIPSYS/PC consists of (1) an interactive graphics module for the generation, review, and modification of piping data, and (2) static and dynamic modules. PIPSYS/PC can be used as a stand-alone piping analysis system or as a graphic input or analysis interface to the mainframe PIPSYS programs (Sargent and Lundy program numbers 09.5.218-2.0 and 09.5.065-6.1).

Table 3B.17-5

MODAL FREQUENCIES (CYCLES/SEC)

Mode Number	PIPSYS	NASTRAN	DYNAL
1	6.07	6.085764	6.0821088
2	10.69	10.94144	10.936468
3	11.48	11.66862	11.666215
4	14.76	15.20947	15.204282
5	20.12	22.25613	22.135260
6	23.87	28.53255	28.505264
7	25.32	30.58105	30.530972
8	28.80	31.22073	31.190062
9	30.00	32.27319	32.199679
10	42.39	43.14653	43.135100
11	42.95	43.50436	43.497053
12	58.02	58.19336	57.991710
13	77.78	76.62025	71.996751
14	90.74	93.69710	92.12974
15	91.8	96.04482	95.167976
16	93.39	97.81956	97.410131
17	96.96	99.40727	98.209594
18	101.42	104.6169	101.64513
19	102.14	105.4910	103.80206
20	103.03	107.7136	107.52304

3B.17.2.2 Validation

The analysis results of the PIPSYS/PC run programs were compared to the results produced by PIPSYS on the mainframe. All results were identical.

3B.17.3 NONLINEAR HEAT TRANSFER ANALYSIS OF AXISYMMETRIC SOLIDS (NOHEAT)

The program number for NOHEAT is 09.5.075 and the authors are I. Harhoomand and E. L. Wilson, University of California, Berkeley, California.

3B.17.3.1 Program Scope

The program uses the finite element method to calculate the temperature distribution in an axisymmetric solid that results from nonlinear heat transfer. The nonlinear effects of conduction, radiation, and convection can be included. A temperature history for each node point is presented. Internal generation has been provided for several of the most frequently used meshes. In addition, stresses resulting from linear thermal expansion are calculated for certain appropriate sections. Options have been added that calculate linearized thermal gradients and that plot the finite-element mesh.

3B.17.3.2 Validation

Two problems have been selected to validate this program. The first is taken from "ASME/Pressure Vessel and Piping/1972 Computer Program Verification" and is problem AER-1, "An Axisymmetrical Transient Thermal Analysis."

The second problem is a straight length of pipe subject to an internal temperature change of 432F in 0.5 second. This problem was solved using both NOHEAT and TSHOK (Sargent and Lundy program number 09.5.033) and the results were compared.

3B.17.4 HYDRAULIC TRANSIENT ANALYSIS (HYTRAN)

The program number for HYTRAN is 09.5.121 and the authors are C. H. Li and V. K. Verma.

3B.17.4.1 Program Scope

HYTRAN calculates pressures, velocities, and force transients in a liquid-filled piping network with up to 60 legs of 40 nodes or 200 legs of 15 nodes each. Transients may be initiated by valve closure, pump trip or startup, or by pressure changes at a piping terminal.

The pump characteristics may be described using two methods: polynomial input or trigonometric input. Sets of data are provided in HYTRAN for pump-specific speeds of 1800, 7600, and 13500 rpm. These data may be chosen and then modified to match available data, or the entire set of data may be input.

Output of force-time history can be plotted and/or saved on a data file for use as input to PIPSYS.

3B.17.4.2 Validation

The program was validated by comparison with the following problems:

A. Hydraulic Transients; V. L. Streeter and E. B. Wylie, 1967 (Problems 3.1, 3.4, and 3.6).

B. Waterhammer Analysis, John Parmakian, 1963 (Problem on pg. 83).

C. Transient Analysis of Offshore Loading Systems, V. L. Streeter and E. B. Wylie, Transactions of the ASME Journal of Engineering Industry, February 1975.

3B.17.5 LOCAL STRESSES IN SPHERICAL AND CYLINDRICAL SHELLS DUE TO EXTERNAL LOADINGS ON NOZZLES (LSS)

The program number for LSS is 09.5.117 and the author is A. J. Weiss.

3B.17.5.1 Program Scope

This program uses the Bijlaard method of stress analysis to calculate stresses due to external loading on nozzles described in the Welding Research Council Bulletin 107. All the empirical curves in Bulletin 107 were put into equation form, using the curve-fitting program POLYFIT (Sargent and Lundy program number 09.5.130-1.0).

3B.17.5.2 Validation

LSS was validated by manual calculation. All equations generated by POLYFIT were also checked by comparing the values generated by the equations with the original input data.

3B.17.6 REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III, 1974.
2. Kinney, J. S., Indeterminate Structural Analysis, Addison Wesley Publishing Company, Reading, Massachusetts, p 377, 1957.
3. "Sample Analysis of a Piping System Class 1 Nuclear," prepared by Working Group on Piping of the Design Subgroup of the Nuclear Power Committee of the ASME Boiler and Pressure Vessel Committee, the American Society of Mechanical Engineers, New York, 1972.
4. ICES DYNAL User's Manual, McDonnell Douglas Automatic Co., September 1971.
5. NASTRAN Theoretical Manual, NASA SP-221, September 1970.
6. NASTRAN User's Manual

C. Transient Analysis of Offshore Loading Systems, V. L. Streeter and E. B. Wylie, Transactions of the ASME Journal of Engineering Industry, February 1975.

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5. NASTRAN Theoretical Manual, NASA SP-221, September 1970.

6. NASTRAN User's Manual

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APPENDIX 3C

DESIGN OF STRUCTURES FOR TORNADO MISSILE IMPACT

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CONTENTS (Cont'd)

TABLES

FIGURES

APPENDIX 3C
DESIGN OF STRUCTURES FOR
TORNADO MISSILE IMPACT

3C.1 INTRODUCTION

3C.1.1 GENERAL

This appendix contains methods and procedures for analysis and design of steel and reinforced concrete structures and structural elements subject to tornado-generated missile impact effects. Structures subject to missile impact, postulated missiles, and other concurrent loading conditions are identified in section 3.5.

Missile impact effects are assessed in terms of local damage and structural response. Local damage (damage that occurs in the immediate vicinity of the impact area) is assessed in terms of perforation and spalling.

Evaluation of local effects is essential to ensure that protected items would not be damaged directly by a missile perforating a protective barrier, or by secondary missiles such as spall particles. Empirical formulae are used to assess local damage. This evaluation was made in accordance with BC-TOP-9-A.

Evaluation of structural response is essential to ensure that protected items are not damaged or functionally impaired by deformation or collapse of the impacted structure.

STRUCTURAL RESPONSE DUE TO

MISSILE IMPACT LOADING

Structural response is assessed in terms of deformation limits, strain energy capacity, structural integrity, and structural stability. Structural dynamic principles are used to predict structural response.

3C.1.2 PROCEDURES

The general procedures for analysis and design of structures or structural elements for missile impact effects include:

A. Defining the missile properties (such as type, material, deformation characteristics, geometry, mass, trajectory, strike orientation, and velocity).

B. Determining impact location, material strength, and thickness required to preclude local failure (such as perforation for steel targets and spalling for reinforced concrete targets).

C. Defining the structure and its properties, (such as geometry, section strength, deformation limits, strain energy absorption capacity, stability characteristics, and dynamic response characteristics).

D. Determining structural response considering other concurrent loading conditions

E. Checking adequacy of structural design (stability, integrity, deformation limits, etc.) to verify that local damage and structural response (maximum deformation) will not impair the function of safety-related items.

3C.2 STRUCTURAL RESPONSE DUE TO MISSILE IMPACT LOADING

3C.2.1 GENERAL

When a missile strikes a structure, large forces develop at the missile-structure interface, which decelerate the missile and accelerate the structure. The response of the structure depends on the dynamic properties of the structure and the time-dependent nature of the applied loading (interface force-time function). The force-time function is, in turn, dependent on the type of impact (elastic or plastic) and the nature and extent of local damage.

In an elastic impact, the missile and the structure deform elastically, remain in contact for a short period of time (duration of impact), and subsequently disengage due to the action of elastic interface restoring forces.

In a plastic impact, the missile or the structure (or both) may deform plastically or sustain permanent deformation or damage (local damage). Elastic restoring forces are small, and the missile and the structure tend to remain in contact after impact. Plastic impact is much more common in nuclear plant design than elastic impact (which is rarely encountered). For example, test data indicate that the impact from all postulated tornado-generated missiles can be characterized as a plastic collision.

If the interface forcing function can be defined or conservatively idealized (from empirical relationships or from theoretical considerations), the structure can be modeled

mathematically, and conventional analytical or numerical techniques can be used to predict structural response. If the interface forcing function cannot be defined, the same mathematical model of the structure can be used to determine structural response by application of conservation of momentum and energy balance techniques with due consideration for type of impact (elastic or plastic).

In either case (in lieu of a more rigorous analysis), a conservative estimate of structural response can be obtained by first determining the response of the impacted structural element and then applying its reaction forces to the supporting structure. The predicted structural response enables assessment of structural design adequacy in terms of strain energy capacity, deformation limits, stability, and structural integrity.

3C.2.2 MASS-SPRING MODEL

To facilitate determination of structural response due to missile impact loading, a dynamically similar lumped mass spring model of the structure can be utilized.

3C.2.2.1 Definition of Model

The structural element that is struck by the missile is modeled as a mass, $M_{(e)}$, backed by a spring that has a resistance-displacement function corresponding to that of the struck element with a concentrated load applied at the location of impact. For dynamic similarity and calculation convenience,

the model is defined so that the following conditions are satisfied:

A. The deflection, internal strain energy, and kinetic energy of the model must be the same as that of the structure.

B. The external work done on the model by the missile and by other concurrent loads must be equal to (or greater than) the external work done on the structure.

Other loads that may be present during structural response can be accounted for in the model by replacing these loads with equivalent concentrated loads (that will do the same amount of external work on the model as would be done on the structure during structural response), using procedures such as those contained in references 1, 2, and 3.

Following these procedures, the relative dynamic displacement of the model will be equal to that of the structure.

3C.2.2.2 Determination of Effective Mass

For distributed mass elements (such as slabs and beams), the effective mass, M_e, during impact varies with the deformed shape of the element during impact. In order for the whole element to be deformed during impact, the duration of impact, t_i, must exceed the stress wave travel time, t_c, between the impact location and the supports. If t_c is significantly less than t_i (which is most generally the case), the deflected shape

during impact can be approximated by the first mode shape which results in the following expression for M_e:

$$M_e = \frac{k}{\omega^2} \text{ or } M_e = k\left[\frac{T_n}{2\pi}\right]^2 \qquad (2\text{-}1)$$

where:

k = spring constant of model spring (same as for a concentrated load applied at the impact location), (load per unit displacement)

ω = calculated natural frequency of the element, rad/s

T_n = calculated natural period of the element, s

For relatively deep short-span elements, the element thickness or depth establishes a lower limit of coupled mass during impact which can exceed that determined from equation 2-1. For these cases, the effective mass should not be less than the following:

For slabs and plates:

$$M_e = \frac{Y}{g} T(D + T)^2 \qquad (2\text{-}2)$$

For beams:

$$M_e = M_b (D + 2T) \qquad (2\text{-}3)$$

where:

γ = weight per unit volume

M_b = mass per unit length of member

T = thickness or depth of member

D = maximum missile contact dimension or effective diameter

Very long span flexural members subjected to a very short duration impact may have insufficient time to approach a first mode deformed shape during impact, in which case effective mass is an undefined variable. An example of this would be the case where the stress wave travel time to the supports, t_c, exceeds the duration of the impact, t_i. In this case, design adequacy can generally be demonstrated by an analysis using an effective mass corresponding to a similar element with a shorter span.

3C.2.3 FORCE-TIME SOLUTION

A force-time solution can be used to determine the maximum displacement when the interface forcing function can be defined (see BC-TOP-9-A). This enables direct solution of the equation(s) of motion for the struck element.

$$F_{(t)} + F_o - R_{(x)} = M_e\ddot{X} \qquad t \leq t_i \qquad (2-4)$$

$$F_o - R_{(X)} = M_e\ddot{X} \qquad t > t_i \qquad (2-5)$$

$$F_o - R_{(x)} = (M_e + M_m)\ddot{X} \qquad t > t_i \qquad (2-6)$$

where:

$F_{(t)}$ = force-time function

F_o = equivalent force due to other concurrent loads

$R_{(x)}$ = available resisting spring force as a function of displacement, x

$\ddot{X}$ = acceleration of mass M_e

M_e = effective mass of the struck element

M_m = mass of the missile

T = time

T_i = duration of impact (pulse duration)

Equation 2-4 is used when the time to maximum response, t_m, is less than t_i. When t_m is greater than t_i and the missile remains disengaged from the struck element (such as in an elastic collision) subsequent to t_i, equations 2-4 and 2-5 are used. When t_m is greater than t_i and the missile and struck element remain in contact subsequent to t_i (plastic impact), equations 2-4 and 2-6 are used. It should be noted that in using these relationships, the forcing function, $F_{(t)}$ should be based on the change of missile velocity, V_c, during time t_i. A more conservative solution is obtained when the striking velocity, V_s, is used in lieu of V_c for defining $F_{(t)}$.

3C.2.4 RESPONSE CHART SOLUTION

Response charts such as figure 3C.2-1 from reference 1 (with modifications) can be used to determine structural response (in lieu of numerical integration of equations 2-4 through 2-6) in cases where the idealized forcing function, $F_{(t)}$, and resistance-displacement function, $R_{(x)}$, are compatible with the charts.

Structural response is determined by entering the charts with calculated values of C_T and C_R to determine the ductility ratio, μ. The dimensionless ratios are defined as follows:

$$C_R = \frac{R_y}{F} \qquad (2\text{-}7)$$

$$C_T = \frac{t_i}{T_n} \qquad (2\text{-}8)$$

$$\mu = \frac{x_m}{x_e} \qquad (2\text{-}9)$$

where:

C_R	=	resistance-to-force ratio
C_T	=	time ratio
μ	=	ductility ratio
R_Y	=	yield resistance
F	=	peak force
t_i	=	force duration
T_n	=	natural period
X_m	=	maximum displacement

X_e = yield displacement

When other loads are acting on the structural element during structural response, the ductility ratio þ and maximum displacement X_m can be determined by the following procedure:

A. Determine C_R using R_a in place of R_y

$$R_a = R_y - R_o \qquad (2\text{-}10)$$

where:

R_o = effective resistance required for other loads (see paragraph 3C.2.2.1 and figure 3C.2-2)

R_a = available resistance

B. Determine the partial ductility ratio μ' from figure C.2-1 or 3C.2-3

$$\mu' = \frac{X'_m}{X'_e} \qquad (2\text{-}11)$$

$$X'_m = X_m - X_o \qquad (2\text{-}12)$$

$$X'_e = X_e - X_o \qquad (2\text{-}13)$$

C. Determine the maximum displacement and combined ductility ratio

$$X_m = \mu'(X_e - X_o) + X_o \qquad (2\text{-}14)$$

$$\mu = \frac{\mu'(X_e - X_o) + X_o}{X_e} \qquad (2\text{-}15)$$

3C.2.5 ENERGY BALANCE SOLUTION

The energy balance method can be used to obtain an upper limit estimate of structural response. This method involves determining the displacement, X_m, at which the available strain energy of the system is equal to the kinetic energy of the system after impact, E_s. An upper limit estimate of E_s is obtained by assuming resisting spring forces, R_x, do not act during impact.

The impact can then be characterized as a collision of two solid bodies; a missile with velocity V_s and mass M_m striking a structural element of mass M_e which is initially at rest. The kinetic energy of the system after a plastic impact would, therefore, be:

$$E_s = \frac{M_m^2 V_s^2}{2(M_m + M_e)} \qquad (2\text{-}16)$$

The kinetic energy after an elastic impact (with the coefficient of restitution assumed to be unity) would be:

$$E_s = \frac{2M_m^2 M_e V_s^2}{(M_m + M_e)^2} \qquad M_m \le M_e \qquad (2\text{-}17)$$

$$E_s = \frac{M_m V_s^2}{2} \qquad M_m > M_e \qquad (2\text{-}18)$$

The maximum displacement, X_m, can then be determined as the displacement at which the available strain energy (see figure 3C.2-2) is equal to E_s.

For an elastic response:

$$X_m = X_o + \left[\frac{2\,E_s}{k}\right]^{1/2} \qquad X_m < X_e \qquad (2\text{-}19)$$

For an elasto-plastic response:

$$X_m = \frac{E_s}{k\,(X_e - X_o)} + \frac{X_e + X_o}{2} \qquad X_m > X_e \qquad (2\text{-}20)$$

$$\mu = \frac{E_s}{R_y(X_e - X_o)} + \frac{X_o}{2X_e} + \frac{1}{2} \qquad (2\text{-}21)$$

where:

X_o = displacement due to other loads

X_e = yield displacement

X_m = maximum combined displacement

R_y = yield resistance

k = elastic spring constant

μ = required ductility ratio

For nonlinear systems, X_m is the displacement that satisfies the following relationship:

$$E_s = \int_{X_o}^{x_m} R_{(x)} d_x - R_o(X_m - X_o) \qquad (2\text{-}22)$$

where:

$R_{(x)}$ = the resistance as a function of displacement

R_o = equivalent static resistance required for other loads

3C.2.6 STRUCTURAL ASSESSMENT

The predicted structural response enables assessment of design adequacy in terms of strain energy capacity, deformation limits, stability, and structural integrity.

For elements required to remain elastic, a check is made to ensure that the usable strength capacity of the element would not be exceeded at the calculated displacement.

For structures allowed to displace beyond yield (elasto-plastic response) a check is made to ensure that deformation limits would not be exceeded by comparing calculated displacements or required ductility ratios with allowable values (such as contained in section 3C.3).

For nonlinear elements, the strain energy utilized in resisting the impact loading, E_s, must be less than the available strain energy at failure, E_f.

$$E_f = \int_{X_o}^{X_f} R_{(x)}dx - R_o(X_f - X_o) \qquad R_o \le R_f \qquad (2\text{-}23)$$

where:

E_f = available strain energy at failure

X_f = displacement at failure

R_f = resistance at failure

When E_f can be well defined such as from test results, E_s should not be greater than $0.7E_f$. When E_f is analytically defined, E_s should not exceed $0.5E_f$.

3C.3 DESIGN GUIDELINES

This section contains criteria and design guidelines for determination of structural capacities, deformations, deformation limits, and dynamic properties of structural elements subject to missile impact.

3C.3.1 GENERAL

Resistance-displacement functions are defined utilizing conventional structural analysis techniques for determining elastic displacements. Methods such as limit design and yield line theory are utilized for determining limiting resistance values for ductile elements. Some typical values of effective yield displacement and maximum resistance for ductile flexural members are listed in tables 3C.3-1 and 3C.3-2 (similar expressions can be developed for other configurations and load cases).

Structures and structural elements are allowed to sustain inelastic deformations, providing the deformation and strain limits specified herein are not exceeded. These structures and structural elements must be designed and proportioned to ensure ductile behavior in the intended deformation mode. Failure leading to collapse in a less ductile failure mode must be precluded and structural stability must be maintained.

The maximum allowable resistance is determined using dynamic section strengths with appropriate capacity reduction factors.

3C.3.1.1 Dynamic Material Strengths

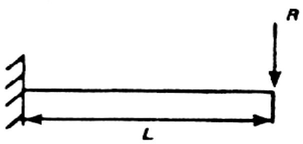
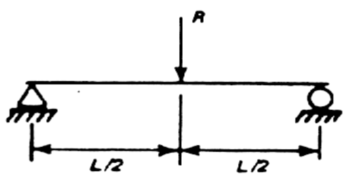
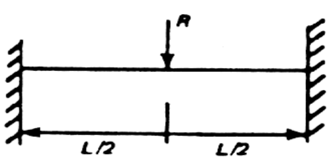
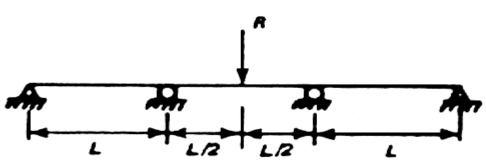
Dynamic material strengths are obtained by multiplying the static material strength values by dynamic increase factors (DIFs). DIF values for various materials are contained in table 3C.3-3

STRUCTURAL RESPONSE DUE TO

MISSILE IMPACT LOADING

Table 3C.3-1

RESISTANCE-YIELD DISPLACEMENT VALUES FOR BEAMS

DESCRIPTION	RESISTANCE	YIELD DISPLACEMENT
(1) CANTILEVER 	$R = \frac{M_u}{L}$	$X_e = \frac{RL^3}{3EI}$
(2) SIMPLY SUPPORTED 	$R = \frac{4M_u}{L}$	$X_e = \frac{RL^3}{48EI}$
(3) FIXED SUPPORTS 	$R = \frac{4(M_u^+ + M_u^-)}{L}$	$X_e = \frac{RL^3}{192EI}$
(4) MULTI-SPAN 	$R = \frac{4(M_u^+ + M_u^-)}{L}$	$X_e = \frac{0.011RL^3}{EI}$

WHERE M_u^+ = PLASTIC POSITIVE MOMENT CAPACITY
M_u^- = PLASTIC NEGATIVE MOMENT CAPACITY
I = MOMENT OF INERTIA (in^4)
FOR REINFORCED CONCRETE $I = I_e$

STRUCTURAL RESPONSE DUE TO

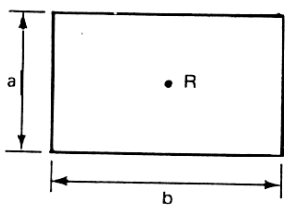
MISSILE IMPACT LOADING

Table 3C.3-2

RESISTANCE YIELD DISPLACEMENT VALUES

FOR SLABS AND PLATES[a]

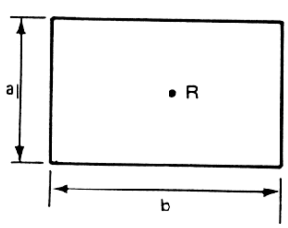
DESCRIPTION	RESISTANCE	YIELD DISPLACEMENT
(1) SIMPLY SUPPORTED ON ALL 4 SIDES WITH LOAD AT CENTER	$R = 2\pi M_u$	$X_e = \frac{\alpha R a^2}{12EI}(1-\nu^2)$



b / a	1.0	1.1	1.2	1.4	1.6	1.8	2.0	3.0	∞
α	.1390	.15.8	.1624	.1781	.1884	.1944	.1981	.2029	.2031

(2) FIXED SUPPORTS ON ALL 4 SIDES WITH LOAD AT CENTER

α = DISPLACEMENT COEFFICIENT
ν = POISSON'S RATIO
t = THICKNESS (in)
E = MODULUS OF ELASTICITY (lb/in^2)
I = MOMENT OF INERTIA PER UNIT WIDTH (in^4/in) FOR REINFORCED CONCRETE SECTION $I = I_e$
M_u^+ = PLASTIC POSITIVE MOMENT CAPACITY (in lb/in)
M_u^- = PLASTIC NEGATIVE MOMENT CAPACITY (in lb/in)



$R = 2\pi (M_u^+ + M_u^-)$ $\quad$ $X_e = \frac{\alpha R a^2}{12EI}(1-\nu^2)$

b/a	1.0	1.2	1.4	1.6	1.8	2.0	∞
α	.0671	.0776	.0830	.0854	.0864	.0866	.0671

a. From references 4 through 8. For plates, this neglects membrane action. Therefore a more detailed analysis utilizing membrane theory is acceptable.

STRUCTURAL RESPONSE DUE TO

MISSILE IMPACT LOADING

Table 3C.3-3

DYNAMIC INCREASE FACTOR[a]

Material and Stress Condition	DIF
Reinforced Or Prestressed Concrete	
Concrete:	
Compression	1.25
Diagonal tension and direct shear (punch out)	1.10
Reinforcing steel:	
Tension, compression and shear steel	
40 ksi yield strength steel	1.20
50 ksi yield strength steel	1.15
60 ksi yield strength steel	1.10
Structural Steel	
Flexural, shear, tension and compression for:	
$F_y \leq 40$ ksi yield strength steel	1.20
$F_y \leq 50$ ksi yield strength steel	1.10
$F_y \leq 60$ ksi yield strength steel	1.00
Shear 1.00	

a. Based on information contained in references 9 through 14.

$$f_{dyn} = (DIF) f_{stat} \qquad (3\text{-}1)$$

where:

f_{dyn} = allowable dynamic strength value

f_{stat} = specified static strength value

DIF = dynamic increase factor

3C.3.1.2 Allowable Deformations

Maximum allowable displacements are determined from the ductility ratios (ratio of maximum displacement to yield displacement) contained in table 3C.3-4 and the provisions of paragraph 3C.3.1.3 and subsections 3C.3.2 and 3C.3.3. As an alternative, the allowable displacement of reinforced concrete flexural members can be based on an upper limit for plastic hinge rotation which can be defined as follows:[9]

$$r_\theta = 0.0065\frac{d}{c} \leq 0.07 \qquad (3\text{-}2)$$

where:

r_θ = hinge rotation, radians

d = distance from compression face to centroid of tensile steel reinforcement, in.

c = distance from compression face to the neutral axis at ultimate strength, in.

A check should be made to ensure that the resulting deformation will not impair the function of essential safety-related equipment.

3C.3.1.3 Nonductile Elements and Components

The deformation of nonductile elements (those subject to abrupt or brittle type failure) must be limited to ensure that the strength capacity of these elements is not exceeded.

STRUCTURAL RESPONSE DUE TO

MISSILE IMPACT LOADING

Table 3C.3-4

DUCTILITY RATIOS

Member Type and Load Condition	Maximum Allowable value of μ
Reinforced Concrete	
Flexure:	
Beams and one-way slabs	$\frac{0.05}{p - p'} \leq 10$
Slabs with two-way reinforcing	$\frac{0.05}{p - p'} \leq 10^{(a)}$
Axial compression:	
Walls and columns[30]	1.3
Shear, concrete beams and slabs in region controlled by shear:	
Shear carried by concrete only	1.3
Shear carried by concrete and stirrups	1.6
Shear carried completely by stirrups	2.0
Shear carried by bent-up bars	3.0
Structural Steel	
Columns and beams with uniform moment[31]	$\mu \leq \frac{14x10^4}{F_y\left(\frac{KL}{r}\right)^2} + 1/2 \leq 10$
Beams with moment gradient	10
Shear	10
Axial tension and steel plates membrane tension[32]	$0.5\frac{e_u}{e_y}$

a. A ductility ratio of 22.8 was used in the cask drop analysis.

Notes:

1. Based on information contained in references 9, 12, and 14 through 25.

2. p and p' are the positive and negative reinforcing steel ratios.

3. See figure 3C.3-2 for allowable ductility ratios where there is a beam-column action.

4. KL/r is the member slenderness ratio. F_y is the yield stress (ksi).

5. e_u and e_y are the ultimate and yield strains. e_u Shall be taken as the ASTM specified minimum.

Structures may contain nonductile elements or components and still be allowed to deform inelastically (per paragraph 3C.3.1.2) provided that the strength capacity of the nonductile elements or components is at least 20% greater than the imposed loading from the structure in its fully developed ductile deformation mode.

3C.3.2 REINFORCED CONCRETE

The dynamic section strengths of reinforced concrete members are determined using strength design methods and dynamic material strengths. For reinforced concrete flexural members (with tension reinforcing only), the plastic resisting moment is:

$$M_{\mu} = \phi A_s f_{dy}\left(d - \frac{a}{2}\right) \qquad (3\text{-}3)$$

$$a = \frac{A_s f_y}{.85 f'_c b}$$

where:

ϕ = capacity reduction factor with a value of 0.9 for flexure

A_s = area of tension steel

a = depth of equivalent stress block

b = width of member

d = distance from compression face to centroid of tension steel

f_{dy} = dynamic yield strength of reinforcing steel (see paragraph 3C.3.1.1)

f'_c = concrete compressive strength, psi

f_y = yield strength of steel, psi

The moment capacity of members with compression reinforcing can be similarly obtained using procedures such as contained in reference 26.

The flexural stiffness of reinforced concrete members is determined using the effective moment of inertia, I_e (10), which is defined as follows:

$$I_e = \left(\frac{M_{cr}}{M_a}\right)^3 I_g + \left[1 - \left(\frac{M_{cr}}{M_a}\right)^3\right] I_c \leq \frac{1}{2}\left(I_g + I_c\right) \qquad (3\text{-}4)$$

where:

M_{cr} = cracking moment = $1.25\sqrt{f'_c}\,bt^2$

M_a = maximum moment in member. For member deforming plastically, $M_a = M_u$

I_g = gross uncracked section moment of inertia

I_c = transformed moment of inertia of the cracked section = Fbd^3

F = coefficient for determining the transformed moment of inertia of the cracked section (see figure 3C.3-1)

To ensure ductile flexural deformations, reinforcing ratios must be within the following limits:

For members with tension reinforcing only:

$$\frac{1.4\sqrt{f'_c}}{f_y}\left(\frac{t}{d}\right)^2 \leq \frac{A_s}{bd} \leq 0.25\,\frac{f'_c}{f_y} \qquad (3\text{-}5)$$

For members with tension and compression reinforcing:

$$\frac{1.4\sqrt{f'_c}}{f_y}\left(\frac{t}{d}\right)^2 \leq \frac{A_s}{bd} \qquad (3\text{-}6)$$

$$\frac{A_s - A'_s}{bd} \leq 0.25\,\frac{f'_c}{f_y} \qquad (3\text{-}7)$$

where:

f'_c = compressive strength of concrete, psi

f_y = yield strength of reinforcing steel

b = width of member

t = total thickness of member

A'_s = area of compression steel

Reinforcing ratios must also satisfy other design requirements such as minimum temperature steel and reinforcing limits for seismic loading.

To ensure ductile deformation in flexure, the shear capacity, as determined by conventional procedures (9) using appropriate DIF for shear, should be at least 20% greater than that required to develop the ductile deformation mode. In cases where the thickness of one-way and two-way reinforced concrete elements is greater than (or equal to) the thickness for threshold of spalling, as determined by applicable empirical local damage formulae (see BC-TOP-9-A) or tests, further design provision for punching shear is not required. Likewise, for two-way elements where the shear intensity diminishes radially from the potential back face fracture plane, further shear failure will not occur outside the fracture plane, and further design provisions for reaction shear is not required.

Impact tests on reinforced concrete panels indicate that the extent of local damage is essentially independent of impact location and overall structural deformation appears to be slightly greater for a center impact (attributable to effects such as an increase in coupled mass and resistance as the impact is moved closer to a support). A center impact is, therefore, considered to be the critical impact location for structural response of two-way concrete elements.

The maximum resistance of reinforced concrete columns loaded in axial compression is:

$$P_u = \phi\left(0.85f'_{dc}A_g + f_{dy}A_{sl}\right) \quad (3\text{-}8)$$

where:

f_{dc} = dynamic compressive strength of the concrete

f_{dy} = dynamic yield strength of longitudinal reinforcing steel

A_g = gross cross-sectional area of the column

A_{sl} = area of longitudinal reinforcing steel

The capacity reduction factor, ϕ, and limiting reinforcing requirements shall be in accordance with reference 9.

The capacity of reinforced concrete members with combined axial and flexural loading can be determined from an interaction diagram based on dynamic material strengths and appropriate capacity reduction factors. The ductility ratio for dynamic axial compression loading shall not exceed that given in table 3C.3-4 for axial compression. The ductility ratio for the dynamic flexural loading is determined as follows.

A. When compression controls the design ($P > P_b$, as determined from the interaction diagram, see figure 3C.3-2 the allowable ductility ratio shall be 1.3.

B. When the compressive load P does not exceed $0.1f'_{dc}A_g$, the allowable ductility ratio shall be that listed in table 3C.3-4 for flexure.

C. When the compressive load P is greater than $0.1f'_{dc}A_g$, but less than that for balanced design, P_b, the ductility ratio shall vary linearly with P between the values specified in listings A and B.

A graphical representation of these provisions is illustrated in figure 3C.3-2.

3C.3.3 STRUCTURAL STEEL

The dynamic section strengths of structural steel members are determined using plastic design methods and dynamic material strengths.

The plastic resisting moment, M_u, of structural steel flexural members is determined as follows:

$$M_u = 0.9f_{dy}Z \quad (3\text{-}9)$$

where:

f_{dy} = dynamic yield strength of the steel (see paragraph 3C.3.1.1)

Z = plastic section modulus of the structural member

The maximum resistance of flexural members is determined by the moment or shear resistance, whichever is less. When shear controls the member, it is still capable of deforming in a ductile mode providing stability is maintained.

Riveted or bolted connections are considered nonductile components and must satisfy the provisions of paragraph 3C.3.1.3.

The maximum resistance of structural steel columns dynamically loaded in axial compression is:

$$P_u = 0.9 f_{dy} A \quad (3\text{-}10)$$

where:

A = cross-sectional area of the column

The capacities of steel members subjected to combined axial flexure can be determined using procedures such as contained in reference 27.

Structural steel members that are allowed to sustain inelastic deformations must satisfy the following provisions for stability:[a]

A. Width-Thickness Ratios:

Outstanding leg of compression flange or other element:

$$\frac{b}{t_b} < \frac{52}{\sqrt{F_y}} \quad (3\text{-}11)$$

Web of beams

$$\frac{d}{t} \leq \frac{257}{\sqrt{F_y}} \quad (3\text{-}12)$$

Web of columns

a. These values were obtained and/or derived from information contained in references 1, 2, 14, 27, and 28

$$\frac{d}{t} \leq \frac{190}{\sqrt{f_y}} \qquad (3\text{-}13)$$

Stiffened compression element

$$\frac{b_s}{t_b} \leq \frac{190}{\sqrt{f_y}} \qquad (3\text{-}14)$$

B. Slenderness Ratios

Columns and beams with uniform moment

$$\frac{KL}{r} \leq \left[\frac{1.4 \times 10^5}{(\mu - 1/2)F_y}\right]^{1/2} < \left[\frac{2.8 \times 10^5}{F_m}\right]^{1/2} \qquad (3\text{-}15)$$

Beams with moment gradients per Section 2.9 (pages 5-61) of reference 28 (AISC Manual).

where:

b = unsupported width of outstanding compression flange or other element, in.

b_s = width of stiffened compression element, in.

t_b = compression element thickness, in.

t = thickness of web, in.

d = depth of member, in.

F_y = steel yield stress, ksi

F_m = maximum stress in member (for $\mu > 1$, $F_m = F_y$, ksi

L = unsupported length of member, in.

r = radius of gyration, in.

μ = ductility ratio

K = effective length factor; for segments of laterally stayed members, K may be taken as 0.54 if adjacent segments are elastic and as 0.8 if adjacent segments are fully yielded

3C.3.4 NATURAL PERIOD OF VIBRATION FOR BEAMS AND SLABS

The structural elements subject to missile impact typically respond in their first (fundamental) mode of vibration and higher mode participation is usually negligible. Therefore, formulae and constants for determining the fundamental period of vibration are included for convenient reference.

3C.3.4.1 Beams and One-Way Slabs

Fundamental period of vibration (first mode) for beams and one-way slabs with uniformly distributed mass is:

$$T_n = \frac{2\pi}{C_n}\sqrt{\frac{ML^4}{EI}} \qquad (3\text{-}16)$$

where:

E = modulus of elasticity, psi

I = moment of inertia of beam cross-section; for reinforced concrete section, $I = I_e$, $in.^4$

L = length of beam or slab, in.

M = mass per unit length, $lb\text{-}s^2/in./in.$

C_n = coefficient (see table 3C.3-5)

3C.3.4.2 Two-Way Slabs

Fundamental period of vibration (first mode) for two-way slabs with uniform distributed mass is:

$$T_n = \frac{2\pi}{C_n}\sqrt{\frac{(1 - \nu^2)M' a^4}{EI}} \qquad (3\text{-}17)$$

where:

M' = mass per unit area, $lb\text{-}s^2/in./in.^2$

ν = Poisson's ratio; for concrete, ν varies between 0 and 0.2, and when unknown, may be taken as 0 with only a slight error

C_n = coefficient (see table 3C.3-6)

a = length of side of slab (see table 3C.3-6)

I = moment of inertia of slab per unit length ($in.^4/in.$); for reinforced concrete section, $I = I_e$

3C.3.5 LOAD CONVERSION FACTORS

The effect of other concurrent loads applied at locations on a member other than that of the impact load can be accounted for (in determining R_o) by replacing these loads with an equivalent concentrated load that will do the same amount of external work during structural response when applied at the location of

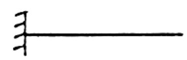
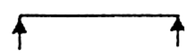
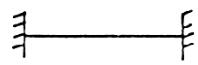
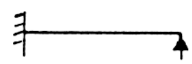
STRUCTURAL RESPONSE DUE TO

MISSILE IMPACT LOADING

Table 3C.3-5

COEFFICIENT FOR FUNDAMENTAL NATURAL PERIOD

OF VIBRATION OF BEAMS AND ONE-WAY SLABS (29)

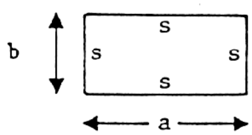
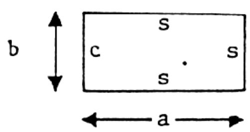
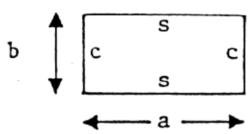
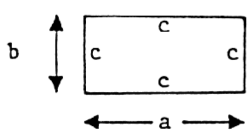
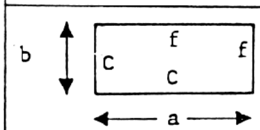
Beam and One-Way Slab End Condition	C_n
Fixed - free (cantilever) 	3.52
Hinged - hinged (simple) 	9.87
Fixed - fixed (built-in) 	22.4
Fixed - hinged 	15.4

STRUCTURAL RESPONSE DUE TO

MISSILE IMPACT LOADING

Table 3C.3-6

COEFFICIENT FOR NATURAL FUNDAMENTAL PERIOD OF VIBRATION OF PLATES AND TWO-WAY SLABS [3][29] (Sheet 1 of 2)

Slab Support Condition	b/a a/b	C_n 1 1	 1.5 1.5	 2 2	 2.5 2.5	 3 3	 ∞ ∞
	b/a	19.74	14.26	12.34	11.45	10.97	9.87
	b/a a/b	23.65 23.65	18.90 15.57	17.33 12.92	16.63 11.75	16.26 11.14	15.43 9.87
	b/a a/b	28.95 28.95	25.05 17.37	23.82 13.69	23.27 12.13	23.99 11.36	22.37 9.87
	b/a	35.98	27.00	24.57	23.77	23.19	22.37
	1	6.97					

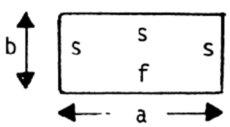
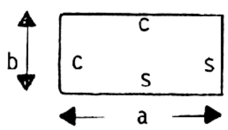
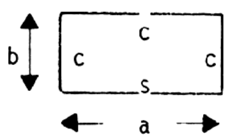
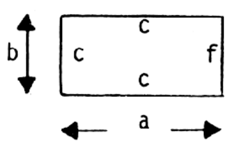
s = denotes simply supported edge
c = denotes built-in or clamped edge
f = denotes free edge
a = span dimension
b = span dimension

STRUCTURAL RESPONSE DUE TO

MISSILE IMPACT LOADING

Table 3C.3-6

COEFFICIENT FOR NATURAL FUNDAMENTAL PERIOD OF VIBRATION OF PLATES AND TWO-WAY SLABS [3][29] (Sheet 2 of 2)

SLAB SUPPORT CONDITION		C_n					
	b/a a/b	1 1	1.5 1.5	2 2	2.5 2.5	3 3	∞ ∞
	a/b	12.9	17.2	23.2	---	---	---
	a/b	27.1	45				
	b/a	27.1	20.4	18.2	17.2	16.7	15.5
	a/b	31.8		73.1			
	b/a	31.8		24.5			22.4
	a/b	25.1	53.5	93.4	145	207	3.7
	b/a	25.1	12.7	8.5	6.6	5.6	

impact. For a concentrated load, F_a, applied at location a, which would displace through a distance X_a during response to a missile impact at location b, the equivalent load F_e at point b would be:

$$F_a X_a = F_e X_b$$

$$F_e = \frac{F_a X_a}{X_b} \tag{3-18}$$

$$F_e = K_L F_a$$

where:

F_e = equivalent load at location b

X_b = displacement at b due to load F_e

K_L = load conversion factor; for this example, numerically equal to X_a/X_b

For a distributed load over a length or area of a member, the load conversion factor is again determined by equating the work done by the distributed load on the member to the work done by the equivalent concentrated load applied at the impact location. Load conversion factors, K_L, for uniform loads on flexural members with midspan impact location are given in table 3C.3-7. Load conversion factors for other impact locations can be similarly obtained. The equivalent concentrated load at the impact location is then determined by multiplying the total force on the member associated with the uniform load by the load conversion factor, K_L.

STRUCTURAL RESPONSE DUE TO

MISSILE IMPACT LOADING

Table 3C.3-7

LOAD CONVERSION FACTORS FOR UNIFORM LOADS ON BEAMS[1]

AND SLABS WITH MIDSPAN IMPACT

BEAM AND ONE-WAY SLAB END CONDITION	LOAD CONVERSION FACTOR (K_L)
Hinged-hinged	0.64
Fixed-fixed	0.53
Fixed-hinged	0.58

TWO-WAY SLAB END CONDITION	LOAD CONVERSION FACTOR (K_L)					
	b/a = 1.0	2.0	3.0	4.0	5.0	10.0
Simply supported four sides	.38	.36	.33	.30	.28	.21
Fixed four sides	.27	.26	.25	.22	.20	.14

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APPENDIX 3D

SEISMIC RESPONSE SPECTRA

FIGURES

FIGURES (cont)

FIGURES (cont)

FIGURES (cont)

APPENDIX 3E

(DELETED)

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APPENDIX 3F

TANGENTIAL AND RADIAL SHEAR

CONTENTS

TABLES

APPENDIX 3F
TANGENTIAL AND RADIAL SHEAR

3F.1 GENERAL

Tangential shear stresses are evaluated in detail in this appendix. The critical loading combinations included in this appendix are listed below:

RLC No. 1: $D + F_i + P_t + T_t$

RLC No. 2: $D + F_i + T_t$

RLC No. 3: $D + F + P_v + T_o$

RLC No. 4: $D + F + E_o + T_o$

RLC No. 11: $D + F + E_{ss} + T_o$

RLC No. 15: $D + F + 1.5\ P_a + T_a$

RLC No. 18: $D + F + 1.25\ P_a + 1.25\ E_o + T_a$

RLC No. 24: $D + F + P_a + E_{ss} + T_a$

3F.2 TANGENTIAL SHEAR

There are no criteria in the code for tangential shear in pre-stressed concrete containments. The tangential shear is evaluated in the following paragraphs using Bechtel's criteria.

A. Containment Sections and Governing Loading Combinations

The only loading that induces significant tangential shear (in-plane shear) in the structure is seismic loading. Also, tangential shear may be significant only in the shell. Furthermore, the effect of

tangential shear is more significant when it occurs simultaneously with the internal pressure (postulated LOCA) because the shear capacity of a section decreases with reduced membrane compression, and internal pressure tends to reduce membrane compression due to pre-stressing and dead load. For these reasons, it will be sufficient to consider only three reference loading combinations. These combinations are: RLC Nos. 11, 18, and 24.

B. Section Resultants

Horizontal and vertical membrane forces (N_h and N_v) due to all loads other than earthquake are obtained from the FINEL analysis and are shown in table 3F-1.

Horizontal and vertical membrane forces (N_{he} and N_{ve}) and tangential shear (V_u) due to earthquake loads are also shown in table 3F-1.

C. Maximum Applied Shear

Maximum applied tangential shear must not exceed $v_u \leq 8.5bt\sqrt{f_c'} \cong 379$ k/ft. In the above equation b = width (12 inches) t = thickness (48 inches), and f_c' = concrete strength (6000 psi). This limit is based on the ACI 318-77 Code.

Table 3F-1 shows that the maximum tangential shear is far less than the maximum allowable for each section.

D. Shear Carried by Concrete

If the section is under biaxial compression, the concrete is allowed to resist the following shear:

$$V_c = \left[(N_h + N_{he})(N_v + N_{ve})\right]^{1/2}$$

Assuming, conservatively, that the maximum membrane forces and tangential shear due to seismic loads occur at the same point, the concrete allowable shear force, V_c, is calculated using the above equation. These values are also shown in table 3F-1 for the given loading combinations.

E. Evaluation of Results

Table 3F-1 shows that V_u exceeds V_c in only three cases. In accordance with the criteria 3F.1, whenever $V_u > V_c$, it is assumed that the shear carried by concrete is equal to zero. Thus, these three cases need further analysis as shown in the following paragraphs.

F. Further Analysis of Section with $V_c = 0$

In this case a total equivalent membrane force is defined as follows:

$$N_{ht} = N_h + \left[N_{he}^2 + V_u^2\right]^{1/2}$$

$$N_{vt} = N_v + \left[N_{ve}^2 + V_u^2\right]^{1/2}$$

The section is then analyzed using these equivalent membrane forces and corresponding bending moments

(table 3F-2). Results of these analyses are given in table 3F-3.

G. Final Results

Table 3F-3 shows that, in the three cases where concrete shear capacity may, conservatively, be assumed to be zero, the resulting concrete and reinforcement stresses are within the allowable limits.

Thus, it is shown that, considering the effects of tangential shear, all the sections are adequate.

APPENDIX 3F

Table 3F-1

MEMBRANE FORCES AND TANGENTIAL SHEAR IN THE SHELL

(Sheet 1 of 2)

Section	Ref. Loading Comb.	Hoop		Meridional				
		N_h k/ft	N_{he} k/ft	N_v k/ft	N_{ve} k/ft	V_c k/ft	V_u k/ft	Remarks
7	11	-469	22	-585	11	507	17	
	18	-88	16	-200	7	118	10	
	24	-164	22	-277	11	194	17	
16	11	-703	40	-578	35	600	56	
	18	-4	30	-194	25	86	34	
	24	-200	40	-271	35	194	56	
18	11	-765	17	-604	120	602	101	
	18	24	13	-220	89	0	61	See note 7
	24	-134	17	-297	120	144	101	
20	11	-516	15	-630	200	464	122	
	18	-76	10	-246	148	80	74	
	24	-154	15	-323	200	131	122	
21	11	-259	26	-636	217	312	121	
	18	-149	17	-253	161	110	73	
	24	-149	26	-329	217	117	121	See note 7
22	11	-221	36	-639	226	276	118	
	18	-162	26	-255	167	109	72	
	24	-135	36	-332	226	102	118	See note 7

Notes:

1. Notation:

   N_h, N_v = hoop and meridional membrane forces due to other loads

   N_{he}, N_{ve} = hoop and meridional membrane forces due to seismic loads

   V_c = shear carried by concrete alone

   V_u = applied tangential shear

2. V_c is zero if either or both total membrane forces are positive (tension)

3. N_h, N_v are from FINEL analysis

Table 3F-1

MEMBRANE FORCES AND TANGENTIAL SHEAR IN THE SHELL

(Sheet 2 of 2)

4. N_{he}, N_{ve}, V_u are from ASHSD analysis
5. Whenever $V_c > V_u$, concrete shear capability alone is adequate to carry tangential shear.
6. In all cases the calculated tangential shear force, V_u, is less than the total allowable shear on the section, 369 k/ft.
7. In these cases, $V_u > V_c$, and therefore further analysis is required considering tangential shear contribution to seismic membrane forces.

Table 3F-2[(a)]

AXIAL FORCE - MOMENT SETS WITH DUE CONSIDERATION TO TANGENTIAL SHEAR

Loading Combination	Section	Primary				Primary + Secondary			
		Meridional		Hoop		Meridional		Hoop	
		Axial	Moment	Axial	Moment	Axial	Moment	Axial	Moment
$D + F + 1.25\ P_a + 1.25\ E_o + T_a$	18	-112	-3	86	7	-112	430	91	346
$D + F + P_a + E_{ss} + T_a$	21	-81	-133	-25	-20	-81	424	-187	629
$D + F + P_a + E_{ss} + T_a$	22	-77	-398	-12	-67	-77	65	-224	618

a. Sign conventions are:

Axial forces (kips) . . . . (+) tension . . . . (-) compression

Moments (ft-kips) . . . . . (+) tension on outside face . . (-) compression on outside face

Table 3F-3

STRESS ANALYSIS RESULTS

Reference Loading Combination	Sec-tion	Concrete Stresses								Reinforcement Stresses								Liner Strains[b]	
		Meridional				Hoop				Meridional				Hoop					
		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary		Primary		Primary and Secondary			
		MEM psi	MEM & BEN psi	MEM psi	MEM & BEN psi	MEM psi	MEM & BEN psi	MEM psi	MEM & BEN psi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Inside ksi	Outside ksi	Meridional x 10^{-6} in/in	Hoop x 10^{-6} in/in
Allowable	Shell	-3600	-4500	-4500	-5100	-3600	-4500	-4500	-5100	±54	±54	±54	±54	±54	±54	±54	±54	±10,000	±10,000
18[c]	18	-194	-226	-194	-2696	(d)	(d)	(d)	-1519	-1.0	-1.2	-1.6	39.3	26.0	10.3	5.4	42.5	-519	-326
24[c]	21	-141	-710	-141	-3138	-43	-86	-325	-2735	3.3	-2.7	-1.8	54.0[e]	-.1	-.4	-4.8	28.6	-932	-640
24[c]	22	-134	-2685	-134	-303	-21	-373	-389	-2672	46.4	-4.9	-1.3	-.1	4.4	-1.1	-5.7	24.3	2317	-623

Notes:

(a) Sign convention:
Stress and strains . . . . (+) tensile . . . . (-) compressive

(b) Allowable liner strains shown are based on the lowest values from the ASME Code, Section III, division 2.

(c) The stresses were obtained from OPTCON computer output.

(d) A completely cracked section

(e) Reinforcement is assumed to yield at 54 ksi, the calculated strain is .00208 in./in.

3F.3 REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III--Rules for Construction of Nuclear Power Plant Components; Division 2--Code for Concrete Reactor Vessels and Containments, ASME Boiler and Pressure Vessel Committee, Subcommittee, Subcommittee on Nuclear Power, and ACI-ASME Joint Technical Committee, 1975 Edition.

2. BC-TOP-5A, Revision 3, February 1975, Prestressed Concrete Nuclear Reactor Containment Structures.

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APPENDIX 3G

SEISMIC STRESSES IN UNDERGROUND STRUCTURES

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APPENDIX 3G
SEISMIC STRESSES IN UNDERGROUND STRUCTURES

3G.1 SUMMARY

This appendix describes methods used for seismic analysis of buried structures such as conduits, tunnels, and well casings. The effects of earthquakes on buried structures may be broadly grouped into two classes: faulting and shaking. Faulting includes the direct, primary shearing displacement of bedrock which may carry through the overburden to the ground surface. Such direct shearing of the rock or soil is generally limited to relatively narrow zones of seismically active faults which may be identified by geological and seismological surveys. From a structural viewpoint, landsliding, ground fissuring, and consolidation of backfill soil have similar effects on buried structures. In general, it is not desirable to design structures to directly sustain such major soil displacements. However, design measures can be taken to mitigate the effects of the displacements and to identify and avoid areas prone to such displacements.

The effects of earthquake ground motion on underground conduits, in the absence of direct fault displacement or unstable soil conditions such as liquefaction, are:

1. Axial tension and compression due to traveling seismic wave
2. Shear and bending due to traveling seismic wave
3. Strain caused by dynamic differential movement at connections

Analytical procedures for evaluating these effects are described in the following sections. For very long structures, procedures are based on the assumption that there is no relative motion between the flexible structure and the ground. Seismic stresses in the conduit are estimated from the calculated strains and curvature in the surrounding soil due to the passage of seismic waves. For short structures, lippage may occur between the conduit and the soil and the calculated axial stresses are proportionately less than those assuming the conduit strain equal to the soil strain. The effects of bends and differential displacement at connections to buildings are evaluated using procedures based on equations for beams on elastic foundations. The calculated seismic stresses must be combined with stresses from other loading conditions, including pressure and surcharge loading, for final design.

The interaction of stresses and strains due to seismic wave propagation and boundary displacements, both at bends and at structures, is a complicated problem. The conservative assumption can be made that the strains due to the several sources are additive and, hence, an SRSS combination may be used. In case these resultant stresses and strains are unacceptable, the problem can be circumvented by designing discontinuities to be flexible to allow for the resultant displacements.

3G.2 STRESSES IN STRAIGHT SECTIONS

3G.2.1 GENERAL EQUATIONS FOR AXIAL AND BENDING STRAIN

The portions of a long, buried structure far from the ends and free of any external support other than the surrounding soil are assumed to be flexible and to follow essentially the displacements and deformations of the soil during seismic ground motion. Soil displacements due to the passage of shear, compression, and surface waves are calculated based on wave propagation velocities and the maximum ground particle acceleration and velocity due to the design earthquake. Stresses in the structure are calculated using the resulting strain, curvature, and modulus of elasticity of the structural material.

The assumption that relative motion between the buried structure and the surrounding soil is negligible has been shown by O'Rourke and Wang (1978) to be a valid assumption for most practical cases. For special situations where the relative motion is not negligible, and analysis techniques described by Hindy and Novak (1978) and O'Rourke and Wang (1978) can be used. Internal walls which may not follow the motion of the surrounding soil can be treated as simple oscillators subject to the design ground motion at the depth of burial.

The basic relations for calculating maximum longitudinal strain and curvature induced in a flexible, buried structure have been presented by Hall and Newmark (1978). For a compression wave propagating along the longitudinal axis of the buried structure:

$$\varepsilon_m = \pm \frac{V_{mp}}{C_p} \qquad \text{(3G-1)}$$

and for a shear wave propagating along the longitudinal axis:

$$\varepsilon_m = \pm \frac{V_{ms}}{2C_s} \qquad (3G\text{-}2)$$

$$K_m = \frac{a_{ms}}{C_s^2} \qquad (3G\text{-}3)$$

where:

ε_m = maximum longitudinal strain

K_m = maximum curvature

V_m = maximum compression wave particle velocity

V_{ms} = maximum shear wave particle velocity

a_{ms} = maximum shear wave particle acceleration

C_p = compression wave propagation velocity

C_s = shear wave propagation velocity

The maximum strain as given by equations 3G-1 and 3G-2 is an upper bound since it is limited by the pipe-soil interface friction. Slippage would occur if the computed axial force, ε_m AE, exceeds the frictional resistance as given by equation 3G-21.

The appropriate particle acceleration (a_m) for calculating maximum soil strain is the maximum ground acceleration. The maximum particle velocity should be selected for the corresponding wave type. For example, the maximum ground velocity for the compression wave portion of ground motion prior to arrival of the surface wave component is typically less than the maximum ground velocity associated with the surface wave component. Therefore, it may be unnecessarily conservative to take the maximum ground velocity in the entire

ground motion when calculating maximum soil strain due to a compression wave.

The value of wave propagation velocity to be used when calculating maximum soil strain surrounding a buried structure is the effective velocity of the ground motion disturbance past the structure. For rock or very stiff and dense soils, the effective propagation velocity is equal to the in situ wave propagation velocity as measured by field or laboratory tests. If the structure is embedded in a softer layer or at a shallow depth in uniform soils, the effective propagation velocity should be taken as the propagation velocity of the underlying competent soil or rock (Hall and Newmark, 1978). For example, the effective shear wave propagation velocity should not be taken as less than the shear wave velocity at a depth of 400 to 500 feet or, in any case, never less than about 2000 feet per second.

3G.2.2 MAXIMUM AXIAL AND BENDING STRESSES

Equations for calculating maximum axial and bending stresses as a function of angle of incidence of the various wave types have been presented by Yeh (1974). For an oblique compression wave of amplitude A_p (figure 3G-1):

$$\sigma_a = \pm \frac{Ev_{mp}}{C_p} \cos^2 \theta \qquad (3G\text{-}4)$$

$$\sigma_b = \pm \frac{ERa_{mp}}{C_p^{\ 2}} \sin \theta \cos^2 \theta \qquad (3G\text{-}5)$$

where:

σ_a = maximum axial stress

σ_b = maximum bending stress

E = modulus of elasticity for the structure

v_{mp} = maximum compression wave particle velocity

a_{mp} = maximum compression wave particle acceleration

R = distance from the cross-sectional neutral axis of the structure to the extreme fiber

θ = angle of incidence of propagating wave from the structural axis

The maximum possible values of the axial and bending stresses due to an oblique compression wave are:

$$\sigma_a = \pm \frac{Ev_{mp}}{C_p} \qquad \text{for } \theta = 0° \qquad (3G\text{-}6)$$

$$\sigma_b = \pm\, 0.385 \frac{ERa_{mp}}{C_p^{\;2}} \qquad \text{for } \theta = 35°16' \qquad (3G\text{-}7)$$

For an <u>oblique shear wave</u> of amplitude A_s (figure 3G-1):

$$\sigma_a = \pm \frac{Ev_{ms}}{C_s} \sin\theta \cos\theta \qquad (3G\text{-}8)$$

$$\sigma_b = \pm \frac{Era_{ms}}{C_s^{\;2}} \cos^3\theta \qquad (3G\text{-}9)$$

where:

v_{ms} = maximum shear wave particle velocity

a_{ms} = maximum shear wave particle acceleration

The maximum possible values of the axial and bending stresses due to an oblique shear wave are:

$$\sigma_a = \pm \frac{Ev_{ms}}{2C_s} \quad \text{for } \theta = 45° \tag{3G-10}$$

$$\sigma_b = \pm \frac{ERa_{ms}}{C_s^2} \quad \text{for } \theta = 0° \tag{3G-11}$$

For an <u>incident surface wave</u> of amplitude A_R, the motion is equivalent to the combination of a compression wave of amplitude A_{Rp} and a shear wave of amplitude A_{Rs} (figure 3G-1) and:

$$\sigma_a = \pm \frac{Ev_{mr}}{C_R} \cos^2 \theta \tag{3G-12}$$

$$\sigma_b = \pm \frac{ERa_{mr}}{C_R^2} \sin \theta \cos^2 \theta \tag{3G-13}$$

for the compressional component

$$\sigma_b = \pm \frac{ERa_{mr}}{C_R^2} \cos^2 \theta \tag{3G-14}$$

for the shear component

where:

v_{mr} = maximum surface wave particle velocity

a_{mr} = maximum surface wave particle acceleration

C_R = surface wave propagation velocity

The maximum possible values of the axial and bending stresses due to an incident surface wave are:

$$\sigma_a = \pm \frac{Ev_{mr}}{C_R} \qquad \text{for } \theta = 0° \qquad (3G\text{-}15)$$

$$\sigma_b = \pm\, 0.385 \frac{ERa_{mr}}{C_R^{\,2}} \qquad \text{at } \theta = 36°16' \qquad (3G\text{-}16)$$

for the compressional comonent

$$\sigma_b = \pm \frac{ERa_{mr}}{C_R^2} \qquad \text{at } \theta = 0° \qquad (3G\text{-}17)$$

for the shear component

3G.2.3 WAVE TYPES AND COMBINATION OF STRESSES

The maximum ground velocity and acceleration for an earthquake motion contain contributions from compressional, shear, and surface waves. The choice of wave type to be used for design depends on the location and orientation of the structure to the earthquake source, as well as on the nature of the source and local geologic conditions along the travel path.

It is not presently possible, in general, to determine the relative contributions to the total motion of each of the various wave types. The axial and bending stresses should be maximized separately according to wave type and angle of incidence, and the resulting maximums for axial and bending stress should be combined by the SRSS method since the maximum values are unlikely to occur simultaneously.

The calculated axial and bending stresses are combined to provide the total seismic design stress. The combined stress is maximized for an incident angle between 0° and 45° for each wave type using the equations provided in subsection 3G.2.2. This combined stress for each wave type will always be less than the sum of the maximum possible values of axial and bending stress which are based on different angles of incidence and, therefore, do not occur simultaneously. The maximized values of axial and bending stress for each wave type are then combined using the SRSS method to give the total seismic design stress ($\sigma_a + \sigma_b$) as follows:

$$\sigma_a = \pm \left[(\sigma_{ap})^2 + (\sigma_{as})^2 + (\sigma_{ar})^2 \right]^{1/2} \qquad \text{(3G-18)}$$

$$\sigma_b = \pm \left[(\sigma_{bp})^2 + (\sigma_{bs})^2 + (\sigma_{br})^2 \right]^{1/2} \qquad \text{(3G-19)}$$

where the subscripts p, s, and r identify the maximum axial and bending stresses due to a compressional, shear, and surface wave, respectively.

For buried piping of relatively small diameter (less than about 48 inches), the bending stresses are small compared to the calculated normal stresses. In this case, the maximum possible values of axial and bending stress for each wave type can be added directly without performing the maximizing procedure prior to combining. For buried structures of much greater dimensions, such as tunnels, and bending stress will be significant compared to the axial component and the maximizing procedure should be carried out.

If the calculated stresses exceed the allowable stresses, increasing the cross-sectional area of the structure is of no

value since the stresses are due to an imposed strain. In this case, the solution may be to either articulate the structure to make it more flexible or to isolate the structure partially or completely from the surrounding soil.

3G.2.4 SHORT SECTIONS

In case of a straight structural element embedded in soil, the transfer of soil strain as axial strain into the element depends on the end bearing of the element against the soil and the frictional resistance between the element surface and the soil. At the ends of a long, straight element, frictional resistance will develop for some length (ℓ) along which the element will displace relative to the surrounding soil due to strain incompatibility between the soil and the element (figure 3G-2). Neglecting end bearing, the minimum length of structure (L) required to develop full friction has been shown by Shah and Chu (1974) to be twice the maximum slippage length (ℓ_m) which is calculated as follows:

$$\ell_m = \frac{\varepsilon_m AE}{f} \tag{3G-20}$$

where:

ε_m = maximum soil strain

A = structure cross-sectional area

E = structure modulus of elasticity

f = friction force per unit length

For buried structures where $L < 2\ell_m$, the calculated axial stresses will be proportionately less than those calculated

assuming no relative slippage between the structure and the soil (figure 3G-2).

The frictional force (f) per unit length of a pipeline structure is given by:

$$f = \pi D p_r \mu \qquad (3G\text{-}21)$$

where:

D = pipe diameter

p_r = average radial soil pressure on pipe

μ = coefficient of friction

The average radial soil pressure on the pipe (p_r) is approximated by:

$$P_r = \frac{1 + K_o}{2} \gamma_{soil} H_d \qquad (3G\text{-}22)$$

where:

K_o = coefficient of lateral stress at rest

λ_{soil} = soil unit weight

H_d = burial depth at pipe centerline

The parameters (μ) and (K_o) are evaluated based on the type of structural material and soil conditions for a specific project. The coefficient of friction (μ) is typically in the range of 0.3 to 0.5 for a smooth pipe embedded in soil. The lateral stress coefficient (K_o) typically ranges from 0.5 to 1.0.

3G.2.5 AXIAL DISPLACEMENT OF FREE END RELATIVE TO THE SOIL

Neglecting the effect of end bearing and considering the maximum soil strain to remain constant over the length of the structure, Shah and Chu (1974) give the longitudinal displacement of the ends of a structure relative to the soil as follows:

$$\Delta = \varepsilon_m \ell_e - \frac{f\ell_e^2}{2AE} \qquad (3G\text{-}23)$$

where:

Δ = Δ (soil) - Δ(structure)

ℓ_e = effective slippage length (figure 3G-2)

In the case of a short structure where $L < 2\ell_m$, the effective slippage length equals one-half the total length ($\ell_e = L/2$) and:

$$\Delta = \frac{\varepsilon_m L}{2} - \frac{fL^2}{8AE} \qquad (3G\text{-}24)$$

For a long structure, $\ell_e = \ell_m$ and:

$$\Delta = \frac{\varepsilon_m \ell_m}{2} \quad \frac{\varepsilon_m^2 AE}{2f} \qquad (3G\text{-}25)$$

Provisions should be made in the design to accommodate this displacement at the intersection of long elements with massive embedded structures.

3G.2.6 SHEAR FORCE DUE TO AN AXIAL SHEAR WAVE

The basic relations for maximum longitudinal strain and curvature presented by Hall and Newmark (1978) can be extended to provide the rate of change of curvature of a

buried structure due to a propagating shear wave. For a shear wave propagating with wave velocity (C_s) along the x-axis, the particle dis-placement in the transverse (y) direction is:

$$y = f(x-C_s t) \qquad (3G\text{-}26)$$

The third derivative of equation 3G-26 with respect to x and t gives the following relation for the rate of change of curvature:

$$\frac{\partial^3 y}{\partial x^3} = f'''(x - C_s t) = -\frac{1}{C_s^{\,3}}\left(\frac{\partial^3 y}{\partial t^3}\right) \qquad (3G\text{-}27)$$

Defining (h) as the maximum derivative of the ground acceleration:

$$h = \frac{\partial^3 y}{\partial t^3} \qquad (3G\text{-}28)$$

and using the elementary beam relationship between the change in curvature and the shearing force (Q):

$$Q = -EI \quad \frac{\partial^3 y}{\partial x^3} \qquad (3G\text{-}29)$$

The shearing force in the buried structure is:

$$Q = EIh \, / \, C_s^{\,3} \qquad (3G\text{-}30)$$

The quantity (h) can be evaluated using the relationships between the maximum values of ground acceleration, displacement, and velocity where $a_m d_m / v_m^2 = 6$ (Hall and Newmark, 1978, Table 1) and $hv_m / a_m^2 = \beta a_m d_m / v_m^2 =$ (Newmark and Rosenblueth, 1971, p. 492). The coefficient (β) accounts for uncertainties in the relationship between the various ground motion

parameters, with a reasonable level of conservatism obtained by taking β = 1.5. Based on these assumptions:

$$h = 9a_m^2 / v_m \qquad (3G\text{-}31)$$

Combining equations 3G-30 and 3G-31 yields the following expression for the maximum shear force in the structure:

$$Q = \frac{9EIa_m^2}{C_s^3 v_m} \qquad (3G\text{-}32)$$

3G.2.7 CURVATURE

The maximum curvature (K_m) at a point can be calculated using equation 3G-3. If the calculated curvature is equal to or less than the allowable value of M/EI, the structure can be assumed to follow the ground motion without overstress and no articulation is necessary. However, some rotational capability may be required in sections where the calculated curvature exceeds the allowable value of M/EI and in the vicinity of connections to structures. The angular distortion for a given length of structure (L) can be calculated using the relation:

$$\phi = K_m L \qquad (3G\text{-}33)$$

If sections of an underground structure are effectively isolated from the surrounding component soil, the angular distortion is a function of the relative motion of the support points. The maximum relative motion in the transverse direction between two points a distance (L) apart during an earthquake can be calculated according to Yeh (1974):

$$\Delta = \frac{v_{ms} L}{C_s} \qquad (3G\text{-}34)$$

The angular distortion is then:

$$\phi = \arcsin \frac{\Delta}{L} \qquad (3G-35)$$

Sufficient rotational capability should be provided at joints and connections to permit the calculated angular distortion (ϕ) from the appropriate equation above.

3G.3 STRESSES AT BENDS

3G.3.1 GENERAL PROCEDURE

The analysis of buried structures with bends or restrained ends is based on the equations for beams on elastic foundations derived by Hetenyi (1946). In the case of a bend, the transverse leg is assumed to deform as a beam on an elastic foundation due to the axial force in the longitudinal leg (figure 3G-3). The displacement (Δ) at the bend is defined by the overall spring constant at the bend (K) where:

$$K = \frac{P}{\Delta} \qquad (3G-36)$$

The spring constant at the bend depends on the stiffness of the longitudinal and transverse legs as well as the degree of fixity at the bend and at the far ends of the legs. The approximate deformed shapes for a number of typical combinations of leg stiffness and end condition are shown in figure 3G-5. The stiffness of the leg is classified according to Hetenyi (1946) as rigid ($\lambda L < \pi/4$), intermediate ($\pi/4 < \lambda L < \pi$), and flexible ($\lambda L > \pi$) where:

$\lambda = 4\sqrt{k / 4EI}$ system characteristic

L = length of the leg

k_s = modulus of subgrade reaction for structure for width (B)

$k = k_s(B)$ where B is width of the structure

Solutions for the bend spring constant (K) for some typical configurations (cases A through E) are shown in table 3G-1. Solutions for other configurations can be derived using the appropriate equations for beams on elastic foundations.

3G.3.2 EQUATIONS FOR STRUCTURE WITH RESTRAINED END

The configuration and deformed shape of a buried structure with a bend are shown in figure 3G-4. According to Shah and Chu (1974), the maximum axial force is:

$$F_{max} = Q + f\ell_e \tag{3G-37}$$

and:

$$\Delta = \frac{Q}{K} \tag{3G-38}$$

Establishing displacement compatibility at the bend leads to the following expression:

$$\frac{F\ell_e^2}{2AE} + \ell_e\left(\frac{f}{K} - \frac{F_{max}}{AE} + \varepsilon_m\right) - \frac{F_{max}}{K} = 0 \tag{3G-39}$$

If the structure is long (L_1 or $L_2 > \ell_e + \ell_m$), $F_{max} = \varepsilon_m AE$ and equation 3G-39 reduces to:

$$\ell_e = \frac{AE}{K}\left(\sqrt{1.0 + \frac{2\varepsilon_m K}{f}} - 1.0\right) \tag{3G-40}$$

In the case of a short structure (L_1 or $L_2 < \ell_e + \ell_m$), F_{max} =

$f(L - \ell_e)$ and equation 3G-39 can be written in the form:

$$\frac{f\ell_e^2}{2AE} + \ell_e \left[\frac{f}{K} - \frac{f(L - \ell_e)}{AE} + \varepsilon_m\right] - \frac{f(L - \ell_e)}{K} = 0 \qquad (3G\text{-}41)$$

Equation 3G-41 can be solved by trial and error for the effective slippage length (ℓ_e). Having the effective slippage length, the displacement (Δ) at the bend can then be calculated. With the displacement (Δ), the shear (Q) and moment (M) in the transverse leg can then be calculated for the appropriate configuration (cases A through E) in table 3G-1. More complicated cases can be handled by discretizing the structure as described by Hindy and Novak (1978).

3G.4 STRESSES AT CONNECTIONS TO BUILDINGS

3G.4.1 AXIAL MOVEMENT

Stresses are induced in buried structures at penetrations to buildings due to relative movement between the building and the soil. In the case of relative movement in the axial direction of an underground structure with the far end unrestrained, the maximum axial force (P) in a long structure ($L > \ell_e$) is given by Yeh (1974):

$$P = \sqrt{2EAf\Delta_x} \qquad (3G\text{-}42)$$

Table 3G-1

BEND CHARACTERISTICS

Case	Spring Constant At Bend (K)	Shear In Transverse Leg (Q)	Moment In Transverse Leg (M)	Remarks
(A)	$K = \frac{k}{2\lambda}$	$Q = \frac{k\Delta}{2\lambda}$	$M = \frac{0.1662k\Delta}{\lambda^2}$ @ $X = \frac{\pi}{4\lambda}$	
(B)	$K = \frac{3k}{4\lambda}$	$Q = \frac{3k\Delta}{4\lambda}$	$M = \frac{k\Delta}{4\lambda^2}$	Equal moment of inertia (I) in longitudinal and transverse legs
(C)	$K = \frac{k}{\lambda}$	$Q = \frac{k\Delta}{\lambda}$	$M = \frac{k\Delta}{2\lambda^2}$	
(D)	$K = \frac{k}{\lambda C_1}$	$Q = \frac{k\Delta}{\lambda C_1}$	$M = \frac{k\Delta c_2}{\lambda^2 C_1}$	$C_1 = \frac{\sinh(2\lambda L) - \sin(2\lambda L)}{\cosh^2(\lambda L) + \cos^2(\lambda L)}$ $C^2 = \frac{\sinh(\lambda L)\cos(\lambda L) + \cosh(\lambda L)\sin(\lambda L)}{\cosh^2(\lambda L) + \cos^2(\lambda L)}$
(E)	$K = \frac{k}{\lambda\left(2C_1 - \frac{C_2^{\,2}}{C_3}\right)}$	$Q = \frac{k\Delta}{\lambda\left(2C_1 - \frac{C_2^{\,2}}{C_3}\right)}$	$M = \frac{k\Delta C_2}{2\lambda^2\left(2C_1C_3 - C_2^{\,2}\right)}$	$C_1 = \frac{\sinh(\lambda L)\cosh(\lambda L) - \sin(\lambda L)\cos(\lambda L)}{\sinh^2(\lambda L) - \sin^2(\lambda L)}$ $C_2 = \frac{\sinh^2(\lambda L) + \sin^2(\lambda L)}{\sinh^2(\lambda L) - \sin^2(\lambda L)}$ $C_3 = \frac{\sinh(\lambda L)\cosh(\lambda L) + \sin(\lambda L)\cos(\lambda L)}{\sinh^2(\lambda L) - \sin^2(\lambda L)}$

Note: See Fig. 3G-4 for definition of cases.

where:

Δ_x = relative movement between the building and soil in the axial direction.

ℓ_e = P/f effective slippage length

For a short structure ($L<\ell_e$), the maximum axial force is limited to:

$$P = fL \qquad (3G\text{-}43)$$

If a bend in the underground structure is located near the penetration, the connection to the building will be influenced by this restraint. In this case, the following expression can be solved for the maximum axial force (F_{max}):

$$\Delta_x = \frac{F_{max}L}{AE} - \frac{fL^2}{2AE} + \frac{F_{max}}{K} - \frac{fL}{K} \qquad (3G\text{-}44)$$

where K is evaluated for the appropriate configuration (figure 3G-4).

3G.4.2 LATERAL MOVEMENT

In the case of relative movement between the building and soil in the direction transverse to the buried structure, stresses are determined assuming the structure to be a semi-infinite beam supported on an elastic foundation with a fixed or hinged end at the connection to the building (Yeh, 1974).

For a fixed connection to the building:

$$\sigma_b = \pm \frac{KR}{2\lambda^2 I}(\Delta_y) \qquad (3G\text{-}45)$$

$$\tau = \frac{\alpha K}{\lambda A}(\Delta_y) \qquad (3G\text{-}46)$$

where:

σb = maximum bending stress at the connection

τ = maximum shear stress at the connection

Δ_y = relative movement between the building and soil in the transverse direction

α = shape factor for the structural cross-section and is equal to 2 for a thin circular section

For a hinged connection to the building:

$$\sigma_b = \pm 0.161 \frac{KR}{\lambda^2 I} (\Delta_y) \quad (3G\text{-}47)$$

$$\tau = \frac{\alpha K}{2\lambda A} (\Delta_y) \quad (3G\text{-}48)$$

where:

σ_b = maximum bending stress located at a distance $\pi/4\lambda$ from the connection

τ = maximum shear stress at the connection

3G.5 DESIGN EXAMPLE

Given An underground steel pipeline connecting two buildings as shown in plan view in figure 3G-6. The properties of the pipe and supporting soil, and the earthquake motion are as follows:

Pipe

30-inch ID

$t = 3/8 - \text{inch}$

$I = 4130 \text{ in.}^4$

$A = 35.8 \text{ in.}^2$

$E = 30x10^6$ psi

$L_1 = 500$ ft

$L_2 = 100$ ft

Soil

$\gamma_{soil} = 118$ pcf

$C_p = 7500$ fps

$C_s = C_R = 3000$ fps

$K_o = 0.7$

$H_d = 6.0$ ft

$\mu = 0.4$

$k_s = 98 \text{ lb / in.}^3$

Earthquake

$a_m = 120 \text{ in./sec}^2$

$v_{mp} = 5$ in. / sec

$v_{ms} = v_{mr} = 14$ in. / sec

Find

(a) Seismic design stresses in the straight sections of the pipeline away from the bend and connections to the buildings.

(b) Design condition at the bend, including:

- stresses in the pipeline if restrained at the bend
- maximum axial displacement of the ends of the pipeline if unrestrained at the bend
- maximum angular distortion at the bend.

(c) Design condition at the building connection, including

- stresses in the pipeline assuming a hinged or fixed connection and 0.5 inch relative movement in the axial or lateral direction
- maximum axial displacement of the ends of the pipeline at the connections assuming no restraint
- maximum angular distortion at the connections

Solution

Since the pipeline is of relatively small diameter, the maximum values of axial and bending stress for each wave type will be added directly without maximizing for angle of incidence as discussed in subsection 3G.2.3. The maximum axial and bending stresses due to individual compression, shear, and surface waves for a pipeline following the ground motion are determined from the appropriate equations of subsection 3G.2.2:

Compression wave

$$\sigma_a = \pm \frac{Ev_{mp}}{C_p} = \pm 1667 \text{ psi}$$

$$\sigma_b = \pm \frac{0.385\ ERa_{mp}}{C_p^2} = \pm 2.6 \text{ psi}$$

Shear wave

$$\sigma_a = \pm \frac{EV_{ms}}{2C_s} = \pm 5833 \text{ psi}$$

$$\sigma_b = \pm \frac{ERa_{ms}}{C_s^2} = \pm 42.7 \text{ psi}$$

Surface wave

$$\sigma_a = \pm \frac{Ev_{mr}}{C_r} = \pm 11{,}667 \text{ psi}$$

$$\sigma_b = \pm \frac{ERa_{mr}}{C_r^2} = \pm 42.7 \text{ psi}$$

(a) Seismic design stresses in the long, straight section (L_1) are obtained from stresses for the individual wave types using the SRSS method:

$$\sigma_a = \pm\left[(1667)^2 + (5833)^2 + (11{,}667)^2\right]^{1/2}$$
$$= \pm\ 13{,}100 \text{ psi}$$

$$\sigma_b = \pm\left[(2.6)^2 + (42.7)^2 + (42.7)^2\ \right] = \pm\ 60 \text{ psi}$$

Design stresses in the shorter section (L_2) can be reduced to account for slippage between the pipeline and the soil as discussed in subsection 3G.2.4:

$$\varepsilon_m = \frac{\sigma_a + \sigma_b}{E} \quad \frac{13{,}096 + 60}{30 \times 10^6} = 0.438 \times 10^{-3}$$

$$P_r = \left(\frac{1 + K_o}{2}\right)\ \gamma_{soil}\ \ (H_d) = 602 \text{ psf}$$

$$f = \pi D p_r \mu = 1935 \text{ 1b / ft}$$

$$\ell_m = \frac{\varepsilon_m AE}{f} = 243 \text{ ft}$$

For the shorter section, $L_2 < 2\ell_m$ and the seismic design stresses can be reduced in accordance with figure 3G-2:

$$\sigma_a = \frac{f}{A}\left(\frac{L_2}{2}\right) = 2700 \text{ psi}$$

(b) If the pipeline is restrained at the bend by a rigid elbow or other structure, shear and bending stresses will be induced in the pipeline in addition to an axial stress as discussed in section 3G.3. For displacement at the bend in the east-west direction (axial force in L_1):

$$\lambda = \left[\frac{k_s B}{4EI}\right]^{1/4} = 8.83 \times 10^{-3}$$

Both pipeline sections (L_1 and L_2) can be considered as infinitely long for purposes of calculating the spring constant at the bend since both λL_1 and $\lambda L_2 > \pi$.

The appropriate spring constant at the bend is case (B) of table 3G-1:

$$K = \frac{3k}{4\lambda} = 2.56 \times 10^5 \text{ lb / in.}$$

The effective slippage length along section L_1 is calculated from equation 3G-40:

$$\ell_e = \frac{AE}{K}\left(\sqrt{1.0 + \frac{2\varepsilon_m K}{f}} - 1.0\right) = 2291 \text{ in.}$$

The shear, moment, and transverse displacement induced in section L_2 at the bend are:

$$Q_2 = F_{max} - f\ell_e = \varepsilon_m AE - f\ell_e = 101{,}000 \text{ lb}$$

$$\Delta_2 = \frac{Q_2}{K} = 0.39 \text{ in.}$$

$$M_2 = \frac{k\ \Delta_2}{4\lambda^2} = 3.77 \times 10^6 \text{ in. lb}$$

For displacement at the bend in the north-south direction (axial force in L_2), one-half the section length (600 inches) is less than the effective slippage length (ℓ_e) = 2291 inches) calculated using equation 3G-40. In this case, equation 3G-41 must be solved for the effective slippage length by trial and error:

$$\ell_e = 470 \text{ in.}$$

The shear, moment, and transverse displacement induced in section L_1 at the bend are:

$$Q_1 = F_{max} - f\ell_e = f(L_2 - \ell_e) - f\ell_e = 41{,}860 \text{ lb}$$

$$\Delta_1 = \frac{Q_1}{K} = 0.16 \text{ in.}$$

$$M_1 = \frac{k\Delta_1}{4\lambda^2} = 1.55 \times 10^6 \text{ in. lb}$$

If the pipeline is not restrained at the bend, the longitudinal displacement of the ends relative to the soil can be calculated by equations 3G-23 and 3G-25. The displacement of the end of the long section (L_1) is:

$$\Delta_1 = \frac{\varepsilon_m{}^2 AE}{2f} = 0.64 \text{ in.}$$

The displacement of the end of the short section (L_2) is:

$$\Delta_2 = \frac{\varepsilon_m L_2}{2} - \frac{fL_2^2}{8AE} = 0.24 \text{ in.}$$

The angular distortion of the pipeline can be calculated by equation 3G-33:

$$\phi = K_m \ (L) = \frac{a_m (L)}{C_s{}^2}$$

For the long section (L_1), ϕ_1 = 0.03 deg.; for the shorter section (L_2), ϕ_2 = 0.01 deg.

(c) Connection at Point (A)

The axial force induced in the longer section (L_1) due to the design axial relative movement (Δ_x) of 0.5 inch is:

$$P_1 = \sqrt{2EAf\Delta_x} = 415{,}800 \text{ lb}$$

for a long structure where $L_1 = 500$ ft > $\frac{P}{f} = 215$ ft

Assuming a fixed connection, the maximum bending and shear stresses in the pipeline at the connection due to the design lateral relative movement (Δ_x) of 0.5 inch are:

$$\sigma_b = \pm \frac{kR}{2\lambda^2 I}(\Delta_y) = \pm\ 35{,}100 \text{ psi}$$

$$\tau = \frac{\alpha k}{\lambda A}(\Delta_y) = 9500 \text{ psi}$$

Assuming a hinged connection, the maximum bending and shear stresses are:

$$\sigma_b = \pm \frac{0.161kR}{\lambda^2 I}(\Delta_y) = \pm\ 11{,}300 \text{ psi at a}$$

distance $\frac{\pi}{4\lambda} = 89$ in. from the connection and

$$\tau = \frac{\alpha k}{2\lambda A}(\Delta_y) = 4800 \text{ psi}$$

<u>Connection at Point (C)</u>

For the shorter section, $L_2 = 100$ ft < $\frac{P}{f} = 215$ ft and equation 6-44 can be solved to obtain the maximum axial force due to the design axial relative displacement (Δ_x) of 0.5 inch:

$$F_{max} = 271{,}000 \text{ lb}$$

The maximum bending and shear stresses in the pipeline at the connection due to the design lateral relative movement

(Δ_y) of 0.5 inch are the same as for the connection at point (A).

Angular Distortion

The design angular distortion at the connections is the same as for the bend:

ϕ_1 = 0.03 deg

ϕ_2 = 0.01 deg

The calculated seismic stresses and displacements at various locations along the pipeline must be combined with stresses due to all other loading conditions to obtain total design stresses (Goodling, 1978). If the total calculated stresses exceed the allowable stresses, the overstressed section can be made more flexible or isolated partially or completely from the surrounding soil. In the vicinity of the connections to the buildings, for example, a fixed connection would result in very high bending stresses which could be greatly reduced by use of a hinged connection.

APPENDIX 3G

3G.6 REFERENCES

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APPENDIX 3H

LATERAL EARTH PRESSURE ON FOUNDATION AND RETAINING WALLS

APPENDIX 3H

LATERAL EARTH PRESSURE ON FOUNDATIONS AND RETAINING WALLS

The total lateral earth pressure on foundation and retaining walls shall be based on the sum of the appropriate static and dynamic lateral forces. Static forces shall be based either on the active case (P_A) for the case of a retaining wall free to rotate and translate, or on the compacted backfill case (P_B) for the case of a rigid foundation wall. Dynamic forces shall be based on the dynamic increment for a level backfill condition (P_{AE}) plus the surcharge effect (P_{AES}), if applicable.

A. Static Conditions

Case	Equivalent Fluid Unit Weight (lb/ft^3) (Horizontal Backfill) Above Water Table	Below Water Table
Active (P_A)	36	19
Passive (P_P)	228	118
Backfill (P_B)	90	47

The increment of lateral pressure due to adjacent surcharge for the case of a rigid foundation wall shall be computed using figure 3H-1.

The increment of lateral pressure due to adjacent surcharge for the case of a retaining wall free to rotate and translate shall be computed using figure 3H-2.

B. Dynamic Conditions

The dynamic lateral force increment due to seismic effects shall be computed in accordance with figure 3H-3.[(1),(2)]

The total dynamic lateral force increment, P_{AE} or P_{AE} + P_{AES}, shall be added to the lateral force calculated for either the active case or the compacted backfill case.

The lateral force is calculated in the usual manner and includes hydrostatic pressure if a water table is present. The dynamic lateral force increments are independent of the water table.

REFERENCES

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CHAPTER 4

REACTOR

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4. REACTOR

4.1 SUMMARY DESCRIPTION

The reactor is of the pressurized water type using two reactor coolant loops. A vertical cross section of the reactor is shown in figure 4.1-1. The reactor core is composed of 241 fuel assemblies and 89 or more control element assemblies (CEAs). The fuel assemblies are arranged to approximate a right circular cylinder with an equivalent diameter of 143.6 inches and an active length of 150 inches. The fuel assembly, which provides for 236 fuel rod positions (16 x 16 array), consists of 5 guide tubes welded to spacer grids and is closed at the top and bottom by end fittings. The guide tubes each displace four fuel rod positions and provide channels which guide the CEAs over their entire length of travel. In-core instrumentation is installed in the central guide tube of selected fuel assemblies. The in-core instrumentation is routed into the bottom of the fuel assemblies through the bottom head of the reactor vessel.

Each fuel rod consists of slightly enriched uranium in the form of sintered uranium dioxide pellets, enclosed in a pressurized Zircaloy or ZIRLO™ tube that forms a hermetic enclosure. Burnable absorber rods are provided in selected fuel assembly locations, and are mechanically similar to fuel rods. The original design of PVNGS fuel assemblies utilized aluminum oxide-boron carbide pellets for the burnable adsorber, whereas reload designs have utilized erbium oxide. The erbium oxide is admixed with slightly enriched uranium in the form of sintered fuel-poison rods. The use of the rare earth element erbium may

provide significant advantages in terms of reduced core power peaking, increased core operating margin, and reduced fuel cycle costs. Reload fuel assemblies also include other incremental design improvements that improve fuel reliability, lower fabrication or fuel cycle costs, or contribute to flexibility in reactor core design or operation.

Fuel assemblies conform with fuel designs that have been analyzed with applicable NRC staff approved codes and methods, and shown by tests or analyses to comply with all fuel safety design bases. Various fuel assembly configurations may be used within the same reactor core when such use is evaluated on a reload-specific basis. A limited number of lead test assemblies that have not completed representative testing may be placed in non-limiting core regions; however, other cladding material may be used only with an NRC approved exemption as required by the PVNGS operating license.

The reactor coolant enters the inlet nozzles of the reactor vessel, flows downward between the reactor vessel wall and the core barrel, and passes through the flow skirt section where the flow distribution is equalized, and into the lower plenum. The coolant then flows upward through the core, removing heat from the fuel rods. The heated coolant enters the core outlet region where the coolant flows around the outside of control element assembly shroud tubes to the reactor vessel outlet nozzles. The control element assembly shroud tubes protect the individual neutron absorber elements of the CEAs from the effects of coolant cross-flow above the core.

The reactor internals support and orient the fuel assemblies, control element assemblies, and in-core instrumentation, and guide the reactor coolant through the reactor vessel. They also absorb static and dynamic loads and transmit the loads to the reactor vessel flange. They will safely perform their functions during normal operating, upset, and faulted conditions. The internals are designed to safely withstand forces due to dead weight, handling, temperature and pressure differentials, flow impingement, vibration, and seismic acceleration. All reactor components are considered Category I for seismic design. The design of the reactor internals limits deflection where required by function. The stress values of all structural members under normal operating and expected transient conditions are not greater than those established by Section III of the ASME Code. The effect of neutron irradiation on the materials concerned is included in the design evaluation. The effect of accident loadings on the internals is included in the design analysis.

Reactivity control is provided by three independent systems: the control element drive mechanism control system (CEDMCS), the chemical and volume control system (CVCS), and the Safety Injection System (SIS). The CEDMCS controls short-term reactivity changes and is used for rapid shutdown. The CVCS is used to compensate for long-term reactivity changes and can make the reactor subcritical without the benefit of the CEDMCS. The SIS provides reactivity control for certain postulated design basis events, such as steam line breaks and Loss of Coolant Accidents (LOCA). The design of the core and the

reactor protective system prevent fuel damage limits from being exceeded for any single malfunction in any of the reactivity control systems.

4.2 FUEL SYSTEM DESIGN

4.2.1 DESIGN BASES

4.2.1.1 Fuel Assembly

The fuel assemblies are required to meet design criteria for each design condition listed below to assure that the functional requirements are met. Except where specifically noted, the design bases presented in this section are consistent with those used for previous designs.

A. Nonoperation and Normal Operation (Condition I)

Condition I situations are those which are planned or expected to occur in the course of handling, initial shipping, storage, reactor servicing, and power operation (including maneuvering of the plant). Condition I situations must be accommodated without fuel assembly failure and without any effect which would lead to a restriction on subsequent operation of the fuel assembly. The guidelines stated below are used to determine loads during Condition I situations:

1. Handling and Fresh Fuel Shipping

Loads correspond to the maximum possible axial and lateral loads and accelerations imposed on the fuel assembly by shipping and handling equipment during these periods, assuming that there is no abnormal contact between the fuel assembly and any surface, nor any equipment malfunction. Irradiation effects on material properties are

considered when analyzing the effects of handling loads which occur during refueling. Additional information regarding shipping and handling loads is contained in paragraph 4.2.3.1.5.

2. Storage

Loads on both new and irradiated fuel assemblies reflect storage conditions of temperature, chemistry, means of support, and duration of storage.

3. Reactor Servicing

Loads on the fuel assembly reflect those encountered during refueling and reconstitution.

4. Power Operation

Loads are derived from conditions encountered during transient and steady-state operation in the design power range. (Hot operational testing, system startup, hot standby, operator-controlled transients within specified rate limits, and system shutdown are included in this category.)

5. Reactor Trip

Loads correspond to those produced in the fuel assembly by control element assembly (CEA) motion and deceleration.

B. Upset Condition (Condition II)

Condition II situations are unplanned events (such as those discussed in chapter 15 and the operating basis

earthquake (OBE)) which may occur with moderate frequency during the life of the plant. The fuel assembly design should have the capability to withstand any upset condition with margin to mechanical failure and with no permanent effects which would prevent continued normal operation.

C. Emergency Conditions (Condition III)

Condition III events are unplanned incidents as discussed in chapter 15 and minor fuel handling accidents which might occur infrequently during plant life. Rod mechanical failure must be prevented for any Condition III event in any area not subject to extreme local conditions (e.g., in any rod not immediately adjacent to the impact surface during a fuel handling accident).

D. Faulted Conditions (Condition IV)

Condition IV incidents are postulated events from chapter 15 and the safe shutdown earthquake (SSE), LOCA (mechanical excitation only), combined SSE and LOCA, and major fuel handling accident whose consequences are such that integrity and operability of the nuclear energy system may be impaired. Mechanical fuel failures are permitted, but they must not impair the operation of the engineered safety features (ESF) systems to mitigate the consequences of the postulated event.

4.2.1.1.1 Fuel Assembly Structural Integrity Criteria

The criteria that apply to the structural integrity of fuel assembly components, with the exception of fuel rods, are presented below. These criteria include the allowable primary stresses and functional requirements for each design condition. As required, limits for secondary stress may be obtained from methods similar to those given in Section III of the ASME Boiler and Pressure Vessel Code. When evaluating secondary stress, all functional requirements, including the stated assumptions regarding material properties and limits, still apply. Criteria for fuel rods are discussed separately in paragraph 4.2.1.2.

A. Design Conditions I and II

$P_m \leq S_m$

$P_m + P_b \leq F_s S_m$

Under cyclic loading conditions, stresses must be such that the cumulative fatigue damage factor does not exceed 0.8. Cumulative damage factor is defined as the sum of the ratios of the number of cycles at a given cyclic stress (or strain) condition to the maximum number permitted for that condition. The selected limit of 0.8 is used in place of 1.0 (which would correspond to the absolute maximum damage factor permitted) to provide additional margin in the design.

During the OBE, fuel assembly deflections must be such that permanent deformations are limited to a value allowing the CEAs to scram.

B. Design Condition III

$P_m \leq 1.5\ S_m$

$P_m + P_b \leq 1.5\ F_s S_m$

C. Design Condition IV

$P_m \leq S_m'$

$P_m + P_b \leq F_s S_m'$

where S_m' = smaller value of 2.4 S_m or 0.7 S_u.

1. If the equivalent diameter pipe break in the LOCA does not exceed 0.5 square foot, the fuel assembly deformation shall be limited to a value not exceeding the deformation which would preclude satisfactory insertion of the CEAs.

2. For pipe break sizes greater than 0.5 square foot, deformation of structural components is limited to maintain the fuel in a coolable array. CEA insertion is not required for these events as the appropriate safety analyses do not take credit for CEA insertion.

3. For the upper end fitting springs, calculated shear stress must not exceed the minimum yield stress in shear.

4. For the spacer grids, the predicted impact loads must be less than the tested grid capability, as defined in reference 1.

5. During the SSE, fuel assembly deflections must be such that permanent deformations are limited to a value allowing the CEAs to scram.

D. Nomenclature

The symbols used in defining the allowable stress levels are as follows:

P_m = Calculated general primary membrane stress[a]

P_b = Calculated primary bending stress

S_m = Design stress intensity value as defined by Section III, ASME Boiler and Pressure Vessel Code[b]

S_u = Minimum unirradiated ultimate tensile strength

F_s = Shape factor corresponding to the particular cross-section being analyzed[c]

---

a. P_m and P_b are defined by Section III, ASME Boiler and Pressure Vessel Code.

b. With the exception of zirconium base alloys, the design stress intensity values, S_m, of materials not tabulated by the Code are determined in the same manner as those in the Code. The design stress intensity of zirconium base alloys shall not exceed two-thirds of the unirradiated minimum yield strength at temperature. Basing the design stress intensity on the unirradiated yield strength is conservative because the yield strength of Zircaloy or ZIRLO™ increases with irradiation. The use of the two-thirds factor ensures 50% margin to component yielding in response to primary stresses. This 50% margin, together with its application to the minimum unirradiated properties and the general conservatism applied in the establishment of design conditions, is sufficient to ensure an adequate design.

c. The shape factor, F_s, is defined as the ratio of the "plastic" moment (all fibers just at the yield stress) to the initial yield amount (extreme fiber at the yield stress and all other fibers stressed in proportion to their distance from the neutral axis). The capability of cross- sections loaded in bending to sustain moments considerably in excess of that required to yield the outermost fibers is discussed in Timoshenko.[2]

S_m' = Design stress intensity value for faulted conditions

The definition of S_m' as the lesser value of 2.4 S_m and 0.7 S_u is contained in the ASME Boiler and Pressure Vessel Code, Section III.

4.2.1.1.2 Material Selection

The original fuel assembly grid cage structure design consists of ten Zircaloy-4 spacer grids, one Inconel 625 spacer grid (at the lower end), five Zircaloy-4 guide tubes, two stainless steel end fittings, and four Inconel X-750 coil springs. Beginning with Batch P3R, reload assemblies incorporate an Inconel 625 top grid, resulting in nine Zircaloy-4 spacer grids and two Inconel 625 spacer grids. Zircaloy-4, selected for fuel rod cladding, guide tubes, and spacer grids, has a low neutron absorption cross-section, and high corrosion resistance to reactor water environment. Also, there is little reaction between the cladding and fuel or fission products. ZIRLO™ material is also used for fuel rod cladding in selected fuel assemblies. As described in subsection 4.2.3, Zircaloy-4 has demonstrated its ability as a cladding, CEA guide tube, and spacer grid material. Reload fuel assemblies have incorporated laser welded Zircaloy ZIRLO™ also has a history of successful use as a cladding material spacer grids.

The original bottom spacer grid is of Inconel 625 and is welded to the lower end fitting. Beginning with Batch P3R, reload assemblies incorporate an Inconel 625 top spacer grid that is held in place by two Zircaloy-4 split rings welded directly to

each guide tube. Inconel 625 was selected rather than Zircaloy-4 to provide additional strength and relaxation resistance for regions of local flow turbulence (bottom grid) and fretting potential (top grid). Inconel 625 is a very strong material with good ductility, corrosion resistance, and stability under irradiation at temperatures below 1000F. Reload fuel assemblies have incorporated a laser welded Inconel grid design, the Guardian™ grid, manufactured by Westinghouse.

The fuel assembly upper and lower end fitting are of cast 304 stainless steel, and the upper and lower end fitting posts are type 304 stainless steel machined components. This material was selected based on considerations of adequate strength and high corrosion resistance. Also, type 304 stainless steel has been used successfully in almost all pressurized water reactor environments, including all currently operating Westinghouse reactors.

4.2.1.1.3 Control Element Assembly Guide Tubes

CEA guide tubes are manufactured in accordance with ASTM B353, Wrought Zirconium and Zirconium Alloy Seamless and Welded Tubes for Nuclear Service, with the following exceptions and/or additions:

A. Chemical Properties

   Additional limits are placed on oxygen, carbon, and silicon.

B. Mechanical Properties

Tensile Properties. Minimum values are specified for the tensile strength, yield strength, and total elongation at room temperature and high temperature.

4.2.1.1.4 Zircaloy-4 Bar Stock

Zircaloy-4 bar stock is fabricated in accordance with ASTM B351, Standard Specification for Hot-Rolled and Cold-Finished Zirconium and Zirconium Alloy Bars, Rod and Wire for Nuclear Application, with the following exceptions and/or additions:

A. Chemical Properties

Additional limits are placed on oxygen and silicon content.

B. Metallurgical Properties

Grain Size. The maximum average grain size is restricted.

4.2.1.1.5 Zircaloy-4 Strip Stock

Zircaloy-4 strip stock is fabricated in accordance with ASTM B352, Standard Specification for Zirconium and Zirconium Alloy Sheet, Strip and Plate for Nuclear Application, with the following exceptions and/or additions:

A. Chemical Properties

Additional limits are placed on oxygen and silicon content.

B. Metallurgical Properties

Grain Size. The maximum average grain size is restricted.

C. Mechanical Properties

Spacer and perimeter strips for spacer grids are to be free of cracks. Strips from each material lot are penetrant inspected in accordance with a quality control plan that ensures, with 95% confidence, that at least 95% of the strips are free of cracks. The method used is capable of detecting known cracks in a standard specimen grid strip. All strips found to have cracks shall be rejected.

4.2.1.1.6 Stainless Steel Castings

Stainless steel castings are fabricated in accordance with Westinghouse specification MACASS01 "Austenitic Stainless Steel Castings". Controls on acceptable ferrite levels are maintained at or less than 30%.

4.2.1.1.7 Stainless Steel Tubing

Stainless steel tubing is fabricated in accordance with ASTM A269, Seamless and Welded Austenitic Stainless Steel Tubing for General Service, with the following addition:

Chemical Properties:

Carbon content is limited on tubing to be welded. Cobalt content is limited.

4.2.1.1.8 Inconel X-750 Compression Springs

Inconel springs are fabricated in accordance with AMS 5699, Alloy Wire, Corrosion and Heat Resistant, with the following addition:

Chemical Properties:

Cobalt content is limited.

4.2.1.1.9 Inconel 625 Spacer Grid Strip Material

Inconel spacer grid strip material is procured in accordance with the Standard Specification for Nickel-Chromium-Molybdenum-Columbium Alloy (UNS N06625) Plate, Sheet, and Strip, Specification ASTM B443, with the following additional requirements:

A. Chemical check analysis is required. Cobalt content is limited.

B. Spacer and perimeter strips shall be free of cracks upon inspection.

4.2.1.2 Fuel Rod

4.2.1.2.1 Fuel Cladding Design Limits

The fuel cladding is designed to sustain the effects of steady-state and expected transient operating conditions without exceeding acceptable levels of stress and strain. Except where specifically noted, the design bases presented in this section are consistent with those used for previous core designs. The fuel rod design accounts for cladding irradiation growth, external pressure, differential expansion of fuel and

clad, fuel swelling, densification, clad creep, fission and other gas releases, initial internal helium pressure, thermal stress, pressure and temperature cycling, and flow-induced vibrations. The structural criteria discussed below are based on the following for the normal upset, and emergency loading combinations identified in paragraph 4.2.1.1. For a discussion of the thermal/hydraulic criteria, see subsection 4.4.1.

A. During normal operating and upset conditions, the maximum primary tensile stress in the ZIRLO™ and/or Zircaloy 4 clad shall not exceed two-thirds of the minimum unirradiated yield strength of the material at the applicable temperature. The corresponding limit under emergency conditions is the material yield strength. The use of the unirradiated material yield strength as the basis for allowable stress is conservative because the yield strength of ZIRLO™ and Zircaloy 4 increases with irradiation. The use of the two-thirds factor ensures 50% margin to component yielding in response to primary stresses. This 50% margin, together with its application to the minimum unirradiated properties and the general conservatism applied in the establishment of design conditions, is sufficient to ensure an adequate design.

B. Net unrecoverable circumferential strain shall not exceed 1% as predicted by computations considering clad creep and fuel-clad interaction effects.

   Data from O'Donnell[3] and Weber[4] were used to determine the present 1% strain limit. O'Donnell

developed an analytical failure curve for Zircaloy cladding based upon the maximum strain of the material at its point of plastic instability. O'Donnell compared his analytical curve to circumferential strain data obtained on irradiated coextruded Zr-U metal fuel rods tested by Weber. The correlation was good, thus substantiating O'Donnell's instability theory. Since O'Donnell performed his analysis, additional data have been derived at Bettis(5)(6)(7) and AECL.(8)(9)

These new data are shown in figure 4.2-1, along with O'Donnell's curve and Weber's data. This curve was then adjusted because of differences in anisotropy, stress states, and strain rates, and the design limit was set at 1%.

The conservatism of the clad strain calculations is provided by the selection of adverse initial conditions and material behavior assumptions, and by the assumed operating history. The acceptability of the 1.0% unrecoverable circumferential strain limit is demonstrated by data from irradiated Zircaloy-clad fuel rods which show no cladding failures (due to strain) at or below this level, as illustrated in figure 4.2-1. Similar results for ZIRLO™ cladding are supported by reference 71.

C. The clad will be initially pressurized with helium to an amount sufficient to prevent gross clad deformation under the combined effects of external pressure and

long-term creep. Modified design criteria for fuel rod pressurization were proposed by C-E in a topical report that justified rod internal pressure exceeding RCS pressure.[10] This report received NRC staff approval and may be used for reload core design, provided core design evaluations consider the potential effects of increased rod pressure on LOCA calculations and DNB propagation in postulated accidents.

D. Cumulative strain cycling usage, defined as the sum of the ratios of the number of cycles in a given effective strain range ($\Delta\varepsilon$) to the permitted number (N) at that range, as taken from figure 4.2-2, will not exceed 0.8.

The cyclic strain limit design curve shown on figure 4.2-2 is based upon the Method of Universal Slopes developed by S. S. Manson[11] and has been adjusted to provide a strain cycle margin for the effects of uncertainty and irradiation. The resulting curve has been compared with known data on the cyclic loading of Zircaloy and ZIRLO™ and has been shown to be conservative. Specifically, it encompasses all the data of O'Donnell and Langer.[12]

As discussed in paragraph 4.2.1.2.5, the fatigue calculation method includes the effect of clad creep to reduce the pellet to clad diametral gap during that portion of operation when the pellet and clad are not in contact. The same model is used for predicting clad fatigue as is used for predicting clad strain. Therefore, the effects of creep and fatigue loadings

are considered together in determining end-of-life clad strain (see figure 4.2-2).

E. There is no specific limit on lateral fuel rod deflection for structural integrity considerations, except that which is brought about through application of cladding stress criteria. The absence of a specific limit on rod deflection is justified because it is the fuel assembly structure, and not the individual fuel rod, that is the limiting factor for the fuel assembly lateral deflection.

F. Fuel rod internal pressure increases with increasing burnup and toward end-of-life the total internal pressure, due to the combined effects of the initial helium fill gas and the released fission gas, can approach values comparable to the external coolant pressure. The maximum predicted fuel rod internal pressure will be consistent with the following criteria.

1. The primary stress in the cladding resulting from differential pressure will not exceed the stress limits specified earlier in this section.

2. The internal pressure will not cause the clad to creep outward from the fuel pellet surface while operating at the design peak linear heat rate for normal operation. In determining compliance with this criterion, internal pressure is calculated for the peak power rod in the reactor, including accounting for the maximum computed fission gas

release. In addition, the pellet swelling rate (to which the calculated clad creep rate is compared) is based on the observed swelling rate of "restrained" pellets (i.e., pellets in contact with clad), rather than on the greater observed swelling behavior of pellets which are free to expand.

The criteria discussed above do not limit fuel rod internal pressure to values less than the primary coolant pressure, and the occurrence of positive differential pressures would not adversely affect normal operation if appropriate criteria for cladding stress, strain, and strain rate were satisfied. Modified design criteria for fuel rod pressurization were proposed by C-E in a topical report that justified rod internal pressure exceeding RCS pressure.[(10)] This report received NRC staff approval and may be used for reload core design, provided core design evaluations consider the potential effects of increased rod pressure on LOCA calculations and DNB propagation in postulated accidents.

G. The design limits of the fuel rod cladding, with respect to vibration considerations, are incorporated within the fuel assembly design. It is a requirement that the spacer grid intervals, in conjunction with the fuel rod stiffness, be such that fuel rod vibration, as a result of mechanical or flow-induced excitation, does not result in excessive wear of the fuel rod cladding at the spacer grid contact areas.

The use of ZIRLO fuel cladding is limited to a maximum allowable corrosion of 100 microns. The corrosion thickness is calculated using the best estimate model described in Reference 71. Contained in reference 71 is a letter from P.W. Richardson (WEC) to J.S. Cushing (NRC), "Response to Requests for Additional Information on Topical Report CENPD-404-P, Rev. 0", LD-2001-0045, Rev. 0, August 10, 2001. This letter specifically addresses the best estimate models for predicting corrosion limits.

The use of ZIRLO fuel cladding is also limited to a maximum radial integrated rod burnup of 60 GWD/MTU.

4.2.1.2.2 Fuel Rod Cladding Properties

4.2.1.2.2.1 Mechanical Properties

A. Modulus of Elasticity

The Modulus of Elasticity is evaluated as a function of temperature, using a Westinghouse proprietary formula.

B. Poisson's Ratio

Poisson's Ratio is evaluated as a function of temperature, using a Westinghouse proprietary formula.

C. Thermal Coefficient of Expansion

Diametral direction Thermal Coefficient of Expansion is evaluated as a function of temperature, using a Westinghouse proprietary formula.

D. Yield Strength

Yield strength in the non-irradiated condition is evaluated as a function of temperature, using a

Westinghouse proprietary formula. Yield strength in the irradiated condition is evaluated as a function of fluence.

The cladding stress limits identified in paragraph 4.2.1.2.1 are based on values taken from the minimum yield strength curve at the appropriate temperatures. The limits are applied over the entire fuel lifetime, during conditions of reactor heatup and cooldown, steady state operation, and normal power cycling. Under these conditions, cladding temperatures and fast fluences can range from 70 to 750F and from 0 to 1 x 10^{22}nvt, respectively.

E. Ultimate Strength

Ultimate tensile strength in the non-irradiated condition is evaluated as a function of temperature, using a Westinghouse proprietary formula. Ultimate tensile strength in the irradiated condition is evaluated as a function of fluence.

F. Uniform Tensile Strain

The uniform tensile strain in the irradiated condition is evaluated as a function of temperature, using a Westinghouse proprietary formula. Uniform tensile strain in the irradiated condition approaches 1% and remains relatively constant.

G. Hydrostatic Burst Test

The Zircaloy-4 cladding specification requires that two samples from each lot of cladding be subjected to room

temperature hydrostatic burst tests. To be acceptable, the burst pressure must exceed a minimum value, based on the cladding geometry and specified tensile properties, and the circumferential elongation must exceed a prescribed minimum value.

Where the use of ZIRLO™ cladding is part of the design, the ZIRLO™ cladding specification includes the requirement for Contractile Strain Ratio (CSR) testing. CSR testing is employed in place of burst testing to quantify the effects of texture on the mechanical properties.

4.2.1.2.2.2 Dimensional Requirements

A. Tube straightness is limited to 0.010 in./ft, and inside diameter and wall thickness are tightly controlled.

B. Ovality is measured as the difference between maximum and minimum outside diameters and is acceptable if within the diameter tolerances.

C. Outside diameter is specified as 0.382 ± 0.002 inches.

D. Inside diameter is specified as 0.332 ± 0.0015 inches.

E. Eccentricity is defined as the difference between maximum and minimum wall thickness at a cross-section, and is specified as 0.004 inches maximum.

F. Wall thickness is specified as 0.023 inches minimum (the nominal value reported in Table 4.2-1 is based on the nominal OD and ID).

4.2.1.2.2.3 Metallurgical Properties

Hydride Orientation. A restriction is placed on the hydride orientation factor for any third wall thickness of the tube cross-section (inside, middle, or outside). The hydride orientation factor, defined as the ratio of the number of radially oriented hydride platelets to the total number of hydride platelets, shall not exceed 0.3. The independent evaluation of three portions of the cross-section is included to allow for the possibility that hydride orientation may not be uniform across the entire cross-section.

4.2.1.2.2.4 Chemical Properties. Fuel rod cladding is manufactured in accordance with ASTM B353, Wrought Zirconium and Zirconium Alloy Seamless and Welded Tubes for Nuclear Service, or ASTM B811, Wrought Zirconium Alloy Seamless Tubes for Nuclear Reactor Fuel Cladding, except additional limits are placed on oxygen, silicon, carbon, iron, and tin content.

4.2.1.2.3 Fuel Rod Component Properties

4.2.1.2.3.1 Zircaloy-4 Bar Stock. Zircaloy-4 bar stock is fabricated in accordance with ASTM B351, Standard Specification for Hot-Rolled and Cold-Finished Zirconium and Zirconium Alloy Bars, Rod and Wire for Nuclear Application, with the following exception and/or additions:

A. Chemical Properties

Additional limits are placed on oxygen, carbon, and silicon content.

B. Metallurgical Properties

The maximum average grain size is restricted.

C. Nondestructive Testing

Ultrasonic inspection is required.

4.2.1.2.3.2 Stainless Steel Compression Springs. Stainless steel springs are fabricated in accordance with AMS 5688, Steel, Corrosion Resistant, Wire 18Cr-9.0Ni (SAE 30302) Spring Temper.

4.2.1.2.4 UO_2 Fuel Pellet Properties

4.2.1.2.4.1 Chemical Composition. Salient points regarding the structure, composition, and properties of the UO_2 fuel pellets are discussed in the following paragraphs. Where the effect of irradiation on a specific item is considered to be of sufficient importance to warrant reflection in the design or analyses, that effect is also discussed.

A. Chemical analyses are performed for the following constituents:

1. Total uranium
2. Carbon
3. Nitrogen
4. Fluorine
5. Chlorine and Fluorine
6. Iron
7. Thorium

8. Nickel

9. Aluminum

10. Silicon

11. Calcium and Magnesium

B. The oxygen-to-uranium ratio is maintained between 1.99 and 2.02.

C. The sum of the cross-sections of the following constituents shall not exceed a specified equivalent thermal-neutron capture cross-section of natural boron:

1. Boron

2. Silver

3. Cadmium

4. Gadolinium

5. Europium

6. Samarium

7. Dysprosium

8. Erbium

D. The total hydrogen content of finished ground pellets is restricted.

E. The nominal enrichment of the fuel pellets will be specified in a manufacturing order.

F. Erbium oxide (Er_2O_3) may be admixed with UO_2 as a burnable poison pellet for reload core designs, in lieu

of the original Al_2O_3-B_4C poison described in section 4.2.1.3.

4.2.1.2.4.2 Microstructure

The average grain size shall exceed a specified minimum size.

4.2.1.2.4.3 Density

A. The density of sintered pellets is determined on a geometric basis, based on a UO_2 theoretical density of 10.96 g/cm^3. The density of UO_2-Er_2O_3 pellets may differ slightly from that of UO_2 pellets, as described in Reference 27.

B. The in-pile stability of the fuel is ensured by the use of NRC-approved out-of-pile tests during production. The details of one of these tests, and the associated rationale, are presented in reference 13.

C. The effects of irradiation on the density of sintered UO_2 pellets are treated by the NRC-approved model for fuel evaluation presented in references 13 and 14.

4.2.1.2.4.4 Thermal Properties of UO_2

A. Thermal expansion

The thermal expansion of UO_2 is described by the following temperature-dependent equations:(15)(16)

From 25C up to 2200C

$$\% \text{ Linear Expansion} = (-1.723 \times 10^{-2}) + (6.797 \times 10^{-4} T) + (2.896 \times 10^{-7} T^2)$$

Above 2200C

$$\% \text{ Linear Expansion} = 0.204 + (3 \times 10^{-4} T) + (2 \times 10^{-7} T^2) + (10^{-10} T^3)$$

where T = temperature, °C

B. Thermal Emissivity

A value of 0.85 is used for the thermal emissivity of UO_2 over the temperature range 800 to 2600K.(17)(18)(19)

C. Melting Point and Thermal Conductivity

The temperature required to incur melting of UO_2 is linearly dependent on local burnup as given by:

$$T_{melt} = 5080 - (290)\left(\frac{\text{Burnup}}{50{,}000}\right)$$

where T_{melt} is in °F and burnup is in MWd/Mtu. This equation is based on UO_2 melt data given by reference 20.

The variation of the thermal conductivity of UO_2 with burnup is not explicitly treated, but is implicitly taken from the porosity relationship discussed in Section 2.2.5 of reference 13.

The melting point and thermal conductivity of UO_2-Er_2O_3 is slightly lower than that of UO_2, as described in Reference 27.

D. Specific Heat of UO_2

The specific heat of UO_2 is described by the following temperature-dependent equations:[21]

For T < 2240F

$$C_p = 49.67 + 2.2784 \times 10^{-3}T - \frac{3.2432 \times 10^6}{(T + 460)^2}$$

For T ≥ 2240F

$$C_p = -126.07 + 0.2621T - 1.399 \times 10^{-4}T^2 + 3.1786 \times 10^{-8}T^3 - 2.489 \times 10^{-12}T^4$$

where:

C_p = specific heat, Btu/ft^3-°F

T = temperature, °F

The specific heat of UO_2-Er_2O_3 is slightly higher than that of UO_2, as described in Reference 27.

4.2.1.2.4.5 Mechanical Properties

A. Young's Modulus of Elasticity

The static modulus of elasticity of unirradiated UO_2 of 97% TD and deformed under a strain rate of 0.097 hr^{-1} is given by:[22]

$E = 14.22 (1.6715 \times 10^6 - 924.4T)$

where:

E = modulus of elasticity, psi

T = temperature, °C, in the range of 1000 to 1700C

B. Poisson's Ratio

The Poisson's Ratio of polycrystalline $UO_{(2)}$ has a value of 0.32 at 25C based on reference 23. The same reference notes a 10% decrease in value over the range of 25 to 1800C. Assuming the decrease is linear, the temperature dependence of the Poisson's ratio is given by

$\upsilon = 0.32 - 1.8 \times 10^{-5} (T-25)$

where:

υ = Poisson's Ratio

T = temperature, °C, in the range of 25 to 1800C

At temperatures above 1800C a constant value of 0.29 is used for Poisson's Ratio.

C. Yield Stress (not applicable)

D. Ultimate Stress (not applicable)

E. Uniform Ultimate Strain (not applicable)

4.2.1.2.5 Fuel Rod Pressurization

Fuel rods are initially pressurized with helium for two reasons:

A. To preclude clad collapse during the design life of the fuel. The internal pressurization, by reducing stresses from differential pressure, extends the time required to produce creep collapse beyond the required service life of the fuel.

B. To improve the thermal conductivity of the pellet-to-clad gap within the fuel rod. Helium has a higher coefficient of thermal conductivity than the gaseous fission products.

In unpressurized fuel, the initially good helium conductivity is eventually degraded through the addition of the fission product gases released from the pellets. The initial helium pressurization results in a high helium-to-fission products ratio over the design life of the fuel, with a corresponding increase in the gap conductivity and heat transfer. The effect of fuel rod power level and pin burnup on fuel rod internal pressure has been studied parametrically.

The initial helium fill pressure for the original fuel design was 380 psig. This initial fill pressure was sufficient to produce a maximum EOL internal pressure consistent with the criteria of paragraph 4.2.1.2.1. The calculational methods employed to generate internal pressure histories are discussed in references 13, 14, 24, and 25. Modified design criteria for fuel rod pressurization were proposed by C-E in a topical report that justified rod internal pressure exceeding RCS pressure.[10] This report received NRC staff approval and may be used for reload core design, provided core design evaluations consider the potential effects of increased rod

pressure on LOCA calculations and DNB propagation in postulated accidents.

4.2.1.2.5.1 Capacity for Fission Gas Inventory. The greater portion of the gaseous fission products remains either within the lattice or the microporosity of the UO_2 fuel pellets, and does not contribute to the fuel rod internal pressure. However, a fraction of the fission gas is released from the pellets by diffusion and pore migration and thereafter contributes to the internal pressure.

The determination of the effect of fission gas generated in and released from the pellet column is discussed in paragraph 4.2.3.2.2. The rod pressure increase which results from the release of a given quantity of gas from the fuel pellets depends upon the amount of open void volume available within the fuel rod and the temperature associated with the various void volumes. In the fuel rod design, the void volumes considered in computing internal pressure are:

- Fuel rod upper-end plenum
- Fuel-clad annulus
- Fuel pellet-end dishes and chamfers
- Fuel pellet open porosity

These volumes are not constant during the life of the fuel. The model used for computing the available volume as a function of burnup and power level accounts for the effects of fuel and clad thermal expansion, fuel pellet densification, clad creep,

clad growth, and irradiation-induced swelling of the fuel pellets.

4.2.1.2.5.2 Fuel Rod Plenum Design. The fuel rod upper-end plenum is required to serve the following functions:

- Provide space for axial thermal expansion and burnup swelling of the pellet column.
- Contain the pellet column holddown spring.
- Act as a plenum region to ensure an acceptable range of fuel rod internal pressure.

Of these functions, the last one is expected to be the most limiting constraint on plenum length selection, since the range of temperatures in the fuel rod, together with the effects of swelling, thermal expansion, and fission gas release, produces a wide range of internal pressure during the life of the fuel. The fuel rod plenum pressure will be consistent with the pressurization and clad collapse criteria specified in paragraph 4.2.1.2.1.

4.2.1.2.5.3 Outline of Procedure Used to Size the Fuel Rod Plenum

A. A parametric study of the effects of plenum length on maximum and minimum rod internal pressure is performed. Because the criteria pertaining to maximum and minimum rod internal pressure differ, the study is divided into two sections:

1. Maximum Internal Pressure Calculation

   Maximum rod pressure is limited by the criteria specified in paragraph 4.2.1.2.1. Maximum end-of-life pressure is determined for each plenum length by including the fission gas released, selecting conservative values for components' dimensions and properties, and accounting for burnup effects on component dimensions. The primary cladding stress produced by each maximum pressure is then compared to the stress limits to find the margin available with each plenum length. Stress limits are listed in paragraph 4.2.1.2.1.

2. Minimum Internal Pressure/Collapse Calculation

   Minimum rod pressure is limited by the criterion that no rod will be subject to collapse during the design lifetime. The minimum pressure history for each plenum length is determined by neglecting fission gas release, selecting a conservative combination of component dimensions and properties, and accounting for dimensional changes during irradiation, including the effects of cladding creep, cladding growth, pellet densification, pellet swelling, and thermal expansion.

B. For each plenum length, there is a resultant range of acceptable initial fill pressures. The optimum plenum length is generally considered to be the shortest which satisfies all criteria related to maximum and minimum rod internal pressure, including a range sufficient to

accommodate a reasonable manufacturing tolerance on initial fill pressure.

C. Additional information on those factors which have a bearing on determination of the plenum length are discussed below:

1. Creep and dimensional stability of the fuel rod assembly influence the fission gas release model and internal pressure calculations, and are accounted for in the procedure for sizing the fuel rod plenum length. Creep in the cladding is accounted for in a change in clad inside diameter, which in turn influences the fuel/clad gap. The gap change varies the gap conductance in the FATES computer code(13)(14)(24)(72), with resulting changes in annulus temperature, internal pressure, and fission gas release. In addition, the change in clad inside diameter causes a change in the internal volume, with its resulting effect on temperature and pressure. Dimensional stability considerations affect the internal volume of the fuel rod, causing changes in internal pressure and temperature. Fuel pellet densification reduces the stack height and pellet diameter. Irradiation-induced radial and axial swelling of the fuel pellets decreases the internal volume within the fuel rod. In-pile growth of the fuel rod cladding contributes to the internal volume. Axial and radial elastic deformation calculations for the cladding are based on the differential pressure the

cladding is exposed to, resulting in internal volume changes. Thermal relocation, as well as differential thermal expansion of the fuel rod materials, also affects the internal volume of the fuel rods.

2. The maximum expected fission gas release in the peak power rod is calculated using the FATES computer code.(13)(14)(24)(72) Rod power history input to the code is consistent with the design limit peak linear heat rate set by LOCA considerations, and therefore the gas release used to size the plenum represents an upper limit. Because of time-varying gap conductance, fuel temperature and depletion, and expected fuel management, the release rate varies as a function of burnup.

4.2.1.2.6 Fuel Rod Performance

Steady-state fuel temperatures are determined by the FATES computer program.(13)(14)(24)(72) The calculational procedure considers the effect of linear heat rate, fuel relocation, fuel swelling, densification, thermal expansion, fission gas release, and clad deformations. The model for predicting fuel thermal performance, including the specific effects of fuel densification on increased LHGR and stored energy, is discussed in references 13, 14, 24, and 72.

Significant parameters such as cold pellet and clad diameters, gas pressure and composition, burnup and void volumes are calculated and used as initial conditions for subsequent

calculations for stored energy during the ECCS analysis. The coupling mechanism between FATES calculations and the ECCS analysis is described in detail in reference 26.

Discussions of uncertainties associated with the model, and of comparative analytical and experimental results, are also included in references 13, 14, 71 and 72.

4.2.1.3 Burnable Poison Rod

UFSAR Section 4.2.1.3 describes the aluminum oxide-boron carbide (Al_2O_3-B_4C) poison rods that were incorporated into the original Combustion Engineering System 80 fuel design for PVNGS. Although this poison is no longer favored for core design, these poison rods are present in many fuel assemblies stored at PVNGS, and are still acceptable for use in operating reactor cores. Therefore, this UFSAR section is retained primarily for historical purposes. Reload core designs may utilize erbium oxide (Er_2O_3) as a poison or absorber, in lieu of Al_2O_3-B_4C poison rods. The erbium oxide is admixed with slightly enriched uranium dioxide (UO_2) fuel in the form of sintered pellets, and the pellets are enclosed in pressurized Zircaloy or ZIRLO™ tubes. These rods are mechanically similar to fuel rods and are manufactured to the same specifications as the UO_2 fuel rods described in Section 4.2.1.2, except that the erbium oxide may constitute several weight percent of the pellets. The UO_2-Er_2O_3 fuel-poison rods meet all of the fuel mechanical design criteria described in Section 4.2.1.2. Reload designs that utilize UO_2-Er_2O_3 rods conform to a

proprietary Combustion Engineering design methodology topical report that has received NRC staff approval.[27]

4.2.1.3.1 Burnable Poison Rod Cladding Design Limits

The burnable poison rod design accounts for external pressure, differential expansion of pellets and clad, pellet swelling, clad creep, helium gas release, initial internal helium pressure, thermal stress, and flow-induced vibrations. Except where specifically noted, the design bases presented in this section are consistent with those used for previous designs. The structural criteria for the normal, upset, and emergency loading combinations identified in paragraphs 4.2.1.1 and 4.2.1.2 are highlighted as follows:

A. During normal operating and upset conditions, the maximum primary tensile stress in the clad shall not exceed two-thirds of the minimum unirradiated yield strength of the material at the applicable temperature. The corresponding limit under emergency conditions is the material yield strength.

B. Net unrecoverable circumferential strain shall not exceed 1% as predicted by computations considering clad creep and poison pellet swelling effects.

C. The clad will be initially pressurized with helium to an amount sufficient to prevent gross clad deformation under the combined effects of external pressure and long-term creep.

4.2.1.3.2 Burnable Poison Rod Cladding Properties

Cladding tubes for burnable poison rods are purchased under the specification for fuel rod cladding tubes. Therefore, the mechanical, metallurgical, chemical, and dimensional properties of the cladding are as discussed in paragraph 4.2.1.2.2.

4.2.1.3.3 Al_2O_3-B_4C Burnable Poison Pellet Properties

The Al_2O_3-B_4C burnable poison pellets used in C-E-designed reactors consist of a relatively small volume fraction of fine B_4C particles dispersed in a continuous Al_2O_3 matrix. The boron loading is varied by adjusting the B_4C concentration in the range from 0.7 to 4.0 wt% (1 to 6.0 v/o). The bulk density of the Al_2O_3-B_4C pellets is specified to be greater than 93% of the calculated theoretical density. Typical pellets have a bulk density of about 95% of the theoretical value. Many properties of the two-phase Al_2O_3-B_4C mixture, such as thermal expansion, thermal conductivity, and specific heat are very similar to the properties of the Al_2O_3 major constituent. In contrast, properties such as swelling, helium release, melting point, and corrosion are dependent on the presence of B_4C. The operating centerline temperature of burnable poison is less than 1150F, with maximum surface temperatures close to 1090F.

4.2.1.3.3.1 Thermal-Physical Properties

A. Thermal Expansion

The mean thermal expansion coefficients of Al_2O_3[28] and B_4C[29] from 0 to 1850F are 4.9 and 2.5 in./in. F x 10^{-6},

respectively. The thermal expansion of the Al_2O_3-B_4C two-phase mixture can be considered to be essentially the same as the value for the continuous Al_2O_3 matrix since the dispersed B_4C phase has a lower expansion coefficient and occupies only 5 v/o of the available volume. The low temperature (80 to 250F) thermal expansion coefficient of Al_2O_3 irradiated at 480, 900, and 1300F does not change as a result of irradiation.[30] The expansion of a similar material, beryllium oxide, up to 1900F has also been reported to be relatively unchanged by irradiation.[31] It is therefore appropriate to use the values of thermal expansion measured for Al_2O_3[28] for the burnable poison pellets:

Temperature Range (°F from 70F to)	Linear Expansion (%)
400	0.12
600	0.23
800	0.30
1000	0.40

B. Melting Point

The melting points of Al_2O_3 (3710F)[32] and B_4C (4400F)[33] are higher than the melting point of the Zr-4 cladding. No reactions have been reported between

the components which would lower the melting point of the pellets to any significant extent. As the B_4C burns up, the lithium atoms formed occupy interstitial sites randomly distributed within the B_4C lattice, rather than forming a lithium-rich phase.[34] The solid solution of lithium in B_4C should not appreciably influence the melting point of the Al_2O_3-B_4C pellets, as only a small quantity of lithium compounds (0.5 wt%) forms during irradiation. It is concluded that the melting point of Al_2O_3-B_4C will remain considerably above the maximum 1150F operating temperature.

C. Thermal Conductivity

The thermal conductivity of Al_2O_3-B_4C was calculated from the measured values for Al_2O_3 and B_4C using the Maxwell-Eucken relationship[35] for a continuous matrix phase (Al_2O_3) with spherical dispersed phase (B_4C) particles. Because of the high Al_2O_3 content of these mixtures and the similarity in thermal conductivity, the resultant values for Al_2O_3-B_4C were essentially the same as the values for Al_2O_3. The measured, unirradiated values of thermal conductivity at 750F are 0.06 cal/s-cm-°K for B_4C and 0.05 cal/s-cm-°K for Al_2O_3.

The thermal conductivity of Al_2O_3 after irradiation decreases rapidly as a function of burnup to values of about one-third the unirradiated values.[30] The irradiated values of Al_2O_3-B_4C calculated from the above

relationships are given below as a function of temperature.[30][36]

Temperature (°F)	Thermal Conductivity (cal/s-cm-°K)
400	0.015
600	0.013
800	0.010
1000	0.008

D. Specific Heat

The specific heat of the Al_2O_3-B_4C mixture can be taken to be essentially the same as pure Al_2O_3 since the concentration of B_4C is low (6.0 v/o maximum). In addition, the effect of irradiation on specific heat is expected to be small based on experimental evidence from similar materials which do not sustain transmutations as a function of neutron exposure.

The values for Al_2O_3 measured on unirradiated samples[36][37] are given below:

Temperature (°F)	Specific Heat (cal/gm-°F)
250	0.12
450	0.13
800	0.14
1000 and above	0.15

4.2.1.3.3.2 Irradiation Properties

A. Swelling

Al_2O_3-B_4C consists of B_4C particles dispersed in a continuous Al_2O_3 matrix, which occupies more than 95% of the poison pellet. The swelling of Al_2O_3-B_4C depends primarily upon the neutron fluence on the continuous Al_2O_3 matrix and, secondarily, on the B^{10} burnup of the dispersed B_4C phase. Recent measurements performed on material containing about 2 wt% B_4C irradiated in a C-E PWR to 100% B^{10} burnup at a fluence of 2.4 x 10^{21} nvt (E > 0.8 MeV) revealed a diametral swelling of about 1%. Pellets similar to the burnable poison used in C-E reactors with up to 3 wt% B_4C also sustained about 100% B^{10} burnup. Experimental data(38) on Al_2O_3 reveal a diametral swelling of about 0.7% at a fluence of 2.4 x 10^{21} nvt (E > 0.8 MeV). Swelling of Al_2O_3 increases linearly with fluence to 1.8% diametral after an exposure of 6 x 10^{21} nvt (E > 0.8 MeV).

These data show that Al_2O_3-B_4C swells somewhat more than Al_2O_3 up to a burnup of $\underset{\sim}{~}$ 90% B^{10} depletion (about 2 x 10^{21} nvt, E > 0.8 MeV).

The C-E design value of Al_2O_3-B_4C swelling rate for fluences less than 2 x 10^{21} nvt is greater than the swelling rate of Al_2O_3, while after 2 x 10^{21} nvt fluence

the swelling rate for Al_2O_3-B_4C is considered equal to that of Al_2O_3.

The data and considerations presented above result in best-estimate diametral swelling values at end-of-life (7×10^{21} nvt, E > 0.8 MeV) of about 2% for Al_2O_3 and from 2 to 3% for Al_2O_3-B_4C loading.

B. Helium Release

Experimental measurements reveal that less than 5% of the helium formed during irradiation will be released.[39] These measurements were performed on Al_2O_3-B_4C pellets irradiated at temperatures to 500F and subsequently annealed at 1000F for 5 days. The helium release in a burnable poison rod which operated for one cycle in a C-E PWR was calculated from internal pressure measurements to be less than 5%.

4.2.1.3.3.3 Chemical Properties

A. Al_2O_3-B_4C Coolant Reaction

Should irradiated B_4C particles be exposed to reactor coolant, the primary corrosion products that would be formed are boric acid (which is soluble in water), hydrogen, free carbon, and a small amount of lithium compounds. The presence of these products in the reactor coolant would not be detrimental to the operation of the plant.

Observations of Al_2O_3-B_4C poison shims have revealed that long-term exposure of this material to reactor coolant can result in gradual leaking out of boron and eventual eroding away of the Al_2O_3 matrix. However, the rate of reaction is such that any resultant changes in reactivity are very gradual.

B. Chemical Compatibility

Chemical compatibility between Al_2O_3-B_4C pellets and the burnable poison rod cladding during long-term normal operation has been demonstrated by examination of a burnable poison rod from the Maine Yankee reactor. The rod had been exposed to an axial average fluence in excess of 2×10^{10} nvt (E > 0.821 MeV). No evidence of a chemical reaction was observed on the cladding I.D.

Short-term chemical compatibility during upset and emergency conditions is demonstrated by the fact that conditions favorable to a chemical reaction between Zr-4 and Al_2O_3 are not present at temperatures below 1300F.[40] This temperature is higher than that which will occur at burnable poison pellet surfaces during Condition II and III occurrences (paragraph 4.2.1.1). The reaction between Zr-4 and Al_2O_3 described by Idaho Nuclear[41] was observed to occur rapidly only at temperatures in excess of 2500F, well above the peak Zr-4 temperatures in the higher-energy fuel rods described in chapter 15.

4.2.1.4 Control Element Assemblies (CEAs)

The mechanical design of the control element assemblies is based on compliance with the following functional requirements and criteria.

A. To provide for or initiate short-term reactivity control under all normal and adverse conditions experienced during reactor startup, normal operation, shutdown, and accident conditions.

B. Mechanical clearances of the CEA within the fuel and reactor internals are such that the requirements for CEA positioning and reactor trip are attained under the most adverse accumulation of tolerances.

C. Structural material characteristics are such that radiation-induced changes to the CEA materials will not impair the functions of the reactivity control system.

4.2.1.4.1 Thermal-Physical Properties of Absorber Material

The primary control rod absorber materials in the Feltmetal® full strength CEAs consist of boron carbide (B_4C) pellets. The control rod absorber material in the AIC full strength CEAs consists of B_4C pellets, and hollow Silver-Indium-Cadmium (AIC) slugs. Alloy 625 is used as the absorber in the part-strength rods. Refer to figures 4.2-3, 4.2-4, and 4.2-5 for the specific application and orientation of the absorber materials. The significant thermal and physical properties used in mechanical analysis of the absorber materials are listed below:

A. Boron Carbide (B_4C)

Configuration	Right cylinder	
Outside diameter, inches	(a) 0.737 ± 0.001 (b) 0.664 ± 0.001, or 0.674[a] ± 0.001	
Pellet length, inches	0.5 to 2.0	
Density, gm/cc	1.84	
Weight % boron, minimum	77.5	
% open porosity in pellet	27	
Ultimate tensile strength, lb/in^2	N/A	
Yield strength, $lb/in.^2$	N/A	
Elongation, %	N/A	
Young's Modulus, psi	N/A	
Thermal conductivity,		
cal/cm-s-°C	Irradiated	Unirradiated
at 800F	8.3×10^{-3}	28×10^{-3}
at 1000F	7.9×10^{-3}	24×10^{-3}

(a) Nominal tip B_4C pellet diameter is 0.664 inches. The 0.674 inch diameter pellet remains in the UFSAR to allow use of existing spares if necessary.

Melting point, °F	4440
% thermal linear expansion	0.23% @ 1000F

B. Silver-Indium-Cadmium (AIC)

Configuration	Hollow right cylinder
Outside diameter, inches	0.734 ± 0.003
Inside diameter, inches	0.250 ± 0.016
Slug length, inches	8.250 ± 0.062
Density, gm/cc	10.17
Young's Modulus, psi	11.52 @ 25°C 9.86 @ 300°C
Thermal Conductivity, cal/CM-s-°C	0.137 irradiated 0.182 unirradiated
Melting Point, °F	1470 ± 18
Thermal linear expansion, in/in/°F (77°F to 932°F)	13.1×10^{-6} irradiated 12.5×10^{-6} unirradiated
Yield Strength, MPa	190 irradiated
Ultimate Strength, MPa	345 irradiated

C. Type 347 Stainless Steel Felt Metal

Configuration	Cylindrical sleeves formed from sheets
Thickness, inches	0.032 ± 0.002
Length of sheet, inches nominal	20

Density, $lbs/in.^3$	0.059
Ultimate tensile strength, $lb/in.^2$	N/A
Elongation, %	N/A
Young's Modulus, $lb/in.^2$	N/A
Thermal conductivity, cal/s-cm-°C	
at 500F	1.26×10^{-3}
at 1000F	1.41×10^{-3}

D. Alloy 625

Configuration (as absorber)	Solid Cylindrical bar (a.k.a., Slug)
Outside diameter, inches	0.737 ± 0.001
Inside diameter, inches	Solid
Length of each absorber slug, inches	7.450 ± 0.020 (part-strength CEA)
Total length of absorber slugs, inches	149.0 (part-strength CEA)
Density, $lb/in.^3$	0.305
Ultimate tensile strength, $lb/in.^2$	120-150

Specified minimum yield strength @ 650F, ksi	65
Elongation in 2 inches, %	30
Young's Modulus, lb/in.^{2}	
at 70F	29.7×10^6
at 650F	27.0×10^6
Thermal conductivity, Btu/h-ft-°F	
at 70F	5.7
at 600F	8.2
Linear thermal expansion, in./in.-°F	7.4×10^{-6} (70 to 600F)

4.2.1.4.2 Compatibility of Absorber and Cladding Materials

The cladding material used for the control elements is Alloy 625. The selection of this material for use as cladding is based on considerations of strength, creep resistance, corrosion resistance, and dimensional stability under irradiation, and also upon the acceptable performance of this material for this application in other Westinghouse reactors currently in operation.

A. B_4C/Alloy 625 Compatibility

Studies have been conducted by HEDL[42] on the compatibility of Type 316 stainless steel with B_4C under irradiation for thousands of hours at temperatures between 1300 and 1600F. Carbide formation to a depth of about 0.004 inch in the 316 stainless steel was measured after 4400 hours at 1300F. Similar compound formation depths were observed after ex-reactor bench testing. After testing at 1000F, only 0.001 in./yr of penetration was measured. Since Alloy 625 is more resistant to carbide formation than 316 stainless steel, and the expected pellet/clad interfacial temperature in the standard design is below 800F, it is concluded that B_4C is compatible with Alloy 625.

B. Silver-Indium-Cadmium (AIC)/Alloy 625 Compatibility

AIC is a corrosion resistant alloy whose compatibility with Alloy 625 has been demonstrated in numerous control rod applications.

4.2.1.4.3 Cladding Stress-Strain Limits

The stress limits for the Alloy 625 cladding are as follows:

A. Nonoperation, Normal Operation, and Upset Design Conditions

$$P_m \leq S_m$$

$$P_m + P_b \leq F_s S_m$$

The net unrecoverable circumferential strain shall not exceed 1% on the cladding diameter, considering the effects of pellet swelling and cladding creep. Near the CEA tip, plastic strain cannot be accommodated; therefore, strain must remain in the elastic range, taken as the proportional limit or 2/3 of the yield stress for irradiated material.

B. Emergency Design Conditions

$$P_m \leq 1.5\ S_m$$

$$P_m + P_b \leq 1.5\ F_s S_m$$

C. Faulted Design Conditions

$$P_m \leq S_m'$$

$$P_m + P_b \leq F_s S_m'$$

where S_m' is the smaller of 2.4 S_m or $0.7S_u$.

For definition of P_m, P_b, S_m, S_m', S_u, and F_s, see paragraph 4.2.1.1.1. For the Alloy 625 CEA cladding, the value of S_m is two-thirds of the minimum specified yield strength at temperature.

For Alloy 625, the specified minimum yield strength is 65,000 lb/in.^{2} at 650F.

F_s = Mp/My where Mp is the bending moment required to produce a fully plastic section and My is the bending moment which first produces yielding at the extreme fibers of the cross-section. The capability of cross-sections loaded in bending to

sustain moments considerably in excess of that required to yield the outermost fiber is discussed in reference 1. For the CEA cladding dimensions, $F_s = 1.33$.

The values of uniform and total elongation of Alloy 625 cladding are estimated to be as follows:

Fluence (E > 1 MeV), nvt	1×10^{22}	3×10^{22}
Uniform elongation, %	3	1
Total elongation, %	6	3

4.2.1.4.4 Irradiation Behavior of Absorber Materials

A. Boron Carbide Properties

1. Swelling. The linear swelling of B_4C increases with burnup according to the relationship

$$\%\Delta L = (0.1)\ B^{10} \text{ burnup, a/o}$$

This relationship was obtained from experimental irradiations on high density (> 90% TD) wafers[43] and pellets with densities ranging between 71 and 98% TD.[42][44] Dimensional changes were measured as a function of burnup, after irradiating at the temperature expected in the design.

2. Thermal Conductivity. The thermal conductivity of unirradiated 73% dense B_4C decreases linearly with temperatures from 300 to 1600F, according to the relationship:

$$\lambda = \frac{1\ \text{cal/cm-°K-s}}{2.17\ (6.87 + 0.017\ T)}$$

where T = temperature, °K

This relationship was obtained from measurements performed on pellets ranging from 70 to 98% TD.[45]

The relationship between the thermal conductivity of irradiated 73% TD B_4C pellets and temperature given below was derived from measured values[45] on higher density pellets irradiated to fluences out to 3 x 10^{22} nvt (E > 1 MeV).

$$\lambda = \frac{1\ \text{cal/cm-°K-s}}{2.17\ (38 + 0.025\ T)}$$

where T = temperature, °K

Thermal conductivity measurements of 17 B_4C specimens with densities ranging from 83 to 98% TD, irradiated at temperatures from 930 to 1600F showed that thermal conductivity decreased significantly after irradiation. The rate of decrease is high at the lower irradiation temperatures, but saturates rapidly with exposure.

3. Helium Release. Helium is formed in B_4C as B^{10} burnup progresses. The fraction of the helium released from the pellets is important for determining rod internal gas pressure. The relationship between helium release and irradiation temperature given below was developed at ORNL[46] to

fit experimental data obtained from thermal reactor irradiations.

$$\%\text{He release} = e^{(C-1.85D)} e^{\frac{-Q}{RT}}$$

where:

C = constant, 6.69 for pellets

D = fractional density, 0.73 for C-E pellets

Q = activation energy constant, 3600 cal/mole

R = gas constant, 1.98 cal/mole-°K

T = pellet temperature, °K

This expression becomes

$$\%\ \text{He release} = 208\, e^{\frac{-1820}{T}} + 5$$

when the above parameters are substituted. In this form, design values for helium release as a function of temperature are generated. The 5% helium release allowance (the last term in the expression) was added to ensure that design values lie above all reported helium release data. Calculated values of helium release obtained from the recommended design expression lie above all experimental data points(42)(47)(48) obtained on B_4C pellet specimens irradiated in thermal reactors.

4. Pellet Porosity. Experimental evidence is available(49) which shows that for pellet densities below 90%, essentially all porosity is open at

beginning-of-life. Irradiation-induced swelling does not change the characteristics of porosity, but only changes the bulk volume of the specimens. Therefore, the amount of porosity available at end-of-life is the same as that present at beginning-of-life.

B. Silver-Indium-Cadmium

1. Swelling. Available data on swelling of AIC in CEA applications (Reference 73) gives a bounding volumetric swelling rate:

$$\frac{\%V}{V} = 0.21\frac{\phi t}{10^{21}} \qquad \text{(E>1MeV)}$$

Diametral swelling is taken as 1/3 volumetric swelling:

$$\frac{\%D}{D} = 0.07\frac{\phi t}{10^{21}} \qquad \text{(E>1MeV)}$$

2. Creep Strength. Creep strength and yield strength of AIC both increase due to irradiation; however, both the creep strength and yield strength remain well below the irradiated yield strength of the Alloy 625 cladding.

3. Helium Release and Pellet Porosity. The AIC slugs do not undergo the same neutron activation reaction as B_{10}; therefore, no helium is generated as a result of irradiation. The AIC slugs are not a ceramic material as B_4C is; therefore, there is no porosity associated with the AIC structure.

C. Alloy 625

1. Swelling. Available information indicates that Alloy 625 is highly resistant to radiation swelling. Exposure of Alloy 625 to a fluence of 3×10^{22} nvt (E > 0.1 MeV) at a temperature of 400C (725F) showed no visible cavities in metallographic examinations(50) so that swelling, if any, would be very minor. Direct measurements made after exposure of Alloy 625 to a fluence 5×10^{22} nvt (E > 0.1 MeV) at LMFBR conditions showed no evidence of swelling.(51) Further exposure to 6 to 10^{22} nvt (E > 0.1 MeV) at 500C (932F) showed essentially no swelling as measured by immersion density, but did show small cavities. Thus, Alloy 625 after fluences of 3×10^{22} nvt (E > 1 MeV) is not expected to swell.

2. Ductility. The ductility of Alloy 625 decreases after irradiation. Extrapolation of lower fluence data on Alloy 625 and 500 indicates that the values of uniform and total elongation of Alloy 625 after 1×10^{22} nvt (E > 1 MeV) are 3 and 6%, respectively.

3. Strength. The value of yield strength of Alloy 625 increases after irradiation in the manner typical for metals. However, no credit is taken for increases in yield strength in the design analyses above the value initially specified.

4.2.1.5 Surveillance Program

4.2.1.5.1 Requirements for Surveillance and Testing of Irradiated Fuel Rods

High burnup performance experience, as described in subsection 4.2.3, has provided evidence that the fuel will perform satisfactorily under design conditions. In addition, C-E conducted a detailed fuel assembly performance evaluation program at the Arkansas Nuclear One - Unit 2 (ANO-2) reactor. Due to the similarity in the ANO-2 and System 80 designs, the evaluation is applicable to System 80 fuel.

A surveillance program has also been performed to evaluate the performance of System 80 fuel in Palo Verde. The program included end-of-cycle visual inspections, dimensional measurements to characterize fuel rod growth, and cladding oxide measurements on precharacterized fuel to track corrosion behavior. A CEA guide tube wear measurement program has been performed on Units' 1 and 2 fuel, at end-of-cycle 1, which indicates wear is within acceptable limits. Results from these surveillance programs indicate the fuel is behaving as expected with no indications that would alter the planned fuel management scheme for System 80 fuel.

A limited, random sample of fuel assemblies is visually inspected during or after each refueling outage, as described in section 4.2.4.

Table 4.2-1
TYPICAL MECHANICAL DESIGN PARAMETERS
(Sheet 1 of 4)

Core Arrangement	
Number of fuel assemblies in core, total	241
Number of CEAs	89
Number of fuel rod locations	56,876
Spacing between fuel assemblies, fuel rod surface to surface, inches	0.208
Spacing, outer fuel rod surface to core shroud, inches	0.214
Hydraulic diameter, nominal channel, feet	0.0393
Total flow area (excluding guide tubes), ft^2	60.9
Total core area, ft^2	112.3
Core equivalent diameter, inches	143.6
Core circumscribed diameter, inches	152.46
Total fuel loading, kg U (assuming all rod locations are fuel rods)	1.07×10^5
Total fuel weight, lb UO_2 (assuming all rod locations are fuel rods)	2.67×10^5
Total weight of Zircaloy and ZIRLO, lb	72,500[a]
Fuel volume (including dishes), ft^3	410.8
Fuel Assemblies	
Fuel rod array square	16 x 16
Fuel rod pitch, inches	0.506
Spacer grid	
Type	Leaf spring
Material	Zircaloy
Number per assembly	10[b]

a. Weight assumes all assemblies are of PVNGS Unit 2 Batch N design. Actual weight varies from core-to-core.
b. Beginning with Batch P3R, reload assemblies have 9 Zircaloy spacer grids.

Table 4.2-1
TYPICAL MECHANICAL DESIGN PARAMETERS
(Sheet 2 of 4)

Fuel Assemblies (Continued)	
Bottom spacer grid	
Type	GUARDIAN™ or Leaf spring
Material	Inconel
Number per assembly	1
Top spacer grid (beginning with Batch P3R)	
Type	Leaf spring
Material	Inconel
Number per assembly	1
Overall dimensions	
Outside rod to outside rod, inches	7.972 x 7.972
Fuel Rod	
Fuel rod material (sintered pellet)	UO_2 or UO_2-Er_2O_3
Pellet diameter, inches	0.3255
Pellet length, inches	0.390
Pellet density, g/cm^3	10.58
Pellet theoretical density, g/cm^3	10.96
Pellet density (% theoretical)	96.5
Stack height density, g/cm^3	10.43
Clad material	Zircaloy or ZIRLO™
Clad ID, inches	0.332
Clad OD (nominal), inches	0.382
Clad thickness (nominal), inches	0.025
Diametral gap (cold, nominal), inches	0.0065
Active length, inches	150
Plenum length, inches	varies

Table 4.2-1
TYPICAL MECHANICAL DESIGN PARAMETERS
(Sheet 3 of 4)

Control Element Assemblies (CEA)	Feltmetal® Full-strength	AIC Full-strength	Part-strength
Number	76	76	13
Absorber elements, number per assembly	12 and 4	12 and 4	4
Type	Cylindrical rods	Cylindrical rods	Cylindrical rods
Clad material	Alloy 625	Alloy 625	Alloy 625
Clad thickness, inches nominal	0.035	0.035	0.035
Clad OD, inches nominal	0.816	0.816	0.816
Diametral gap, inches nominal	0.009	0.009	0.009
Elements			
Poison material	B_4C/felt metal and reduced dia. B_4C	B_4C / AIC	Alloy 625
Poison length, inches	135-1/2/12-1/2	131 / 16.5	150.0 (including tip of finger)
Poison Diameter, inches	0.737/0.664 or 0.737/0.674[b] (B_4C pellet)	0.737 (B_4C) / 0.734 OD, .250 ID AIC	0.737 (Alloy 625 slugs)
B_4C pellet density, % of theoretical density of 2.52 g/cm^3	73	73	N/A
Weight % boron, minimum	77.5	77.5 (B_4C pellets)	N/A

Burnable Poison Rod, Original Design[c]	
Absorber material	Al_2O_3-B_4C
Pellet diameter, inches	0.307

(b) Nominal tip B_4C pellet diameter is 0.664 inches. The 0.674 inch diameter pellet remains in the UFSAR to allow use of existing spares if necessary.

(c) Reload core designs may utilize erbium oxide (Er_2O_3), admixed with UO_2 fuel, in lieu of Al_2O_3-B_4C poison rods. The reload design poison rods are mechanically similar to UO_2 fuel rods.

Table 4.2-1
TYPICAL MECHANICAL DESIGN PARAMETERS
(Sheet 4 of 4)

Burnable Poison Rod, Original Design[c] (Continued)	
Pellet length, inches, min.	0.875(1”) and 0.500(0.5”)
Pellet density (% theoretical), min.	93(1”) and 91(0.5”)
Theoretical density, Al_2O_3, g/cm^3	3.94
Theoretical density, B_4C, g/cm^3	2.52
Clad material	Zircaloy-4
Clad ID, inches	0.332
Clad OD, inches	0.382
Clad thickness (nominal), inches	0.025
Diametrical gap (cold, nominal), inches	0.025
Active length, inches	136.0
Plenum length, inches	varies

4.2.2 DESCRIPTION AND DESIGN DRAWINGS

This subsection summarizes the mechanical design characteristics of the fuel system and discusses the design parameters which are of significance to the performance of the reactor. A summary of typical mechanical design parameters is presented in table 4.2-1. These data are intended to be descriptive of the design and, in some cases, are approximate values. Limiting values of these and other parameters are discussed in the appropriate sections, and specific values are determined for each core reload.

4.2.2.1 Typical Fuel Assembly

The fuel assembly (figure 4.2-6) consists of 236 fuel and poison rods, 5 guide tubes, 11 fuel rod spacer grids, upper and lower end fittings, and a holddown device. The outer guide tubes, spacer grids, and end fittings form the structural frame of the assembly.

The fuel spacer grids (figure 4.2-7) maintain the fuel rod array by providing positive lateral restraint to the fuel rod but only frictional restraint to axial fuel rod motion. The grids are fabricated from preformed Zircaloy or Inconel strips (the top and bottom spacer grid material is Inconel) interlocked in an egg-crate fashion and welded together. Each cell of the spacer grid contains leaf springs and arches. The leaf springs press the rod against the arches to restrict relative motion between the grids and the fuel rods. The perimeter strips contain features designed to prevent hangup of grids during a refueling operation.

The spacer grids are fastened to the Zircaloy-4 guide tubes by welding to form a grid cage assembly. The Zircaloy-4 spacer grids are fastened directly to the guide tubes while the Inconel 625 top grid is held in place by two Zircaloy-4 split rings welded to each guide tube. In the original design, the lowest spacer grid (Inconel) was not welded to the guide tubes due to material differences. It was supported by an Inconel 625 skirt which was welded to the spacer grid and to the perimeter of the lower end fitting. In reload designs, the proprietary GUARDIAN™ grid replaces the lowest Inconel grid, and the perimeter strip is welded to the lower end fitting, in lieu of a skirt.

The upper end fitting is an assembly consisting of two cast 304 stainless steel plates, five machined posts, and four helical Inconel X-750 springs. The end fitting attaches to the guide tubes to serve as an alignment and locating device for each fuel assembly and has features to permit lifting of the fuel assembly. The lower cast plate locates the top ends of the guide tubes and is designed to prevent excessive axial motion of the fuel rods.

The Inconel X-750 springs are of conventional coil design. Inconel X-750 was selected for this application because of its previous use for coil springs and good resistance to relaxation during operation.

The upper cast plate of the assembly, called the holddown plate, together with the helical compression springs, comprise the holddown device. The holddown plate is movable, acts on the underside of the tube sheet tubes, and is loaded by the

compression springs. Since the springs are located at the upper end of the assembly, the spring load combines with the fuel assembly weight to counteract upward hydraulic forces. The determination of upward hydraulic forces includes factors accounting for flow maldistribution, fuel assembly component tolerances, crud buildup, drag coefficient, and bypass flow. The springs are sized and the spring preload selected such that a net downward force will be maintained for all normal and anticipated transient flow and temperature conditions. The design criteria limit the maximum stress under the most adverse tolerance conditions to below yield strength of the spring material. The maximum stress occurs during cold conditions and decreases as the reactor heats up. The reduction in stress is due to a decrease in spring deflection resulting from differential thermal expansion between the Zircaloy fuel bundles and the stainless steel internals.

During normal operation, a spring will never be compressed to its solid height. However, if the fuel assembly were loaded in an abnormal manner such that a spring were compressed to its solid height, the spring would continue to serve its function when the loading condition returned to normal.

The lower end fitting assembly is a simple stainless steel casting consisting of a plate with flow holes and a support leg at each corner (total of four legs) that aligns the lower end of the fuel assembly with the core support structures' alignment pins. Alignment pins are required to position the corners of the lower end fittings. A center post is threaded into the central portion of the flow plate and welded into position. Reload assemblies may have a lower end fitting

design whereby the center post is an integral part of the lower end fitting casting.

The four outer guide tubes have a widened region at the upper end which contains an internal thread. Connection with the upper end fitting is made by passing the externally threaded end of the guide posts through holes in the lower cast flow plate and into the guide tubes. When assembled, the flow plate is secured between flanges on the guide tubes and on the guide posts. The connection with the upper end fitting is locked with a mechanical crimp. Each outer guide tube has, at its lower end, a welded Zircaloy fitting. This fitting has a threaded portion which passes through a hole in the fuel assembly lower end fitting and is secured by either a Zircaloy nut or a stainless steel bolt. This joint is secured with a stainless steel locking ring welded to the lower end fitting.

The central instrumentation guide tube inserts into a socket and a sleeve in the upper and lower end fittings, respectively, and is thus retained laterally by the relatively small clearance at these locations. The upper end fitting socket is created by the center guide tube post which is threaded into the lower cast flow plate and tack-welded in two places. The lower end fitting sleeve is an extension from the center post of the lower end fitting assembly. There is no positive axial connection between the central guide tube and the end fittings.

The five guide tubes have the effect of ensuring that bowing or excessive swelling of the adjacent fuel rods cannot result in

obstruction of the control element pathway. This is so because:

A. There is sufficient clearance between the fuel rods and the guide tube surface to allow an adjacent fuel rod to reach rupture strain without contacting the guide tube surface.

B. The guide tube, having considerably greater diameter and wall thickness (and also, being at a lower temperature) than the fuel rod, is considerably stiffer than the fuel rods and would, therefore, remain straight, rather than be deflected by contact with the surface of an adjacent fuel rod.

Therefore, the bowing or swelling of fuel rods would not result in obstruction of the control element channels such as could hinder CEA movement.

The fuel assembly design enables reconstitution, i.e., removal and replacement of fuel and poison rods, of an irradiated fuel assembly. Reconstitution of fuel assemblies is done in accordance with Reference 70. Reference 70 describes a methodology of using inert replacement rods (solid stainless steel rods) to replace failed or damaged fuel rods, including burnable poison rods, during reconstitution of fuel assemblies for core reloads. The inert replacement rods require mechanical, neutronic, and thermal-hydraulic analyses to demonstrate that the inclusion of the inert replacement rods in fuel assemblies with the specific configurations and core locations chosen for a specific fuel cycle is acceptable with respect to the overall fuel performance and safety conclusions.

These analyses were performed in Reference 70, with generic bounding results achieved if the placement of stainless steel rods is limited to certain locations within the assembly. In fact, if the placement rules of Reference 70 are followed, then no further cycle specific analyses are required. Further, placement outside of the guidelines was not reviewed and approved. The fuel and poison rod lower end caps are conically shaped to ensure proper insertion within the fuel assembly grid cage structure. The lower end caps used with the Guardian™ grid in reload assemblies are longer than the end caps used in the original System 80 fuel design for PVNGS. The upper end caps are designed to enable grappling of the fuel and poison rod for purposes of removal and handling. Threaded joints which mechanically attach the upper end fitting to the control element guide tubes will be properly torqued and locked during service, but may be removed to provide access to the fuel and poison rods.

Loading and movement of the fuel assemblies are conducted in accordance with strictly monitored administrative procedures and, at the completion of fuel loading, an independent check as to the location and orientation of each fuel assembly in the core is required.

The serial number provided on the fuel assembly upper end fitting enables verification of fuel enrichment and orientation of the fuel assembly. The serial number is also provided on the lower end fitting to ensure preservation of fuel assembly identity in the event of upper end fitting removal.

During the manufacturing process, each fuel rod is marked to provide a means of maintaining a record of pellet enrichment, pellet lot, and fuel stack weight. In addition, the Westinghouse quality control program requires that measures be established for the identification and control of materials, components, and partially fabricated subassemblies. These means provide assurance that only acceptable items are used and also provide a method of relating an item or assembly from initial receipt through fabrication, installation, repair, or modification to an applicable drawing, specification, or other pertinent technical document.

Starting with reload Batch N, fuel rod fabrication was moved from Hematite, MO, to the Columbia, SC, facility. Fuel rod changes that resulted from this move include:

A. In reload assemblies prior to Batch N, the fuel rod end cap to cladding tube weld is a Magnetic Force (i.e., resistance) Weld whose outer surface is subsequently machined (i.e., deflashed). Beginning with Batch N, the joint was converted to Tungsten Inert Gas (TIG) welding. The latter also utilizes a separate (TIG) seal weld to close the opening through which the rod is pressurized.

B. The upper and lower end caps were redesigned to make them compatible with the TIG welding process.

C. The cladding tube was modified to make it compatible with the TIG welding process.

D. The fuel rod spring was redesigned for compatibility with the TIG welding process.

E. The alumina spacer between the pellet stack and the lower end cap was eliminated.

F. The combined effect of redesigning the lower end cap and eliminating the alumina spacer is to lower the active fuel region by 0.355 inch. This change in core elevation is relative to the Batch M design.

G. The combined effect of redesigning the plenum spring and eliminating the alumina spacer is to increase the rod's internal void volume by 0.032 cubic inch, relative to the Batch M design.

H. Reload rods for Batches N and later are fabricated at the Columbia facility, which builds its pellet stacks directly in the cladding tubes. Their stacks are built up, 25 at a time, from a series of shorter preassembled segments that are fed into a like number of tubes by a vibratory feeder. Before feeding the last row of segments into the tubes, the distance from the end of the tube to the end of the pellet stack is checked with a guage. If necessary, an appropriate number of pellets are added to or removed from each segment in the row. The gamma scanning system is used to certify dimensions related to stack lengths.

4.2.2.2 Fuel Rod

The fuel rods consist of slightly-enriched UO_2 or OO_2-Er_2O_3 cylindrical ceramic pellets, a round wire Type 302 stainless steel compression spring, and an alumina spacer disc located at each end of the fuel column, all encapsulated within a Zircaloy-4 or ZIRLO™ tube seal-welded with Zircaloy-4 end

caps. Reload assemblies may be manufactured without the alumina spacer discs. The fuel rods are internally pressurized with helium during assembly. Figure 4.2-8 depicts the fuel rod design. Figure 4.2-8a compares the Batch M and N urovia rods.

Each fuel rod assembly is marked to ensure traceability of the fabrication history of each fuel rod component.

The fuel cladding is cold-worked and stress-relief-annealed Zircaloy-4 or ZIRLO™ tubing 0.025 inch thick. The actual tube forming process consists of a series of cold-working and annealing operations, the details of which are selected to provide the combination of properties discussed in paragraph 4.2.1.2.2.

The UO_2 pellets are dished at both ends in order to better accommodate thermal expansion and fuel swelling. The density of the sintered pellets is determined on a geometric basis, based on a UO_2 theoretical density of 10.96 grams per cubic centimeter. The allowable range of pellet density is controlled by Westinghouse specification, and may vary slightly between batches of fuel. Furthermore, because the pellet dishes and chamfers constitute a small portion of the volume of the pellet stack, the average density of the pellet stack is lower than that of the individual pellets. This reduced value, the stack density, may likewise vary between batches of fuel.

The compression spring located at the top of the fuel pellet column maintains the column in its proper position during handling and shipping. The alumina spacer disc at the lower end of the fuel rod (prior to Batch N) reduces the lower end cap temperature. The fuel rod plenum, which is located above

the pellet column, provides space for axial thermal differential expansion of the fuel column and accommodates the initial helium loading and evolved fission gases. (See paragraphs 4.2.1.2.5.1 and 4.2.1.2.5.2.) The specific manner in which these factors are taken into account, including the calculation of temperatures for the gas contained within the various types of rod internal void volume, is discussed in references 13 and 14.

4.2.2.3 Burnable Poison Rod

The original burnable neutron absorber (poison) rods, figure 4.2-9, were included in selected fuel assemblies to reduce the beginning-of-life moderator coefficient. They replaced fuel rods at selected locations. The poison rods were mechanically similar to fuel rods, but contained a column of burnable poison pellets instead of fuel pellets. The poison material was alumina with uniformly-dispersed boron carbide particles. The balance of the column consisted of Zircaloy-4 spacers, with the total column length the same as the column length in fuel rods. The burnable poison rod plenum spring was designed to produce a smaller preload on the pellet column than that in a fuel rod, because of the lighter material in the poison pellets.

Each burnable poison rod assembly includes a serial number, to record fabrication information of each component in the rod assembly.

Reload assemblies may use UO_2-Er_2O_3 fuel-poison pellets, as described in Section 4.2.1.3. Figure 4.2-9a compares the Batch N and M erbia rods

4.2.2.4 Control Element Assembly Description and Design

The control element assemblies consist of either four or twelve neutron absorber elements arranged to engage the peripheral guide tubes of fuel assemblies. The neutron absorber elements are connected by a spider structure which couples to the control element drive mechanism (CEDM) drive shaft extension. The neutron absorber elements of a four-element CEA engage the four corner guide tubes in a single fuel assembly. The four-element CEAs are used for power shaping functions and make up the first control rod group to be inserted at high power. The twelve-element CEAs engage the four corner guide tubes in one fuel assembly and the two nearest corner guide tubes in adjacent fuel assemblies. The twelve-element CEAs make up the balance of the control groups of CEAs and provide a bank of strong shutdown rods. The control element assemblies are shown in figures 4.2-3 through 4.2-5. The pattern of CEAs (total of 89) is shown in figure 4.2-10. Note that up to eight additional CEAs may be installed if desired for additional flexibility or future use.

Part-strength CEAs are differentiated from full-strength CEAs by using alphanumeric serialization (i.e., P-XXX vs. F-XXX).

The control elements of a Feltmetal® full-strength CEA consist of an Alloy 625 tube loaded with a stack of cylindrical absorber pellets. The absorber material consists of 73% TD

boron carbide (B_4C) pellets, with the exception of the lower portion of the elements, which contains reduced diameter B_4C pellets wrapped in a sleeve of type 347 stainless steel felt metal.

The design objective realized by the use of felt metal and reduced diameter B_4C pellets in the element tip zones is that as the B_4C pellets swell due to irradiation, the felt metal sleeve compresses as a result of the applied loading. This compression limits the amount of induced strain in the cladding. Therefore, buffering of the CEA following scram, which occurs when the element tips enter a reduced diameter portion of the fuel assembly guide tubes, is not affected with long-term exposure of the CEA to reactor operating conditions.

The control elements of an AIC full-strength CEA consist of an Alloy 625 tube loaded with a stack of cylindrical B_4C absorber pellets and cylindrical AIC hollow absorber slugs. The B_4C pellets are 73% TD boron carbide material. The design objective realized by the use of hollow AIC slugs in the element tip zones is that as the AIC slugs swell due to thermal expansion and irradiation, the low AIC creep strength relative to the Alloy 625 cladding yield strength results in the AIC filling the central hole, which limits the amount of induced strain in the cladding. Therefore, buffering of the CEA following scram, which occurs when the element tips enter a reduced diameter portion of the fuel assembly guide tubes, is not affected with long-term exposure of the CEA to reactor operating conditions.

During normal power operation, most of the CEAs are expected to be in the fully withdrawn position. Thus, the local B-10 burnup progresses at a lower rate, and CEA life is prolonged.

Above the poison column is a plenum which provides expansion volume for helium released from the B_4C. The plenum volume contains a Type 302 stainless steel holddown spring, which restrains the absorber material against longitudinal shifting with respect to the clad, while allowing for differential expansion between the absorber and the clad. The spring develops a load sufficient to maintain the position of the absorber material during shipping and handling.

Each full-strength control element is sealed by welds which join the tube to an Alloy 625 nose cap at the bottom, and an Alloy 625 connector at the top which makes up part of the end fitting at the top. The end fittings, in turn, are threaded and crimped in place by a locking nut to the spider structure which provides rigid lateral and axial support for the control elements. The spider hub bore is specially machined to provide a point of attachment for the CEA extension shaft.

Thirteen of the 89 CEAs are part-strength CEAs. The control elements of a part-strength CEA consist of solid Alloy 625 slugs over their entire active length. A holddown spring, similar to the spring in the full-strength rods, maintains the orientation of the Alloy 625 slugs. The FSCEA/PSCEA pattern is shown in figure 4.2-10.

Each full-strength or part-strength CEA is positioned by a magnetic jack control element drive mechanism (CEDM) mounted on the reactor vessel closure head. The extension shaft joins

with the CEA spider and connects the CEA to the CEDM. Full and part-strength CEAs may be connected to any extension shaft depending on control requirements. Mechanical reactivity control is achieved by positioning groups of CEAs by the CEDMs.

In the outlet plenum region, all FSCEAs/PSCEAs are enclosed in CEA shrouds which provide guidance and protect the FSCEA/PSCEA and extension shaft from coolant cross flow. Within the core, each element travels in a Zircaloy guide tube. The guide tubes are part of the fuel assembly structure and ensure proper orientation of the control elements with respect to the fuel rods.

When the extension shaft is released by the CEDM, the combined weight of the shaft and CEA causes the CEA to insert into the fuel assembly.

The lower ends of the four outer fuel assembly guide tubes are tapered gradually to form a region of reduced diameter which, in conjunction with the control element on the CEA, constitutes an effective hydraulic buffer for reducing the deceleration loads at the end of a trip stroke. This purely hydraulic damping action is augmented by a spring and plunger arrangement on the CEA spider. When fully inserted, full- and part-strength CEAs rest on the upper guide structure support plate.

The capability of the CEAs to scram within the allowable time is demonstrated as part of the tests discussed in paragraph 4.2.4.4.

4.2.3 DESIGN EVALUATION

4.2.3.1 Fuel Assembly

4.2.3.1.1 Vibration Analyses

Four sources of periodic excitation are recognized in evaluating the fuel assembly susceptibility to vibration damage. These sources are as follows:

A. Reactor Coolant Pump Blade Passing Frequency

Precritical vibration monitoring on previous C-E reactors indicates that peak pressure pulses are expected at the pump blade passing frequency (120 Hz), and a lesser but still pronounced peak at twice this frequency.

B. Lower Support Structure Motion

Random lateral motion between the fuel assembly and the lower support structure is expected to occur with an amplitude similar to that of other C-E reactors in the frequency range of between 2 and 10 Hz.

C. Fuel Rod Vibration

Flow-induced fuel rod vibration resulting from coolant flow through the fuel assembly. The expected amplitude of such vibration is 0.004 inch or less.

D. Flow-Induced Control Element Vibration

System-80 incorporates design features that ensure that the vibration of CEAs is such as to produce no significant wear in the guide tubes.

These sources of periodic motion are not expected to have an adverse effect on the performance of the Standard System 80 fuel assembly.

The capability of the Standard System 80 fuel assembly to sustain the effects of flow-induced vibration without adverse effects has been demonstrated in the dynamic flow tests as reported in Section 4.2.3.1.8.

4.2.3.1.2 CEA Guide Tube

The CEA guide tubes are evaluated for structural adequacy using the criteria given in paragraph 4.2.1.1 in the following areas:

A. Steady axial load due to the combined effects of axial hydraulic forces and upper end fitting holddown forces.

   For normal operating conditions, the resultant guide tube stress levels are significantly less than the design limits.

B. Short-term axial load due to the impact of the spring-loaded CEA spider against the upper guide structure support plates at the end of a CEA trip.

   For trips occurring during normal power operation, solid impact is not predicted to occur due to the kinetic energy of the CEA being dissipated in the hydraulic buffer and by the CEA spring.

C. Short-term differential pressure load occurring in the hydraulic buffer regions of the outer guide tubes at the end of each trip stroke.

The buffer region slows the CEA during the last few inches of the trip stroke. The resultant differential pressure across the guide tube in this region gives rise to circumferential stresses which are significantly less than the design limits. The trip is assumed to be repeated daily. However, the resultant stress is too small to have a significant effect on fatigue usage.

For conditions other than normal operation, the additional mechanical loads imposed on the fuel assembly by an OBE (equivalent to one-half DBE), DBE, and large break LOCA and their resultant effect on the control element guide tubes are discussed in the following paragraphs.

4.2.3.1.2.1 Operating Basis Earthquake (OBE). During the postulated OBE, the fuel assembly is subjected to lateral and axial accelerations which, in turn, cause the fuel assembly to deflect from its normal shape. The method of calculating these deflections is described in paragraph 3.7.3.14. The magnitude of the lateral deflections and resultant stresses were evaluated for acceptability. The method for calculating stresses from deflected shapes is described in reference 1. The fuel assembly is designed to be capable of withstanding the axial loads without buckling and without sustaining excessive stresses. The results of the stress analysis demonstrate that the component stresses are less than the allowable values discussed in section 4.2.1.1.

4.2.3.1.2.2 Safe Shutdown Earthquake (SSE). The axial and lateral loads and deformation sustained by the fuel assembly during a postulated SSE have the same origin as those discussed above for the OBE, but they arise from initial ground accelerations twice those assumed for the OBE. The analytical methods used for the SSE are identical to those used for the OBE. The predicted component stresses were less than the allowable values discussed in reference 1.

4.2.3.1.2.3 Loss-of-Coolant Accident (LOCA). In the event of a large break LOCA, there will occur rapid changes in pressure and flow within the reactor vessel. Associated with the transient are relatively large axial and lateral loads on the fuel assemblies. The response of a fuel assembly to the mechanical loads produced by a LOCA is considered acceptable if the fuel rods are maintained in a coolable array, i.e., acceptably low grid crushing. The methods used for analysis of combined seismic and LOCA loads and stresses are described in reference 1. The results of the LOCA analysis were that component stresses were within the limits established in reference 1.

4.2.3.1.2.4 Combined SSE and LOCA. It is not considered appropriate to combine the stresses resulting from the SSE and LOCA events. Nevertheless, for purposes of demonstrating margin in the design, the maximum stress intensities for each individual event were derived by a square root of sum of the squares (SRSS) method. This was performed as a function of fuel assembly evaluation and position, e.g., the maximum stress intensities for the center guide tube at the upper grid

elevation (as determined in the analysis discussed in the above paragraphs for SSE and LOCA) were combined by the SRSS method. The results demonstrated that the allowable stresses described in reference 1 were not exceeded for any position along the fuel assembly even under the added conservatism provided by this load combination.

To qualify the complete fuel assembly, full-scale hot loop testing has been conducted. These tests evaluated fretting and wear of components, refueling procedures, fuel assembly uplift forces, holddown performance, and compatibility of the fuel assembly with interfacing reactor internals, CEAs, and CEDMS under conditions of reactor water chemistry, flow velocity, temperature, and pressure. The details of the System 80 hot loop testing are reported in Section 4.2.3.1.8.

4.2.3.1.3 Spacer Grid Evaluation

The function of the spacer grids is to provide lateral support to fuel and burnable poison rods in such a manner that the axial forces are not sufficient to buckle or bow the rods, and that the wear resulting at the grid-to-clad contact points will be limited to acceptably small amounts. It is also a criterion that the grid be capable of withstanding the lateral loads imposed during the postulated seismic and LOCA events.

Fuel assemblies are designed such that the combination of fuel rod rigidity, grid spacing, and grid preload will not result in significant fuel rod deformation under axial loads, and the long-term effects of clad creep (reduction in clad OD), the reduction of grid stiffness with temperature, and the partial relaxation of the grid material during operation ensure that

this criterion is also satisfied during all operating conditions. Moreover, inspection of irradiated fuel assemblies from the Maine Yankee (14 x 14), Arkansas (16 x 16), Calvert Cliffs (14 x 14), Palisades (15 x 15), and Omaha (14 x 14) reactors has not shown significant bowing of the fuel rods. In view of these factors and the similarity of these designs to the Standard System 80 designs, it is concluded that the axial forces applied by the grids on the cladding will not result in a significant degree of fuel rod bow. The influence of fuel rod lateral deflection is discussed further in paragraph 4.2.3.2.6. Additional discussion of the causes for and effects of fuel rod bowing are contained in paragraph 4.2.3.2.6 and in reference 52.

The capability of the grids to support the clad without excessive clad wear is demonstrated by out-of-pile flow testing on the Standard System 80 assembly design, and by the results of post-irradiation examination of grid-to-clad contact points in Maine Yankee fuel assemblies which showed only negligible clad wear (reference 53).

The capability of the grid to withstand the lateral loads produced during the postulated seismic and LOCA events is demonstrated by impact testing the reference grid design, and comparing the test results with the analytical predictions of the seismic and LOCA loads.

The Zircaloy spacer grid material is of similar composition as the fuel rods and guide tubes with which it is in contact, thereby obviating any problem of chemical incompatibility with those components. For the same reason, adequate resistance to

corrosion from the coolant is assured (see paragraph 4.2.3.2.3, listing A, for additional information relative to the corrosion-resistance of Zircaloy-4 in the primary coolant environment).

The Inconel 625 material used for the lowest and uppermost spacer grid is in contact with the coolant, the 304 stainless steel lower end fitting (to which the lowest spacer grid is welded), the Zircaloy-4 split rings (top grid), the Zircaloy-4 or ZIRLO fuel rods, the poison rods, and the Zircaloy-4 guide tubes. The mutual chemical compatibility of these materials in a reactor environment has been demonstrated by Westinghouse use of these materials in fuel assemblies that have been operated in other Westinghouse reactors and for which post-irradiation examination has yielded no evidence of chemical reaction between these components. In addition, experiments have also been performed at Westinghouse of Inconel-type alloys and Zircaloy-4 which showed that eutectic reactions did not occur below 2200F, a temperature far in excess of that anticipated at the lower grid location in the event of a LOCA.

4.2.3.1.4 Dimensional Stability of Zircaloy or ZIRLO™

Zircaloy components and ZIRLO™ cladding are designed to allow for dimensional changes resulting from irradiation-induced growth. Extensive analyses of in-pile growth data have been performed to formulate a comprehensive model of in-pile growth.[54] [71] The in-pile growth equations are used to determine the minimum axial differential growth allowance which must be included in the axial gap between the fuel rods and the

upper end fitting. For determining the gap between the fuel rods and the upper end fitting, the growth correlations for fuel rod and guide tube growth are combined statistically, such that the minimum initial gap is adequate to accommodate the upper 95% probability level of differential growth between fuel rods and guide tubes in the peak burnup fuel assembly. For the purpose of predicting axial and lateral growth of the fuel assembly structure (thereby establishing the minimum initial clearance with interfacing components), the equations are used in a conservative manner to ensure adequate margins to interference are maintained. The manner in which the in-pile growth equations are used in design is described in reference 55.

4.2.3.1.5 Fuel Handling and Shipping Design Loads

Three specific design bases have been established for shipping and handling loads. These are as follows:

A. The fuel assembly, when supported in the new fuel shipping container, shall be capable of sustaining the effect of 5g axial, lateral, or vertical acceleration without sustaining stress levels in excess of those allowed for normal operation. The 5g criterion was originally established experimentally, and its adequacy is continually confirmed by the presence of impact recorders, as discussed in the following paragraph.

   Impact recorders, included with each shipment, indicate if loadings in excess of 5g are sustained. A record of shipping loads in excess of 5g indicates an unusual

shipping occurrence in which case the fuel assembly is inspected for damage prior to releasing it for use.

The axial shipping load path is through either end fitting to the guide tubes. A 5g axial load produces a compressive stress level in the guide tubes less than the two-thirds yield stress limit that is allowed for normal condition events. The fuel assembly is prevented from buckling by being clamped at grid locations. For lateral or vertical shipping loads, the grid spring tabs have an initial preload which exceeds five times the fuel rod weight. Therefore, the spring tabs see no additional deflection as a result of 5g lateral or vertical acceleration of the shipping container. In addition, the side load on the grid faces produced by a 5g lateral or vertical acceleration is less than the measured impact strength of the grids.

B. The fuel assembly shall be capable of sustaining a 5000-pound axial load applied at the upper end fitting by the refueling grapple (and resisted by an equal load at the lower end fitting) without sustaining stress levels in excess of those allowed for normal operation. The 5000-pound load was chosen in order to provide adequate lift capability should an assembly become lodged. This load criterion is greater than any lift load that has been encountered in service.

C. The fuel assembly shall be capable of withstanding a 0.125-inch deflection in any direction whenever the fuel assembly is raised or lowered from a horizontal

position without sustaining a permanent deformation beyond the fuel assembly inspection envelope.

Fuel handling procedures required the use of a strongback to limit the fuel assembly deflection to a maximum of 0.125-inch in any direction whenever the fuel assembly is raised or lowered to a horizontal position. This limits the stress and strain imposed upon the fuel assembly to values well below the limits set for normal operating conditions. The adequacy of the 0.125-inch criterion is based on the inclusion of this limitation in specifications and procedures for fuel handling equipment, which is thereby constrained to provide support such that lateral deflection is limited to 0.125 inches.

4.2.3.1.6 Fuel Assembly Analysis Results

The results of the fuel assembly analyses confirm that the design criteria of paragraph 4.2.1.1, regarding stress, strain, and strain fatigue, are satisfied.

4.2.3.1.7 Fuel Assembly Lift-off Analysis

The results of the analysis confirm that the fuel assembly will not lift off during reactor operation. This analysis considers the appropriate combination of forces as described in paragraph 4.2.2.1.

4.2.3.1.8 Hot Loop Flow Testing

4.2.3.1.8.1 Summary

Hot loop flow testing for System 80 was completed during 1980 and 1981. Test components included an array of five fuel assemblies, a twelve rod control element assembly (CEA) and supporting structures. Pressure drops and CEA scram times were measured for a range of temperature and flowrate settings. Results were nearly as predicted based on analyses and the results of hot loop tests preceding those for System 80. A 1300 hour wear test was run, finding no fretting wear on fuel rods and no other wear on fuel exterior surfaces. Some wear occurred inside rodded CEA guide tubes, but at acceptable rates.

4.2.3.1.8.2 Test Facility Description

Tests were performed in the 36" ID main section of the C-E TF-2 hot loop. The piping arrangement in this loop is shown in Figure 4.2-11. The loop is rated at 15000 gpm, 650°F, 2500 psia. System 80 wear tests were near loop limits, at 14000 gpm, 620°F, 2250 psia. The loop includes systems which maintain steady temperature and pressure and normal reactor water chemistry.

4.2.3.1.8.3 Test Components

4.2.3.1.8.3.1 Stackup

The test component stackup is shown in Figure 4.2-12. The support structures were bolted to lugs and a support ring at the bottom of the test vessel. The fuel assemblies and CEA were

enclosed within lower and upper support structures which were joined by bolts at the fuel alignment plate.

4.2.3.1.8.3.2 Fuel Assemblies

4.2.3.1.8.3.2.1 Details of Design

Fuel assemblies closely matched the production reactor fuel design. Differences include:

A. Fuel rod loading - 46% of the fuel rods (544) were of prototype construction, with depleted UO_2 pellets. 54% (636) were dummy rods of solid stainless steel. Prototype rods were used in all positions of concern with respect to fretting wear.

B. Lower end fitting leg braces - Braces are deleted between legs of the lower end fitting. The test design, with braces, is considered less favorable with respect to fretting wear.

C. Inside dimension of guide tubes and upper end fitting posts - The I.D. in upper ends of guide tubes and in UEF posts for production fuel will be enlarged slightly as a precaution, allowing use of wear sleeves if needed. The tube enlargement should have little effect on guide tube wear tendency, and will speed CEA scrams very slightly.

4.2.3.1.8.3.2.2 Spacer Grid Spring Settings

All spacer grip springs were set for the minimum restraint of fuel rods expected during the fuel lifetime.

4.2.3.1.8.3.2.3 Fuel Array in Test

The array of five fuel assemblies is shown in Figure 4.2-13, with relationships to the fuel shroud and CEA.

4.2.3.1.8.3.3 Control Element Assembly

System 80 reactors utilize both 4 rod and 12 rod control element assemblies. The twelve rod CEA was chosen for hot loop tests because it has a lower weight per rod ratio (hence slower scrams) and is a more complex structure. The test CEA was functionally identical to that shown in Figure 4.2-4.

4.2.3.1.8.3.4 Support Structures

The support structures were prototypical sections of a System 80 reactor and provided support and alignment of the fuel assemblies and CEA. The lower ends of the fuel assemblies engages alignment pins on an open grid beam array. The fuel shroud cross section is noted in Figure 4.2-13. All possible corner shapes and fuel to shroud clearances were included. Shroud tubes in the upper guide structure were held by the upper guide structure support plate (UGSSP) and fuel alignment plate (FAP), and engaged the four posts of each fuel upper end fitting. The region between the FAP and the UGSSP is an outlet plenum, where flow passes up around the shroud tubes and exits the outlet nozzle. Effects of a pressure gradient across the reactor outlet plenum were included in tests. The gradient causes flow circulation through small holes in the UGSSP upward near the reactor centerline and downward near the outlet nozzles. In TF-2 the flow circulation was driven through

external piping, employing a CEA shroud and seal assembly above the UGSSP.

4.2.3.1.8.4 Test Results

4.2.3.1.8.4.1 Scram Time vs Acceptance Curve

Hot loop tests previewed the scram performance checks that will be required for every reactor CEA, during pre-operation functional tests. Measured position vs. time for reactor scrams must fall below an acceptance curve applied in safety analyses. The reactor scram tests are run at approximately 525°F with all pumps running. The TF-2 scram for this condition is plotted in Figure 4.2-14, along with the acceptance curve.

4.2.3.1.8.4.2 Pressure Drops in Fuel

Fuel assembly pressure drops were measured over a range of flow Reynolds Number. Results are in good agreement with measurements for similar fuel in prior TF-2 tests. The test results support the flow resistances used in design analyses for System 80 and based on the prior measurements. Those analyses include fuel holddown spring design requirements, support structure hydraulic loadings and the prediction of system flow rate.

4.2.3.1.8.4.3 Fuel Rod Fretting

The test for fuel rod fretting ran 1300 hours, at 620°F, with flow ≥13,400 gpm through the fuel. The setting was based on worst case reactor conditions at full power, with 116% design flow. Test fluid velocities exceeded those expected in any

System 80 reactor. No fretting was found on any of the fuel rod surfaces.

4.2.3.1.8.4.4 Guide Tube Wear

In view of observed CEA motion dependence on upper guide structure flow, a sequence of different flow conditions was set during the wear test. With each change of flow conditions the CEA was raised to a new position. Conditions included the maximum pressure differences expected across the reactor UGSSP, both upward and downward, and an intermediate equalized condition. Following the tests all CEA guide tubes were inspected with an eddy current probe. Four tubes which gave the largest indications were removed and sectioned longitudinally (clamshelled) for precise inspection. Greatest wear occurred for the UGSSP upflow condition, at points of CEA rod tip contact in guide tubes. Guide tube wear at the highest rate observed in tests will not contribute to violation of stress limits in Section 4.2.3.

4.2.3.2 Fuel Rod Design Evaluation

The evaluations discussed in this section are based on assumed fuel rod operation within certain linear heat rate limits related to avoiding excessive fuel and clad temperatures. Information concerning the bases for these limits is contained in section 4.4.

4.2.3.2.1 Results of Vibration Analyses

Four sources of periodic excitation are recognized in evaluating the fuel rod susceptibility to vibration damage. These sources are as described in paragraph 4.2.3.1.1.

These sources of periodic motion are not expected to have an adverse effect on the performance of the fuel rod. Paragraph 4.2.3.2.4 includes additional information on fuel rod response to the sources.

4.2.3.2.2 Fuel Rod Internal Pressure and Stress Analysis

A fuel rod cladding stress analysis is conducted to determine the circumferential stress and strain resulting from normal, upset, and emergency conditions. The analysis includes the calculation of cladding temperatures and rod internal pressures during each of the occurrences listed in paragraph 4.2.1.1. The design criteria to be used to evaluate the analytical results are specified in paragraph 4.2.1.2.1. Fuel rod stresses resulting from seismic events are calculated using the methodology described in reference 1.

The results of the fuel rod analyses confirm that the design criteria of paragraph 4.2.1.2.1, regarding stress, strain, and strain fatigue, are satisfied.

4.2.3.2.3 Potential for Chemical Reaction

A. Corrosion

Zircaloy-4 fuel rod tubing has been visually examined in the spent fuel pool after six reactor cycles at Ft. Calhoun, five reactor cycles at Calvert Cliffs, and

others at Palo Verde 1 and 2, ANO-2, and Maine Yankee. In addition, oxide thicknesses were measured in the hot cell after one cycle at Maine Yankee, five cycles at Calvert Cliffs, and six cycles at Ft. Calhoun. The oxide appearance and oxide thickness measured were similar to that from autoclave behavior for that time and temperature.

Coolant chemistry parameters have been specified that minimize corrosion product release rates and their mobility in the primary system. Specifically, the precore hot functional environment is controlled (pH and oxygen) to provide a thin, tenacious, adherent, protective oxide film. This approach minimizes corrosion product release and associated inventory on initial startup and subsequent operation. During operation, the recommended lithium concentration range effects a chemical potential gradient or driving force between hot and cooler surfaces (fuel cladding and steam generator tubing, respectively), such that soluble iron and nickel species will preferentially deposit on the steam generator surfaces. The associated pH also minimizes general corrosion product release rates from primary system surfaces. Moreover, the specified hydrogen concentration's range insures reducing conditions in the core, thereby avoiding low solubility Fe^{3+}. Additionally, dissolved hydrogen promotes rapid recombination of oxidizing species. (Recall, oxidizing species and a fast neutron flux are

synergistic prerequisites to accelerated Zircaloy-4 corrosion.)

During operation lithium, dissolved oxygen, and dissolved hydrogen will be monitored at a frequency consistent with maintaining these parameters within their specifications.

Post-operational examinations of fuel cladding that has operated within these specifications has shown no significant chemical or corrosive attack of the Zircaloy cladding. ZIRLO™ cladding corrosion characteristics are found to be equally acceptable as discussed in Section 4.5 of Ref. 71.

B. External Hydriding

During operation of the reactor with exposure to high temperature, high pressure water, Zircaloy-4 or ZIRLO™ cladding will react to form a protective oxide film in accordance with the following equation:

$$Zr + 2H_2O \rightarrow ZrO_2 + 2H_2$$

Approximately 20% of the hydrogen is absorbed by the Zircaloy. Based on data described in WAPD-MRP-107, the cladding would be expected to contain up to 250 ppm of hydrogen following three years of exposure.

A series of burst tests were performed on Zircaloy-2 tubes containing 340 ppm and 460 ppm of hydrogen precipitated as hydride platelets in a circumferential manner.(56) Burst tests at 660F showed that the burst test specimens with 340 ppm had normal burst ductility

of 12%. Therefore, hydrogen normally absorbed in Zr-4 tubing will not prove deleterious to the cladding integrity. This is also true of the ZIRLO™ tubing as discussed in Section 4.4.2.5 of Ref. 71.

C. Internal Hydriding

A number of reported fuel rod failures have resulted from excessive moisture available in the fuel. Under operation, this moisture oxidizes the Zircaloy.

The hydrogen, which was not absorbed during normal oxidation, would then be absorbed into the Zircaloy through a scratch in the oxide film. This localized hydrogen absorption by the cladding would shortly result in a localized fuel rod failure. Work performed at the Institute for Atomenergi, Halden, Norway, demonstrated that a threshold value of water moisture is required for hydride sunbursts to occur.[57] Through a series of in-pile experiments, the level of this threshold value was established. The allowable hydrogen limit in the fuel complies with this requirement, ensuring that hydride sunbursts will not occur.

D. Crud

Crud layers on zirconium oxide films are usually porous and non-insulating. As an example, heavy but non-insulating crud layers have been found in Yankee Rowe (WCAP-3317-6094, Yankee Core Evaluation Program, Final Report, 1971). With porous crud, water is free to flow through the crud and provide heat transfer by

convection. Under these conditions, crud-enhanced corrosion should not occur.

Water chemistry monitoring is a continuous process and should ensure no dense crud buildup.

E. Fuel-Cladding Chemical Reaction

An in-depth post-irradiation examination has been conducted wherein fuel-cladding chemical reactions were among those items studied.[26] This study concluded that early unpressurized elements containing unstable fuel were more susceptible to stress corrosion attack than is the current design that utilizes stable fuel and pressurized cladding. By carefully monitoring the primary coolant activity of operating reactors, it has been concluded that the current fuel designs are not susceptible to stress corrosion (or other types of corrosion) during normal plant operation. Since stress corrosion attack is the result of a combination of stress imposed by the fuel on the cladding and the corrosive chemical species available to the cladding, irradiation programs have been pursued to define the conditions under which pellet-clad interaction will damage the cladding. These programs have been conducted at Halden, at Petten in the Netherlands, and at Studsvik in Sweden, and have confirmed that current fuel designs are not susceptible to failure by stress corrosion cracking during normal plant operation.

4.2.3.2.4 Fretting Corrosion

The phenomenon of fretting corrosion, particularly in Zircaloy clad fuel rods supported by Zircaloy spacer grids, has been extensively investigated. Since irradiation-induced stress relaxation causes a reduction in grid spring load, spacer grids must be designed for end-of-life conditions as well as beginning-of-life conditions to prevent fretting caused by flow-induced tube vibrations.

Examination of Zircaloy-clad fuel rods after six cycles of exposure in Ft. Calhoun, five cycles in Calvert Cliffs-1, and four cycles in Arkansas Nuclear One-Unit 1 indicates fuel rod fretting between the fuel rod and spacer grid is rare. The usual result of the contact between grid components and fuel rods is a small cladding surface mark with no appreciable depth. The grid to rod fretting issue for ZIRLO™ cladding is discussed in Section 5.4.7 of Ref. 71 and concludes that fretting failures with ZIRLO™ cladding will remain at the low levels seen with Zircaloy-4 clad.

4.2.3.2.5 Fuel Rod Bowing

Experience has proven that any specific criterion on allowable deflections (bowing), with respect to the effects which such deflections might have on thermal-hydraulic performance, is not necessary beyond the initial fuel rod positioning requirements required of the grids. This variation in spacing is accounted for in thermal-hydraulic analysis through the introduction of hot channel factors in calculating the maximum enthalpy rise in calculating DNBR. This adjustment is called the Pitch, Bowing,

and Clad Diameter Factor, which is conservatively applied to simulate a reduced flow area along the entire channel length. The value of this factor is given in table 4.4-2 and its application in defining overall uncertainty penalty factors is discussed in section 4.4.

The subject of fuel rod bowing is discussed in reference 52 and 71.

4.2.3.2.6 Irradiation Stability of Fuel Rod Cladding

The combined effects of fast flux and cladding temperature are considered in three ways as discussed below:

A. Cladding Creep Rate

The in-pile creep performance of Zircaloy-4 and ZIRLO™ is dependent upon both the local material temperature and the local fast neutron flux. The functional form of the dependencies is presented in references 13, 14, and 24 for gap conductance calculations, and in reference 58 for cladding collapse time predictions.

B. Cladding Mechanical Properties

The yield strength, ultimate strength, and ductility of Zircaloy-4 and ZIRLO™ are dependent upon temperature and accumulated fast neutron fluence. The temperature and fluence dependence are discussed in paragraph 4.2.1.2.2.1. Unirradiated properties were used depending upon which is more restrictive for the phenomenon being evaluated.

C. Irradiation-Induced Dimensional Changes

Zircaloy-4 and ZIRLO™ have been shown to sustain dimensional changes (in the unstressed condition) as a function of the accumulated fast fluence. These changes are considered in the appropriate clearances between the various core components. The irradiation-induced growth correlation method is discussed in reference 54.

Zircaloy-4 and ZIRLO™ fuel cladding have been utilized in pressurized water reactors at temperatures and burnups anticipated in current designs with no failures attributable to radiation damage. Mechanical property tests on Zircaloy-4 cladding exposed to neutron irradiation of 4.7×10^{21} nvt (E > 1 MeV) (estimated) have revealed that the cladding retains a significant amount of ductility (in excess of 4% elongation). Typical results are shown in table 4.2-2. It is believed that the fluence of 4.7×10^{21} nvt (E > 1 MeV) is at saturation so that continued exposure to irradiation will not change these properties.[(59)]

4.2.3.2.7 Cladding Collapse

Reference 60 presents the results of a study which deals with the phenomena of interpellet gap formation and clad collapse in modern PWR fuel. The conclusion drawn from this report[(61)] is that clad collapse analyses are not necessary for modern Westinghouse manufactured fuel because of the absence of large axial gaps between pellets. These same conclusions apply to

the use of ZIRLO™ cladding as discussed in Section 5.4.1 of Ref. 71.

4.2.3.2.8 Fuel Dimensional Stability

Fuel swelling due to irradiation (accumulation of solid and gaseous fission products) and thermal expansion results in an increase in the fuel pellet diameter. The design makes provision for accommodating both forms of pellet growth. The fuel-clad diametral gap is more than sufficient to accommodate the thermal expansion of the fuel. To accommodate irradiation-induced swelling, it is conservatively assumed that the fuel-clad gap is used up by the thermal expansion and that only the fuel porosity and the dishes on each end of the pellets are available. Thermal and irradiation-induced creep of the restrained fuel results in redistribution of fuel so that the swelling due to irradiation is accommodated by the free volume. These conclusions also apply to the use of ZIRLO™ cladding.

Table 4.2-2

TENSILE TEST RESULTS ON IRRADIATED

SAXTON CORE III CLADDING[59]

Fluence (>1 MeV) 4.7×10^{21} n/cm^2 (estimated)						
Rod ID	Location From Bottom (in.)	Testing Temp. (°F)	0.2% Yield Stress (lb/$in.^2$ x 10^3)	Ultimate Tensile Strength (lb/$in.^2$ x 10^3)	Uniform Strain in 2-in. Gage Length (%)	Total Strain in 2-in. Gage Length
BO	11-17	650	61.4	65.6	2.2	6.8
BO	26-32	650	58.1	68.9	2.4	11.3
RD	3-9	650	62.2	70.0	2.0	4.2
RD	12-18	650	60.5	65.4	1.7	5.8
MQ	12-18	675	70.4	77.4	1.9	6.1
MQ	28-34	675	66.0	75.1	1.6	6.2
FS	28-34	675	57.2	71.4	3.9	12.9
GL	12-18	675	60.5	71.5	2.4	9.3

For such restrained pellets, and at a total fission-product-induced swelling rate of 0.4% $\Delta V/V$ per 10^{20} fiss/cm^3, 0.24% would be accommodated by the fuel porosity and dishes through fuel creep, and 0.16% would increase the fuel diameter. Assuming peak burnup, this would correspond to using up a void volume equal to 3.30% of the fuel volume and increasing the fuel rod diameter by a maximum of < 0.0025 inch (< 0.7% clad strain). When these numbers were compared to the minimum available volume and the maximum allowable strain, it was concluded that sufficient accommodation volume has been provided even under the most adverse burnup and tolerance conditions.

Early work on the swelling rates for UO_2 is described in references 6, 55, 56, 57, 62 and 63. The experiments were conducted using fuel materials made prior to the discovery of densification and would be appropriate for some of C-E's early production. The incorporation of pore-formers that provide more representative fuel microstructures makes a more recent set of data from a C-E-conducted program more appropriate for swelling rates.

Fuel pellets were fabricated by C-E and irradiated for four cycles to burnup levels up to 50 GWd/Mtu.[(64)] Immersion density measurements taken from pellets of various burnups were plotted to determine the rate of volume increase with burnup. The rate derived from these measurements was 1.0% $\Delta V/V$ per 10 GWd/Mtu. Since the levels of burnup were after cladding contact, the swelling value obtained is a restrained swelling rate. The

0.4% value per 4 GWd/Mtu is approximately equal to 0.4% $\Delta V/V$ per 10^{20} fiss/cm^3 used for the calculation above.

4.2.3.2.9 Potential for Waterlogging Rupture and Chemical Interaction

The potential for waterlogging rupture is considered remote. Basically, the necessary factors, or combination of factors, include the presence of a small opening in the cladding, time to permit filling of the fuel rod with water, and finally, a rapid power transient. The size of the opening necessary to cause a problem falls within a fairly narrow band. Above a certain defect size, the rod can fill rapidly, but during a power increase it also expels water or steam readily without a large pressure buildup. Defects which could result in an opening in cladding are scrupulously checked for during the fuel rod manufacturing process by both ultrasonic and helium leak testing. Clad defects which could develop during reactor operation due to hydriding are also controlled by limiting those factors; e.g., hydrogen content of fuel pellets, which contributes to hydriding.

The most likely time for a waterlogging rupture incident would be after an abnormally long shutdown period. After this time, however, the startup rate is controlled so that even if a fuel rod were filled with coolant, it would "bake out," thus minimizing the possibility of additional cladding rupture. The combination of control and inspection during the manufacturing process and the limits on the rate of power change restrict the potential for waterlogging rupture to a very small number of fuel rods.

The UO_2 fuel pellets are highly resistant to attack by reactor coolant in the event cladding defects should occur. Extensive experimental work and operating experience have shown that the design parameters chosen conservatively account for changes in thermal performance during operation and that coolant activity buildup resulting from cladding rupture is limited by the ability of uranium dioxide to retain solid and gaseous fission products.

4.2.3.2.10 Fuel Burnup Experience

The Westinghouse fuel rod design is based on an extensive experimental data base and by an extension of experimental knowledge through design application of Westinghouse fuel rod evaluation codes. The experimental data base includes data from C-E or C-E/Kraftwerk Union (KWU) joint irradiation experiments, from C-E, Westinghouse and KWU operating commercial plant performance, and from many basic experiments conducted in various research reactors which are available in the open literature. Some of these sources will be discussed below. Evidence currently available indicates that Zircaloy (or ZIRLO™) and UO_2 fuel performance is satisfactory to exposures in excess of 60,000 MWd/Mtu.

A. Public Information

   General fuel performance information available in the open literature has provided part of the Westinghouse fuel rod design data base. Particular experiments that have been cited in the past as key references are:

1. Determination of the effect of fuel-cladding gap on the linear heat rating to melting for UO_2 fuel rods, conducted in the Westinghouse test reactor.
2. Shippingport irradiation experience.
3. Saxton irradiation experience.
4. Combined Vallencitos boiling water reactor (VBWR) - Dresden irradiation.
5. Large Seed Blanket Reactor (LSBR) rod experience
6. Joint U.S.-Euratom Research and Development Program to evaluate central fuel melting in the Consumers Power Co. Big Rock Point reactor.

Since the information from these programs is available in the open literature, they will not be described here. However, details as to the significance of the results to Westinghouse fuel burnup experience are presented in reference 65.

B. C-E/KWU Technical Exchange

C-E entered into a technical agreement with KWU beginning in 1972 for the complete exchange of information and technology relating to pressurized water reactor systems including fuel. This agreement made available to C-E the total experience of 10 years successful operation of commercial PWR fuel in systems designed and fabricated by KWU and is the most advanced of its type in the world. An essential part of this broad-based exchange involves joint sponsorship of numerous fuel testing programs.

C. Operating Fuel Experience

C-E and KWU have fabricated more than 1,335,000 Zircaloy-clad fuel rods, both internally pressurized and unpressurized. Of this total, 530,000 rods remain in operation, some with average burnups in excess of 40,000 MWd/Mtu. Overall performance of this fuel has been excellent. The fuel rod reliability level, estimated from coolant activities, has been excellent. Reliability levels are continually validated by extensive pool-side fuel inspection programs conducted by C-E at reactor sites during refueling shutdowns.

D. Fuel Irradiation Programs

C-E is involved in diversified fuel irradiation test programs to confirm the adequacy of the C-E fuel rod design bases and models by experimental means. Some of these programs involve safety-related research, while other programs provide confirmatory data on performance capability or evaluate design and fabrication variables or methods which may improve and extend our current knowledge of fuel rod performance.

Some of the key fuel performance evaluation programs that will be summarized below include:

- Fuel densification experiments at the Battelle Research Reactor (BRR).
- Joint C-E/KWU fuel densification experiments including tests in the MZFR reactor at Karlsruhe,

West Germany, and the EEI experiments in the General Electric Test Reactor (GETR).

- Direct participation in the Halden Project in Norway with access to all Halden base program fuel test data.
- Irradiation of special instrumented fuel rods to obtain dynamic in-reactor measurements in Halden experimental rigs.
- Ramp test programs on fuel rods to evaluate fuel load-follow capabilities and the pellet clad interaction/stress corrosion phenomenon in both the Studsvik and Petten test reactors. Other in-reactor experiments have been conducted in Obrigheim pressurized water reactor.
- Irradiation of special test and surveillance assemblies in operating C-E reactors.
- Similar irradiation programs are in operation for ZIRLO™ fuel rods as discussed in Ref. 71.

E. C-E Fuel Densification Experiments

C-E has conducted several experiments which provided data on the in-reactor densification behavior of various UO_2 fuel types. These include the BRR, EEI, and MZFR densification experiments.

F. BRR Fuel Densification Experiment

The object of this program was to examine the in-pile densification behavior of various fuel types and

microstructures fabricated with and without pore-formers. The non-pore-former fuel types had initial densities of 93% to 94% theoretical with a grain size of less than six microns, with a large fraction of pores less than four microns in diameter. The pore-former fuel types had initial densities of 93% to 95% and were characterized by a combination of large grain size and/or large pore size. Fuel pellets of each experimental type were irradiated in six BRR capsules at linear heat ratings between 2.8 and 4.6 kW/ft for periods of up to 1500 hours. Post-irradiation examination of the BRR results showed significant differences in the densification behavior between pore-former and non-pore-former fuel. The pore-former fuel showed little change in density (high stability) while the non-pore-former fuel densified rapidly. A trend towards increased densification with lower initial density was apparent in the non-pore-former fuel. It was concluded that UO_2 microstructure played a dominant role in the kinetics and extent of in-reactor densification. Consequently, fuel exhibiting the desirable microstructural features to reduce in-reactor densification (i.e., large fraction of the pore volume in the large pore size range) became part of the standard C-E fuel design.

G. C-E/KWU Fuel Densification Experiment (MZFR)

As a follow-on to the C-E experiment in the BRR, a joint C-E/KWU program has been conducted in the German MZFR to evaluate the performance of several

non-densifying fuel types at higher power levels for longer times and to higher burnups.

Sixteen full-length fuel rods each containing a different fuel type were irradiated at powers up to 11 kW/ft for burnups up to 4000 MWd/Mtu. Included in these rods are UO_2 and UO_2-PuO_2 fuels, most of which were fabricated using techniques intended to minimize densification. Six rods employed C-E fabricated UO_2 fuels, five of which included pore-former additives and one fabricated without a pore-former to serve as a referenceable control sample. Eight rods were fabricated using KWU experimental fuel representing a wide range of sintering times and temperatures, initial densities, and enrichments. The remaining two rods were fabricated using UO_2-PuO_2 fuels of two different densities, with and without a pore-former additive. Each of the fuel pellet types and fuel rods was extensively characterized prior to testing to permit comparison with similar post-irradiation measurements.

The results of the post-irradiation examination showed that fuel types fabricated with pore-formers (similar to current production fuel) experienced significantly less in-pile densification compared to those fabricated without pore-formers. The data also support use of a standardized out-of-pile resintering test developed by C-E to characterize expected in-pile densification at the time of fabrication. This simulation test has been

submitted to the NRC and approved for use by C-E in LOCA calculations.

H. EEI Fuel Densification Experiment

The prime objective of the EEI Fuel Irradiation Test Program conducted in the General Electric Test Reactor (GETR) was to isolate and characterize the in-reactor densification behavior of pore-former (or stable) fuel types. C-E and KWU were among 11 participants in the program.

This program entitled C-E to obtain densification data on nine base program fuel pellet types with varying microstructures. An additional four fuel types were fabricated by C-E and KWU. These included C-E fuel types, two with and one without a pore-former additive, and a KWU standard production fuel. The pellets in the program were well characterized prior to irradiation. Four of the fuel types were irradiated in one pressurized (53 atmospheres) capsule. Two of the fuel types were also irradiated in a separate non-pressurized capsule (one atmosphere). Each of the capsules contained thermocouples to continuously monitor capsule power generation during irradiation to assure that the desired operating conditions were maintained. Post-irradiation examination of these test capsules confirmed that UO_2 fuel with specific ranges of microstructural characteristics, such as produced by pore-former additives, are stable with respect to densification. The largest in-reactor density changes

occurred for those types having a combination of the smallest pore size, the largest volume percent of porosity m less than 4 microns in the smallest initial grain size, and the lowest initial density.[66]

I. Halden Program Participation

The experimental facilities and programs of the OECD Halden Reactor Project in Norway represent one of the most advanced efforts in quantifying the effects and interaction of the various design parameters of Zircaloy-clad fuel rods through measurements made in-reactor. C-E has been a member of the project since 1973. C-E reviews the data generated by the project in considerable detail and utilizes the results in various fuel development programs.

The Halden test reactor has unique capability for measuring fuel rod operation during irradiation. This capability has been utilized by C-E with specific experiments to provide information in the following areas:

1. Fuel densification phenomenon, including measurements of the rate of fuel column shortening as a function of the initial fuel density, power level, and fuel fabrication process.

2. Fuel clad mechanical interaction involving studies of the effects of pellet design (shape and density) and operating parameters on cladding deformation.

3. Modeling of fuel rod behavior with emphasis on heat transfer characteristics.

The first three test assemblies sponsored jointly by C-E and KWU contained 24 well-characterized fuel rods. These assemblies included the following range of design and operating parameters:

- Helium fill pressures from 22 to 35 atmospheres.
- Initial fuel densities from 91 to 96% TD.
- Linear heat ratings to 15 kW/ft.
- U_{235} enrichments from 6 to 12%; 9 rods fabricated with mixed-oxide fuel.

The objectives of these tests were to determine the dynamic changes in fuel rod internal pressure, fuel centerline temperature, and fuel stack length during operation as a function of burnup. Two of these assemblies (six test rods each) were discharged from the reactor after receiving a peak burnup of ~24,000 MWd/Mtu. The third rig (12 rods) was irradiated to a peak burnup of approximately 40,000 MWd/Mtu so that fuel swelling and gas release behavior could be evaluated to high burnups. The objectives of a fourth six-rod test assembly were to evaluate the effects of such design variables as pellet-clad gap, fill-gas composition, and linear heat rating (to 15 kW/ft) on heat transfer characteristics. This experiment also provided gap conductance data on UO_2 and mixed-oxide fuel. This test was discharged

from the reactor after reaching a peak burnup of ~4000 MWd/Mtu.

Instrumentation used to measure fuel behavior during irradiation included centerline thermocouples, internal pressure transducers, linear variable differential transformers (LVDTs) for fuel column length changes, and flux monitors for axial and radial power profiles.

Fuel column length change data obtained support data generated by the EEI, BRR, and MZFR experiments and confirm the in-reactor stability of C-E pore-former fuel types. In addition, the internal pressure monitor and centerline thermocouple data have confirmed the adequacy of the C-E thermal performance design models.

In addition to these C-E/KWU assemblies, C-E has designed and irradiated three rods in the Halden high temperature, high pressure loop to simulate PWR coolant temperature and pressure conditions. The purpose of these experiments was to distinguish the effects of pellet configuration on the formation of circumferential ridging and on the elongation of the rods. Each rod contained three pellet types with one type as a standard. This program, in combination with the results of other experiments, gives C-E a firm basis upon which to optimize fuel rod design with respect to dimensional changes, and to improve fuel performance models developed to predict rod dimensional stability.

J. Power Ramp Programs

C-E and KWU participated in the Studsvik and Petten/Pathfinder programs to evaluate fuel rod performance(67) under ramp conditions to power levels not recently attained. These can occur either after refueling or after extended periods of low power operation or during control rod maneuvers. The effects of various fuel rod design variables on power ramp limits were also investigated as a means to further optimize design. The Petten/Pathfinder program which began in 1973 was conducted jointly by C-E and KWU in the Obrigheim PWR reactor and Petten test reactor facilities. One special test assembly has been irradiated each year from 1973 to 1980 in the Obrigheim reactor. Included in this assembly, which is designed to facilitate fuel rod removal and replacement, are well-characterized segmented rods or "rodlets" which are axially connected to form a complete fuel rod. These rodlets were "pre-irradiated" in the Obrigheim reactor for one to four operating cycles, and then separated and irradiated in a test reactor to evaluate performance under ramp conditions. Ninety-nine of these rodlets irradiated in Obrigheim have been discharged and ramped in Petten. An additional 40 of these rodlets have been tested at the R2 reactor at Studsvik. Post-irradiation, hot-cell examination programs form an integral part of both the Petten/Pathfinder and Studsvik experiments to characterize fuel rod behavior, particularly with

respect to dimensional stability and fission product release. These test programs are designed to distinguish between fuel rod power ramps which occur on start-up and those which might occur during reactor power maneuvering operations.

Operating flexibility of a plant requires that the fuel rods maintain integrity during periodic changes in power. Power cycling tests of this type have been jointly conducted by C-E/KWU in Obrigheim and Petten. In the Petten test, a single unpressurized fuel rod was power cycled between 9 kW/ft and 17 kW/ft at a power change rate of about 3 kW/ft/min. The fuel rod successfully completed 400 cycles and achieved a burnup of 8000 MWd/Mtu. Power cycling tests were then conducted in Obrigheim on eight short pressurized and unpressurized fuel rods. The test fuel rods were attached to a control rod drive mechanism and driven from the low power to a high power position on a nominal cycle. Power changes from 50% to 100% at rates of 20% per minute for 880 cycles were included. After successfully completing the experiment, the test rods achieved a peak burnup of 30,000 MWd/Mtu without substantial cladding deformation or fuel rod perforation.

K. Fuel Surveillance Programs

C-E has conducted a number of fuel surveillance programs on fuel in operating plants. Thus far, a total of more than 38 pool-side fuel inspection

programs of varying detail have been performed by C-E (see table 4.2-3). A large number of assemblies have been visually examined, and dimensional measurements have also been obtained on a large number of these assemblies. Fuel bundle disassembly operations have been conducted either to obtain information of particular aspects of performance of interest or as part of test assembly surveillance programs. A listing of these programs and a summary of the results are found in reference 68. The results of the C-E pool-side inspection program have been used to verify fuel assembly operation and provide data in support of design. A pool-side fuel surveillance program was performed for C-E's first System 80 fuel at Palo Verde.

4.2.3.2.11 Temperature Transient Effects Analysis

4.2.3.2.11.1 Waterlogged Fuel. The potential for a fuel rod to become waterlogged during normal operation is discussed in paragraph 4.2.3.2.9. In the event that a fuel rod does become waterlogged at low or zero power, it is possible that a subsequent power increase could cause a buildup of hydrostatic pressure. It is unlikely that the pressure would build up to a level that could cause cladding rupture because a fuel pin with the potential for rupture requires the combination of a very small defect together with a long period of operation at low or zero power.

Table 4.2-3
C-E POOL-SIDE FUEL INSPECTION PROGRAM SUMMARY
(Sheet 1 of 2)

Reactor	Shutdown Date/Cycle	Inspection Program Scope[(a)]
Palisades	Aug 1973/1A	VE, GS, CS
Main Yankee	June 1974/1	VE, S, SRE, CS
	May 1975/1A	VE, S
	Apr 1977/2	VE, SRE
	Feb 1980/4	VE, S, SRE
	Apr 1987/9	VE, UT, SRE
Ft. Calhoun	Feb 1975/1	VE
	Oct 1975/2	VE, CS
	Sep 1977/3	VE
	Oct 1978/4	VE, DM on DOE test bundles
	Jan 1980/5	VE, DM on DOE test bundles
	Sept 1981/6	VE, DM and SRE on DOE test bundles
	Dec 1982/7	VE, DM and SRE on DOE test bundles
St. Lucie-1	Jul 1976/1	VE, SRE
	Mar 1978/1A	VE
Calvert Cliffs-1	Dec 1976/1	VE, SRE on C-E/EPRI test bundles
	Jan 1978/2	VE, SRE on C-E/EPRI test bundles
	Apr 1979/3	VE, DM, SRE on C-E/EPRI test bundles
	Oct 1980/4	VE, DM, SRE on C-E/EPRI test bundles
	Apr 1982/5	VE, SRE on C-E/EPRI and C-E/BG&E test bundles
	Oct 1983/6	VE, DM

a. VE - Visual examination
GS - Gamma-scanning
CS - Crud sampling
S - Sipping
UT - Ultrasonic testing
SRE - Disassembly and single rod examinations
DM - Dimensional measurements

Table 4.2-3
C-E POOL-SIDE FUEL INSPECTION PROGRAM SUMMARY
(Sheet 2 of 2)

Reactor	Shutdown Date/Cycle	Inspection Program Scope[(a)]
Calvert Cliffs-1 (cont.)	Apr 1985/7	VE, DM, SRE on C-E/BG&E test bundles
	Nov 1986/8	VE, DM, UT, SRE on C-E/BG&E test bundles
Calvert Cliffs-2	Apr 1984/5	VE, DM, S
	Apr 1987/7	VE, UT
Millstone-2	Nov 1977/1	VE
	Feb 1982/4	VE
St. Lucie-2	Oct 1987/3	VE, UT
ANO-2	Apr 1981/1	VE, DM, SRE on C-E/EPRI test bundles
	Sep 1982/2	VE, DM
	Sep 1983/3	VE, DM, SRE on C-E/EPRI test bundles
	Mar 1985/4	VE, DM, SRE on C-E/EPRI test bundles
	Jun 1986/5	VE, DM, UT
San Onofre-2	Nov 1984/1	VE, DM
	Apr 1985/2	VE, DM
	Sep 1987/3	VE, UT, GS
San Onofre-3	Sep 1985/1	VE, UT
Palo Verde-1	Oct 1987/1	VE, DM, SRE
	May 1989/2	VE, DM, SRE
Palo Verde-2	Feb 1988/1	VE, DM, UT
	Apr 1990/2	VE
Palo Verde-3	May 1989/1	VE

Tests which have been conducted using intentionally waterlogged fuel pins (capsule drive core at SPERT)[62][69] showed that the resulting failures did eject some fuel material from the rod and greatly deformed the test specimens. However, these test rods were completely sealed, and the transient rates used were several orders of magnitude greater than those allowed in normal operation.

In those instances where waterlogged fuel rods have been observed in commercial reactors, it has not been clear that waterlogging was the cause, and not just the result, of associated cladding failures; and C-E has not observed and is not aware of any case in which material was expelled from waterlogged fuel rods or in which the fuel cladding was significantly deformed in a normal power reactor.

It is therefore concluded that the effect of normal power transients on waterlogged fuel rods is not likely to result in cladding rupture, and even if rupture does occur it will not produce the sort of postulated burst failures that would expel fuel material or damage adjacent fuel rods or fuel assembly structural components.

4.2.3.2.11.2 Intact Fuel. The thermal effects of anticipated operational occurrences on fuel rod integrity are discussed in the following paragraphs.

A. Fuel rod thermal transient effects are basically manifested as the change in internal pressure, the changes in clad thermal gradient and thermal stresses, and the differential thermal expansion between pellets

and clad. These effects are discussed in paragraphs 4.2.3.2.2 and 4.2.3.2.11.

B. Another possible effect of transients would be to cause an axial expansion of the pellet column against a flattened (collapsed) section of the clad. However, the fuel rod design includes specific provisions to prevent clad flattening, and, therefore, such interactions will not occur.

4.2.3.2.12 Energy Release During Fuel Element Burnout

The reactor protective system provides fuel clad protection so that the probability of fuel element burnout during normal operation and anticipated operational occurrences is extremely low. Thus, the potential for fuel element burnout is restricted to faulted conditions. The LOCA is the limiting event since it results in the larger number of fuel rods experiencing burnout; thus, the LOCA analysis, which is very conservative in predicting fuel element burnout, provides an upper limit for evaluating the consequences of burnout. The LOCA analysis explicitly accounts for the additional heat release due to the chemical reaction between the Zircaloy clad and the coolant following fuel element burnout in evaluating the consequences of this accident. LOCA analysis results are discussed in sections 6.3.3 and 15.6.5.

4.2.3.2.13 Energy Release on Rupture of Waterlogged Fuel Elements

A discussion of the potential for waterlogging fuel rods and for subsequent energy release is presented in paragraph 4.2.3.2.9.

4.2.3.2.14 Fuel Rod Behavior Effects from Coolant Flow Blockage

An experimental and analytical program was conducted to determine the effects of fuel assembly coolant flow maldistribution during normal reactor operation. In the experimental phase, velocity and static pressure measurements were made in cold, flowing water in an oversize model of a C-E 14 x 14 fuel assembly in order to determine the three-dimensional flow distributions in the vicinity of several types of flow obstruction. The effects of the distributions on thermal behavior were evaluated, where necessary, with the use of a preliminary version of the TORC thermal and hydraulic code.(63) Subjects investigated included:

A. The assembly inlet flow maldistribution caused by blockage of a core support plate flow hole. Evaluation of the flow recovery data indicated that even the complete blockage of a core support plate flow hole would not produce a W-3 DNBR of less than 1.0, even though the reactor might be operating at a power sufficient to produce a DNBR of 1.3 without the blockage.

B. The flow maldistribution within the assembly caused by complete blockage of one to nine channels. Flow distributions were measured at positions upstream and downstream of a blockage of one to nine channels. The influence of the blockage diminished very rapidly in the upstream direction. Analysis of the data for a single channel blockage indicated that such a blockage would not produce a W-3 DNBR of less than 1.0 downstream of the blockage, even though the reactor might be operating at a power sufficient to produce a DNBR of 1.3 without the blockage.

The results presented above were obtained through flow-testing an oversize model of a standard 14 x 14 fuel assembly. Because of the great similarity in design between the Standard System 80, 16 x 16 assembly, and the earlier 14 x 14 array, these test results also constitute an adequate demonstration of the effects that flow blockage would have on the 16 x 16 assembly. This conclusion is also supported by the fact that the 16 x 16 assembly has been demonstrated to have a greater resistance to axial flow than would occur with the 14 x 14 array. The effect of the higher flow resistance to produce more rapid flow recovery, i.e., more nearly uniform flow, is analogous to the common use of flow resistance devices (screens or perforated plates) to smooth non-uniform velocity profiles in ducts or process equipment.

4.2.3.2.15 Fuel Temperatures

Steady-state fuel temperatures are determined by the FATES computer program. The calculational procedure considers the

effect of linear heat rate, fuel relocation, fuel swelling, densification, thermal expansion, fission gas release, and clad deformations. The model for predicting fuel thermal performance is discussed in detail in references 13, 14, 24, 71 and 72.

Two sets of burnup and axially-dependent linear heat rate distributions are considered in the calculation. One is the hot rod, time averaged, distribution expected to persist during long-term operation, and the other is the envelope of the maximum linear heat rate at each axial location. The long-term distributions are integrated over selected time periods to determine burnup, which is in turn used for the various burnup-dependent behavioral models in the FATES computer program. The envelope accounts for possible variations in the peak linear heat rate at any elevation which may occur for short periods of time, and is used exclusively for fission gas release calculations.

The power history used assumes continuous 100% reactor power from beginning-of-life. Using this history, the highest fuel temperatures occur at beginning-of-life. It has been shown that fuel temperatures for a given power level at any burnup are insensitive to the previous history used to arrive at the given power level.

Fuel thermal performance parameters are calculated for the hot rod. These parameters for any other rod in the core can be obtained by using the axial location in the hot rod, whose local power and burnup correspond to the local power and burnup in the rod being examined. This procedure will yield

conservatively high stored energy in the fuel rod under consideration.

The maximum power density, including the local peaking as affected by anticipated operational occurrences, is discussed in sections 4.3 and 4.4, and chapter 15.

4.2.3.3 Al_2O_3-B_4C Burnable Poison Rod

4.2.3.3.1 Burnable Poison Rod Internal Pressure and Cladding Stress

A poison shim cladding analysis was performed to determine the stress and strain resulting from the various normal, upset, and emergency conditions discussed in paragraph 4.2.1.1. Specific accounting was made for differential pressure, differential thermal expansion, cladding creep, and irradiation-induced swelling of the Al_2O_3-B_4C burnable poison material. Owing to the very low linear heat generation rates in these rods (maximum local is less than 1.5 kW/ft), the stress analysis can be accomplished using conventional strength of materials formulae.

The results of the burnable poison rod analyses confirm that the design criteria of paragraph 4.2.1.3.1, regarding stress, strain, and strain fatigue, are satisfied.

4.2.3.3.2 Potential for Chemical Reaction

A discussion of possible chemical reaction between the poison material and the coolant was presented in paragraph 4.2.1.3.3.3, along with information on chemical compatibility between poison material and cladding. Since the cladding

material is identical to that of the fuel rod (paragraph 4.2.1.3.2), the description of potential chemical reactions between cladding and coolant in paragraph 4.2.3.2.3 is applicable to both fuel and poison rods.

The potential for waterlogging rupture in poison rods is much lower than that in fuel rods because of the smaller thermal and dimensional changes that occur in a poison rod during reactor power increases. Refer to paragraph 4.2.3.2.10 for a discussion of the potential for waterlogging rupture in fuel rods.

4.2.3.4 Control Element Assembly

The Feltmetal® full-strength CEAs are designed for a lifetime of 8-EFPY (i.e., about 5 cycles) based on estimates of neutron absorber burnup and B_4C pellet swelling, allowable plastic strain of the Alloy 625 cladding, and the resultant dimensional clearances of the elements within the fuel assembly guide tubes.

The AIC full-strength CEAs are designed for a lifetime of 6.8×10^{20} n/cm^2 (approximately 11 EFPY) for neutrons with energies greater than 1 MeV, based on 20% filling of the central hole in the AIC slugs. This fast fluence value is a high confidence estimate of the design life since it is shown analytically that clad strain limits are satisfied beyond 40% hole fill even with a 5X multiplier on available AIC creep strength data.

A. Internal Pressure

The value of internal pressure in the control elements is dependent on the following parameters:

1. Initial fill gas pressure

2. Gas temperature

3. Helium generated and released

4. Available volume including B_4C porosity

Of the absorber materials utilized in the CEA design, only the B_4C contributes to the total quantity of gas which must be accommodated within the control element. The helium is produced by the nuclear reaction $n^1 + {}_5B^{10} \rightarrow {}_3Li^7 + {}_2He^4$, and the fraction of the quantity generated which is actually released to the plenum is temperature-dependent and is predicted by the empirical equation discussed in paragraph 4.2.1.4.4, listing A.3.

Temperatures used for release fraction calculations are the maximum predicted to occur during normal operation.

The results of the CEA analyses confirm that the design criteria of paragraph 4.2.1.4, regarding stress, strain, and strain fatigue, are satisfied.

B. Thermal Stability of Absorber Materials

None of the materials selected for the control elements are susceptible to thermally-induced phase changes at reactor operating conditions. Linear thermal expansion, thermal conductivity, and melting points are given in paragraph 4.2.1.4.

C. Irradiation Stability of Absorber Materials

Irradiated properties of the absorber materials are discussed in paragraph 4.2.1.4. Irradiation-induced chemical transmutations are produced in B_4C. Neutron bombardment of B-10 atoms results in the production of lithium and helium. The percent of helium released is given by the expression in paragraph 4.2.1.4.

Irradiation-enhanced swelling characteristics of the absorber materials are given in paragraph 4.2.1.4. Accommodations for swelling of the absorbers have been incorporated in the design of the control elements and include the following measures:

1. All B_4C pellets have rounded edges to promote sliding of the pellets in the cladding due to differential thermal expansion and irradiation-enhanced swelling.
2. The creep strength of the AIC slugs used in the tip sections of AIC full-strength CEAs is substantially lower than the yield strength of the Alloy 625 cladding. Stress due to irradiation induced swelling causes the AIC material to creep into the central hole in the slug instead of causing strain in the cladding.
3. Dimensionally stable Type 304 stainless steel spacers are located at the bottom of all absorber stacks adjacent to the nose cap to minimize strain at the weld joint.

4. A felt metal sleeve containing reduced diameter B_4C pellets is located in the bottom length of the absorber stacks in Feltmetal® full-strength control elements. The felt metal sleeve laterally positions the reduced diameter B_4C pellets uniformly with respect to the clad, and in addition absorbs the differential thermal expansion and irradiation-induced swelling of the B_4C pellets, thereby limiting the amount of induced strain in the clad.

D. Potential for and Consequences of CEA Functional Failure

The probability for a functional failure of the CEA is considered to be very small. This conclusion is based on the conservatism used in the design, the quality control procedures used during manufacturing, operational history of similar designs, and on testing of similar full-size CEA/CEDM combinations under simulated reactor conditions for lengths of travel and numbers of trips greater than that expected to occur during the design life. The consequences of CEA/CEDM functional failure are discussed in chapter 15.

A postulated CEA failure mode is cladding failure. In the event that an element is assumed to partially fill with water under low or zero power conditions, the possibility exists that upon returning to power, the path of the water to the outside could be blocked. The expansion of the entrapped water could cause the

element to swell. In tests, specimens of CEA cladding were filled with a spacer representing the poison material. All but 9% of the remaining volume was filled with water. The sealed assembly was then subjected to a temperature of 650F and an external pressure of 2250 lb/in.^{2} followed by a rapid removal of the external pressure. The resulting diametral increases of the cladding were on the order of 15 to 25 mils and were not sufficient to impair axial motion of the CEA, which has a 0.084 diametral clearance with the fuel assembly guide tubes. This test result, coupled with the low probability of a cladding failure leading to a waterlogged rod, demonstrates that the probability for a CEA functional failure from this cause is low.

Another possible consequence of failed cladding is the release of small quantities of CEA filler materials, and helium and lithium (from the neutron-boron reactions). However, the amounts which would be released are too small to have significant effects on coolant chemistry.

4.2.3.5 CEA Axial Growth Analysis

Analysis has shown that adequate axial clearance exists between the bottom of the CEA finger and the fuel assembly guide tube. This clearance, representative of the limiting design condition, has been calculated on the basis of worst-case dimensional tolerances and considers the relative thermal growth between the fuel assembly and the fully inserted CEA.

4.2.4 TESTING AND INSPECTION PLAN

PVNGS shall visually inspect a limited number of randomly selected (about 10 to 15) discharged fuel assemblies during or following each refueling. The visual inspection shall be conducted with underwater viewing equipment (will include inspection of the four sides of each inspected fuel assembly) and is intended to detect gross problems of structural integrity, gross fuel rod failure, gross bowing, spacer grid strap damage, insufficient fuel rod shoulder gap spacing, or crud deposition. Underwater viewing may be accomplished with an underwater camera or binoculars.

Fuel bundle assembly and control element assembly quality assurance is attained by adherence to Westinghouse procedures during fabrication and shipping. New fuel receipt inspection is performed under the PVNGS QA Program, but is based on Westinghouse inspection guidelines and instructions.

Vendor product certification, process surveillance, inspections, tests, and material check analyses are performed to ensure conformity of all fuel assembly and control element assembly components to the design requirements from material procurement through receiving inspection at the plant site. The following are basic quality assurance measures which are performed:

4.2.4.1 Fuel Assembly

A comprehensive quality control plan is established to ensure that dimensional requirements of the drawings are met. In those cases where a large number of measurements are required

and 100% inspection is impractical, these plans provide a high statistical confidence that these dimensions are within tolerance. Sensitivity and accuracy of all measuring devices are within ±10% of the dimensioned tolerance. The basic quality assurance measures which are performed in addition to dimensional inspections and material verifications are described in the following sections.

4.2.4.1.1 Weld Quality Assurance Measures

The welded joints used in the fuel assembly design are listed below in series of paragraphs which describe the type and function of each weld, and include a brief description of the testing (both destructive and nondestructive) performed to ensure the structural integrity of the joints. The welds are listed from top to bottom in the fuel assembly.

The CEA guide tube joints (between the tube and threaded upper and lower ends) are butt welds between the two Zircaloy subcomponents. The welds are required to be full penetration welds and must not cause violation of dimensional or corrosion resistance standards.

The upper end fitting center guide post to lower cast flow plate joint has a threaded connection which is prevented from unthreading by tack welding the center guide post to the bottom of the lower cast plate using the gas tungsten arc (GTA) process. Each weld is inspected for compliance with a visual standard.

The Zircaloy spacer grid welds at the intersection of perpendicular Zircaloy-4 grid strips are made by the GTA

process. Each intersection is welded top and bottom, and each weld is inspected by comparison with a visual standard.

For the Zircaloy spacer grid to CEA guide tube weld (both components Zircaloy-4), each grid is welded to each guide tube with eight small welds, evenly divided between the upper and lower faces of the grid. Each weld is required to be free of cracks and burn-through and each weld is inspected by comparison to a visual standard. Also, sufficient testing of sample welds is required to establish acceptable corrosion resistance of the weld region. Each guide tube is inspected after welding to show that welding has not affected clearance for CEA motion.

The Inconel top spacer grid is held in place by split rings that are welded directly to each guide tube. Each ring is welded to the guide tube in four locations around its circumference, at the end of the ring away from the grid. A total of 20 welds on each side of the grid (four welds in each of five rings) provides the same number of welds used to attach the standard Zircaloy top grid to the guide tubes. Each weld is required to be free of cracks and burn-through, and each weld is inspected by comparison to a visual standard. Also, sufficient testing of sample welds is required to establish acceptable corrosion resistance of the weld region. Each guide tube is inspected after welding to show that welding has not affected clearance for CEA motion.

The lower spacer grid welds at spacer strip intersections and between spacer and perimeter strips (all components Inconel 625) have the same configuration as for the Zircaloy

and are all inspected for compliance with appropriate visual standards.

The lower spacer grid (Inconel) to Inconel skirt weld is made using the GTA process. Each weld is inspected to ensure compliance with a visual standard.

The Inconel skirt to lower end fitting (304 stainless steel) weld is made using the GTA process and each weld is inspected to ensure compliance with a visual standard.

The lower end fitting is fastened to the Zircaloy guide tubes using threaded connections. The connections are prevented from unthreading by stainless steel locking rings which are welded to the lower end fitting. Each ring is tack welded to the end fitting in four places using the GTA process, and each weld is inspected for compliance with a visual standard.

Reload assemblies may use proprietary, laser welded Guardian™ grids (lower Inconel grids), as well as laser welded spacer grids. Welds are to be free of cracks and burn-through upon inspection.

The inspection requirements and acceptance standards for each of the welds are established on the basis of providing adequate assurance that the connections will perform their required functions.

4.2.4.1.2 Other Quality Assurance Measures

All guide tubes are internally gaged ensuring free passage within the tubes including the reduced diameter buffer region.

Each upper end fitting post to guide tube joint is inspected for compliance with a visual standard.

The spacer grid to fuel rod relationship is carefully examined at each grid location. Each grid cell in the top grid and in the lower Inconel grid is inspected for proper spring preset during fuel assembly fabrication. Grid cells in all other grids are inspected for proper spring preset in accordance with a Westinghouse sampling plan. Every grid cell is checked for tightness prior to installation of the upper end fitting assembly.

The uranium concentration on the exterior surface of the fuel rods is maintained within 10 $dpm/100cm^2$.

Each completed fuel assembly is inspected for cleanliness, wrapped to preserve its cleanliness, and loaded within shipping containers.

Visual inspection of the conveyance vehicle, shipping container, and fuel assembly are performed at the reactor site. Approved procedures are provided for unloading the fuel assemblies. Following unloading, exterior portions of the fuel assembly components are inspected for shipping damage and cleanliness. If damage is detected, the assembly may be repaired onsite or returned to the manufacturing facility for repair. In the event that the repair process were other than one normally used by the manufacturing facility, or that the repaired assembly did not meet the standard requirements for new fuel, the specific process or assembly would be reviewed before the process or assembly would be accepted.

4.2.4.2 Fuel Rod

4.2.4.2.1 Fuel Pellets

During the conversion of source material to ceramic grade uranium dioxide powder, the UO_2 powder is divided into lots blended to form uniform isotopic, chemical, and physical characteristics. Two samples are tested from each powder blend to verify compliance with the specification limits for the blend. Additional finished pellets are tested for the final enrichment certification of the pellets.

Pellets are divided into lots during fabrication with all pellets within the lot being processed under the same conditions as defined per the pellet specification. Representative samples are obtained from each lot for product acceptance tests. Hydrogen content of the finished ground pellets is restricted. The pellets' diameters are inspected and certified to meet the design tolerance requirements at a 95/99 confidence level. All other pellet dimensions meet a 90/90 confidence level. Density requirements of the sintered pellets must meet a 95/95 confidence level. Sample pellets from each pellet lot are prepared for metallographic examination to ensure conformance to microstructural requirements. Surface finish of ground pellets is restricted and meets a 90/90 confidence level. Pellet surfaces are inspected for chips, cracks, and fissures in accordance with approval standards.

4.2.4.2.2 Cladding

Lots are formed from tubing produced from the same ingot, annealed in the same final vacuum annealing charge, and fabricated using the same procedures. Samples of either finished tubing or ingots are selected for chemical analysis to ensure conformance to specified chemical requirements, and to verify tensile properties and hydride orientation. Each finished tube is ultrasonically tested for internal soundness; visually inspected for cleanliness and the absence of acid stains, surface defects, and deformation; and inspected for inside dimension and wall thickness.

4.2.4.2.3 Fuel Rod Assembly

Immediately prior to loading, pellets must be capable of passing approved visual standards. Each fuel pellet stack is weighed to within 0.1% accuracy. The loading process is such that cleanliness and dryness of all internal fuel rod components are maintained until after the final end cap weld is completed. Loading and handling of pellets are carefully controlled to minimize chipping of pellets. The allowable gap between pellets, and the allowable cumulative gaps in a fuel column, are to be within specified limits.

Loaded fuel rods are pressurized with helium to a prescribed pressure as determined for the fuel batch. Impurity content of the fill gas during rod pressurization shall not exceed 0.5% by volume.

The fuel rod end cap-to-fuel rod cladding tube welds are butt welds between the Zircaloy-4 or ZIRLO™ cladding tube and the

Zircaloy-4 end cap machined from bar stock. Quality assurance on the end cap weld is as follows:

A. Radiographic examination or ultrasonic testing of all end cap welds (Batches N and later only) to certify bond length and to detect porosity or undercut.

B. Destructive examination of a sufficient number of weld samples to establish that the maximum allowable percent of unbonded wall thickness and the maximum allowable continuous unbonded region are not exceeded. An alternate process may be specified in lieu of cut samples.

C. Visual examination of all end cap welds to establish freedom from cracks, seams, inclusions, and foreign particles (Note: In Batches A through M, that examination was performed) after final machining of the weld region.

D. Helium leak checking of all end cap welds to establish that no air equivalent leak rate greater than 10^{-8} cm^3/s (STP) is present.

E. Corrosion testing of a sufficient number of samples to establish that weld zones do not exhibit excessive corrosion compared to a visual standard.

All finished fuel rods are visually inspected to ensure a proper surface finish (scratches greater than 0.001 inch in depth, cracks, slivers, and other similar defects are not acceptable).

Each fuel rod is marked to provide a means of identification.

4.2.4.3 Burnable Poison Rod

4.2.4.3.1 Burnable Poison Pellets

B_4C powder is sampled to verify particle size and wt% boron requirements prior to its use in pellet production. Finished pellets are 100% inspected for diameter and must satisfy a 90/90 confidence level on other dimensions. Samples are taken from each of the pellet lots and examined for uniform dispersion of the B_4C in Al_2O_3.

Conformance with density range requirements is demonstrated at a 95/95 confidence level and with B_4C loading requirements at a 90/90 level. Samples are drawn from each lot to verify acceptable impurity levels. Finally, all pellets are inspected for conformance with surface chip and crack standards.

4.2.4.3.2 Cladding

The testing and inspection plan for burnable poison rod cladding is identical to that for fuel rod cladding (paragraph 4.2.4.2.2).

The moisture content of poison pellets prior to loading is limited to values below that which would be required to produce primary hydride penetration of the cladding. Total moisture inventory is comparable to that which has been shown to be acceptable in fuel rods.[57] The fabrication process is such that all steps from component drying through final welding are carefully controlled so as to minimize the possibilities for excessive moisture pickup. Final verification of pellet dryness is made by moisture analysis.

The following procedure is used during fabrication to assure that there are no axial gaps in poison rods.

The operator stacks pellets onto V troughs that are gage marked to be the proper column height. When pellet stacking is completed, all column heights are overchecked by Quality Control. The pellets are subsequently loaded into tubes. After loading, the distance from the end of the tube to the end of the pellet column is checked with a gage.

Loaded poison rods are evacuated and backfilled with helium to a prescribed level. Impurity content of the fill gas must not exceed 0.5%.

End cap weld integrity and corrosion resistance are ensured by a quality control plan identical to that used in fuel rod fabrication (paragraph 4.2.4.2.3).

Each poison rod is marked to provide a means of identification.

4.2.4.4 Control Element Assemblies

The CEAs are subjected to numerous inspections and tests during manufacturing and after installation in the reactor. A general product specification controls the fabrication, inspection, assembly, cleaning, packaging, and shipping of CEAs. All materials are procured to AMS, ASTM, U.S. General Services Administration, military (MIL), or Westinghouse specifications. In addition, various CEA hardware tests have been conducted.

During manufacturing, the following inspections and tests are performed:

A. The loading of each control element is carefully controlled to obtain the proper amounts and types of filler materials for each type of CEA application (e.g., full-strength or part-strength).

B. All end cap welds are liquid penetrant examined and helium leak tested. All full penetration welds, including end cap welds, are radiographed.

C. Each CEA is serialized to distinguish it from the others. See figures 4.2-3 through 4.2-5.

Once fully assembled, the CEAs are checked for proper alignment of the neutron absorber elements using a special fixture. The alignment check ensures that the frictional force that could result from adverse tolerances is below the force which could significantly increase trip time.

In addition to the basic measures discussed above, the manufacturing process includes numerous other quality control steps for ensuring that the individual CEA components satisfy design requirements for material quality, detail dimensions, and process control.

After installation in the reactor, but prior to criticality, each CEA is traversed through its full stroke and tripped. A similar procedure will also be conducted at refueling intervals.

The required 90% insertion SCRAM time for full-strength CEAs is 4.0 seconds under worst case conditions. Verification of

adequacy has been determined by testing in the C-E TF-2 flow test facility. This test facility contained prototypical (System 80) reactor components consisting of fuel assemblies, CEA shroud, control element drive mechanism, and a simulation of surrounding core internal support components. The test conditions simulated the range of temperatures and flow rates predicted for System 80 normal plant operation.

4.2.5 REACTOR INTERFACE REQUIREMENTS

Detailed below are the interface requirements that the reactor places on certain aspects of the BOP, listed by categories. In addition, applicable General Design Criteria (GDC) and Regulatory Guides which Westinghouse utilizes in its design of the reactor are presented. The GDC and Regulatory Guides are listed only to show what Westinghouse considers to be relevant, and are not imposed as interface requirements unless specifically called out as such in a particular interface requirements.

Relevant GDC -	1, 2, 3, 4, 10, 11, 12, 14, 15, 26, 27, 28, 29, 30, 31, 32, 61, 62, 63
Relevant Reg. - Guides	1.13, 1.2, 1.20, 1.25, 1.28, 1.29, 1.31, 1.34, 1.36, 1.37, 1.38, 1.43, 1.44, 1.46, 1.48, 1.50, 1.51, 1.54, 1.60, 1.61, 1.64, 1.65, 1.68, 1.71, 1.74, 1.84, 1.85

A. Power

Not applicable

B. Protection from Natural Phenomena

1. High winds, tornado, tornado missile, and flooding requirements relating to the reactor are in accordance with Criterion 2 of 10CFR50 Appendix A.

2. The spent fuel pool shall be a seismic Category I structure.

3. The load-bearing members of the spent fuel storage racks shall withstand the forces induced by the SSE vertical and horizontal seismic loadings. These forces shall be assumed as acting simultaneously in conjunction with the combined dead weight and live loads, without exceeding minimum material yield stresses as specified by ASTM.

4. The spent fuel storage racks shall be seismic Category I.

C. Protection from Pipe Failure

1. The fuel shall be protected from the effects of pipe whip while in storage.

2. Refer to subsection 5.1.4 for protective measure requirements for the reactor.

3. Spent fuel shall be protected from the effects of pipe rupture.

D. Missiles

1. A removable structure shall be located above the reactor vessel to block any missile that could be generated by a control element drive mechanism.

2. The fuel shall be protected from the effects of missiles while in storage.

E. Separation

1. New Fuel Storage Racks

a. The new fuel storage racks shall be designed such that fuel assemblies will not be inserted in other than prescribed locations.

b. Adequate margin to criticality shall be provided for full rack loadings of fuel assemblies having a mechanical design similar to that described in chapter 4.0 and a maximum, radially averaged, U-235 enrichment up to 4.80 weight percent.

c. The degree of subcriticality provided shall be consistent with the requirements of ANSI Standard N18.2 Section 5.7.4.1.

F. Independence

Not applicable.

G. Thermal Limitations

1. Cooling air shall be provided to the CEDMs at a minimum flow rate of 700 standard ft^3/min per CEDM at a temperature in the range of 80 to 120F.

2. Drains, permanently connected systems, and other features of the spent fuel pool shall be designed so that neither maloperation nor failure can result

in loss of coolant that would uncover the stored fuel.

3. Spent fuel pool cooling shall be capable of removing the decay heat generated from one complete core of spent fuel placed in the pool 7 days after shutdown in addition to one-third of a completed core that has been in the pool 90 days after shutdown.

H. Monitoring

1. Low water level alarms shall be provided for the refueling pool and the spent fuel pool.

2. A system shall be provided to monitor the reactor coolant system for internal loose parts. The system shall have ability to detect a loose part striking the internal surface of reactor coolant system components with an energy level of one-half foot-pound or more. The system shall have alarm and recording capability. The system design shall be suitable for the temperature and humidity environment experienced in the area where the equipment normally operates.

I. Operational/Controls

Not applicable.

J. Inspection and Testing

Inservice inspection shall be performed in accordance with Section XI of the ASME Code.

K. Chemistry/Sampling

Not applicable.

L. Materials

See paragraph 5.1.4.L.3.

M. System/Component Arrangement

Not applicable.

N. Radiological Waste

Not applicable.

O. Overpressure Protection

Not applicable.

P. Related Services

1. For refueling operations, the containment building crane shall have a minimum capacity of 225 tons.

   a. A hoisting speed of 6 inches per minute or less shall be utilized during refueling operations.

   b. A load measuring device shall be provided for use during heavy lifts.

   c. A low inching speed is required during those portions of the lift when close tolerance surfaces are engaging each other.

2. An overhead crane shall be provided in the new fuel storage area to facilitate handling new fuel.

   a. The crane capacity shall be at least 1 ton to accommodate the weight of a fuel assembly.

b. A vertical hoisting speed of 6 feet/minute or less shall be provided.

c. The crane load shall be capable of being limited to prevent the hoist load from exceeding 5000 pounds when handling fuel assemblies.

3. See paragraph 5.1.4.P.3.

Q. Environmental

Not applicable.

4.2.6 CESSAR REACTOR INTERFACE REQUIREMENTS EVALUATION

The CESSAR interface requirements listed in subsection 4.2.5 are met by the PVNGS design as follows:

A. Power

Not applicable

B. Protection from Natural Phenomena

1. Refer to section 3.3 for a discussion of protection for the reactor from high winds, tornadoes, and tornado missiles. Section 3.4 discusses flood protection.

2. The spent fuel pool is located in the fuel building, which is a Seismic Category I structure as described in subsection 9.1.2.

3. The spent fuel storage racks are designed such that the load bearing members will withstand the forces induced by the SSE vertical and horizontal seismic

loadings that are assumed as acting simultaneously on this equipment in conjunction with the combined dead weight and live loads without exceeding minimum material yield stresses as specified by ASTM.

4. The spent fuel storage racks are designed as Seismic Category I.

C. Protection from Pipe Failure

1. The fuel is protected from the effects of pipe whip while in storage by routing all pressurized pipes away from the fuel storage locations.

2. Refer to section 3.6 and subsection 5.1.5 for a discussion of reactor protection from pipe failures.

3. Spent fuel is protected from the effects of pipe rupture while in storage by routing all pressurized pipes away from the spent fuel storage locations as discussed in Section 3.6. Accidental criticality is prevented by assuring that K_{eff} remains less than 1.0 assuming unborated water and by assuring that K_{eff} remains less than or equal to 0.95 taking credit for 900 ppm soluble boron in the water (which is normally at ≥ 2150 ppm). Dilution analysis has shown that the final boron concentration in the spent fuel pool would remain well above the required 900 ppm as a result of the most limiting boron dilution event.

D. Missiles

1. Refer to subsection 3.5.2.

2. There are no credible sources for missile generation that could affect the fuel while in storage since the fuel building is designed to withstand tornado missiles and there are no sources of internally generated missiles.

E. Separation

1. New Fuel Storage Racks

a. The new fuel storage racks are designed such that fuel assemblies can be inserted only in prescribed locations.

b. The new fuel storage racks are designed to provide adequate margin to criticality for full rack loadings of fuel assemblies having a mechanical design similar to that described in chapter 4.0 and a maximum radially averaged U-235 enrichment of 4.80 weight percent.

c. The degree of subcriticality provided will be consistent with the requirements of ANSI Standard N18.2 Section 5.7.4.1.

F. Independence

Not applicable.

G. Thermal Limitations

1. An adequate flow rate of cooling air is provided to the CEDMs to ensure that the CEDMs operating

service design temperature is not exceeded (refer to subsection 9.4.6).

2. Drains, permanently connected systems, and other auxiliary features are designed such that neither their malfunction nor failure would result in loss of pool coolant and expose the stored fuel to the atmosphere.

3. Spent fuel pool cooling is provided as discussed in subsection 9.1.3.

H. Monitoring

1. Low and low-low level alarms (fed from separate instrument loops) are provided for the spent fuel pool and refueling pool. However, only the low level alarm is set to alarm prior to reaching the Technical Specification LCO minimum requirement.

2. Refer to section 7.7.1.1.8 for a description of the loose parts monitoring system provided for PVNGS units.

I. Operational/Controls

Not applicable.

J. Inspection and Testing

Refer to subsection 5.1.5, listing J, for the evaluation of these interface requirements.

K. Chemistry/Sampling

Not applicable.

L. Materials

Refer to subsection 5.1.5, listing L.3, for the evaluation of these interface requirements.

M. System/Component Arrangement

Not applicable.

N. Radiological Waste

Not applicable.

O. Overpressure Protection

Not applicable.

P. Related Services

1. The containment crane has a minimum capacity of 225 tons.

   a. A hoisting speed of 6 inches per minute or less is provided.

   b. The containment crane is provided with a load measuring device.

   c. The containment crane is provided with a low inching speed.

2. A new fuel handling crane is provided.

   a. The new fuel handling crane has a 10-ton capacity.

   b. A vertical hoisting speed of 10 feet per minute, (+ 2 fpm tolerance), is provided. While this is greater than the speed

identified in Section 4.2.5, it has been evaluated to be acceptable.

c. This crane has an adjustable load limiting device that is adjusted to prevent the hoist load from exceeding 5000 pounds when handling fuel assemblies.

3. The fire protection system provided to protect the RCS is discussed in subsection 9.5.1.

Q. Environmental

Not applicable.

4.2.7 REFERENCES

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4.3 NUCLEAR DESIGN

4.3.1 DESIGN BASES

The bases for the nuclear design of the fuel and reactivity control systems for Units 1, 2, and 3 are discussed in the following paragraphs.

4.3.1.1 Excess Reactivity and Fuel Burnup

The excess reactivity provided for each cycle is based on the depletion characteristics of the fuel and burnable poison and the desired burnup for each cycle. The desired burnup is based on an economic analysis of the fuel cost and the projected operating load cycle for PVNGS. The average burnup is chosen to ensure that the peak rod-averaged burnup is within the limits of 60,000 MWd/Mtu (60 MWd/kgU) discussed in References 1 and 2. This design basis, along with the design basis in paragraph 4.3.1.8, satisfies General Design Criterion 10.

4.3.1.2 Core Design Lifetime and Fuel Replacement Program

The core design lifetime and fuel replacement programs are based on refueling intervals of 18 to 24 months with up to one-half of the fuel assemblies replaced at each refueling in the later cycles. Explicit evaluations are performed to assure applicability of all analyses to the previous cycle's final burnup. Explicit evaluations are also performed prior to entering Mode 4 after a refueling outage to verify that the integrated spent fuel pool heat load within the design cooling capability of the auxiliary cooling systems (Refer to

sections 9.1 and 9.2 for these cooling systems design bases and descriptions).

4.3.1.3 Negative Reactivity Feedback

In the power operating range, the net effect of the prompt inherent nuclear feedback characteristics (fuel temperature coefficient, moderator temperature coefficient, and moderator pressure coefficient) tends to compensate for a rapid increase in reactivity. The negative reactivity feedback provided by the design satisfies General Design Criterion 11.

4.3.1.4 Reactivity Coefficients

The values of each coefficient of reactivity are consistent with the design basis for net reactivity feedback (paragraph 4.3.1.3), and with analyses that predict acceptable consequences of postulated accidents and anticipated operational occurrences, where such analyses include the response of the reactor protective system (RPS).

4.3.1.5 Burnable Poison Requirements

The burnable poison reactivity worth provided in the design is sufficient to ensure that the moderator coefficients of reactivity are consistent with the design bases of paragraphs 4.3.1.1 through 4.3.1.4.

4.3.1.6 Stability Criteria

The reactor and the instrumentation and control systems are designed to detect and suppress xenon-induced power distribution oscillations that could, if not suppressed, result in conditions

that exceed the specific acceptable fuel design limits. The design of the reactor and associated systems precludes the possibility of power level oscillations. This basis satisfies General Design Criterion 12.

4.3.1.7 Maximum Controlled Reactivity Insertion Rate

The core, control element assemblies (CEAs), reactor regulating system, and boron charging portion of the chemical and volume control system are designed so that the potential amount and rate of reactivity insertion due to normal operation and postulated reactivity accidents do not result in:

A. Violation of the specified acceptable fuel design limits.

B. Damage to the reactor coolant pressure boundary.

C. Disruption of the core or other reactor internals sufficient to impair the effectiveness of emergency core cooling.

This design basis, along with paragraph 4.3.1.11, satisfies General Design Criteria 25 and 28.

4.3.1.8 Power Distribution Control

The core power distribution is controlled such that, in conjunction with other core operating parameters, the power distribution does not result in violation of the limiting conditions for operation. Limiting conditions for operation and limiting safety system settings are based on the accident analyses described in chapters 6 and 15 such that specified acceptable fuel design limits and other criteria are not exceeded

for accidents. This basis, along with paragraph 4.3.1.1, satisfies General Design Criterion 10.

4.3.1.9 Excess CEA Worth with Stuck Rod Criteria

The amount of reactivity available from insertion of withdrawn CEAs under all power conditions, even when the highest worth CEA fails to insert, will provide for at least 2% excess CEA worth after cooldown to hot zero power, plus any additional shutdown reactivity requirements assumed in the safety analysis. This basis, along with paragraph 4.3.1.10, satisfies General Design Criteria 26 and 27.

4.3.1.10 Chemical Shim Control

The chemical and volume control system (CVCS) (subsection 9.3.4) is used to adjust the dissolved boron concentration in the moderator. After a reactor shutdown, this system is able to compensate for the reactivity changes associated with xenon decay and reactor coolant temperature decreases to ambient temperature, and it provides adequate shutdown margin during the refueling. This system also has the capability of controlling, independently of the CEAs, long-term reactivity changes due to fuel burnup and reactivity changes during xenon transients resulting from changes in reactor load. This design basis, along with paragraph 4.3.1.9, satisfies General Design Criteria 26 and 27.

4.3.1.11 Maximum CEA Speeds

Maximum CEA speeds are consistent with the maximum controlled reactivity insertion rate design basis discussed in paragraph 4.3.1.7. Maximum CEA speeds are also discussed in section 4.2.

4.3.2 DESCRIPTION

The description of the nuclear design for Units 1, 2, and 3 is discussed in the following paragraphs.

4.3.2.1 Nuclear Design Description

This section summarizes the nuclear characteristics of the core and discusses the important design parameters that affect the performance of the core in steady-state and normal transient operation. A summary of typical nuclear design parameters is presented in table 4.3-1. The data is intended to be representative of a reload cycle design.

Table 4.3-1

TYPICAL NUCLEAR DESIGN CHARACTERISTICS

(Sheet 1 of 2)

Item	Value
General Characteristics	
Fuel management	3-batch, Low Leakage CENTRAL ZONE
Core average burnup (MWd/T), 10 ppm soluble boron	18,500
Core average U-235 enrichment (wt%)	4.0
Number of control element assemblies	
Full-strength	76
Part-strength	13
Burnable Poison Rods	
Number	9,500
Material	Er_2O_3
Dissolved Boron	
Dissolved boron content for criticality, ppm (CEAs withdrawn, BOC)	
Cold, 68F	2,400
Hot, zero power, 565F	2,100
Hot, full power, equilibrium Xe	1,700

Table 4.3-1

TYPICAL NUCLEAR DESIGN CHARACTERISTICS

(Sheet 2 of 2)

Item	Value
Dissolved boron content (ppm) for:	
Refueling	
5% subcritical, cold (135F) (all CEAs out)	1,850
5% subcritical, hot (564F) (all CEAs out)	2,200
Boron worth, ppm/%$\Delta\rho$ (BOC/EOC)	
Hot, 594F	140/100
Cold, 68F	85/61
Neutron parameters	
Prompt neutron generation time, ℓ^* (cycle average), microseconds	22.95
Delayed neutron fraction (cycle average)	0.0056

Cycle-specific data are calculated for each unit reload. Bounding design limit values for these and other parameters are discussed in the appropriate sections.

The cycle designs feature fuel enrichment zoning loading schemes in which the assemblies contain rods of different enrichments and Er_2O_3 integrated burnable absorber. In earlier assemblies fuel pins that exhibit tendency to experience peak power are integrated with Er_2O_3 in an effort to hold down assembly power. Fuel pins adjacent to guide tubes and water holes are specifically targeted. These unique systems of fuel enrichment zoning offer lower power peaking as well as improved

long-term control over the local assembly power distribution. A typical fuel loading pattern is shown in figure 4.3-1. Cycle-specific data are identified for each reload. Physical features of the lattice, fuel assemblies, and CEAs are described in section 4.2.

Typical enrichments, core burnup, critical soluble boron concentrations and worths, and delayed neutron fractions and neutron lifetime are shown in table 4.3-1. The soluble boron insertion rates, as discussed in subsection 9.3.4, are sufficient to compensate for the maximum reactivity addition due to xenon burnout and normal plant cooldown.

4.3.2.2 Power Distribution

4.3.2.2.1 General

At all times during operations, it is intended that the power distribution and coolant conditions be controlled so that the peak linear heat rate and the minimum departure from nucleate boiling ratio (DNBR) are maintained within operating limits supported by the safety analyses (chapters 6 and 15) with due regard for the correlations between measured quantities, the power distribution, and uncertainties in the determination of power distribution.

Methods of controlling the power distribution include the use of full- or part-strength CEAs to alter the axial power distribution; decreasing CEA insertion by boration, thereby improving the radial power distribution; and correcting off-optimum conditions which cause margin degradations (e.g., CEA misoperation).

The Core Operating Limit Supervisory System (COLSS) will indicate continuously to the operator how far the core is from the operating limits and give an audible alarm should an operating limit be exceeded. Such a condition signifies a reduction in the capability of the plant to withstand an anticipated transient, but does not necessarily imply a violation of fuel design limits. If the margin to fuel design limits continues to decrease, the RPS initiates a trip to assure that the specified acceptable fuel design conditions are not exceeded.

The COLSS, described in section 7.7 and reference 3, continually generates an assessment of the margin to linear heat rate and DNBR operating limits. The data required for these assessments include measured in-core neutron flux data, CEA positions, and coolant inlet temperature, pressure, and flow. In the event of an alarm indicating that an operating limit has been exceeded, power must be reduced unless the alarm can be cleared by improving either the power distribution or another process parameter. The validity of the COLSS calculations is verified periodically as discussed in the Technical Specifications. In addition to the monitoring performed by COLSS, the core protection calculator system (CPCS, section 7.2) continually infers the core power distribution and DNBR by processing reactor coolant data, signals from excore neutron flux detectors, each containing three axially stacked elements, and input from redundant reed switch assemblies to indicate CEA position. In the event the power distributions or other parameters are perturbed as the result of an anticipated operational occurrence that would

violate fuel design limits, the high local power density or low DNBR algorithm in the CPCS will initiate a reactor trip.

4.3.2.2.2 Nuclear Design Limits on the Power Distribution

The design limits on the power distribution stated here were employed during the design process, both as design input and as initial conditions for accident analyses described in chapters 6 and 15. However, for the monitoring system, it is the final operating limit determination that is used to assure that the consequences of an anticipated operational occurrence or postulated accident will not be any more severe than the consequences shown in chapters 6 and 15. The initial conditions used in this operating limit determination are actually stated in terms of peak linear heat generation rate and required power margin for minimum DNBR.

The design limits on power distribution are as follows:

A. The limiting three-dimensional heat flux peaking factor, F^nq, was established for full power conditions at 2.28 and 2.35 for first and equilibrium cycles, respectively. The lower value for the first cycle reflects the presence of burnable poison shims in the fuel lattice and a corresponding reduction in the number of fuel rods. F^nq is defined in paragraph 4.4.2.2.2.1, listing C, and is termed the nuclear power factor or the total nuclear peaking factor.

B. The thermal margin to a minimum DNBR of the SAFDL (using the CE-1 CHF correlation as discussed in paragraphs 4.4.2.2 and 4.4.4.1, and statistical

treatment of the core inlet flow distribution as discussed in paragraph 4.4.2.2), which is available to accommodate anticipated operational occurrences, is a function of several parameters, including:

1. The coolant conditions.
2. The axial power distribution.
3. The axially integrated radial peaking factor, $F^n r$; where $F^n r$ is the rod radial nuclear factor or the rod radial peaking factor and is defined in paragraph 4.4.2.2.2.1, listing A (referred to as rod radial power factor in that section).

The coolant conditions assumed in the safety analyses, $F^n r$, a cycle dependent radial design limit, and the set of axial shapes displayed in figure 4.4-4 constitute a set of limiting combinations of parameters for full power operation. Other combinations giving acceptable accident analysis consequences are equally acceptable. Implementation of these limits in the Technical Specification is via a power operating limit based on DNBR which maintains an appropriate amount of thermal margin to the DNBR limit. It will be shown in the following paragraphs that operation within these design limits is achievable.

4.3.2.2.3 Expected Power Distributions

The planar radial power distributions and unrodded core average axial power distributions are calculated for every reload cycle. These calculations identify conditions expected at full power for various times in the fuel cycle. It is expected that the normal operation of the reactor will be with limited CEA

insertion so that these power distributions represent the expected power distribution during most of the cycle. The uncertainty associated with these calculated power distributions is discussed in paragraph 4.3.3.1.2.2.3.

The capability of the core to follow a load transient without exceeding power distribution limitations depends on the margin to operating limits compared to the margin required for base loaded, unrodded operation.

The radial and axial power distributions and estimates of $F^{n}q$ and $F^{n}r$ are obtained from either 3D ROCS/MC, 3D SIMULATE-3, or 2D ROCS/MC with HERMITE.

The detailed radial power distribution within any assembly is a function of the location of that assembly within the core as well as the time in life, CEA insertion, etc. The normalized assembly power distribution used for the sample DNB calculation discussed in paragraph 4.4.2.2 is shown on figure 4.3-2. The accuracy of calculations of the power distribution within a fuel assembly is discussed in paragraph 4.3.3.1.2.

4.3.2.2.4 Allowances and Uncertainties on Power Distributions

In comparing the expected power distributions and implied peak linear heat generation rate (PLHGR) produced by analysis with the design limits stated in paragraph 4.3.2.2.2, consideration must be given to the uncertainty and allowances associated with on-line monitoring by COLSS, and those associated with calculational procedures.

4.3.2.2.5 Comparisons Between Limiting and Expected Power Distributions

As was discussed in paragraph 4.3.2.2.3, the maximum calculated $F^n q$ augmented by uncertainty factors provides an upper limit on $F^n q$. Additionally, the calculations described in paragraph 4.3.2.2.3 show that, with proper use of the part-strength CEAs, no appreciable increase in the peak linear heat rate occurs during these maneuvering transients. In the event that the part-strength CEAs were not moved properly, the power distribution could have become unacceptable. In this case, the monitoring system would indicate if insufficient margin to operating limits has been reached, and that action has to be taken to improve the core power distribution, to improve the coolant conditions, or to reduce core power.

Allowing for uncertainty, the maximum expected unrodded $F^n r$ that occurs at full power is typically 1.72. Again, as demonstrated by the calculations of the power distributions expected to occur during maneuvering transients, no appreciable loss in thermal margin is expected to occur during these transients.

4.3.2.3 Reactivity Coefficients

Reactivity coefficients relate changes in core reactivity to variations in fuel or moderator conditions. Subsection 4.3.3 presents comparisons of calculated and measured moderator temperature coefficients and power coefficients for various operating reactors. The good agreement shown in that subsection provides confidence that the data calculated for the current reload cycles adequately characterize the current PVNGS

reactors. Chapters 6 and 15 provide the bounding values used in the safety analyses. In these chapters each accident analysis applies suitable conservation uncertainties, as discussed in paragraph 4.3.3.1.2 and other conservatism to the calculated values. Therefore, the values used in the safety analyses may fall outside the ranges (in conservative direction) of the data presented in this section.

The calculational methods used to compute reactivity coefficients are discussed in paragraph 4.3.3.1.1. All data discussed in subsequent paragraphs were calculated with two-dimensional and three-dimensional, quarter-core nuclear models. Spatial distributions of materials and flux weighting are explicitly performed for the particular conditions at which the reactivity coefficients are calculated. The adequacy of this method is discussed in paragraph 4.3.3.1.2.

4.3.2.3.1 Fuel Temperature Coefficient

The fuel temperature coefficient is the change in reactivity per unit change in fuel temperature. A change in fuel temperature affects the reaction rates in both the thermal and epithermal neutron energy regimes. Epithermally, the principal contributor to the change in reaction rate with fuel temperature is the Doppler effect, arising from the increase in absorption widths of the resonances with an increase in fuel temperature. The ensuing increase in absorption rate with fuel temperature causes a negative fuel temperature coefficient. In the thermal energy regime, a change in reaction rate with fuel temperature arises from the effect of temperature-dependent scattering properties of the fuel matrix on the thermal neutron

spectrum. In typical PWR fuels containing strong resonance absorbers such as U-238 and Pu-240, the magnitude of the component of the fuel temperature coefficient arising from the Doppler effect is more than a factor of 10 larger than the magnitude of the thermal energy component.

Figure 4.3-3 shows a typical dependence of the calculated fuel temperature coefficient on the fuel temperature, both at the beginning and the end of cycle.

4.3.2.3.2 Moderator Temperature Coefficient

The moderator temperature coefficient relates changes in reactivity to uniform changes in moderator temperature, including the effects of moderator density changes with changes in moderator temperature. Typically, an increase in the moderator temperature causes a decrease in the core moderator density, and therefore, less thermalization, which reduces the core reactivity. However, when soluble boron is present in the moderator, a reduction in moderator density causes a reduction in the content of soluble boron in the core, thus producing a positive contribution to the moderator temperature coefficient. To limit the dissolved boron concentration, burnable poison rods (shims) are provided in the form of cylindrical pellets of integrated $U0_2$ and Er_20_3 particles. A typical number of shims is given in table 4.3-1. Cycle-specific data are identified for each reload.

The moderator temperature coefficients for various core conditions at the beginning and end of each cycle are calculated for each reload cycle. The moderator temperature coefficients are more negative at end-of-cycle because the

soluble boron in the coolant is reduced. The buildup of equilibrium xenon produces a net negative change in the moderator temperature coefficient, due mainly to the accompanying reduction in critical soluble boron. The changing fuel isotopic concentrations and the changing neutron spectrum during the fuel cycle depletion also contribute a small negative component to the moderator temperature coefficient.

The bounds of the allowed MTC are identified in each unit's Core Operating Limits Report (COLR).

4.3.2.3.3 Moderator Density Coefficient

The moderator density coefficient is the change in reactivity per unit change in the average core moderator density at constant moderator temperature. A positive moderator density coefficient translates into a negative contribution to the total moderator temperature coefficient, which is defined in paragraph 4.3.2.3.2. The density coefficient is always positive in the operating range, although the magnitude decreases as the soluble boron level in the core is increased. The density coefficients explicitly used in the accident analyses are based upon core conditions with the most limiting temperature coefficients allowed by the technical specification.

4.3.2.3.4 Moderator Nuclear Temperature Coefficient

The moderator nuclear temperature coefficient is the change in reactivity per unit change in core average moderator temperature, at constant moderator density. The source of this reactivity dependence is the variation of the spectral effects

associated with the change in thermal scattering properties of water molecules as the internal energy, represented by the bulk water temperature, is changed. The magnitude of the moderator nuclear temperature coefficient is equal to the difference between the moderator temperature coefficient, defined in paragraph 4.3.2.3.2, and the moderator density coefficient, defined in paragraph 4.3.2.3.3.

4.3.2.3.5 Moderator Pressure Coefficient

The moderator pressure coefficient is the change in reactivity per unit change in reactor coolant system pressure. Since an increase in pressure, at constant moderator temperature, increases the water density, the pressure coefficient is merely the density coefficient expressed in a different form.

4.3.2.3.6 Moderator Void Coefficient

The anticipated occurrence of small amounts of local subcooled boiling in the reactor during full power operation results in a predicted core average steam (void) volume fraction substantially less than 1%. Changes in the moderator void fraction produce reactivity changes that are quantified by the void coefficient of reactivity. An increase in voids decreases core reactivity, but the presence of soluble boron tends to add a positive contribution to the coefficient.

4.3.2.3.7 Power Coefficient

The power coefficient is the change in reactivity per unit change in core power level. All previously described coefficients contribute to the power coefficient, but only the

moderator temperature coefficient and the fuel temperature coefficient contributions are significant. The contributions of the pressure and void coefficients are negligible, because the magnitudes of these coefficients and the changes in pressure and void fraction per unit change in power level are small. The contribution of moderator density change is included in the moderator temperature coefficient contribution. In order to determine the change in reactivity with power, it is necessary to know the changes in the average moderator and effective fuel temperature with power. The average moderator (coolant) temperature is controlled to be a linear function of power.

The core average linear heat rate is also linear with power. The average effective fuel temperature dependence on the core average linear heat rate is calculated from the following semi-empirical relation:

$$T_f = TT_{MOD} + (\sum_{i=o}^{2} B_i * M^i) * P + (\sum_{j=o}^{3} C_j * M^j) * p^2 \qquad (1)$$

T_{MOD} is the average moderator temperature (°F), M is the exposure in MWd/T, P is the linear heat generation rate in the fuel in kW/ft, and T_f is the average effective fuel temperature (°F). The coefficients B_i and C_j are determined from least squares fitting of the fuel temperature generated by FATES. For a System 80 fuel pin, the following values apply:

$B_o = 146.526$

$B_1 = 0.8841 * 10^{-3}$

$B_2 = -0.2052 * 10^{-6}$

$C_o = -2.0355$

$C_1 = -0.5121 * 10^{-3}$

$C_2 = 0.5043 * 10^{-7}$

$C_3 = -0.1071 * 10^{-11}$

The basis for this relation is discussed in paragraph 4.3.3.1.2.2.1.

The total power coefficient at a given core power can be determined by evaluation, for the conditions associated with the given power level, of the following expression:

$$\frac{d\rho}{dp} = \frac{\partial\rho}{\partial T_f} * \frac{\partial T_f}{\partial p} + \frac{\partial\rho}{\partial T_m} * \frac{\partial T_m}{\partial p} \qquad (2)$$

The first term of equation (2) provides the fuel temperature contribution to the power coefficient, which is shown as a function of power in figure 4.3-4.

The first factor of the first term is the fuel temperature coefficient of reactivity discussed paragraph 4.3.2.3.1. A typical example of this dependence is shown in figure 4.3-3.

The second factor is obtained by calculating the derivative of equation (1).

$$\frac{\partial T_f}{\partial p} = \left(\sum_{i=o}^{2} B_i * M^i\right) + 2\left(\sum_{j=o}^{3} C_j * M^j\right) * P \qquad (3)$$

The second term in equation (2) provides the moderator contribution to the power coefficient. The first factor of this term, the moderator temperature coefficient, is discussed in paragraph 4.3.2.3.2. The second factor is a constant since the moderator temperature is controlled to be a linear function of power.

Since the factors $\partial p/\partial T_f$ and $\partial p/\partial T_m$ are functions of one or more independent variables, e.g., burnup, temperature, soluble boron

content, xenon worth, and CEA insertion, the total power coefficient, $d\rho/dp$, also depends on these variables.

The power coefficient tends to become more negative with burnup because the fuel and moderator temperature coefficients become more negative. The insertion of the CEAs, while maintaining constant power, results in a more negative power coefficient, because the soluble boron level is reduced and because of the spectral effects of the CEAs.

4.3.2.4 Control Requirements

There are three basic types of control requirements that influence the design of this reactor:

A. Reactivity control so that the reactor can be operated in the unrodded critical, full power mode for the design cycle length.

B. Power level and power distribution control so that (a) the reactor power may be safely varied from full-rated power to cold shutdown, and (b) the power distribution at any given power level is controlled within acceptable limits.

C. Shutdown reactivity control sufficient to mitigate the effects of postulated accidents.

Reactivity control is provided by several different means. The amount and enrichment of the fuel and burnable poison shims are design variables that determine the initial and end-of-cycle reactivity for an unrodded, unborated condition. Soluble boron and CEA poisons are flexible means of controlling long-term and short-term reactivity changes, respectively.

The following paragraphs discuss the reactivity balances associated with each type of control requirement.

4.3.2.4.1 Reactivity Control at BOC and EOC

Excess positive reactivity is available to compensate for burnup and fission product poisoning. Typical soluble boron concentrations required for criticality at various core conditions are shown in table 4.3-1. This boron is used to compensate for slow reactivity changes such as those due to burnup, changes in xenon content, etc. At EOC, the reactivity worth of the residual poison is less than 1%, and the soluble boron concentration is near zero. The reactor is to be operated in essentially an unrodded condition at power. The CEA insertion at power is limited by the power-dependent insertion limit (PDIL) for short-term reactivity changes.

4.3.2.4.2 Power Level and Power Distribution Control

The regulating CEA groups may be used to compensate for changes in reactivity associated with routine power level changes. In addition, regulating CEAs may be used to compensate for minor variations in moderator temperature and boron concentrations during operation at power, and to dampen axial xenon oscillations. The reactivity worths of various CEA control groups are calculated and measured for each cycle. Soluble boron is used to maintain shutdown reactivity at cold zero power conditions. The soluble boron can also be used to compensate for changes in reactivity due to power level changes and minor changes in reactivity which might occur during normal reactor operation. Thirteen part-strength CEAs are provided in

the design to help control the core power distribution. This function includes the suppression of xenon-induced axial power oscillations.

4.3.2.4.3 Shutdown Reactivity Control

The reactivity worth requirements of the full complement of CEAs are primarily determined by the power defect, the excess CEA worth with the stuck rod criteria discussed in paragraph 4.3.1.9. Table 4.3-2 shows typical reactivity component allowances that define the total reactivity allowance and may vary from cycle to cycle. Each allowance component is further discussed below. No CEA allowance is provided for xenon reactivity effects, e.g., Table 4.3-2

TABLE 4.3-2

TYPICAL CEA REACTIVITY ALLOWANCES (%$\Delta\rho$)

Fuel temperature variation	1.04
Moderator temperature variation	3.08
Moderator voids	0.1
CEA bite	0.3
Part-strength CEA effects	0.0
Cooldown to minimum temperature (SLB accident analysis)	3.79
Total reactivity allowance	8.31

undershoot, since these effects are controlled with soluble boron rather than with CEAs.

The worth of all CEAs except the most reactive, which is assumed stuck in the fully withdrawn position, provides more shutdown capability than required by the total reactivity allowance shown in table 4.3-2. This margin is calculated for the end of each reload cycle. The margin is more than sufficient to compensate for calculated uncertainties in the nominal design allowances and in the CEA reactivity worth. Thus, the shutdown reactivity control provided in this design is sufficient at all times in the cycle.

4.3.2.4.3.1 Fuel Temperature Variation. The increase in reactivity that occurs when the fuel temperature decreases from the full power value to the zero power value is due primarily to the Doppler effect in U-238. The CEA reactivity allowance for fuel temperature variations shown in table 4.3-2 is a conservative allowance. Measurements of first cycle power coefficients at Omaha, Calvert Cliffs, and Millstone-2 lead to a power defect of 1.2% $\Delta\rho$. The slight increase in power defect with exposure due to the presence of plutonium isotopes is offset by the reduction in the fuel temperature resulting from fuel swelling and clad creep-down.

4.3.2.4.3.2 Moderator Temperature Variation. The moderator temperature variation allowance is large enough to compensate for any reactivity increase that may occur when the moderator temperature decreases from the full power value to the zero power (hot standby) value. This reactivity increase, which is primarily due to the negative moderator temperature coefficient, is largest at the end-of-cycle when the soluble

boron concentration is near zero and the moderator coefficient is strongly negative. At beginning-of-cycle, when the moderator temperature coefficient is less negative, the reactivity change is smaller.

The CEA reactivity allowance for moderator temperature variation given in table 4.3-2 is actually the sum of three allowances. The first, and most important, is the allowance for the moderator temperature coefficient effect. The second is an allowance for the reduction in CEA worth resulting from the shorter neutron diffusion length at the zero power moderator density relative to the full power moderator density. This allowance is necessary because the CEA worths were calculated at full power. The third allowance is intended to cover the reactivity effects associated with the greatest expected axial flux redistribution, resulting from the difference in moderator temperature profile between full and zero power, and the asymmetric axial isotopic distribution at EOC.

4.3.2.4.3.3 Moderator Voids. Reducing the power level from full power to zero power causes a negligible increase in reactivity resulting from the collapsing of steam bubbles caused by local boiling at full power. The amount of void in the core is small and is estimated to be substantially less than 1% at full power. As with the moderator temperature effect, the maximum increase in reactivity from full to zero power occurs at end-of-cycle, when the least amount of dissolved boron is present. The reactivity effect is small, and allowance for this effect is shown in table 4.3-2.

4.3.2.4.3.4 Control Element Assembly Bite. The CEA bite is the amount of reactivity worth in CEAs that can be inserted in the core at full power to initiate ramp changes in reactivity associated with load changes, and to compensate for minor variations in moderator temperature, boron concentration, xenon concentration, part-strength CEA (PSCEA) movement, and power level. The reactivity allowance for this effect is shown in table 4.3-2.

4.3.2.4.3.5 Part-Strength CEA Effects. No reactivity allowance is provided or required for the PSCEAs because of the moderate negative reactivity provided by Alloy 625 used as the neutron poison as described in paragraph 4.2.2.4. During normal operation, PSCEAs are not inserted more than the PSCEA PDIL of 50% of active core height. On reactor trip, the PSCEAs insert completely.

4.3.2.4.3.6 Accident Analysis Allowance. The allowance shown in table 4.3-2 for accident analysis is consistent with that assumed under various postulated accident conditions addressed in chapter 15, which result in predicted acceptable consequences.

4.3.2.5 Control Element Assembly Patterns and Reactivity Worths

The locations of all CEAs are shown in figure 4.2-10. The FSCEAs designated as regulating control rods are divided into five groups; the shutdown CEAs are divided into two groups; and the PSCEAs are divided into two groups. These groups are

identified in figure 4.3-6. All CEAs in a group are withdrawn or inserted quasi-simultaneously. Shutdown groups are inserted after the regulating groups are inserted, and are withdrawn before the regulating groups are withdrawn. The reactivity worths of these sequentially inserted CEA groups are calculated for the beginning and end of each cycle where the maximum rod planar radial peaking factors (F_{xy}) for these configurations occur. The values of F_{xy} for these times are also calculated.

It is expected that the core will be essentially unrodded during full power steady-state operation, except for limited insertion of the first regulating group in order to compensate for minor variations in moderator temperature and boron concentration. For operation with substantial CEA insertion, the relationship between power level and the maximum permitted CEA insertion is identified in each unit's Core Operating Limits Report (COLR). The COLR limits also identify the regulating group insertion order (5-4-3-2-1) and the 40% fixed overlap between successive regulating groups. It is noted here that reduced CEA overlap is permitted. However, the order of insertion and withdrawal must be maintained. Compliance with the power-dependent insertion limits throughout the cycle insures that adequate shutdown margin is maintained and that the core conditions are no more severe than the initial conditions assumed in the accident analyses described in chapter 15.

Reactivity insertion rates for the safety analysis of the core are presented in chapter 15. Please refer to UFSAR Chapter 15 for a description of CEA worth for CEA ejections, CEA withdrawals, and CEA drops.

The typical reactivity insertion during a reactor scram is discussed in chapter 15. This reactivity insertion is computed by the HERMITE code at various scram CEA positions, and it is used for all accidents which are terminated by a scram, unless otherwise indicated. The reactivity insertion is conservative since only the minimum shutdown worth is assumed to be available at hot full power. The scram reactivity insertion for the loss of flow is implicit in the kinetic axial analysis.

4.3.2.6 Criticality of Reactor During Refueling

The Technical Specifications LCO for boron concentration requirements during refueling ensure that the k_{eff} of the core during refueling does not exceed 0.95. Typical soluble boron concentrations during refueling are shown in table 4.3-1.

4.3.2.7 Stability

4.3.2.7.1 General

Pressurized water reactors (PWRs) with negative overall power coefficients are inherently stable with respect to power oscillations. Therefore, this discussion will be limited to xenon-induced power distribution oscillations. Xenon-induced oscillations occur as a result of rapid perturbations to the power distribution which cause the xenon and iodine distributions to be out of phase with the perturbed power distribution. This results in a shift in the iodine and xenon distribution that causes the power distribution to change in an opposite direction from the initial perturbation, and thus an oscillatory condition is established. The magnitude of the power distribution oscillation can either increase or decrease

with time. Thus, the core can be considered to be either unstable or stable with respect to these oscillations. Discussed below are the methods of analyzing the stability of the core with respect to xenon oscillations. The tendency of certain types of oscillations to increase or to decrease is calculated, and the method of controlling unstable oscillations is presented.

4.3.2.7.2 Method of Analysis

Xenon oscillations may be analyzed by two methods. The first method consists of an explicit analysis of the spatial flux distribution accounting for the space-time solution of the xenon concentrations. Such a method is useful for testing various control strategies and evaluating transitional effects (such as power maneuvers). The second method consists of modal perturbation theory analysis, which is useful for the evaluation of the sensitivity of the stability to changes in the reactor design characteristics, and for the determination of the degree of stability for a particular oscillatory mode.

The stability of a reactor can be characterized by a stability index or a damping factor, which is defined as the natural exponent which describes the growing or decaying amplitude of the oscillation. A xenon oscillation may be described by the following equation.

$$\phi(\bar{r},t) = \phi_o(\bar{r}) + \Delta\phi_o(\bar{r})\, e^{bt} \sin(\omega t + \delta)$$

where

$\phi(\bar{r},t)$ is the space-time solution of the neutron flux

$\phi_o(\bar{r})$ is the initial fundamental flux

$\Delta\phi_o(\bar{r})$ is the perturbed flux mode

b is the stability index

ω is the frequency of the oscillation

δ is a phase shift

Modal analysis consists of an explicit solution of the stability index b using known fundamental and perturbed flux distributions. A positive stability index b indicates an unstable core, and a negative value indicates stability for the oscillatory mode being investigated. The stability index is generally expressed in units of inverse hours, so that a value of -0.01/h would mean that the amplitude of each subsequent oscillation cycle decreases by about 25% (for a period of about 30 hours for each cycle).

Xenon oscillation modes in PWRs can be classified into three general types: radial, azimuthal, and axial. To analyze the stability for each oscillation mode, only the first overtone needs to be considered since higher harmonic modes decay more rapidly than the first overtone. Furthermore, since the first overtone of a radial oscillation decays more rapidly than the first overtone of an azimuthal oscillation, only the latter of these two modes will be considered in detail.

4.3.2.7.3 Expected Stability Indices

4.3.2.7.3.1 Radial Stability. A radial xenon oscillation consists of a power shift inward and outward from the center of the core to the periphery. This oscillatory mode is generally more stable than an azimuthal mode. This effect is illustrated in figure 4.3-9, which shows that for a bare cylinder, the radial mode is more stable than the azimuthal mode.

4.3.2.7.3.2 Azimuthal Stability. An azimuthal oscillation consists of an X-Y power shift from one side of the reactor to the other. Modal analysis for this type of oscillation is performed for a range of expected reactor operating conditions.

The expected variation of the azimuthal oscillation stability index during the first cycle is shown in figure 4.3-10. These results are obtained from analyses which consider the spatial flux shape changes during the cycle, the changes in the moderator and Doppler coefficient during the cycle, and the change in xenon and iodine fission yield due to plutonium buildup during the cycle. As is shown on the figure, the expected stability index is no greater than $-0.04h^{-1}$ at any time during the cycle for the expected mode of reactor operation. Comparison of the predicted stability index with those actually measured on operating cores, as discussed in paragraph 4.3.3.2.3, provides a high confidence level in the prediction of azimuthal stability. Measurements of xenon spatial stability in large cores have been made(4) which provide confidence in the methods that are used to predict the azimuthal stability of this core.

4.3.2.7.3.3 Axial Stability. An axial xenon oscillation consists of a power shift toward the top and bottom of the reactor core. This type of oscillation may be unstable during the first cycle. Table 4.3-3 shows the calculated variation of the axial stability index during the first cycle. It is anticipated that control action with part-strength rods and/or full-strength rods may be required to limit the magnitude of the oscillation. As discussed in paragraph 4.3.2.2, the axial power distribution is monitored by COLSS and the RPS. Based on the COLSS measurement of the axial power distribution, the operator may move either the full-strength or the part-strength CEAs so as to control any axial oscillations.

Table 4.3-3

TYPICAL VARIATION OF THE AXIAL STABILITY INDEX DURING THE FIRST CYCLE[a] (h^{-1})

Power Level (% of Full Power	BOC	EOC
100	-.006	+.115

a. Equilibrium xenon conditions

4.3.2.7.4 Control of Axial Instabilities

The control of axial oscillations during a power maneuver is accomplished through the use of full-strength and/or part-strength control element assemblies (CEAs). CEAs are used throughout these maneuvers to limit the change in the power distribution. The difference between an uncontrolled and a controlled xenon oscillation is illustrated in figure 4.3-11. It was assumed in the calculation of the controlled oscillation

that the CEAs were moved in such a way as to preserve the initial axial shape in the core prior to the initiating perturbation. The calculations were performed at the end of the first cycle, which corresponds to the expected least stable condition for axial xenon oscillations.

4.3.2.7.5 Summary of Special Features Required by Xenon Instability

The RPS described in subsection 7.2.2 is designed to prevent exceeding acceptable fuel design limits and to limit the consequences of postulated accidents. In addition, a means is provided to assure that under all allowed operating modes, the state of the reactor is confined to conditions not more severe than the initial conditions assumed in the design and analysis of the protective system.

Since the reactor is predicted to be stable with respect to radial and azimuthal xenon oscillations, no special protective system features are needed to accommodate radial or azimuthal mode oscillations. Nevertheless, a maximum quadrant tilt is prescribed in the Technical Specifications along with prescribed operating restrictions in the event that the tilt is exceeded. The azimuthal power tilt is determined by COLSS and included in the COLSS determination of core margin. The azimuthal power tilt limit is accounted for in the RPS.

4.3.2.7.5.1 Features Provided for Azimuthal Xenon Effects

A. Administrative limits on azimuthal power tilt.

B. Monitoring and indicating the azimuthal power tilt in COLSS as well as accounting for this tilt in the COLSS determination of core margin.

C. Accounting for azimuthal power tilt limit in the RPS.

4.3.2.7.5.2 Features Provided for Axial Xenon Effects and Power Distribution Effect and Control

A. PSCEAs or regulating CEAs for control of the axial power distribution, if required.

B. Monitoring and accounting for changes in the axial power distribution in COLSS.

C. Monitoring and accounting for the axial power distribution in the RPS.

4.3.2.8 Vessel Irradiation

The design of reactor internals and of the water annulus is such that the vessel fluence greater than 1 MeV is estimated to be less than 3.29E+19 neutrons per square centimeter for a 40-year lifetime. This estimate is confirmed periodically during plant lifetime by a material surveillance program.

4.3.3 ANALYTICAL METHODS

4.3.3.1 Reactivity and Power Distribution

4.3.3.1.1 Method of Analysis

The nuclear design analysis of low enrichment PWR cores is based on either of the multigroup two-dimensional transport codes, DIT or CASMO-4 which provide cross-sections appropriately averaged over a few broad energy groups, for the whole assembly or individual cells and few-group one, two, and three dimensional diffusion theory calculations of integral and differential reactivity effects and power distributions. Comparisons between calculated and measured data that validate the design procedures are presented in paragraph 4.3.3.1.2. As improvements in analytical procedures are developed and improved data become available, they are incorporated into the design procedures after validation by comparison with related experimental data.

4.3.3.1.1.1 Cross Section Generation Using DIT. Few-group cross sections for coarse-mesh and fine-mesh diffusion theory codes are prepared by the DIT lattice code. These cross sections are used in ROCS (coarse-mesh) and in MC (fine-mesh). The ROCS/DIT code system is documented in an NRC-approved Topical Report.[5]

The essential components of the DIT lattice code are:

A. Spectrum calculations using integral transport theory in up to 85 energy groups for typical portions of the assembly geometry (e.g., fuel cell, fuel cell and burnable absorber, fuel cell and water-hole).

B. Few-group spatial calculations in exact assembly geometry followed by a leakage calculation to maintain a critical spectrum.

C. Isotopic depletion calculations for every cell in the assembly.

Thus, the use of the two-dimensional integral transport theory code DIT ensures that the effects of lattice heterogeneities are explicitly treated. Few-group cross sections for coarse-mesh spatial calculations are obtained without laborious intermediate fine-mesh calculations to perform accurate weighting of the various types of fuel, absorber, and waterhole cells.

The assembly calculation, which is performed in several broad energy groups (ranging from 2 to 12), is preceded by spectrum calculations performed in the basic cross section library energy group structure of up to 85 groups. The geometries used in the spectrum calculations are replicas of portions of the true assembly geometry. Boundary conditions recycled from the assembly calculation are used for each spectrum geometry.

Group condensation based on the spectra calculated for all the different types of cells and subregions within them is performed to obtain few-group macroscopic cross sections that are passed on directly to the assembly calculations. Since the accuracy of the spectrum calculations is high, the group condensation can normally be performed with a standard four-group structure. In cases where conventional group condensation methods break down, more groups can be (and are) used in the assembly calculation.

The assembly calculation as well as the spectrum calculations are performed by integral transport theory with multi-group interface current used to couple adjacent cells.

This entire sequence of calculations is normally performed assuming that there is no net leakage from the assembly geometry. Following the assembly calculation, fine-group spectra are constructed for all subregions in the assembly based on the spatial distribution of the few-group assembly flux and on the energy and space distribution of the fine-group flux from the spectrum calculations. A correction for the influence of global leakage is then made on the basis of a B1 calculation with the fine energy group structure for the homogenized assembly to maintain criticality of the assembly. The ROCS code uses Assembly Discontinuity Factors (ADF's) in order to provide improved internal agreement between ROCS and DIT codes. ADF's are a standard method used in the nuclear industry to eliminate homogenization errors in nuclear design analysis where the heterogenous solution is known.

Few-group microscopic cross sections for use in the depletion stage of DIT are formed using the basic cross section library and the spectrum calculated as described. Spatial averages of microscopic and macroscopic cross sections are performed for editing purposes and are passed on to ROCS and MC.

The above calculations are performed in one single job step without manual intervention. Few-group coarse-mesh cross sections are prepared in the HARMONY format[6] for ROCS by the editing code CESAW, and fine-mesh cross sections are input to MC via the editing code MCXSEC.

The DIT code utilizes a data library containing multigroup cross sections, fission spectra, fission product yields, and other supplemental data. The principal source of data for the library is ENDF/B-IV. Three adjustments to the library data have been made to reflect changes to ENDF/B-IV recommended by the Cross Sections Evaluations Working Group (CSEWG) for incorporation into ENDF/B-V.

These adjustments include:

A. A reduction of about 3% in the shielded resonance integral of U-238.

B. The adaption of the harder Watt fission spectra for U-235 and PU-239, later incorporated in ENDF/B-V.

C. A moderate upward adjustment of U-235 and Pu-239 thermal $\bar{y}$-values of about 0.1% improving the $\bar{y}$, h discrepancy but not going as far as ENDF/B-V.

In the epithermal region, the ENDF/B-IV files are processed with ETOG[7] to provide cross section resonance parameters and scattering matrices for the isotopes contained in the library. ETOG prepares this data in 99 energy groups spanning the range from 14.9 MeV to 0.414 eV. The GAM portion of GGC-3[8] is used to condense the 99 group data into 50 energy groups spanning the energy range 14.8 MeV to 1.855 eV weighted with a spectrum representative of that in a PWR assembly.

In the resolved energy region (9.1 KeV to 1.855 eV), the capture and fission cross sections of resonant absorbers are replaced with resonance tables.

In the thermal region, the ENDF/B-IV files are processed with FLANGE-II[9] to provide cross sections and full scattering matrices in the thermal region (1.855 eV to 0.00025 eV). The cross sections of isotopes containing resonances in the thermal region are Doppler broadened. For hydrogen, scattering matrices are prepared with FLANGE-II using ENDF/B-IV thermal scattering low parameters for $H_2 0$.

The cross sections and scattering matrices are tabulated on the library for a sufficient number of temperatures to span the range expected during power reactor operation and to permit linear interpolation.

Cross sections for the resolved resonance region (9.1 KeV to 1.855 eV) are prepared with C-E RABBLE, an extension of the RABBLE[10] code using resolved resonance parameters from ENDF/B-IV. The cosine current approximation in RABBLE was replaced with an integral transport routine. Group averaged resonance cross sections are generated with the modified RABBLE code which performs a space-dependent calculation of the slowing down sources. The cross sections from the C-E RABBLE calculations are corrected to include the proper group-dependent smooth calculations which are derived from the ETOG/GGC-3 calculations. RABBLE is also used to validate interference effects among resonance absorbers as calculated by the DIT algorithm.

Following the assembly spectrum calculation, a depletion time step takes place for each individual pin in the assembly and, when required, for subdivisions of a pin. At the end of the depletion step, new isotopic compositions are defined for use

in the spectrum calculation of the next time step. This process is extended over the expected life of the fuel assembly.

4.3.3.1.1.2 Coarse Mesh Methods Using ROCS. Static and depletion-dependent reactivities and nuclide concentration flux, and power distribution in two- and three-dimensional representation of the core are determined by a diffusion-depletion program, ROCS-MC. The ROCS code is designed to perform two- or three-dimensional coarse-mesh reactor core calculations based on two-group higher order difference (HOD) or nodal expansion (NEM) methods with full-, half-, or quarter-core symmetric geometries. The use of HOD or NEM methods is determined by the version of ROCS used. Before using ROCS-NEM for nuclear design analysis for Palo Verde, Combustion Engineering performed extensive verification to confirm that the calculational biases and uncertainties obtained with both methods were equivalent. The mesh consists of rectangular parallelepiped "nodes" arranged contiguously in the xy-plane, with one or more axial meshes (or planes) in the z-direction. In most applications, only the active core region is represented, with albedo-like boundary conditions[11] assigned to exterior nodes. A typical ROCS core geometry uses four nodes per assembly in the xy-plane and 20 to 30 axial planes depending upon core height and in-core instrument locations.

The nodal macroscopic group constants used in the neutronics calculation are constructed from detailed isotopic concentrations and microscopic cross sections processed by the

code. The isotopes specified include fixed depletable isotopes and a lumped residual representing nondepletable isotopes. The depletable isotopes include fission chain isotopes, fission products, and burnable absorbers. Control rods are represented by macroscopic cross sections specific to different rod banks.

The ROCS system performs coarse-mesh depletion calculations for each node in a two- or three-dimensional core configuration. The allowed depletion chains are internally modeled with fixed completion equations so that beyond the input cross section data the user need supply only such data as initial concentrations, decay constants, and fission yields for each depletion nuclide.

These include the principal uranium and plutonium isotopes, a fuel exposure chain, xenon and samarium fission product chains, and boron and gadolinium burnable absorber chains. The fixed depletion equations used in the ROCS code are derived through the standard procedure of analytically integrating the coupled linear rate equations which represent each chain.

The depletion equations are solved using the flux and microscopic cross section values based on the neutronics and thermal-hydraulic feedback calculations preceding the depletion time step. The initial flux and cross sections are assumed constant over the depletion time step. Cross section information used in the ROCS system is derived from microscopic cross sections supplied by DIT for each nuclide in two energy groups. This information is utilized in two basic forms. First, two-group macroscopic cross sections are used in the basic flux and eigenvalue calculation. The macroscopic

contributions due to thermal-hydraulic feedbacks, xenon, soluble boron, and control rods are added prior to the flux calculation. Second, two-group microscopic cross sections are used explicitly in the depletion and xenon short-term time-stepping calculations.

The two-group microscopic cross sections for each nuclide are supplied in table form. Represented for each nuclide and energy group are:

σ_{tr} = transport cross section (b)

σ_a = absorption cross section (b)

σ_R = removal cross section (b)

σ_f = fission cross section (b)

ν = average number of neutrons released per fission

κ = average energy release per fission (watt-sec)

The tables represent the above values as nonlinear functions of important independent variables (e.g., exposure, initial enrichment, soluble boron concentration) evaluated for nominal thermal-hydraulic conditions. In addition, multipliers (called G-factors) may be included in the table for any of the cross sections. The G-factors may also be represented as functions of pertinent independent variables. Thus a typical cross-section table interpolation can be represented symbolically by:

$$\sigma(\rho_o, T_{Mo}, T_{Fo}) = (N_1, N_2, N_3) G(N_4, N_5, N_6),$$

$$\rho_o, T_{Mo}, T_{Fo}$$

where

ρ_o, T_{Mo}, T_{Fo} = nominal moderator density, moderator temperature, and fuel temperature

$N_1, ..., N_6$ = independent variables for table interpolation

The cross sections are assumed to vary with moderator temperature, moderator density, and the square root of the fuel temperature for small changes about the nominal. The dependence of the cross sections on the thermal-hydraulic parameters is usually approximated by the inclusion of the first derivative of the cross section, for example:

$$\sigma(\rho, T_M, T_F) = \sigma(\rho_o, T_{Mo}, T_{Fo}) + \frac{\partial\sigma}{\partial\rho}\Delta\rho + \frac{\partial\sigma}{\partial T_M}\Delta T_M + \frac{\partial\sigma}{\partial (T_F)^{1/2}}\Delta(T_F)^{1/2}$$

where

$\Delta\rho = \rho - \rho_o$ = change in density from nominal value

$\Delta T_M = T_M - T_{Mo}$ = change in moderator temperature from nominal value

$\Delta(T_F)^{1/2} = (T_F)^{1/2} - (T_{Fo})^{1/2}$ = change in square root of fuel temperature from nominal value

The ROCS neutronics calculation is linked to optional independent feedback calculations for thermal-hydraulic parameters (moderator density, moderator temperature, fuel temperature[(12)(13)] and for equilibrium I-135 - Xe-135 distributions. The thermal-hydraulic calculation is performed

iteratively with the flux calculation when any combination of thermal-hydraulic feedbacks is specified. For each feedback variable specified, the macroscopic cross sections used in the flux calculation are updated through the appropriate feedback term. In the case of xenon, the macroscopic cross sections are updated each iteration cycle using calculated I-135 and Xe-135 equilibrium concentrations based on the two-group flux distribution from the previous iteration. The number of feedback iterations is governed by independent convergence criteria for each feedback parameter, so that the final flux solution is obtained after all specified feedbacks have converged.

In addition to the above feedback models, the ROCS code contains optional eigenvalue search models for the following control variables: control rod bank insertion, soluble boron concentration, reactor power level, and inlet moderator temperature. The search calculations employ numerical iteration techniques which update the specified control variable to obtain convergence on the search eigenvalue, and are generally used along with feedback calculations. The power level and inlet temperature searches require use of thermal-hydraulic feedbacks. These latter search calculations are performed after alternate feedback iterations, while the boron and rod search calculations are performed after each feedback iteration.

4.3.3.1.1.3 Fine-Mesh Methods Using MC. The MC code performs pin peaking calculations for each node in two- or three-dimensional core geometries. MC uses an imbedded

fine-mesh diffusion theory method for obtaining pin power distributions from coarse-mesh calculations.

A method has been developed for determining diffusion coefficients which, when combined with the finite difference formulation of MC, permits the inclusion of transport effects in a rigorous fashion. The diffusion coefficients have the property of conserving cell-averaged fluxes, reaction rates, and net leakages across cell boundaries. Thus, MC has the capability to effectively reproduce DIT local power distributions.

Having determined diffusion coefficients that exactly reproduce average fluxes, reaction rates, and net currents from transport theory for a particular geometry, it is then asserted that they are universally applicable independent of the size of the flux gradients seen in the core.

The nodal diffusion equations are solved as a boundary source problem for the imbedded calculation. The partial in-currents on each nodal face and the global eigenvalue are supplied by the ROCS coarse-mesh calculation.

After completion of the fine-mesh imbedded calculation, the fine-mesh power distribution is renormalized to the coarse-mesh power level to assure that coarse-mesh and fine-mesh node average powers and burnups will remain the same during depletion.

The MC-imbedded calculation uses a macroscopic cross section model based upon interpolation of multi-dimensional macroscopic tables. These tables are created by the MCXSEC code which processes DIT results for all assembly types, and are typically

burnup-, enrichment-, moderator-, and fuel temperature-dependent for each fine-mesh pin type. Lagrange linear interpolations are performed to obtain the macroscopic cross sections. The interpolated absorption cross section is then corrected for soluble boron and xenon changes by using boron and xenon microscopic cross sections along with number densities obtained from the core soluble boron and local xenon equilibrium concentrations. In addition, axial leakage is represented by adding a DB^2 term to the absorption cross section.

4.3.3.1.1.4 Cross Section Generation Using CASMO-4. The multigroup, two-dimensional transport theory code, CASMO-4, prepares cross sections for the two-group nodal diffusion code, SIMULATE-3. The CASMO-4/SIMULATE-3 code system is documented in an NRC-approved Topical Report.[30] As stated in PVNGS letter 102-04518-CDM/SAB/JAP, dated 1/3/2001, to NRC, and the NRC's Safety Evaluation for the issuance of amendments on CASMO-4/SIMULATE-3 (TS Amendment #132), dated 3/20/2001, PVNGS agreed to certain limitations associated with its application of CASMO-4/SIMULATE-3. Specifically, the NRC Safety Evaluation wording stating limiting the use of CASMO-4/SIMULATE-3 to, "the range of fuel configurations and core design parameters as stated and referenced by the June 8, 2000, application (reference 30). Introduction of significantly different or new fuel designs will require further validation of the above stated physics methods for application to PVNGS by the licensee and will require review by the NRC staff." In the NRC Safety Evaluation, the NRC staff further stated that, "It is clear

that interpolation between or modest extrapolations from cases implicitly analyzed in the topical report are not "significantly different" or "new fuel designs." However, a new fuel design would involve physics components which are not benchmarked in the topical report." Additional discussion on interpreting these limitations are contained in reference 31.

Features of CASMO-4 are listed below:

A. Nuclear data are collected in a library containing microscopic cross sections in 70 energy groups. Up to 40 energy groups are allowed in the two-dimensional transport theory calculation.

B. Effective resonance cross sections are calculated individually for each fuel pin.

C. The calculation sequence starts in a simplified geometry. Energy groups are then collapsed as spatial detail is increased. The two-dimensional calculation is performed in the true heterogeneous geometry using the KRAM characteristics module. The intermediate macro-group calculation is performed in two dimensions using a response matrix method.

D. A fundamental mode calculation is performed to account for leakage effects.

E. The microscopic depletion is calculated in each fuel pin and burnable absorber pin.

F. In the depletion calculation a predictor-corrector approach is used which greatly reduces the number of burnup steps necessary for a given accuracy.

G. Output gives few-group cross sections and reaction rates for any region of the assembly for use in overall reactor calculations.

H. Discontinuity factors are calculated at the boundary between bundles and for reflector regions.

The flow of calculations in CASMO-4 starts with the calculation of effective resonance cross sections for important resonance absorbers. The effective cross sections in the resonance energy region for important resonance absorbers are calculated using an equivalence theorem, which relates tabulated effective resonance integrals for each resonance absorber in each resonance group to the particular heterogeneous problem. The resonance integrals obtained from the equivalence theorem are used to calculate effective absorption and fission cross sections. The screening effect between different pins is considered by the use of Dancoff factors.

Macroscopic group cross sections are calculated for the succeeding micro group calculations. Microscopic cross sections in the library group structure are read from the data library. Macroscopic cross sections for any spatial region are directly calculated from the densities, geometries, etc. given in the input. The cross sections thus prepared are used in a series of micro group calculations to obtain detailed neutron energy spectra to be used for energy condensation of the pin cells.

The library contains cross sections tabulated for different temperatures. Data for the actual temperature are obtained by use of linear interpolation.

The nodal data is dependent on the flux distribution used to homogenize and collapse the cross sections. Using the true heterogeneous nature of the lattice in the energy group structure in the nuclear data library would result in prohibitively long execution times on some machines. To simplify the problem, the lattice calculations are performed in a smaller number of energy groups. The cross sections in the smaller group must be representative of those from the original group structure. Therefore, the cross sections must be condensed with an appropriate flux spectrum.

The condensation scheme in CASMO-4 consists of one-dimensional pin cell calculations followed by a two-dimensional response matrix (RM) calculation, where all regions of each pin cell are homogenized into an equivalent single region cell. The pin cell calculations are performed in the micro group structure of the cross section library (40 or 70 groups). Cross sections for each region of the lattice are then condensed to the macro group structure (typically 40 groups), where the RM calculation is performed. The spatial distribution of neutrons across each pin cell is obtained from the pin cell calculations, while the energy distribution of neutrons within each pin cell is updated by the RM calculation.

Normally, a micro group calculation is performed for each pin type in the fuel assembly. Collision probabilities are determined in a simplified geometry consisting of the different material regions of the pin type. Normal fuel pins are typically modeled using either three or four regions (i.e., fuel, air, canning, and coolant). For inert rods (e.g., water rods, guide tubes, etc.), a fuel-containing

“buffer” region is added to the outside of the coolant and is used to drive the flux across the cell. Burnable absorber rods, specifically fuel rods containing Gadolinium or Erbium, are modeled using a geometry similar to that used for inert rods. The fuel region of the burnable absorber rod, however, is automatically split into many annular subregions, used to represent the strong variations in the number density of the burnable absorber across the fuel region once the pin begins to deplete.

The macro group calculation is used to adjust the energy distribution of neutrons in all regions of the lattice to account for the effects of the surroundings. The calculation is performed on the entire lattice using homogenized pin cell regions. The macro group calculation is performed using a response matrix method.

In the response matrix method, the regions of the lattice are coupled together using their surface currents, rather than their scalar fluxes. An outgoing current is calculated along each surface of each mesh. This current will become the incoming current to the neighboring mesh.

Both the pin cell spectral calculations, described above, and the response matrix method solve the integral transport equation.

Following the two-dimensional macro group calculation, the neutron energy distribution throughout each macro region in the assembly is updated to include the effects of the surroundings. Since the macro group calculation is performed using homogenized pin cell regions, it is incapable of modifying the

distribution of neutrons in space across a cell. In order to account for the effects of the surroundings on the shape of the flux across the various regions of each pin cell, CASMO-4 performs a two-dimensional, heterogeneous calculation on the entire lattice in the 2D-group energy structure. Cross sections for each micro region of the lattice are condensed to the 2D-group structure using the updated spectrum from the macro group calculation. The flux distribution throughout the lattice is determined by solving the Boltzmann transport equation using the method of characteristics (KRAM module).

In single bundle calculations, a fundamental buckling mode is used for modifying the infinite lattice results obtained from the transport calculation to include the effects of leakage. This calculation is normally made in diffusion theory. The fundamental mode calculation should be bypassed in calculations on two by two segments, reflectors and fuel storage racks.

The burnup calculation is carried out in two steps. In going from the time t_{n-1} to t_n a "predictor" step is first taken using the fluxes obtained from the neutron calculation at t_{n-1}. The predictor step provides predicted number densities at t_n. The cross sections are then updated and the new spectrum calculation gives fluxes to be used in a "corrector" step after which final number densities at t_n are given by the average value of the results from the predictor and corrector steps.

The SIMULATE-3 code uses Assembly Discontinuity Factors (ADFs). CASMO-4 calculates ADFs at the boundary between bundles and for reflector regions.

The CASLIB code produces a binary neutron cross section library for input to CASMO-4 from a card-image, formatted library. The card-image, formatted library, supplied with CASMO-4, is based mainly on data from ENDF/B-IV, although some data come from other sources. It contains cross sections for 108 materials, most of which are individual nuclides. A few materials are either elements of natural composition or mixtures of elements.

Microscopic cross sections are tabulated in 70 energy groups. The group structure was taken over from the WIMS code with the addition that a boundary has been put in at 1.855 eV. The group structure of the library fulfills the following requirements:

A. The 14 fast groups give enough detail in the fast energy region to calculate the leakage and fast fission accurately.

B. The 13 resonance groups provide correct flux levels as a function of energy for the calculation of resonance absorption.

C. The 43 thermal groups (below 4 eV, which is the cut off for up-scattering) make the thermal cross sections independent of the weighting spectrum used for their generation. Groups are concentrated around the 0.3 eV resonance in Pu-239 and the 1 eV resonance in Pu-240.

The library contains absorption, fission, nufission, transport and scattering cross sections. Data are tabulated as a function of temperature when needed. Shielded resonance integrals versus potential background cross section and

temperature are tabulated for resonance absorbers. The library also contains yields and decay constants for fission products.

Typically, each unique PWR fuel assembly type (defined by geometry, enrichment, and burnable poison pins) is separately modeled in CASMO-4 (usually with octant symmetry). Enrichment zoning among fuel pins, burnable poison pins, and guide tubes are explicitly modeled. The water gap between assemblies in the reactor core is included in the CASMO-4 model. The spacer grid material is also included.

Several depletion cases are needed to generate each fuel assembly type’s average cross section data. First, the fuel assembly is depleted at hot full power, no control rods, reactor average conditions. Moderator temperature, fuel temperature, and soluble boron concentration are set to constant average values for the complete depletion. Next, depletions called history depletions are performed at various other moderator temperatures, fuel temperatures, and boron concentrations. Each fuel assembly type is depleted to burnups which bracket licensed burnup limits.

Branch cases are performed to calculate instantaneous effects. The branch cases are executed from the hot full power reactor average conditions and from the history conditions discussed above at a selection of exposures. Branch cases are run for a range of boron concentrations, moderator temperatures, control rodded conditions, and fuel temperatures. Both isothermal and non-isothermal cases are performed.

CASMO-4 also generates top, bottom, and radial reflector cross sections. Reflector cross sections are typically modeled as a

function of soluble boron concentration and moderator temperature.

TABLES-3 is a data processing program that links CASMO-4 to SIMULATE-3. The program processes the following types of data from CASMO-4:

A. two-group cross sections,

B. discontinuity factors,

C. fission product data,

D. in-core instrument response data,

E. pin power reconstruction data,

F. kinetics data, and

G. isotopics data.

TABLES-3 reads the CASMO-4 card image files and functionalizes the data into a one-, two-, or three-dimensional, master binary cross section library for SIMULATE-3. CMS-LINK is a modern version of TABLES-3, which performs all of the above functions in a more automated manner. In addition, CMS-LINK processes additional CASMO data for (future) use with space-time kinetics calculations.

Typically, data from the following CASMO-4 card image files are combined into binary cross section libraries for input to SIMULATE-3:

A. HFP Reactor Average Depletion + Branches + History Depletions,

- Fuel Temperature Branches

- Moderator Temperature Branches
- Soluble Boron Concentration Branches
- Control Rod Insertion Branches
- Cold Branches (293 K < T < 569 K)
- Boron History
- Fuel Temperature History
- Moderator Temperature History

B. Bottom Reflector

C. Top Reflector

D. Radial Reflector

4.3.3.1.1.5 Coarse-Mesh Methods Using SIMULATE-3. SIMULATE-3 is a two- or three-dimensional (2-D or 3-D), two-group coarse mesh diffusion theory reactor simulator program. Homogenized cross sections and discontinuity factors are applied to the coarse mesh nodal model to solve the two-group diffusion equation using the QPANDA neutronics model. QPANDA employs fourth order polynomial representations of the intranodal flux distributions in both the fast and thermal groups. The equations are derived by subdividing the spatial domain of the reactor into a set of rectangular parallelepipeds, referred to as nodes. Each node will typically represent a full assembly or a quarter assembly in the radial plane and a 15 - 30 cm axial region of an assembly. A typical SIMULATE-3 core geometry for Palo Verde uses four nodes per assembly in the xy-plane and 25 axial nodes.

Early generation nodal models related the currents between nodes to the difference between fluxes in neighboring nodes using simple finite-difference or modified coarse-mesh finite-difference approximations. The QPANDA nodal model does not make this approximation, and the coupling relationships are derived directly from the neutron diffusion equation.

Traditionally, nodal codes have relied on user-adjusted albedos to treat the neutron reflection and the fuel/baffle interface. SIMULATE-3 explicitly models the baffle/reflector region, eliminating the need to normalize to higher-order fine mesh calculations such as PDQ.

The SIMULATE-3 program performs a macroscopic depletion, as opposed to using isotopic number densities and microscopic cross sections. Individual Uranium, Plutonium, and lumped fission product isotopic concentrations are not computed. However, microscopic depletion of Iodine, Xenon, Promethium, and Samarium is included to model typical reactor transients. Microscopic cross sections for boron are also used in SIMULATE-3.

The nodal thermal hydraulic properties are calculated based on the inlet temperature, RCS pressure, coolant mass flow rate, and the heat addition along the channels.

4.3.3.1.1.6 Fine-Mesh Methods Using SIMULATE-3. The pin-by-pin power distributions, on a 2-D or 3-D basis, are constructed from the inter- and intra-assembly information from the coarse mesh solution and the pin-wise assembly power distribution from CASMO-4. The SIMULATE-3 pin power reconstruction method is based on the assumption of

separability of the global flux (homogeneous intranodal flux) and local flux shapes (heterogeneous form functions). If the separability approximation is made, detailed pin-by-pin flux (and power) within an assembly can be approximated by the product of a global homogenized distribution and a local heterogeneous form function.

The SIMULATE-3 pin power reconstruction method is motivated by two observations: 1) if the intranodal power distribution can be very accurately modeled, it should be possible to compute accurate pin power distributions by using form functions from single-assembly (zero-leakage) spectrum/depletion calculations, and 2) since the fast group contribution to the intra-assembly pin power is relatively smooth, it should be possible to use total power (not group-wise) form functions.

Intranodal power distributions are computed from group-wise nodal (homogenized) fission cross sections and flux distributions.

The SIMULATE-3 intranodal fast flux distribution is accurately represented by a non-separable polynomial expansion.

However, the same polynomial flux shapes cannot accurately model the large localized thermal flux gradients which occur at assembly interfaces. SIMULATE-3 approximates the intranodal thermal flux distribution by assuming the thermal flux to be composed of an asymptotic term and a surface transition term.

The QPANDA nodal model provides accurate node-averaged fluxes, surface-averaged fluxes, and surface-averaged currents which can be used as constraints on the flux expansions. Additional constraints are obtained by requiring the flux expansions to

preserve fluxes at nodal corner points, and estimates of the corner-point fluxes are obtained by an interpolation method.

The corner-point fluxes provide four constraints (in addition to the node-averaged flux, 4 surface-averaged fluxes, 4 surface-averaged currents) for the homogeneous flux expansion. The complete flux expansion requires 25 constraints, and only 13 are directly available. However, it has been determined that accurate intranodal flux distributions can be determined without these additional constraints. Consequently, 12 of the cross terms in the flux expansions are neglected, and the 13 expansion coefficients are determined directly from the aforementioned constraints.

nce depletion has occurred, the intranodal distribution of homogenized cross section must be known. The exposure-induced variation of intranodal cross sections is modeled using separable biquadratic expansions which preserve the node-averaged and surface-averaged exposures. The biquadratic exposure distribution is integrated over each pin location and the resulting pin-wise homogeneous exposures are used to evaluate pin-wise homogenized fission cross sections.

The use of flux and power form functions from single assembly (zero leakage) spectrum/depletion calculations leads to an additional complication because of spectral interactions at assembly interfaces. These spectral interactions produce significantly different plutonium buildup and uranium depletion rates at assembly interfaces than those implicit in the single assembly spectrum/depletion calculation.

It is assumed that the differences between the local (intranodal) homogenized cross sections and the single assembly cross sections are proportional to the difference between the local two-group spectrum and the single assembly spectrum. This can be manipulated to obtain an approximate expression for the cross-section variations as a function of spectral history. Spectral history is a function of the local and single assembly fast to thermal flux ratios.

Since CASMO-4 history depletion calculations are evaluated during generation of the macroscopic cross-section library, the same data is interpreted to evaluate the spectral variation of cross sections as a function of spectral history. The difference in the homogenized cross section between a branch (from base depletion to history condition) and a history depletion is assumed to be a function of the exposure-integrated ratio of spectra, and the change in the cross section-per-unit-of spectral history is approximated by a function of spectral history. Spectral history is approximated by a function of the history and base depletion fast to thermal flux ratios.

The actual changes in cross sections are computed from the local value of spectral history and exposure. Since the spectral-induced variations in homogenized cross sections are driven by assembly spectrum interactions, the actual values of spectral history need only be retained for nodal surfaces; and the spatial distribution of change in cross sections is assumed to have the shape of the local thermal flux expansion.

The treatment of cross-section variation with spectral history permits direct evaluation of spectral-interaction effects within the nodal code.

Explicit modeling of intranodal exposure and spectral-history distributions allows evaluation of pin-by-pin distribution of fission cross sections.

4.3.3.1.1.7 Other Analysis Methods. As the size of large power reactors increases, space-time effects during reactor transients become more important. In order not to penalize reactor performance unduly with overly conservative design methods, it is desirable to have the capability of performing detailed space-time neutronics calculations for both design and off-design transients.

The HERMITE(14) computer code has been developed to meet this objective. It solves the few-group, space- and time-dependent neutron diffusion equation including feedback effects of fuel temperature, coolant temperature, coolant density, and control rod motion. The neutronics equations in one, two, and three dimensions are solved by the nodal expansion method. The fuel temperature model explicitly represents the pellet, gap, and clad regions of the fuel pin, and the governing heat conduction equations are solved by a finite difference method. Continuity and energy conservation equations are solved in order to determine the coolant temperature and density. In the one-dimensional mode, HERMITE also has the option of finding the axial-dependent poison distribution required to produce a particular user-specified axial power shape. This option is often used to produce conservative axial power shapes

corresponding to the LCO limits on axial power shape, from which simulations of core transients are subsequently initiated.

4.3.3.1.2 Comparisons with Experiments

NOTE: This UFSAR section is retained for historical purposes, because it describes critical experiments that supported the initial license for PVNGS. Further, more recent information on critical experiments involving UO_2-Er_2O_3 may be found in a proprietary C-E topical report approved by NRC staff.[29] See also the ROCS topical report, Reference 5. For information on the CASMO-4/SIMULATE-3 code system and benchmark, see APS CASMO-4/SIMULATE-3 topical report, Reference 30.

The nuclear analytical design methods in use for SYSTEM 80 have been checked against a variety of critical experiments and operating power reactors. In the first type of analysis, reactivity and reaction rates and power distribution calculations are performed, which lead to information concerning the validity of the basic fuel cell calculation. The second type of analysis consists of a core follow program in which power distributions, reactivity coefficients, reactivity depletion rate, and CEA worths are analyzed to provide a global verification of the nuclear design package.

4.3.3.1.2.1 Critical Experiments. Selected critical experiments have been analyzed with the DIT code. Selection of criticals is based on the following criteria:

- Applicability to C-E PWR fuel and assembly designs,
- Self-consistency of measured parameters, and
- Availability of adequate data to model the experiments.

Two groups of critical experiments using rod arrays representative of the 14 x 14 assembly have been employed in this evaluation. The first is a series of clean experiments with UO_2 fuel carried out in 1967[15], and the second is a set of experiments carried out in 1969.[16] Tables 4.3-4 and 4.3-5 give the principal parameters for each of the experimental configurations. The moderator-to-fuel volume ratios were varied by changing the cell pitch of the fuel rod arrangement. The moderator and reflector material for all cores was H_20.

Measurements included the criticality parameters and the fission rate distributions in selected fuel rods. This section addresses the comparisons between measured and calculated criticality, as well as between measured and calculated fissions rate distributions done to establish calculative biases and uncertainties in predicting intra-assembly power peaking for both 14 x 14 and 16 x 16 arrays.

Table 4.3-4

C-E CRITICALS

Lattice	Core Configuration Fuel Rod Array	Core Configuration Fuel Cell Pitch (in.)	Number of Fuel Rods	Temp. of Core (°F)	Soluble Boron Conc. (ppm)	Number of Control Rod Channels
#12	30x30	0.600	880	68	0	5
#32	30x30	0.600	832	68	0	17
#43	30x30	0.600	880	68	323	5
#53	30x30	0.575	832	68	0	17
#56	30x30	0.575	832	68	302	17

<u>Fuel Rod Design</u>

Clad OD	0.4683 in.
Clad thickness	0.03145 in.
Clad material	Zr-4
Fuel pellet OD	0.400 in.
Fuel density	10.40 gr/cc
Fuel enrichment	2.72 w/o

Table 4.3-5

FUEL SPECIFICATION (KRITZ EXPERIMENTS)

Fuel material (pellets)	UO_2
Fuel density (dishing included), g/m^3	10.15
U235 in U, wt%	3.10
Fuel length, mm	2,650
Pellet length, mm	11
Oxide diameter, mm	9.08
Cladding material	Zircaloy 4
Density, g/cm^3	6.55
Outer diameter, mm	10.74
Inner diameter, mm	9.30

4.3.3.1.2.1.1 Description of the Experiments.

A. Combustion Engineering Sponsored UO_2 Critical Experiments

A series of critical experiments were performed for Combustion Engineering by Westinghouse Corporation at the Westinghouse Reactor Evaluation Center (WREC) employing the CRX reactor. The experimental program consisted of approximately 70 critical configurations of fuel rods. The basic core configuration was a 30 x 30 square, fuel rod array of Zr-4 clad UO_2 fuel having an enrichment of 2.72 w/o U-235. Fuel rods were removed to create internal water holes or channels to accommodate

control rods or to simulate control rod channels and water gaps representative of the C-E 14 x 14 fuel assembly design.

The majority of the experiments employed a lattice pitch of 0.600 inches with several experiments repeated with a lattice pitch of 0.575 inches. These values of 0.600 and 0.575 inches, together with the fuel pellet dimensions and enrichment and the rod diameter, resulted in hydrogen-to-fuel ratios representative of the 14 x 14 design at room and at operating temperatures, respectively.

B. KRITZ Experiments

A program of critical experiments, sponsored jointly by Combustion Engineering and KWU, was performed at the KRITZ CRITICAL FACILITY of AB Atomenergi, Studsvik, Sweden. The program consisted of analyzing a number of core configurations of interest to C-E and KWU. The C-E configurations were representative of the 14 x 14 fuel assembly, including the 5 large control rod channels. A basic cell pitch of 0.5650 inches was used for all lattices. The cores were relatively large, both in cross-sectional area and height. Each core contained about 1450 rods 265 cm in length. The core was reflected with water on the four sides and the bottom. Soluble boron was employed for gross reactivity control.

Table 4.3-6

COMPARISON OF REACTIVITY LEVELS FOR NON-UNIFORM CORE

Core	Vol. Mod. / Vol. Fuel	Number of Large Water Holes	Measured Axial Buckling M-2	Soluble Boron Conc. (ppm)	K_{eff}
C-E Criticals					
2.7% U-235, 68F					
#12	1.49	5	3.53	0	1.0017
#32	1.49	17	3.70	0	1.0006
#43	1.49	5	1.64	323	1.0032
#53	1.26	17	2.82	0	1.0021
#56	1.26	17	1.07	302	1.0006
KRITZ					
UO_2, 445F	1.79	21	2.20	959	1.0014

4.3.3.1.2.1.2 Results of Analyses. The results of the analyses of the six critical experiments are summarized in Table 4.3-6. The average K_{eff} is 1.0016.

As part of the C-E Criticals and the KRITZ CRITICALS experiment programs, pin-by-pin power distributions were also measured, to provide a data base with which to define biases and uncertainties in predicted water hole peaking factors. This analysis is described in detail in reference 17. The bias and 95/95 tolerance limit in assembly-wise peaking factor are 0.0 and + 2.4%, respectively.

4.3.3.1.2.2 Power Reactors. The accuracy of the calculational system in its entirety can only be assessed through the analysis of experimental data collected on operating power reactors. The data under investigation consists of critical conditions, reactivity coefficients, and rod worths measured during the startup period, and of critical conditions, power distributions, and reactivity coefficients measured throughout the various cycles.

4.3.3.1.2.2.1 Startup Data. Measured data obtained during reactor start-up are the most reliable, because they consist of well-controlled conditions. Eleven cores have been analyzed, covering four cycles of fuel management.

Table 4.3-7 shows the measured and predicted hot, zero power, xenon free, all rods out critical boron concentrations for each cycle. Over the eleven points of the data base, the critical soluble boron concentration is underestimated by an average of 14 ppm, with tolerance limits of ± 25 ppm at a 95/95 probability/confidence level. In terms of reactivity, this corresponds to an underprediction by 0.18% $\Delta\rho$ with two-sided tolerance limits of ± 0.31% $\Delta\rho$.

A. Isothermal Temperature Coefficient

   The Isothermal Temperature Coefficient (ITC) is the change in core reactivity resulting from a 1°F change in moderator and fuel temperatures.

   Isothermal Temperature Coefficients have been measured for a number of reactors and cycles, both at power and at zero power, and for a wide range of soluble boron

concentrations (83 to 1342 ppm). Three-dimensional ROCS calculations were performed at the same conditions as the measurements using concentration files taken from core follow depletions. This data base contains 37 comparisons which are shown in table 4.3-8. Included in the table are the calculated and measured ITCs, their differences, and the respective power level and soluble boron concentration.

Measured and calculated ITCs were found to be linear functions of the measured soluble boron concentration (ppm). The ITC calculated - measured differences were also a linear function of ppm; therefore, a least squares linear fit was used to determine a ppm-dependent bias.

The deviations of the ITC calculated - measured differences about this least squares fit were found to be normally distributed. The plant-by-plant variances about the overall linear fit to PPM passed the Bartlett test for poolability. The calculated - measured differences showed no statistically significant dependence on power level, fuel exposure, or assembly design. Thus the final results of this analysis consisted of a ppm-dependent bias curve and the associated tolerance band of $0.18 \times 10^{-4}/°F$ in 95/95 confidence level about that curve (figure 4.3-12).

Table 4.3-7

BEGINNING-OF-CYCLE, HOT ZERO POWER,

XENON FREE, UNRODDED

CRITICAL BORON CONCENTRATION

Plant	Cycle	Critical Boron Concentration (ppm)	
		Measured	Calculated (ROCS/DIT)
BG&E I	1	1,096	1,078
	2	1,013	984
	3	1,220	1,216
	4	1,342	1,340
BG&E II	1	1,097	1,087
	2	1,185	1,175
	3	1,191	1,181
FPL	1	962	944
	2	1,024	995
	3	1,137	1,127
ANO2	1	1,012	999
Average Difference (measured minus calculated) = 14 ppm 95/95 Confidence Level = ±25 ppm			

Table 4.3-8

ITC SUMMARY FOR ROCS/DIT

(Sheet 1 of 2)

Core	Cycle	%Power	Ppm	Measured	Calculated ($x10^{-4}\Delta\rho/°F$)	Difference
BG&E II	1	HZP	1090	+.24	+.48	+.24
		50	827	-.10	+.03	+.13
		96	745	-.27	-.17	+.10
	2	HZP	1121	+.43	+.52	+.09
		50	940	+.01	+.16	+.15
		100	690	-.50	-.54	-.04
	3	HZP	1191	+.25	+.47	+.22
		50	923	-.11	-.01	+.10
FP&1	1	HZP	962	+.10	+.36	+.26
		50	696	-.25	-.10	+.15
	1A	51	681	-.21	-.12	+.09
		83	619	-.35	-.29	+.06
		98	585	-.42	-.35	+.07
		95	296	-1.01	-.89	+.12
	2	HZP	1024	+.27	+.48	+.21
		100	670	-.23	-.28	-.05
		97	288	-.89	-1.13	-.24
	3	HZP	1137	+.32	+.54	+.22
		100	757	-.25	-.24	+.01
BG&E I	1	HZP	1087	+.26	+.49	+.23
		20	923	+.05	+.22	+.17
		50	820	-.11	+.06	+.17
		80	764	-.18	-.08	+.10
		100	740	-.21	-.14	+.07
		100	365	-.85	-.81	+.04
		95	83	-1.38	-1.48	-.10

Table 4.3-8

ITC SUMMARY FOR ROCS/DIT

(Sheet 2 of 2)

Core	Cycle	%Power	Ppm	Measured	Calculated ($x10^{-4} \Delta\rho/°F$)	Difference
BG&E I	2	HZP	1013	+.07	+.35	+.28
		50	765	-.24	-.13	+.11
		100	593	-.72	-.67	+.05
	3	HZP	1220	+.39	+.67	+.28
		50	989	+.04	+.24	+.28
		100	660	-.78	-.60	+.18
	4	HZP	1342	+.36	+.63	+.27
		50	1066	+.19	+.24	+.05
ANO2	1	HZP	1012	+.03	+.34	+.31
		20	825	-.20	+.34	+.23
		50	720	-.33	-.15	+.18

B. Control Rod Bank Worths

Sequential insertions of regulating and shutdown control rod banks from start-up tests were simulated with three-dimensional ROCS calculations. Homogenized macroscopic cross sections for rodded nodes in the coarse-mesh calculations may also be obtained using pairs (rodded and unrodded) of assembly calculations performed with DIT. The paired DIT calculations for individual assembly types are over a range of conditions of burnup, moderator temperature, and soluble boron concentration applicable to reactor start-up and operating conditions. The effects of rod insertions in the ROCS models are represented using two-group delta-macroscopic cross sections in rodded nodes, which are the direct differences in flux- and volume-averaged macroscopic cross sections obtained from the paired DIT assembly calculations. The ROCS CEA cross sections are functionalized with burnup, soluble boron, moderator temperature, and enrichment.

The comparisons of ROCS calculated control rod bank worths to the measured values are shown in tables 4.3-9 and 4.3-10.

The estimated calculative tolerance intervals, $\pm kS_c$, for the difference between ROCS/DIT and truth are ± 6% for first cycles and at most ± 9% for reload cycles. Thus the accuracy of ROCS/DIT with both methods of calculating control rod cross sections is comparable to

currently approved C-E methods and is acceptable for the calculation of control rod worths.

C. Dropped, Ejected and Net Rod Worths

Reactivity worths for some non-sequential asymmetric rod configurations are calculated and compared to measured values. The results for these anomalous rod configurations are then related to those for normal control rod operation.

All the data analyzed were obtained during the start-up test programs of first cycles.

The dropped, ejected, and net rod worth comparisons all showed similar good results which are consistent with the previous analysis of control rod bank worths. This is demonstrated in Table 4.3-11 where the means and standard deviations for the upset rod configurations are compared with reactivity results for normal sequential insertions of control rod banks. The normal rod bank reactivity results are taken from the first

Table 4.3-9

COMPARISON OF CONTROL ROD BANK WORTHS

CALCULATED (C) 3D ROCS (DIT) VS MEASURED (M)

$\% \Delta \rho$

Plant/Cycle	ANO 2 CY 1		C.C.1 CY 1		C.C.11 CY 1		St.L.1 CY 1	
Sequential Rod Bank								
First Cycles	C	M	C	M	C	M	C	M
7	- - -		- - -		- - -		.740	.734
6	.561	.568	- - -		- - -		.530	.520
5	.530	.524	.531	.552	.525	.558	.358	.346
4	.745	.743	.362	.363	.358	.389	1.343	1.297
3	.831	.792	.891	.932	.884	.908	.499	.531
2	.960	.916	.761	.778	.765	.806	1.484	1.414
1	1.307	1.276	.927	.963	.916	.893	.722	.692
C	- - -		1.239	1.303	1.253	1.260	- - -	
B	- - -		1.041	.997	.976	.959	.449	.422

Plant/Cycle	C.C.1 CY 2		C.C.11 CY 2		St.L.1 CY 2		C.C.1 CY 3		C.C.11 CY 3		St.L.1 CY 3		C.C.1 CY 4	
Sequential Rod Bank														
Later Cycles	C	M	C	M	C	M	C	M	C	M	C	M	C	M
7	- - -		- - -		.727	.691	- - -		- - -		.768	.705	- - -	
6	- - -		- - -		.428	.430	- - -		- - -		.450	.420	- - -	
5	.544	.508	.557	.563	.195	.197	.335	.305	.521	.546	.218	.201	.561	.550
4	.370	.329	.404	.372	1.284	1.153	.357	.320	.170	.167	1.461	1.317	.196	.178
3	.527	.484	.535	.542	.337	.320	.977	.925	.588	.584	.640	.622	.584	.592
2	.396	.411	.451	.455	1.226	1.184	- - -		.644	.642	1.117	1.019	.478	.460
1	.951	.875	.628	.600	.367	.375	1.199	1.091	.892	.864	.539	.519	.835	.788
C	- - -		- - -		- - -		1.126	1.174	- - -		- - -		- - -	
B	- - -		- - -		- - -		- - -		- - -		- - -		- - -	

Table 4.3-10

COMPARISON OF CONTROL ROD BANK WORTHS

3D ROCS (DIT) VS MEASUREMENT[a]

Plant/Cycle	ANO 2 CY 1	C.C.I CY 1	C.C.II CY 1	St.L.I CY 1	C.C.I CY 2	C.C.II CY 2	St.L.I CY 2	C.C.I CY 3	C.C.II CY 3	St.L.I CY 3	C.C.I CY 4
Sequential Rod Bank											
7	---	---	---	+0.82	---	---	+5.20	---	---	+8.95	---
6	-1.23	---	---	+1.92	---	---	-0.47	---	---	+7.16	---
5	+1.15	-3.80	-5.91	+3.47	+7.09	-1.07	-1.02	+9.84	-4.58	+8.22	+2.00
4	+0.27	+2.50	-3.52	+3.55	+12.46	+8.60	+11.36	+11.56	+1.80	+10.16	+10.79
3	+4.92	-4.40	-2.64	-6.03	+8.88	-1.29	+5.31	+5.62	+0.68	+2.82	-1.36
2	+4.80	-2.19	-5.09	+4.95	-3.65	-0.88	+3.54	---	+0.31	+9.57	+3.91
1	+2.51	-2.73	+2.57	+4.33	+8.69	+4.67	-2.13	+9.90	+3.24	+3.91	+5.96
C	---	-4.91	-0.56	---	---	---	---	-4.09	---	---	---
B	---	+4.41	+1.77	+6.40	---	---	---	---	---	---	---
Cycle Mean	+2.07	-1.59	-1.91	+2.43	+6.69	+2.00	+3.11	+6.57	+0.29	+7.25	+4.26
± Std.Dev.	±2.48	±3.61	±3.28	±3.83	±6.11	±4.45	±4.74	±6.35	±2.95	±2.84	±4.53
Overall $\mu \pm \sigma$	+0.26 ±3.80				+4.40 ±4.92						

a. Units of % difference from measured worth.

Table 4.3-11

SUMMARY OF ANOMALOUS ROD REACTIVITY WORTHS

	Mean Calc-Meas Difference	(Units)	Standard Deviation
Single Rod Drops	+ .006%Δρ	(Abs.)	± .018%Δρ
Single Rod Ejections	- .010%Δρ	(Abs.)	± .028%Δρ
Net (N-1) Worth	-3.60%Δρ	(Rel.)	±1.47%Δρ
First Cycle Rod Banks	- .014%Δρ	(Abs.)	± .028%Δρ
	-1.80%Δρ	(Rel.)	±3.66%Δρ

cycle only calculations because all upset rod calculations here were for first cycles.

D. Power Coefficient

The power coefficient is the change in core reactivity due to a 1% change in power level. In addition to proper functionalization of the temperature-dependence of the microscopic cross sections, accurate calculation of power coefficients depends on the model used for the effective fuel temperature. All current ROCS models employ fuel temperature correlations that are both local (nodal) power density and fuel exposure dependent. Direct fits to FATES[13] fuel temperature data are used for each fuel type.

Table 4.3-12 shows 15 calculated and measured power coefficients and the differences between them. The average bias was small and slightly positive and therefore conservative. That is, the calculated power coefficients were about 10% less negative than the measured values.

Table 4.3-12

COMPARISON OF POWER COEFFICIENTS

3D ROCS (DIT) VS MEASUREMENT[a]

Plant/Cycle		Power (%)	Calculated	Measured	Difference
Calvert Cliffs I	2	50	-1.06	-1.18	+0.12
		100	-0.94	-1.02	+0.08
	3	50	-1.03	-1.06	+0.03
		100	-0.86	-1.10	+0.24
	4	50	-0.89	-1.08	+0.19
Calvert Cliffs II	1	50	-1.07	-1.07	0.00
		96	-0.86	-0.94	+0.08
	2	50	-0.95	-1.12	+0.17
		100	-0.77	-0.94	+0.17
	3	50	-0.92	-1.01	+0.09
St. Lucie I	1	50	-1.15	-1.16	+0.01
		83	-0.96	-1.06	+0.10
		98	-0.85	-0.90	+0.05
	2	100	-0.83	-0.72	-0.11
	3	100	-0.77	-0.82	+0.05

Mean Difference + .10

Standard Deviation ± .07

a. Units of 10^{-4} $\Delta\rho$/%P.

The uncertainty in ROCS/DIT power coefficients is characterized by tolerance limits of ± 0.18 x 10^{-4} $\Delta\rho$/%power on a 95/95 probability/confidence level.

4.3.3.1.2.2.2 Depletion Data. The two quantities which are monitored on a continuing basis during nominal full power

operation are the reactivity depletion rate and the power distributions. The constant monitoring of these quantities establishes the validity of the nuclear design. The reactivity depletion rate is monitored by comparing measured critical steady states conditions with corresponding calculated conditions. These conditions are characterized by exposure, power level, boron concentration, inlet temperature, and control rod insertion.

Since the measured and the calculated critical conditions most likely differ in some respects, an interpolation scheme was devised to infer a calculated reactivity at each measured condition. The results are displayed in Figure 4.3-13 for five later cycles of the 14 x 14 fuel assembly type core. It shows a small and consistent burnup independent reactivity bias of -0.25% $\Delta\rho$, with a 95/95 probability level of $\pm$ 0.22% $\Delta\rho$. This bias is in good agreement with the hot zero power bias given earlier, demonstrating that Doppler and thermal hydraulics reactivity effects, as well as fission product worth, are correctly treated throughout life by the ROCS/DIT system.

For cores of the 16 x 16 assembly type such as System 80, the experimental data base is not as large. Figure 4.3-14 shows a composite picture of the reactivity bias for both reactor types. This demonstrates that the reactivity predictive capabilities for System 80 are comparable to those for current reload cycles of the earlier design.

4.3.3.1.2.2.3 Assembly Power Distributions. The uncertainty to be attributed to calculated fuel assembly power distributions can be obtained by comparing detailed three-dimensional calculations of the assembly powers with those inferred from in-core measurements with the CECOR[18] system using fixed in-core rhodium detectors. The resulting differences are a reflection of both measurement and calculational errors. In order to determine the uncertainty to be attributed to the calculation, the measurement uncertainty has been subtracted out from these difference distributions as described below. The measurement uncertainty was taken from an evaluation of the uncertainty associated with the CECOR system.[17]

Estimates have been made of σ^{c}_{FR}, σ^{c}_{FXY}, and σ^{c}_{FQ}, for the standard deviations of the differences between calculated and true assembly power. The data base included Arkansas Nuclear One Unit 2 (ANO2) cycle 1, Calvert Cliffs Unit I (BGE I) cycles 1-2, Calvert Cliffs Unit 2 (BGE II) cycles 1-2, and St. Lucie Unit 1 (FPL) cycles 1-3. ANO2 is a 177-assembly core with a 16 x 16 fuel pin lattice, while the other cores have 217 assemblies with a 14 x 14 lattice. Overall, comparisons were made for these 8 cycles over 112 time points with about 40 instrument strings each, resulting in about 20,000 data points.

Table 4.3-13 summarizes the calculational uncertainties.[19]

Table 4.3-13

SUMMARY OF ROCS/DIT CALCULATIVE UNCERTAINTIES

ROCS Calculational Uncertainty	F_{XY}	F_Q	F_R
Percent deviation, S_C	1.88%	2.89%	1.47%
95/95 Confidence internal, KS_C(%)	4.94%	5.25%	3.44%

4.3.3.2 Spatial Stability

4.3.3.2.1 Methods of Analysis

An analysis of xenon-induced spatial oscillations may be done by two classes of methods: time-dependent spatial calculations and linear modal analysis. The first method is based on computer simulation of the space-, energy-, and time-dependence of neutron flux and power density distributions. The second method calculates the damping factor based on steady-state calculations of flux, importance (adjoint flux), xenon and iodine concentrations, and other relevant variables.

The time-dependent calculations are indispensable for studies of the effects of CEAs on core margin, out-of-core, and in-core detector responses, and are performed in one, two, and three dimensions with few-group diffusion theory, using tested computer codes and realistic modeling of the reactor core. The linear modal analysis methods are used to calculate the effect on the damping factors of changes in fuel zoning, enrichment, CEA patterns, operating temperature, and power levels. These methods, using information at a single point in time, are particularly suited to survey-type calculations. Methods are based on the work of Randall and St. John[20] as

extended by Stacey.[21] These methods are verified by comparison with time-dependent calculations.

4.3.3.2.2 Radial Xenon Oscillations

To confirm that the radial oscillation mode is extremely stable, a space-time calculation was run for a reflected, zoned core representative of System 80 without including the damping effects of the negative power coefficient. The initial perturbation was a poison worth of 0.4% in reactivity placed in the central 20% of the core for 1 hour. Following removal of the perturbation the resulting oscillation was followed in 4-hour time steps for a period of 80 hours. The resulting oscillation died out very rapidly with a damping factor of about -0.06 per hour. When this damping factor is corrected for a finite-time step size by the formula in Reference 22, a more negative damping factor is obtained indicating an even more strongly convergent oscillation. On this basis, it is concluded that a radial oscillation instability will not occur.

4.3.3.2.3 Azimuthal Xenon Oscillations

Two-dimensional modal analysis techniques were used to calculate the damping factor for azimuthal oscillations, and included both the fuel-temperature and moderator-temperature components of the total power coefficient. These calculational techniques were used to predict the results of azimuthal oscillation tests at Maine Yankee at 75% power. The predicted damping factor of -0.045 per hour for azimuthal oscillations was found to agree well with the measured value of -0.047 % 0.005 per hour.

4.3.3.2.4 Axial Xenon Oscillations

To check and confirm the predictions of the linear modal analysis approach, numerical space-time calculations were performed for both beginning and end-of-cycle. The fuel and poison burnup distributions were obtained by depletion with soluble boron control, so that the power distribution was strongly flattened. Spatial Doppler feedback was included in these calculations. In figure 4.3-15, the time variation of the power distribution along the core axis is shown for the end-of-cycle with reduced Doppler feedback.

The initial perturbation used to excite the oscillations was a 50% insertion into the top of the core of a 1.5% reactivity CEA bank for 1 hour. The damping factor for this case was calculated to be about 0.02 per hour; however, when corrected for finite-time step intervals by the methods of Reference 22, the damping factor is increased to approximately +0.04. When this damping factor is plotted on figure 4.3-16 at the appropriate eigenvalue separation for this mode at end-of-cycle, it is apparent that good agreement is obtained with the modified Randall-St. John distribution of the moderator coefficient about the core midplane, and its consequent flux and adjoint weighted integrals of approximately zero.

Axial xenon oscillation experiments performed at Omaha at a core exposure of 7000 MWd/T and at Stade at beginning of cycle and at 12000 MWd/T[23] were analyzed with a space-time one-dimensional axial model. The results are given in table 4.3-14 and show no systematic error between the experimental and analytical results.

Table 4.3-14

AXIAL XENON OSCILLATIONS

Reactor	Exposure (MWd/T)	Period (h)		Damping (h_{-1})	
		Measured	Calculated	Measured	Calculated
Omaha	7075	29	32	-0.027	-0.030
Stade	BOC	36	36	-0.096	-0.090
Stade	12200	27	30	-0.021	-0.019

4.3.3.3 Reactor Vessel Fluence Calculation Model

The general method for calculation of fluence to the reactor vessel uses results obtained from two dimensional transport calculations with the DORT code, which is a routine within the Oak Ridge National Laboratory's DOORS code suite.[(24)] The DORT model uses a r, r,θ, and r,z coordinate system to represent the geometry of the core, surrounding water, internals, and vessel and follows the guidance of Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence."[(26)]

The preliminary vessel fluence data given in paragraph 4.3.2.8 is calculated by a more approximate one dimensional subset of this method using ANISN.[(25)] The calculated vessel fluence was obtained by applying a one-dimensional cylindrical geometry model for the core and vessel configuration based upon the azimuthal location of the peak vessel fluence.

The calculated vessel fluence is validated in part by comparisons between calculation and measurements of surveillance capsule data.

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4.4 THERMAL AND HYDRAULIC DESIGN

This section presents the steady-state thermal and hydraulic analysis of the reactor core, the analytical methods, and the experimental work done to support the analytical techniques. Discussions of the analyses of anticipated operational occurrences and accidents are presented in chapter 15. The prime objective of the thermal and hydraulic design of the reactor is to ensure that the core can meet steady-state and transient performance requirements without violating the design bases.

The thermal and hydraulic design of the reactor coolant system are discussed in subsection 4.4.3. The line lengths and sizes of the safety injection lines are given in table 4.4-1 and a simplified safety injection piping diagram is provided in figure 4.4-1.

4.4.1 DESIGN BASES

Avoidance of thermally or hydraulically induced fuel damage during normal steady-state operation and during anticipated operational occurrences is the principal thermal hydraulic design basis. The design bases for accidents are specified in chapter 15. In order to satisfy the design basis for steady-state operation and anticipated operational occurrences, the following design limits are established, but violation of these will not necessarily result in fuel damage. The reactor protective system (RPS) provides for automatic reactor trip or other corrective action before these design limits are violated.

Table 4.4-1
SAFETY INJECTION PIPING (Sheet 1 of 3)

Injection Route		Length (ft)	Size (in.)
From	To		
LPSI Pump SIA-P01 (via valve SIA-UV635)	RCS cold leg	119 108 177 41	10 20 12 14
LPSI Pump SIB-P01 (via valve SIB-UV615)	RCS cold leg	108 72 173 34	10 20 12 14
LPSI Pump SIA-P01 (via valve SIA-UV645)	RCS cold leg	119 105 273 34	10 20 12 14
LPSI Pump SIB-P01 (via valve SIB-UV625)	RCS cold leg	108 68 161 34	10 20 12 14
HPSI Pump SIA-P01 (via valve SIA-UV637)	RCS cold leg	235 22 26 21 124 41	4 2 4 3 12 14
HPSI Pump SIB-P02 (via valve SIB-UV646)	RCS cold leg	361 15 22 27 217 34	4 2 4 3 12 14
HPSI Pump SIA-P02 (via valve SIA-UV647)	RCS cold leg	235 13 23 27 217 34	4 2 4 3 12 14

Table 4.4-1
SAFETY INJECTION PIPING (Sheet 2 of 3)

Injection Route		Length (ft)	Size (in.)
From	To		
HPSI Pump SIB-P02 (via valve SIB-UV636)	RCS cold leg	362 12 28 21 124 41	4 2 4 3 12 14
HPSI Pump SIA-P02 (via valve SIA-UV627)	RCS cold leg	335 15 30 22 106 34	4 2 4 3 12 14
HPSI Pump SIB-P02 (via valve SIB-UV626)	RCS cold leg	209 12 29 22 106 34	4 2 4 3 12 14
HPSI Pump SIA-P02 (via valve SIA-UV617)	RCS cold leg	335 25 49 23 80 34	4 2 4 3 12 14
HPSI Pump SIB-P02 (via valve SIB-UV616)	RCS cold leg	209 18 48 23 80 34	4 2 4 3 12 14
HPSI Pump SIA-P02 (via valve SIA-HV604)	RCS hot leg	27 375 12	4 3 16
HPSI Pump SIB-P02 (via valve SIB-UV609)	RCS hot leg	27 266 43	4 3 16

Table 4.4-1
SAFETY INJECTION PIPING (Sheet 3 of 3)

Injection Route		Length (ft)	Size (in.)
From	To		
SI Tank SIE-X01A	RCS cold leg	77	14
SI Tank SIE-X01B	RCS cold leg	78	14
SI Tank SIE-X01C	RCS cold leg	75	14
SI Tank SIE-X01D	RCS cold leg	77	14

4.4.1.1 Minimum Departure from Nucleate Boiling Ratio (DNBR)

The minimum DNBR shall be such as to provide at least a 95% probability with 95% confidence that departure from nucleate boiling (DNB) does not occur on a fuel rod having that minimum DNBR during steady-state operation and anticipated transients of moderate frequency. A value of 1.34 provides this probability and confidence, as described in paragraph 4.4.2.2.1.

4.4.1.2 Hydraulic Stability

Operating conditions shall not lead to flow instability during steady-state operation or anticipated operational occurrences.

4.4.1.3 Fuel Design Bases

A. The peak temperature of the fuel shall be less than the melting point (5080F unirradiated, reduced by 58F per 10,000 MWd/Mtu for burnup and adjusted for burnable poisons per CENPD-382-P-A) during steady-state operation and anticipated occurrences of moderate frequency.

B. The fuel design bases for fuel clad integrity and fuel assembly integrity are given in subsection 4.2.1. Thermal and hydraulic parameters that influence the integrity include maximum linear heat rate, core coolant velocity, coolant temperature, clad temperature, fuel-to-clad gap conductance, fuel burnup, and UO_2 temperature. Other than the design limits already specified, no limits need to be applied to these parameters directly. Conformance with the design limits

specified here and conformance with the design bases specified in subsection 4.2.1 are sufficient to ensure fuel clad integrity, fuel assembly integrity, and the avoidance of thermally or hydraulically induced fuel damage for steady-state operation and anticipated occurrences of moderate frequency.

4.4.1.4 Coolant Flow, Velocity, and Void Fraction

The primary coolant flow with all four pumps in operation shall be neither less than the design minimum nor greater than the design maximum. A percentage of the flow entering the reactor vessel is not effective for cooling the core. This percentage is called the core bypass flow. The design minimum value for the calculated core flow is obtained by subtracting the design maximum value for the calculated core bypass flow from the design minimum primary coolant flow. For thermal margin analyses, the design minimum value for the calculated core flow is used. The design minimum primary coolant flow is listed in table 4.4-2.

The design pre-core and post-core maximum primary coolant flows are equal to 1.22 and 1.16 times the design minimum primary coolant flow, respectively. The design maximum primary coolant flow is used in the determination of design hydraulic loads in the manner described in paragraph 4.4.2.6.3.

Design of the reactor internals provides for the coolant flow to be distributed to the core such that the core is adequately cooled during steady-state operation and anticipated

operational occurrences. Therefore, no specific orificing configuration is used.

Although the coolant velocity, its distribution, and the coolant voids affect the thermal margin, design limits need not be applied to these parameters because they are not in themselves limiting. These parameters are included in the thermal margin analyses and thus affect the thermal margin to the design limits.

Table 4.4-2
TYPICAL THERMAL HYDRAULIC PARAMETERS AT FULL POWER
(Sheet 1 of 2)

General Characteristics	Units	PVNGS Units[d] 1, 2, & 3	Waterford Steam Electric Station Unit 3
Total heat output (core only)	MWt 10^6 Btu/hr	3,990 13,614	3,390 11,570
Fraction of heat generated in fuel rod	--	0.975	0.975
Primary system pressure, nominal	psia	2,250	2,250
Inlet temperature, nominal	°F	560.4	553.0
Total reactor coolant flow (minimum steady state)[a]	gpm 10^6 lbm/hr	423,320 155.8	396,000 145.8
Coolant flow through core (minimum)	10^6 lbm/hr	151.1	140.6
Hydraulic diameter (nominal channel)	ft	0.039	0.039
Average mass velocity	10^6 lbm/hr-ft^2	2.61	2.61
Core average heat flux (accounts for fraction of heat generated in fuel rod and axial densification factor)	Btu/hr-ft^2	192,203[b]	182,400

a. Licensed minimum flow rate.

b. Representative value; depends on the number of non-fuel rods. This value assumes all rod locations are fuel rods, except for 100 non-fuel rods for the purposes of fuel reconstitution.

Table 4.4-2
TYPICAL THERMAL HYDRAULIC PARAMETERS AT FULL POWER
(Sheet 2 of 2)

General Characteristics	Units	PVNGS Units[d] 1, 2, & 3	Waterford steam Electric Station Unit 3
Total heat transfer area (accounts for axial densification factor)	ft^2	68,323[b]	62,000
Average linear heat rate of undensified fuel rod (accounts for fraction of heat generated in fuel rod)	kW/ft	5.62[b]	5.34
Average core enthalpy rise	Btu/lbm	90.1	81
Engineering heat flux factor	--	1.03[c]	1.03
Engineering enthalpy rise factor	--	1.03[c]	1.03
Rod pitch, bowing, and clad diameter factor	--	1.05[c]	1.05
Maximum augmentation factor	--	1.0	1.041

c. These factors have been combined statistically with other uncertainty factors as described in reference 1 to define overall uncertainty penalty factors to be applied in the DNBR calculations in COLSS and CPC which, when used in conjunction with the appropriate DNBR limit for that cycle, provide assurance at the 95/95 confidence/probability level that the hot rod will not experience DNB.

d. These values are typical (Generic) design operating conditions that do not necessarily reflect any specific unit and cycle.

Table 4.4-3
TYPICAL THERMAL AND HYDRAULIC PARAMETERS FOR FSAR ANALYSES

Reactor Parameters	PVNGS Units 1, 2, & 3	Waterford Steam Electric Station Unit 3 (Docket No. 50-382)
Design maximum core bypass flow, % of primary	3.0	3.5
Power distribution factors:		
Rod radial power factor	1.55	1.55
Nuclear power factor	2.28	2.28
Total heat flux factor	2.35	2.35
Engineering factor on linear heat rate	1.03	1.03
Fuel densification factor (axial)	1.002	1.002
Characteristics of rod and channel with minimum DNBR:		
Maximum fuel rod heat flux, Btu/hr-ft^2	447,000	428,000
Maximum fuel rod linear heat rate, kW/ft	13.1	12.5
UO_2 maximum steady state temperature, °F	3,200	3,180
Outlet temperature, °F	652	642
Outlet enthalpy, Btu/lbm	699	680
Minimum DNBR at nominal conditions (CE-1 correlation)	1.79	2.07

4.4.2 DESCRIPTION OF THERMAL AND HYDRAULIC DESIGN OF THE REACTOR CORE

4.4.2.1 Summary Comparison

Typical thermal and hydraulic parameters for the reactor are listed in tables 4.4-2 and 4.4-3. A comparison of these parameters with those for the Waterford Steam Electric Station Unit 3 (Docket No. 50-382) is included in these tables.

The principal difference between the two reactors is the total core heat output.

4.4.2.2 Critical Heat Flux Ratios

4.4.2.2.1 Departure from Nucleate Boiling Ratio

The margin to DNB in the core is expressed in terms of the departure from nucleate boiling ratio (DNBR). The DNBR is defined as the ratio of the heat flux required to produce departure from nucleate boiling at the calculated local coolant conditions to the actual heat flux.

The DNB correlation used for design of the core is the CE-1 correlation.(2)(3) Based on statistical evaluation of the CE-1 correlation and relevant data for 14 x 14 and 16 x 16 fuel assemblies, Combustion Engineering concluded that the appropriate minimum DNBR is 1.13.(2)(3) NRC evaluation of the uniform axial power distribution data for 16 x 16 assemblies resulted in their concluding that the CE-1 critical heat flux correlation, when coupled with the TORC code, provided an acceptable correlation of uniform axial CHF data and that the minimum acceptable DNBR was 1.19.(4) Statistical combination of

uncertainties (SCU) methods were later used to statistically combine the uncertainties of the thermal hydraulic code input parameters (system parameters) as described in reference 5. Using this SCU methodology, the following uncertainties were statistically combined with CE-1 CHF correlation statistics at 95/95 confidence/probability level to yield a 1.231 DNBR limit for Cycle 1:

- Systematic variation on fuel rod pitch
- Systematic variation on fuel clad OD
- Engineering enthalpy rise factor
- Engineering heat flux factor
- Penalty on minimum DNBR due to fuel rod bowing
- Statistics associated with the NRC-approved 1.19 DNBR limit

Also included in this MDNBR limit are a 0.01 penalty[6] for the use of HID spacer grid, the penalty due to the CHF correlation uncertainty and penalties imposed by the NRC to account for CHF correlation "prediction uncertainty" and TORC code uncertainty. Beginning with cycle 2, the MDNBR limit was increased from 1.231 to 1.24 due to the increase in rod bow penalty from 0.8% in cycle 1 to 1.75% starting with cycle 2. The DNBR limit was used in safety analysis, CPC trip set points, and COLSS power operating limit calculations in conjunction with a CETOP model based on a nominal geometry.

Beginning with Unit 3 Cycle 5, a topical report supplement[7] was utilized that treats the core inlet flow distribution data

in a statistical manner, as opposed to a deterministic manner, for use with SCU methodology for assessing core thermal margin. Utilizing this statistical approach removes conservatism inherent in the deterministic approach and results in a gain of additional calculated core thermal margin. The MDNBR was increased from 1.24 to 1.30 due to using the statistical treatment of the core inlet flow distribution data with the SCU methodology.

Beginning with U2C11, the DNBR Safety Limit was increased from 1.30 to 1.34. This change accommodated increased DNBR sensitivity to uncertainties in inlet flow to the hot assembly and adjacent assemblies. This increased sensitivity was attributed to the flatter power distributions of the more efficient present day erbium core designs.

This increased DNBR sensitivity to inlet flow was first encountered in Unit 1 Cycle 7. Since the NRC Safety Evaluation (issued May 26, 1994 for PVNGS Units 1, 2, and 3) for the then current 1.30 DNBR limit stated "Uncertainties in inlet flow to the hot assembly and adjacent assemblies can be accounted for statistically by either increasing DNBR [Limit] or applying a thermal margin penalty using approved SCU methods." it was chosen to account for the increased DNBR sensitivity by applying a thermal margin penalty to COLSS and CPC. This approach was also used for the subsequent cycles in Units 1 and 3. Prior to U2C11 a new bounding DNBR limit (1.34) had been calculated. It took into account the increased DNBR sensitivity to inlet flow. Implementing the new bounding DNBR limit moved the accounting for the increased DNBR sensitivity to inlet flow from a thermal margin penalty on COLSS and CPC to

an increase in the DNBR limit. This change modified the reload safety analysis and setpoint design bases to make them less confusing thus simplifying their human interface with respect to DNBR limit (since the Safety Limit and effective DNBR trip setpoint are the same again) to avoid possible future errors.

When required, additional increases in DNBR sensitivity to flow uncertainties will continue to be addressed as a thermal penalty in accordance with the May 26, 1994 NRC Safety Evaluation.

A historical comparison of the minimum DNBRs computed using different correlations for the same power, flow, coolant temperature and pressure, and power distribution is presented in table 4.4-4. The minimum DNBR values in both the limiting matrix subchannel and the limiting subchannel next to the guide tube are presented. The correlations compared are the CE-1 correlation, the original W-3 correlation,[8] the revised W-3 correlation,[9] and the B&W-2 correlation.[9] The differences between the original and revised W-3 correlations as used here are in the Tong F-factor (which accounts for the effects of nonuniform axial heat flux distributions) and cold wall correction factor (which accounts for the effects of different heated and wetted equivalent diameters). The Tong F-factor is also known as a "C-factor" or "shape factor" in the referenced correlation source documents.

Table 4.4-4

COMPARISON OF THE DEPARTURE FROM NUCLEATE BOILING RATIOS COMPUTED WITH DIFFERENT CORRELATIONS[a]

	DNBRs for Nominal Reactor Conditions		DNBRs for Reactor Conditions Giving a 1.19 CE-1 Minimum DNBR in Matrix Subchannel	
Correlation	Matrix Subchannel	Subchannel Next to Guide Tube	Matrix Subchannel	Subchannel Next to Guide Tube
CE-1	1.99	1.79	1.19	1.15
Original W-3[8]	1.95	2.04	1.08	1.16
Revised W-3[9]	1.95	1.90	1.08	1.21
B&W-2[9]	2.41	2.62	1.42	1.68

(a) This comparison is based on the Cycle 1 MDNBR limit of 1.19. The overall comparison would be similar to the current MDNBR limit of 1.34.

Additional comparisons are contained in CENPD-162-A.[2] In general, the CE-1 correlation predicts lower values of CHF than the B&W-2 correlation, with the differences increasing with increasing inlet subcooling. In comparison with the W-3 correlation, the CE-1 correlation tends to predict lower values of CHF with high inlet subcooling, and higher values of CHF with low inlet subcooling.

The TORC and the CETOP computer codes[10][11] are used to compute the local coolant conditions in the core and thereby the minimum DNBR. A discussion of the CE-1 DNB correlation and the analytical methods is presented in paragraphs 4.4.4.1 and 4.4.4.5.2, respectively. The parameter ranges over which the CE-1 correlation is valid are presented in paragraph 4.4.4.1.

4.4.2.2.2 Application of Power Distribution and Engineering Factors

Distribution of power in the core is expressed in terms of factors that define the local power per unit length produced by the fuel relative to the core average power per unit length produced by the fuel. The method used to compute these factors, which describe the core power distribution, is discussed in section 4.3. The energy produced in the fuel deposits in the fuel pellets, fuel cladding, and the moderator, and results in the generation of heat in those places. The fraction of energy deposited in the fuel pellet and cladding is called the fuel rod energy deposition fraction. Accordingly, the core average heat flux from the fuel rods is determined by multiplying the core power by the average fuel rod energy deposition fraction, and then dividing by the total heat transfer area.

The effects on local heat flux and subchannel enthalpy rise of within tolerance deviations from nominal dimensions and specifications are included in thermal margin analyses by certain factors called engineering factors. These factors are applied to increase the local heat flux at the location of minimum DNBR and to increase the enthalpy rise in the subchannel adjacent to the rod with the minimum DNBR. Diversion cross-flow and turbulent interchange mixing are not input as factors on subchannel enthalpy rise but are explicitly treated in the TORC and CETOP codes' analytical models.

Uncertainties in the power distribution factors are discussed in paragraph 4.4.2.9.4.

4.4.2.2.2.1 Power Distribution Factors

A. Rod Radial Power Factor

The rod radial power factor is the ratio of the average power per unit length produced by a particular fuel rod to the average power per unit length produced by the average powered fuel rod in the core. The maximum rod radial power factor is the ratio of the average power per unit length produced by the highest powered rod in the core to the average power per unit length produced by the average powered fuel rod in the core. Radial power distributions are dependent upon a variety of parameters (control rod insertion, power level, fuel exposure, etc.). The core wide and hot assembly radial power distributions used for a typical DNB analysis are shown in figures 4.4-2 and 4.4-3. The maximum rod radial power factor for those figures is selected as 1.55 for better comparison with the Waterford Station Unit 3. The actual maximum rod radial power reactor in the core is not limited to a maximum value of 1.55. The only limits are those specified in subsection 4.4.1. The protection system, in conjunction with the reactor operator maintaining Technical Specification limiting conditions for operation (LCOs), ensures that those design limits are not violated.

B. Axial Power Factor

The axial power factor is the ratio of the local power per unit length produced by a fuel rod to the average power per unit length produced by the same fuel rod.

The maximum axial power factor is the ratio of the maximum local power per unit length produced by a rod to the average power per unit length produced by the same fuel rod. The axial power distribution directly affects DNBR.

Typically, the farther the location of the peak heat flux is from the core inlet, the lower the value of the peak heat flux needed to reach the DNBR limit. On the other hand, fuel temperature is almost independent of the location of the peak heat flux and is principally dependent on the value of the peak heat flux or linear heat rate. Section 4.3 describes the power distributions and their control. Figure 4.4-4 shows several axial power distributions used for this analysis. The minimum DNBR in table 4.4-3 is determined using the 1.26 peaked axial power distribution, whereas the maximum heat fluxes are determined using the 1.47 peaked axial power distribution.

C. Nuclear Power Factor

The nuclear power factor is the ratio of the maximum local power per unit length produced in the core to the average power per unit length produced by the average powered fuel rod in the core. It is conservatively calculated as the product of the maximum axial and radial power factors. For better comparisons with Waterford Station Unit 3, a value of 2.28 is selected for computing maximum heat fluxes. The actual value of

the nuclear power factor is not limited to a maximum value of 2.28. The design limits are those specified in subsection 4.4.1. The protection and supervisory system and Technical Specification LCOs assure that those design limits are not violated.

D. Total Heat Flux Factor

The total heat flux factor is the ratio of the local fuel rod heat flux to the core average fuel rod heat flux. The effects of fuel densification are not included in this factor. To determine the maximum local heat flux including the effect of gaps occurring between the fuel rod pellets, the augmentation factor should be applied. From this definition, the total heat flux factor is the product of the nuclear power factor, the engineering heat flux factor, and the ratio of the hot to the average rod energy deposition fractions. The total heat flux factor is given in table 4.4-3.

E. Augmentation Factor

The densification of the fuel may lead to axial gaps in the fuel pellets stacks and can cause increased localized power peaking. This effect is expressed in terms of the augmentation factor which is defined as the ratio of the local heat flux to the unperturbed heat flux. The axial length over which the localized power perturbation is considered to occur is called the gap length. The augmentation factor is given in

table 4.4-2. The effect of this factor on DNBR is discussed in paragraph 4.4.2.2.3.

4.4.2.2.2.2 Engineering Factors

A. Engineering Heat Flux Factor

The effect on local heat flux due to normal manufacturing deviations from nominal design dimensions and specifications is accounted for by the engineering heat flux factor. Design variables that contribute to this engineering factor are initial pellet density, pellet enrichment, pellet diameter, and clad outside diameter.

These variables are combined statistically to obtain the engineering heat flux factor. The design value used for the engineering heat flux factor is based on deviations obtained from fuel manufacturing inspection data for over 25 batches of fuel for previous reactor cores. Similar tolerances and quality control procedures are used for the PVNGS cores. The engineering heat flux factor is applied to the rod with the minimum DNBR and increases the heat flux when calculating DNBR. It does not affect the enthalpy rise in the subchannel; the effect on the enthalpy rise in the subchannel due to normal manufacturing deviations from normal design dimensions and specifications is accounted for by the engineering enthalpy rise factor.

B. Engineering Factor on Linear Heat Rate

The effect of deviations from nominal fuel rod design dimensions and specifications of fuel temperature is accounted for by the engineering factor on linear heat rate. An engineering factor of 1.03 conservatively bounds the established fuel rod design dimensional tolerances and specifications.

C. Engineering Enthalpy Rise Factor

The engineering enthalpy rise factor accounts for the effects of normal manufacturing deviations in fuel fabrication from nominal dimensions and specifications on the enthalpy rise in the subchannel adjacent to the rod with the minimum DNBR. Tolerance deviations (average over the length of the fuel rods that adjoin the subchannel) for fuel pellet density, enrichment, and diameter contribute to this factor.

The engineering enthalpy rise factor is applied by multiplying by the factor, the rod radial power factor of each of the fuel rods adjacent to the subchannel adjoining the rod with the minimum DNBR. This increases the enthalpy rise in the subchannels which adjoin the same fuel rods.

D. Pitch and Bow Factor

The pitch and bow factor is an allowance for the effect of enthalpy rise or the possible decreased flowrate in the subchannel resulting from a smaller than nominal subchannel flow area.

The pitch and bow factor is applied by multiplying by the factor, the incremental enthalpy rise in the limiting subchannel adjacent to the rod with the minimum DNBR. This increases the enthalpy rise in that subchannel in the same manner as does the engineering enthalpy rise factor, but does not directly affect the heat input into the surrounding subchannels. The combined effects of diversion cross-flow and turbulent interchange resulting from the higher heat input and enthalpy rise are computed by the TORC code. The pitch and bow factor to account for the effects of fuel rod bowing has been superseded by an explicit rod bow DNBR penalty. Based on CENPD-225,[12] a 0.8% rod bow penalty for fuel bundle burnups up to 20,000 MWd/Mtu was used in cycle 1. Starting with cycle 2, a 1.75% penalty for burnups up to 30,000 MWd/Mtu was used. Bundles having burnups in excess of 30,000 MWd/Mtu are not limiting with respect to DNB margin due to the lower radial peaks in higher burnup bundles. The rod bow penalty is included in the minimum DNBR limit as discussed in paragraph 4.4.2.2.1. Additional discussions of fuel and poison rod bowing are presented in CENPD-225.[12]

4.4.2.2.3 Fuel Densification Effect on DNBR

The perturbation in local heat flux due to fuel densification is given in table 4.4-3.

As shown in CENPD-207[3] (see paragraph 4.4.4.1), even much larger local heat flux variations have no significant adverse effect on DNB in San Onofre Units 2 and 3 fuel assemblies.

Therefore, no specific allowance is made or required for the effect on DNBR of local heat flux variations due to densification of the fuel.

4.4.2.3 Linear Heat Generation Rate

The core average and maximum fuel rod linear heat generation rates are given in tables 4.4-2 and 4.4-3. The maximum fuel rod linear heat generation rate is determined by multiplying the core average fuel rod linear heat generation rate by the product of the nuclear power factor, the engineering factor on linear heat rate, and the ratio of the hot to the average fuel rod energy deposition fractions. The effects of fuel densification are not included in the maximum fuel rod linear heat generation rate presented in table 4.4-3; although, to determine the maximum local linear heat generation rate including the effect of gaps occurring between the fuel pellets, the augmentation factor is applied.

4.4.2.4 Void Fraction Distribution

The core average void fraction and the maximum void fraction are calculated using the Maurer method.(13) The void fractions discussed below are values for the reactor operating conditions and engineering factors given in tables 4.4-2 and 4.4-3, for the radial power distribution in figures 4.4-2 and 4.4-3, and for the 1.26 peaked axial power distribution in figure 4.4-4. For these conditions, only subcooled boiling occurs in the core.

The core average void fraction is less than 0.1%. The local maximum void fraction is 10% and occurs at the exit of the

subchannel adjacent to the rod with the minimum DNBR. The average exit void fractions and qualities in different regions of the core are shown in figure 4.4-5 for the core radial power distribution shown in figure 4.4-2. The axial distribution of void fraction and quality in the subchannel adjacent to the rod with the minimum DNBR is shown in figure 4.4-6. The average void fraction in that subchannel is 0.5%.

4.4.2.5 Core Coolant Flow Distribution

The core inlet flow distribution is required as input to the TORC thermal margin code (refer to paragraph 4.4.4.5.2). The inlet flow distribution for four-loop operation was determined from flow tests. Descriptions of the tests and the resulting core inlet flow distribution are given in paragraph 4.4.4.2.1.

4.4.2.6 Core Pressure Drops and Hydraulic Loads

4.4.2.6.1 Reactor Vessel Flow Distribution

The design minimum coolant flow entering the four reactor vessel inlet nozzles is given in table 4.4-2. The main coolant flow path in the reactor vessel is down the annulus between the reactor vessel and the core support barrel, through the flow skirt, up through the core support region and the reactor core, through the fuel alignment plate, and out through the two reactor vessel outlet nozzles. A portion of this flow leaves the main flow path as shown schematically in figure 4.4-7. Part of the bypass flow is used to cool the reactor internals in the areas not in the main coolant flow path and to cool the CEAs. Table 4.4-5 lists the bypass flow paths and the percent of the total vessel flow that enters and leaves these paths.

Table 4.4-5
BEST ESTIMATE REACTOR COOLANT FLOWS IN BYPASS CHANNELS

Bypass Route	Percent of Total Vessel Flow
Outlet nozzle clearances	1.0
Alignment keyways	0.4
Core shroud annulus	0.3
Guide tubes	0.6
Total Bypass	2.3

The thermal margin calculations conservatively use the design bypass flow of 3.0% of the total vessel flow shown in table 4.4-3 as compared to the calculated bypass flow of 2.3% shown in table 4.4-5.

4.4.2.6.2 Reactor Vessel and Core Pressure Drops

The irrecoverable pressure losses from the inlet to the outlet nozzles are calculated using standard loss coefficient methods and information from flow model tests. These pressure losses have been verified by results from flow tests for the System 80 reactor, as described in section 4.4.4.2.1.1.

Pressure losses at 100% power, the design minimum primary coolant flow, and an operating pressure of 2250 lb/in^2 are listed in table 4.4-6 together with the coolant temperature used to calculate each pressure loss. The calculated pressure losses include both geometric and Reynolds number dependent effects.

Table 4.4-6
REACTOR VESSEL BEST ESTIMATE
PRESSURE LOSSES AND COOLANT TEMPERATURES[(a)]

Component	Pressure Loss (lb/in.^{2})	Temperature (°F)
Inlet nozzle and 90° turn	9.6	565
Downcomer, lower plenum, and support structure	12.3	565
Fuel assembly	16.4	595
Fuel assembly outlet to outlet nozzle	14.8	625
Total pressure loss	53.1	

(a) Note: Best estimate pressure losses are evaluated on a cycle-by-cycle basis to consider the effect of fuel mechanical design and other changes in plant design or operation. For example, the best estimate pressure loss across the Unit 1 Cycle 8 core is 16.3 psid, and the total pressure loss is 52.6 psid, or within 1% of the values in this table.

4.4.2.6.3 Hydraulic Loads on Internal Components

The significant hydraulic loads which act on the reactor internals during steady state operation are listed in table 4.4-7. These loads are determined from analytical methods and from results of reactor flow model and components test programs (refer to paragraphs 4.4.4.2.1 and 4.4.4.2.2, respectively). The design hydraulic loads consist of steady-state drag and impingement loads, and the fluctuating loads induced by pump-induced pressure pulsations, vortex shedding, and turbulence.

The hydraulic loads are initially evaluated on a best estimate basis with a flow rate equal to the design maximum flow rate minus expected measurement uncertainty. The effects of uncertainties in the input, such as flow rates, force coefficients, and dimensional tolerances, are added to the best estimate loads. Finally, where appropriate, the effect of a six psi increase in core Δp due to crudding is added to arrive at the final design hydraulic loads.

In evaluating the design hydraulic loads, consideration is given to the particular pump operating configuration and coolant temperature that maximize the hydraulic load for a given internal component.

All hydraulic loads in table 4.4-7 are based on the design maximum primary coolant flow and a coolant temperature of 500F. When other coolant conditions result in more limiting loading for individual components, the loads in table 4.4-7 are adjusted in the detailed design analysis.

Hydraulic loads for postulated accident conditions are discussed in paragraph 3.9.2.5.

Table 4.4-7
DESIGN STEADY STATE HYDRAULIC LOADS
ON VESSEL INTERNALS AND FUEL ASSEMBLIES[(a)]

Component	Steady State Load Description	Load Value
Core support barrel	Radial pressure differential directed inward opposite inlet duct Uplift load Lateral load	95 lb/in^2 1.5×10^6 lb 0.36×10^6 lb
Upper guide structure	Uplift load Lateral load	0.7×10^6 lb 0.42×10^6 lb
Flow skirt	Radial pressure differential directed inward Axial load directed downward	68 max. psi 27 avg. psi 3050 max. lb/ft of circ. 1400 avg. lb/ft of circ.
Instrumentation plate supports	Lateral drag load directed inward	380 lb, max. support
Instrumentation support plate	Uplift load	3300 lb
Instrumentation tube	Lateral drag load directed inward	1200 lb, max. tube
Bottom plate	Drag load directed upward	111,600 lb
Lower support structure beams	Drag load directed upward Lateral load	1,900 lb 7,500 lb
Fuel assembly	Uplift load	2270 lb
Core shroud	Radial pressure differential directed outward	40 lb/in^2 at bottom 0 lb/in^2 at top
Fuel alignment plate	Drag load directed upward	320,600 lb
CEA shroud tubes	Lateral drag load	2400 lb, max. tube
Upper guide plate	Load directed downward	278,800 lb

a. Load values at 500F. Actual values may vary.

4.4.2.7 Correlations and Physical Data

4.4.2.7.1 Heat Transfer Coefficients

The correlations used to determine cladding temperatures for nonboiling forced convection and nucleate boiling are discussed here. The surface temperature of the cladding is dependent on the axial and radial power distributions, the temperature of the coolant, and the surface heat transfer coefficient.

The surface heat transfer coefficient for nonboiling forced convection is obtained from the Dittus-Boelter correlation[14] where fluid properties are evaluated at the bulk condition.

$$h_{db} = \frac{0.023k}{De} \left(N_R\right)^{0.8} \left(N_{Pr}\right)^{0.4}$$

where:

h_{db} = heat transfer coefficient, Btu/h-ft^2-°F

k = thermal conductivity, Btu/h-ft-°F

De = equivalent diameter = $4A/P_w$, ft

N_R = Reynolds number, based on the equivalent diameter and coolant properties evaluated at the local bulk coolant temperature

N_{Pr} = Pradtl number, based on coolant properties evaluated at the local bulk coolant temperature

A = cross-sectional area of flow subchannel, ft^2

P_w = wetted perimeter of flow subchannel, ft

No specific allowance is made or considered necessary for the uncertainties associated with the Dittus-Boelter correlation because the Dittus-Boelter correlation is not used directly in computing thermal margin, but rather plays a part in determining pressure drop and cladding temperature. The validity of the overall scheme for predicting pressure drop is shown by the excellent agreement between predicted and experimental values obtained during the DNB test program and described in paragraph 4.4.4.1. The uncertainty associated with the cladding temperatures calculated for single phase heat transfer is not a major concern because the limiting fuel and cladding temperatures occur where the cladding-to-coolant heat transfer is by nucleate boiling.

The temperature drop across the surface film is calculated from:

$$\Delta T_{film} = q''/h_{db}$$

where:

q'' = fuel rod surface heat flux, Btu/h-ft^2

The maximum fuel rod heat flux is the product of the core average fuel rod heat flux and the total heat flux factor (refer to tables 4.4-2 and 4.4-3 and paragraph 4.4.2.2.2). Nucleate boiling may occur on the clad surface. In the nucleate boiling regime, the surface temperature of the cladding is determined from the Jens and Lottes correlation:[15]

$$T_{wall} = T_{sat} + 60\ (q'' \times 10^{-6})^{0.25}\ [\exp\ (-P/900)]$$

where:

P = pressure, psia

q" = defined above

T_{sat} = saturation temperature, °F

Nucleate boiling is assumed to exist if T_{wall} is less than the sum of $T_{coolant}$ plus ΔT_{film}.

The cladding surface temperature is calculated by summing the temperature of the coolant at the particular location and the temperature drop across the surface film; or if nucleate boiling is occurring, it is calculated directly from the Jens and Lottes correlation.

4.4.2.7.2 Core Irrecoverable Pressure Drop Loss Coefficients

Irrecoverable pressure losses through the core result from friction and geometric changes. The pressure losses through the lower and upper end fittings were initially calculated using the standard loss coefficient method and then verified by test (refer to paragraph 4.4.4.2.2). The correlations used to determine frictional and geometric losses in the core are presented in paragraph 4.4.4.2.3.

4.4.2.7.3 Void Fraction Correlations

There are three separate void regions to be considered in flow boiling. Region 1 is highly subcooled in which a single layer of bubbles develops on a heated surface and remains attached to the surface. Region 2 is a transition region from highly subcooled to bulk boiling where the steam bubbles detach from the heated surface. Region 3 is the bulk boiling regime.

The void fraction in regions 1 and 2 is predicted using the Maurer Method.[13] The calculation of the void fraction in the bulk boiling regime is discussed in paragraph 4.4.4.2.3.

4.4.2.8 Thermal Effects of Operational Transients

Design basis limits on DNBR and fuel temperature are established so that thermally-induced fuel damage will not occur during steady-state operation and during the anticipated operational occurrences. The COLSS provides information to the operator so he can assure that proper steady-state conditions exist. The RPS ensures that the design limits are not violated. The COLSS provides the reactor operator with a comparison of the actual core operating power to the licensed power, and to the limiting power based on DNBR and linear heat rate. If the operating power reaches one of the limiting powers, an alarm is sounded. These limits are maintained by LCO using COLSS, or CPC when COLSS is out of service, to provide sufficient margin not to exceed the design basis limits in the event the most limiting anticipated operational occurrence occurs simultaneously with the operating power being at the limiting power in steady state.

The COLSS thermal margin algorithm is an analytical approximation to the standard thermal margin design methods described in paragraph 4.4.4.5.2.

4.4.2.9 Uncertainties in Estimates

4.4.2.9.1 Pressure Drop Uncertainties

The reactor vessel pressure losses in table 4.4-6 are the best-estimate values calculated for the design minimum flow with standard loss coefficient methods. The uncertainties in the correlations for the loss coefficients and the dimensional uncertainties on the reactor vessel and internals are accounted for when determining maximum and minimum vessel hydraulic resistance. The uncertainties at the 2σ level are estimated to be equivalent to approximately ± 12% of the best estimate vessel pressure loss.

4.4.2.9.2 Hydraulic Load Uncertainties

When determining the design hydraulic loads for normal operation (refer to paragraph 4.4.2.6.3), the effects of uncertainties in the input are considered. The uncertainties in items such as flow rate, force and pressure coefficients, and dimensional tolerances are evaluated at the 2.33σ level.

4.4.2.9.3 Fuel and Clad Temperature Uncertainty

Uncertainty in the ability to predict the maximum fuel temperature is a function of gap conductance, thermal conductivities, peak linear heat rate, and heat generation distribution. Uncertainties in gap conductance and thermal conductivity are taken into account in the analytical model. Uncertainties in the peak linear heat rate are accounted for by including the uncertainty in estimating the total nuclear peak. Uncertainties in fuel pellet density, enrichment, pellet

diameter, and clad diameters are expressed by the engineering factor on linear heat rate (paragraph 4.4.2.2.2).

Uncertainty in predicting the cladding temperature at the location of maximum heat flux is the uncertainty in the film temperature drop, which is minimal at this location where nucleate boiling occurs.

4.4.2.9.4 DNBR Calculation Uncertainties

A. The uncertainty in the calculation of minimum DNBR is divided into:

   1. The uncertainty in the input to the core analytical model, the TORC code. This includes the core geometry, power distribution, inlet flow and temperature distribution, exit pressure distribution, single phase friction factor constants, spacer grid loss coefficients, diversion cross-flow resistance and momentum parameters, turbulent interchange constants, and hot fuel rod energy deposition fraction.

   2. The uncertainty in the analytical model to compute the actual distribution of flow and the local subchannel coolant conditions.

   3. The uncertainty in the CE-1 correlation to predict DNB.

B. The following paragraphs discuss the above uncertainties and the allowances for them, if needed, in the thermal margin analysis of the core:

1. Uncertainty in the input to the core analytical model:

a. Uncertainty in core geometry, as manifested by manufacturing variations within tolerances, is considered by the inclusion of engineering factors in the DNBR analyses; see paragraph 4.4.2.2.2 for discussion of the method used to compute conservative values.

b. Uncertainties on the power distribution factors are applied in the COLSS and RPS (see Chapter 7).

c. The core inlet flow distribution is obtained from flow model testing discussed in section 4.4.4.2. Uncertainties in the core flow distribution are included in the design method for TORC analyses.

d. Uncertainties in the core inlet temperature distribution and core exit pressure distribution are included in the design method for TORC analyses.

e. The Blasius single-phase friction factor equation for smooth rods is given and shown to be valid in paragraph 4.4.4.2.3. The spacer grid loss coefficient for the high impact grid

is obtained from pressure drop data discussed in paragraph 4.4.4.2.3.

f. The value of minimum DNBR is relatively insensitive to cross-flow resistance and momentum parameters.[10]

g. Paragraph 4.4.4.1 describes the testing to determine the inverse Peclet number which is indicative of the turbulent flow interchange between subchannels. The inverse Peclet number is input to the TORC code and is used to determine the effect of turbulent interchange on the enthalpy rise in adjacent subchannels. From the testing, a value of 0.0035 is justified.

h. The same fuel rod energy deposition fraction used for the hot rod is used for the average rod. The hotter the rod, the lower the actual value of energy deposition fraction is with respect to that for the average rod. A lower energy deposition fraction reduces the hot rod heat flux and thereby increases its DNBR. The use of the average rod energy deposition fraction for the hot rod is therefore conservative. See section 4.3 for a discussion of the calculation of the energy deposition fractions.

2. Uncertainty in the analytical model:

   The ability of the TORC code to accurately predict subchannel local conditions in rod bundles is described in CENPD-161.[10] The ability of the code to accurately predict the core-wide coolant conditions is described in CENPD-206.[16]

3. Uncertainty in the DNB correlation:

   The uncertainty in the DNB correlation is determined by a statistical analysis of DNB test data. A value of 1.34 has been shown to provide a 95% probability with 95% confidence that DNB will not occur on a fuel rod having that minimum DNBR.[1][2][3]

   A discussion on the method of Statistical Combination of Uncertainties (SCU) to combine uncertainties into minimum DNBR limit is provided in paragraph 4.4.2.2.1.

4.4.2.10 Flux Tilt Considerations

An allowance for degradation in the power distribution in the x-y plane (commonly referred to as flux tilt) is provided in the protection limit set points even though little, if any, tilt in the x-y plane is expected.

The tilt, along with other pertinent core parameters, is continually monitored during operation by the COLSS (described in section 7.7). If the core margins are not maintained, the

COLSS actuates an alarm, requiring the operator to take corrective action.

The thermal margin calculations used in designing the reactor core are performed using the TORC and CETOP codes. The TORC and CETOP codes, which are described in paragraph 4.4.4.5.2, are based on an open core analytical method for performing such calculations and treat the entire core on a three-dimensional basis. Thus, any asymmetry or tilt in the power distribution is analyzed by providing the corresponding power distribution in the TORC and CETOP input.

4.4.3 DESCRIPTION OF THE THERMAL AND HYDRAULIC DESIGN OF THE REACTOR COOLANT SYSTEM (RCS)

A summary description of the RCS is given in section 5.1.

4.4.3.1 Plant Configuration Data

4.4.3.1.1 Configuration of the RCS

An isometric view of the RCS is given in figure 4.4-8. Dimensions are shown on general arrangement drawings in Chapter 5. Table 4.4-8 lists the valves and pipe fittings which form part of the RCS.

Table 4.4-9 lists the design minimum flow through each flowpath in the RCS.

Table 4.4-10 provides the estimated volume, minimum flow area, flowpath length, height and liquid level of each volume, and bottom elevation for each component within the RCS.

The line lengths and sizes of the safety injection lines are given in table 4.4-1.

4.4.3.2 Operating Restrictions on Pumps

The minimum RCS pressure at any given temperature is limited by the required net positive suction head (NPSH) for the reactor coolant pumps during portions of plant heatup and cooldown. To ensure that the pump NPSH requirements are met under all possible operating conditions, operating curves are used which gives permissible RCS pressure as a function of temperature, for each of the allowed RCP combinations.

The reactor coolant pump NPSH restrictions on these curves are determined by using the NPSH requirement for one pump operation (maximum flow, hence, maximum required NPSH) and correcting it for pressure and temperature instrument errors, pressure drop, and pressure measurement location. The NPSH required versus pump flow is supplied by the pump vendor. Plant operation below these curves is prohibited. At low reactor coolant temperature and pressure, other considerations require that the minimum pressure versus temperature curve be above the NPSH curve.

4.4.3.3 Power Flow Operating Map (BWR)

This subsection is not applicable to Palo Verde Nuclear Generating Station.

Table 4.4-8
RCS VALVES AND PIPE FITTINGS

Pressure Boundary Valves

Valve	Valve No.	Size (in.)	Quantity
Pressurizer safety Valves	RC-200, RC-201 RC-202, RC-203	6 x 8	4
Pressurizer spray control valves	RC-100E, RC-100F	3	2
Spray bypass needle valves	RC-236, RC-237	3/4	2
Refueling level indicator connection isolation valve	RC-214	3/4	1
Reactor vessel head vent isolation valve	RC-212	3/4	1

RCS Pipe Fittings

Elbows	Size (in.)	Radius (in.)	Quantity
35°	42	63	2
45°	30	45	4
90°	30	45	8
44°9'	30	45	4

Table 4.4-9
RCS DESIGN MINIMUM FLOWS

Flow Path	Flow (lbm/hr)
Total minimum RCS flow	155.8×10^6
Core bypass flow (design maximum)	4.7×10^6
Core flow	151.1×10^6
Hot leg flow	77.9×10^6
Cold leg flow	38.95×10^6

4.4.3.4 Temperature - Power Operating Map (PWR)

RCS temperature and pressure limits are discussed in Chapter 5 and the Technical Specification.

The adequacy of natural circulation for decay heat removal after reactor shutdown has been verified analytically and by tests on the Palisades reactor (Docket No. 50-255) and Calvert Cliffs I (Docket No. 50-317). The core ΔT in the analysis has been shown to be lower than the normal full power ΔT; thus the thermal and mechanical loads on the core structure are less severe than normal design conditions. In addition, St. Lucie Unit I (Docket No. 50-335) successfully performed a cooldown from full power conditions using only natural circulation cooling following a reactor trip.

Heat removed from the core during natural circulation may be rejected either by dumping steam to the main condenser or to the atmosphere. The rate of heat removal may be controlled to maintain core ΔT within allowable limits.

Table 4.4-10
REACTOR COOLANT SYSTEM GEOMETRY
(Sheet 1 of 2)

Component	Flow Path Length (ft)	Top Elevation[d] (ft)	Bottom Elevation[d] (ft)	Minimum Flow Area (ft^2)	Volume[g][h] (ft^3)
Hot leg	14.06	2.38	-1.75	9.62	135.27
Suction leg	24.32	0.58	-9.97	4.91	119.38
Discharge leg	19.30	1.25	-1.25	4.91	94.74
Pressurizer	----	(f)	----	----	1800
Liquid level (full power)	----	(f)	(f)	50.07[a]	900
Surge line[e]	69.44	(f)	1.75	0.56	38.82
Steam Generator					
Inlet Nozzle (each)	3.07	3.90	-0.48	9.62	31.30
Outlet nozzle	2.79	2.41	-1.19	4.91	13.70
Inlet plenum	4.74[b]	6.48	-0.10	19.07	332.41
Outlet plenum	4.74[b]	6.48	-0.10	9.74	332.41
Tubes (active and inactive)	61.15	40.94	6.48	0.002[c]	1634.20

(a) For the cylinder.

(b) Represents a geometrical rather than an actual flow path length.

(c) Flow path area per tube.

(d) Reactor vessel nozzle centerline is the reference elevation. It has an elevation of 0.0 ft.

(e) Nominal value is given.

(f) Depends on individual plant surge line height.

(g) Reactor Coolant Pump volume (approximately 134ft^3 each) is implicitly modeled.

(h) See Table 5.1-3 for total Reactor Coolant System volume and volume totals of major RCS constituents.

Table 4.4-10
REACTOR COOLANT SYSTEM GEOMETRY
(Sheet 2 of 2)

Component	Flow Path Length (ft)	Top Elevation[d] (ft)	Bottom Elevation[d] (ft)	Minimum Flow Area (ft^2)	Volume (ft^3)
Reactor Vessel					
Inlet nozzle (each)	3.7	1.4	-1.5	4.9	21.7
Downcomer	21.4	11.7	-22.6	33.8	1157.1
Lower plenum	3.2	-20.5	-25.9	32.5	430.2
Lower support structure & inactive core	2.8	-17.7	-20.5	44.4	239.2
Active core	12.5	-5.3	-17.8	60.8	888.2
Upper inactive core	2.8	-2.5	-5.3	46.3	262.9
Outlet plenum	5.7	2.1	-2.4	26.6	459.4
Core shroud bypass	15.9	-2.7	-19.6	0.1	240.6
CEA shroud assembly & tie tubes	17.9	15.6	-3.5	0.4	1352.5
UGS, CEA shroud annulus	10.6	12.7	2.1	1.6	226.0
Top head	3.2	19.9	12.7	7.8	422.6
Outlet nozzle (each)	4.0	1.7	-1.8	9.6	32.2

4.4.3.5 Load Following Characteristics

The design features of the RCS influence its load following and transient response. The RCS is capable of following the normal transients identified in paragraph 3.9.1.1. These requirements are considered when designing the pressurizer spray and heater systems, charging/letdown system, reactor regulating system (RRS), and feedwater regulating system. Finally, these transients are included in the equipment specification for each RCS component to ensure the structural integrity of the system.

When load changes are initiated, the RRS senses a change in the turbine power and positions CEAs to attain the programmed coolant average temperature. RCS boron concentration can also be adjusted to attain the appropriate coolant temperature. The feedwater system employs a controller which senses changes in steam flow, feedwater flow, and water level, and acts to maintain steam generator level at the desired point. The pressurizer pressure and level control systems respond to deviations from preselected setpoints caused by the expansion or contraction of the reactor coolant, and actuate the spray or heaters and the charging or letdown systems as necessary to maintain pressurizer pressure and level.

4.4.3.6 Thermal and Hydraulic Characteristics Table

Typical thermal and hydraulic characteristics of the RCS components are listed in table 4.4-11. Specific values may vary between the PVNGS units or between reloads.

4.4.4 EVALUATION

4.4.4.1 Critical Heat Flux

The margin to critical heat flux (CHF) or DNB is expressed in terms of the DNBR. The DNBR is defined as the ratio of the heat flux required to produce DNB at the calculated local coolant conditions to the actual heat flux.

The CE-1 correlation[2][3] is used with the TORC and CETOP computer codes[10][11] to determine DNBR values for normal operation and anticipated operational occurrences. The CE-1 correlation is used specifically for DNB margin predictions for fuel assemblies with standard spacer grids similar to those in System 80.

Topical Reports CENPD-162[2] and CENPD-207[3] provide detailed information on the CE-1 correlation and source data, and also provide comparisons with other data and correlations. In brief, the correlation is based on data from tests conducted for Combustion Engineering at the Chemical Engineering Research Laboratories of Columbia University. Those tests used electrically-heated 5 x 5 array rod bundles corresponding dimensionally to a portion of a 16 x 16 or 14 x 14 assembly with standard spacer grids. The test programs conducted for the 16 x 16 and 14 x 14 assembly geometries each included tests to determine the effects on DNB of the CEA guide tube, bundle heated length, axial grid spacing, and lateral and axial power distributions.

Table 4.4-11
TYPICAL REACTOR COOLANT SYSTEM COMPONENT
THERMAL AND HYDRAULIC DATA[(a)(e)]
(Sheet 1 of 3)

Component	Data
Reactor Vessel	
Rated core thermal power, MWt	3990
Design pressure, psia	2500
Operating pressure, psia	2250
Coolant outlet temperature, °F	618.8
Coolant inlet temperature, °F	560.4
Coolant outlet state	Subcooled
Total coolant flow, 10^6 lb/h	155.8[(b)]
Average coolant enthalpy	
Inlet, Btu/lb	560
Outlet, Btu/lb	641
Average coolant density	
Inlet, lb/ft^3	46.2
Outlet, lb/ft^3	41.4
Steam Generators	
Number of units	2
Primary side (or tube sides)	
Design pressure/temperature, psia/°F	2500/650
Operating pressure, psia	2250
Inlet temperature, °F	618.8
Outlet temperature, °F	560.4
Secondary (or shell side)	
Design pressure/temperature, psia/°F	1270/575

a. Full power conditions.
b. Licensed minimum design flow.

Table 4.4-11
TYPICAL REACTOR COOLANT SYSTEM COMPONENT
THERMAL AND HYDRAULIC DATA[(a)(e)]
(Sheet 2 of 3)

Component	Data
Steam Generators (con't)	
Full load steam pressure/ temperature, psia/°F	1030/548
Zero load steam pressure, psia	1170
Total steam flow per gen., lb/h	9.0×10^6
Full load steam quality, %	99.9
Feedwater temperature, full power, °F	450[(c)]
Pressurizer	
Design pressure, psia	2500
Design temperature, °F	700
Operating pressure, psia	2250
Operating temperature, °F	653
Internal volume (ft^3)	1800
Heaters	
Type and rating of heaters, Kw	Immersion/50
Installed heater capacity, Kw	1750 (U1)
	1700 (U2)
	1800 (U3)
Reactor Coolant Pumps	
Number of units	4
Type	Vert.-Centrifugal
Design capacity, gal/min	111,400
Design pressure/temperature, psia/°F	2500/650

c. Lower feedwater temperature may be utilized for some accident analyses presented in Chapter 15.

Table 4.4-11
TYPICAL REACTOR COOLANT SYSTEM COMPONENT
THERMAL AND HYDRAULIC DATA[a][e]
(Sheet 3 of 3)

Component	Data
Reactor Coolant Pumps (con't)	
Operating pressure, psia	2250
Type drive	Squirrel cage induction motor
Total dynamic head, ft	365
Rating and power requirements, hp, hot	8850
Pump speed, r/min	1190
Total heat input to RCS, MWt	23 to 26[d]
Reactor Coolant Piping	
Flow per loop (10^6 lb/h)	
Hot leg	77.9[b]
Cold leg	38.95[b]
Pipe size (inside dia.), in.	
Hot leg	42
Cold leg	
Suction leg	30
Discharge leg	30
Pipe design pressure/ temperature, psia/°F	2500/650
Pipe opeating pressure/ temperature, psia/°F	
Hot leg	2250/618.8
Cold leg	2250/560.4

d. Reactor Coolant Pump heat input varies between the PVNGS units.

e. These values are typical (Generic) design operating conditions that do not necessarily reflect any specific unit and cycle.

The uniform axial power CE-1 correlation[2] was developed from DNB data for six test sections with the following characteristics:

Fuel Assembly Geometry	No. Heated Rods	Lateral Power Distr.	Heated Length (ft)	Axial Grid Spacing (in.)
16 x 16	25	Uniform	7	16.0
16 x 16	21	Nonuniform	7	18.3
16 x 16	21	Nonuniform	12.5	17.4
14 x 14	25	Uniform	7	14.3
14 x 14	21	Nonuniform	7	14.3
14 x 14	21	Nonuniform	12.5	14.3

Local coolant conditions at the DNB location were determined by using the TORC code in a manner consistent with the use of the code for reactor thermal margin calculations. The uniform axial power CE-1 correlation was developed from 731 DNB data points, and was determined to predict the source data with a mean and standard deviation of the ratio of measured and predicted DNB heat fluxes of 1.000 and 0.068, respectively.[2] However, the NRC has approved the use of a 1.19 minimum DNBR for the 16 x 16 assembly based on a subset of the 731 source data as reported in the SER for CENPD-162.[4] The 1.19 limit was increased to 1.20 for CE's HID fuel design to account for the small differences between the HID fuel and the standard fuel simulated in the CE-1 CHF test. The validity of the CE-1 correlation for predicting DNB for 16 x 16 fuel assemblies was further verified by the analysis of data obtained by repeating

one of the tests for the 16 x 16 assembly geometry at the Winfrith Laboratory of the UKAEA.

For nonuniform axial power distributions, the uniform axial power CE-1 correlation is modified by the Tong F-factor.[9] The conservatism of that method of predicting DNB for 16 x 16 fuel assemblies with nonuniform axial flux shapes was demonstrated in CENPD-207.[3] CENPD-207 presents measured and predicated DNB heat fluxes for a series of tests using nonuniform axial power rod bundles representative of 16 x 16 or 14 x 14 fuel assemblies with standard spacer grids. Those test sections had the following characteristics.

Fuel Assembly Geometry	No. Heated Rods	Lateral Power Distr.	Axial Power Distr.	Heated Length (ft)	Axial Grid Spacing (in.)
16 x 16	21	Nonuniform	1.46 symmetric	12.5	14.2
16 x 16	21	Nonuniform	1.47 top peak	12.5	14.2
14 x 14	21	Uniform	1.68 top peak	12.5	17.4
14 x 14	21	Nonuniform	1.68 bottom peak	12.5	17.4

The DNB data from those tests were evaluated using the CE-1 correlation modified by the Tong F-factor, and the TORC code was used in a manner consistent with the use of the code for reactor calculations. It was found that the mean and standard deviation of the ratio of measured and predicted DNB heat fluxes were 1.229 and 0.125, respectively, for the 369 DNB data points obtained from these tests.

Testing was also conducted with rod bundles representative of the 16 x 16 fuel assembly to determine the effect on DNB of local perturbations in heat flux. Results are presented in CENPD-207[3] for two nonuniform axial power rod bundles which were similar except that one test bundle had a heat flux spike (23% higher heat flux for a 4-inch length) at the location where DNB was anticipated. The results show that there is no significant adverse effect on DNB due to that flux spike. Therefore, it is concluded that no allowance is required for the effect on DNB of local heat flux perturbations less severe than that tested.

The CE-1 CHF correlation that is utilized by the CETOP and TORC computer codes is empirical in nature, because it is derived from the series of tests described above. The correlation equation includes proprietary coefficients that were determined by nonlinear least-squares regression analysis of test data within the following parameter ranges:

Pressure (psia)	1785 to 2415
Inlet temperature (°F)	382 to 644
Local coolant quality	-0.16 to 0.20
Local mass velocity (lb/hr-ft^2)	0.87×10^6 to 3.21×10^6
Subchannel heated equivalent diameter (inches)	0.4713 to 0.7837
Subchannel wetted equivalent diameter (inches)	0.3588 to 0.5447
Heated length (inches)	84 and 150

The CE-1 correlation is therefore valid throughout these parameter ranges.

One important factor in the prediction of DNB and local coolant conditions is the treatment of coolant mixing or turbulent exchange. The effect of turbulent interchange on enthalpy rise in the subchannels of 16 x 16 fuel assemblies with standard spacer grids is calculated in the TORC code by

$$\hat{Pe} = \frac{w'}{\overline{G}\,\overline{D}_e} = 0.0035$$

where:

$\hat{Pe}$ = inverse Peclet number

w' = turbulent interchange between adjacent subchannels, lb/h-ft

$\overline{D}_e$ = average equivalent diameter of the adjacent subchannels, ft

$\overline{G}$ = average mass velocity of the adjacent subchannels, lb/h-ft^2

The value of 0.0035 for the inverse Peclet number for use with the 16 x 16 fuel assembly with standard spacer grids was originally chosen based on cold water dye mixing tests conducted for the 14 x 14 assembly and for a "prototype" of the Palisades reactor fuel assembly. The validity of the inverse Peclet number of 0.0035 for the 16 x 16 assembly with standard

grids was verified with data obtained in the tests conducted at Columbia University.[2]

The design basis requires that the minimum DNBR for normal operation and anticipated operational occurrences be chosen to provide a 95% probability at the 95% confidence level that DNB will not occur on a fuel rod having that minimum DNBR. Statistical evaluation of the CE-1 correlation and relevant data shows that the appropriate minimum DNBR is 1.13.[2][3]

Based on review of CENPD-162[2], the NRC required use of a minimum DNBR of 1.19 for CE standard grid fuel assemblies and 1.20 for CE HID fuel. This minimum DNBR has been increased to 1.34 to account for system parameter uncertainties as described in paragraph 4.4.2.2.1.

4.4.4.2 Reactor Hydraulics

4.4.4.2.1 Reactor Flow Model Tests

The hydraulic design of the System 80 reactor vessel and internals is supported by a three-phase flow test program with geometrically scaled models. In the first phase, 1/8-scale air-flow model tests were conducted at Kraftwerk Union (KWU) to refine the geometry of the lower plenum and core support structure to attain an acceptable core inlet flow distribution. In these tests, geometric scaling was maintained up to the core inlet. The reactor core was represented by a single orifice plate matching the flow resistance through the lower end fitting and lower-most spacer grid, housed in a core shroud envelope. The core inlet flow distribution was mapped by velocity probe measurements downstream of the orifice plate.

Because of the simplified core modeling and measurement technique, the KWU test results are considered to be preliminary.

In the second phase, 3/16-scale water-flow tests were conducted in the C-E Nuclear Laboratories to refine the hydraulic performance of the upper plenum region, with respect to pressure drop and structure hydraulic loading. In these tests there was no representation of the reactor core.

In the third phase, a 3/16-scale water-flow model of the entire reactor and internals was tested to verify the design hydraulic parameters based on analysis and results of earlier tests. This reactor flow model incorporates the minor design changes made after completion of the earlier model tests. Model components are geometrically similar to reactor components, except for the core.

Individual fuel assemblies are represented in the third test model by an array of square tubes. An axial distribution of orifice plates and of cross-flow holes in the double-wall boundaries between adjoining core tubes are sized to provide the axial and lateral flow hydraulic resistances of the reactor core. This "open-core" flow modeling technique is a continuation of testing methods applied for the C-E 3400-series reactors (San Onofre Units 2 and 3, Forked River Unit 1, Waterford Unit 3, Pilgrim Unit 2), as described in CENPD-206.[16] Details of the 3/16 scale System 80 reactor flow model test and portions of the test results are presented in section 4.4.4.2.1.1.

Subsequent tests were also performed on the Yonggwang 177-assembly model, and provided further data on the relationship between the lower core support structure and inlet flow distribution.

Hydraulic design parameters derived from reactor flow model test results included:

- The core inlet flow distribution and core exit pressure distribution.
- Pressure drops in the reactor vessel.
- Hydraulic loads on reactor internal components.

A. Core Inlet Flow and Core Exit Pressure Distributions

The core inlet flow and the core exit pressure distributions are required as input to the TORC code for core thermal margin analysis (refer to paragraph 4.4.4.5.2).

The four-loop core inlet flow distribution used in the TORC analysis is based on the results from flow tests. The core exit pressure distribution is based on an extrapolation of the pressure distribution measured in the 3410 MWt class reactor flow model test program described in CENPD-206.[16]

These core hydraulic boundary conditions were verified by the results from the 3/16-scale System 80 reactor flow model test and subsequent Yonggwang test.

B. Reactor Pressure Losses

Reactor vessel pressure drop predictions other than for the core region were verified by flow model test results. Where appropriate, corrections are made to flow model test results to account for differences in Reynolds number and surface relative roughness between model and reactor. Reactor pressure drop predictions for the core region are based on data from C-E 16 x 16 fuel assembly components tests (see paragraph 4.4.4.2.2). Best estimate reactor vessel pressure drop predictions are given in table 4.4-6 (see paragraph 4.4.2.6.2).

C. Hydraulic Loads on Reactor Internal Components

Design hydraulic loads on reactor internal components for normal operating conditions are based on analytical methods which utilize available flow model and components test nondimensionalized experimental data (see paragraph 4.4.2.6.3). Flow model measurements related to derivation of design hydraulic loads include incremental pressure drops, surface static pressure distributions, wall pressure differentials, and fluid velocity distributions.

4.4.4.2.1.1 SYSTEM 80 REACTOR FLOW MODEL TEST PROGRAM

4.4.4.2.1.1.1 INTRODUCTION

Flow model tests have been conducted to determine the hydraulic performance of the System 80 class reactors. Tests in 1973-1975 at Kraftwerk Union (KWU) with a 1/8 scale model of

the downcomer and lower support structure, and in 1975-1976 at C-E with a 3/16 scale model of the outlet plenum region, were conducted to refine basic hydraulic design. Objectives were to produce an acceptable core inlet flow distribution, and to minimize hydraulic loadings and resistance to flow. The reactor core was not represented in these tests, except for simplified provisions to represent a portion of the core inlet resistance for inlet flow distribution mapping in the KWU lower plenum tests. The test results obtained through 1976 were treated as preliminary in view of the simplified core modelling. Results were used in design analyses of core thermal margin, system pressure drop, and component hydraulic loading.

Final verification of reactor design hydraulic parameters is based on tests with a 3/16 scale model having all structures in the main flow paths, including a dynamically scaled core. This model was constructed in 1976-1977 and tested in 1978, in the C-E Nuclear Laboratories.

4.4.4.2.1.1.2 DESCRIPTION OF FLOW MODEL

4.4.4.2.1.1.2.1 PRESSURE VESSEL AND CORE SUPPORT STRUCTURES

A cross-sectional view of the flow model is presented in Figure 4.4-9. Geometric similarity to the reactor main flow paths is maintained, with a scaling factor of 3/16, except in the model core. Relatively stagnant regions at the top of the downcomer and in the upper guide structure and closure head volume are truncated for ease and economy of model assembly.

4.4.4.2.1.1.2.2 MODEL CORE

The model core consists of an array of 241 square tubes, each representing one fuel assembly. Six levels of flow resistor plates match the axial flow resistance of reactor fuel assemblies, and approximately match the axial distribution of axial flow resistance over the length of the assembly. Aligned round holes through adjoining tube walls match the resistance to cross-flow between reactor fuel assemblies. Model and reactor fuel assemblies are compared in Figure 4.4-10. The model core design and associated "open-core" flow model testing technique follow the methodology of flow model tests for the C-E 3400-Series reactors, as described in CENPD-206-P[16].

4.4.4.2.1.1.2.3 MODEL INSTRUMENTATION

Model instrumentation consists of wall static pressure taps in the inlet and outlet ducts, at the top and bottom of the downcomer, on the flow skirt and bottom plate, in the inlet and outlet of each core tube, at several points on the upper guide structure, and in the closure head volume. These taps provide for assessment of the breakdown of reactor vessel pressure drop, component steady state hydraulic loading, and for measurement of core inlet and core outlet pressure boundary conditions. A detailed summary of pressure tap locations is provided in Figure 4.4-11.

4.4.4.2.1.1.3 DESCRIPTION OF TEST FACILITY

4.4.4.2.1.1.3.1 TEST FACILITY AND OPERATING CONDITIONS

Testing was conducted in the C-E Large Scale Hydraulic Test Facility, TF-15. For the configuration representing full flow with four operating reactor coolant pumps, model flow was set at 11,000 gpm. All tests were conducted at approximately 80°F fluid temperature. At these conditions flow in the model is fully turbulent, with an outlet duct Reynolds Number of 2.6×10^6. The corresponding reactor Reynolds Number at full power is 1.5×10^7. It is expected that non-dimensionalized pressure drops and flow distributions do not change at the higher reactor Reynolds Numbers.

4.4.4.2.1.1.3.2 TEST LOOP

The TF-15 test loop, as used for System 80 Flow Model full flow testing is depicted in Figure 4.4-12. Three circulating pumps are required to provide the 11,000 gpm model flow rate. Individual inlet and outlet duct flow settings are established with flow control valves and calibrated flow meters. Flow meter signals are continuously fed to the data acquisition system to verify constancy of flow settings.

4.4.4.2.1.1.3.3 DATA ACQUISITION SYSTEM

The data acquisition system used for this test is depicted in Figure 4.4-13. Model point pressures are sequentially connected through computer-operated solenoid valves to a series of differential pressure transducers. Point pressures are read against an internal reference pressure at mid-elevation in the

model core. Electrical output is repeatedly scanned and averaged for each point after a dwell period in which pressure differences are allowed to stabilize. Switching and digital voltmeter readout is controlled by a computer. Operator control of test progress and screening of measurements is accomplished with a teletypewriter. Data is recorded on magnetic tape for further reduction with a digital computer.

4.4.4.2.1.1.3.4 CALIBRATION STANDARDS

Calibration of the instruments is made utilizing fixed water columns or variable height mercury columns, as appropriate for the range of each instrument. Calibrations are made at the beginning of each test run, and are confirmed upon completion of each test run.

4.4.4.2.1.1.4 DATA ANALYSIS

4.4.4.2.1.1.4.1 MODEL POINT PRESSURES

Model point pressures, measured relative to an internal reference pressure at core mid-elevation, are converted to Euler numbers of one of several forms.

a. For the planar pressure distributions at the core inlet and core outlet, Pin and Pout:

$$Ei = \left(Pi - \overline{Pi}\right) / \left(\overline{Pin} - \overline{Pout}\right)$$

b. For other point and spatially averaged pressures:

$$Ei = \left(Pi - \overline{Pin}\right) / VH_{ref}$$

where VH_{ref} is a reference model inlet velocity head.

c. For point-to-point pressure differentials:

$$Ei = (P\ \text{upstream} - P\ \text{downstream}) / VH_{ref}$$

Euler numbers are readily converted to desired pressure drop loss coefficient and hydraulic loading coefficient forms, considering averaged data from repeat runs.

4.4.4.2.1.1.4.2 CORE INLET FLOW DISTRIBUTION

The core inlet flow distribution for the normal condition with four operating reactor coolant pumps is provided in Figure 4.4-14. At each fuel assembly location, the inlet flow is expressed as a fraction of the average fuel assembly flow rate in the core. Flow model test data, in the form of the core inlet pressure distribution, is scaled to reactor conditions and used in a TORC-HERMITE simulation of the System 80 core to determine the core inlet flow field. This technique for determining the core inlet flow distribution is discussed further in CENPD-206-P[16].

Figure 4.4-14 also provides the revised flow distribution based on subsequent tests at Yonggwang.

4.4.4.2.1.1.4.3 CORE OUTLET PRESSURE DISTRIBUTION

The reactor core outlet pressure distribution is provided in Figure 4.4-15, for the normal condition with four operating reactor coolant pumps. Euler numbers at fuel assembly locations express the core outlet pressure distribution in a non-dimensional form which is defined as,

$$E_i)_{outlet} = \frac{P_i - \overline{P}\ \text{outlet}}{k_{core}\ \overline{q}_{core}}$$

where: P_i = local static pressure, core outlet

$\overline{P}$ = core average static pressure, core outlet

K_{core} = core overall loss coefficient, based on core flow area

$\overline{q}_{core}$ = average core outlet velocity head, based on core flow area

The core outlet pressure distribution is obtained as a result of interfacing two analytical simulations: the first simulation is a representation of the core region, using the TORC code; the second is a multi-flow-path simulation of the upper plenum region between the core exit and the outlet nozzles. Input to the TORC code contains the core inlet flow distribution as determined earlier from flow model test data. Input to the upper plenum simulation contains the flow resistances found in flow model tests for this region. Matching of the interface conditions between the two simulations provides the core outlet flow and pressure distributions.

Uncertainty in core outlet pressure distribution takes into account the uncertainty in the TORC representation of the core and the uncertainty in the analytical model of the outlet plenum and core exit regions. The typical uncertainty in core outlet pressure distribution (ΔE_i) is 0.008 at the 1σ level.

4.4.4.2.1.1.4.4 REACTOR VESSEL PRESSURE DROP

Best estimate reactor vessel incremental loss coefficients and pressure drops, are provided in Table 4.4-6.

4.4.4.2.1.1.4.5 COMPONENT HYDRAULIC LOADING

Reactor internal component design steady state hydraulic loads which have been verified using scale model flow test data include the following:

a. Core support barrel and upper guide structure uplift forces.

b. Differential pressure loadings on the:

- Flow skirt
- Bottom plate
- Fuel alignment plate
- Upper guide structure support barrel

c. Steady state drag loading on the cylindrical shroud tubes in the outlet plenum and instrument nozzles in the lower plenum.

Design values for these hydraulic loads based on earlier flow model test results and on analytical methods are in all cases shown to be conservative, on the basis of final model test results.

4.4.4.2.2 Components Testing

Components test programs have been conducted in support of all C-E reactors. The tests subject a full-size reactor core module comprising one to five fuel assemblies, control rod assembly and extension shaft, control element drive mechanism, and reactor internals to reactor conditions of water chemistry, flow velocity, temperature, and pressure under the most adverse

operating conditions allowed by design. Two objectives of the programs are to confirm the basic hydraulic characteristics of the components and to verify that fretting and wear will not be excessive during the components' lifetime.

Thus, components tests have been run on the Palisades design, the cruciform control rods, on the Fort Calhoun design with CEAs and rack-and-pinion control element drive mechanisms (CEDMs), on the Maine Yankee design with a duel CEA and a magnetic jack CEDM, and on the Arkansas design with a 16 x 16 fuel assembly, a CEA, and magnetic jack CEDM.

During the course of the tests, information is obtained on fuel rod fretting, on CEA/CEDM trip behavior, and on fuel assembly uplift and pressure drop. The first two subjects are discussed in section 4.2. The third is discussed below.

As part of the assessment of fuel assembly margin to uplift in the reactor, measurements are made of the flow rate required to produce fuel assembly lift-off over a temperature range of 150 to 600F at a system pressure of 350 to 2250 psia. To obtain the desired information, the point of fuel assembly lift-off is determined with load beams or lift-off conductivity probes. With the first approach, one of the fuel assemblies of the module is mounted on the load beam so that the assembly net weight can be monitored as a function of flow rate and temperature. Fuel assembly lift-off is established when the net weight goes to zero. With the second approach, the lift-off probes are mounted to contact the bottom of the fuel assembly. When the fuel assembly is seated, the contact between the assembly and lift-off probes complete an electrical

circuit. The point of lift-off is indicated by a large step change in the circuit resistance caused by the break in contact between the probes and the fuel assembly.

Data reduction involves the calculation of an uplift coefficient, describing the hydraulic uplift force acting on the assembly; the coefficient is defined as follows:

$$Kup = Wo/\rho V^2 A/2gc$$

where:

Wo = wet weight of assembly, lb

V = flow velocity in assembly at the point of lift-off, ft/sec

A = envelope area of assembly, ft^2

ρ = water density, lb/ft^3

A plot of the Kup data shows that they can be fitted by the relation:

$$Kup = \alpha N_R^{-B}$$

where α and B are peculiar to the particular components test being run and the standard error of estimate is typically 4%, including the replication and instrument error.

The uplift coefficient and its associated uncertainty are employed in the analysis of the uplift forces on the fuel assemblies in the reactor. The force is determined for the most adverse assembly location for startup and normal operating conditions. Additional input to the calculation includes analytical corrections to the coefficient for the absence of

the CEA, for crud information, and for small geometrical differences among the fuel assemblies for the different reactor designs all nominally describable by the same components test.

Pressure measurements are also made during the components test to verify the accuracy of the calculated loss coefficients for various fuel assembly components. Direct reduction of the pressure drop data yields the loss coefficients for the lower and upper end fitting region, while the spacer grid loss coefficient is evaluated by subtracting a calculated fuel rod friction loss from the measured pressure drop across the fuel rod region.

Experience has shown that the experimental end fitting loss coefficients are essentially independent of the Reynolds number and, with their sample standard deviations, are in reasonable agreement with the predicted values used in the calculation of core pressure drop (paragraph 4.4.2.6). The design value for the 16 x 16 fuel assembly high impact design spacer grid is based upon experimental results from the 16 x 16 fuel assembly design components test program.

As described in section 4.2, a components test was performed on the System 80 reactor design. The test hardware consists of five fuel assemblies, core support structure, CEA shroud, control rod assembly, and drive mechanism. Component pressure drop measurements for the fuel assemblies were taken during the tests to verify pressure loss and fuel assembly uplift design values.

4.4.4.2.3 Core Pressure Drop Correlations

The total pressure drop along the fuel rod region of the core is computed as the sum of the individual losses resulting from friction, acceleration of the fluid, the change in elevation of the fluid, and spacer grids. The individual losses are computed using the momentum equation and the consistent set of empirical correlations presented in the TORC code.[10]

In the following paragraphs, the correlations used are summarized and the validity of the scheme is demonstrated with a comparison of measured and predicted pressure drops for single-phase and two-phase flow in rod bundles with CEA-type geometry.

For isothermal, single phase flow, the pressure drop due to friction for flow along the bare rods is based on the equivalent diameter of the bare rod assembly and the Blasius friction factor:

$$f = 0.184\ N_R^{\ -0.2}$$

The pressure drop associated with the spacer grids is computed using a grid loss coefficient (K_{SG}) given by a correlation which has the following form:

$$K_{SG} = D_1\ (N_R)^{D_2} \pm \text{Standard Error of Estimate}$$

The constants, D_n, are determined from pressure drop data obtained for a wide range of Reynolds numbers for isothermal flow through a CEA-type rod bundle fitted with the high impact design spacer grids. The data come from a components test program on a 16 x 16 fuel assembly design (paragraph 4.4.4.2.2). The standard error of estimate

associated with the loss coefficient relation includes replication and instrument error.

To compute pressure drop either for heating without boiling or for subcooled boiling, the friction factor given above for isothermal flow is modified through the use of the multipliers given in Pyle.[17] It is important to recognize that the multipliers were developed in such a way as to incorporate the effects of subcooled voids on the acceleration and elevation components of the pressure drop, as well as the effect on the friction losses. Consequently, it is not necessary to compute specifically either a void fraction for subcooled boiling or the individual effects of subcooled boiling on the friction, acceleration, or elevation components of the total pressure drop.

The effect of bulk boiling on the friction pressure drop is computed using a curve fit to the Martinelli-Nelson data[18] above 2000 psia, or the Martinelli-Nelson correlation[18] with the modification given in Pyle[17] below 2000 psia. The acceleration component of the pressure drop for bulk boiling conditions is computed in the usual manner for the case of two-phase flow where there may be a nonunity slip ratio.[19] The elevation and spacer grid pressure drops for bulk-boiling are computed as for single phase flow except that the bulk coolant density ($\bar{\rho}$) is used, where:

$$\bar{\rho} = \alpha\rho_{\upsilon} + (1 - \alpha)\rho_{\ell}$$

and

α = bulk boiling void fraction

ρ_{υ} = density of saturated vapor, lb/ft^3

ρ_{ℓ} = density of saturated liquid, lb/ft^3

The bulk boiling void fraction used in computing the elevation, acceleration, and spacer grid losses is calculated by assuming a slip ratio of unity if the pressure is greater than 1850 psia, or by using the Martinelli-Nelson void fraction correlation(18) with the modifications presented in Pyle(17) if the pressure is below 1850 psia.

To verify that the scheme described above accurately predicts pressure drop for single-phase and two-phase flow through the 16 x 16 assembly, geometry comparisons have been made of measured pressure drop and the pressure drop predicted by TORC,(10) for the rod bundles used in the DNB test program at Columbia University (refer to paragraph 4.4.4.1). Figure 6.7 of CENPD-161(10) shows some typical results for a 21-rod bundle of the 16 x 16 fuel assembly geometry (5 x 5 array with four rods replaced by a control rod guide tube). The excellent agreement demonstrates the validity of the methods described above.

4.4.4.3 Influence of Power Distributions

The reactor operator will restrict operation of the plant such that power distributions which are permitted to occur will have adequate margin to satisfy the design bases during anticipated operational occurrences. A discussion of the methods of controlling the power distributions is given in paragraph 4.3.2.4.2. A discussion of the expected power

distributions is given in paragraph 4.3.2.2.3. The full-power maximum rod radial power factor is used in the calculations of the core thermal margins.

If CEAs or PLCEAs are inserted in the core, the same planar radial power distribution does not exist at each axial elevation of the core, nor does the same axial power distribution exist as each radial location in the core. From the analysis of many three-dimensional power distributions, the important parameters which establish the thermal margin in the core are the maximum rod power and its axial power distribution.[16] Examination of many axial power distributions shows the 1.26 peaked axial power distribution in figure 4.4-4 to be among those giving the lowest DNBRs. The combination of that axial shape and the maximum rod radial power factor is therefore a meaningful combination for DNB analyses. The maximum linear heat rate at a given power is determined directly from the core average fuel rod linear heat rate and the nuclear power factor. The typical value of 2.28 for the nuclear power factor is selected and corresponds to a 1.55 rod radial power factor combined with the 1.47 peaked axial shape shown in figure 4.4-4.

4.4.4.4 Core Thermal Response

Steady-state core parameters are summarized in tables 4.4-2 and 4.4-3 for normal four-pump operation. Figure 4.4-16 shows the sensitivity of the minimum DNBR to small changes in pressure, inlet temperature and flow. The same 1.26 peaked axial power distribution and 1.55 maximum rod radial power factor are used.

The response of the core to anticipated operational occurrences is discussed in chapter 15. The response of the core at the design overpower cannot be presented with any meaning. The concept of a design overpower is not applicable for the PVNGS core since the RPS prevents the design basis limits from being exceeded.

4.4.4.5 Analytical Methods

4.4.4.5.1 Reactor Coolant System Flow Determination

The design minimum flow to be provided by the reactor coolant pumps is established by the required mass flow to result in no violation of the design limits in subsection 4.4.1 during steady-state operation and anticipated operational occurrences. This design minimum flow is specified in table 4.4-2.

The reactor coolant pumps are sized to produce a flow greater than or equal to the design minimum flow for the maximum expected system flow resistance. The maximum system flow resistance is determined by adding an allowance for uncertainty to the best estimate system flow resistance. From this maximum system flow resistance, the required minimum reactor coolant pump head is determined.

Upon completion of the manufacturing and testing of the pumps, the characteristic pump head or performance curve is established. The expected maximum, best estimate, and minimum reactor coolant system flow rates are determined as follows:

A. Best Estimate Expected Flow

   The best estimate expected RCS flow is determined by equating the head loss around the reactor coolant flow

path to the head rise supplied by the reactor coolant pumps (subsection 5.4.1 provides a description of the pumps).

B. Maximum Expected Flow

The maximum expected flow is determined in a manner analogous to the best estimate expected flow, except that statistical techniques are employed. A pump performance curve probability distribution for each pump is calculated by statistically combining measurement uncertainties in flow and head. The uncertainties are based on performance and acceptance testing done at the pump vendor's facility. The system head loss uncertainty distributions are evaluated by statistically combining the uncertainties in the correlations for loss coefficients and normal manufacturing tolerances about nominal dimensions. The expected flow rate probability distribution is determined from the statistical combination of the respective pump curve probability distributions and the probability distributions for the system resistances. This probability distribution for the expected flow rate is used in turn to define the maximum and minimum expected flow rates. The maximum expected flow rate is defined by the upper flow rate limit on the expected flow rate probability distribution, above which the actual flow rate has only a 2.3% probability of existing. This maximum expected flow rate will be equal to or less than the design maximum flow.

C. Minimum Expected Flow

The minimum expected flow is also determined by using the expected flow rate probability distribution discussed above. The minimum expected flow rate is defined as the lower flow rate limit on the expected flow rate probability distribution, below which the actual flow rate has only a 2.3% chance of existing. This minimum expected flow rate will be equal to or greater than the design minimum flow.

Upon installation of the pumps in the reactor coolant system, the operating flow is determined by one or more of the following flow measurement techniques:

A. Pump casing differential pressure method, using a correlation between pump casing differential pressure and flow rate.

B. Calorimetric methods (may be a heat balance performed on either the primary or secondary coolant).

C. By other nonintrusive flow measurement methods such as ultrasonic flow meters.

The uncertainties included in the calculation of the operating flow are those uncertainties associated with the measurement technique or techniques used above. These uncertainties are statistically combined to give the overall uncertainty in primary coolant flow as determined from onsite tests. The best estimate flow reduced for uncertainties shall be greater than the design minimum flow.

Any significant formation of crud buildup is detected by continuous monitoring of the reactor coolant system flow. A significant buildup of crud is not anticipated, however, due to the design of the water chemistry.

4.4.4.5.2 Thermal Margin Analysis

Thermal margin analyses of the reactor core are performed using the TORC and the CETOP codes which are based on the open core analytical method of the COBRA-IIIC code.[20] A complete description of the TORC code and application of the code for detailed core thermal margin analyses is contained in CENPD 161.[10] The CETOP code is used for design thermal margin calculations. CETOP is described in detail in reference 11. A brief description of the codes and their uses is given here.

The COBRA-IIIC code solves the conservation equations for mass, axial and lateral momentum, and energy for a collection of parallel flow channels that are hydraulically open to each other. Since the size of a channel in design varies from the size of fuel assembly or more to the size of a subchannel within a fuel assembly, certain modifications were necessary to enable a realistic analysis of thermal-hydraulic conditions in both geometries. The principal revisions to arrive at the TORC code, which leave a basic structure of COBRA-IIIC unaltered, are in the following areas:

A. Modification of the lateral momentum equation for core-wide calculations where the smallest channel size is typically that of a fuel assembly.

B. Addition of the capability for handling nonzero lateral boundary conditions on the periphery of a collection of parallel flow channels. This capability is particularly important when analyzing the group of subchannels within the hot fuel assembly.

C. Addition of the capability to handle nonuniform core exit pressure distributions.

D. Insertion of standard C-E empirical correlations and the ASME fluid property relationships.

Details of the lateral momentum equations and the empirical correlations used in the TORC code are given in CENPD-161.[10]

The application of the TORC code for detailed core thermal margin calculations typically involves two or at most three stages. In the two stage TORC, stage one represents the coarse-mesh quarter core layout with one node per quarter of an assembly. In stage two, each fuel pin and sub channel in the limiting assembly are modeled. The three stage approach is discussed below.

The first stage consists of calculating coolant conditions throughout the core on the coarse-mesh basis. The core is modeled such that the smallest unit represented by a flow channel is a single fuel assembly. The three-dimensional power distribution in the core is superimposed on the core coolant inlet flow and temperature distributions. The core inlet flow and core exit static pressure distribution are obtained from flow model tests discussed in paragraph 4.4.4.2, and the inlet temperature for normal four-loop operation is assumed uniform. The axial distributions of flow and enthalpy in each fuel

assembly are then calculated on the basis that the fuel assemblies are hydraulically open to each other. Also determined during this stage are the transport quantities of mass, momentum, and energy which cross the lateral boundaries of each flow channel.

In the second state, typically the hot assembly and adjoining fuel assemblies are modelled with a coarse mesh. The hot assembly is typically divided into four to five partial assembly regions. One of these regions is centered on the subchannels adjacent to the rod having the minimum DNBR. The three-dimensional power distribution is superimposed on the core coolant inlet flow and temperature distributions. The lateral transport of mass, momentum, and energy from the stage one calculations is imposed on the peripheral boundary enclosing the hot assembly and the neighboring assemblies. The axial distributions of flow and enthalpy in each channel are calculated as well as the transport quantities of mass, momentum, and energy which cross the lateral boundary of each flow channel.

The third stage involves a fine-mesh modelling of the partial assembly region which centers on the subchannel adjacent to the rod having the minimum DNBR. All of the flow channels used in this stage are hydraulically open to their neighbors. The output from the stage two calculations, in terms of the lateral transport of mass, momentum, and energy, is imposed on the lateral boundaries of the stage three partial assembly region. Engineering factors are applied to the minimum DNBR rod and subchannel to account for uncertainties on the enthalpy rise and heat flux due to manufacturing tolerances. The local

coolant conditions are calculated for each flow channel. These coolant conditions are then input to the DNB correlation and the minimum value of DNBR in the core is determined.

A more detailed description of this procedure with example is contained in CENPD-161.[10] This procedure is used to analyze in detail any specific three-dimensional power distribution superimposed on an explicit core inlet flow distribution. The detailed core thermal margin calculations are used primarily to develop and to support the CETOP[11] design core thermal margin calculational scheme discussed below. The CETOP code, a variant of the TORC code, is used as a design code for thermal margin analyses. The CETOP code uses transport coefficients for improved prediction of diversion cross flow and turbulent mixing between adjoining channels. Furthermore, a prediction-correlation method is used to solve the conservation equations, replacing the iterative method used in the TORC code. CETOP is benchmarked against TORC DNBR data to ensure that CETOP DNBR results are accurate or conservative relative to TORC.

The method used for design calculations using CETOP is discussed in detail in reference 11. In summary, the method is to use one limiting hot assembly radial power distribution for all analyses, to raise or lower the hot assembly power to provide the proper maximum rod radial power factor, and to use the core average mass velocity in all fuel assemblies except the hot assembly. The appropriate reduction for the hot assembly mass velocity was determined after completion of the System 80 flow model tests (see paragraph 4.4.4.2.1). This

methodology is used in the thermal margin analyses of the System 80 reactors.

4.4.4.5.3 Hydraulic Instability Analysis

Flow instabilities leading to flow excursions or flow oscillations have been observed in some boiling flow systems containing one or more closed, heated channels. Flow instability phenomena are a concern primarily because they may lead to a reduction in the DNB heat flux relative to that observed during a steady flow condition. Flow instabilities are not, however, expected to reduce thermal margin in C-E PWRs during normal operation or anticipated operational occurrences. This conclusion is based upon available literature, experimental evidence, and the results of core flow stability analyses.

Review of the available information on boiling systems has resulted in the following qualitative observations. Flow instabilities which have been observed have occurred almost exclusively in closed channel systems operating at pressures low relative to PWR operating pressures. Increasing pressure has been found to have a stabilizing influence in many cases where flow instabilities have been observed(21), and the high operating pressure characteristics of PWRs minimize the potential for flow instability. For PWR operating pressures, experimental results(22) have shown that, even with closed channel systems, operating limits due to the occurrence of Critical Heat Flux (CHF) are encountered before the flow stability threshold is reached. It would be expected that the low resistance to coolant cross-flow among subchannels of C-E

PWR fuel assemblies would have a stabilizing effect, and that expectation is confirmed by experimental results[23][24][25], which show that flow stability in parallel heated channels is enhanced by cross connections between the channels.

Experimental evidence that flow instabilities will not adversely affect thermal margin is provided by the data from the rod bundle DNB tests conducted by C-E[2][3]; many rod bundles have been tested over wide ranges of operating conditions with no evidence of premature DNB or of inconsistent data which might be indicative of flow instabilities in the rod bundle.

Analytical support for the conclusion that flow instabilities will not reduce the thermal margin of C-E PWRs is provided in reference 26. That document presents an assessment of core flow stability for a typical C-E PWR. The assessment was made using the CE-HYDNA code, the C-E version of the HYDNA flow stability code presented in reference 27. In addition to the C-E PWR flow stability assessment, reference 26 contains:

- A description of the CE-HYDNA flow stability code.
- A user's manual and Fortran listing of the CE-HYDNA code.
- Results of sensitivity studies and of code verification through comparison with experimental data.

The CE-HYDNA code provides the fundamental analytical tool for the assessment of flow stability in C-E PWRs. The code has the capability of analyzing transient one-dimensional flow phenomena in several groups of laterally closed channels with common entrance and exit plena. The use of CE-HYDNA for

analysis of open-array C-E PWR cores is conservative because the stabilizing effects of interchannel communication(17)(21)(22) are neglected.

The results presented in reference 26 are for a C-E 3450 MWt class reactor but those results are representative of all C-E PWRs. It was found that, for nominal coolant conditions, the flow is stable throughout the range of reactor power levels examined (100 to 250% rated power). Additional calculations were performed covering a wide range of operating conditions. These calculations showed that, even under severely adverse operating conditions, the flow is stable at greater than 100% of rated power. The results provide additional evidence that flow instabilities will not adversely affect core thermal margin during normal operation or anticipated operational occurrences.

4.4.5 TESTING AND VERIFICATION

Data descriptive of thermal and hydraulic conditions within the reactor vessel were obtained as part of the startup program described in Chapter 14.

4.4.6 INSTRUMENTATION REQUIREMENTS

In-core instrumentation is used to confirm core power distributions and assist in the calibration of the ex-core flux measurement system. Further information is provided in Chapter 7.

4.4.7 REFERENCES

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4.5 REACTOR MATERIALS

4.5.1 CONTROL ELEMENT DRIVE STRUCTURAL MATERIALS

4.5.1.1 Material Specifications

A. The materials used in the control element drive mechanism (CEDM) reactor coolant pressure boundary components are as follows:

1. Motor housing assembly

   SA 182, Type 347 (austenitic stainless steel)

   SA 182, Grade F6, and Code Case N-4-11 (Modified Type 403 martensitic stainless steel)

   SB 166 (nickel-chromium alloy)

2. Upper pressure housing

   SA 213, Type 316 (austenitic stainless steel)

   SA 479, Type 316 (austenitic stainless steel)

The above listed materials are also listed in Section III of the ASME Boiler and Pressure Vessel Code (1998 Edition through 2000 Addenda). In addition, the materials comply with Section II and IX of the ASME Boiler and Pressure Vessel Code.

The functions of the above listed components are described in Section 3.9.4.1.

B. The materials in contact with the reactor coolant used in the CEDM motor assembly components are as follows:

1. Latch guide tubes

   ASTM A269, Type 316 (austenitic stainless steel)

Chrome Oxide (plasma spray treatment)

2. Magnet and spacer

   ASTM A276, Type 410 (martensitic stainless steel)

3. Latch housing and insert

   ASTM A276, Type 316 (austenitic stainless steel)

   QQ-C-320a, Class 2B (chrome plating)

   ASTM A276 Type 440C (martensitic stainless steel)

4. Lift Spacer

   ASTM A240, 300 Series austenitic stainless steel

5. Alignment Tab

   ASTM A276 Type 440 (martensitic stainless steel)

6. Spring

   AMS 5698, Inconel X-750 (nickel base alloy)

7. Pin

   Haynes Stellite No. 6B (cobalt base alloy)

8. Dowel pin

   300 Series Austenitic stainless steel

9. Spacer and screw

   ASTM A240, 300 Series austenitic stainless steel

10. Stop

    ASTM A276, Type 410 (martensitic stainless steel)

11. Latch and pin

    Haynes Stellite No. 36 (cobalt base alloy)

12. Locking cup and screws

    300 Series austenitic stainless steel

13. Lower Lift

    300 Series austenitic stainless steel

The functions of the CEDM motor assembly components are described in Section 3.9.4.1.

C. The materials in contact with the reactor coolant used in the extension shafts are listed below:

1. Shafts, rod, and plunger

   ASTM A276, Type 304 (austenitic stainless steel)

   ASTM A264, Type 304 (austenitic stainless steel)

2. Gripper

   ASTM B446, Alloy 625 (nickel-chromium-molybdenum-columbium alloy)

   QQ-C-320a, Class 2B (chrome plating)

3. Spring

   AMS 5699, Inconel X-750 (nickel base alloy)

4. Pin

   304 austenitic stainless steel

The functions of the extension shaft components are described in Section 3.9.4.1.

D. The weld rod filler materials used with the above listed components are 308 stainless steel, 316 stainless steel and Inconel 52.

The material in the above listings, A through D, are similar to those used in an extensively tested CEDM assembly that exceeded lifetime requirements, as described in Section 3.9.4.4.1.

4.5.1.2 Control of the Use of 90 ksi Yield Strength Material

The only control element drive structural material identified in Section 4.5.1.1 which has a yield strength greater than 90 ksi is ASTM A276, Type 440, martenistic stainless steel. Its usage is limited to the steel ball in the vent valve on the top of the CEDM and bearing inserts in the motor assembly. The ball is used as a seal and is not a primary load bearing member of the pressure boundary while the inserts are 440 for surface hardness, see little stress and are not part of the safety release mechanism in the motor assembly. This material was tested and exceeded lifetime requirements. Also, this material has been used in reactors such as Maine Yankee (Docket 50-209), Calvert Cliffs (Docket 50-317) and St. Lucie Unit I (Docket 50-335) and has performed satisfactorily for the same application.

4.5.1.3 Control of the Use of Sensitized Austenitic Stainless Steel

Control of the use of sensitized austenitic stainless steel is consistent with the recommendations of Regulatory Guide 1.44, as described in Sections 4.5.1.3.1 through 4.5.1.3.3, except for the criterion used to demonstrate freedom from sensitization. The ASTM A708 Strauss Test is used in lieu of the ASTM A262 Method E, Modified Strauss Test, to demonstrate freedom from sensitization in fabricated unstablized austenitic

stainless steel. The former test has shown, through experimentation, excellent correlation with the type of corrosion observed in severely sensitized austenitic stainless steel.

4.5.1.3.1 Solution Heat Treatment Requirements

All raw austenitic stainless steel, both wrought and cast, employed in the fabrication of the control element drive mechanism structural components is supplied in the solution annealed condition.

4.5.1.3.2 Material Inspection Program

Extensive testing on stainless steel mockups, fabricated using production techniques, has been conducted to determine the effect of various welding procedures on the susceptibility of unstabilized 300 series stainless steels to sensitization-induced intergranular corrosion. Only those procedures and/or practices demonstrated not to produce a sensitized structure are used in the fabrication of control element drive mechanism structural components. The ASTM Standard A708 (Strauss Test) is the criterion used to determine susceptibility to intergranular corrosion. This test has shown excellent correlation with a form of localized corrosion preculiar to sensitized stainless steels. As such, ASTM A708 is utilized as a go/no-go standard for acceptability.

4.5.1.3.3 Avoidance of Sensitization

Homogeneous or localized heat treatment of unstabilized austenitic stainless steel in the temperature range 800 to 1500 F is prohibited.

Weld heat affected zone sensitized austenitic stainless steel (which will fail in the Strauss Test, ASTM A708), is avoided in control element drive mechanism structural components by careful control of:

a. Weld heat input to less than 60 kJ/in

b. Interpass temperature to 350 F maximum

c. Carbon content

4.5.1.4 Control of Delta Ferrite in Austenitic Stainless Steel Welds

The austenitic stainless steel, primary pressure retaining welds in the control element drive mechanism structural components are consistent with the recommendations of Regulatory Guide 1.31 as follows:

The delta ferrite content of A-No. 8 (Table QW-442 of the ASME Code, Section IX) austenitic stainless steel welding materials is controlled to 5FN-23FN. The delta ferrite determination is carried out using a calibrated magnetic measuring instrument and undiluted weld deposits produced in accordance with the American Welding Society Specification AWS A.5.4 or another comparable procedure for other than coated electrodes. The ferrite requirement is met for each heat, lot or heat/lot combination of weld filler material.

Delta ferrite contents of consumable inserts, rod or wire filler metal used with the gas tungsten are welding process, and deposits made with the plasma are welding process may be determined from their chemical compositions using a constitutional diagram for austenitic stainless steel welding material.

As an alternative, the delta ferrite determination may be carried out on production welds by magnetic measurement methods. The average delta ferrite content must be 3FN or more, with no single reading less than 1FN when measured at four equally spaced positions. Each production weld greater than one inch in thickness is examined while welds of thicknesses one inch and less are tested in accordance with a sampling plan.

4.5.1.5 Cleaning and Contamination Protection Procedures

The procedure and practices followed for cleaning and contamination protection of the control element drive mechanism structural components are in compliance with the recommendations of Regulatory Guide 1.37 and are described below:

Specific requirements for cleanliness and contamination protection are included in the equipment specifications for components fabricated with austenitic stainless steel. The provisions described below indicate the type of procedures utilized for components to provide contamination control during fabrication, shipment, and storage.

Contamination of austenitic stainless steels of the 300 type by compounds that can alter the physical or metallurgical structure and/or properties of the material is avoided during all stages of fabrication. Painting of 300 series stainless steels is prohibited. Grinding is accomplished with resin or rubber-bonded aluminum oxide or silicon carbide wheels that have not previously been used on materials other than 300 series stainless alloys.

Internal surfaces of completed components are cleaned to the extent that grit, scale, corrosion products, grease, oil, wax, gum, adhered or embedded dirt, or extraneous material are not visible to the unaided eye.

Cleaning is effected by either solvents (acetone or isopropyl alcohol) or inhibited water (30-100 ppm hydrazine). Water will conform to the following requirements:

Halides	
Chloride, ppm	< 0.60
Fluoride, ppm	< 0.40
Conductivity, μhos/cm	< 5.0
pH	6.0 - 8.0
Visual clarity	No turbidity, oil or sediment

To prevent halide-induced intergranular corrosion that could occur in an aqueous environment with significant quantities of dissolved oxygen, flushing water may be inhibited with hydrazine. Experiments have proven this to be effective. Operational chemistry specifications for halides and oxygen are described in section 9.3.4.3.

4.5.2 REACTOR INTERNALS MATERIALS

4.5.2.1 Material Specifications

The materials used in fabrication of the reactor internal structures are primarily Type 304 stainless steel. The flow skirt is fabricated from Inconel. Welded connections are used where feasible; however, in locations where mechanical connections are required, structural fasteners are used which are designed to remain captured in the event of a single failure. Structural fastener material is typically a high strength austenitic stainless steel; however, in less critical applications Type 316 stainless steel is employed. Hardfacing of Stellite material is used at wear points. The effect of irradiation of the properties of the materials is considered in the design of the reactor internal structures. Work hardening properties of austenitic stainless steels are not used.

The following is a list of the major components of the reactor internals together with their material specifications:

A. Core support barrel assembly

   1. Type 304 austenitic stainless steel to the following specification:

      a. ASTM-A-182

      b. ASTM-A-213

      c. ASTM-A-240

      d. ASTM-A-479

2. Precipitation hardening stainless steel to the following specifications:

   a. ASTM-A-453, Grade 660

   b. ASTM-A-638, Grade 660

B. Upper guide structure assembly

1. Type 304 austenitic stainless steel to the following specifications:

   a. ASTM-A-182

   b. ASTM-A-240

   c. ASTM-A-213

   d. ASTM-A-479

2. Precipitation hardening stainless steel to the following specifications:

   a. ASTM-A-638, Grade 660

   b. Core shroud assembly

1. Type 304 austenitic stainless steel to the following specifications:

   a. ASTM-A-182

   b. ASTM-A-240

D. Holddown ring

ASTM-A-182, modified to ASME Code Case 1747

E. Bolt and pin material

ASTM-A-453 and ASTM-A-638, Grade 660 material (trade name A-286) is used for bolting and pin applications. This

alloy is heat treated to a minimum yield strength of 85,000 lb/in.^{2}. Its corrosion properties are similar to those of the 300 series austenitic stainless steels. It is austenitic in all conditions of fabrication and heat treatment. This alloy was used for bolting in previous reactor systems and test facilities in contact with primary coolant and has proven completely satisfactory.

F. Chrome plating and hardfacing

Chrome plating or hardfacing are employed on reactor internals components or portions thereof where required by function. Chrome plating complies with Federal Specification No. QQ-C-320b. The hardfacing material employed is Stellite 25.

All of the materials employed in the reactor internals and in-core instrument support system have performed satisfactorily in reactors such as Palisades (Docket 50-255), Fort Calhoun (Docket 50-285) and Maine Yankee (Docket 50-309).

4.5.2.2 Welding Acceptance Standards

Welds employed on reactor internals and core support structures meet the acceptance standards delineated in article NG-5000, Section III, Division I, and control of welding is performed in accordance with Sections III, Division I, and IX of the ASME Code. In addition, consistency with the recommendations of Regulatory Guides 1.31 and 1.44 is described in Section 4.5.2.3.

4.5.2.3 Fabrication and Processing of Austenitic Stainless Steel

The following information applies to unstabilized austenitic stainless steel as used in the reactor internals.

4.5.2.3.1 Control of the Use of Sensitized Austenitic Stainless Steel

The recommendations of Regulatory Guide 1.44, as described in Sections 4.5.2.3.1.1 through 4.5.2.3.1.5, are followed except for the criterion used to demonstrate freedom from sensitization. The ASTM A708 Strauss test is used in lieu of the ASTM A262 Method E, Modified Strauss Test, to demonstrate freedom from sensitization in fabricated unstabilized austenitic stainless steel, since the former test has shown, through experimentation, excellent correlation with the type of corrosion observed in severely sensitized austenitic stainless steel.

4.5.2.3.1.1 Solution Heat Treatment Requirements

All raw austenitic stainless steel material, both wrought and cast, employed in the fabrication of the reactor internals is supplied in the solution annealed condition, as specified in the pertinent ASTM or ASME B&PV Code material specification; viz, 1900 to 2050 F for 1/2 to 1 h/in of thickness and rapidly cooled to below 700F. The time at temperature is determined by the size and the type of component.

Solution heat treatment is not performed on completed or partially fabricated components. Rather, the extent of

chromium carbide precipitation is controlled during all stages of fabrication as desired in Section 4.5.2.3.1.4.

4.5.2.3.1.2 Material Inspection Program

Extensive testing of stainless steel mockups, fabricated using production techniques, was conducted to determine the effect of various welding procedures on the susceptibility of unstabilized 300 series stainless steels to sensitization-induced inter-granular corrosion. Only those procedures and/or practices demonstrated not to produce a sensitized structure are used in the fabrication of reactor internals components. The ASTM Standard A708 (Strauss Test) is the criterion used to determine susceptibility to intergranular corrosion. This test has shown excellent correlation with a form of localized corrosion peculiar to sensitized stainless steel. As such, ASTM A708 is utilized as a go/no-go standard for acceptability.

As a result of the above tests, a relationship was established between the carbon content of Type 304 stainless steel and weld heat input. This relationship is used to avoid weld heat affected zone sensitization as described in Section 4.5.2.3.1.4.

4.5.2.3.1.3 Unstabilized Austenitic Stainless Steels

The unstabilized grade of austenitic stainless steel with a carbon content greater than 0.03% used for components of the reactor internals is Type 304. This material is furnished in the solution annealed condition, The acceptance criterion used for this material, as furnished from the steel supplier, is ASTM A262, Method E.

Exposure of completed or partially fabricated components to temperatures ranging from 800 to 1500 F is prohibited except as described in Section 4.5.2.3.1.5.

Duplex, austenitic stainless steels containing more than 5FN delta ferrite (weld metal, cast metal, weld deposit overlay), are not considered unstabilized since these alloys do not sensitize; i.e., form a continuous network of chromium-iron carbides. Specifically, alloys in this category are:

-F8M	Cast stainless steel (delta ferrite controlled to 5FN-33FN)
-CF8	Cast stainless steel (5FN-33FN)
-Type 308	Singly and combined
-Type 309	stainless steel weld filler metals
-Type 312	(delta ferrite controlled to
-Type 316	5FN-23FN as deposited)

In duplex austenitic/ferritic alloys, chromium-iron carbides are precipitated preferentially at the ferrite/austenite interfaces during exposure to temperatures ranging from 800-1500°F. This precipitate morphology precludes intergranular penetrations associated with sensitized 300 series stainless steels exposed to oxygenated or otherwise faulted environments.

4.5.2.3.1.4 Avoidance of Sensitization

Exposure of unstabilized ustenitic 300 series stainless steels to temperatures ranging from 800 to 1500F will result in carbide precipitation. The degree of carbide precipitation or sensitization depends on the temperature, the time at that temperature, and also the carbon content. Severe sensitization is defined as a continuous grain boundary chromium-iron carbide

network. This condition induces susceptibility to intergranular corrosion in oxygenated aqueous environments, as well as those containing halides. Such a metallurgical structure will readily fail the Straus Test, ASTM A708. Discontinuous precipitates (i.e., an intermittent grain boundary carbide network) are not susceptible to intergranular corrosion in a PWR environment.

Weld heat affected zone sensitized austenitic stainless steels are avoided (which will fail the Strauss Test, ASTM A708) by careful control of:

- Weld heat input to less than 60 kJ/in
- Interpass temperature to 350 F maximum
- Carbon content

A weld heat input of less than 60 kJ/in is used during most fabrication stages of the Type 304 stainless steel core support structure. Higher heat inputs are used in some heavy section weld joints. Freedom from weld heat affected zone sensitization in those higher heat input weldments is demonstrated with weld runoff samples produced at the time of component welding in material having a carbon content equal to or greater than the highest carbon content of those heats of steel being fabricated. Specimens so provided are subjected to the Strauss Test, ASTM A708.

4.5.2.3.1.5 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitizing Temperature

Sensitization, which may be susceptible to intergranular corrosion, is avoided during welding as described in

Section 4.5.2.3.1.4. Homeneous or localized heat treatment of unstabilized stainless steels in the temperature range 800 to 1500 F is avoided. Complex substructures may be thermally stabilized after fabrication and prior to final machining. Such treatment produces only minor, discontinuous precipitates. In addition to thermocouple records during this heat treatment, a sample of Type 304 stainless steel, having a carbon content equal to or greater than the highest carbon heat of material present in the structure, is included as a monitor sample. After heat treatment, the monitor sample is subjected to the Strauss Test, ASTM A708, as well as a metallographic examination to verify freedom from sensitization.

4.5.2.3.2 Non-Metallic Thermal Insulation

Non-metallic thermal insulation is not used on the reactor internals.

4.5.2.3.3 Control of Delta Ferrite in Welds

The recommendations of Regulatory Guide 1.31 are followed, as described in paragraph 4.5.1.4.

Furthermore, for submerged arc welding processes, the delta ferrite determination for each fire/flux combination may be made on a production or simulated (qualification) production weld, and the delta ferrite content is controlled to 3FN-23FN.

4.5.2.3.4 Control of Electroslag Weld Properties

The electroslag process, Regulatory Guide 1.34, is not utilized to fabricate reactor internal components.

4.5.2.3.5 Welder Qualification for Areas of Limited Accessibility

The specific recommendations of Regulatory Guide 1.71 were not followed by C-E. However, performance qualifications for personnel welding under conditions of limited accessibility are conducted and maintained in accordance with the requirements of ASME Code, Sections III and IX. A requalification is required when:

a. Any of the essential variables of Section IX is changed.

b. When authorized personnel have reason to question the ability of the welder to satisfactorily perform to the applicable requirements.

Production welding is monitored for compliance with the procedure parameters, and welding qualification requirements are certified in accordance with Sections III and IX. Further assurance of acceptable welds of limited accessibility is afforded by the welding supervisor assigning only the most highly skilled personnel to these tasks. Finally, weld quality, regardless of accessibility, is verified by the performance of the required non-destructive examination.

4.5.2.4 Contamination Protection and Cleaning of Austenitic Stainless

Compliance with the recommendations of Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants", is discussed in paragraph 4.5.1.5.

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4.6 FUNCTIONAL DESIGN OF REACTIVITY CONTROL SYSTEMS

PVNGS includes the following reactivity control systems: the control element drive mechanisms (CEDM), the safety injection system (SIS), and the chemical and volume control system (CVCS). The CEDM's are referred to collectively as the control rod drive system (CRDS). The pertinent information, evaluations, and testing of the CRDS are treated in Section 4.6.1, 4.6.2, and 4.6.3 respectively. The combined performance of the CRDS and other reactivity control system is discussed in Section 4.6.4 and 4.6.5.

4.6.1 INFORMATION FOR CRDS

The CRDS consists of the CEDMs. Component diagrams, description, and characteristics of the CEDM's are presented in Section 3.9.4.

4.6.2 EVALUATION OF CRDS

The safety function of the CRDS is to drop CEA'S into the reactor core when the motive power is removed from the CEDM power bus. The active interface between the RPS and the CRDS is at the trip circuit breakers located in the reactor trip switchgear (RTSG).

4.6.2.1 Single Failure

A failure mode and effects analysis of the RPS (including the RTSG) is presented in Section 7.2, which demonstrates compliance with IEEE Standard 279-1971, and shows that no single failure in the RPS can prevent the removal of electrical motive power from the CEDM's. For the trip function, the

CEDM's are essentially passive devices. When power is removed from the CEDM coils, the armature springs automatically cause the latches to be disengaged from the CEDM drive shafts, allowing insertion of the CEA's by gravity. For the execution of the trip function, all the CEDM's are independent of one another. In other words, the failure of one CEDM to trip does not affect the operability of any other CEDM. Sufficient shutdown margin is always maintained to assure that the shutdown capability can be retained in the event of a failure of any CEDM. Therefore, no single failure can prevent the CRDS from providing sufficient scram reactivity to achieve a shutdown.

4.6.2.2 Isolation of the CRDS from other Equipment

The interface between the CEDMs and the CEDM Control System is at the CEDMCS power switches, which provide the isolation of the motive power from the low voltage logic control signal. The interface between the CEDMs and the CEAs involves no non-essential elements. Therefore, no isolation is required.

4.6.2.3 Protection from Common Mode Failure

4.6.2.3.1 Pipe Breaks

Protection of essential systems from the consequences of a postulated pipe rupture shall be by separation via physical plant layout, pipe restraints, protective structures and compartments, watertight rooms, isolation capability or other suitable means, as described in section 3.6.

4.6.3 TESTING AND VERIFICATION OF THE CRDS

The precore and post-core CEDM performance test is described in Chapter 14 which verifies the proper operation and sequencing of the CEDMs.

4.6.4 INFORMATION FOR COMBINED PERFORMANCE OF THE REACTIVITY CONTROL SYSTEMS

Plan and elevation layout drawings of the reactivity control systems are presented in section 1.7.

Table 4.6-1 lists postulated accidents analyzed in Chapter 15 that take credit for two or more reactivity control systems for preventing or mitigating each accident. The related reactivity systems are also tabulated.

4.6.5 EVALUATION OF COMBINED PERFORMANCE

The CRDS, CVCS and SIS are separated and totally diverse in design and operation. In addition, since the CRDS, the SIS, and the CVCS are protected from missiles, pipe breaks and their effects, (as delineated in Section 6.3 and 9.3.4), there are no credible potential common mode failures that could cause the combination of the CRDS, SIS, and CVCS to fail to provide sufficient reactivity insertion to achieve a shutdown under design conditions.

TABLE 4.6-1

POSTULATED ACCIDENTS

Event	CRDS	SIS	CVCS
Feedwater Line Break	A	A	A
Steam Line Break	A	A	A
LOCA	A	A	A
Sample Line or Letdown Line Break	A	A	B
Steam Generator Tube Rupture	A	A	C
CEA Ejection	A	A	C
Boron Dilution	A	C	A
Uncontrolled CEA Withdrawal	A	B	C
CEA Drop	A	B	C
Inadvertent Opening of Atmospheric Dump Valve or Main Steam Safety Valve	A	B	C
Loss of Normal Feedwater Flow	A	B	C
Reactor Coolant Pump Shaft Seizure	A	B	C

A = Use expected, and required

B = Use expected, but not required

C = Use not expected, and not required

APPENDIX 4A

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CHAPTER 5

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

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FIGURES

FIGURES (cont)

FIGURES (cont)

5. REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The reactor is a pressurized water reactor (PWR) with two coolant loops. The reactor coolant system (RCS) circulates water in a closed cycle, removing heat from the reactor core and internals and transferring it to a secondary (steam generating) system. The steam generators provide the interface between the reactor coolant (primary) system and the main steam (secondary) system. The steam generators are vertical U-tube heat exchangers with an integral economizer in which heat is transferred from the reactor coolant to the main steam system. Reactor coolant is prevented from mixing with the secondary steam by the steam generator tubes and the steam generator tube sheet, making the RCS a closed system thus forming a barrier to the release of radioactive materials from the core of the reactor to the containment building.

The arrangement of the RCS is shown in Figure 4.4-8 and engineering drawing 03-M-RCP-001. The major components of the system are the reactor vessel; two parallel heat transfer loops, each containing one steam generator and two reactor coolant pumps; a pressurizer connected to one of the reactor vessel outlet pipes; and associated piping. All components are located inside the containment building.

Table 4.4-11 shows the principal pressures, temperatures, and flowrates of the RCS under normal steady-state, full-power operating conditions. Instrumentation provided for operation and control of the system is described in Chapter 7.

System pressure is controlled by the pressurizer, where steam and water are maintained in thermal equilibrium. Steam is formed by energizing immersion heaters in the pressurizer, or is condensed by the pressurizer spray to limit pressure variations caused by contraction or expansion of the reactor coolant.

The average temperature of the reactor coolant varies with power level and the fluid expands or contracts, changing the pressurizer water level.

The charging pumps and letdown control valves in the chemical and volume control system (CVCS) are used to maintain a programmed pressurizer water level. A continuous but variable letdown purification flow is maintained to keep the RCS chemistry within prescribed limits. A charging nozzle and a letdown nozzle are provided on the reactor coolant piping for this operation. The charging flow is also used to alter the boron concentration or correct the chemical content of the reactor coolant.

Other reactor coolant loop penetrations are the pressurizer surge line in one reactor vessel outlet pipe; the four safety injection inlet nozzles, one in each reactor vessel inlet pipe; two outlet nozzles to the shutdown cooling system, one in each reactor vessel outlet pipe; two pressurizer spray nozzles; vent and drain connections; and sample and instrument connections.

Overpressure protection for the reactor coolant pressure boundary is provided by four spring-loaded ASME Code safety valves connected to the top of the pressurizer. These valves discharge to the reactor drain tank, where the steam is

released under water to be condensed and cooled. If the steam discharge exceeds the capacity of the reactor drain tank, it is relieved to the containment atmosphere via a rupture disc installed in the tank. The reactor drain tank is part of the Chemical and Volume Control System (Section 9.3.4).

Overpressure protection for the secondary side of the steam generators is provided by spring-loaded ASME Code safety valves located in the main steam system upstream of the steam line isolation valves.

Components and piping in the RCS are insulated with a material compatible with the temperatures involved to reduce heat losses and protect personnel from high temperatures.

Principal parameters of the RCS are listed in Table 4.4-11. Table 5.1-3 lists RCS volumes. Table 5.1-2 contains the principal component material specifications.

Shielding requirements of the surrounding structures are described in Section 12.3. Reactor coolant system shielding permits limited personnel access to the containment building during power operation. The reactor vessel sits in a primary shield well. This and other shielding reduces the dose rate within the containment and outside the shield wall during full power operation to acceptable levels.

Refer to section 18.II.B.1 for a discussion of the reactor coolant gas vent system (RCGVS).

5.1.1 SCHEMATIC FLOW DIAGRAM

The principal pressures, temperatures, and flowrates at major components are listed in Table 5.1-1. These parameters are

referenced to the piping and instrument diagram, by numbered locations.

5.1.2 PIPING AND INSTRUMENT DIAGRAM

Refer to engineering drawings 01, 02, 03-M-RCP-001, -002 and -003 for the reactor coolant system (RCS) piping and instrumentation diagrams applicable to PVNGS. Instrumentation provided for operation and control of the RCS Level is described in Chapter 7. The engineering drawings listed above also show PVNGS tag numbers and vent/drain valves.

5.1.3 ELEVATION DRAWING

Reactor Coolant system plan & elevation drawings are provided as engineering drawing 03-M-RCP-001. Additionally, engineering drawings 13-P-00B-007 and 13-P-00B-008 are elevation drawings that show the principal dimensions of the RCS in relation to the supporting or surrounding concrete structures from which a measure of the protection shielding and missiles afforded by the arrangement and the safety considerations incorporated in the layout can be gained.

5.1.4 CESSAR INTERFACE REQUIREMENTS

The following interface requirements are repeated from CESSAR Section 5.1.4:

Below are detailed the interface requirements that the nuclear steam supply system (NSSS) places on certain aspects of the balance of plant, listed by categories. In addition, applicable General Design Criteria (GDC) and Regulatory Guides, which C-E utilizes in its design of the reactor coolant system

(RCS), are presented. These GDC and Regulatory Guides are listed only to show what C-E considers to be relevant, and are not imposed as interface requirements, unless specifically called out as such in a particular interface requirement

Relevant GDC:	1, 2, 3, 4, 5, 14, 15, 26, 27, 28, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 54, 55, 56, 57.
Relevant Reg. Guides:	1.1, 1.2, 1.4, 1.14, 1.24, 1.26, 1.29, 1.31, 1.34, 1.36, 1.38, 1.42, 1.43, 1.44, 1.45, 1.46, 1.47, 1.48, 1.49, 1.50, 1.51, 1.54, 1.61, 1.64, 1.65, 1.66, 1.67, 1.71, 1.73, 1.74, 1.79, 1.83, 1.84, 1.85.

A. Power

See Chapters 7 and 8 for further power information.

B. Protection from Natural Phenomena

1. The containment shall remain functional for the full range, per GDC 2, of natural phenomena (earthquakes, tornadoes, tornado missiles, flooding conditions, hurricanes, winds, snow, and ice) and external environmental conditions.

2. The steam piping and associated supports from the steam generators up to and including the Main Steam Isolation Valves (MSIVs) and any auxiliary steam supply systems up to the isolation valves which connect upstream of the MSIVs shall be seismic category I and designed to ASME B&PV Code, Section III, Class 2 requirements.

3. The valves, piping, and associated supports of the Feedwater System from and including the Main Feedwater Isolation Valves (MFIVs) to the steam generator feed nozzles shall be Seismic Category I and designed to ASME B&PV Code Section III, Class 2 requirements.

4. All components and piping of the Emergency Feedwater System between the steam generators and the containment isolation valves shall be Seismic Category I and designed to ASME B&PV Code Section III, Class 2 requirements.

5. All components, piping and associated supports in the condensate storage facilities for Emergency Feedwater shall be Seismic Category I and designed in accordance with ASME B&PV Code Section III, Class 3.

6. All components and piping associated with steam generator blowdown between the steam generator and the containment isolation valves shall be Seismic Category I and designed to ASME B&PV Code Section III, Class 2 requirements.

C. Protection from Pipe Failure

1. The following valves shall be protected against internally generated missiles or the effects resulting from a high energy pipe rupture (e.g., pipe whip, jet impingement and steam environment) such that these events will not prevent the valves from performing their requisite safety functions.

a. MSIVs.

b. Secondary Safety Valves.

c. Atmospheric Dump Valves (ADVs).

d. MSIV Bypass Valves.

e. MFIVs.

f. Blowdown Isolation Valves.

2. The MSIVs shall be supported such that the valve body and actuator will not be distorted or displaced as a result of pipe break thrust loadings to such a degree that the valve cannot close.

3. Feedwater piping shall be routed, protected and restrained such that in the case of a rupture of a feedwater line or any other system pipeline, a single failure criteria will not be exceeded with regard to safe shutdown of the plant.

4. A containment shall be provided to limit the release of energy and radioactivity to the environs in the event of a rupture of the RCS and to protect the public health and safety.

5. The containment, including penetrations, shall not be subject to loss of function from dynamic effects (e.g., missiles, pipe reactions, fluid reaction forces) resulting from failure of RCS equipment or piping within the containment.

6. The design pressure and temperature of the containment shall, as a minimum:

a. Be equal to the peak pressure and temperature resulting from either (1) complete blowdown of the reactor coolant through any rupture of the RCS piping, up to and including a postulated double-ended severance of the largest reactor coolant pipe or, (2) a complete blowdown of the unisolated steam system through any rupture of the steam line piping, up to and including a postulated double ended severance of the largest main steam line pipe, assuming a sequence of events for either case which leads to the peak transient accumulation of energy in the building atmosphere. To meet this end, a spectrum of loss-of-coolant accidents (LOCA) and main steam line breaks (MSLB) have been analyzed. They shall be used by the applicant to establish the design pressure and temperature of the containment. (Refer to Sections 6.2.1.3 and 6.2.1.4).

b. Take into account all credible post-blowdown energy additions to the containment atmosphere, such as core residual heat, thin and thick structural metal stored energy, steam generator reverse heat transfer, metal-water reactions and other possible chemical reactions resulting from a loss-of-coolant accident.

7. Compartments within the containment including the reactor vessel cavity shall be designed for the

maximum pressure differential between the compartment and the remainder of the containment based on the maximum RCS pipe break that can occur in the compartment as defined in Section 3.6.

D. Missiles

1. The RCS, which is a potential source of missiles, shall to the extent possible, be either surrounded by barriers or restrained to prevent missiles from reaching other parts of the RCS, the containment lines, the secondary steam and feedwater piping or the engineered safeguards systems. See Section 3.5 for additional discussion of missiles.

2. A containment structure shall be provided to protect the RCS from loss of function due to missiles generated outside the containment, including those resulting from equipment failure, and weather induced forces such as tornadoes and hurricanes.

E. Separation

1. Adequate physical separation shall be maintained between the redundant electrical and instrumentation systems used for emergency control and safe shutdown of the reactor, and between the multiple instrumentation channels in the Plant Protection System.

2. Each MSIV shall have two physically separate and electrically independent closure solenoids in order to provide redundant means of valve operation. A

Main Steam Isolation Signal (MSIS) shall be provided to each solenoid.

3. Redundant feedwater system isolation valves in each feedwater line meeting the single failure criteria shall be provided in piping interconnecting the steam generators to preclude blowdown of both steam generators following a pipe rupture.

F. Independence

1. The provisions of General Design Criteria 54 and 57 for containment isolation valves shall be met.

2. The feedwater system piping, Emergency Feedwater System piping, and main steam piping and all of their associated supports and restraints shall be designed so that a single adverse event, such as a ruptured feedwater line, emergency feedwater line, main steam line inside containment, or a closed isolation valve can occur without:

   a. Initiating a Loss-of-Coolant incident.

   b. Causing failure of the other steam generator's safety class steam and feedwater lines, MSIVs, safety valves, MFIVs blowdown line isolation valves, or ADVs.

   c. Reducing the capability of any of the Engineered Safety Features systems or the Plant Protective System.

   d. Transmitting excessive loads to the containment pressure boundary.

e. Compromising the function of the plant control room.

f. Precluding orderly cooldown of the RCS.

3. An electrical or mechanical malfunction of one solenoid shall not prevent a MSIV from closing.

4. No single failure in the control circuits shall prevent closure of the MSIV bypass valves.

5. The MSIV bypass valve control circuits shall be designed, or precautions shall be taken, such that no single electrical failure would result in the spurious motion of the valves.

6. The ADV control circuits shall be designed or precautions taken, such that no single electrical failure would result in the opening of valves with a total combined capacity greater than 1.9×10^6 lb/hr at 1000 psia.

7. No single failure in the control circuits shall prevent operation of at least one ADV on each steam generator.

8. Each MFIV actuator shall be physically and electrically independent of the other such that failure of one will not cause failure of the other.

9. No single active or passive component failure, single passive or active electrical component failure, or power supply failure shall preclude adequate operation of the Emergency Feedwater System, such as the following events:

a. Loss of normal feedwater with or without a concurrent loss of normal onsite or offsite AC power.

b. Minor secondary system pipe breaks with or without a concurrent loss of normal onsite or offsite AC power.

c. Steam generator tube rupture with or without a concurrent loss of normal onsite or offsite AC power.

d. Major secondary system pipe breaks with or without a concurrent loss of normal onsite or offsite AC power.

e. Small LOCA with or without a concurrent loss of normal onsite or offsite AC power.

10. The ability of the Emergency Feedwater System to perform its design function considering a power supply failure, a single active or passive mechanical component failure, a single active or passive failure of an electrical component, or the effects of a high or moderate energy pipe rupture shall be demonstrated.

11. The Emergency Feedwater System shall provide double isolation from the Main Feedwater System during plant conditions when the Emergency Feedwater System is not required.

12. Blowdown piping exiting containment shall have redundant blowdown line isolation valves which shall

be actuated by an Emergency Feedwater Actuation Signal (EFAS).

G. Thermal Limitations

1. A component cooling system (CCS) shall provide cooling water to each RCP as shown in Figure 5.1.2-2.

2. RCP heat load and flow data presented in Table 5.1.4-1 shall be utilized in the design of the cooling water system.

3. The maximum and minimum temperature of the component cooling water during normal operation shall be 105F and 65F, respectively.

4. Power operated atmospheric dump valves shall be provided in each of the four main steam lines to allow cooldown of the steam generators when the main steam line isolation valves are closed, or when the main condenser is not available as a heat sink. Each ADV shall be capable of holding the plant at hot standby dissipating core decay and reactor coolant pump heat, and allowing controlled cooldown from hot standby to Shutdown Cooling System initiation conditions. Each valve shall be sized to allow a rupture, which renders one steam generator unavailable for heat removal, concurrent with a loss of normal A.C. power and single failure of one of the remaining two ADVs. To accomplish the above, each ADV shall have sufficient capacity to meet the saturated steam flow conditions in Figure 5.1.4-1.

Also no single valve shall have a maximum capacity greater than 1.9 x 10^6 lb/h at 1000 psia.

5. Following the events stated in Section 5.1.4.F.9, the emergency feedwater system shall maintain adequate inventory in the steam generator(s) for residual heat removal and be capable of the following:

   a. Maintaining the NSSS at hot standby with or without normal offsite and normal onsite power available.

   b. Facilitating NSSS cooldown at the maximum administratively controlled rate of 75F/h from hot standby to shutdown cooling initiation with or without normal offsite or onsite power available. (The Shutdown Cooling System becomes available for plant cooldown when the RCS temperature and pressure are reduced to approximately 350F and 400 psia.)

6. The Emergency Feedwater System shall be available to deliver flow to the steam generator(s) automatically upon receipt of an EFAS as follows:

   a. Within 10 seconds when normal offsite or normal onsite power is available.

   b. Within 45 seconds when both normal onsite and normal offsite power are not available.

7. The required emergency feedwater flow, based on residual heat removal requirements is 875 gpm

delivered to the steam generator(s) downcomer feedwater nozzle. Maximum expected steady state steam generator pressure at the downcomer nozzle is approximately 1275 psia.

8. Emergency feedwater temperature shall be at least 40F and no greater than 180F.

9. A minimum of 300,000 gallons of secondary quality makeup water as defined in Section 10.3.4 shall be available to the Emergency Feedwater System for delivery to the intact steam generator(s). This amount ensures sufficient feedwater to allow an orderly plant cooldown to shutdown cooling initiation conditions.

10. Each MSIV leak flow shall not exceed 0.001 percent of nominal flow at 1270 psia in the forward direction and shall not exceed 0.1 percent of nominal flow at 1270 psia in the reverse direction.

11. No single MSIV bypass valve or bypass valve line shall have a capacity greater than 1.9×10^6 lb/hr of saturated steam at 1000 psia.

12. No single turbine bypass valve shall have a capacity greater than 1.9×10^6 lb/hr at 1000 psia.

13. The total reverse leak rate of feedwater check valves to each steam generator shall not exceed 1000 cc/hr.

H. Monitoring

1. Means shall be provided for detection of reactor coolant leakage into the secondary side of the steam generators and cooling water systems associated with components containing reactor coolant.

2. Applicant supplied component designs and RCS construction procedures shall ensure that RCS leakage from known sources will not exceed 10 gpm; from steam generator tubes will not exceed 1.0 gpm; and from unknown sources will not exceed 1 gpm, to minimize in-plant airborne and surface activity levels and activity releases to the environs at system normal operating temperature and pressure.

3. Capability for monitoring each MSIV, MFIV, ADV and blowdown line isolation valve position shall be provided locally and in the control room.

4. The required accuracy of the feedwater temperature measurement devices shall be $\pm$1F for any calorimetric measurement.

I. Operational/Controls

1. A power-operated MSIV capable of establishing shutoff under conditions of design pressure, design temperature, and flow conditions resulting from a break just upstream or downstream shall be provided in each main steam line outside of containment.

2. Capability for controlling MSIV position shall be provided in the control room and the remote shutdown panel.

3. The MSIV and MSIV bypass valve shall be either a fail close valve or a valve that is shown by the applicant to close upon receipt of a MSIS.

4. The full open to close stroke time of each MSIV and MSIV bypass valve shall be 5 seconds or less upon receipt of an MSIS.

5. The ADVs shall be fail close and shall be capable of being remote manually positioned to control the plant cooldown rate.

6. The ADVs shall be provided with manual operators such that the valves may be hand operated from the control room and remote shutdown panel in the event of a loss of normal power supply.

7. In the combined event of either a steam line break or steam generator tube rupture and the loss of power operation of the ADVs, personnel access to the manual operators of the intact valves on the other steam generator shall be possible.

8. A MSIS actuation signal shall close the MSIVs, MSIV bypass valve, MFIVs and the steam generator blowdown valves.

9. Redundant feedwater system isolation valving shall be provided in both the economizer feedlines and the downcomer feedlines such that the following criteria

are met when the effects of single failure criteria are imposed:

a. Complete termination of forward feedwater flow is assumed within 5 seconds after receipt of an MSIS.

b. Abrupt complete termination of reverse feedwater flow with the existence of a reverse flow condition. Check valves are considered to be an acceptable means of achieving the above.

10. The economizer and downcomer feedwater line isolation valves (MFIVs) in each main feedwater line shall be remote-operated and be capable of maintaining leak rate of less than 1000 cc/hr under the main feedwater line pressure, temperature and flow resulting from the transient conditions associated with a pipe break on either side of the valves.

11. The Emergency Feedwater System shall be controllable in a post-accident environment from either the control room or a remote shutdown station.

12. The Emergency Feedwater System shall be controllable such that post accident operation will not result in overfilling the intact steam generator(s).

13. If the Emergency Feedwater System is used as an auxiliary feedwater system, the emergency feedwater pumps shall be designed for operation when steam generator pressure is negligible and not result in damage to the pumps or effect the ability of the

system to deliver the required emergency feedwater flow. Such a condition can exist during startup or shutdown operation subsequent to an EFAS which starts the emergency feedwater pumps and fully opens the system isolation and control valves.

J. Inspection and Testing

1. All ASME B&PV Code, Section III, Class 1 and 2 valves shall be designed, fabricated and installed such that they are capable of being periodically tested in accordance with ASME OM Code.

2. Adequate clearances shall be provided for in-service inspection of the Reactor Coolant Pressure Boundary and the ASME B&PV Code Section III, Class 2 portions of the Main Steam, Main Feed, Emergency Feed, and Blowdown systems' piping, in accordance with the provisions of Section XI of the ASME Boiler and Pressure Vessel Code.

3. Biological shielding and all other insulation, if installed around the Reactor Coolant Pressure Boundary, shall be designed to afford access for inservice inspection as defined by Section XI of the ASME Boiler and Pressure Vessel Code.

4. The pressurizer manway shall be accessible for internal examination of the pressurizer.

K. Chemistry/Sampling

1. A sampling system which provides a means of obtaining remote liquid samples from the RCS for

chemical and radiochemical laboratory analysis shall be provided. The sampling system shall be designed to allow for the following tests: corrosion product activity levels, dissolved gas, fission product activity, chloride concentration, coolant pH, conductivity levels and boron concentration. The pressurizer steam space sample lines shall contain 7/32" x 1" orifice as close to the pressurizer as possible. The sample system shall be as shown on Figure 5.1.2-1.

2. A system or systems shall be provided to maintain the steam generator secondary water chemistry within Section 10.3.4 specifications during plant operation. The system or systems shall incorporate steam generator blowdown, chemical addition, and monitoring.

3. Provisions shall be made to allow sampling of the RCS during Shutdown Cooling System operation.

4. Provisions shall be made to allow sampling of the RCS during startup.

L. <u>Materials</u>

1. The materials used for the containment and its internal structures shall be compatible with both the normal operating environment and the most severe thermal, chemical, and radiation environment expected during post-accident conditions (refer to Section 3.11 for the environmental parameters). Consideration shall be given to compatibility with

spray water chemistry and recirculating water chemistry to ensure that containment materials will withstand this exposure without causing deleterious or undesirable reactions, or significantly altering the existing water chemistry of recirculating ECCS water.

2. The following elements and components shall not come in contact with surfaces which will later be in contact with reactor coolant, at any stage of manufacture, assembly or inspection. These are: (a) lead or lead compounds, (b) mercury or mercury compounds, (c) halogen containing solvents or other halogen compounds.

3. The use of the following materials shall be minimized on surfaces normally in contact with reactor coolant:

   a. sulfonated cutting oils,

   b. zinc metal or zinc compounds,

   c. magnesium metal,

   d. asbestos,

   e. aluminum,

   f. copper acid etchants,

   g. penetrants.

   If the above materials are intended to be used, the use shall first be approved by C-E.

4. The sample lines in contact with the reactor coolant, including welds shall be designed such that the material is compatible with the fluid chemistry described in Section 9.3.4.

5. Construction materials or protective coatings containing low melting point elements, particularly lead, mercury and sulfur, shall not be used if they could come in contact with the secondary systems. This is required to reduce to a minimum the potential for stress corrosion cracking of Inconel material in the steam generators.

6. The secondary system piping shall be designed to allow cleaning for the removal of foreign material and rust prior to operation and to prevent introduction of this material into the steam generator. Chemical cleaning or hand cleaning may be employed. During chemical cleaning, no fluid shall enter the steam generators. Suitable bypass piping shall be provided if required.

7. Non-metallic insulation used on the Reactor Coolant Pressure Boundary shall conform to Regulatory Guide 1.36. The chloride and fluoride content of the non-metallic insulation shall be in the acceptable region as shown in Regulatory Guide 1.36. Tests shall be made on representative samples of the non-metallic thermal insulation shall be demineralized or distilled water.

8. No contaminants, except for cutting oils, shall be left on any RCS component surface except for the time required to perform and evaluate the particular fabrication or inspection operation.

9. Field welding of the RCS piping assemblies and components shall be done in accordance with a welding procedure or procedures by welders qualified to ASME Section IX requirements.

M. System/Component Arrangement

1. The pressurizer and surge line shall be located entirely above the reactor coolant loops.

2. The pressurizer surge line maximum L/D (equivalent) shall be 330 assuming 12-inch Schedule 160 piping. The L/D equivalent (Le/D) excludes entrance and exit losses but includes the height of the pressurizer above the hot leg centerline. The equivalent L/D of the height is found by use of:

$$\frac{Le}{D} = 5Z$$

where:

Z is the height of the pressurizer surge nozzle above the hot leg centerline in feet.

3. The maximum acceptable pressure drop through the pressurizer spray line piping is 19 psi at a total flow rate of 375 gpm and at a water temperature of 565F. This requirement is for the piping only, allowance does not have to be made for elevation

losses, the valves, or for the entrance and exit nozzles.

4. Flooding of the reactor cavity from systems other than the RCS shall be precluded to prevent immersion of the reactor vessel during operation. This is normally accomplished by routing only RCS piping inside the reactor cavity, by minimizing drainage paths to the reactor cavity, and/or providing gravity drainage paths out of the cavity below the bottom head of the vessel. The combined reactor cavity and in-core instrumentation chase may be designed without gravity drainage paths below the hot and/or cold leg pipe penetrations, thereby allowing the reactor cavity to flood in the event of a breach of the reactor coolant pressure boundary inside the cavity.

5. The RCS sample piping shall be designed so that the overall transient time from the loop to the containment wall is approximately 90 seconds to permit the decay of short-lived radionuclides (high energy nuclides such as N-16).

6. The RCS and main steam piping, MSIVs, primary and secondary safety valves and their discharge piping and ADVs shall be arranged and supported such that the limiting loads are not exceeded for normal and relieving conditions.

7. Following a secondary line break, either all steam paths downstream of the MSIVs shall be shown to be

isolated by their respective control systems following a MSIS actuation signal, or the results of a blowdown through a non-isolated path shall be shown to be acceptable. An acceptable maximum steam flow from a non-isolated steam path is 10% of the main steam rate (MSR) (1.9 x 10^6 lb/hr @ 1000 psia saturated steam). It is not required that the control systems for downstream valves nor the downstream valves themselves be designed to IEEE 279 and IEEE 308 or ASME Code, Section III and Seismic Category I criteria respectively.

8. The MSIVs for each steam generator shall be arranged such that a maximum of 2000 cubic feet (total for two steam lines per steam generator) is contained in the piping between each steam generator and its associated MSIVs. This volume shall include all lines off of the main steam line up to their isolation valves.

9. The main steam lines shall be arranged such that a maximum of 14,000 cubic feet is contained between the MSIVs and the turbine stop valves. This volume shall include all lines off to the main steam line up to their isolation valves.

10. The main steam lines shall be headered together prior to the turbine stop valves but not upstream of the MSIVs, and a crossconnect line shall be provided which will maintain steam generator pressure

differences within the following limits for all normal and upset conditions.

a. 0-15% power operation pressure difference to be 1 psi.

b. 15-100% power operation pressure difference to be 3 psi.

11. No automatically actuated valves shall be located upstream of the MSIVs except as required for supply to steam driven emergency feedwater pumps. Provisions shall be made to prevent blowdown of both steam generators through the emergency feedwater supply headers in the event of a steamline break. The maximum allowable flow rate per valve is 1.9×10^6 lb/hr.

12. There shall be no isolation valves in the main steam lines between the steam generators and the secondary relief valves.

13. The main steam safety valves shall be arranged such that any condensate in the line between the safety valves and main steam line drains back to the main steam line.

14. All valves in the main steam line outside of containment up to and including the MSIVs shall be located as close as practical to the containment wall.

15. A 90° or 45° elbow facing downward shall be attached to each feedwater nozzle. Such a pre-caution will aid in the prevention of water hammer.

16. The MFIVs shall be located outside of the containment building as close to the containment wall as possible.

17. The MFIVs for each steam generator shall be arranged such that a maximum of 550 cubic feet of fluid is contained in the piping between each steam generator and its associated isolation valves. This volume shall also include the volumes between the redundant MFIVs. This volume shall include the volumes up to their respective isolation valves of all lines off of the main feedwater lines downstream of the MFIVs for which a mechanism exists for getting the fluid into the main feedwater line (e.g., gravity, flow or flushing).

18. The Emergency Feedwater System connection shall be located in the downcomer feedwater line between the MFIVs and the steam generator down-comer nozzle. Emergency feedwater flow shall be directed to the downcomer nozzle only. A safety Class 2 check valve shall be located in the main feedwater piping upstream of this interface to prevent back flow of emergency feedwater to other portions of the Main Feedwater System.

N. Radiological Waste

1. Actuator-operated valves in the RCS were supplied with double packing with lantern ring and leakoff connection unless they are diaphragm (packless) type. Leakoffs have been capped. During original plant design, an evaluation determined that leakoffs piped to the reactor drain tank present a greater ALARA concern than capping the valve leakoff. The cap has been designed as part of the RCS pressure boundary. The leakoffs for all RCS valves are capped except for the pressurizer spray control (RC-100E and 100F) and bypass (RC-236 and 237) valves.

2. Provisions shall be provided to process the steam generator blowdown water. If separately provided, the radioactive steam generator blowdown processing system shall include filtration and ion exchanger or equivalent processes. With design operating conditions in the steam generator, the blowdown water radio-activity will decrease by 90%.

O. Overpressure Protection

1. Each primary safety valve inlet line shall be designed to pass 125 percent of the minimum required safety valve capacity of 460,000 lb/hr with a maximum pressure drop of 50 psi. This pressure drop of 50 psi is for piping and nozzle losses. (Pressure loss factor for pressurizer nozzle is K = 0.23 based on 6" Schedule 160 pipe.)

2. Each primary safety valve discharge line shall be designed to pass 125 percent of the minimum required safety valve capacity with a maximum valve back pressure of 500 psig at the safety valve discharge during blowdown, assuming the discharge tank is at 132 psig. The minimum required flow rate for each safety valve is 460,000 lb/hr. For the common discharge line, the minimum safety valve flow is 1,840,000 lb/hr (total flow of four valves). Discharge tank design pressure is 130 psig. Maximum pressure of 132 psig is calculated from rupture disk burst pressure of 120 psig plus 10% tolerance.

3. Each main steam line shall be provided with ASME Code, springloaded secondary safety valves between the containment and the isolation valves.

4. The total relieving capacity of the secondary safety valves shall be equally divided between the main steam lines.

5. The total secondary safety valve capacity shall be sufficient to pass 19 x 10^6 lb/hr at the maximum valve set pressure.

6. The maximum steam flow per secondary safety valve shall be no greater than 1.9 x 10^6 lbs/hr at 1000 psia.

7. Secondary safety valve set pressure shall be calculated in accordance with Article NC-7000 of ASME Section III, which requires that the following be considered:

a. A maximum allowable set pressure of 110% steam generator design pressure (1270 psia) which equals 1397 psia.

b. A valve accumulation of 3%

c. A valve set pressure error of ±1%

d. Incorporation of the WP between the steam generator nozzles and the safety valves.

8. The design pressure, temperature, and flow rating of the main steam piping and valves shall be greater than or at least equal to the design pressure, temperature, and flow rating of the steam generator secondary side.

P. <u>Related Service</u>

1. The pressure and thermal transients described in Subsection 3.9.1.1 shall be utilized in the design of those portions of the RCS not within the CESSAR design scope.

2. The systems or portions of reactor coolant pressure boundary outside of the CESSAR design scope shall be Safety Class I unless the conditions of 10CFR50.55A are met.

3. A fire protection system shall be provided to protect the RCS consistent with the requirements of GDC and, shall include as a minimum, the following features:

a. Facilities for fire detection and alarming.

b. Facilities for methods to minimize the probability of fire and its associated effects.

c. Facilities for fire extinguishment.

d. Methods of fire prevention such as use of fire resistant and non-combustible materials whenever practical, and minimizing exposure of combustible materials to fire hazards.

e. Assurance that fire protection systems do not adversely affect the functional and structural integrity of safety related structures, systems, and components.

f. Fire protection systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the capability of safety related structures, systems, and components.

4. Systems shall be provided for the detection of reactor coolant leakage from unidentified sources.

5. If air-operated ADVs are used, a safety related control air system shall be provided to supply air to the ADV actuators should the normal air supply fail to be available.

6. Air for the ADV and MFIV pneumatic valve operator shall be clean, dry and oil-free. The air shall be delivered at the point of use under system full flow conditions at a pressure of 70 psig minimum.

Pneumatic lines and fittings shall have a minimum design pressure of 150 psig.

7. The containment structure shall be designed and sized to accommodate the Reactor Coolant System arrangement shown in Figures 5.1.3-1 and 5.1.3-2.

Q. Environmental

1. For the applicant supplied NSSS components one of the following options shall be followed.

   a. Demonstration of other environmental qualification envelopes for any or all of these buildings not to exceed the qualification envelopes of Section 3.11.

   b. Exclusion of specific components from extreme environmental conditions by suitable physical separations or environmental control system techniques.

   c. Use of the same environmental qualification conditions being employed by C-E supplied NSSS components.

2. The containment pressure and temperature transients resulting from the LOCA shall meet criteria specified in Section 6.2.1.5.

3. A containment ventilation system shall be provided to handle the total RCS heat losses to containment. Table 5.1.4-2 lists the heat loads from NSSS support structures to containment. Table 5.1.4-3 lists typical loads through the NSSS insulation to

containment. These values will be confirmed by each Applicant since the final value depends on system insulation efficiency.

R. Mechanical Interaction Between Components

1. The following components shall be designed to withstand the loads arising from the various normal operating and design basis events.

   a. The main steam piping, supports and restraints.

   b. The steam generator steam and feedwater nozzles.

   c. The MSIVs and the MSIV bypass valves and supports.

   d. Main Steam Safety Valves.

   e. The main feedwater piping, supports and restraints.

   f. MFIVs and supports.

   g. Blowdown piping, supports and restraints.

   h. Blowdown isolation valves.

2. Structures shall be provided to mate with C-E supplied component supports to restrain and support RCS components. The loading conditions specified in Section 3.9.3.1 shall be utilized in the design of the Applicant's supporting structures. C-E will provide to the Applicant the loads at the support/structure interface locations under normal, upset, emergency, faulted, and test conditions,

taking into account the local characteristics of the specific Applicant's structures at the support/structure interfaces.

3. The loadings imposed by connecting system piping on RCS nozzles under normal, upset, emergency, faulted, and test conditions shall be less than the design loads for these nozzles. C-E will confirm using the loads developed by the Applicant that the piping nozzles are within Code allowable stress limits.

5.1.5 CESSAR INTERFACE EVALUATION

The CESSAR interface requirements are met by PVNGS design as follows:

A. Power

See section 8.3.

B. Protection from Natural Phenomena

1. The containment is designed to remain functional for the full range of natural phenomena and external environmental conditions in agreement with General Design Criterion 2. Refer to sections 3.2, 3.3, 3.4, 3.5, 3.7, and 3.8.

2. The steam piping and associated supports from the steam generators up to and including the MSIVs and up to and including the containment isolation valves of any auxiliary steam supply systems which connect upstream of the main steam isolation valves (MSIVs)

are Seismic Category I and designed to ASME Section III, Class 2.

3. The valves, piping, and associated supports and restraints of the feedwater system from and including the main feedwater containment isolation valves to the steam generator feed nozzles are classified Seismic Category I and are designed to ASME Section III, Class 2 requirements, as stated in section 3.2.

4. All components and piping of the auxiliary feed-water system between the steam generators and the containment isolation valves are Seismic Category I and are designed to ASME Section III, Class 2 requirements.

5. All safety-related components, piping, and associated supports in the condensate storage facilities for auxiliary feedwater are Seismic Category I and designed in accordance with ASME B&PV Code Section III, Class 3.

6. All components and piping associated with steam generator blowdown between the steam generator and the containment isolation valves are Seismic Category I and are designed to ASME Section III, Class 2 requirements.

C. Protection from Pipe Failure

1. The MSIVs, secondary safety valves, atmospheric dump valves, main feedwater isolation valves (MFIVs), blowdown isolation valves, and MSIV bypass valves

are environmentally qualified to withstand the pressure and temperature environment resulting from pipe rupture.

2. The MSIVs are supported such that the valve body and actuator will not be distorted or displaced, as a result of pipe break thrust loadings, to such a degree that the valve cannot close.

3. Feedwater piping is routed, protected, and restrained such that in the case of a rupture of a feedwater line or any other system piping, the plant can be brought to safe shutdown with a single active failure.

4. A containment structure is provided to limit the release of energy and radioactivity to the environs in the event of a rupture of the RCS and to protect the public health and safety. Refer to section 6.2.

5. The containment, including penetrations, will not be subject to loss of function from dynamic effects (e.g., missiles, pipe reactions, fluid reaction forces) resulting from failure of RCS equipment or piping within the containment (refer to sections 3.5 and 3.6).

6. The design pressure and temperature of the containment building are discussed in subsection 6.2.1.

7. The design of the containment building compartments for differential pressure as well as the containment pressure design is addressed in subsection 6.2.1.

D. Missiles

1. Section 3.5 describes RCS generated missiles. Protection provided for the RCS and other systems from missiles that could be generated by the RCS is also discussed in section 3.5.

2. Refer to section 3.5 for a discussion of the reactor coolant pressure boundary (RCPB) missile protection design and the protection of the RCS from missiles generated outside of containment.

E. Separation

1. Adequate physical separation is maintained between the redundant electrical and instrumentation systems used for emergency control and safe shutdown of the reactor, and between the multiple instrumentation channels in the plant protection system as discussed in chapter 7.

2. Each MSIV has two physical separate and electrically independent closure solenoids in order to provide redundant means of valve operation. A main steam isolation signal (MSIS) is provided to each solenoid. Refer to paragraph 10.3.2.2.2.

3. Redundant feedwater system isolation valves in each feedwater line meeting the single failure criteria are provided in piping interconnecting the steam generators to preclude blowdown of both steam generators following a pipe rupture. Refer to paragraph 10.4.7.2 for a discussion of main feedwater isolation valves.

F. Independence

1. The provisions for redundancy and independence of containment isolation valves are as discussed in subsection 6.2.4. Table 6.2.4-1 addresses the conformance of each containment isolation valve arrangement to the specific NRC General Design Criteria 54 through 57.

2. Feedwater system piping, auxiliary feedwater piping, and main steam piping and supports are designed so that a single failure, such as a ruptured feedwater line, auxiliary feedwater line, main steam line inside the containment, or a closed isolation valve, can occur without:

    a. Initiating a loss-of-coolant incident.

    b. Causing failure of the other steam generator's steam and feedwater lines, MSIV, safety valves, MFIVs, blowdown isolation valves, or atmospheric dump valves.

    c. Reducing the capability of the engineered safety features (ESF) or the plant protection system (PPS).

    d. Transmitting excessive loads to the containment pressure boundary.

    e. Compromising the function of the plant control room.

    f. Precluding orderly cooldown of the RCS.

Refer to section 3.6 for a discussion of the pipe break analyses.

3. An electrical or mechanical malfunction of one actuator control element will not prevent the MSIV from closing.

4. A single failure of the control circuits will not prevent closure of the MSIV bypass valves. The control circuits were designed to IEEE Standard 279-1971 and IEEE Standard 308-1974.

5. The MSIV bypass valve control circuits are designed such that a single electrical failure will not result in the spurious motion of the valves.

6. The atmospheric dump valves control circuits are designed such that no single electrical failure can result in the spurious opening of the valves.

7. No single failure of the control circuits will prevent operation of at least one atmospheric dump valve on each steam generator. Refer to section 10.3 for the operational description. Refer to paragraph 7.4.1.1 for a description of the control circuits.

8. Each main feedwater isolation valve actuator is physically and electrically independent of the other such that failure of one will not cause failure of the other.

9. No single active or passive component failure, single passive or active electrical component

failure, or power supply failure will preclude adequate operation of the auxiliary feedwater system, such as the following events:

a. Loss of normal feedwater with or without a concurrent loss of normal offsite ac power.

b. Minor secondary system pipe breaks with or without a concurrent loss of normal offsite ac power.

c. Steam generator tube rupture with or without a concurrent loss of normal offsite ac power.

d. Major secondary system pipe breaks with or without a concurrent loss of normal offsite ac power.

e. Small LOCA with or without a concurrent loss of normal offsite ac power.

10. The ability of the auxiliary feedwater system to perform its design function considering a power supply failure, a single active or passive mechanical component failure, a single active or passive failure of an electrical component, or the effects of a high or moderate energy pipe rupture is discussed in subsection 10.4.9.

11. The safety-related portion of the auxiliary feedwater system (AFS) is isolated from the main feedwater system during normal plant operation when the safety-related portion of the AFS is not required, as shown in engineering drawings 01, 02, 03-M-AFP-001 and as described in subsection 7.3.1.

12. Blowdown piping exiting containment has redundant blowdown line isolation valves which are actuated by an auxiliary feedwater actuation signal (AFAS).

G. Thermal Limitations

1. Cooling water is provided for the reactor coolant pumps (RCPs) as presented in subsection 9.2.2.

2. Reactor coolant pump heat load and flow data is used in the design of the cooling water system as provided in subsection 9.2.2 which meets CESSAR requirements.

3. The maximum and minimum temperatures of the nuclear component cooling water during normal operation are 105F and 65F, respectively.

4. One atmospheric dump valve is provided in each of the main steam lines to allow cooldown of the steam generators when the main steam line isolation valves are closed, or when the main condenser is not available as a heat sink. Each valve is sized to hold the plant at hot standby, dissipating core decay and reactor coolant pump heat, and to allow controlled cooldown from hot standby to shutdown cooling initiation temperatures. To meet this requirement, each atmospheric dump valve has a maximum capacity of 1.47×10^6 pounds per hour at 1000 psia.

5. Following the events stated in CESSAR Section 5.1.4.F.9, the auxiliary feedwater system

can maintain adequate inventory in the steam generator(s) for residual heat removal and be capable of the following:

a. Maintaining the NSSS at hot standby with or without normal offsite and normal onsite power available.

b. Facilitating NSSS cooldown at a maximum administratively controlled rate of 75F per hour from hot standby to shutdown cooling initiation with or without normal offsite or onsite power available. (The shutdown cooling system becomes available for plant cooldown when the RCS temperature and pressure are reduced to approximately 350F and 400 psia.)

Refer to section 10.4 for a description of the system design.

6. The AFS will deliver flow to the steam generator(s) automatically upon receipt of an AFAS as follows:

   a. For the motor-driven pump, within 22 seconds when normal offsite or normal onsite power is available. The deviation from the CESSAR requirement of 10 seconds is acceptable to Combustion Engineering as discussed in paragraph 1.9.2.4.10.

   b. For the motor-driven pump, within 45 seconds when normal onsite and normal offsite power are not available.

c. For the steam turbine-driven pump, within 45 seconds regardless of power conditions. The deviation from the CESSAR requirement of 10 seconds is acceptable to Combustion Engineering as discussed in paragraph 1.9.2.4.10.

7. Each of the safety-related auxiliary feedwater pumps is capable of delivering 650 gallons per minute to the intact steam generator downcomer nozzle at 1270 psia or equivalent at the entrance of steam generators. The deviation from the CESSAR requirement of 875 gallons per minute is acceptable to Combustion Engineering as discussed in paragraph 1.9.2.4.10.

8. The auxiliary feedwater temperature will be no less than 40F and no greater than 180F.

9. Refer to subsection 9.2.6 for a discussion of the condensate tank capacity. A minimum of 300,000 gallons will be available for the intact steam generator(s). The quality of the condensate tank water will be equivalent to that of normal main feedwater makeup.

10. Each MSIV leak flow will not exceed 0.001% of nominal flow at 1270 psia in the forward direction and will not exceed 0.1% of nominal flow at 1270 psia in the reverse direction.

NOTE: These valves are excluded from 10CFR50, Appendix J Type C Leakage Testing - NPF-41 Amendment 111, NPF-51 Amendment 103, NPF-74 Amendment 83.

11. Each single MSIV bypass valve or bypass valve line has a capacity not greater than 1.9×10^6 pounds per hour.

12. No single turbine bypass valve has a capacity greater than 1.9×10^6 pounds per hour at 1000 psia.

13. The total reverse leak rate of feedwater check valves to each steam generator does not exceed 1000 cubic centimeters per hour.

H. Monitoring

1. Means are provided for detection of RCS leakage into the secondary side of the steam generators and cooling water systems associated with components containing reactor coolant as discussed in subsections 10.4.2 and 9.2.2.

2. Reactor coolant system component designs and RCS construction procedures ensure that RCS leakage from known sources will not exceed 10 gallons per minute; from steam generator tubes will not exceed 1.0 gallons per minute; and from unknown sources will not exceed 1.0 gallons per minute, to minimize in-plant airborne and surface activity levels and activity releases to the environs at system normal operating temperature and pressure.

3. Capability for monitoring each MSIV, MFIV, ADV, and blowdown line isolation valve position is provided locally and in the control room.

4. The accuracy of the feedwater temperature measurement devices is ±1.5F for any calorimetric measurement. An accuracy of ±1.5F for the feedwater temperature measurement devices is within the uncertainty analysis assumptions for the COLSS secondary calorimetric power calculation.

I. Operational/Controls

1. A power-operated MSIV capable of establishing shutoff under conditions of design pressure, design temperature, and flow conditions resulting from a break upstream or downstream is provided in each main steam line outside of containment. Refer to subsection 10.3.2.

2. Each MSIV position is monitored and controlled locally and in the control room.

3. An MSIS closes the MSIV bypass valves and MSIVs.

4. The full "open to close" stroke time of each MSIV and MSIV bypass valve is 4.6 seconds or less upon receipt of an MSIS.

5. The ADVs fail closed and are capable of being remote manually positioned to control the plant cooldown rate.

6. The ADVs are provided with remote manual controllers such that the valves can be operated from the control room and remote shutdown panel in the event of a loss of offsite power supply.

7. In the combined event of either a steam line break or steam generator tube rupture and the loss of power operation of the atmospheric dump valves, personnel access to the manual operators of the intact valves on the other steam generator is possible.

8. A MSIS actuation signal will close the MSIVs, MSIV bypass valves, MFIVs, and the steam generator blowdown valves.

9. Redundant feedwater system isolation valving is provided in both the economizer feedlines and the downcomer feedlines such that the following criteria are met when the effects of single failure criteria are imposed:

   a. Complete termination of forward feedwater flow is assumed within 9.6 seconds after receipt of an MSIS. The deviation from the CESSAR requirement of 4.6 seconds is acceptable to Combustion Engineering as discussed in paragraph 1.9.2.4.10.

   b. Abrupt complete termination of reverse feedwater flow with the existence of a reverse flow condition. Check valves are considered to be an acceptable means of achieving the above.

10. The economizer and downcomer feedwater line isolation valves (MFIVs) in each main feedwater line are remote-operated and capable of maintaining a leak rate of less than 1000 cubic centimeters per

hour under the main feedwater line pressure, temperature, and flow resulting from the transient conditions associated with a pipe break on either side of the valves.

11. The safety-related AFS can be controlled from either the control room or remote shutdown station as described in subsection 7.3.1.

12. The AFS is controllable such that post-accident operation will not result in overfilling the intact steam generator(s).

13. The auxiliary feedwater pumps of the AFS are designed for operation when steam generator pressure is negligible and will not result in damage to the pumps or affect the ability of the system to deliver the required auxiliary feedwater flow. Such a condition can exist during startup or shutdown operation subsequent to an AFAS which starts the auxiliary feedwater pumps and fully opens the system isolation and control valves.

J. Inspection and Testing

1. All ASME B&PV Code Section III, Class 1 and 2 valves are designed, fabricated, and installed such that they are capable of being periodically tested in accordance with ASME OM Code.

2. Adequate clearances are provided for inservice inspection of the RCPB and the ASME B&PV Code Section III, Class 2 portions of the main steam, main feed, auxiliary feed, and blowdown systems

piping, in accordance with the provisions of Section XI of the ASME B&PV.

3. Biological shielding, where installed around the RCPB, is designed to afford access for inservice inspection as discussed in section 12.1.

4. The pressurizer manway is accessible for internal examination of the pressurizer.

K. Chemistry/Sampling

1. A sampling system which provides a means of obtaining remote liquid samples from the RCS for chemical and radiochemical laboratory analysis is provided. The sampling system is designed to allow for the following tests: corrosion product activity levels, dissolved gas, fission product activity, chloride concentration, coolant pH, conductivity levels, and boron concentration. The pressurizer steam space sample lines contain a 7/32-inch x 1-inch orifice as close to the pressurizer as possible. The sample system is designed as shown in subsection 9.3.2.

2. A system is provided to maintain the steam generator secondary water chemistry within the specifications described in section 10.3.5.1. The system incorporates steam generator blowdown, chemical addition and monitoring, and condensate purification. Refer to subsection 10.4.6.

3. Provisions are made to allow sampling of the RCS during shutdown cooling system operation.

4. Provisions are made to allow sampling of the RCS during startup.

L. Materials

1. The materials used for the containment and its internal structures are compatible with both the normal operating environment and the most severe thermal, chemical, and radiation expected during post-accident conditions (refer to section 3.11). Section 6.1 additionally describes material compatibility.

2. Precautions will be taken to prevent the following elements from being in contact with system surfaces in contact with reactor coolant:

   a. Lead or lead compounds

   b. Mercury or mercury compounds

   c. Halogens or compounds and solvents containing halogens

3. The use of the following materials will be minimized on surfaces normally in contact with reactor coolant:

   a. Sulfonated cutting oils

   b. Zinc metal or zinc compounds

   c. Magnesium metal

   d. Asbestos

   e. Aluminum

g. Copper acid etchants

h. Penetrants

4. The sample lines in contact with the reactor coolant, including welds, are designed such that the material is compatible with the fluid chemistry described in section 9.3.4.3.

5. The use of construction materials or protective coatings containing low melting point elements, particularly lead, mercury, and sulphur, where they could come in contact with the secondary systems is avoided.

6. The secondary system piping is designed to allow cleaning for the removal of foreign material and rust prior to operation and to prevent introduction of this material into the steam generator. Fluids other than demineralized water meeting steam generator chemistry requirements or materials used in cleaning operations in the secondary system piping will not be allowed to enter the steam generators.

7. Care will be taken to limit the amount of leachable halogens in insulation used on austenitic stainless steel in the RCS. Conformance to Regulatory Guides 1.36 and 1.37 is discussed in section 1.8.

8. No contaminants, except for cutting oils, will be left on any RCS component surface except for the time required to perform and evaluate the particular fabrication or inspection operation.

9. Field welding of the RCS piping assemblies and components will be done in accordance with a welding procedure or procedures by welders qualified to ASME Section IX requirements. Additionally, the control of sensitized stainless steel will utilize the guidance stated in Regulatory Guides 1.31 and 1.44 as stated in section 1.8.

M. System/Component Arrangement

1. The pressurizer and surge line is located entirely above the reactor coolant loops.

2. The pressurizer surge line equivalent L/D is less than 330.

3. The maximum pressure drop through the pressurizer spray line piping is less than 19 psi at a total flowrate of 375 gallons per minute and at a water temperature of 565F.

4. Flooding of the reactor cavity from systems other than the RCS is precluded by routing only RCS piping inside the reactor cavity and by providing gravity drainage of the cavity to the incore instrumentation sump.

5. The sample piping is designed to ensure a total transit time from the RCS of approximately 90 seconds.

6. The reactor coolant and secondary safety valve discharge piping are arranged and supported such

that the limiting loads are not exceeded for normal and relieving conditions.

7. Following a secondary line break, all steam paths downstream of the MSIVs can be isolated by their respective control systems following a MSIS actuation signal.

8. The MSIVs for each steam generator are arranged such that a maximum of 1534 cubic feet (total for two steam lines per steam generator) is contained in the piping between each steam generator and its associated MSIVs. This volume includes all lines off the main steam line up to their isolation valves.

9. The main steam lines are arranged such that a maximum of 3390 cubic feet is contained between the MSIVs and the turbine stop valves. This volume includes all lines off of the main steam line up to their isolation valves.

10. The main steam lines are headered together prior to the turbine stop valves but not upstream of the MSIVs, and a cross-connect line is provided which will maintain steam generator pressure differences within the following limits for all normal and upset conditions:

    a. 0 to 15% power operation pressure difference to be 1 psi.

    b. 15 to 100% power operation pressure difference to be 3 psi.

11. No automatically actuated valves are located upstream of the MSIVs except as required for supply to the steam-driven auxiliary feedwater pump. Provisions are made to prevent blowdown of both steam generators through the auxiliary feedwater supply headers in the event of a steam line break. The maximum flowrate per valve is 1.9×10^6 pounds per hour.

12. There are no isolation valves in the main steam lines between the steam generators and the secondary relief valves.

13. The main steam safety valves are arranged such that any condensate in the line between the safety valves and main steam line drains back to the main steam line.

14. All valves in the main steam line outside of the containment up to and including the MSIV are located as close to the containment wall as is practical (refer to section 10.3).

15. A 45° elbow facing downward is attached to each feedwater nozzle, to aid in the prevention of water hammer.

16. The main feedwater isolation valves are located outside of the containment as close to the containment wall as possible as required by NRC General Design Criterion 57, Closed System Isolation Valves.

17. The MFIVs for each steam generator are arranged such that a maximum of 527 cubic feet of fluid is contained in the piping between each steam generator and its associated isolation valves. This volume also includes the volumes between the redundant MFIVs. This volume includes the volumes of all lines off of the main feedwater lines downstream of the MFIVs up to their respective isolation valves, for which a mechanism exists for getting the fluid into the main feedwater line (e.g., gravity, flow, or flushing).

18. The auxiliary feedwater interface with the main feedwater system is located between the main feedwater isolation valves and the steam generator nozzles in the feedwater line to the downcomer:

    a. Auxiliary feedwater flow is directed to both downcomer nozzles.

    b. A Safety Class 2 check valve is located upstream of the interface to prevent backflow of auxiliary feedwater to the main feedwater system.

N. Radiological Waste

1. Actuator-operated valves in the RCS were supplied with double packing with lantern ring and leakoff connection unless they are diaphragm (packless) type. During original plant design, an evaluation determined that leakoffs piped to the reactor drain tank present a greater ALARA concern than capping

the valve leakoff. The cap has been designed as part of the RCS pressure boundary. The leakoffs for all RCS valves are capped except for the pressurizer spray control (RC-100E and 100F) and bypass (RC-236 and 237) valves. The pressurizer spray control and bypass valve leakoffs are piped to the reactor drain tank.

2. Provisions have been provided to process the steam generator blowdown water to radioactivity levels equivalent to that found in the condenser hotwell. Refer to subsection 10.4.6.

O. Overpressure Protection

1. Each primary safety valve inlet line was designed to pass 125% of the original minimum required safety valve capacity of 460,000 pounds per hour with a maximum pressure drop of 50 psi. This pressure drop of 50 psi is for piping and nozzle losses. (Pressure loss factor for pressurizer nozzle is K = 0.23 based on 6-inch Schedule 160 pipe.)

   For each Pressurizer Safety Valve a flow rate of 473,000 lb/hr of saturated steam at a setpoint of 2475 psia plus 3% accumulation ensures the current safety analysis requirements are met.

2. Each primary safety valve discharge line was designed to pass 125% of the original minimum required safety valve capacity with a maximum valve back pressure of 500 psig at the safety valve discharge during blowdown, assuming the discharge

tank is at 132 psig. The original minimum flowrate for each safety valve was 460,000 pounds per hour. For the common discharge line, the minimum safety valve flow was 1,840,000 pounds per hour (total flow of four valves). For each pressurizer safety valve a flow rate of 473,000 lb/hr of saturated steam at the setpoint of 2475 psia plus 3% accumulation ensures the current safety analysis requirements are met. Discharge tank design pressure is 130 psig. Maximum pressure of 132 psig is calculated from rupture disk burst pressure of 120 psig plus 10% tolerance.

3. Each main steam line is provided with ASME Code spring-loaded safety valves between the containment, and the isolation valves (refer to engineering drawings 01, 02, 03-M-SGP-002, -001). The total relieving capacity of these valves is equally divided between the main steam lines (refer to subsection 10.3.2).

4. The total relieving capacity of these valves is equally divided between the main steam lines (refer to subsection 10.3.2).

TABLE 5.1-1

PROCESS DATA POINT TABULATION*

Parameter	Pressurizer	S.G. 1-A Midpoint	Pump 1-B Outlet	R.V. Midpoint	Pump 1-A Outlet	S.G. 2-A Midpoint	Pump 2-A Outlet	Pump 2-B Outlet
Data Point	1	2	3	4	5	6	7	8
Pressure, psia	2250	2227	2324	2291	2324	2227	2324	2324
Temperature°F	652.7	585.3	556.8	586.9	556.8	585.3	556.8	556.8
Mass Flow Rate lbm/hr	-	86.2×10^6	43.1×10^6	172.4×10^6	43.1×10^6	86.2×10^6	43.1×10^6	43.1×10^6
Volumetric Flow Rate, gpm	-	242.3×10^3	115.6×10^3	485.3×10^3	115.6×10^3	242.3×10^3	115.6×10^3	115.6×10^3

*For normal steady state 100% power conditions

4013 MWt = 3990 MWt (core) + 23 MWt (RCP Heat)

Reference calc is vendor calc 26-ST99-C-022, "PVNGS - 2 RSG Chapter 15 CENTS BASEDECK", APS log no. MN725-A00107

TABLE 5.1-2

REACTOR COOLANT SYSTEM MATERIALS

(Sheet 1 of 5)

Component	Material Specification
Reactor Vessel	
Shell[e]	SA-533 Grade B, Class 1 Steel
Forgings	SA-508 Class 1, 2 and 3
Cladding[a]	Weld deposited austenitic stainless steel with 5FN-23FN delta ferrite or NiCrFe alloy (equivalent to SB-168)
Replacement Closure Head	SA-508, GRADE 3, CLASS 1
Reactor vessel head CEDM Nozzles	ASME SB-166 UNS N06690
Vessel internals[a]	Austenitic Stainless Steel and NiCrFe alloy
Fuel cladding[a]	Zircaloy-4 or ZIRLO
Instrument nozzles	ASME SB-166 UNS N06690 and N06600
Control element drive mechanism housings	
Lower	Modified Type 403 stainless steel according to Code Case N-4-11 with end fittings to be SB-166 and/or SA-182 Type F347, stainless steel
Upper	SA-479 and SA-213 Type 316 stainless steel with end fitting of SA 479 Type 316 and vent valve seal of Type 316
Closure head bolts	SA-540 B24 or B23
Pressurizer[d]	
Shell Cladding[a]	SA-533 Grade B Class 1 Weld deposited austenitic stainless steel with 5 FN-23FN delta ferrite or NiCrFe alloy (equivalent to SG-166)

a. Materials exposed to reactor coolant

d. Heater sleeve plug design and heater sleeve outside diameter weld repair exposes minimal section of shell to reactor coolant

e. Unit 3 No. 3 ICI half nozzle repair exposes a minimal portion of the carbon steel reactor vessel bottom head to reactor coolant.

TABLE 5.1-2
REACTOR COOLANT SYSTEM MATERIALS

(Sheet 2 of 5)

Component	Material Specification
Forged nozzles	SA-508 Class
Instrument nozzles	SB-166
Surge and safety valve nozzle safe ends	SA-182
Studs and nuts	SA-540-B24 or B23
Steam Generator (SG) Primary Head	SA-508 Class 3 Forging
SG Nozzles	
SG Safe Ends	SA-508 Class 1A Forging
Unit 2 Primary head cladding[(a)]	Weld deposited austenitic stainless steel with 5FN-23FN delta ferrite
Unit 1 and 3 SG Primary head cladding[(a)]	Weld deposited austenitic stainless steel with 5FN-15FN delta ferrite
Unit 2 SG Tubesheet	SA-508 Class 3 Forging
Unit 1 and 3 SG Tubesheet	SA-508 Class 3a Forging
SG Tubesheet stay	SA-508 Class 3 Forging
SG Tubesheet cladding[(a)]	Weld deposited NiCrFe alloy (equivalent to SB-168)
SG tube (a)	NiCrFe alloy - Inconel 690 TT
Unit 2 SG Secondary shell and head	SA-533 Grades B, Class I plate
Unit 1 and 3 SG Secondary Shell and Head	SA-508 Class 3a Forging or SA-533 GR. B Class 1 Plate
Unit 2 RSG Secondary nozzles	SA-508 Class 3 or SA-508 Class 1a or SA-936 Class F12
Unit 1 and 3 SG Secondary Nozzles	SA-508 Class 3 or SA-508 Class 3a or SA-336 Class F12
SG Secondary nozzle safe ends	SA-508 Class 1a or Inconel buttering
SG Secondary instrument nozzles	SA-508 Class 1a
SG Studs and nuts	SA-540 Grade B24 or SA-193 Grade B7 or SA-194 GR 7

TABLE 5.1-2

REACTOR COOLANT SYSTEM MATERIALS

(Sheet 3 of 5)

Component	Material Specification
Reactor coolant Pumps	
Casing(a)	SA-508 Class 2 or 3
Cladding	Weld deposited austenitic stainless steel with 5FN-23FN delta ferritie
Internals	SA-487 CAGNM, SA 336 Grade F8
Reactor Coolant Piping(c)))	
Pipe (30 in. and 42 in.) except as noted below	SA-516 Grade 70
SG Cold Leg Elbow	SA-508 Class 3 Forging
SG Spool Pieces	SA-508 Class 1a Forging
Cladding(a)	Weld deposited austenitic stainless steel with 5FN-23FN delta ferrite
Piping nozzles and safe ends	
Nozzle forgings	SA-105 Grade II, SA-541, CC 1, or SB-166
Nozzle safe ends	SA-182 or SB-166
FSWOL Nozzles	
Pressurizer Spray nozzle to safe end Pressurizer Spray nozzle to safe end Pressurizer Spray nozzle to safe end Pressurizer Spray nozzle to safe end Pressurizer Spray nozzle to safe end Pressurizer Spray nozzle to safe end Hot Leg Surge nozzle to safe end Hot Leg SDC nozzle to safe end – "A" Hot Leg SDC nozzle to safe end – "B"	A Full Structural Weld Overlay (FSWOL) modification has been implemented on these pressurizer and hot leg nozzle Dissimilar Metal Weld (DMW) locations in order to mitigate susceptibility to Primary Water Stress Corrosion Cracking (PWSCC).
Valves	SA-351, CF8M or SA-182

c. Hot leg half nozzle design, RTD plug & 3/4 designs, as well as any temporarily installed mechanical nozzle seal assemblies, exposes minimal area of piping to reactor coolant.

TABLE 5.1-2

REACTOR COOLANT SYSTEM MATERIALS

(Sheet 4 of 5)

WELD MATERIALS FOR REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

	Material Specification	Base material	Weld Material
1.	SA-533 Gr. B C1.1	SA-533 Gr. B C1.1	a. SFA 5.5,(b) E-8018-C3, E8018-G b. MIL-E-18193, B-4
2.	SA-508 1 C1.2	SA-533 Gr. B C1.1	a. SFA 5.5, E-8018-C3, E-8018-G b. MIL-E-18193, B-4
3.	SA-508 C1.1	SA-508 C1.2	a. SFA 5.5, E-8018-C3, E-8018-G
4.	SA-516 Gr. 70	SA-516 Gr. 70	a. SFA 5.1, E-7018
5.	SA-182 F1	SA-516 Gr. 70	a. SFA 5.1, E-7018
6.	SA-105 GR11	SA-351 CF8M	a. SFA 5.14, ERNiCr-3
7.	SA-182 F1	SA-351 CF8M	a. SFA 5.11, ENiCrFe-3
8.	SA-105 Gr. 11	SA-182 F316	a. SFA 5.14, ERNiCr-3
9.	SB-166	SA-182 F316	a. SFA 5.14, SFA 5.11, Root ERNiCr-3 Remaining ENiCrFe-3
10.	SB-167	SA-182 F304	a. Root SFA 5.14, ERNiCr-3 Remaining 5.11, ENiCrFe-3
11.	SA-516 Cr. 70	SA-351 CF8M	a. SFA 5.1, E-7018 b. MIL-E-18193, B-4
12.	SA-182 F1	SA-182 F316	a. SFA 5.1, E-7018
13.	SB-166. SB-167. OR SB-168	SA-533 GR. B. C1.1	a. SFA 5.14, ERNiCr-3 ERNiCrFe-7 or ERNiCrFe-7A

b. Special weld wire with low residual elements of copper wind phosphorous as specified for the reactor vessel core beltline region.

TABLE 5.1-2

REACTOR COOLANT SYSTEM MATERIALS

(Sheet 5 of 5)

WELD MATERIALS FOR REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

	Material Specification	Base material		Weld Material
14.	SA-182 Code Case 1334	SB-167	a.	SFA 5.14, ERNiCr-3
15.	SA-516 GR. 70	SA-508 C1.2	a.	SFA 5.5,(b) E-8016-C3
16.	Austenitic stainless steel cladding		a.	SFA 5.9, ER-308 SFA 5.9, ER-309 SFA 5.9, ER-312
17.	Inconel	Inconel	a.	ENiCrFe-3 ERNiCr-3 ERNiCrFe-7 INCO 52 Code Case 2142 UNS N06052 ERNiCrFe-7A INCO 52M Code Case 2142-2 UNS N06054
18.	SB-166 Gr. 690	SA-516 Gr. 70	a.	INCO 52, UNS N06052 Code Case 2142

b. Special weld wire with low residual elements of copper wind phosphorous as specified for the reactor vessel core beltline region.

* List of BASE MATERIALS and Relevant welding Materials for current S/Gs

	Base Material	Base materials to be welding on Previous one	Welding Materials
18.	SA-508 Cl. 3	SA-503 Cl. 3	SFA 5.5 E9018-G SFA 5.23 EF3N mod
19.	SA-508 Cl. 1a	SA-508 Cl. 3	SFA 5.5 E9018-G
20.	SA-533 Gr. B Cl. 1	SA-508 Cl. 3	SFA 5.5 E9018-G SFA 5.23 EF3N mod
21.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	SFA 5.5 E9018-G SFA 5.23 EF3N mod
22.	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	SFA 5.5 E9018-G SFA 5.23 EF3N mod
23.	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	SFA 5.5 E9018-G SFA 5.23 EF3N mod
24.	SA-336 Cl. F12	SA-533 Gr. B Cl. 1	SFA 5.5 E9018-G SFA 5.23 EF3N mod
25.	Build Up	SA-533 Gr. B Cl. 1	SFA 5.5 E9018-G SFA 5.23 EF3N mod
26.	Austenitic SS Cladding	SA-508 Cl. 3	ER NICR3 ER 309 L ER 308 L
27.	Inconel Cladding	SA-508 Cl. 3	ER NICR3 ER 309 L ER 308 L
28.	SB-166	SA-508 Cl. 3	ER NICR3 ER 309 L ER 308 L

TABLE 5.1-3

REACTOR COOLANT SYSTEM VOLUMES

Component	Volume[(a)] (Ft3)
Reactor Vessel	5759
Steam Generators	2947.0 each
Reactor Coolant Pumps	134 each
Piping	1161
Pressurizer Steam Volume (full power)	900
System Water Volume (without pressurizer)	13,351

(a) Indicated volumes derived from summing individual RCS node volumes indicated in CENTS-CN-OA-04-24 NF-APS-07-168, Rev. 00 “Westinghouse CENTS Basedeck for PVNGS Rev 3, NF-APS-07-168”

TABLE 5.1-4

(Sheet 1 of 9)

SHUTDOWN COOLING SYSTEM FMEA (CESSAR TABLE 5.4.7-3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
1.	LPSI Pump Suction Isolation Valves SI-683 SI-692	a) Fails open	Elect. Malf., Mech. binding	Inability to double isolate pump suction from the RWT during shutdown cooling	Position indication in control room, Periodic testing	Redundant SCS flow path.	
		b) Fails closed	Elect. Malf., Mech. binding	None	Same as 1a	None required	Valve is required to be closed during shutdown cooling
2.	LPSI Pumps No. 1 or No. 2	Fails to pump	Elect. Malf., Bearing failure	No flow through one LPSI rain to RCS cold leg	No flow indication from F-307 or F-306. Periodic testing, Pump "Run" light	Redundant LPSI pump and containment spray pump will permit shutdown cooling although the cooling time will be extended	Shutdown cooling with one pump out of service will be extended from 24 hours to approxi-mately 56 hours.
3.	LPSI Pump Discharge Isolation Valves SI-435 SI-447	a) Fails open	Mech. binding	None	Periodic testing	None required	
		b) Fails closed	Mech. binding	Same as 2	Same as 2	Redundant SCS train	Valve is normally locked open at valve.
4.	SCS pumps re-circulation Isolation valves SI-664 SI-665 SI-668 SI-669	a) Fails open	Elect. Malf., Mech. binding	Possible diversion of flow, during shutdown cooling, to RWT	Position indication in control room, Periodic testing	Redundant series mini-flow isolation valves (SI-659, SI-660) prevent flow to RWT during shutdown cooling operation	These valves are closed during shutdown cooling operation
		b) Fails closed	Elect. Malf., Mech. binding	Loss of min-flow protection against operating one pump dead headed during refueling operation	Same as 4a	Redundant SCS train will not be affected	Valve is normally locked open in control room

TABLE 5.1-4
(Sheet 2 of 9)
SHUTDOWN COOLING SYSTEM FMEA (CESSAR TABLE 5.4.7-3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
5.	Mini-flow Isolation Valves SI-659, SI-660	a) Fails open	Mech. binding, Contamination	None	Position indicator in control room, Periodic testing		SCS pumps recirculation valves (SI-664, SI-665, SI-668, SI-669) isolate SCS from RWT
		b) Fails closed	Mech. binding, Contamination	Loss of minimum-flow protection against operating one LPSI pump and one CS pump dead headed during refueling operation.	Same as 5a	Redundant SCS train will not be affected	Valve is normally locked open in control room
6.	CS Pump Suction Valves SI-184, SI-185	a) Fails open	Mech. binding	No effect on shutdown cooling	Periodic testing	None required	Valve is normally locked closed at valve
		b) Fails closed	Mech. binding	Unable to use one CS pump for shutdown cooling. See item 8.	No flow indication from F-348 or F-338, Periodic testing	The associated LPSI pump and redundant SCS train will not be affected.	
7.	CS pump Isolation Valves SI-104, SI-105	a) Fails open	Mech. binding	Inability to double isolate pump suction from the RWT during shutdown cooling	Periodic testing	Redundant SCS subsystem	Valve is normally locked open at valve
		b) Fails closed	Mech. binding	None during shutdown cooling	Same as 7a	None required during shutdown cooling. Redundant train will not be affected.	
8.	CS Pump No. 1 or No. 2	Fails to pump	Elect. Malf., Bearing failure	No flow from one CS pump through SCS	No flow indication from F-348 or F-338, Pump "Run" light, Periodic testing	Tandem LPSI pump and redundant SDC train assure shutdown cooling although cooling time will be extended.	See item 2
9.	CS Pump Discharge to SDCHX Valves SI-684, SI-689	a) Fails open	Elect. Malf., Mech. binding	None during normal shutdown cooling. During post LOCA shutdown cooling, inability to isolate one SCS flow path from one containment spray flow path.	Position indication in control room, Periodic testing	Redundant SCS and containment spray flow paths.	Valve is normally locked open in the control room.

TABLE 5.1-4
(Sheet 3 of 9)
SHUTDOWN COOLING SYSTEM FMEA (CESSAR TABLE 5.4.7-3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
		b) Fails closed	Elect. Malf., Mech. binding	Same as 8	Low flow indication from F-306, F-307. Periodic testing, Position indication in control room.	Same as 9a	
10.	SDCHX Flow Regulator Valve SI-678, SI-679	a) Fails open	Elect. Malf., Mech. binding	During shutdown cooling, inability to operate CS pump in parallel with the LPSI pump	Position indicator in control room, Periodic testing	Redundant SCS train assures shutdown cooling	
		b) Fails closed	Elect. Malf., Mech. binding	Loss of flow from one CS pump during shutdown cooling	Same as 10a	LPSI pump and redundant SCS train assure shutdown cooling	Valve is normally locked open in the control room.
11.	CS Pump Bypass Valves SI-688, SI-693	a) Fails open	Elect. Malf., Mech. binding	None during shutdown cooling	Position indication in control room, Periodic testing	Redundant series isolation valves SI-671, SI-672 (normally closed during plant oper.) and SI-687, SI-695 (normally closed during shutdown cooling operation)	Valve is normally locked closed at control room.
		b) Fails closed	Elect. Malf., Mech. binding	None during normal shutdown cooling. During post LOCA shutdown cooling inability to align one CS subsystem to bypass SDCHX	Position indication in control room, Periodic testing	Redundant Containment Spray and shutdown cooling subsystems.	Valve is required to be closed during latter stages of shutdown cooling operation.
12.	Crossover Valves between LPSI Pump Discharge and SDCHX SI-685, SI-694	a) Fails open	Elect. Malf., Mech. binding	None	Position indication in control room, Periodic testing	None required	Valve is normally locked closed in control room
		b) Fails closed	Elect. Malf., Mech. binding	Inability to align one shutdown cooling train	Position indication in control room, High temperature indication from T-351 or T-352, Periodic testing	Redundant shutdown cooling train will not be affected.	

TABLE 5.1-4
(Sheet 4 of 9)
SHUTDOWN COOLING SYSTEM FMEA (CESSAR TABLE 5.4.7-3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
13.	Shutdown Cooling HX No. 1 or No. 2	a) Loss of Cooling Water	Insufficient Cooling Water	Diminished ability of one subsystem to provide RCS temperature reduction	High temperature indication from T-303Y or T-303X, Periodic testing	Redundant heat exchanger	
		b) Cross Leakage	Corrosion	Leakage from SCS system to the Component Cooling System (CCS)	Radiation and/or level indication in CCS.	Leaking heat exchanger can be isolated. Redundant shutdown cooling subsystem will be unaffected.	
14.	SCS Bypass Flow Control Valves SI-306, SI-307	a) Fails open	Mech. binding, Elect. Malf.	Reduced reactor coolant flow through one shutdown cooling HX	Abnormal temperature indication from T-351 or T-352, Valve position indication, Periodic testing	Redundant SCS subsystem will assure shutdown cooling although cooling time will be extended.	
		b) Fails closed	Elect. Malf., Mech. binding	During initial stage of shutdown cooling, one SDC subsystem would pump excessively cooled water to the reactor core. Reduction in shutdown margin.	Same as 14a. Also, low temperature indication from T-351 or T-352	Operator can turn off the SCS subsystem. The RCS is pre-borated to provide sufficient shutdown margin.	The valve is normally locked open at control room
15	LPSI pump Throttle Valves SI-657, SI-658	a) Fails open	Elect. Malf., Mech. binding	Inability to regulate and maintain cooldown rate. See 14b.	Position indications in control room, Abnormal temperature from T-352 or T-351	Same as 14b	Valve is normally locked closed at control room
		b) Fails closed	Elect. Malf., Mech. binding	No flow through one shutdown cooling HX. Reduced cooling capability	Position Indications in control room, No Delta temperature across SDCHX as indicated by T-351 or T-352	Redundant shutdown cooling subsystem.	Three piece seal ring assembly in valve was replaced with one piece modified retaining ring. Valve does not isolate flow when closed.
16.	Shutdown Purification Valves SI-418, SI-419, SI-420, SI-421	a) Fails open	Corrosion, Mech. binding	None during shutdown cooling	Periodic testing	None required	Valve is normally locked closed at valve

TABLE 5.1-4
(Sheet 5 of 9)
SHUTDOWN COOLING SYSTEM FMEA (CESSAR TABLE 5.4.7-3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
		b) Fails closed	Corrosion Mech. binding	Inability to remove contaminants from one SCS flow path during long-term cooling	Same as 16a. The failure to purify would be detected by periodic sampling	Redundant purification connections to other SCS subsystem	
17.	RWT Return Line Isolation Valves SI-460, SI-464	a) Fails open	Mech. binding	None	Periodic testing	Valves in series prevent inadvertent refilling of the RWT	
		b) Fails closed	Mech. binding	No effect on shutdown cooling. Inability to return water to the RWT until a repair is made.	Same as 17a	Redundant flow path exists to return refueling pool water to RWT prior to startup	Valve is normally locked closed at valve
18.	SDCHX Discharge Valves to LP Headers SI-686, SI-696	a) Fails open	Elect. Malf., Mech. binding	None	Position indication in control room, Periodic testing	None required	Valve is normally locked closed in control room
		b)Fails closed	Elect. Malf., Mech. binding	Isolation of one shutdown cooling HX.	High temperature indication from T-351 or T-352. Also same as 18a.	Redundant shutdown cooling subsystem will not be affected	
19.	Spray Header Isolation Valves for SDCHX SI-687, SI-695	a) Fails open	Elect. Malf., Mech. binding	Inability to align one shut down cooling subsystem to provide entry into shutdown cooling while allowing for simultaneous operation of one containment spray subsystem.	Position indication in control room	Redundant containment spray subsystem and shutdown cooling subsystem will not be affected. Shutdown cooling operation in faulted train not affected.	Valve is normally locked open in control room
		b) Fails closed	Elect. Malf., Mech. binding	No effect on shutdown cooling or refueling operations	Position indication in control room	None required	During shutdown cooling operations these isolation valves are closed. Redundant containment spray subsystem assures adequate containment spray capability.

TABLE 5.1-4
(Sheet 6 of 9)
SHUTDOWN COOLING SYSTEM FMEA (CESSAR TABLE 5.4.7-3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
20.	Containment Spray Valves SI-671, SI-672	a) Fails open	Elect. Malf., Mech. binding	No effect on shutdown cooling or refueling operations	Position indication in control room, Periodic testing	The header isolation valves (SI-687 and SI-695) prevent coolant from being blown through CS nozzles.	Valve is opened by CSAS
		b) Fails closed	Elect. Malf., Mech. binding	Same as 20a	Same as 20a	None required	Valve is normally locked closed in control room and is required to be closed during shutdown cooling operation. Redundant containment spray subsystem assures adequate containment spray capability.
21	LPSI Valves SI-615, SI-625, SI-635, SI-645	a) Fails open	Elect, Malf., Mech. Binding	Inability to gradually warm up the shutdown cooling lines during the shutdown cooling alignment procedure.	Position indication in control room, Periodic testing	Redundant shutdown cooling subsystem will not be affected.	The safety injection piping and nozzles are designed for a limited number of thermal cycles such as could result from operating the Shutdown Cooling subsystem without prior warm up.
		b) Fails closed	Elect. Malf., Mech. binding	Inability to inject cooled coolant into one of the RCS cold legs.	Position indications in control room, Periodic testing	Redundant SCS train	
22.	SCS Return Crossover Valves SI-690, SI-691	a) Fails open	Elect. Malf., Mech. binding	Diversion of flow from discharge leg to suction leg of SCS without passing through the reactor core during shutdown cooling operations.	Position indication in control room, Periodic testing	Redundant shutdown cooling subsystem will not be affected	These valves are gradually closed once warmup and flow rate stability have been reached.
		b) Fails closed	Elect. Malf., Mech. binding	See 21a	Position indication in control room, Periodic testing	Same as 21a	See 21a

TABLE 5.1-4

(Sheet 7 of 9)

SHUTDOWN COOLING SYSTEM FMEA (CESSAR TABLE 5.4.7-3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
23.	SCS Stop Valves for Suction Line SI-651, SI-652, SI-653, SI-654	a) Fails open	Elect. Malf., Mech. binding	None	Position indication in control room, Periodic testing	The redundant series valve ensures that SCS is protected from normal RCS pressure during power operation	Interlocks associated with the valves prevent overpressurization. These interlocks prevent the valves in the suction line of the SCS from being opened if RCS pressure exceeds 400 pisa. These valves automatically close if RCS pressure should rise above the accumulation pressure of the SCS suction line relief valves. This pressure is 700 psia
		b) Fails closed	Elect. Malf., Mech. binding	Prevention of decay heat removal from core via one SCS subsystem during normal shutdown cooling or long term cooling following a small LOCA	Position indication in control room, Periodic testing	Redundant shutdown cooling subsystem assures adequate cooling although cooling time will be extended.	
24.	SI Tank Isolation Valves SI-614, SI-624, SI-634, SI-644	a) Fails open	Elect. Malf., Mech. binding	Unable to isolate one SI tank from the RCS.	Position indication in control room, Periodic testing	None required	During shutdown cooling these valves are closed. However, if a LOCA occurs a SIAS will automatically open these valves. SCS interlock prevents initiation of shutdown cooling unless SIT pressure is reduced to a safe level. SIT pressure can be lowered by bleeding off nitrogen

TABLE 5.1-4
(Sheet 8 of 9)

SHUTDOWN COOLING SYSTEM FMEA (CESSAR TABLE 5.4.7-3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
		b) Fails closed	Elect. Malf., Mech. binding	No effect during shutdown cooling	Valve position indications in control room, Periodic testing	None required	
25.	Shutdown Cooling Line Isolation Valves SI-655, SI-656	a) Fails open	Elect. Malf., Mech, binding	No effect on shutdown cooling	Valve position indication in control room, Periodic testing	None required during shutdown cooling operations	Valve is normally locked closed in control room
		b) Fails closed	Elect. Malf., Mech. binding	Inability to align one shutdown cooling subsystem for shutdown cooling	Valve position indication in control room, Periodic testing	Redundant shutdown cooling subsystem	
26.	PCPS Crossover Valves to SCS SI-256, SI-442, SI-455, SI-458	a) Fails open	Mech. binding	None	Periodic testing	Adjacent valve (SI-204, SI-443, SI-450, SI-454) provides back-up isolation.	Valve is normally locked closed
		b) Fails closed	Mech. binding	None during shutdown cooling. Isolation of the spent fuel pool cooling system from one train of the SCS prevents use of one SDCHX to assist in cooling the spent fuel pool when it contains 1-1/3 cores.	Periodic testing	PCPS connection with redundant SDCHX	One of the shutdown cooling HX may be aligned to the PCPS when no longer needed to maintain reactor coolant at refueling temperature
27.	Shutdown Cooling Line	a) One line clogs	Contaminants	Effective loss of one shutdown cooling subsystem	Low flow indications from F-307 or F-306, Periodic testing	Redundant shutdown cooling subsystem	Periodic sampling will monitor buildup of contaminants
		b) Limited Leakage in one train	Seal failure	Release of coolant and radioactivity outside of containment.	Local leak detection.	The leak can be isolated without affecting the redundant subsystem	
28.	Flow Indicator F-306, F-307 F-338, F-348	False indication	Elect. Malf.	Inability to control cooldown rate in affected train.	Comparison with redundant indicator, with all other process instrumentation and valve position indications consistent.	Redundant indicator	

TABLE 5.1-4
(Sheet 9 of 9)
SHUTDOWN COOLING SYSTEM FMEA (CESSAR TABLE 5.4.7-3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
29.	Pressure Indicator P-307, P-306, P-303X, P-303Y	False indication	Elect. Malf	None	Periodic testing. Comparison with redundant indicator.	Redundant indicator	
30.	Temperature Indicator T-351, T-352, T-303X, T-303Y	False indication	Elect. Malf.	Inability to control cooldown rate in affected train.	Comparison with redundant indicators, with all other process instrumentation and valve position indications consistent. Periodic testing.	Redundant SCS train	

* The Method of Detection column is used to show that it is passible to detect the failure during or before Shutdown Cooling System operation.

5. The total secondary safety valve capacity per steam generator is sufficient to pass 19 x 10^6 pounds per hour steam flow at the valve set pressure (105% of steam generator maximum flow).

6. The maximum steam flow per secondary safety valve is no greater than 1.9 x 10^6 pounds per hour at 1000 psia.

7. Safety valve set pressure will be calculated in accordance with Article NC-7000 of ASME Section III, with the following being considered:

   a. Maximum allowable set pressure such that 110% of steam generator design pressure (1270 psia), which equals 1397 psia, is not exceeded.

   b. Valve accumulation of 3%.

   c. Valve set pressure error of $\pm$1%.

   d. Incorporation of the pressure drop between the steam generator nozzles and the safety valves.

8. The design pressure, temperature, and flow rating of the main steam piping and valves are greater than or equal to the design pressure, temperature, and flow rating of the steam generator secondary side.

P. Related Services

1. The pressure and thermal transients described in CESSAR Section 3.9.1.1 were utilized in the design of those portions of the RCS not within the CESSAR scope of design.

2. The portions of the RCPB outside the CESSAR design scope are either Safety Class 1 or meet the requirements of 10CFR50.55a.

3. The fire protection system provided to protect the RCS is discussed in subsection 9.5.1.

4. Systems have been provided for the detection of reactor coolant leakage from unidentified sources. The intent and guidance of Regulatory Guide 1.45 were utilized as described in paragraph 5.2.5.1.

5. A safety-related nitrogen accumulator system has been provided to supply motive power to the ADV actuators should the normal pneumatic (either air or nitrogen) supply fail to be available.

6. Oil-free Instrument Air will be supplied to the ADV's at a static air pressure of 100 to 125 psig meeting air quality standards (ISA-S7.3) with an approximate dewpoint of -40 degrees F. Full flow conditions will provide Instrument Air at no less than 81 psig. Piping shall be designed to withstand at least 150 psig.

7. The containment structure has been designed and sized to accommodate the RCS arrangement shown in CESSAR Figures 5.1.3-1 and 5.1.3-2.

Q. Environmental

1. For the non-C-E-supplied NSSS components, the demonstration of environmental qualification

envelopes for any or all of these buildings is provided in section 3.11.

2. The containment pressure and temperature transients resulting from the LOCA meets criteria specified in CESSAR Section 6.2.1.5.

3. A containment ventilation system has been provided to handle the RCS heat losses to the containment as described in subsection 9.4.6.

R. Mechanical Interaction Between Components

1. The following components have been designed to withstand the loads arising from the various normal operating and design basis events.

   a. The main steam piping, supports, and restraints

   b. The steam generator steam and feedwater nozzles

   c. The MSIVs and the MSIV bypass valves and supports

   d. Main steam safety valves

   e. The main feedwater piping, supports, and restraints

   f. MFIVs and supports

   g. Blowdown piping, supports, and restraints

   h. Blowdown isolation valves

2. Structures are provided to mate with C-E-supplied component supports to restrain and support RCS components. The loading conditions specified in CESSAR Section 3.9.3.1 are utilized in the design of

the supporting structures. The loads at the support/structure interface locations under normal, upset, emergency, faulted, and test conditions, taking into account the local characteristics of specific structures at the support/structure interfaces, were provided by C-E.

3. The loadings imposed by connecting system piping on RCS nozzles under normal, upset, emergency, faulted, and test conditions are less than the design loads for these nozzles. Combustion-Engineering reviewed the loads developed on the PVNGS and confirmed that the piping nozzles are within code allowable stress limits.

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

This section discusses the measures employed to provide and maintain the integrity of the Reactor Coolant Pressure Boundary (RCPB) throughout the facility's design lifetime. The reactor coolant pressure boundary is defined in accordance with ANSI N18.2-1973. Included are all pressure-containing components such as pressure vessels, piping, pumps, and valves which are:

A. Part of the Reactor Coolant System, or

B. Connected to the Reactor Coolant System, up to and including the following:

   1. The outermost containment isolation valve in piping which penetrates the containment;

   2. The second of two valves normally closed during reactor operation in piping which does not penetrate the containment;

5.2.1 COMPLIANCE WITH CODES AND CODE CASES

5.2.1.1 Compliance with 10CFR50.55a

PVNGS RCS pressure boundary components are listed in table 5.2-1. Additionally, those components not in C-E's scope of supply will comply with the ASME Code addenda required by 10CFR50.55a (refer to table 5.2-2). The preservice inspection will be conducted in accordance with 10CFR 50.55a(g). The inserice inspection (ISI) program will be updated to a more recent code during each inspection interval as determined to be practical in accordance with the requirements of 10CFR 50.55a(g)(4).

5.2.1.2 Applicable Code Cases

Reactor Coolant Pressure Boundary components are fabricated in accordance with the ASME code Section III.

Unless otherwise stated, Combustion Engineering, Inc., complied with Regulatory Guides 1.84 and 1.85 in determining suitable ASME Code Cases. Similarly, Ansaldo complied with Regulatory Guides 1.84, 1.85 and 1.147 in determining suitable ASME Code Cases for the steam generators and Doosan complied with Regulatory Guide 1.84 in determining suitable ASME Code cases for analysis of the reactor vessel closure head, CEDMs and RVLMS housings. Code Cases not included in the Regulatory Guides, may be used with specific authorization from the Commission under 10CFR 50.55a. Additionally, refer to section 1.8 for a discussion relative to Regulatory Guides 1.84, 1.85, and 1.147.

Tables 5.2-3 and 5.2-4 indicate code cases applicable to PVNGS.

5.2.2 OVERPRESSURE PROTECTION

5.2.2.1 Design Bases

Appendix 5B presents the design bases for sizing the overpressurization protection system. The loss of load transient which is used to size the primary safety valves is not intended to be used as a design transient for any other NSSS equipment.

5.2.2.2 Design Evaluation

Chapter 15 provides the functional design evaluation of the overpressurization protection system. In this analysis, the adequacy of the overpressure protection system to maintain secondary and primary operating pressures within 110% of design is clearly demonstrated for the loss of load analysis. The analytical model used in the analysis is discussed in Chapter 15, Section 15.2, Loss of External Load.

Table 15.2.3-3 of Chapter 15 lists the assumptions used in the loss of condenser vacuum analysis. These assumptions are chosen so that they tend to maximize the required pressure relieving capacity of the primary and secondary valves. The analysis demonstrates that sufficient relieving capacity has been provided so that when acting in conjunction with the reactor protective system the safety valves will prevent the pressure from exceeding 110% of the design pressure.

Table 5.2-1

REACTOR COOLANT SYSTEM

PRESSURE BOUNDARY CODE REQUIREMENTS

Component	Supplier	ASME Boiler & Pressure Vessel Code, Section III, Nuclear Power Plant Components		
		Class	Edition	Addenda
Reactor vessel	CE-CNO	1	1971	W-73
Reactor vessel closure head	Doosan	1	1998	2000
Steam generator				
Primary	Ansaldo	1	1989	None
Secondary	Ansaldo	2	1989	None
Pressurizer	CE-CNO	1	1971	W-73
RC Pipe	CE-CNO	1	1974	S-74
RC Pump	CE-KSB	1	1974	None
Valves				
Pres. safety	Dresser	1	1974	S-75
Pneumatic	Fisher	1	1974	S-75
	NVD	1	1974	S-75
Motor-operated	NVD	1, 2, 3	1974	S-75
	Posi-Seal	1, 2, 3	1974	W-75
Manual 2 inch	NVD	1, 2, 3	1974	S-75
2 inch	NVD	1, 2, 3	1974	S-75
	ITT	1	1974	S-76
	Hammel-Dahl	1	1974	S-76
Check 2 inch	NVD	1, 2, 3	1974	S-75
2 inch	NVD	1, 2, 3	1974	W-75
	Target Rock	1, 2, 3	1974	W-75
Solenoid	Target Rock	1, 2, 3	1974/1989	S-76/None
	Valcor	1, 2, 3	1977	W-77
Control Element Drive Mechanisms	Doosan	1	1998	2000

Table 5.2-2

REACTOR COOLANT PRESSURE BOUNDARY CODE REQUIREMENTS

Components	Codes and Classes
Piping (all other RCPB except steam generator cold leg elbow)	1. ASME Boiler and Pressure Vessel Code, Section III, Class 1, through Winter 1975 Addenda (Summer 1979 Addenda for Sub-sections NB3650 through NB3680). 2. ASME Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, through Summer 1975 Addenda.
Steam generator cold leg elbows	1. ASME Boiler and Pressure Vessel Code, Section III, Class 1, 1989.
Valves (non-NSSS)	1. ASME Boiler and Pressure Vessel Code, Section III, Class 1, in accordance with the Code Edition and Addenda in effect at time of purchase order. 2. ASME Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, through Summer 1975 Addenda.
Bolting (studs and nuts)	1. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Class 1, in Accordance with the Code Edition And Addenda in effect at time of Purchase order. 2. ASME Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, through Summer 1975 Addenda.

Table 5.2-3

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Case No.	Title	Notes
1361-2	Socket Welds, Section III	c
1481-1[(a)]	Elevated Temperature Design of Section III, Class 2 and 3 Components	d
1516-2 (N-24)	Welding of Seats or Minor Internal Permanent Attachments in Valves for Section III Applications	e,o
1539-1 (N-30-1)	Metal Bellows and Metal Diaphragm Stem Sealed Valves Section III, Division 1, Class 1, 2, and 3	ac
1540-1	Elastomer Diaphragm Valves, Section III, Classes 2 and 3	f,p
1540-2	Elastomer Diaphragm Valves, Section III, Classes 2 and 3	p
1580 (N-44)	Butt-welded Alignment Tolerance and Acceptable Slopes for Concentric Centerlines for Section III, Class 1, 2, and 3 Construction	z
1588	Electro-Etching of Section III Code Symbols	c
1592-4[(a)]	Class 1 Components in Elevated Temperature Service	d
1606-1	Stress Criteria for Section III, Class 2 and 3 Piping Subject to Upset, Emergency, and Faulted Operating Conditions	d,g
1607-1	Stress Criteria for Section III Class 2 and 3 Vessels Designed to NC/ND-3300 Excluding the NC-3200 Alternate	d,i,h
1614	Hydrostatic Testing of Piping Prior to or Following the Installation of Spray Nozzles for Section III, Class 1, 2, and 3 Piping Systems	j

Table 5.2-3

NRC REGULATORY GUIDE 1.84 CODE CASES USED ON PVNGS

(Sheet 2 of 7)

Case No.	Title	Notes
1635	Stress Criteria for Section III, Class 2 and 3 Valves Subject to Upset, Emergency,and Faulted Operating Conditions	ad
1635-1	Stress Criteria for Section III, Class 2 and 3 Valves Subject to Upset, Emergency, and Faulted Operating Conditions	d,e,k,l,m, n,o,p,q
1636-1	Stress Criteria for Section III, Class 2 and 3 Pumps Subject to Upset, Emergency, and Faulted Operating Conditions	r
1661	Post Weld Heat Treatment P-No. 1 Materials for Section III, Class 1 Vessels	y
1662	Shop Assembly of Components, Appurtenances and Piping Subassem-blies for Section III, Class 1, 2, 3, and MC Construction	d
1677 (N-82)	Clarification of Flange Design Loads, Section III, Class 1, 2, and 3	o,q,z
1678	Butterfly Valves of Circular Cross Section Larger than 24 Inch NPS for Section III, Class 2 and 3 Construction	e
1681-1	Organizations Accepting Overall Responsibility for Section III Construction	x
1685	Furnace Brazing, Section III, Class 1, 2, 3, and MC Construction	s
1686	Furnace Brazing, Section III, Subsec-tion NF, Component Supports	s
1702 (N-96)	Flanged Valves Larger than 24 Inches for Section III, Class 1, 2, and 3 Construction	e

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NRC REGULATORY GUIDE 1.84 CODE CASES USED ON PVNGS
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Case No.	Title	Notes
1711	Pressure Relief Valve Design Rules, Section III, Division 1, Class 1, 2, and 3	x,z
1729	Minimum Edge Distance - Bolting for Section III, Division 1, Class 1, 2, 3, and MC Construction of Component Supports	s,x
1734	Weld Design for Use for Section III, Division 1, Class 1, 2, 3, and MC Construction of Component Supports	s
1744	Carbon Steel Pipe Flanges Larger than 24 Inch, Section III, Division 1, Class 2 and 3 Construction	t
1761-1 (N-133)	Use of SB-148 Alloy CA954, Section III, Division 1, Class 3	o
1769-1	Qualification of NDE Level III Personnel Section III, Division 1.	x
1774-1	Minimum Wall Thickness for Class 2 and 3 Valves, Section III, Division 1	o,u
1780	Hydrostatic Testing and Stamping of Pumps for Class 1 Construction, Section III, Division 1	x
1791 (N-154)	Projection Resistance Welding of Valve Seats, Section III, Division 1, Class 1, 2, and 3 Valves	z
1796	Body Neck Thickness Determination for Valves with Inlet Conditions 4 Inch Nominal Pipe Size and Smaller, Section III, Division 1, Class 1, 2, and 3	ac
1818	Welded Joints in Component Standard Supports, Section III, Division 1	s

Table 5.2-3
NRC REGULATORY GUIDE 1.84 CODE CASES USED ON PVNGS
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Case No.	Title	Notes
N-122	Stress Indices for Integral Structural Attachments, Class 1 Section III, Division 1	aa
N-192-2	Use of Braided Flexible Connectors, Section III, Division 1, Class 2 and 3	v
N-210[a,b]	Exemptions to Hydrostatic Testing After Repair, Section XI, Division 1	w
N-226	Temporary Attachment of Thermocouples, Section III, Division 1, Class 1, 2, and 3 Construction	w
N-237	Hydrostatic Testing of Internal Piping, Section III, Division 1	w
N-240	Hydrostatic Testing of Open Ended Piping, Section III, Division 1	w, ag
N-247	Certified Design Report Summary for Component Standard Supports, Section III, Division 1, Class 1, 2, 3, and MC	s
N-252	Low Energy Capacitive Discharge Welding Method for Temporary or Permanent Attachments to Components and Supports Section III, Division I and XI	ae
N-272	Compiling Data Report Forms, Section III, Division 1	ab
N-302	Tack Welding	af
N-316	Alternative Rules for Fillet Weld Dimensions for Socket Welded Fittings	x
N-328	Thermit Brazing or Welding of Nonstructural Attachments	w

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Case No.	Title	Notes
N-338[a]	Use of Mild Steel Washers for Section III, Division I, NF Construction	s
N-339[a]	Examination of Ends of Fillet Welds for Class 1, 2, and MC Construction	w
	Alternative Damping Values for Seismic Analysis of Class 1, 2, and 3 Piping Sections, Section III, Division 1	
N-4-11	Special Type 403 Modified Forgings or Bars Section III, Division 1 Class 1 and CS	ah
N-646	Alternative Stress Intensification Factors for Circumferential Fillet Welded or Socket Welded Joints for Class 2 or 3 Piping, Section III, Division 1	ai

a. Code cases not currently incorporated in Regulatory Guide 1.84 but approved for use on PVNGS.

b. Additional contingencies in the use of this code case have been required by the NRC. They are documented in the specification to which the code case is applicable.

c. C-E scope (pressurizer assembly 14273-PE-130). See Relief Request 30 regarding pressurizer heaters and heater sleeves.

d. Hydrogen recombiners (12-NM-993)

e. Nuclear service butterfly valves (13-JM-605).

f. C-E scope (elastomeric sealed valves 14273-PE-709)

g. Piping for the following systems: radioactive waste drains, CVCS, safety injection shutdown, essential chilled water, essential spray pond, essential cooling water, reactor coolant, fuel pool cooling and cleanup, nuclear cooling water, auxiliary feedwater, main steam, nuclear sampling, condensate transfer and storage, diesel fuel oil and transfer, diesel generator (13-PM-100 through -115), and mechanical penetration assemblies (13-MM-500)

h. C-E scope (shutdown cooling heat exchangers 14273-PE-301)
(regenerative heat exchangers 14273-PE-302)
(letdown heat exchangers 14273-PE-303)
(ASME Section III Code tanks 14273-PE-605)

Table 5.2-3
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(C-E-designated ASME Section III Code tanks 14273-PE-603)
(C-E-designed ion exchangers 14273-PE-651)
(filters radioactive service 14273-PE-201)

i. Shop-fabricated tanks (13-MM-105)

j. C-E scope (containment spray nozzles 14273-PE-404)

k. Nuclear service control valves - two-way (13-JM-601A)

l. Nuclear service control valves - three-way (13-JM-601B)

m. Solenoid valves - nuclear (13-JM-603/13-JN-603/13-JN-699)

n. Nuclear service valves - 2 inches and smaller (13-PM-221A)

o. Nuclear service valves - 2-1/2 inches and larger (13-PM-221B)

p. Nuclear service diaphragm valves (13-PM-231)

q. Main steam and feedwater isolation valves (13-MM-234)

r. Auxiliary feed pump - motor- and turbine-driven, horizontal centrifugal pump, vertical centrifugal pump, diesel generator fuel oil transfer pumps (13-MM-021, -093, -095, -098)

s. Nuclear pipe supports (13-PM-209 and 209A)

t. Q-Class heat exchangers (13-MM-071)

u. C-E scope (motor-operated butterfly valves 14273-PE-705)

v. Flexible metal hose (13-JM-711)

w. Field fabrication and installation of nuclear piping (13-PM-204).

x. C-E scope (reactor coolant pump 14273-PE-480)

y. C-E scope (reactor coolant pipe 14273-PE-140)
(pressurizer 14273-PE-130)
(steam generators 14273-PE-120)

Table 5.2-3

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z. C-E scope (gas stripper 14273-PE-231)

aa. Piping for the following systems: reactor coolant, chemical and volume control, and safety injection (13-PM-101, -102, -106)

ab. Used in preparing N-5 Code data reports

ac. Nuclear service valves 2 inches and smaller (3-PM-221C)

ad. Anchor/Darling valves (P.O. 13-PM-221B)

ae. Test guideline (PETG-6-XX-1)

af. Project Welding Manual WD-1, Form WR-5A, utilized for socket welds and/or support welds.

ag. Field-fabrication and erection of sanitary waste, roof drain systems, embedded drainage, domestic water piping, and floor and equipment drain systems (13-PM-302).

ah. Doosan Scope (Control Element Drive Mechanism PV-132ES-001)

ai. Piping in Safety Injection, Main Steam and Secondary Chemistry systems.

Table 5.2-4
NRC REGULATORY GUIDE 1.85 CODE CASES USED ON PVNGS
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Case No.	Title	Notes
1332-6	Requirements for Steel Forgings, Section III and VIII, Division 2	a
1335-9	Requirements for Bolting Materials, Section III	b
1335-10 (N-3-10)	Requirements for Bolting Materials, Section III	ai
1557	Steel Products Refined by Secondary Remelting, Section III, and Section VIII	c
1567	Testing Lots of Carbon and Low Alloy Steel Covered Electrodes, Section III	d,e,m, ah
1571	Additional Material for SA-234 Carbon Steel Fittings, Section III	f
1605 (N-52)	Cr-Ni-Mo-V Bolting Material for Section III, Class 1 Components	aj
1609-01 (N-55)	Inertia and Continuous Drive Friction Welding Section I, III, IV, VIII - Division 1 and 2 and IX	i,q
1634-2	Use of SB-359 for Section III, Division 1, Class 3 Construction	h
1644	Additional Materials for Component Supports, Section III, Subsection NF, Class 1, 2, 3, and MC Construction	b,i
1644-4	Additional Materials for Component Supports, and Alternate Design Requirements for Bolted Joints, Section III, Division 1 Subsection NF, Class 1, 2, 3, and MC Construction	b,i,j

Table 5.2-4
NRC REGULATORY GUIDE 1.85 CODE CASES USED ON PVNGS
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Case No.	Title	Notes
1644-5	Additional Materials for Component Supports and Alternate Design Requirements for Bolted Joints, Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Construction	i,k
1644-6	Additional Materials for Component Supports and Alternate Design Requirements for Bolted Joints, Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Construction	b,i,k, al
1644-7	Additional Materials for Component Supports, Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Component Supports	i,l
1644-8 (N-71-8)	Additional Materials for Component Supports, Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Component Supports	aj,ak, al,aa, z
1646-6	Partial Postponement of Section XI, Category BC Examination for Class 1 Components	a
1682	Alternate Rules for Material Manufacturers and Material Suppliers, Section III, Division 1, Subarticle NA-3700	m,n
1682-1	Alternate Rules for Material Manufacturers and Material Suppliers, Section III, Division 1, Subarticle NA-3700	ag
1690	Stock materials for Section III Construction, Section III, Division 1	i
1698	Waiver of Ultrasonic Method, Sections III, V and VIII, Division 1	o
1728	Steel Structural Shapes and Small Material Products for Component Supports, Section III, Division 1	i,l

Table 5.2-4

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Case No.	Title	Notes
1731	Basic Calibration Blocks for Section XI, Division 1 - Ultrasonic Examination of Welds 10 Inches to 14 Inches Thick	q
1747	Requirements for Martensitic Stainless Steel Forgings with 13% Chromium and 4% Nickel, Section III, Division 1, Class 1, 2, 3, and CS Construction	f
1781 (N-147)	Use of Modified SA-487 Grade CA6NM, Section III, Division 1, Class 1, 2, 3, MC, or CS	f
1820	Alternative Ultrasonic Examination Technique, Section III, Division 1	r
N-71-7	Additional Materials for Component Supports, Section III, Division I, Subsection NF, Class 1, 2, 3 and MC Component Supports	i
N-71-10	Additional Materials For Component Supports Fabricated By Welding, Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Component Supports	i
N-71-12	Additional Materials for Component Supports Fabricated by Welding, Section III, Division 1, Class 1, 2, 3, and MC	an
N-108 (1724)	Deviation from the Specified Silicon Ranges in ASME Material Specifications, Sections III, Division 1, and VIII, Divisions 1 and 2	i
N-180	Examination of Springs for Class 1 Component Standard Supports	i
N-181	Steel Castings Refined by the Argon Decarburization Process, Section III, Division 1	e,m
N-188-1	Use of Welded Ni-Fe-Cr-Mo-Cu (Alloy 875) and Ni-Cr-Mo-Cb (Alloy 625) Tubing, Section III, Division 1, Class 2 and 3	s

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NRC REGULATORY GUIDE 1.85 CODE CASES USED ON PVNGS
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Case No.	Title	Notes
N-225	Certification and Identification of Material for Component Supports, Section III, Division 1	i
N-242	Materials Certification, Section III, Division 1, Class 1, 2, 3, MC, and CS Construction	f,t, u,x, y,aa
N-242-1	Materials Certification, Section III, Division 1, Classes 1, 2, 3, MC, and CS Construction	z,ac, ae,af, am,ao
N-249-2	Additional Materials for Component Supports Fabricated Without Welding, Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Component Supports	i
N-274[w]	Alternate Rules for Examination of Weld Repairs for Section III, Division 1 Construction	v
N-275[w]	Repair of Welds, ASME Section III, Division 1	v
N-295	Section III, Division 1 Construction, NCA-1140, Material	ab
N-310-1[w]	Certification of Bolting Materials, Section III, Division 1, Class 1, 2, 3, MC and CS	ad
N-474-1	Design stress Intensities and Yield Strength Values for UNS N06990 with a Minimum Specified Yield Strength of 35 KSI, Class 1 Components, Section III, Division 1	ap
N-20-3	SB-163 Nickle-Chromium Tubing Alloys 600 and 690	aq
N-474-2	Alloy 690 Design Stress Intensities	aq

a. C-E scope (reactor vessel 14273-PE-110)
(reactor coolant pipe 14273-PE-140)

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b. Air handling and filtration unit (13-MM-721B)

c. C-E scope (reactor vessel 14273-PE-110)

d. Nuclear service control valves - three-way (13-JM-601B)

e. Nuclear service valves - 2 inches and smaller (13-PM-221A)

f. C-E scope (reactor coolant pumps 14273-PE-480)

g. Not used

h. Water chillers (13-MM-723)

i. Nuclear pipe supports (13-PM-209 and 209A)

j. Hydrogen recombiners (13-NM-993)

k. C-E scope (steam generator upper supports components 14273-PE-507)
(steam generator upper supports hardware 4273-PE-509)
(reactor vessel support column 14273-PE-516)
(reactor coolant pump support clevices and pins 14273-PE-517)
(safety injection tanks 14273-PE-601)
(reactor coolant pumps 14273-PE-480)

l. Instrument tubing clamps and valve support brackets (13-JM-712)

m. Nuclear service valves - 2-1/2 inches and larger (13-PM-221B)

n. C-E scope (reactor vessel 14273-PE-110)

o. C-E scope (reactor vessel 14273-PE-110)
(pressurizer 14273-PE-130)
(reactor coolant pipe 14273-PE-140)

p. Not used

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NRC REGULATORY GUIDE 1.85 CODE CASES USED ON PVNGS
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q. C-E scope (reactor vessel 14273-PE-110)

r. C-E scope (reactor vessel 14273-PE-110)
(reactor coolant pumps 14273-PE-480)
(reactor coolant piping 14273-PE-140)

s. Flexible metal hose (13-JM-711)

t. Diesel generator and auxiliaries (13-MM-018)

u. Diesel generator fuel oil transfer pumps (13-MM-098)

v. Field-fabrication installation of nuclear piping (13-PM-204)

w. Code cases not currently incorporated in Regulatory Guide 1.85, but approved for use on PVNGS

x. Nuclear safety relief valves (13-JM-691)

y. Horizontal centrifugal pumps - Q-Class (13-MM-093)

z. C-E scope (reactor vessel load limiter assembly material for PVNGS Units 1, 2, and 3 14273-PE-514)

aa. C-E scope steam generator sliding base key way shims - Unit 3 only 14273-PE-510)

ab. Air handling unit 13-M-HJN-A03 cooling coils (13-MM-598)

ac. C-E scope (safety injection tanks 14273-PE-601)

ad. Safety-related piping and supports (13-PM-300)

ae. Shop-fabrication of nuclear service piping (13-PM-201)

af. Nuclear service pipe and fittings - 2 inches and smaller (13-PM-307)

ag. C-E scope (high-pressure safety injection pumps 14273-PE-410)

Table 5.2-4
NRC REGULATORY GUIDE 1.85 CODE CASES USED ON PVNGS
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ah. C-E scope (gas stripper 14273-PE-231)

ai. C-E scope (pneumatically-operated valves 14273-PE-704)

aj. C-E scope (steam generator upper supports hardware 14273-PE-509)

ak. C-E scope (steam generator upper supports snubber 14273-PE-503)
(steam generator upper supports components 14273-PE-507)

al. C-E scope (steam generator and reactor vessel support fasteners 14273-PE-508)

am. C-E scope (miscellaneous safety and relief valves 14273-PE-715)

an. Steam generator sliding base circular shims - Unit 3 only, Nonconformance Report NC-1833 to FMR F149456-HO

ao. C-E supplied reactor coolant pump hex nuts for spare parts. Reference ECE-RC-A035, and paragraphs 1-4 of Code Case N-242-1.

ap. C-E scope reactor coolant system Alloy 690 penetrations.

aq. Steam Generators (Spec MN725)

5.2.2.3 Piping and Instrumentation Diagrams

Engineering drawings 01, 02, 03-M-SGP-002 and -001 show the secondary safety valves, and engineering drawings 01,02, 03-M-RCP-001, -002 and -003 show the primary safety valves. In addition, the piping and instrumentation diagram showing the reactor drain tank is given in 01, 02, 03-M-CHP-001, through -005.

5.2.2.4 Equipment and Component Description

The primary safety valves are direct acting, spring loaded, stainless steel valves with enclosed bonnets. These valves are mounted on the top of the pressurizer. For further description of these valves, refer to Section 5.4.13. A schematic drawing of the primary safety valve is given in Figure 5.4-6. Valve parameters are given in Table 5.4-40.

Primary safety valve operation is characterized by a sharp pop at the set pressure. This sharp opening is produced by two stages of reaction working together to produce a continuous action. The initial lift is produced when the steam pressure under the disc exceeds the spring force. The escaping steam reacts against the upper guide ring and pushes the disc up to a high lift. The reaction of the deflected steam against the underside of the disc lifts it higher on an accumulation of pressure. The valve reaches a lift in excess of full bore lift within an accumulation of 3 percent above the set pressure.

As the system pressure drops, the valve disc settles to a moderate lift, and closes sharply with a blowdown of approximately 5 percent of the set pressure.

5.2.2.4.1 Transients

The primary safety valves are designed to withstand the following transients without failure or malfunction:

A. 650°F to 375°F in 50 seconds and return to 650°F in 2000 seconds for 5 cycles (Loss of secondary pressure)

B. 100°F to 400°F and return to 100°F at a rate of 100°F/hr with concurrent pressure changes from 400 psig to 2250 psig and returning to 400 psig in step changes for 200 cycles. (Plant leak test).

C. ± 10°F step change from 653°F for 1,030,000 cycles. (Plant loading and unloading, ± 10% step load, normal plant variation).

D. 75°F to 653°F and return to 75°F at a rate of 200°F/hr with pressures at saturation levels for 500 cycles. (Plant heat up and cool down).

Note: Heat up and cool down are separate transients, each beginning at steady state conditions.

E. Pressurize to 1.5 times set pressure at 100°F-200°F for 10 cycles plus number of hydros conducted prior to valve shipment. (Hydrostatic test).

F. 480 cycles from closed to full open to closed. (Turbine Trip)

5.2.2.4.2 Environment

The primary safety valves are designed to operate in the following environmental conditions.

5.2.2.4.2.1 Normal Environment

A. 120°F maximum

B. Relative humidity of 20 - 90%

5.2.2.4.2.2 Main Steam Line Break (One occurrence)

350°F maximum Superheated steam/air mixture for 12 minutes followed by saturated steam/air mixture.

5.2.2.4.3 Main Steam Safety Valves

The main steam safety valves are direct acting, spring loaded, carbon steel valves. The valves are mounted on each of the main steam lines upstream of the steam line isolation valves, and outside containment. A schematic drawing of the main steam safety valves is given in Figure 5.4-7. The valve parameters are given in Table 5.4-41. For a description of overpressure protection equipment and components for the main steam system refer to Subsection 10.3.2.

5.2.2.4.3.1 Main Steam Safety Valve Operation. The operation of these valves is similar to the primary safety valves, Section 5.2.2.4.2.

5.2.2.4.3.2 Transients. The main steam safety valves are designed to withstand the following transients without failure or malfunction.

A. 565°F to 75°F in 60 seconds for 5 cycles (loss of secondary pressure).

B. Pressure changes from 0 psig to 1375 psig, at a temperature range of between 100°F to 200°F for 200 cycles (secondary side leak test).

C. ± 10°F step change from 553°F, 10^6 cycles (normal plant variations).

D. 75°F to 565°F and return to 75°F at a rate of 100°F/hr with pressures at saturation levels for 500 cycles (plant heatup and cool down).

Note: Heat up and cool down are separate transients, each beginning at steady state conditions.

E. Pressurize to 1.5 times set pressure at 100°F - 200°F for 10 cycles plus number of hydros conducted prior to valve shipment (hydrostatic test).

F. 480 opening and closing cycles to full stem movement (turbine trip).

5.2.2.4.3.3 Environment. The main steam safety valves are designed to operate in the following environmental conditions:

5.2.2.4.3.3.1 Normal Environment

A. 120°F maximum.

B. Relative humidity 20 – 90%.

5.2.2.4.3.3.2 Main Steam Line Break (One Occurrence)

A. 330°F maximum for 3 minutes.

B. Relative humidity of 100%.

5.2.2.4.4 Safety Injection System Relief Valves SI-169 and SI-469

These relief valves are direct acting, spring loaded, stainless steel valves with enclosed bonnets. The design parameters of these valves are:

set pressure	2485 psig
rated flow	15 gpm
water chemistry	0 - 4 weight percent boric acid
throat area	.023 in^2
design temperature	650°F

5.2.2.4.4.1 Valve Operation. As the set pressure is reached, the disc raises off the nozzle seat. This lift continues until the valve is fully open at 10 percent accumulation. The lift decreases as pressure drops until the

seat and disc contacts and seals closed. The valve is fully closed at a maximum of 10% below set pressure (10% blowdown).

5.2.2.4.4.2 Transients. These relief valves are designed to withstand the following transients without failure or malfunction.

A. 60°F to 400°F in 5 seconds, 400°F to 60°F in 15 minutes for 55 cycles.

B. 60°F to 350°F in 15 minutes, 350°F to 60°F in 2.9 hours for 500 cycles.

C. 120°F to 60°F in 5 seconds, 60°F to 120°F in 15 minutes for 660 cycles.

5.2.2.4.4.3 Environment. These relief valves are designed to operate in the following environmental conditions.

A. 122°F maximum.

B. 95% relative humidity at 60°F to 80°F.

C. Fixed moisture content equivalent to 95% RH at 80°F at temperatures above

5.2.2.4.4.4 Material Specifications. Material specifications for the primary safety valves are given in Table 5.4-40.

Material specifications for the main steam safety valves are given in Table 5.4-41.

5.2.2.5 Mounting of Pressure Relief Devices

5.2.2.5.1 Location of Pressure Relief Devices

The design bases for the assumed loads for the primary and secondary side pressure relief devices of the steam generator are described in paragraph 3.9.3.3. Pressure relief devices for the reactor coolant system comprise the four pressurizer safety valves shown in engineering drawing 13-P-RCF-114. These discharge to the reactor drain tank by common header. Engineering drawings 01-P-SGF-118, -155 and 01, 02, 03-P-SGF-401 provide design installation details for the pressure relief devices mounted on the steam lines which are part of the secondary side of the steam generator.

5.2.2.5.2 Design Bases for Mounting of RCPB Pressure Relief Devices

The RCPB pressure relief devices are mounted and installed as follows:

A. Each discharge pipe is supported as close to the valve as practical to transfer transient discharge load to the adjacent structure.

B. There is no rigid restraint in the vertical directions. Thermal vertical load is transferred to pressurizer shear lugs by pipe stubs. The piping system moves up or down with the pressurizer during heat up or cool down. Weight of the piping system is carried by seven variable and two constant spring supports.

C. The support provided on the discharge piping is as close as possible to each safety and relief valve discharge nozzle so that forces and moments during operating plant conditions (normal, upset, emergency, and faulted) will not jeopardize the integrity of the valves, the inlet lines to the valves, and the nozzles on the pressurizer.

D. Pipe breaks are postulated in the high energy piping at the pressurizer nozzle, long radius elbow, and valve flange point (refer to figure 3.6-12). Pipe breaks are not postulated in the safety relief valve discharge piping (i.e., piping from the valve discharge flange to the reactor drain tank). This piping is not considered to be high energy piping because it operates less than 2% of normal plant operating time. Discharge piping is classified as moderate energy piping as defined in paragraph 3.6.2.1.2. Through-wall cracks are not postulated since this piping is adequately separated from other safety-related active systems subject to impairment by such failures.

Dynamic analysis for seismic and valve discharge loadings have been performed to verify the design of the support configuration.

5.2.2.5.3 Pressurizer Safety and Relief Analysis - Loading Criteria and Methods of Analysis

The pressurizer safety lines and relief line are shown as an isometric projection in engineering drawing 13-P-RCF-114.

5.2.2.5.3.1 Loading Conditions. For loading combinations, see tables 3.9-5 and 3.9-6.

5.2.2.5.3.2 Pressure. Pressure loading is identified as membrane design pressure. The membrane design pressure is used in connection with the longitudinal pressure stress calculations in accordance with the ASME B&PV Code. The design pressure is 2485 psig for Class 1 piping and 550 psig for B31.1 piping.

5.2.2.5.3.3 Weight. A weight analysis is performed by applying a 1.0g load downward on the complete piping system. The piping is assigned a distributed mass or weight as a function of its properties. This method provides a distributed loading to the piping system as a function of the weight of the pipe and contained fluid and insulation during normal operating conditions. Hydrotest conditions are also considered.

5.2.2.5.3.4 Seismic. The structural response due to the OBE loadings is analyzed by normal mode theory using the ME 101 computer program. The lumped parameter multidegree-of-freedom model is used along with the appropriate response spectra input for the computer solution. These spectra are the envelope of the in-structure response spectra at the piping support just

downstream of the valve, combined with the response spectra of the pressurizer nozzle. A response spectrum is applied in the horizontal (x and z) and vertical (y) directions.

5.2.2.5.3.5 Thrust.

5.2.2.5.3.5.1 Hydraulic Forces of Thrust. The pressurizer safety valve discharge piping system is a closed system in which no sustained reaction force from a free discharging jet of fluid can exist. However, transient hydraulic forces are imposed at various points in the piping system from the time a safety valve begins to open until steady flow is completely developed. Since no water loop seal is applied, no transient hydraulic forces can occur due to the liquid being forced through the safety valve and then being accelerated down the piping system.

5.2.2.5.3.5.2 Structural Analysis of Thrust. The dynamic structural solution for the thrust loading is obtained using a modified-predictor-corrector-integration technique and normal mode theory.

Subprogram RVDFT (relief valve discharge flow transients) is used in this analysis and predicts the transient flows resulting from actuation of a safety relief valve under normal operating conditions. It also predicts the resulting piping loads to be used as dynamic forcing functions for structural design of discharge piping and its supporting components. The computation is based on finite difference solutions by the method of effluent characteristics. The computed transient

pressure, velocity, and density are then used to calculate loads on bends and pipe runs.

5.2.2.5.4 Pressurizer Safety and Relief Analysis - Summary of Results

5.2.2.5.4.1 Stress Allowables.

Stainless Steel at 460F:	SA 358 Type 304 (Class 1) SA 376 Type 304 (Class 1)
Type 304 at 700F:	B31.1 Code Allowable = 15,980 psi = S_h
Type 304	Class 1 Code Allowable = 15,900 psi = S_m

5.2.2.5.4.2 Stress Summary of Highest Stress Points. Stresses calculated for the highest stress points are within code allowable values.

5.2.2.5.4.3 Anchor Support Points. See engineering drawing 13-P-RCF-114.

5.2.2.5.5 Main Steam Safety Valve Analysis

Engineering drawings 01-P-SGF-118,-115 and 01, 02, 03-P-SGF-401 provide design and installation details.

5.2.2.5.5.1 Valve Forces and Reactor Load Paths. Two conditions were considered in the stress analyses of the safety valve installations; namely, the dynamic effects of the safety valve opening phase and the steady-state flow condition reached

after the valve has opened and is exhausting into the stack. During the valve opening time, dynamic forces due to the hydraulic transients in the valve are compensated by the reaction forces of the header supports via the header. When the valve has opened, and the steam is exhausting into the stack, the valve forces are balanced due to the tee and piston design, and the discharge thrust is compensated by the reaction forces of the stack support structure.

The force versus rise time curve for the safety valve and the valve natural period resulted in a dynamic load factor of 1.22, which was conservatively increased to 1.25. Each valve has a thrust load of 30,500 pounds for a line pressure of 1318 psi; hence, the header reaction load per valve is 38,125 pounds.

It was conservatively assumed that each valve opened simultaneously, resulting in stresses in the headers and support loads within code allowable values.

5.2.2.5.5.2 Loading Conditions. For design loading conditions, see tables 3.9-5 and 3.9-6.

5.2.2.5.5.3 Stress Summary of Safety Valve Headers. The stresses for the main steam line headers are within code allowable values.

Load Cases:

A. Upset Condition

Weight + longitudinal pressure + seismic inertia (OBE) + safety valve thrust

B. Emergency Condition

Weight + longitudinal pressure + seismic inertia (OBE) + fast valve closure

C. Stress Due to Thermal Plant Condition

Thermal expansion + seismic anchor movement

5.2.2.6 Applicable Codes and Classification

Refer to table 3.2-1 and Section 5.2.1.2 for codes and classifications applicable to PVNGS.

5.2.2.7 Material Specification

Refer to Section 5.4.13. In addition, for material specifications related to the secondary system overpressurization protection refer to subsection 10.3.2.

5.2.2.8 Process Instrumentation

Process instrumentation for the overpressurization protection equipment that is associated with the Reactor Coolant System is shown in engineering drawings 01, 02, 03-M-RCP-001, -002 and -003 and described in Chapter 7. Instrumentation associated with pressurizer relief discharge is described in Section 18.II.D.3. In addition, refer to engineering drawings 01, 02, 03-M-RCP-001, -002 and –003 and 01, 02, 03-M-SGP-002 and -001 for the instrumentation related to primary and secondary system overpressurization protection, respectively.

5.2.2.9 System Reliability

Reliability of the main steam system reliefs is discussed in the interface Section 5.1.4. The primary safety valves are passive, spring actuated mechanisms, and cannot fail closed if setpoint pressure is exceeded. The operational reliability of the primary safety valves is assured by:

- Stringent compliance with ASME III and XI Code for safety valves.
- Conservative design criteria.
- Selection of a vendor with proven experience and expertise.
- Accounting for thermal cycling during valve operation.
- Technical Specifications.

Also, refer to subsections 5.1.5 and 10.3.2 for a discussion of secondary system overpressure protection reliability.

5.2.2.10 Testing and Inspection

Testing and inspection of primary and secondary valves are governed by ASME OM Code. Testing and inspection of the secondary safety valves is discussed in sections 3.9, 14.2, and in the Technical Specifications.

5.2.2.11 Overpressure Protection During Low Temperature Conditions

Overpressure protection of the RCS during low-temperature conditions is provided by the relief valves located in the shutdown cooling system (SCS) suction lines. Section 5.4.7 provides a description of the SCS. The SCS is schematically shown on the Safety Injection System (SIS) engineering drawings 01, 02, 03-M-SIP-001, -002 and -003. The electrical schematic for the SCS isolation valves is provided in the SIS P&ID. The SCS relief valves are shown in the engineering drawings listed above and described in paragraph 5.4.7.3.

Alignment of the SCS relief valve to the RCS is provided via plant procedures to ensure RCS overpressure protection for all temperatures below the pressure-temperature (P-T) operating curve limits corresponding to the metal temperature of at least RT_{NDT} + 90°F at the limiting reactor vessel beltline location.

Overpressure protection is provided by the pressurizer safety valves described in subsection 5.2.2.

5.2.2.11.1 Design Criteria

A discussion follows of the criteria considered in the design of the overpressure mitigating system to provide low temperature overpressure protection (LTOP) for the RCS.

5.2.2.11.1.1 Credit for Operator Action. No credit is taken for operator action for 10 minutes after the operator is made aware that a transient is in progress.

5.2.2.11.1.2 Single Failure. In the LTOP mode, each SCS relief valve is designed to protect the reactor vessel given a single failure in addition to a failure that initiated the pressure transient. The event initiating the pressure transient is considered to result from either an operator error or equipment malfunction. The SCS relief valve system is independent of a loss of offsite power. Each SCS relief valve is a self actuating spring-loaded liquid relief valve which does not require control circuitry. The valve opens when the RCS pressure exceeds its setpoint.

The redundant SCS suction line trains between the RCS and SCS relief valves meet the single failure criteria as described in paragraph 5.4.7 and table 5.1-4. No single failure of an isolation valve or its associated interlock will prevent one relief valve from performing its intended function.

5.2.2.11.1.3 Testability. Periodic testing of the SCS isolation valves is defined in the Technical Specifications.

5.2.2.11.1.4 Seismic Design and IEEE 270 Criteria. The SCS suction line relief valves, isolation valves, associated interlocks, and instrumentation are designed to Seismic Category I requirements as discussed in subsections 3.2.1, paragraph 5.4.7 and table 3.2-1. The interlocks and instrumentation associated with the SCS suction isolation valves satisfy the appropriate portions of IEEE 279 criteria as discussed in paragraphs 5.4.7, 7.6.2.1.1 and 7.6.2.2.1.

5.2.2.11.2 Design and Analysis

In demonstrating that the SCS relief valves meet the criteria listed in paragraph 5.2.2.11.1, the following additional information is provided.

5.2.2.11.2.1 Limiting Transients. Transients during the low temperature operating mode are more severe when the RCS is operated in the water-solid condition. Addition of mass or energy to an isolated water-solid system produces increased system pressure. The severity of the pressure transients depends upon the rate and total quantity of mass or energy addition. The most limiting transients initiated by a single operator error or equipment failure are:

A. An inadvertent safety injection actuation (mass input).

B. A reactor coolant pump start when a positive steam generator to reactor vessel ΔT exists (energy input)

The transients were determined as most limiting by conservative analyses which maximize mass and energy additions to the RCS. In addition, the RCS is assumed to be in a water-solid condition at the time of the transient; such a condition has been noticed to exist infrequently during plant operation since the operator is instructed to avoid water-solid conditions whenever possible.

The limiting LTOP mass addition transient results from the simultaneous operation of two HPSI and three charging pumps, along with the simultaneous addition of energy from decay heat

and the pressurizer heaters. Calculated results from the mass addition transient show a peak pressure, given a core power (including instrument uncertainty) of 4070 Mwt, of less than 499 psia.

The limiting LTOP energy addition transient results from startup of a single reactor coolant pump when the steam generator fluid temperature is 100 degrees F higher than the coolant temperature in the reactor vessel. This temperature difference is the maximum allowed by technical specification during the LTOP mode. In addition to considering the energy addition to the RCS from the steam generator secondary side, energy addition from decay heat, the reactor coolant pump and all pressurizer heaters were also included. In this analysis the steam generators were assumed to be filled to the zero power, normal water level. For conservatism, the secondary water, both around and above the U-tubes, was assumed to be thermally mixed in order to maximize the energy input to the primary side. This assumption is conservative since as a result of the temperature distribution within the steam generator during the transient, the water inventory above the tubes is practically isolated thermally from the heat transfer region. Therefore the heat transfer rate, and thus the primary side pressure, is not sensitive to the secondary side water level as long as the tubes are covered.

On the basis of experience, the ΔT value of 100°F used in the analysis is much larger than any ΔT that might be expected during plant operation. This maximum allowable ΔT of 100°F

will prevent pressurizer pressure from exceeding the minimum P-T limit allowed for the lowest system temperature during the LTOP mode of operation. During RCS cooldown using the shutdown cooling system, coolant circulating with the reactor coolant pumps serves to cool the steam generator to keep the temperature difference between the reactor vessel and the steam generator minimal. Procedures will direct the operator to maintain the ΔT below approximately 20°F.

LTOP transients have not been analyzed for the simultaneous startup of more than one reactor coolant pump (RCP). Such operation is procedurally precluded since the operator starts only one RCP at a time and a second RCP is not started until system pressure is stabilized. Additionally, there is an LTOP transient alarm that should indicate that a pressure transient is occurring. Accordingly, the second RCP would not be started.

Technical Specifications require that the operator not start an RCP if the ΔT exceeds 100°F. However, as mentioned above, administrative procedures will ensure that the ΔT is maintained below approximately 20°F.

The calculated peak reactor coolant system pressure resulting from the limiting LTOP energy addition transient, given a core power (including instrument uncertainty) of 4070 MWt, is less than 505 psia.

The results of the analyses show that the use of either SCS relief valve will provide sufficient pressure relief capacity to mitigate the most limiting LTOP events identified above.

5.2.2.11.2.2 Provision for Overpressure Protection. During heatup, RCS pressure is maintained below the maximum pressure for SCS operation until RCS cold leg temperature exceeds the LTOP enable temperature. If SI-651 and 653 or SI-652 and 654 SCS suction isolation valves are open and RCS pressure exceeds the maximum pressure for SCS operation, an alarm will notify the operator that a pressurization transient is occurring during low temperature conditions. Either SCS relief valve will terminate inadvertent pressure transients occurring during RCS temperature below the LTOP enable temperature. Above the maximum LTOP temperature, overpressure protection is provided by the pressurizer safety valves when the SCS relief valve is isolated from the RCS.

During cooldown whenever RCS cold leg temperature is below the applicable temperature for LTOP, the SCS relief valves provide the necessary protection. If the SCS is not aligned to the RCS before cold leg temperature is decreased to the maximum temperature requiring LTOP, an alarm will notify the operator to open the SCS suction isolation valves (SI-651, 652, 653, 654). The maximum temperature requiring LTOP is based upon the evaluation of the applicable P-T curves. However, the SCS can not be aligned to the RCS until the pressure is below the maximum pressure allowing SCS operation (see paragraph 5.4.7).

These LTOP conditions are within the SCS operating range. Technical Specifications require the SCS suction line isolation valves to be open when operating in the LTOP mode. Also, Technical Specifications ensure that appropriate action is

taken if one or more SCS relief valves are out of service during the LTOP mode of operation.

Either SCS relief valve will provide sufficient relief capacity to prevent any pressure transient from exceeding the isolation interlock setpoint.

5.2.2.11.2.3 Equipment Parameters. The SCS relief valves are spring-loaded liquid relief valves with sufficient capacity to mitigate the most limiting overpressurization event. Pertinent valve parameters are as follows:

Parameter

Nominal Setpoint 467 psig

Accumulation 10%

Capacity 5635 (@ 10% acc) gal/min

Since each SCS relief valve is a self actuating spring-loaded liquid relief valve, control circuitry is not required. The valve will open when RCS pressure exceeds its setpoint.

The SCS relief valves are sized, based on an inadvertent safety injection actuation signal (SIAS) with full pressurizer heaters operating from a water-solid condition. The SIAS assumes simultaneous operation of two HPSI pumps and three charging pumps with letdown isolated. The resulting flow capacity requirement for water is less than 4000 gpm. The analysis in Section 5.2.2.11.2.1 assumed that either SCS relief valve relieved water at this rate. The design relief capacity of each of two SCS relief valves as supplied by the valve

manufacturer meets the minimum required relief capacity which contains sufficient margin in relieving capacity for even the worst transient. The SCS relief valves are Safety Class 2, designed to Section III of the ASME Code.

5.2.2.11.2.4 Administrative Controls. Administrative controls necessary to implement the LTOP provisions are limited to those controls that open the SCS isolation valves. Before entering the low temperature region for which overpressure protection is necessary, RCS pressure is decreased to below the maximum pressure required for SCS operation. Once the SCS is aligned, no further specific administrative procedural controls are needed to ensure proper overpressure protection. The SCS will remain aligned whenever the RCS is at low temperatures and the reactor vessel head is secured. As designated in Table 7.5-1, indication of SCS isolation valve position is provided.

5.2.3 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

5.2.3.1 Material Specifications

A list of specifications for the principal ferritic materials, austenitic stainless steels, bolting and weld materials, which are part of the reactor coolant pressure boundary is given in Table 5.1-2.

Studies have shown that the irradiation induced mechanical property changes of SA-533B materials can depend significantly upon the amount of residual elements present in the compositions, namely; copper, phosphorous, and vanadium. It

has also been found that residual sulfur affects the initial toughness of SA-533B materials. Specific controls are placed on the residual chemistry of reactor vessel plates and the as-deposited welds used to join these plates to limit the maximum predicted increase in the reference temperature (RT_{NDT}, which is discussed in Section 5.3.1.6) and to limit the extent of the reactor vessel beltline. The beltline is defined by Appendix G of 10CFR50. In addition, for steam generator tubing, RCS piping nozzles and pressurizer heater sleeve plugs, SB-163, SB-166, or Alloy 690 is used at PVNGS.

In addition, pressurizer heater sleeve plugs are also fabricated from SA-479 TP316 material.

For CEDM and RVLMS housings, the pressure housings are manufactured from SA-213TP316, SA-479 Type 316, SA-182, F347, Code Case N-4-11, and SB-166 Alloy 690 materials.

Relief Request 17 allows use of a code alternative for mechanical nozzle seal assemblies (MNSAs). The NRC approved Relief Request 17 in a safety evaluation dated October 01, 2001. The APS submittal (dated April 01, 2001, letter no. 102-04551) requesting Relief Request 17, committed to the following actions for all approved MNSA applications (RCS system hot leg pipe nozzles and RCS pressurizer heater sleeves) should MNSAs need to be used in any of the Palo Verde units:

(1) As required by IWA-4820, a VT-I preservice inspection will be performed on all MNSA installations in accordance with IWB-2200.

(2) During plant startup (Mode 3) after initial MNSA installation and during subsequent plant restarts following outages, the pressurizer heater sleeve MNSAs will be pressure tested and inspected for leakage. To ensure quality of installation and continued operation with the absence of leakage, a pressure test with visual inspection will be performed on each of the installed MNSAs with the insulation removed. The test will be performed as part of plant re-start and will be conducted at normal operating pressure with the test temperature determined in accordance with the PVNGS Pressure and Temperature Limits as stated in PVNGS Technical Specifications. Additionally, VT-3 exams will be performed to verify general structural and mechanical condition of the MNSAs.

(3) This request for alternative is for up to two cycles of operation, unless additional relief is requested and approved. Prior to exceeding two operating cycles, installed MNSAs will be removed and appropriate repair or replacement activities will be implemented.

(4) APS will verify pipe wall thickness prior to machining MNSA bolt holes to further assure that adequate pipe wall reinforcement exists.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 Reactor Coolant Chemistry

Controlled water chemistry is maintained within the RCS. Control of the reactor coolant chemistry is the function of the CVCS which is described in section 9.3.4. Water chemistry limits applicable to the RCS are given in section 9.3.4.3.

The possibility of reactor coolant leaking onto the reactor vessel head and causing corrosion of the RCS pressure boundary has been evaluated by Combustion Engineering. Testing has demonstrated that reactor coolant leakage onto surfaces of the RCS pressure boundary will not adversely affect the integrity of the pressure boundary when exposure is limited to short periods of time. The requirements of Generic Letter 88-05 have been implemented to ensure that boric acid corrosion does not lead to degradation of the RCS pressure boundary components. Therefore, the RCS has a very low probability of developing abnormal leakage, rapidly propagating failure or gross rupture.

5.2.3.2.2 Materials of Construction Compatibility with Reactor Coolant

The materials of construction used in the RCPB which are in contact with reactor coolant are designated by an "a" in Table 5.1-2. These materials have been selected to minimize corrosion and have previously demonstrated satisfactory performance in other existing operating reactor plants.

5.2.3.2.3 Compatibility with External Insulation and Environmental Atmosphere

The System 80 NSSS design scope for insulation on the RCS is limited to the major components of the RCS. The insulation provided within the System 80 design scope is of the stainless steel reflective type. This insulation minimizes contamination in the event of chemical solution spillage.

Insulation provided for the steam generators is also of the stainless steel reflective type. Further discussion is provided in section 6.2.2.2.

In addition, tables 6.2.2-1 and 6.2.2-2 present a list of insulation utilized on other piping and equipment inside the containment.

5.2.3.3 Fabrication and Processing Ferritic Materials

5.2.3.3.1 Fracture Toughness

5.2.3.3.1.1 Components in the C-E, Ansaldo or Doosan Scope of Supply.

NSSS Components. Fracture toughness requirements for Reactor Coolant Pressure Boundary components are established in accordance with the ASME Boiler and Pressure Vessel Code, Section III. Data from these tests will be available after the required testing has been performed and may be examined upon request at the appropriate manufacturing facility. Fracture toughness testing was performed in accordance with applicable ASME Code and Addenda.

C-E and Ansaldo complied with 10CFR Part 50 Appendix G, "Fracture Toughness Requirements" as enacted July 1973 with the following exceptions:

A. Section II, "Definitions," A. "ASME Code." The applicable Code Edition and Addenda for each System 80 plant will be as specified in 10CFR Part 50.55a, "Codes and Standards"

B. Section III, "Fracture Toughness Tests", B.5 Mill test reports containing fracture toughness test results do not include a certification that the tests have been performed in accordance with the requirements of 10CFR50 Appendix G. However, the test reports are certified to conform with the requirements of the applicable ASME Code Edition and Addenda specified in the component purchase order. Appendix G to 10CFR50 references the ASME Code for fracture toughness testing requirements; therefore, conformance with the applicable Code meets the intent of Section III B.5.a. Conformance with the Code also entails the certification requirements set forth in item III B.5.b., c., and d.

C. Section III, C.2. Excess material for the test specimens representing reactor vessel beltline weldments is not necessarily from the actual production plates, although it is from the same P-number classification. The same heat of filler material and the same production welding conditions

as those used in joining the corresponding shell materials are used. Material prepared for the reactor vessel material surveillance program, however, is from the actual production plate used in the reactor vessel. Details of the materials surveillance program are found in Section 5.3.1.6.

Consideration is given to the effects of irradiation on material toughness properties in the core beltline region of the reactor vessel to assure adequate fracture toughness for the service lifetime of the vessel. Refer to Section 5.3.1.6 for discussion concerning prediction of irradiation effects and the material surveillance program. In addition, C-E complied with the guidance of Regulatory Guide 1.2, "Thermal Shock to Pressure Vessels".

Testing and measuring equipment for fracture toughness tests for the reactor vessel, replacement reactor vessel closure head, steam generators, pressurizer, piping and reactor coolant pumps are calibrated in accordance with Subarticle NB2360 of the ASME Code, Section III.

Fracture toughness data for the reactor coolant pressure boundary components for Palo Verde Unit 1 are presented in tables 5.2-5 through 5.2-31, data for Unit 2 are presented in tables 5.2-5A through 5.2-31A, and data for Unit 3 are presented in tables 5.2-5B through 5.2-31B. A schematic of the reactor vessel beltline region showing weld seam numbers and plate code numbers is shown in figure 5.2-6.

Charpy transition curves (including upper and lower shelf levels for energy absorbed, lateral expansion, and percent cleavage fracture) for the six belt line plate materials, obtained from specimens tested in the weak direction (transverse orientation), are shown in figure 5.2-1 for Unit 1, figure 5.2-2 for Unit 2, and figure 5.2-3 for Unit 3. The personnel performing the Charpy and drop height impact testing were qualified by schooling, training, and many years of experience. Their qualification to perform work was certified by qualified supervisory personnel. Records of the certification of personnel are maintained and available for review at C-E's Chattanooga facility.

Individuals performing inservice fracture toughness tests shall be qualified by training and experience and shall have demonstrated competency to perform the tests in accordance with written procedures and ASME Code, Section III, Subarticle NB-2300, Fracture Toughness Requirements for Materials. The recommendations for qualification of nuclear power plant inspection, examination, and testing personnel that are included in ANSI N45.2.6-1973 are generally acceptable and provide an adequate basis for complying with Paragraph III.B.4 of Appendix G, 10CFR50.

All beltline welds are fabricated using submerged arc and shielded metal arc technique.

Table 5.2-5

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

REACTOR VESSEL (PLATES)

Piece Number	Reference Drawing No.:	Material Code No:	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} (°F)	Minimum Upper Shelf Energy (ft-lbs)
142-102	E-78173-161-003-02	M-4311-1	SA533-GRB-CL1	Lower Shell Plate	-10	-10[a]	134
142-102	E-78173-161-003-02	M-4311-2	SA533-GRB-CL1	Lower Shell Plate	-40	-40[a]	127
142-102	E-78173-161-003-02	M-4311-3	SA533-GRB-CL1	Lower Shell Plate	-20	-20[a]	142
124-102	E-78173-161-003-02	M-6701-1	SA533-GRB-CL1	Intermediate Shell Plate	-40	+30[a]	83
124-102	E-78173-161-003-02	M-6701-2	SA533-GRB-CL1	Intermediate Shell Plate	-50	+40[a]	96
124-102	E-78173-161-003-02	M-6701-3	SA533-GRB-CL1	Intermediate Shell Plate	-30	+40[a]	100
122-102	E-78173-161-003-02	M-6701-4	SA533-GRB-CL1	Upper Shell Plate	-30	+60[a]	N/A
122-102	E-78173-161-003-02	M-6701-5	SA533-GRB-CL1	Upper Shell Plate	-30	+40[a]	N/A
122-102	E-78173-161-003-02	M-6701-6	SA533-GRB-CL1	Upper Shell Plate	-30	+40[a]	N/A
150-102	E-78173-161-003-02	M-6715-1	SA533-GRB-CL1	Bottom Head Dome	-30	-30[a]	N/A
150-102	E-78173-161-003-02	M-6715-2	SA533-GRB-CL1	Bottom Head Dome	-40	-10[a]	N/A

a. Determined per applicable ASME B&PV-Code, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

N/A Not applicable (no minimum upper shelf requirement).

Table 5.2-5A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

REACTOR VESSEL (PLATES)

Piece Number	Reference Drawing No.:	Material Code No:	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} [(a)] (°F)	Minimum Upper Shelf Energy (ft-lbs)
122-102	E-79173-161-003-02	F-765-01	SA533-GRB-CL1	Upper Shell Plate	-30	0	N/A
122-102	E-79173-161-003-02	F-765-02	SA533-GRB-CL1	Upper Shell Plate	-40	10	N/A
122-102	E-79173-161-003-02	F-765-03	SA533-GRB-CL1	Upper Shell Plate	-30	0	N/A
124-102	E-79173-161-003-02	F-765-04	SA533-GRB-CL1	Intermediate Shell	-30	-20	114
124-102	E-79173-161-003-02	F-765-05	SA533-GRB-CL1	Intermediate Shell	-20	10	121
124-102	E-79173-161-003-02	F-765-06	SA533-GRB-CL1	Intermediate Shell	-30	10	126
150-102	E-79173-161-003-02	F-771-01	SA533-GRB-CL1	Bottom Head Plate	-90	-50	N/A
150-102	E-79173-161-003-02	F-771-02	SA533-GRB-CL1	Bottom Head Plate	-70	-50	N/A
142-102	E-79173-161-003-02	F-773-01	SA533-GRB-CL1	Lower Shell Plate	-40	10	105
142-102	E-79173-161-003-02	F-773-02	SA533-GRB-CL1	Lower Shell Plate	-50	0	127
142-102	E-79173-161-003-02	F-773-03	SA533-GRB-CL1	Lower Shell Plate	-60	-60	129

a. Determined per application ASME B&PV Code, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

Table 5.2-5B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR VESSEL (PLATES)

Piece Number	Reference Drawing No.:	Material Code No:	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} (°F)	Minimum Upper Shelf Energy(ft-lbs)
122-102	E-65173-161-003-03	F-6407-01	SA533-GRB-CL1	Upper Shell Plate	-20	-20[a]	N/A
122-102	E-65173-161-003-03	F-6407-02	SA533-GRB-CL1	Upper Shell Plate	-30	-30[a]	N/A
122-102	E-65173-161-003-03	F-6407-03	SA533-GRB-CL1	Upper Shell Plate	-20	-20[a]	N/A
124-102	E-65173-161-003-03	F-6407-04	SA533-GRB-CL1	Intermediate Shell Plate	-30	-30[a]	129
124-102	E-65173-161-003-03	F-6407-05	SA533-GRB-CL1	Intermediate Shell Plate	-20	-20[a]	114
124-102	E-65173-161-003-03	F-6407-06	SA533-GRB-CL1	Intermediate Shell Plate	-20	-20[a]	133
150-102	E-65173-161-003-03	F-6410-01	SA533-GRB-CL1	Bottom Head Plate	-70	-60[a]	N/A
150-102	E-65173-161-003-03	F-6410-02	SA533-GRB-CL1	Bottom Head Plate	-70	-70[a]	N/A
142-102	E-65173-161-003-03	F-6411-01	SA533-GRB-CL1	Lower Shell Plate	-40	-40[a]	156
142-102	E-65173-161-003-03	F-6411-02	SA533-GRB-CL1	Lower Shell Plate	-10	- 0[a]	111
142-102	E-65173-161-003-03	F-6411-03	SA533-GRB-CL1	Lower Shell Plate	-60	-60[a]	107

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

Table 5.2-6

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 1 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-001	N05065-01-01	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-002	N05065-01-02	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-003	N05065-01-03	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-004	N05065-01-04	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-005	N05065-01-05	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-006	N05065-01-06	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-007	N05065-01-07	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-008	N05065-01-08	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-009	N05065-01-09	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-010	N05065-01-10	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-011	N05065-01-11	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-012	N05065-01-12	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-013	N05065-01-13	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-014	N05065-01-14	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-015	N05065-01-15	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-016	N05065-01-16	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-017	N05065-01-17	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-018	N05065-01-18	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-019	N05065-01-19	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-020	N05065-01-20	Modified Type 403[a]	60

Table 5.2-6

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 2 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-021	N05065-01-21	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-022	N05065-01-22	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-023	N05065-01-23	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-024	N05065-01-24	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-025	N05065-01-25	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-026	N05065-01-26	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-027	N05065-01-27	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-028	N05065-01-28	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-029	N05065-01-29	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-030	N05065-01-30	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-031	N05065-01-31	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-032	N05065-01-32	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-033	N05065-01-33	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-034	N05065-01-34	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-035	N05065-01-35	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-036	N05065-01-36	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-037	N05065-01-37	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-038	N05065-01-38	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-039	N05065-01-39	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-040	N05065-01-40	Modified Type 403[a]	60

Table 5.2-6

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 3 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-041	N05065-01-41	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-042	N05065-01-42	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-043	N05065-01-43	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-044	N05065-01-44	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-045	N05065-01-45	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-046	N05065-01-46	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-047	N05065-01-47	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-048	N05065-01-48	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-049	N05065-01-49	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-050	N05065-01-50	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-051	N05065-01-51	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-052	N05065-01-52	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-053	N05065-01-53	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-054	N05065-01-54	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-055	N05065-01-55	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-056	N05065-01-56	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-057	N05065-01-57	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-058	N05065-01-58	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-059	N05065-01-59	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-060	N05065-01-60	Modified Type 403[a]	60

Table 5.2-6

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 4 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-061	N05065-01-61	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-062	N05065-01-62	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-063	N05065-01-63	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-064	N05065-01-64	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-065	N05065-01-65	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-066	N05065-01-66	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-067	N05065-01-67	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-068	N05065-01-68	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-069	N05065-01-69	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-070	N05065-01-70	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-071	N05065-01-71	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-072	N05065-01-72	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-073	N05065-01-73	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-074	N05065-01-74	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-075	N05065-01-75	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-076	N05065-01-76	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-077	N05065-01-77	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-078	N05065-01-78	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-079	N05065-01-79	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-080	N05065-01-80	Modified Type 403[a]	60

Table 5.2-6

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 5 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-081	N05065-01-81	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-082	N05065-01-82	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-083	N05065-01-83	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-084	N05065-01-84	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-085	N05065-01-85	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-086	N05065-01-86	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-087	N05065-01-87	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-088	N05065-01-88	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV1R6000-089	N05065-01-89	Modified Type 403[a]	60

a. See Code Case N-4-11, Special Type 403 Modified Forgings or Bars, Section III, Division 1, Class 1 and CS

b. Lowest service temperature per NB-2332, required Cv values per Table 2332(a)-1, nominal wall thickness > 3/4 inch but $\leq$ 1-1/2 inches

Table 5.2-6A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 1 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-001	N05065-02-01	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-002	N05065-02-02	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-003	N05065-02-03	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-004	N05065-02-04	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-005	N05065-02-05	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-006	N05065-02-06	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-007	N05065-02-07	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-008	N05065-02-08	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-009	N05065-02-09	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-010	N05065-02-10	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-011	N05065-02-11	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-012	N05065-02-12	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-013	N05065-02-13	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-014	N05065-02-14	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-015	N05065-02-15	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-016	N05065-02-16	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-017	N05065-02-17	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-018	N05065-02-18	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-019	N05065-02-19	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-020	N05065-02-20	Modified Type 403[a]	60

Table 5.2-6A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 2 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-021	N05065-02-21	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-022	N05065-02-22	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-023	N05065-02-23	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-024	N05065-02-24	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-025	N05065-02-25	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-026	N05065-02-26	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-027	N05065-02-27	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-028	N05065-02-28	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-029	N05065-02-29	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-030	N05065-02-30	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-031	N05065-02-31	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-032	N05065-02-32	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-033	N05065-02-33	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-034	N05065-02-34	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-035	N05065-02-35	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-036	N05065-02-36	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-037	N05065-02-37	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-038	N05065-02-38	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-039	N05065-02-39	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-040	N05065-02-40	Modified Type 403[a]	60

Table 5.2-6A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 3 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-041	N05065-02-41	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-042	N05065-02-42	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-043	N05065-02-43	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-044	N05065-02-44	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-045	N05065-02-45	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-046	N05065-02-46	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-047	N05065-02-47	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-048	N05065-02-48	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-049	N05065-02-49	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-050	N05065-02-50	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-051	N05065-02-51	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-052	N05065-02-52	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-053	N05065-02-53	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-054	N05065-02-54	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-055	N05065-02-55	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-056	N05065-02-56	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-057	N05065-02-57	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-058	N05065-02-58	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-059	N05065-02-59	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-060	N05065-02-60	Modified Type 403[a]	60

Table 5.2-6A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 4 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-061	N05065-02-61	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-062	N05065-02-62	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-063	N05065-02-63	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-064	N05065-02-64	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-065	N05065-02-65	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-066	N05065-02-66	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-067	N05065-02-67	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-068	N05065-02-68	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-069	N05065-02-69	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-070	N05065-02-70	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-071	N05065-02-71	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-072	N05065-02-72	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-073	N05065-02-73	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-074	N05065-02-74	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-075	N05065-02-75	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-076	N05065-02-76	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-077	N05065-02-77	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-078	N05065-02-78	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-079	N05065-02-79	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-080	N05065-02-80	Modified Type 403[a]	60

Table 5.2-6A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 5 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-081	N05065-02-81	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-082	N05065-02-82	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-083	N05065-02-83	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-084	N05065-02-84	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-085	N05065-02-85	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-086	N05065-02-86	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-087	N05065-02-87	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-088	N05065-02-88	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV2R6000-089	N05065-02-89	Modified Type 403[a]	60

a. See Code Case N-4-11, Special Type 403 Modified Forgings or Bars, Section III, Division 1, Class 1 and CS

b. Lowest service temperature per NB-2332, required Cv values per Table 2332(a)-1, nominal wall thickness > 3/4 inch but $\leq$ 1-1/2 inches

Table 5.2-6B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 1 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-001	N05065-03-01	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-002	N05065-03-02	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-003	N05065-03-03	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-004	N05065-03-04	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-005	N05065-03-05	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-006	N05065-03-06	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-007	N05065-03-07	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-008	N05065-03-08	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-009	N05065-03-09	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-010	N05065-03-10	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-011	N05065-03-11	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-012	N05065-03-12	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-013	N05065-03-13	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-014	N05065-03-14	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-015	N05065-03-15	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-016	N05065-03-16	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-017	N05065-03-17	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-018	N05065-03-18	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-019	N05065-03-19	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-020	N05065-03-20	Modified Type 403[a]	60

Table 5.2-6B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 2 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-021	N05065-03-21	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-022	N05065-03-22	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-023	N05065-03-23	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-024	N05065-03-24	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-025	N05065-03-25	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-026	N05065-03-26	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-027	N05065-03-27	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-028	N05065-03-28	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-029	N05065-03-29	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-030	N05065-03-30	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-031	N05065-03-31	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-032	N05065-03-32	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-033	N05065-03-33	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-034	N05065-03-34	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-035	N05065-03-35	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-036	N05065-03-36	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-037	N05065-03-37	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-038	N05065-03-38	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-039	N05065-03-39	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-040	N05065-03-40	Modified Type 403[a]	60

Table 5.2-6B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 3 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-041	N05065-03-41	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-042	N05065-03-42	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-043	N05065-03-43	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-044	N05065-03-44	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-045	N05065-03-45	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-046	N05065-03-46	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-047	N05065-03-47	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-048	N05065-03-48	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-049	N05065-03-49	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-050	N05065-03-50	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-051	N05065-03-51	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-052	N05065-03-52	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-053	N05065-03-53	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-054	N05065-03-54	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-055	N05065-03-55	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-056	N05065-03-56	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-057	N05065-03-57	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-058	N05065-03-58	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-059	N05065-03-59	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-060	N05065-03-60	Modified Type 403[a]	60

Table 5.2-6B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 4 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-061	N05065-03-61	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-062	N05065-03-62	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-063	N05065-03-63	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-064	N05065-03-64	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-065	N05065-03-65	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-066	N05065-03-66	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-067	N05065-03-67	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-068	N05065-03-68	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-069	N05065-03-69	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-070	N05065-03-70	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-071	N05065-03-71	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-072	N05065-03-72	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-073	N05065-03-73	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-074	N05065-03-74	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-075	N05065-03-75	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-076	N05065-03-76	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-077	N05065-03-77	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-078	N05065-03-78	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-079	N05065-03-79	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-080	N05065-03-80	Modified Type 403[a]	60

Table 5.2-6B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

CONTROL ELEMENT DRIVE MECHANISM MAGNETIC JACK MOTOR HOUSING

(Sheet 5 of 5)

Piece No.	Reference Drawing No.	Motor Housing Serial Number	Name Plate Stencil Serial No.	Material	Lowest Service Temp. (°F)[b]
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-081	N05065-03-81	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-082	N05065-03-82	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-083	N05065-03-83	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-084	N05065-03-84	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-085	N05065-03-85	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-086	N05065-03-86	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-087	N05065-03-87	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-088	N05065-03-88	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-089	N05065-03-89	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-090[c]	N05065-03-90[c]	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-091[c]	N05065-03-91[c]	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-092[c]	N05065-03-92[c]	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-093[c]	N05065-03-93[c]	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-094[c]	N05065-03-94[c]	Modified Type 403[a]	60
D-PV-13260-C01-3	D-PV-13260-C01	PV3R6000-095[c]	N05065-03-95[c]	Modified Type 403[a]	60

a. See Code Case N-4-11, Special Type 403 Modified Forgings or Bars, Section III, Division 1, Class 1 and CS

b. Lowest service temperature per NB-2332, required Cv values per Table 2332(a)-1, nominal wall thickness > 3/4 inch but $\leq$ 1-1/2 inches

c. 6(Six) motor housings supplied as spare loose parts

Table 5.2-7
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
REACTOR VESSEL (FORGINGS)

Piece Number	Reference Drawing No.	Material Code No.	Material Specification	Location	Drop Weight NDT (°F)		RT_{NDT} (°F)	
					0°	180°	0°	180°
128-301	E-78173-161-003-02	M-4304-1	SA508-CL2	Outlet Nozzle	-10	-10	-10[a]	-10[a]
128-301	E-78173-161-003-02	M-4304-2	SA508-CL2	Outlet Nozzle	-10	-10	-10[a]	-10[a]
131-102	E-78173-161-003-02	M-4307-1	SA508-CL2	Outlet Nozzle Safe End	-10	-10	+10[a]	+10[a]
131-102	E-78173-161-003-02	M-4307-2	SA508-CL2	Outlet Nozzle Safe End	-10	-10	+10[a]	+10[a]
128-101	E-78173-161-003-02	M-6703-1	SA508-CL2	Inlet Nozzle	-20	-20	0[a]	0[a]
128-101	E-78173-161-003-02	M-6703-2	SA508-CL2	Inlet Nozzle	+10	+10	+10[a]	+10[a]
128-101	E-78173-161-003-02	M-6703-3	SA508-CL2	Inlet Nozzle	-10	-10	-10[a]	-10[a]
128-101	E-78173-161-003-02	M-6703-4	SA508-CL2	Inlet Nozzle	0	0	0[a]	0[a]
126-101	E-78173-161-003-02	M-6705-1	SA508-CL2	Vessel Flange	-70	-70	-70[a]	-70[a]
02-201	D-PV-11102-C02		SA508-GR3-CL1	Closure Head Assembly	-45	-45-	-45[a]	-45[a]
128-501	E-78173-161-003-02	M-6708-1	SA508-CL2	Inlet Nozzle Extension	+20	+20	+20[a]	+20[a]
128-501	E-78173-161-003-02	M-6708-2	SA508-CL2	Inlet Nozzle Extension	+20	+20	+20[a]	+20[a]
128-501	E-78173-161-003-02	M-6708-3	SA508-CL2	Inlet Nozzle Extension	+20	+20	+20[a]	+20[a]
128-501	E-78173-161-003-02	M-6708-4	SA508-CL2	Inlet Nozzle Extension	+20	+20	+20[a]	+20[a]
131-101	E-78173-161-003-02	M-6712-1	SA508-CL1	Inlet Nozzle Safe End	-10	-10	-10[a]	-10[a]
131-101	E-78173-161-003-02	M-6712-2	SA508-CL1	Inlet Nozzle Safe End	-10	-10	-10[a]	-10[a]
131-101	E-78173-161-003-02	M-6712-3	SA508-CL1	Inlet Nozzle Safe End	-10	-10	-10[a]	-10[a]
131-101	E-78173-161-003-02	M-6712-4	SA508-CL1	Inlet Nozzle Safe End	-10	-10	-10[a]	-10[a]

a. Determined per applicable ASME B&PV Code and addenda, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

Table 5.2-7A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

REACTOR VESSEL (FORGINGS)

Piece Number	Reference Drawing No.	Material Code No.	Material Specification	Location	Drop Weight NDT (°F) 0-DEG	Drop Weight NDT (°F) 180-DEG	RT_{NDT} (°F)	
							0-DEG or LST[c]	180-DEG
02-201	D-PV-11102-C02		SA508-GR3-CL1	Closure Head Assembly	-45	-45	-45[a]	-45[a]
126-101	E-79173-161-003-02	F-762-01	SA508-CL2	Vessel Flange Forging	-40	-40	-40[a]	-40[a]
128-301	E-79173-161-003-02	F-764-01	SA508-CL2	Outlet Nozzle	-10	-10	-10[a]	-10[a]
128-301	E-79173-161-003-02	F-764-02	SA508-CL2	Outlet Nozzle	-10	-10	-10[a]	-10[a]
131-101	E-79173-161-003-02	F-766-01	SA508-CL1	Inlet Noz. Safe End	-10	-10	-10[a]	-10[a]
131-101	E-79173-161-003-02	F-766-02	SA508-CL1	Inlet Noz. Safe End	0	0	+10[a]	+10[a]
131-101	E-79173-161-003-02	F-766-03	SA508-CL1	Inlet Noz. Safe End	0	0	+10[a]	+10[a]
131-101	E-79173-161-003-02	F-766-04	SA508-CL1	Inlet Noz. Safe End	-30	-30	-20[a]	-20[a]
131-102	E-79173-161-003-02	F-767-01	SA508-CL1	Outlet Noz. Safe End	-30	-30	-10[a]	-10[a]
131-102	E-79173-161-003-02	F-767-02	SA508-CL1	Outlet Noz. Safe End	-30	-30	-10[a]	-10[a]
128-201	E-79173-161-003-02	F-774-01	SA508-CL3	Inlet Nozzle	-20	-20	-20[a]	-20[a]
128-201	E-79173-161-003-02	F-774-02	SA508-CL3	Inlet Nozzle	-30	-30	-30[a]	-30[a]
128-201	E-79173-161-003-02	F-774-03	SA508-CL3	Inlet Nozzle	-40	-40	-30[b]	-30[b]
128-201	E-79173-161-003-02	F-774-04	SA508-CL3	Inlet Nozzle	-40	-40	-40[a]	-40[a]

a. Determined per applicable ASME B&PV Code and addenda, Section III, Article NB-2331-(a-1, 2, 3)

b. Determined per applicable ASME B&PV Code and addenda, Section III, Article NB-2331-(a-4)

c. Lowest service temperature

Table 5.2-7B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR VESSEL (FORGINGS)

Piece Number	Reference Drawing No.	Material Code No.	Material Specification	Location	Drop Weight NDT (°F)		RT_{NDT} (°F)	
					0°	180°	0°/LST[b]	180°
02-201	D-PV-11102-C02		SA508-GR3CL1	Closure Head Assembly	-45	-45	-45[a]	-45[a]
126-101	E-65173-161-003-03	F-6402-01	SA508-CL2	Vessel Flange Forging	-40	-40	-40[a]	-40[a]
128-3301	E-65173-161-003-03	F-6404-01	SA508-CL3	Outlet Nozzle	-20	-20	+10[a]	+10[a]
128-3301	E-65173-161-003-03	F-6404-02	SA508-CL3	Outlet Nozzle	-20	-20	+10[a]	+10[a]
131-3302	E-65173-161-003-03	F-6405-01	SA508-CL1	Outlet Nozzle Safe End	-30	-30	+10[a]	+10[a]
131-3302	E-65173-161-003-03	F-6405-02	SA508-CL1	Outlet Nozzle Safe End	-30	-30	+10[a]	+10[a]
131-3301	E-65173-161-003-03	F-6406-01	SA508-CL1	Inlet Nozzle Safe End	-20	-20	+20[a]	-20[a]
131-3301	E-65173-161-003-03	F-6406-02	SA508-CL1	Inlet Nozzle Safe End	-20	-20	+20[a]	-20[a]
131-3301	E-65173-161-003-03	F-6406-03	SA508-CL1	Inlet Nozzle Safe End	-20	-20	+20[a]	-20[a]
131-3301	E-65173-161-003-03	F-6406-04	SA508-CL1	Inlet Nozzle Safe End	-20	-20	+20[a]	-20[a]
128-3201	E-65173-161-003-03	F-6409-01	SA508-CL3	Inlet Nozzle	-50	-50	-50[a]	-50[a]
128-3201	E-65173-161-003-03	F-6409-02	SA508-CL3	Inlet Nozzle	-60	-60	-60[a]	-60[a]
128-3201	E-65173-161-003-03	F-6409-03	SA508-CL3	Inlet Nozzle	-30	-30	-30[a]	-30[a]
128-3201	E-65173-161-003-03	F-6409-04	SA508-CL3	Inlet Nozzle	-40	-40	-40[a]	-40[a]

a. Determined per applicable ASME B&PV Code and Addenda, Section III, Article NB-2331-(a-1, 2, 3)

b. Lowest service temperature

Table 5.2-8

PVNGS UNITS 1, 2, AND 3 REACTOR COOLANT PRESSURE BOUNDARY WELD SEAM IDENTIFICATION: REACTOR VESSEL

Seam No.	Weld Seam Nomenclature
202-128 A-D	Inlet nozzle extension to inlet nozzle safe end
201-141	Lower shell course to bottom head dome
101-142 A-C[a]	Lower shell long seam
101-150	Bottom head segment joining seams
101-171[a]	Lower shell course to intermediate shell course girth seam
101-121	Intermediate shell course to upper shell course girth seam
103-121 A-D	Inlet nozzle to intermediate shell course
105-121 A and B	Outlet nozzle to intermediate shell course
201-121	Vessel flange to upper shell course
101-122 A-C	Upper shell long seams
101-124 A-C[a]	Intermediate shell long seams
401-128 A and B	Outlet nozzle to outlet nozzle safe end
201-128 A-D	Inlet nozzle to inlet nozzle extension

a. Belt Line Welds

Table 5.2-9

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 1 of 6)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-121	Flux electrode comb. (SAA)	0091	0653	-50	-50
101-121	Flux electrode comb. (SAA)	0091	0653	-60	-60
101-121	Flux electrode comb. (SAA)	0091	1054	-60	-60
101-121	Flux electrode comb. (SAA)e	0091	0653	-30	-30
101-122	Flux electrode comb. (SAA)	0091	0145	-70	-70
101-122	Flux electrode comb. (SAA)	0091	0145	-50	-50
101-122	Flux electrode comb. (SAA)	0091	0842	-60	-60
101-122	Flux electrode comb. (SAA)	0091	0842	-50	-50
101-124A	Flux electrode comb. (SAA)	0091	0145	-50	-50

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-9

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 2 of 6)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-142A	Flux electrode comb. (SAA)	0091	1054	-80	-80
101-150	Flux electrode comb. (SAA)	124	0751	-60	-60
101-171	Flux electrode comb. (SAA)	124	1061	-70	-70
103-121	Flux electrode comb. (SAA)	124	0951	-60	-60
103-121	Flux electrode comb. (SAA)	124	0951	-80	-70
103-121	Flux electrode comb. (SAA)	0091	1054	-70	-70
103-121	Flux electrode comb. (SAA)	124	0951	-60	-60
103-121	Flux electrode comb. (SAA)	124	0662	-70	-70
103-121	Flux electrode comb. (SAA)	124	0662	-60	-60
105-121	Flux electrode comb. (SAA)	0091	1054	-70	-70
201-121	Flux electrode comb. (SAA)	124	1061	-70	-70
201-121	Flux electrode comb. (SAA)	124	1061	-80	-80
201-128	Flux electrode comb. (SAA)	0091	0653	-30	-30
201-128	Flux electrode comb. (SAA)	0091	1054	-60	-60
201-141	Flux electrode comb. (SAA)	124	0662	-80	-80

Table 5.2-9

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 3 of 6)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
202-128	Flux electrode comb. (SAA)	0091	1054	-70	-70
202-128	Flux electrode comb. (SAA)	124	0751	-50	-50
401-128	Flux electrode comb. (SAA)	80-20	0344	-40	-20
401-128	Flux electrode comb. (SAA)	80-20	0351	-20	-20

Table 5.2-9

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 4 of 6)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-121	Coated electrode (MA)	JAACE	-70	-70
101-121	Coated electrode (MA)	IA0JE	-80	-80
101-122	Coated electrode (MA)	HAAID	-50	-50
101-122	Coated electrode (MA)	FA0ED	-60	-60
101-122	Coated electrode (MA)	GABFE	-60	-60
101-122	Coated electrode (MA)	FA0JE	-60	-60
101-122	Coated electrode (MA)	HAACE	-70	-70
101-122	Coated electrode (MA)	HA0EE	-70	-70
101-122	Coated electrode (MA)	IA0JE	-80	-80
101-122	Coated electrode (MA)	AABHG	-60	-60
101-124A	Coated electrode (MA)	HAAID	-50	-50
101-124A	Coated electrode (MA)	FA0ED	-60	-60
101-124A	Coated electrode (MA)	JAAEF	-60	-60
101-124A	Coated electrode (MA)	GABFE	-60	-60
101-124A	Coated electrode (MA)	HAOEE	-70	-70
101-124A	Coated electrode (MA)	HAACE	-70	-70
101-124A	Coated electrode (MA)	BABEF	-70	-70
101-142A	Coated electrode (MA)	IAOCE	-80	-80
101-142A	Coated electrode (MA)	BABEF	-70	-70
101-142A	Coated electrode (MA)	KA0GE	-70	-70
101-142A	Coated electrode (MA)	JAAEF	-60	-60
101-150	Coated electrode (MA)	AA0HF	-80	-80
101-150	Coated electrode (MA)	JAAEF	-60	-60
101-150	Coated electrode (MA)	IA0CE	-80	-80

Table 5.2-9

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 5 of 6)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-150	Coated electrode (MA)	KAOGE	-70	-70
101-150	Coated electrode (MA)	FAAFF	-70	-70
101-171	Coated electrode (MA)	DABGG	-70	-70
101-171	Coated electrode (MA)	FABBG	-50	-50
101-171	Coated electrode (MA)	DBBJG	-70	-70
103-121	Coated electrode (MA)	AA0HF	-80	-80
103-121	Coated electrode (MA)	HABIE	-80	-80
103-121	Coated electrode (MA)	KA0GE	-70	-70
103-121	Coated electrode (MA)	FAAHF	-60	-50
103-121	Coated electrode (MA)	AABHG	-60	-60
105-121	Coated electrode (MA)	HABJF	-70	-70
105-121	Coated electrode (MA)	IA0CE	-80	-80
105-121	Coated electrode (MA)	KA0CE	-70	-70
105-121	Coated electrode (MA)	AA0HF	-80	-80
105-121	Coated electrode (MA)	BABEF	-70	-70
201-121	Coated electrode (MA)	KABIF	-50	-50
201-121	Coated electrode (MA)	AABHG	-60	-60
201-121	Coated electrode (MA)	LAOGF	-40	-40
201-121	Coated electrode (MA)	JAAEF	-60	-60
201-128	Coated electrode (MA)	HAACE	-70	-70
201-128	Coated electrode (MA)	IA0CE	-80	-80
201-128	Coated electrode (MA)	JA0AE	-50	-50
201-141	Coated electrode (MA)	IA0BF	-70	-70
201-141	Coated electrode (MA)	BBAGG	-60	-60
201-141	Coated electrode (MA)	CA0JG	-60	-30
202-128	Coated electrode (MA)	HAAEE	-20	-20
202-128	Coated electrode (MA)	JA0CE	-50	-50
202-128	Coated electrode (MA)	FAAFF	-70	-70

Table 5.2-9

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 6 of 6)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
202-128	Coated electrode (MA)	GA0AF	-40	-40
202-128	Coated electrode (MA)	HAACE	-70	-70
202-128	Coated electrode (MA)	IA0CE	-80	-80
401-128	Coated electrode (MA)	LABHC	-50	-50

Table 5.2-9A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 1 of 4)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-121	Coated electrode (MA)	AABHG	-60	-60
101-121	Coated electrode (MA)	JAAEF	-60	-60
101-122	Coated electrode (MA)	EAAHF	-60	-40
101-122	Coated electrode (MA)	FAAFF	-70	-70
101-122	Coated electrode (MA)	FABAF	-60	-60
101-122	Coated electrode (MA)	GAOAF	-40	-40
101-128	Coated electrode (MA)	FAAFF	-70	-70
101-128	Coated electrode (MA)	FAAHF	-60	-50
101-128	Coated electrode (MA)	FABAF	-60	-60
101-142	Coated electrode (MA)	FAAFF	-70	-70
101-142	Coated electrode (MA)	LAOGF	-40	-40
101-150	Coated electrode (MA)	DABGG	-70	-70
101-150	Coated electrode (MA)	FAAFF	-70	-70
101-150	Coated electrode (MA)	LAOGF	-40	-40
101-171	Coated electrode (MA)	EAOAH	-60	-60
101-171	Coated electrode (MA)	JAOEH	-60	-30
103-121	Coated electrode (MA)	ABCAH	-60	-60
103-121	Coated electrode (MA)	BBAGG	-60	-60
103-121	Coated electrode (MA)	CAOJG	-60	-30
103-121	Coated electrode (MA)	GABGG	-50	-50
103-121	Coated electrode (MA)	HAAHG	-70	-70
103-121	Coated electrode (MA)	HABJF	-70	-70
103-121	Coated electrode (MA)	HACJG	-40	-40
103-121	Coated electrode (MA)	IABBG	-60	-60

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-9A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 2 of 4)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
103-121	Coated electrode (MA)	JAAEF	-60	-60
103-121	Coated electrode (MA)	LAOBF	-70	-70
103-121	Coated electrode (MA)	LAOGF	-40	-40
103-121	Coated electrode (MA)	LAOHG	-50	-30
105-121	Coated electrode (MA)	AABHG	-60	-60
105-121	Coated electrode (MA)	DABGG	-70	-70
105-121	Coated electrode (MA)	FABBG	-50	-50
201-121	Coated electrode (MA)	CABCG	-60	-30
201-121	Coated electrode (MA)	HACJG	-40	-40
201-141	Coated electrode (MA)	ABCAH	-60	-60
201-141	Coated electrode (MA)	BAOIG	-40	-40
201-141	Coated electrode (MA)	LAOHG	-50	-30
401-128	Coated electrode (MA)	HAOKF	-50	-50
401-128	Coated electrode (MA)	DAOAF	-40	-40
401-128	Coated electrode (MA)	BBAGG	-60	-60
401-128	Coated electrode (MA)	DABGG	-70	-70

Table 5.2-9A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[(a)]

COMPONENT: REACTOR VESSEL (Sheet 3 of 4)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[(b)] (°F)	RT_{NDT}[(b)] (°F)
101-121	Flux electrode comb. (SAA)	124	1061	-70	-70
101-121	Flux electrode comb. (SAA)	124	1061	-80	-80
101-122	Flux electrode comb. (SAA)	124	0662	-80	-30
101-122	Flux electrode comb. (SAA)	124	0662	-70	-70
101-124	Flux electrode comb. (SAA)	124	0951	-80	-60
101-142	Flux electrode comb. (SAA)	124	0662	-80	-80
101-150	Flux electrode comb. (SAA)	124	0751	-60	-60
101-150	Flux electrode comb. (SAA)	124	0951	-80	-80
101-171	Flux electrode comb. (SAA)	124	0871	-60	-30
103-121	Flux electrode comb. (SAA)	124	1061	-80	-80
105-121	Flux electrode comb. (SAA)	124	0171	-90	-90
105-121	Flux electrode comb. (SAA)	124	0171	-80	-70

Table 5.2-9A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 4 of 4)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
201-121	Flux electrode comb. (SAA)	124	0871	-80	-80
201-121	Flux electrode comb. (SAA)	124	0871	-80	-60
201-141	Flux electrode comb. (SAA)	124	0161	-50	-50
401-128	Flux electrode comb. (SAA)	124	1061	-60	-60

Table 5.2-9B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 1 of 4)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-121	Coated electrode (MA)	BAOIG	-40	-40
101-121	Coated electrode (MA)	GABGG	-50	-50
101-121	Coated electrode (MA)	LAOHG	-50	-30
101-122	Coated electrode (MA)	GABGG	-50	-50
101-122	Coated electrode (MA)	HACJG	-40	-40
101-124	Coated electrode (MA)	FABBG	-50	-50
101-124	Coated electrode (MA)	GABGG	-50	-50
101-124	Coated electrode (MA)	HACJG	-40	-40
101-142	Coated electrode (MA)	EAOAH	-60	-60
101-142	Coated electrode (MA)	HAAHG	-70	-70
101-142	Coated electrode (MA)	JAOEH	-60	-30
101-142	Coated electrode (MA)	LAOHG	-50	-30
101-171	Coated electrode (MA)	CAAIJ	-60	-60
101-171	Coated electrode (MA)	IAOHJ	-50	-50
103-121	Coated electrode (MA)	CABDI	-50	-50
103-121	Coated electrode (MA)	DAOFI	-60	-40
103-121	Coated electrode (MA)	FABAF	-50	-50
103-121	Coated electrode (MA)	FAODI	-60	-30
103-121	Coated electrode (MA)	JABCH	-60	-60
103-121	Coated electrode (MA)	JAOEH	-60	-30
103-121	Coated electrode (MA)	KAAEI	-60	-60
105-121	Coated electrode (MA)	AAOCJ	-50	-40
105-121	Coated electrode (MA)	EAOAH	-60	-60
105-121	Coated electrode (MA)	HABJF	-70	-70
105-121	Coated electrode (MA)	JABCH	-60	-60
105-121	Coated electrode (MA)	LAOHG	-50	-30

a. Per ASME B&PV Code, Section III, Article NB-2430
b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-9B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[(a)]

COMPONENT: REACTOR VESSEL (Sheet 2 of 4)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[(b)] (°F)	RT_{NDT}[(b)] (°F)
201-121	Coated electrode (MA)	FABGI	-50	-20
201-141	Coated electrode (MA)	CAAEI	-60	-60
201-141	Coated electrode (MA)	FABGI	-50	-20
203-128	Coated electrode (MA)	BAOBH	-60	-40
203-128	Coated electrode (MA)	GABGG	-50	-50
401-128	Coated electrode (MA)	FABJG	-50	-50
401-128	Coated electrode (MA)	JAOCG	-50	-50
401-128	Coated electrode (MA)	HAAHG	-70	-70

Table 5.2-9B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 3 of 4)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-121	Flux electrode comb. (SAA)	124	0281	-80	-80
101-121	Flux electrode comb. (SAA)	124	0871	-80	-70
101-121	Flux electrode comb. (SAA)	124	0871	-80	-60
101-121	Flux electrode comb. (SAA)	124	0871	-80	-80
101-122	Flux electrode comb. (SAA)	124	0871	-80	-70
101-122	Flux electrode comb. (SAA)	124	0871	-80	-60
101-124	Flux electrode comb. (SAA)	124	0171	-60	-50
101-142	Flux electrode comb. (SAA)	124	0281	-80	-50
101-150	Flux electrode comb. (SAA)	124	0281	-80	-80
101-171	Flux electrode comb. (SAA)	124	1061	-70	-70
103-121	Flux electrode comb. (SAA)	124	0281	-80	-60

Table 5.2-9B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR VESSEL (Sheet 4 of 4)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
105-121	Flux electrode comb. (SAA)	124	0281	-50	-10
201-121	Flux electrode comb. (SAA)	124	0597	-80	-40
201-121	Flux electrode comb. (SAA)	124	0597	-80	-40
201-141	Flux electrode comb. (SAA)	124	1061	-50	-50
201-141	Flux electrode comb. (SAA)	124	1061	-70	-30
203-128	Flux electrode comb. (SAA)	124	0871	-80	-80
401-128	Flux electrode comb. (SAA)	124	0871	-80	-80

Table 5.2-10

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

REACTOR VESSEL (Sheet 1 of 2)

Seam Number	Weld Procedure Qualification No.	Materials Joined[b]		Fracture Toughness[c]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-122 A-C	SAA-SMA-12.12-102	P No. 3	P No. 3	-20	0	-50	-50	-20	0
101-122 A-C	SMA-12.12-110	P No. 3	P No. 3	-50	-20	-60	-60	-50	-20
101-122 A-C	SMA-12.12-108	P No. 3	P No. 3	-40	-30	-60	-60	-40	-30
101-122 A-C	SMA-3.3-126	P No. 3	P No. 3	0	0	-40	-40	0	0
101-122 A-C	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	+10
101-124 A-C	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
101-124 A-C	SMA-12.12-108	P No. 3	P No. 3	-40	-30	-60	-60	-40	-20
101-124 A-C	SMA-12.12-110	P No. 3	P No. 3	-50	-20	-60	-60	-50	-20
101-124 A-C	SAA-SMA-12.12-102	P No. 3	P No. 3	-20	0	-50	-50	-20	0
103-121 A-D	SMA-12.12-110	P No. 3	P No. 3	-50	-20	-60	-60	-50	-20
103-121 A-D	SMA-12.12-108	P No. 3	P No. 3	-40	-30	-60	-60	-40	-20
103-121 A-D	SAA-SMA-12.12-102	P No. 3	P No. 3	-20	0	-50	-50	-20	0
103-121 A-D	SAA-SMA-3.3-106	P No. 3	P No. 3	-50	-50	-50	-50	-50	-50
103-121 A-D	SMA-3.3-126	P No. 3	P No. 3	0	0	-40	-40	0	0
103-121 A-D	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
101-128 A&B	SAA-SMA-1.12-103	P No. 1[d]	P No. 3	-10	-10	-50	-50	-20	-20
201-128 A-D	SAA-SMA-12.12-102	P No. 3	P No. 3	-20	0	-50	-50	-20	0
201-128 A-D	SMA-12.12-110	P No. 3	P No. 3	-50	-20	-60	-60	-50	-20
201-128 A-D	SMA-12.12-108	P No. 3	P No. 3	-40	-30	-60	-60	-40	-30

a. Per ASME B&PV Code Section III, Article NB 4330

b. P-number designation from ASME B&PV Code, Section IX, Article QW-420, Table QW-422

c. Fracture toughness determined per ASME B&PV Code, Section III, Article NB 2330

d. Allowable by ASME B&PV Code, Section IX, Paragraph QW-403.11 of Article IV (Welding Data)

Table 5.2-10

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

REACTOR VESSEL (Sheet 2 of 2)

Seam Number	Weld Procedure Qualification No.	Materials Joined[b]		Fracture Toughness[c]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
202-128 A-D	SAA-SMA-1.12-106	P No. 1	P No. 3	-30	-20	-70	-20	-50	-50
202-128 A-D	SMA-3.3-126	P No. 3[d]	P No. 3[d]	0	0	-40	-40	0	0
202-128 A-D	SMA-3.3-127	P No. 3[d]	P No. 3[d]	-50	10	-50	-50	-50	10
202-128 A-D	SMA-12.12-108	P No. 3[d]	P No. 3[d]	-60	-30	-60	-60	-60	-30
202-128 A-D	SMA-12.12-108	P No. 3[d]	P No. 3[d]	-50	-20	-60	-60	-50	-20
105-121 A&B	SAA-SMA-12.12-102	P No. 3	P No. 3	-20	0	-50	-50	-20	0
105-121 A&B	SMA-3.3-126	P No. 3	P No. 3	0	0	-60	-40	0	0
105-121 A&B	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
201-121	SAA-SMA-3.3-107	P No. 3	P No. 3	-50	-50	-50	-40	-50	-50
201-121	SMA-3.3-127	P No. 3	P No. 3	-50	-10	-50	-50	-50	10
101-121	SAA-SMA-3.3-103	P No. 3	P No. 3	-50	10	-60	-60	-50	40
201-141	SAA-SMA-3.3-106	P No. 3	P No. 3	-50	-50	-50	-50	-50	-50
201-141	SMA-3.3-126	P No. 3	P No. 3	0	0	-40	-40	0	0
201-141	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
101-142 A-C	SAA-SMA-3.3-103	P No. 3	P No. 3	-50	40	-60	-60	-50	40
101-141 A-C	SMA-3.3-126	P No. 3	P No. 3	0	0	-40	-40	0	0
101-141 A-C	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
101-141 A-C	SMA-21.12-110	P No. 3	P No. 3	-60	-30	-60	-60	-60	-30
101-141 A-C	SMA-12.12-108	P No. 3	P No. 3	-20	0	-50	-50	-20	0
101-150	SAA-SMA-12.12-106	P No. 3	P No. 3	-70	-70	-70	-70	-70	-70
101-150	SMA-12.12-110	P No. 3	P No. 3	-50	-20	-60	-60	-50	-20
101-150	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
101-150	SMA-12.12-108	P No. 3	P No. 3	-40	-30	-60	-60	-40	-30
101-171	SAA-SMA-3.3-107	P No. 3	P No. 3	-50	-50	-50	-40	-50	-50
101-171	SMA-3.3-126	P No. 3	P No. 3	0	0	-40	-40	0	0
101-171	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10

Table 5.2-10A

PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

REACTOR VESSEL (Sheet 1 of 2)

Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-121	SAA-SMA-3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-122	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
101-122	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
101-122	SAA-SMA-3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-124	SAA-SMA-3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-142	SAA-SMA-3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-150	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
101-150	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
101-150	SAA-SMA-12.12-106	5082	5082	-70	-70	-70	-70	-70	-70
101-171	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
101-171	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
101-171	SAA-SMA-3.3-103	5331	5331	-50	+10	-50	-40	-50	+10
103-121	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
103-121	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
103-121	SAA-SMA-3.3-106	5331	5331	-20	0	-50	-50	-20	0
105-121	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
105-121	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
105-121	SAA-SMA-3.3-106	5331	5331	-20	0	-50	-50	-20	0
201-121	SAA-SMA-3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
201-141	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fraction toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-10A

PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

REACTOR VESSEL (Sheet 2 of 2)

Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
201-141	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
201-141	SAA-SMA-3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
401-128	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
401-128	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
401-128	SAA-SMA-1.3-100	5167	5331	-50	-50	-80	-80	+10	+10

Table 5.2-10B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

REACTOR VESSEL (Sheet 1 of 2)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-121	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-122	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-124	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-142	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-150	SAA-SMA -1.3-107	5331	5331	-50	+10	-50	-40	-50	+10

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-10B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[(a)]

REACTOR VESSEL (Sheet 2 of 2)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[(b)]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-171	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
103-121	SAA-SMA -3.3-106	5331	5331	-20	0	-50	-50	-20	0
105-121	SAA-SMA -3.3-106	5331	5331	-20	0	-50	-50	-20	0
201-121	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
201-141	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
203-128	SAA-SMA -1.3-100	5167	5331	-50	-50	-80	-80	+10	+10
401-128	SAA-SMA -1.3-100	5167	5331	-50	-50	-80	-80	+10	+10

Table 5.2-11

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PIPING (PLATES) (Sheet 1 of 2)

Piece Number	Reference Drawing No.:	Material Code No:	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} (°F)
722-102	E-78473-761-001-00	M-7601-1	SA516-GR70	Straight Segment	-10	+10[a]
722-102	E-78473-761-001-00	M-7601-2	SA516-GR70	Straight Segment	-10	+10[a]
722-102	E-78473-761-001-00	M-7601-3	SA516-GR70	Straight Segment	-10	+10[a]
722-102	E-78473-761-001-00	M-7601-4	SA516-GR70	Straight Segment	-10	+10[a]
722-104	E-78473-761-002-02	M-7602-1	SA516-GR70	Straight Segment	-10	+10[a]
722-104	E-78473-761-002-02	M-7602-2	SA516-GR70	Straight Segment	-10	+10[a]
722-104	E-78473-761-002-02	M-7602-3	SA516-GR70	Straight Segment	-10	+20[a]
722-104	E-78473-761-002-02	M-7602-4	SA516-GR70	Straight Segment	-10	+20[a]
722-104	E-78473-761-002-02	M-7602-5	SA516-GR70	Straight Segment	-10	+10[a]
722-104	E-78473-761-002-02	M-7602-6	SA516-GR70	Straight Segment	-10	+10[a]
722-104	E-78473-761-002-02	M-7602-7	SA516-GR70	Straight Segment	-10	+20[a]
722-104	E-78473-761-002-02	M-7602-8	SA516-GR70	Straight Segment	-10	+10[a]
722-106	E-78473-761-002-02	M-7603-1	SA516-GR70	Straight Segment	-10	0[a]
722-106	E-78473-761-002-02	M-7603-2	SA516-GR70	Straight Segment	-10	0[a]
722-106	E-78473-761-002-02	M-7603-3	SA516-GR70	Straight Segment	-10	0[a]
722-106	E-78473-761-002-02	M-7603-4	SA516-GR70	Straight Segment	-10	0[a]
722-106	E-78473-761-002-02	M-7603-5	SA516-GR70	Straight Segment	-10	0[a]
722-106	E-78473-761-002-02	M-7603-6	SA516-GR70	Straight Segment	-10	0[a]
722-106	E-78473-761-002-02	M-7603-7	SA516-GR70	Straight Segment	-10	0[a]
722-106	E-78473-761-002-02	M-7603-8	SA516-GR70	Straight Segment	-10	0[a]
722-102	E-78473-761-002-02	M-7604-1	SA516-GR70	Elbow Segment	-10	+10[a]
722-204	E-78473-761-002-02	M-7605-1	SA516-GR70	Elbow Segment	-10	+10[a]
722-204	E-78473-761-002-02	M-7605-2	SA516-GR70	Elbow Segment	-10	-10[a]

a. Determined per applicable ASME B&PV Code Section III, Subsection NB, Article NB-2331(a-1, 2, 3)

Table 5.2-11

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PIPING (PLATES) (Sheet 2 of 2)

Piece Number	Reference Drawing No.:	Material Code No:	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} (°F)
722-204	E-78473-761-001-00	M-7605-3	SA516-GR70	Elbow Segment	-10	-10[a]
722-204	E-78473-761-001-00	M-7605-4	SA516-GR70	Elbow Segment	-10	+10[a]
722-208	E-78473-761-001-00	M-7606-1	SA516-GR70	Elbow Segment	-10	+10[a]
722-208	E-78473-761-001-00	M-7606-2	SA516-GR70	Elbow Segment	-10	+10[a]
722-104	E-78473-761-002-02	M-7606-6	SA516-GR70	Straight Segment	-10	+10[a]
722-104	E-78473-761-002-02	M-7606-7	SA516-GR70	Straight Segment	-10	+20[a]
722-104	E-78473-761-002-02	M-7606-8	SA516-GR70	Straight Segment	-10	+10[a]

Table 5.2-11A
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
REACTOR COOLANT PIPING (PLATES)

Piece Number	Reference Drawing No.:	Material Code No:	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} [a] (°F)
722-102	E-79473-761-001-01	F-1701-01	SA516-GR70	Straight Segment	-10	-10
722-102	E-79473-761-001-01	F-1701-02	SA516-GR70	Straight Segment	-10	-10
722-102	E-79473-761-001-01	F-1701-03	SA516-GR70	Straight Segment	-10	-10
722-102	E-79473-761-001-01	F-1701-04	SA516-GR70	Straight Segment	-10	-10
722-104	E-79473-761-002-01	F-1702-01	SA516-GR70	Straight Segment	-10	10
722-104	E-79473-761-002-01	F-1702-02	SA516-GR70	Straight Segment	-10	0
722-104	E-79473-761-002-01	F-1702-03	SA516-GR70	Straight Segment	-10	0
722-104	E-79473-761-002-01	F-1702-04	SA516-GR70	Straight Segment	-10	10
722-104	E-79473-761-002-01	F-1702-05	SA516-GR70	Straight Segment	-10	10
722-104	E-79473-761-002-01	F-1702-06	SA516-GR70	Straight Segment	-10	10
722-104	E-79473-761-002-01	F-1702-07	SA516-GR70	Straight Segment	-10	0
722-104	E-79473-761-002-01	F-1702-08	SA516-GR70	Straight Segment	-10	0
722-106	E-79473-761-002-01	F-1703-01	SA516-GR70	Straight Segment	-10	-10
722-106	E-79473-761-002-01	F-1703-02	SA516-GR70	Straight Segment	-10	-10
722-106	E-79473-761-002-01	F-1703-03	SA516-GR70	Straight Segment	-10	-10
722-106	E-79473-761-002-01	F-1703-04	SA516-GR70	Straight Segment	-10	-10
722-106	E-79473-761-002-01	F-1703-05	SA516-GR70	Straight Segment	-10	-10
722-106	E-79473-761-002-01	F-1703-06	SA516-GR70	Straight Segment	-10	-10
722-106	E-79473-761-002-01	F-1703-07	SA516-GR70	Straight Segment	-10	-10
722-106	E-79473-761-002-01	F-1703-08	SA516-GR70	Straight Segment	-10	-10
742-102	E-79473-761-002-01	F-1704-01	SA516-GR70	Elbow Segment	-10	0
742-204	E-79473-761-002-01	F-1705-01	SA516-GR70	Elbow Segment	-10	-10
742-204	E-79473-761-002-01	F-1705-02	SA516-GR70	Elbow Segment	-10	-10
742-204	E-79473-761-001-01	F-1705-03	SA516-GR70	Elbow Segment	-10	-10
742-204	E-79473-761-001-01	F-1705-04	SA516-GR70	Elbow Segment	-10	-10
742-208	E-79473-761-001-01	F-1706-01	SA516-GR70	Elbow Segment	-10	0
742-208	E-79473-761-001-01	F-1706-02	SA516-GR70	Elbow Segment	-10	0

a. Per ASME B&PV Code Section III, Article NB-2331-A-1, 2, 3

Table 5.2-11B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PIPING (PLATES) (Sheet 1 of 2)

Piece Number	Reference Drawing No.:	Material Code Number	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} (°F)
722-102	E-65473-761-001-02	F-7301-01	SA516-GR70	Straight Segment	-10	-10[a]
722-102	E-65473-761-001-02	F-7301-02	SA516-GR70	Straight Segment	-10	-10[a]
722-102	E-65473-761-001-02	F-7301-03	SA516-GR70	Straight Segment	-10	-10[a]
722-102	E-65473-761-001-02	F-7301-04	SA516-GR70	Straight Segment	-10	-10[a]
722-104	E-65473-761-002-02	F-7302-01	SA516-GR70	Straight Segment	-10	-10[a]
722-104	E-65473-761-002-02	F-7302-02	SA516-GR70	Straight Segment	-10	-10[a]
722-104	E-65473-761-002-02	F-7302-03	SA516-GR70	Straight Segment	-10	-10[a]
722-104	E-65473-761-002-02	F-7302-04	SA516-GR70	Straight Segment	-10	-10[a]
722-104	E-65473-761-002-02	F-7302-05	SA516-GR70	Straight Segment	-10	-10[a]
722-104	E-65473-761-002-02	F-7302-06	SA516-GR70	Straight Segment	-10	-10[a]
722-104	E-65473-761-002-02	F-7302-07	SA516-GR70	Straight Segment	-10	-10[a]
722-104	E-65473-761-002-02	F-7302-08	SA516-GR70	Straight Segment	-10	-10[a]
722-106	E-65473-761-002-02	F-7303-01	SA516-GR70	Straight Segment	-10	-10[a]
722-106	E-65473-761-002-02	F-7303-02	SA516-GR70	Straight Segment	-10	-10[a]
722-106	E-65473-761-002-02	F-7303-03	SA516-GR70	Straight Segment	-10	-10[a]
722-106	E-65473-761-002-02	F-7303-04	SA516-GR70	Straight Segment	-10	-10[a]
722-106	E-65473-761-002-02	F-7303-05	SA516-GR70	Straight Segment	-10	-10[a]
722-106	E-65473-761-002-02	F-7303-06	SA516-GR70	Straight Segment	-10	-10[a]
722-106	E-65473-761-002-02	F-7303-07	SA516-GR70	Straight Segment	-10	-10[a]
722-106	E-65473-761-002-02	F-7303-08	SA516-GR70	Straight Segment	-10	-10[a]

a. Determined per applicable ASME B&PV Code Section III, Subsection NB, Article NB-2331 (a-1, 2, 3)

Table 5.2-11B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PIPING (PLATES) (Sheet 2 of 2)

Piece Number	Reference Drawing No.:	Material Code Number	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} (°F)
742-102	E-65473-761-001-02	F-7304-01	SA516-GR70	Elbow Segment	-10	-10[a]
742-204	E-65473-761-002-02	F-7305-01	SA516-GR70	Elbow Segment	-10	-10[a]
742-204	E-65473-761-002-02	F-7305-02	SA516-GR70	Elbow Segment	-10	-10[a]
742-204	E-65473-761-001-02	F-7305-03	SA516-GR70	Elbow Segment	-10	-10[a]
742-204	E-65473-761-001-02	F-7305-04	SA516-GR70	Elbow Segment	-10	-10[a]
742-208	E-65473-761-002-02	F-7306-01	SA516-GR70	Elbow Segment	-10	-10[a]
742-208	E-65473-761-002-02	F-7306-02	SA516-GR70	Elbow Segment	-10	-10[a]

Table 5.2-12
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
REACTOR COOLANT PIPING (FORGINGS)

Piece Number	Reference Drawing No.	Material Code No.	Material Specification	Location	Drop Weight NDT (°F)		RT_{NDT}(°F)/LST[c](°F)	
					0°	180°	0°	180°
728-101	E-78473-761-001-00	M-7607-1	SA541-CL1	Surge Nozzle	-10		+10[a]	
728-201	E-78473-761-001-00	M-7608-1	SA541-CL1	Shutdown Cooling Outlet Nozzle	-10		+10[a]	
728-201	E-78473-761-001-00	M-7608-1	SA541-CL1	Shutdown Cooling Outlet Nozzle	-10		+10[a]	
728-202	E-78473-761-002-02	M-7609-1	SA541-CL1	Spray Nozzle	N/A		+40[b]	
728-202	E-78473-761-002-02	M-7609-2	SA541-CL1	Spray Nozzle	N/A		+40[b]	
728-102	E-78473-761-002-02	M-7610-1	SA541-CL1	Letdown Drain Nozzle	N/A		+40[b]	
728-102	E-78473-761-002-02	M-7610-2	SA541-CL1	Letdown Drain Nozzle	N/A		+40[b]	
728-102	E-78473-761-002-02	M-7610-3	SA541-CL1	Letdown Drain Nozzle	N/A		+40[b]	
728-102	E-78473-761-002-02	M-7610-4	SA541-CL1	Letdown Drain Nozzle	N/A		+40[b]	
728-103	E-78473-761-002-02	M-7612-1	SA182-GRF1	Safety Injection Nozzle	0		0[a]	
728-103	E-78473-761-002-02	M-7612-2	SA182-GRF1	Safety Injection Nozzle	-10		-10[a]	
728-103	E-78473-761-002-02	M-7612-3	SA182-GRF1	Safety Injection Nozzle	0		0[a]	
728-103	E-78473-761-002-02	M-7612-4	SA182-GRF1	Safety Injection Nozzle	0		0[a]	
728-203	E-78473-761-002-02	M-7613-1	SA182-GRF1	Charging Inlet Nozzle	0		0[a]	
102-1	PX-DWD-80-010	N/A	SA-508 CL 3	Cold Leg Elbow	-22		-22[a]	
102-2	PX-DWD-80-010	N/A	SA-508 CL 3	Cold Leg Elbow	-22		-22[a]	
103-1	PX-DWD-80-010	N/A	SA-508 CL 1a	Spool Piece	-31		-31[a]	
103-2	PX-DWD-80-010	N/A	SA-508 CL 1a	Spool Piece	-31		-31[a]	

a. Determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

b. "Lowest service temperature" - determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2332-a

c. Lowest service temperature

Table 5.2-12A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PIPING (FORGINGS)

Piece Number	Reference Drawing No.	Material Code No.	Material Specification	Location	Drop Weight NDT (°F) 0°	Drop Weight NDT (°F) 180°	RT_{NDT} (°F)/LST[c] (°F) 0°	RT_{NDT} (°F)/LST[c] (°F) 180°
728-101	E-79473-761-001-01	F-1707-01	SA541-CL1	Surge Nozzle	-10		-10[a]	
728-201	E-79473-761-001-01	F-1708-01	SA541-CL1	Shutdown Cooling Outlet Nozzle	-10		-10[a]	
728-201	E-79473-761-001-01	F-1708-02	SA541-CL1	Shutdown Cooling Outlet Nozzle	-10		-10[a]	
728-202	E-79473-761-002-01	F-1709-01	SA541-CL1	Spray Nozzle	N/A		40[b]	
728-202	E-79473-761-002-01	F-1709-02	SA541-CL1	Spray Nozzle	N/A		40[b]	
728-102	E-79473-761-002-01	F-1710-01	SA541-CL1	Letdown Drain Nozzle	N/A		40[b]	
728-102	E-79473-761-002-01	F-1710-02	SA541-CL1	Letdown Drain Nozzle	N/A		40[b]	
728-102	E-79473-761-002-01	F-1710-03	SA541-CL1	Letdown Drain Nozzle	N/A		40[b]	
728-102	E-79473-761-002-01	F-1710-04	SA541-CL1	Letdown Drain Nozzle	N/A		40[b]	
728-103	E-79473-761-002-01	F-1718-01	A541-CL3	Safety Injection Nozzle	0		10[a]	
728-103	E-79473-761-002-01	F-1718-02	A541-CL3	Safety Injection Nozzle	0		0[a]	
728-103	E-79473-761-002-01	F-1718-03	A541-CL3	Safety Injection Nozzle	0		0[a]	
728-103	E-79473-761-002-01	F-1718-04	A541-CL3	Safety Injection Nozzle	0		0[a]	
728-203	E-79473-761-002-01	F-1719-01	A541-CL3	Charging Inlet Nozzle	0		0[a]	
102-1	PV-DWF-80-010	N/A	SA508, CL3	Cold Leg Elbow	-17		-17	
102-2	PV-DWF-80-010	N/A	SA508, CL3	Cold Leg Elbow	-17		-17	
103-1	PV-DWF-80-010	N/A	SA508, CL1a	Tube	-26		-26	
103-2	PV-DWF-80-010	N/A	SA508, CL1a	Spool Pieces	-26		-26	

a. Per ASME B&PV Code, Section III, Article NB-2331-A-1, 2, 3

b. Per ASME B&PV Code, Section III, Article NB-2332-A

c. Lowest service temperature

Table 5.2-12B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PIPING (FORGINGS) (Sheet 1 of 2)

Piece Number	Reference Drawing No.	Material Code No.	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT}[c] (°F)
728-101	E-65473-761-001-02	F-7307-01	SA541-CL1	Surge Nozzle	-10	-10[a]
728-201	E-65473-761-001-02	F-7308-01	SA541-CL1	Shutdown Cooling Outlet Nozzle	-10	+10[a]
728-201	E-65473-761-001-02	F-7308-02	SA541-CL1	Shutdown Cooling Outlet Nozzle	+10	+10[a]
728-202	E-65473-761-002-01	F-7309-01	SA541-CL1	Spray Nozzle	N/A	+40[b]
728-202	E-65473-761-002-01	F-7309-02	SA541-CL1	Spray Nozzle	N/A	+40[b]
728-102	E-65473-761-002-02	F-7310-01	SA541-CL1	Letdown Drain Nozzle	N/A	+40[b]
728-102	E-65473-761-002-02	F-7310-02	SA541-CL1	Letdown Drain Nozzle	N/A	+40[b]
728-102	E-65473-761-002-02	F-7310-03	SA541-CL1	Letdown Drain Nozzle	N/A	+40[b]
728-102	E-65473-761-002-02	F-7310-04	SA541-CL1	Letdown Drain Nozzle	N/A	+40[b]

a. Determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

b. "Lowest service temperature" - determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2332-a

c. Lowest service temperature

Table 5.2-12B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PIPING (FORGINGS) (Sheet 2 of 2)

Piece Number	Reference Drawing No.	Material Code No.	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT}[c] (°F)
728-103	E-65473-761-002-02	F-7311-01	A541-CL3	Safety Injection Nozzle	0	0[a]
728-103	E-65473-761-002-02	F-7311-02	A541-CL3	Safety Injection Nozzle	0	0[a]
728-103	E-65473-761-002-02	F-7311-03	A541-CL3	Safety Injection Nozzle	0	0[a]
728-103	E-65473-761-002-02	F-7311-04	A541-CL3	Safety Injection Nozzle	0	0[a]
728-203	E-65473-761-002-02	F-7312-01	A541-CL3	Charging Inlet Nozzle	0	0[a]
102-1/SG1	PX-DWD-80-010	N/A	SA-508 Cl 3	Cold Leg Elbow	-40	-40
102-2/SG1	PX-DWD-80-010	N/A	SA-508 Cl 3	Cold Leg Elbow	-40	-40
103-1/SG1	PX-DWD-80-010	N/A	SA-508 Cl 1a	Spool Piece	-31	-31
103-2/SG1	PX-DWD-80-010	N/A	SA-508 Cl 1a	Spool Piece	-31	-31
102-1/SG2	PX-DWD-80-010	N/A	SA-508 Cl 3	Cold Leg Elbow	-22	-22
102-2/SG2	PX-DWD-80-010	N/A	SA-508 Cl 3	Cold Leg Elbow	-40	-40
103-1/SG2	PX-DWD-80-010	N/A	SA-508 Cl 1a	Spool Piece	-22	-22
103-2/SG2	PX-DWD-80-010	N/A	SA-508 Cl 1a	Spool Piece	-22	-22

Table 5.2-13

PVNGS UNITS 1, 2, AND 3 REACTOR COOLANT

PRESSURE BOUNDARY WELD SEAM IDENTIFICATION

PRIMARY PIPING[(a)]

Seam No.	Weld Seam Nomenclature
209-742	Elbow segment long seam
105-722	Straight pipe long seam
203-742	Elbow segment long seam
108-711	Letdown and drain nozzle to primary pipe
104-711	Pipe elbow to straight pipe girth seam
102-711	Straight pipe to pipe elbow girth seam
205-742	Elbow segment long seam
103-722	Straight pipe long seam
101-741	Straight pipe to pipe elbow girth seam
106-741	Spray nozzle to primary pipe
104-741	Safety injection nozzle to primary pipe
301-741	Pipe elbow to straight pipe girth seam
103-722	Straight pipe long seam
304-741	Safety injection nozzle to primary pipe
306-741	Charging inlet nozzle to primary pipe
501-741	Straight pipe to elbow
504-741	Spray nozzle to primary pipe
701-741	Pipe elbow to straight pipe girth seam
704-741	Safety injection nozzle to primary pipe
101-722	Straight pipe long seam
101-742	Elbow segment long seam
201-741	Straight pipe to pipe elbow girth seam
203-771	Surge nozzle to primary pipe
205-771	Shutdown coolant nozzle to primary pipe
401-771	Straight pipe to pipe elbow girth seam
403-771	Shutdown coolant outlet nozzle to primary pipe
CW-052	Cold Leg Elbow to Spool Piece

a. Shop welds only (field welds excluded)

Table 5.2-14

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 1 of 7)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-722	Flux electrode comb. (SAA)	124	1061	-80	-80
101-722	Flux electrode comb. (SAA)	124	1061	-80	-80
101-741	Flux electrode comb. (SAA)	124	0871	-80	-60
101-742	Flux electrode comb. (SAA)	124	0171	-80	-70
101-742	Flux electrode comb. (SAA)	124	0171	-80	-70
102-711	Flux electrode comb. (SAA)	124	0871	-80	-60
102-711	Flux electrode comb. (SAA)	124	0871	-80	-60
102-711	Flux electrode comb. (SAA)	124	0171	-80	-70
102-711	Flux electrode comb. (SAA)	124	0871	-80	-60
103-722	Flux electrode comb. (SAA)	H-400	23	-10	+40
103-722	Flux electrode comb. (SAA)	124	0171	-80	-70
103-722	Flux electrode comb. (SAA)	H-400	23	-10	-40
103-722	Flux electrode comb. (SAA)	124	1061	-80	-80
103-722	Flux electrode comb. (SAA)	H-400	23	-10	-40
103-722	Flux electrode comb. (SAA)	124	1061	-80	-80
103-722	Flux electrode comb. (SAA)	H-400	23	-40	-40

a. Per ASME B&PV Code, Section III, Article NB 2430
b. Per ASME B&PV Code, Section III, Article NB 2330

Table 5.2-14

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[(a)]

COMPONENT: PIPING (Sheet 2 of 7)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[(b)] (°F)	RT_{NDT}[(b)] (°F)
103-722	Flux electrode comb. (SAA)	124	1061	-80	-80
104-711	Flux electrode comb. (SAA)	124	0871	-80	-60
104-711	Flux electrode comb. (SAA)	124	0871	-80	-60
104-711	Flux electrode comb. (SAA)	124	0171	-80	-70
104-711	Flux electrode comb. (SAA)	124	0171	-80	-70
105-722	Flux electrode comb. (SAA)	124	0171	-80	-70
105-722	Flux electrode comb. (SAA)	124	0171	-80	-70
105-722	Flux electrode comb. (SAA)	H-400	23	-10	+40
105-722	Flux electrode comb. (SAA)	H-400	23	-10	+40
105-722	Flux electrode comb. (SAA)	124	-061	-80	-80
105-722	Flux electrode comb. (SAA)	H-400	23	-10	-40
105-722	Flux electrode comb. (SAA)	124	0171	-80	-70
201-741	Flux electrode comb. (SAA)	124	0871	-80	-60
203-742	Flux electrode comb. (SAA)	124	0171	-80	-70
203-742	Flux electrode comb. (SAA)	124	0171	-80	-70
203-742	Flux electrode comb. (SAA)	124	0171	-80	-70
203-742	Flux electrode comb. (SAA)	124	0171	-80	-70

Table 5.2-14

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[(a)]

COMPONENT: PIPING (Sheet 3 of 7)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[(b)] (°F)	RT_{NDT}[(b)] (°F)
205-742	Flux electrode comb. (SAA)	124	0171	-80	-70
205-742	Flux electrode comb. (SAA)	124	0171	-80	-70
205-742	Flux electrode comb. (SAA)	124	0171	-80	-70
205-742	Flux electrode comb. (SAA)	124	0171	-80	-70
209-742	Flux electrode comb. (SAA)	124	0171	-80	-70
209-742	Flux electrode comb. (SAA)	124	0171	-80	-70
209-742	Flux electrode comb. (SAA)	124	0171	-80	-70
209-742	Flux electrode comb. (SAA)	124	0171	-80	-70
209-742	Flux electrode comb. (SAA)	124	0171	-80	-70
209-742	Flux electrode comb. (SAA)	124	0171	-80	-70
209-742	Flux electrode comb. (SAA)	124	0171	-80	-70
209-742	Flux electrode comb. (SAA)	124	0171	-80	-70
301-741	Flux electrode comb. (SAA)	124	0871	-80	-60
401-771	Flux electrode comb. (SAA)	124	0171	-80	-70
501-741	Flux electrode comb. (SAA)	124	0871	-80	-60
701-741	Flux electrode comb. (SAA)	124	0871	-80	-60
CW 052	Flux electrode comb. (SAA)	Fluorite Basic	1400654	-85	-85

Table 5.2-14

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[(a)]

COMPONENT: PIPING (Sheet 4 of 7)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT} (b) (°F)	RT_{NDT} (b) (°F)
101-722	Coated electrode (MA)	EABDF	-50	-50
101-722	Coated electrode (MA)	EABDF	-50	-50
101-722	Coated electrode (MA)	AA0CG	-40	-40
101-741	Coated electrode (MA)	FABJG	-50	-50
101-742	Coated electrode (MA)	IABAG	-50	-50
101-742	Coated electrode (MA)	AA0CG	-40	-40
101-742	Coated electrode (MA)	FABJG	-50	-50
101-742	Coated electrode (MA)	EA0CG	-30	-30
101-742	Coated electrode (MA)	IABAG	-50	-50
101-742	Coated electrode (MA)	AA0CG	-40	-40
101-742	Coated electrode (MA)	IABAG	-50	-50
101-742	Coated electrode (MA)	FABJG	-50	-50
102-711	Coated electrode (MA)	LCAGF	-50	-50
102-711	Coated electrode (MA)	FABJG	-50	-50
102-711	Coated electrode (MA)	LCAGF	-50	-50
102-711	Coated electrode (MA)	FABJG	-50	-50
102-711	Coated electrode (MA)	LCAGF	-50	-50
102-711	Coated electrode (MA)	IABAG	-50	-50
102-711	Coated electrode (MA)	FABJG	-50	-50
102-711	Coated electrode (MA)	IABAG	-50	-50
102-711	Coated electrode (MA)	FABJG	-50	-50
103-722	Coated electrode (MA)	AA0CG	-40	-40
103-722	Coated electrode (MA)	AA0CG	-40	-40
103-722	Coated electrode (MA)	AA0CG	-40	-40
104-711	Coated electrode (MA)	FABJG	-50	-50
104-711	Coated electrode (MA)	JAACG	-60	-60
104-711	Coated electrode (MA)	FABJG	-50	-50
104-711	Coated electrode (MA)	FABJG	-50	-50
104-711	Coated electrode (MA)	FABJG	-50	-50
104-711	Coated electrode (MA)	IABAG	-50	-50
104-741	Coated electrode (MA)	IABAG	-50	-50
104-741	Coated electrode (MA)	FABJG	-50	-50
104-741	Coated electrode (MA)	EA0CG	-30	-30

Table 5.2-14
PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: PIPING (Sheet 5 of 7)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
105-722	Coated electrode (MA)	EA0CG	-30	-30
105-722	Coated electrode (MA)	EA0CG	-30	-30
105-722	Coated electrode (MA)	AAOCG	-40	-40
105-722	Coated electrode (MA)	EAOCG	-30	-30
105-722	Coated electrode (MA)	IAAEF	-50	-50
105-722	Coated electrode (MA)	AA0CG	-40	-40
105-722	Coated electrode (MA)	EA0CG	-30	-30
106-741	Coated electrode (MA)	IAEAG	-50	-50
106-741	Coated electrode (MA)	FABJG	-50	-50
106-741	Coated electrode (MA)	EA0CG	-30	-30
108-711	Coated electrode (MA)	IABAG	-50	-50
108-711	Coated electrode (MA)	FABJG	-50	-50
108-711	Coated electrode (MA)	EA0CG	-30	-30
108-711	Coated electrode (MA)	IABAG	-50	-50
108-711	Coated electrode (MA)	FABJG	-50	-50
108-711	Coated electrode (MA)	EA0CG	-30	-30
108-711	Coated electrode (MA)	IABAG	-50	-50
108-711	Coated electrode (MA)	FABJG	-50	-50
108-711	Coated electrode (MA)	EAOCG	-30	-30
108-711	Coated electrode (MA)	IABAG	-50	-50
108-711	Coated electrode (MA)	EA0CG	-30	-30
108-711	Coated electrode (MA)	FABJG	-50	-50
201-741	Coated electrode (MA)	FABJG	-50	-50
203-742	Coated electrode (MA)	IAAEF	-50	-50
203-742	Coated electrode (MA)	EA0CG	-30	-30
203-742	Coated electrode (MA)	FABJG	-50	-50
203-742	Coated electrode (MA)	IAAEF	-50	-50
203-742	Coated electrode (MA)	AA0CG	-40	-40
203-742	Coated electrode (MA)	LCAGF	-50	-50
203-742	Coated electrode (MA)	FABJG	-50	-50
203-742	Coated electrode (MA)	EA0CG	-30	-30
203-742	Coated electrode (MA)	AA0CG	-40	-40
203-742	Coated electrode (MA)	IAAEF	-50	-50
203-742	Coated electrode (MA)	LCAGF	-50	-50
203-742	Coated electrode (MA)	EA0CG	-30	-30
203-742	Coated electrode (MA)	FABJG	-50	-50

Table 5.2-14

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 6 of 7)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
203-742	Coated electrode (MA)	IABAG	-50	-50
203-742	Coated electrode (MA)	AAOCG	-40	-40
203-742	Coated electrode (MA)	AE0CG	-30	-30
203-742	Coated electrode (MA)	FABJG	-50	-50
203-771	Coated electrode (MA)	IABAG	-50	-50
203-771	Coated electrode (MA)	FABJG	-50	-50
203-771	Coated electrode (MA)	EA0CG	-30	-30
205-742	Coated electrode (MA)	AA0CG	-40	-40
205-742	Coated electrode (MA)	AA0CG	-40	-40
205-742	Coated electrode (MA)	IAAEF	-50	-50
205-742	Coated electrode (MA)	IABAG	-50	-50
205-742	Coated electrode (MA)	EAOCG	-30	-30
205-742	Coated electrode (MA)	FABJG	-50	-50
205-771	Coated electrode (MA)	IABAG	-50	-50
205-771	Coated electrode (MA)	EAOCG	-30	-30
209-742	Coated electrode (MA)	AAOCG	-40	-40
209-742	Coated electrode (MA)	IAAEF	-50	-50
209-742	Coated electrode (MA)	FABJG	-50	-50
209-742	Coated electrode (MA)	EAOCG	-30	-30
209-742	Coated electrode (MA)	IAAEF	-50	-50
209-742	Coated electrode (MA)	AA0CG	-40	-40
209-742	Coated electrode (MA)	EA0CG	-30	-30
209-742	Coated electrode (MA)	IAAEF	-50	-50
209-742	Coated electrode (MA)	IAEAG	-50	-50
209-742	Coated electrode (MA)	IAAEF	-50	-50
209-742	Coated electrode (MA)	AAOCG	-40	-40
209-742	Coated electrode (MA)	IAAEF	-50	-50
209-742	Coated electrode (MA)	AAOCG	-40	-40
209-742	Coated electrode (MA)	EAOCG	-30	-30
209-742	Coated electrode (MA)	FABJG	-50	-50
209-742	Coated electrode (MA)	IAAEF	-50	-50
209-742	Coated electrode (MA)	AA0CG	-40	-40
209-742	Coated electrode (MA)	IAAEF	-50	-50
209-742	Coated electrode (MA)	AA0CG	-40	-40

Table 5.2-14

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 7 of 7)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
209-742	Coated electrode (MA)	IABAG	-50	-50
209-742	Coated electrode (MA)	EA0CG	-30	-30
209-742	Coated electrode (MA)	IAAFF	-50	-50
209-742	Coated electrode (MA)	AA0CG	-40	-40
301-741	Coated electrode (MA)	FABJG	-50	-50
304-741	Coated electrode (MA)	IABAG	-50	-50
304-741	Coated electrode (MA)	FABJG	-50	-50
304-741	Coated electrode (MA)	EA0CG	-30	-30
306-741	Coated electrode (MA)	FABJG	-50	-50
306-741	Coated electrode (MA)	EA0CG	-30	-30
401-771	Coated electrode (MA)	FABJG	-50	-50
401-771	Coated electrode (MA)	EA0CG	-30	-30
403-771	Coated electrode (MA)	IABAG	-50	-50
403-771	Coated electrode (MA)	EAOCG	-30	-30
403-771	Coated electrode (MA)	FABJG	-50	-50
501-741	Coated electrode (MA)	FABJG	-50	-50
504-741	Coated electrode (MA)	IABAG	-50	-50
504-741	Coated electrode (MA)	EA0CG	-30	-30
506-741	Coated electrode (MA)	IABAG	-50	-50
506-741	Coated electrode (MA)	EA0CG	-30	-30
506-741	Coated electrode (MA)	FABJG	-50	-50
701-741	Coated electrode (MA)	FABJG	-50	-50
704-741	Coated electrode (MA)	IABAG	-50	-50
704-741	Coated electrode (MA)	EA0CG	-30	-30
704-741	Coated electrode (MA)	FABJG	-50	-50
CW 052	Coated electrode (MA)	4374003	-76	-76

Table 5.2-14A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 1 of 5)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-722	Coated electrode (MA)	FABJG	-50	-50
101-741	Coated electrode (MA)	BAOBH	-60	-40
101-741	Coated electrode (MA)	LAOEH	-60	-40
101-742	Coated electrode (MA)	AAOEH	-60	-60
101-742	Coated electrode (MA)	BAOBH	-60	-40
101-742	Coated electrode (MA)	EAOCG	-30	-30
101-742	Coated electrode (MA)	FABJG	-50	-50
101-742	Coated electrode (MA)	JAACG	-60	-60
102-711	Coated electrode (MA)	CABGH	-60	-60
102-711	Coated electrode (MA)	CAOHI	-50	-50
102-711	Coated electrode (MA)	CBAHH	-70	-70
102-711	Coated electrode (MA)	GABDH	-50	-50
103-722	Coated electrode (MA)	BAOBH	-60	-40
103-722	Coated electrode (MA)	EAOCG	-30	-30
103-722	Coated electrode (MA)	FABJG	-50	-50
103-722	Coated electrode (MA)	JAACG	-60	-60
104-711	Coated electrode (MA)	CABGH	-60	-60
104-711	Coated electrode (MA)	CAOHI	-50	-50
104-711	Coated electrode (MA)	CBAHH	-70	-70
104-711	Coated electrode (MA)	GABDH	-50	-50
104-711	Coated electrode (MA)	LAOEH	-60	-40
104-741	Coated electrode (MA)	GABDH	-50	-50
104-741	Coated electrode (MA)	LAOEH	-60	-40
105-722	Coated electrode (MA)	AAOEH	-60	-60
105-722	Coated electrode (MA)	BAOBH	-60	-40
105-722	Coated electrode (MA)	EAOCG	-30	-30
105-722	Coated electrode (MA)	FABJG	-50	-50
105-722	Coated electrode (MA)	LCAGF	-50	-50
106-722	Coated electrode (MA)	GABDH	-50	-50
106-722	Coated electrode (MA)	LAOEH	-60	-40

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-14A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 2 of 5)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
108-711	Coated electrode (MA)	CAOHI	-50	-50
108-711	Coated electrode (MA)	CBAHH	-70	-70
108-711	Coated electrode (MA)	GABDH	-50	-50
108-711	Coated electrode (MA)	LAOEH	-60	-40
201-741	Coated electrode (MA)	AAOEH	-60	-60
201-741	Coated electrode (MA)	BAOBH	-60	-40
203-742	Coated electrode (MA)	AAOEH	-60	-60
203-742	Coated electrode (MA)	BAOBH	-60	-40
203-742	Coated electrode (MA)	EAOCG	-30	-30
203-742	Coated electrode (MA)	GABDH	-50	-50
203-742	Coated electrode (MA)	GABHH	-40	-40
203-742	Coated electrode (MA)	JAACG	-60	-60
203-771	Coated electrode (MA)	BAOBH	-60	-40
203-771	Coated electrode (MA)	GABDH	-50	-50
203-771	Coated electrode (MA)	LAOEH	-60	-40
205-742	Coated electrode (MA)	AAOEH	-60	-60
205-742	Coated electrode (MA)	BAOBH	-60	-40
205-742	Coated electrode (MA)	EAOCG	-30	-30
205-742	Coated electrode (MA)	GABDH	-50	-50
205-742	Coated electrode (MA)	JAACG	-60	-60
205-771	Coated electrode (MA)	GABDH	-50	-50
205-771	Coated electrode (MA)	LAOEH	-60	-40
209-742	Coated electrode (MA)	AAOEH	-60	-60
209-742	Coated electrode (MA)	BAOBH	-60	-40
209-742	Coated electrode (MA)	FABJG	-50	-50
209-742	Coated electrode (MA)	GABHH	-40	-40
209-742	Coated electrode (MA)	JAACG	-60	-60
209-742	Coated electrode (MA)	LCAGF	-50	-50
301-741	Coated electrode (MA)	BAOBH	-60	-40
304-741	Coated electrode (MA)	GABDH	-50	-50
304-741	Coated electrode (MA)	LAOEH	-60	-40

Table 5.2-14A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 3 of 5)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
306-741	Coated electrode (MA)	CBAHH	-70	-70
306-741	Coated electrode (MA)	GABDH	-50	-50
306-741	Coated electrode (MA)	LAOEH	-60	-40
401-771	Coated electrode (MA)	AAOEH	-60	-60
401-771	Coated electrode (MA)	CBAHH	-70	-70
401-771	Coated electrode (MA)	GABDH	-50	-50
401-771	Coated electrode (MA)	LAOEH	-60	-40
403-771	Coated electrode (MA)	GABDH	-50	-50
403-771	Coated electrode (MA)	LAOEH	-60	-40
501-741	Coated electrode (MA)	GABDH	-50	-50
501-741	Coated electrode (MA)	LAOEH	-60	-40
504-741	Coated electrode (MA)	GABDH	-50	-50
504-741	Coated electrode (MA)	LAOEH	-60	-40
506-741	Coated electrode (MA)	GABDH	-50	-50
506-741	Coated electrode (MA)	LAOEH	-60	-40
701-741	Coated electrode (MA)	GABDH	-50	-50
701-741	Coated electrode (MA)	LAOEH	-60	-40
704-741	Coated electrode (MA)	CBAHH	-70	-70
704-741	Coated electrode (MA)	GABDH	-50	-50
704-741	Coated electrode (MA)	LAOEH	-60	-40

Table 5.2-14A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 4 of 5)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-722	Flux electrode Comb. (SAA)	124	0871	-80	-80
101-722	Flux electrode Comb. (SAA)	H-400	78	-10	40
101-722	Flux electrode Comb. (SAA)	H-400	23	-10	50
101-741	Flux electrode Comb. (SAA)	124	0281	-50	-10
101-742	Flux electrode Comb. (SAA)	124	0281	-60	-60
101-742	Flux electrode Comb. (SAA)	124	0281	-80	-70
102-711	Flux electrode Comb. (SAA)	124	0281	-50	-10
103-722	Flux electrode Comb. (SAA)	124	0281	-80	-80
103-722	Flux electrode Comb. (SAA)	124	0871	-80	-80
103-722	Flux electrode Comb. (SAA)	H-400	78	-10	40
104-711	Flux electrode Comb. (SAA)	124	0281	-80	-80
104-711	Flux electrode Comb. (SAA)	124	0281	-50	-10
105-722	Flux electrode Comb. (SAA)	124	0281	-60	-60
105-722	Flux electrode Comb. (SAA)	124	0281	-80	-80
105-722	Flux electrode Comb. (SAA)	H-400	78	-10	40
201-741	Flux electrode Comb. (SAA)	124	0281	-50	-10

Table 5.2-14A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 5 of 5)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
203-742	Flux electrode comb. (SAA)	124	0281	-60	-60
203-742	Flux electrode comb. (SAA)	124	0281	-50	-10
205-742	Flux electrode comb. (SAA)	124	0281	-50	-10
209-742	Flux electrode comb. (SAA)	124	0281	-60	-60
209-742	Flux electrode comb. (SAA)	124	0281	-80	-70
301-741	Flux electrode comb. (SAA)	124	0281	-50	-10
401-771	Flux electrode comb. (SAA)	124	0281	-50	-10
501-741	Flux electrode comb. (SAA)	124	0281	-80	-80
501-741	Flux electrode comb. (SAA)	124	0281	-50	-10
701-741	Flux electrode comb. (SAA)	124	0281	-80	-80
CW-052[c]	GTAW	-	-	Not Req'd	Not Req'd
CW-052[c]	SMAW (Electrode)	-	-	-58	-58
CW-052[c]	SMAW (Electrode)	-	-	-31	-31
CW-052[c]	SMAW (Electrode)	-	-	-58	-58
CW-052[c]	SMAW (Electrode)	-	-	-85	-85
CW-052[c]	SMAW (submerged arc)	-	-	-87	-87

(c) Applies to steam generator cold leg elbow and spool piece.

Table 5.2-14B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 1 of 5)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-722	Coated electrode (MA)	HAADI	-60	-60
101-722	Coated electrode (MA)	HABDI	-40	-40
101-741	Coated electrode (MA)	HAADI	-60	-60
101-741	Coated electrode (MA)	HABDI	-40	-40
101-741	Coated electrode (MA)	IBBDI	-60	-40
101-742	Coated electrode (MA)	HABDI	-40	-40
101-742	Coated electrode (MA)	IAOFI	-40	-40
102-711	Coated electrode (MA)	FABJJ	-40	-40
102-711	Coated electrode (MA)	IAAGJ	-60	-60
102-711	Coated electrode (MA)	IBBDI	-60	-40
102-711	Coated electrode (MA)	JBBIJ	-40	-40
102-711	Coated electrode (MA)	KABHI	-50	-50
103-722	Coated electrode (MA)	HAADI	-60	-60
103-722	Coated electrode (MA)	HABDI	-40	-40
103-722	Coated electrode (MA)	IAOFI	-40	-40
104-711	Coated electrode (MA)	FABJJ	-40	-40
104-711	Coated electrode (MA)	HABDI	-40	-40
104-711	Coated electrode (MA)	IAAGJ	-60	-60
104-711	Coated electrode (MA)	IAOFI	-40	-40
104-711	Coated electrode (MA)	IBBDI	-60	-40
104-741	Coated electrode (MA)	FABJJ	-40	-40
104-741	Coated electrode (MA)	IBBDI	-60	-40
104-741	Coated electrode (MA)	KABHI	-50	-50
105-722	Coated electrode (MA)	HAADI	-60	-60
105-722	Coated electrode (MA)	HABDI	-40	-40
106-741	Coated electrode (MA)	FABJJ	-40	-40
106-741	Coated electrode (MA)	IBBDI	-60	-40

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330.

Table 5.2-14B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 2 of 5)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
108-711	Coated electrode (MA)	FABJJ	-40	-40
108-711	Coated electrode (MA)	IBBDI	-60	-40
201-771	Coated electrode (MA)	HAADI	-60	-60
201-771	Coated electrode (MA)	HABDI	-40	-40
201-771	Coated electrode (MA)	IBBDI	-60	-40
203-742	Coated electrode (MA)	HAADI	-60	-60
203-742	Coated electrode (MA)	HABDI	-40	-40
203-742	Coated electrode (MA)	IAOFI	-40	-40
203-771	Coated electrode (MA)	FABJJ	-40	-40
203-771	Coated electrode (MA)	IBBDI	-60	-40
205-771	Coated electrode (MA)	FABJJ	-40	-40
205-771	Coated electrode (MA)	IBBDI	-60	-40
209-742	Coated electrode (MA)	HAADI	-60	-60
209-742	Coated electrode (MA)	HABDI	-40	-40
209-742	Coated electrode (MA)	IAOFI	-40	-40
301-741	Coated electrode (MA)	FABJJ	-40	-40
301-741	Coated electrode (MA)	HABDI	-40	-40
301-741	Coated electrode (MA)	IBBDI	-60	-40
304-741	Coated electrode (MA)	FABJJ	-40	-40
304-741	Coated electrode (MA)	IBBDI	-60	-40
304-741	Coated electrode (MA)	KABHI	-50	-50
306-741	Coated electrode (MA)	FABJJ	-40	-40
306-741	Coated electrode (MA)	IBBDI	-60	-40
401-771	Coated electrode (MA)	HAADI	-60	-60
401-771	Coated electrode (MA)	HABDI	-40	-40
401-771	Coated electrode (MA)	IBBDI	-60	-40
403-771	Coated electrode (MA)	FABJJ	-40	-40
403-771	Coated electrode (MA)	IBBDI	-60	-40

Table 5.2-14B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 3 of 5)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
501-741	Coated electrode (MA)	FABJJ	-40	-40
501-741	Coated electrode (MA)	IAAGJ	-60	-60
501-741	Coated electrode (MA)	IBBDI	-60	-40
504-744	Coated electrode (MA)	FABJJ	-40	-40
504-744	Coated electrode (MA)	IBBDI	-60	-40
504-744	Coated electrode (MA)	JBBIJ	-40	-40
504-744	Coated electrode (MA)	KABHI	-50	-50
506-741	Coated electrode (MA)	FABJJ	-40	-40
506-741	Coated electrode (MA)	IBBDI	-60	-40
701-741	Coated electrode (MA)	FABJJ	-40	-40
701-741	Coated electrode (MA)	HABDI	-40	-40
701-741	Coated electrode (MA)	IBBDI	-60	-40
704-741	Coated electrode (MA)	FABJJ	-40	-40
704-741	Coated electrode (MA)	IBBDI	-60	-40
704-741	Coated electrode (MA)	KABHI	-50	-50
CW 052	SFA 5.5 E9018-G	4452004	-74	-74
CW 052	SFA 5.23 F8P6-EG-F3	PG31223720	-76	-76

Table 5.2-14B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 4 of 5)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-722	Flux electrode comb. (SAA)	124	0797	-90	-70
101-741	Flux electrode comb. (SAA)	124	1061	-80	-80
101-742	Flux electrode comb. (SAA)	124	0797	-90	-70
102-711	Flux electrode comb. (SAA)	124	1061	-80	-80
103-722	Flux electrode comb. (SAA)	124	0797	-90	-70
104-711	Flux electrode comb. (SAA)	124	1061	-80	-80
105-722	Flux electrode comb. (SAA)	124	0797	-90	-70
201-771	Flux electrode comb. (SAA)	124	1061	-80	-80
203-742	Flux electrode comb. (SAA)	124	0797	-90	-70
203-742	Flux electrode comb. (SAA)	124	0797	-90	-70
203-742	Flux electrode comb. (SAA)	124	0797	-90	-70
301-741	Flux electrode comb. (SAA)	124	1061	-80	-80
401-771	Flux electrode comb. (SAA)	124	1061	-80	-80

Table 5.2-14B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PIPING (Sheet 5 of 5)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
501-741	Flux electrode comb. (SAA)	124	1061	-80	-80
701-741	Flux electrode comb. (SAA)	124	1061	-80	-80
CW 052	Flux electrode comb. (SAA)	Fluorite Basic	5047010	-76	-76

Table 5.2-15

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA(a)

PIPING (Sheet 1 of 4)

Seam Number	Weld Procedure Qualification No.	Materials Joined[b]		Fracture Toughness[c]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
209-742	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
209-742	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
209-742	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
205-742	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
205-742	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
205-742	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
105-722	SAA-SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
105-722	SMA-1.1-171	P No. 1	P No. 1	-70		-70	-70	-70	
105-722	SMA-1.1-163	P No. 1	P No. 1	-50	-40	-50	-50	-40	-40
203-742	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
203-742	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
203-742	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
108-711	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
109-728	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
201-711	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
104-711	SAA-SMA-1.1-103	P No. 1	P No. 1	-50	-50	-50	-50	-50	-50
104-711	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
104-711	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
104-711	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
104-711	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40

a. Per ASME B&PV Code Section III, Article NB 4330

b. P-number designation from ASME B&PV Code, Section IX, Article QW-420, Table QW-422

c. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

d. Allowable by ASME B&PV Code, Section IX, Paragraph QW-403 of Article IV (Welding Data)

Table 5.2-15

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PIPING (Sheet 2 of 4)

Seam Number	Weld Procedure Qualification No.	Materials Joined[b]		Fracture Toughness[c]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
205-771	SMA-1.1-63	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
203-728	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
302-771	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
401-771	SAA-SMA-1.1-103	P No. 1	P No. 1	-50	-50	-50	-50	-50	-50
401-771	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
401-771	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
401-771	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
401-771	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	
701-741	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
701-741	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
701-741	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
704-741	SMA-1.12-103	P No. 1	P No. 3	-40	-40	-60	-60	-50	-50
704-741	SMA-1.3-123	P No. 1	P No. 3	-30	-30	-30	-30	-70	-70
704-741	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
801-741	SMA-3.8-101	P No. 3	P No. 8	-10	20	N/A	N/A	N/A	N/A
101-722	SAA-SMA-1.1-110	P No. 1	P No. 1	-50	-50	-50	10	-50	-50
101-722	SMA-1.1-171	P No. 1	P No. 1	-20	-20	-70	-70	-60	-60
101-722	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
101-742	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
101-742	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
101-742	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
401-741	SMA-3.8-101	P No. 3	P No. 8	-10	-20	N/A	N/A	N/A	N/A
306-741	SMA-1.12-103	P No. 1	P No. 3[d]	-40	-40	-60	-60	-50	-50
306-741	SMA-1.3-123	P No. 1	P No. 3[d]	-30	-30	-30	-30	-70	-70

Table 5.2-15

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[(a)]

PIPING (Sheet 3 of 4)

Seam Number	Weld Procedure Qualification No.	Materials Joined[(b)]		Fracture Toughness[(c)]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
206-728	SMA-3.8-101	P No. 3	P No. 8	-10	20	N/A	N/A	N/A	N/A
402-741	SMA-3.8-101	P No. 3	P No. 8	-10	20	N/A	N/A	N/A	N/A
501-741	SAA-SMA-1.1-109	P No. 1	P No. 1	-60	-60	-60	-60	-60	-60
501-741	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
501-741	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
504-741	SMA-1.12-103	P No. 1	P No. 3	-40	-40	-60	-60	-50	-50
504-741	SMA-1.3-123	P No. 1	P No 3	-30	-30	-30	-30	-70	-70
506-741	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
201-741	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
201-741	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
201-741	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
201-741	SAA-SMA-1.1-103	P No. 1	P No. 1	-50	-50	-50	-50	-50	-50
201-741	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
203-771	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
103-728	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
301-771	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
102-711	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
102-711	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
102-711	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
103-722	SAA-SMA-1.1-110	P No. 1	P No. 1	-50	-50	-50	10	-50	-50
103-722	SMA-1.1-171	P No. 1	P No. 1	-20	-20	-70	-70	-60	-60
103-722	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40

Table 5.2-15

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[(a)]

PIPING (Sheet 4 of 4)

Seam Number	Weld Procedure Qualification No.	Materials Joined[(b)]		Fracture Toughness[(c)]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-741	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
101-741	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
101-741	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
209-728	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
602-741	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
106-741	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
209-728	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
202-741	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
104-741	SMA-1.12-103	P No. 1	P No. 3[d]	-40	-40	-60	-60	-50	-50
104-741	SMA-1.3-123	P No. 1	P No. 3[d]	-30	-30	-30	-30	-70	-70
106-728	SMA-3.8-101	P No. 3	P No. 8	-10	20	N/A	N/A	N/A	N/A
201-741	SMA-3.8-101	P No. 3	P No. 8	-10	20	N/A	N/A	N/A	N/A
301-741	SAA-SMA-1.1-109	P No. 1	P No. 1	-50	-50	-60	-60	-50	-50
301-741	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
301-741	SMA-1.1-153	P No. 1	P No. 1	-40	-40	-40	-40	-40	-40
304-741	SMA-1.12-103	P No. 1	P No. 3[d]	-40	-40	-60	-60	-50	-50
304-741	SMA-1.3-123	P No. 1	P No. 3[d]	-30	-30	-30	-50	-70	-70
403-771	SMA-1.1-163	P No. 1	P No. 1	-40	-40	-50	-50	-40	-40
203-728	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
501-771	SMA-1.8-103	P No. 1	P No. 8	-50	-50	N/A	N/A	N/A	N/A
CW 052	1696/G + 1627/E Int +1829	P No. 1	P No. 3[(d)]	N/A	N/A	-22	N/A	N/A	N/A

Table 5.2-15A

PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PIPING (Sheet 1 of 3)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-722	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
101-722	SAA-1.1-1971	5167	5167	-20	-20	-70	-70	-20	-20
101-722	AA-SMA-1.1-110	5167	5167	-50	-50	-50	-50	-50	-50
101-741	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
101-741	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
106-741	AA-SMA-1.1-103	5167	5167	-50	-50	-50	-50	-50	-50
101-742	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
101-742	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
101-742	AA-SMA-1.1-103	5167	5167	-50	-50	-50	-50	-50	-50
101-742	AA-SMA-1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
102-711	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
102-711	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
102-711	AA-SMA-1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
103-722	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
103-722	SAA-1.1-1971	5167	5167	-20	-20	-70	-70	-20	-20
103-722	AA-SMA-1.1-110	5167	5167	-50	-50	-50	-50	-50	-50
104-711	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
104-711	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
104-711	AA-SMA-1.1-103	5167	5167	-50	-50	-50	-50	-50	-50
104-741	SMA-1.12-103	5167	5331	-40	-40	-40	-40	-50	-50
104-741	SMA-1.12-104	5167	5331	0	0	-40	-40	-50	-50
104-741	SMA-1.3-123	5167	5331	0	0	-30	-30	-50	-50
105-722	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
105-722	SAA-1.1-1971	5167	5167	-20	-20	-70	-70	-20	-20
105-722	AA-SMA-1.1-110	5167	5167	-50	-50	-50	-50	-50	-50
106-741	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-15A

PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PIPING (Sheet 2 of 3)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
108-711	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
201-741	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
201-741	SAA-SMA-1.1-103	5167	5167	-50	-50	-50	-50	-50	-50
203-742	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
203-742	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
203-742	SAA-SMA-1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
203-771	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
205-742	SAA-SMA-1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
205-742	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
205-742	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
205-771	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
209-742	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
209-742	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
209-742	SAA-SMA-1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
301-741	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
301-741	SAA-SMA-1.1-103	5167	5167	-50	-50	-50	-50	-50	-50
304-741	SMA-1.12-103	5167	5331	-40	-40	-40	-40	-50	-50
304-741	SMA-1.12-104	5167	5331	0	0	-40	-40	-50	-50
304-741	SMA-1.3-123	5167	5331	0	0	-30	-30	-50	-50
306-741	SMA-1.12-103	5167	5331	-40	-40	-40	-40	-50	-50
306-741	SMA-1.12-104	5167	5331	0	0	-40	-40	-50	-50
306-741	SMA-1.3-123	5167	5331	0	0	-30	-30	-50	-50
401-771	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
401-771	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
401-771	SAA-SMA-1.1-103	5167	5167	-50	-50	-50	-50	-50	-50
401-771	SAA-SMA-1.1-109	5167	5167	-50	-50	-60	-60	-50	-50

Table 5.2-15A

PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[(a)]

PIPING (Sheet 3 of 3)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[(b)]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
403-771	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
501-741	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
501-741	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
501-741	SAA-SMA-1.1-103	5167	5167	-50	-50	-50	-50	-50	-50
504-741	SMA-1.12-103	5167	5331	-40	-40	-40	-40	-50	-50
504-741	SMA-1.12-104	5167	5331	0	0	-40	-40	-50	-50
504-741	SMA-1.3-123	5167	5331	0	0	-30	-30	-50	-50
506-741	SMA-1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
701-741	SMA-1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
701-741	SAA-SMA-1.1-103	5167	5167	-50	-50	-50	-50	-50	-50
704-741	SMA-1.12-103	5167	5331	-40	-40	-40	-40	-50	-50
704-741	SMA-1.12-104	5167	5331	0	0	-40	-40	-50	-50
704-741	SMA-1.3-123	5167	5331	0	0	-30	-30	-50	-50
CW-052[(c)]	1696/G	SA508 Cl.3	SA508 Cl.3	NR	NR	NR	NR	NR	NR
CW-052[(c)]	1627/E + Int(Saw)	SA508 Cl.3	SA508 Cl.3	-	-76	-	-67	-	-
CW-052[(c)]	1627/E + Int(Saw)	SA508 Cl.3	SA508 Cl.3	-	-61.6	-	-58	-	-

(c) Applicable to steam generator cold leg elbow and spool pieces.

Table 5.2-15B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PIPING (Sheet 1 of 6)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-722	SAA -1.1-171	5167	5167	N/A	N/A	-70	-70	N/A	N/A
101-722	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
101-741	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
101-741	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
101-741	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
101-741	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
101-742	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
101-742	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
101-742	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
101-742	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
102-711	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
102-711	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Codes, Section III, Article NB-2330

Table 5.2-15B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PIPING (Sheet 2 of 6)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
102-711	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
102-711	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
103-722	SAA -1.1-171	5167	5167	N/A	N/A	-70	-70	N/A	N/A
103-722	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
104-711	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
104-711	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
104-711	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
104-711	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
104-741	SMA -1.12-103	5167	5331	-40	-40	-60	-60	-50	-50
104-741	SMA -1.12-104	5167	5331	0	0	-40	-40	-50	-50
104-741	SMA -1.3-123	5167	5331	0	0	-30	-30	-50	-50
105-722	SAA -1.1-171	5167	5167	N/A	N/A	-70	-70	N/A	N/A
105-722	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50

Table 5.2-15B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PIPING (Sheet 3 of 6)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
106-741	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
108-711	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
108-711	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
201-771	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
201-771	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
201-771	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
201-771	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
203-742	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
203-742	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
203-742	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
203-742	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
203-771	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
205-742	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
205-742	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
205-742	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
205-742	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50

Table 5.2-15B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[(a)]

PIPING (Sheet 4 of 6)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[(b)]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
205-771	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
209-742	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
209-742	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
209-742	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
209-742	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
301-741	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
301-741	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
301-741	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
301-741	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
304-741	SMA -1.12-103	5167	5331	-40	-40	-60	-60	-50	-50
304-741	SMA -1.12-104	5167	5331	0	0	-40	-40	-50	-50
304-741	SMA -1.3-123	5167	5331	0	0	-30	-30	-50	-50
306-741	SMA -1.12-103	5167	5331	-40	-40	-60	-60	-50	-50
306-741	SMA -1.12-104	5167	5331	0	0	-40	-40	-50	-50
306-741	SMA -1.3-123	5167	5331	0	0	-30	-30	-50	-50

Table 5.2-15B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA(a)

PIPING (Sheet 5 of 6)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
401-771	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
401-771	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
401-771	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
401-771	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
403-771	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
501-741	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
501-741	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
501-741	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
501-741	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
504-741	SMA -1.12-103	5167	5331	-40	-40	-60	-60	-50	-50
504-741	SMA -1.12-104	5167	5331	0	0	-40	-40	-50	-50
504-741	SMA -1.3-123	5167	5331	0	0	-30	-30	-50	-50
506-741	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50
701-741	SMA -1.1-153	5167	5167	-50	-50	-40	-40	-50	-50
701-741	SMA -1.1-163	5167	5167	-50	-50	-50	-50	-50	-50

Table 5.2-15B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PIPING (Sheet 6 of 6)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
701-741	SAA-SMA -1.1-104	5167	5167	-50	-50	-60	-60	-50	-50
701-741	SAA-SMA -1.1-109	5167	5167	-50	-50	-60	-60	-50	-50
704-741	SMA -1.12-103	5167	5331	-40	-40	-60	-60	-50	-50
704-741	SMA -1.12-104	5167	5331	0	0	-40	-40	-50	-50
704-741	SMA -1.3-123	5167	5331	0	0	-30	-30	-50	-50
CW 052	1696/G + 1627/E Int.2 + 1829 Int.	SA 508 Cl. 3	SA-508 Cl. 1a	N/A	N/A	-22	-22	N/A	N/A

Table 5.2-16

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

PRESSURIZER (PLATES)

Piece Number	Reference Drawing No.	Material Code No.	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} (°F)
602-101	E-78373-661-002-04	M-7313-1	SA533-GRB-CL1	Top Head Dome	-10	-10[a]
642-102	E-78373-661-002-04	M-5008-1	SA533-GRB-CL1	Lower Shell Plate	-10	-10[a]
642-102	E-78373-661-002-04	M-5008-2	SA533-GRB-CL1	Lower Shell Plate	-10	+20[a]
676-102	E-78373-661-002-04	M-7030-1	SA533-GRB-CL1	Manway Cover	-10	-10[a]
622-102	E-78373-661-002-04	M-7309-2	SA533-GRB-CL1	Upper Shell Plate	-10	-10[a]
622-102	E-78373-661-002-04	M-7309-2	SA533-GRB-CL1	Upper Shell Plate	-10	-10[a]
652-101	E-78373-661-002-04	M-7313-1	SA533-GRB-CL1	Bottom Head Dome	-10	-10[a]

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331 (a-1, 2, 3)

Table 5.2-16A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

PRESSURIZER (PLATES)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Drop Weight NDT (°F)	RT_{NDT} (a) (°F)
676-102	E-79373-661-002-02	F-1294-01	SA533-GRB-CL1	Top Head Dome	-10	-10
602-101	E-79373-661-002-02	F-1405-1A	SA533-GRA-CL1	Top Head Dome	-10	-10
652-101	E-79373-661-002-02	F-1405-1B	SA533-GRA-CL1	Bottom Head Plate	-10	-10
642-102	E-79373-661-002-02	F-1410-01	SA533-GRA-CL1	Lower Shell Plate	-10	-10
642-102	E-79373-661-002-02	F-1410-02	SA533-GRA-CL1	Lower Shell Plate	-10	-10
622-102	E-79373-661-002-02	F-1411-01	SA533-GRA-CL1	Upper Shell Plate	-10	-10
622-102	E-79373-661-002-02	F-1411-02	SA533-GRA-CL1	Upper Shell Plate	-10	-10

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331 (a-1, 2, 3)

Table 5.2-16B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

PRESSURIZER (PLATES)

Piece Number	Reference Drawing Number	Material Code Number	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} (°F)
676-102	E-65373-661-002-04	F-6717-01	SA533-GRB-CL1	Manway Cover	-23	-23[a]
622-102	E-65373-661-002-04	F-7010-01	SA533-GRA-CL1	Upper Shell Plate	-10	-10[a]
622-102	E-65373-661-002-04	F-7010-02	SA533-GRA-CL1	Upper Shell Plate	-10	-10[a]
642-102	E-65373-661-002-04	F-7011-01	SA533-GRA-CL1	Lower Shell Plate	-10	+30[a]
642-102	E-65373-661-002-04	F-7011-02	SA533-GRA-CL1	Lower Shell Plate	-10	+20[a]
602-101	E-65373-661-002-04	F-7012-1A	SA533-GRA-CL1	Top Head Dome	-10	-10[a]
652-101	E-65373-661-002-04	F-7012-1B	SA533-GRA-CL1	Bottom Head Plate	-10	-10[a]

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

Table 5.2-17
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
PRESSURIZER (FORGINGS)

Piece Number	Reference Drawing No.	Material Code No.	Material Specification	Location	Drop Weight NDT (°F)	RT_{NDT} (°F)
656-101	E-78373-661-002-03	M-7301-1	SA508-CL2	Support Skirt	-10	-10[a]
658-201	E-78373-661-002-03	M-7302-1	SA541-CL2	Surge Nozzle	-10	-10[a]
608-303	E-78373-661-002-03	M-7303-1	SA541-CL2	Safety Valve Nozzle	-10	+40[a]
608-303	E-78373-661-002-03	M-7303-2	SA541-CL2	Safety Valve Nozzle	-10	+40[a]
608-303	E-78373-661-002-03	M-7303-3	SA541-CL2	Safety Valve Nozzle	-10	+40[a]
608-303	E-78373-661-002-03	M-7303-4	SA541-CL2	Safety Valve Nozzle	-10	+40[a]
608-304	E-78373-661-002-03	M-7304-1	SA541-CL2	Spray Nozzle Nozzle	-10	+10[a]

a. Determined per applicable ASME B&PV Code and addenda Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

Table 5.2-17A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

PRESSURIZER (FORGINGS)

Piece Number	Reference Drawing Number	Material Code Number	Material Specification	Location	Drop Weight NDT (°F) 0-DEG	Drop Weight NDT (°F) 180-DEG	RT_{NDT} (a) (°F) or LST 0-DEG	RT_{NDT} (a) (°F) or LST 180-DEG
608-3101	E-79373-661-002-02	F-1401-01	A541-CL3	Spray Nozzle	-10		-10	
608-3201	E-79373-661-002-02	F-1402-01	A541-CL3	Safety Valve Nozzle	-10		-10	
608-3201	E-79373-661-002-02	F-1402-02	A541-CL3	Safety Valve Nozzle	-10		-10	
608-3201	E-79373-661-002-02	F-1402-03	A541-CL3	Safety Valve Nozzle	N/A		40	
608-3201	E-79373-661-002-02	F-1402-04	A541-CL3	Safety Valve Nozzle	N/A		40	
658-3101	E-79373-661-002-02	F-1403-01	A541-CL3	Surge Nozzle	N/A		40	
656-101	E-79373-661-002-02	F-1408-01	SA508-CL3	Support Skirt				

a. Determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

Table 5.2-17B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

PRESSURIZER (FORGINGS)

Piece Number	Reference Drawing No.	Material Code No.	Material Specifi-cation	Location	Drop Weight NDT (°F)	RT_{NDT}[(c)] (°F)
608-3201	E-65373-661-002-04	F-7007-01	SA508-CL3	Safety Valve Nozzle	-10	+10[(b)]
608-3201	E-65373-661-002-04	F-7007-02	SA508-CL3	Safety Valve Nozzle	-10	+10[(b)]
608-3201	E-65373-661-002-04	F-7007-03	SA508-CL3	Safety Valve Nozzle	-10	+10[(b)]
608-3201	E-65373-661-002-04	F-7007-04	SA508-CL3	Safety Valve Nozzle	-10	+10[(b)]
608-3101	E-65373-661-002-04	F-7008-01	A541-CL3	Spray Nozzle	-20	0[(b)]
658-3301	E-65373-661-002-04	F-7009-01	A541-CL3	Surge Nozzle	-10	+30[(a)]
656-3101	E-65373-661-002-04	F-7013-01	SA508-CL3	Support Skirt	-10	-10[(a)]

a. Determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

b. Determined per MTEB 5-2

c. Lowest service temperature

Table 5.2-18

PVNGS UNITS 1, 2, AND 3 REACTOR COOLANT

PRESSURE BOUNDARY WELD SEAM

IDENTIFICATION: PRESSURIZER

Seam No.	Weld Seam Nomenclature
101-622	Upper Shell Long Seam
101-642	Lower Shell Long Seam
106-601	Spray Nozzle to Top Head
104-601	Safety Valve Nozzle to Upper Shell
103-651	Surge Nozzle to Bottom Head
101-621	Top Head to Upper Shell Course Girth Seam
103-641	Bottom Head to Lower Shell Course Girth Seam
301-671	Upper Shell Course to Lower Shell Course Girth Seam
105-601	Pressurizer Manway Weld Buildup

Table 5.2-19

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PRESSURIZER (Sheet 1 of 2)

Component Weld Seam	Electrode Code	Flux Type	Flux Lot	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-621	Flux Electrode Comb. (SAA)	124	0871	-80	-70
101-622	Flux Electrode Comb. (SAA)	124	1061	-80	-80
101-622	Flux Electrode Comb. (SAA)	124	0171	-80	-60
101-642	Flux Electrode Comb. (SAA)	124	1061	-70	-70
101-642	Flux Electrode Comb. (SAA)	124	0171	-80	-60
103-641	Flux Electrode Comb. (SAA)	124	0871	-70	-70
105-601	Flux Electrode Comb. (SAA)	124	1061	-80	-80
105-601	Flux Electrode Comb. (SAA)	124	0171	-80	-80
301-671	Flux Electrode Comb. (SAA)	124	0171	-80	-70
301-671	Flux Electrode Comb. (SAA)	124	0171	-80	-80

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-19

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PRESSURIZER (Sheet 2 of 2)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-621	Coated Electrode (MA)	GABGG	-50	-50
101-621	Coated Electrode (MA)	HA0JG	-40	-40
101-621	Coated Electrode (MA)	HAAHG	-70	-70
101-622	Coated Electrode (MA)	LAOGF	-40	-40
101-622	Coated Electrode (MA)	DABGG	-70	-70
101-642	Coated Electrode (MA)	LA0GF	-40	-40
101-642	Coated Electrode (MA)	JAAEF	-60	-60
101-642	Coated Electrode (MA)	CA0JG	-60	-30
103-641	Coated Electrode (MA)	GABGG	-50	-50
103-641	Coated Electrode (MA)	FABBG	-50	-50
103-641	Coated Electrode (MA)	CABCG	-60	-30
103-641	Coated Electrode (MA)	HA0JG	-40	-40
103-651	Coated Electrode (MA)	CABCG	-60	-30
103-651	Coated Electrode (MA)	FABBG	-50	-50
103-651	Coated Electrode (MA)	DABGG	-70	-70
104-601	Coated Electrode (MA)	LA0GF	-40	-40
104-601	Coated Electrode (MA)	CA0JG	-60	-30
104-601	Coated Electrode (MA)	DABGG	-70	-70
104-601	Coated Electrode (MA)	DBBJG	-70	-70
104-601	Coated Electrode (MA)	GABGG	-50	-50
104-601	Coated Electrode (MA)	FABBG	-50	-50
105-601	Coated Electrode (MA)	DABBG	-70	-70
105-601	Coated Electrode (MA)	CA0JG	-60	-30
106-601	Coated Electrode (MA)	CAOJG	-60	-30
106-601	Coated Electrode (MA)	DABGG	-70	-70
106-601	Coated Electrode (MA)	LAOGF	-40	-40
106-601	Coated Electrode (MA)	GABGG	-50	-50
106-601	Coated Electrode (MA)	FABBG	-50	-50
106-601	Coated Electrode (MA)	DBBJG	-70	-70
301-671	Coated Electrode (MA)	GABGG	-50	-50
301-671	Coated Electrode (MA)	FABBG	-50	-50
301-671	Coated Electrode (MA)	DABGG	-70	-70

Table 5.2-19A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PRESSURIZER (Sheet 1 of 2)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	$^{T}NDT^{(b)}$ (°F)	$^{RT}NDT^{(b)}$ (°F)
101-621	Coated Electrode (MA)	JAOEH	-60	-30
101-622	Coated Electrode (MA)	ABCAH	-60	-60
101-622	Coated Electrode (MA)	GABGG	-50	-50
101-622	Coated Electrode (MA)	HAAHG	-70	-70
101-622	Coated Electrode (MA)	HACJG	-40	-40
101-642	Coated Electrode (MA)	HACJG	-40	-40
103-641	Coated Electrode (MA)	EAOAH	-60	-60
103-641	Coated Electrode (MA)	HAAHG	-70	-70
103-641	Coated Electrode (MA)	JAOEH	-60	-30
103-651	Coated Electrode (MA)	ABCAH	-60	-60
103-651	Coated Electrode (MA)	HABJF	-70	-70
103-651	Coated Electrode (MA)	LAOHG	-50	-30
104-601	Coated Electrode (MA)	ABCAH	-60	-60
104-601	Coated Electrode (MA)	EAOAH	-60	-60
104-601	Coated Electrode (MA)	HAAHG	-70	-70
104-601	Coated Electrode (MA)	LAOHG	-50	-30
106-601	Coated Electrode (MA)	ABCAH	-60	-60
106-601	Coated Electrode (MA)	EAOAH	-60	-60
106-601	Coated Electrode (MA)	LAOHG	-50	-30
301-671	Coated Electrode (MA)	ABCAH	-60	-60
301-671	Coated Electrode (MA)	LAOHG	-50	-30

a. Per ASME B&PV Code, Section III, Article NB-2430
b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-19A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[(a)]

COMPONENT: PRESSURIZER (Sheet 2 of 2)

Component Weld Seam Number	Electrode Code	Flux Type	Flux Lot	T_{NDT}[(b)] (°F)	RT_{NDT}[(b)] (°F)
101-621	Flux Electrode Comb. (SAA)	124	0281	-80	-60
101-621	Flux Electrode Comb. (SAA)	124	0281	-50	-10
101-622	Flux Electrode Comb. (SAA)	124	0871	-80	-70
101-642	Flux Electrode Comb. (SAA)	124	0871	-80	-70
103-641	Flux Electrode Comb. (SAA)	124	0281	-80	-80
105-601	Flux Electrode Comb. (SAA)	124	0871	-80	-80
105-601	Flux Electrode Comb. (SAA)	124	0871	-80	-70
301-671	Flux Electrode Comb. (SAA)	124	0281	-80	-80

Table 5.2-19B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PRESSURIZER (Sheet 1 of 2)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-621	Coated Electrode (MA)	DAAHJ	-40	-40
101-621	Coated Electrode (MA)	JABCJ	-50	-50
101-621	Coated Electrode (MA)	KAOEJ	-70	-70
101-622	Coated Electrode (MA)	AAOCJ	-50	-40
101-622	Coated Electrode (MA)	CAAIJ	-60	-60
101-622	Coated Electrode (MA)	IAOHJ	-50	-50
101-622	Coated Electrode (MA)	KAAEI	-60	-60
101-622	Coated Electrode (MA)	LAADI	-60	-60
101-642	Coated Electrode (MA)	CAAIJ	-60	-60
101-642	Coated Electrode (MA)	KAAEI	-60	-60
103-641	Coated Electrode (MA)	AAOCJ	-50	-40
103-641	Coated Electrode (MA)	CAAIF	-60	-60
103-641	Coated Electrode (MA)	IAOHJ	-50	-50
103-651	Coated Electrode (MA)	AAAGJ	-60	-60
103-651	Coated Electrode (MA)	CAAIJ	-60	-60
103-651	Coated Electrode (MA)	IAOHJ	-50	-50
104-601	Coated Electrode (MA)	CAAIJ	-60	-60
104-601	Coated Electrode (MA)	DAAHJ	-40	-40
104-601	Coated Electrode (MA)	IAOHJ	-50	-50
104-601	Coated Electrode (MA)	KAOEJ	-70	-70
105-601	Coated Electrode (MA)	CAAIJ	-60	-60
106-601	Coated Electrode (MA)	CAAIJ	-60	-60
106-601	Coated Electrode (MA)	DAAHJ	-40	-40
106-601	Coated Electrode (MA)	IAOHJ	-50	-50
106-601	Coated Electrode (MA)	KAOEJ	-70	-70
301-671	Coated Electrode (MA)	CAAIJ	-60	-60
301-671	Coated Electrode (MA)	IAOHJ	-50	-50

a. Per ASME B&PV Code, Section III, Article NB-2430
b. Per ASME B&PV Code, Section III, Article NB-2330

INTEGRITY OF REACTOR

COOLANT PRESSURE BOUNDARY

Table 5.2-19B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: PRESSURIZER (Sheet 2 of 2)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
101-621	Flux Electrode Comb. (SAA)	124 1203	-70	-70
101-622	Flux Electrode Comb. (SAA)	124 0797	-100	-30
101-642	Flux Electrode Comb. (SAA)	124 0797	-100	-30
103-641	Flux Electrode Comb. (SAA)	124 0797	-90	-70
103-651	Flux Electrode Comb. (SAA)	124 0797	-70	-70
105-601	Flux Electrode Comb. (SAA)	124 0797	-90	-70
301-671	Flux Electrode Comb. (SAA)	124 0797	-90	-70

Table 5.2-20

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PRESSURIZER (Sheet 1 of 2)

Seam Number	Weld Procedure Qualification No.	Materials Joined[b]		Fracture Toughness[c]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-622	SAA-SMA-3.3-107	P No. 3	P No. 3	0	0	-50	-40	0	0
101-622	SMA-3.3-127	P No. 3	P No. 3	-50	-10	-50	-50	-60	10
101-642	SAA-SMA-3.3-107	P No. 3	P No. 3	0	0	-50	-40	0	0
101-642	SMA-3.3-127	P No. 3	P No. 3	-50	-10	-50	-50	-50	10
101-642	SAA-SMA-3.3-106	P No. 3	P No. 3	-50	-10	-50	-50	-50	-10
106-601	SMA-3.3-126	P No. 3	P No. 3	0	0	-40	-40	0	0
106-601	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
104-601	SMA-3.3-126	P No. 3	P No. 3	0	0	-40	-40	0	10
104-601	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
103-651	SMA-3.3-126	P No. 3	P No. 3	0	0	-40	-40	0	0
	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
101-621	SAA-SMA-3.3-106	P No. 3	P No. 3	-50	-10	-50	-50	-50	-10
101-621	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
		No.							

a. Per ASME B&PV Code, Section III, Article NB-4330

b. P-number designation from ASME B&PV Code, Section IX, Article QW-420, Table QW-422

c. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-20

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PRESSURIZER (Sheet 2 of 2)

Seam Number	Weld Procedure Qualification No.	Materials Joined[b]		Fracture Toughness[c]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
103-641	SAA-SMA-3.3-106	P No. 3	P No. 3	-50	-10	-50	-50	-50	-10
103-641	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
301-671	SMA-3.3-127	P No. 3	P No. 3	-50	10	-50	-50	-50	10
301-671	SAA-SMA-3.3-106	P No. 3	P No. 3	-50	-10	-50	-50	-50	-10
301-671	SAA-SMA-3.3-107	P No. 3	P No. 3	0	0	-50	-40	0	0
105-601	SAA-SMA-3.3-106	P No. 3	P No. 3	-50	-10	-50	-50	-50	-10

Table 5.2-20A

PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[(a)]

PRESSURIZER

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[(b)]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-621	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
101-621	SAA-SMA-3.3-106	5331	5331	-20	0	-50	-50	-20	0
101-622	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
101-622	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
101-622	SAA-SMA-3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-642	SAA-SMA-12.12-102	5331	5331	-20	0	-50	-50	-20	0
103-641	SAA-SMA-3.3-106	5331	5331	-20	0	-50	-50	-20	0
103-651	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
103-651	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
104-601	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
104-601	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
105-601	SAA-SMA-3.3-106	5331	5331	-20	0	-50	-50	-20	0
106-601	SMA-3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
106-601	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
301-671	SMA-3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
301-671	SAA-SMA-3.3-106	5331	5331	-20	0	-50	-50	-20	0

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-20B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

PRESSURIZER (Sheet 1 of 2)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
101-621	SMA -3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
101-621	SAA-SMA -3.3-106	5331	5331	-20	0	-50	-50	-20	0
101-622	SMA -3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
101-622	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
101-642	SMA -3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
101-642	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
103-641	SMA -3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
103-641	SMA -3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
103-641	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10
103-651	SAA -3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
103-651	SAA-SMA -3.3-112	5331	5331	+10	+10	-60	-60	+10	+10

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-20B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[(a)]

PRESSURIZER (Sheet 2 of 2)

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[(b)]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
104-601	SMA -3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
104-601	SMA -3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
105-601	SAA-SMA -3.3-106	5331	5331	-20	0	-50	-50	-20	0
106-601	SMA -3.3-126	5331	5331	-40	-30	-40	-40	-40	-30
106-601	SMA -3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
301-671	SAA -3.3-127	5331	5331	-50	+10	-50	-50	-50	+10
301-671	SAA-SMA -3.3-107	5331	5331	-50	+10	-50	-40	-50	+10

Table 5.2-21

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 1 (PLATES and FORGINGS)

Position	Reference Drawing Number	Material Specification	Location in Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F)	Material Code No.
3	PX-DWD-10-060	SA-508 Class 3	Primary Head	-30	-30	-
5	PX-DWD-10-060	SA-508 Class 3	Stay Cylinder	+1	+1	-
6	PX-DWD-10-061	SA-508 Class 3	Primary Inlet Nozzle	+1	+1	-
7	PX-DWD-10-061	SA-508 Class 1a	Primary Inlet Safe-End	-17	-17	-
8	PX-DWD-10-061	SA-508 Class 3	Primary Outlet Nozzle	+1	+1	-
11	PX-DWD-10-054	SB-166	Primary Instrument Nozzle	(a)	(a)	-
12	PX-DWD-11-051	SA-508 Class 3a	Tubesheet	-50	-50	-
45-2	PX-DWD-15-080	SA-533 GR B Cl 1	Primary Manway Cover Plate	-39	-39	-

a. Not required as per ASME III NB 2311-6 and 7.

Table 5.2-21A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 1 (PLATES AND FORGINGS) (Sheet 1 of 3)

Piece Number	Reference Drawing Number	Material Code Number	Material Specification	Location	Drop Weight$_{NDT}$	RT_{NDT} [(a)]
1	PV-DWD-10-ABB065	-	SA-508 Cl. 3	Support Skirt	-20	-20
3	PV-DWD-10-ABB060	-	SA-508 Cl. 3	Primary Head	-50	-50
5	PV-DWD-10-ABB060	-	SA-508 Cl. 3	Stay Cylinder	-20	-20
6	PV-DWD-10-ABB061	-	SA-508 Cl. 3	Primary Inlet Nozzle	+10	+10
7	PV-DWD-10-ABB061	-	SA-508 Cl. 1a	Primary Inlet Safe-End	-8	-8
8	PV-DWD-10-ABB061	-	SA-508 Cl. 3	Primary Outlet Nozzle	+10	+10
11	PV-DWD-10-ABB054	-	SB-166	Primary Instrument Nozzle	Note 1	Note 1
12	PV-DWD-11-ABB051	-	SA-508 Cl. 3	Tubesheet	-35	-35
13	PV-DWD-11-ABB051	-	SA-508 Cl. 1a	Tubesheet Drain Nozzle	-35	-26
14	PV-DWD-11-ABB051	-	SA-336 F 12	Tubesheet Blowdown Nozzle	+10	+10
15	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Stub Barrel	-47	-47
16	PV-DWD-11-ABB055	-	SA-508 Cl. 3	Feedwater Nozzle	-29	-29
17	PV-DWD-11-ABB055	-	SA-508 Cl. 1a	Feedwater Safe-End	-8	-8
18	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Lower Shell Level Nozzle	-35	-26
19	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Intermediate Shell	-47	-47
20	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Shell Cone	-16	-16
21	PV-DWD-12-ABB068	-	SA-336 Cl. F 12	Downcomer Blowdown Nozzle	+10	+10
22	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Shell Cone Level Nozzle	-35	-26
23	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Upper Shell	+10	+10
24	PV-DWD-13-ABB058	-	SA-508 Cl. 3	Recirculation Nozzle	-17	-17
25	PV-DWD-13-ABB058	-	SA-508 Cl. 1a	Recirculation Nozzle Safe-End	-8	-8

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

Note 1: Not requested as per ASME III NB 2311-6 and 7

Table 5.2-21A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 1 (PLATES AND FORGINGS) (Sheet 2 of 3)

Piece Number	Reference Drawing Number	Material Code Number	Material Specification	Location	Drop Weight$_{NDT}$	RT_{NDT}(a)
26	PV-DWD-12-ABB057	-	SA-508 Cl. 3	Downcomer Feedwater Nozzle	-17	-17
27	PV-DWD-12-ABB057	-	Alloy 690	Downcomer Feedwater Nozzle Safe-end	Note 1	Note 1
28	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Upper Shell Level Nozzle	-35	-26
29	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Top Head Torus	-31	-31
30-1	PV-DWD-13-ABB059	-	SA-508 Cl. 1a	Steam Outlet Nozzle	-8	-8
30-2	PV-DWD-13-ABB059	-	SA-508 Cl. 1a	Pressure Tap Nozzle	-35	-26
31	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Pressure Test Nozzle	-35	-26
33	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Lower Shell	-35	-35
34	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Top Head Dome	-31	-31
36-1	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Sampling Nozzle	-35	-26
37	PV-DWD-12-ABB057	-	SA-508 Cl. 1a	Downcomer FW Nozzle Transition Piece	-29	-29
41-1	PV-DWD-15-ABB081	-	SA-508 Cl. 3	Secondary Manway Nozzle	-8	-8
41-2	PV-DWD-15-ABB081	-	SA-533 Gr B Cl. 1	Secondary Manway Cover Plate	-29	-29
43-1	**PV-DWD-11-ABB056**	**-**	**SFA 5.5** **SFA 5.23**	**Handhole (build-up)**	**-58** **-58**	**-49** **-49**
43-2	PV-DWD-15-ABB081	-	SA-533 Gr B Cl. 1	Cover Plate	-29	-29
44-1	**PV-DWD-11-ABB056**	**-**	**SFA 5.5** **SFA 5.23**	**Handhole (build-up)**	**-58** **-58**	**-49** **-49**
44-2	**PV-DWD-23-ABB074**	**-**	**SA-106 Gr. B**	**Sleeve**	**NR**	**NR**
45-1	**PV-DWD-10-ABB060**	**-**	**SFA 5.5**	**Primary Manway (build-up)**	**-49**	**-49**
45-2	PV-DWD-15-ABB080	-	SA-533 Gr B Cl. 1	Cover Plate	-29	-29
45-9	PV-DWD-10-ABB060	-	SB-163	Drain Tube	Note 1	Note 1

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

Note 1: Not requested as per ASME III NB 2311-6 and 7

Table 5.2-21A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 1 (PLATES AND FORGINGS) (Sheet 3 of 3)

Piece Number	Reference Drawing Number	Material Code Number	Material Specification	Location	Drop Weight$_{NDT}$	RT_{NDT} (a)
51-1	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Snubber Lug Arm	-35	-35
52	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Key Bracket	-8	-8
53	PV-DWD-10-ABB070	-	SB-168 or SB-564	Outlet Clamp Ring	Note 1	Note 1
55	PV-DWD-10-ABB070	-	SB-168 or SB-564	Inlet Clamp Ring	Note 1	Note 1
57-1	PV-DWD-10-ABB069	-	SB-168	Divider Plate	Note 1	Note 1
57-2	PV-DWD-10-ABB069	-	SB-168	Inner Patch Plate Assembly	Note 1	Note 1
57-3	PV-DWD-10-ABB069	-	SB-168	Divider Bars	Note 1	Note 1
57-6	PV-DWD-10-ABB069	-	SB-168	Outer Patch Plate Assembly	Note 1	Note 1
70-1	PV-DWD-11-ABB056	-	SA-508 Cl. 3	Handhole	-8	-8
70-2	PV-DWD-23-ABB092	-	SA-106 Gr. B	Sleeve	not required	not required
71	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Key Bracket	-8	-8
72	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Lug	+10	+10
78-1	PV-DWD-11-ABB056	-	SFA 5.5	Handhole (build-up)	**-58**	**-49**
			SFA 5.23		**-58**	**-49**
81	PV-DWD-23-ABB071	-	SA-516 Gr. 70	Upper Support Ring	-58	-58
85	PV-DWD-23-ABB071	-	SA-516 Gr. 70	Lower Support Ring	-58	-58
87	PV-DWD-23-ABB072	-	SA-516 Gr. 70	Divider Support Bar	-40	-40
107-1	PV-DWD-11-ABB056	-	SA-508 Cl. 3	Handhole	-8	-8
108	PV-DWD-24-ABB066	-	SA-516 Gr. 70	Shroud Lateral Support	-40	-40

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331-(a-1, 2, 3)

Note 1: Not requested as per ASME III NB 2311-6 and 7

Table 5.2-21B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 1 (PLATES AND FORGINGS)

Position	Reference Drawing Number	Material Specification	Location in Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F)	Material Code Number
3	PX-DWD-10-060	SA-508 Class 3	Primary Head	-30	-30	-
5	PX-DWD-10-060	SA-508 Class 3	Stay Cylinder	+1	+1	-
6	PX-DWD-10-061	SA-508 Class 3	Primary Inlet Nozzle	+1	+1	-
7	PX-DWD-10-061	SA-508 Class 1a	Primary Inlet Safe-End	-17	-17	-
8	PX-DWS-10-061	SA-508 Class 3	Primary Outlet Nozzle	+1	+1	-
11	PX-DWD-10-054	SB-166	Primary Instrument Nozzle	(a)	(a)	-
12	PX-DWD-11-051	SA-508 Class 3a	Tubesheet	-50	-50	-
45-2	PX-DWD-15-080	SA-533 Gr B Cl 1	Primary Manway cover Plate	-39	-39	-

a. Not required as per ASME III NB 2311-6 and 7

Table 5.2-22

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 1 (FORGINGS)

See Table 5.2-21

Table 5.2-22A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 1 (FORGINGS)

See Table 5.2-21A

Table 5.2-22B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 1 (FORGINGS)

See Table 5.2-21B

Table 5.2-23

REACTOR COOLANT

PRESSURE BOUNDARY WELD SEAM IDENTIFICATION:

STEAM GENERATORS 1 AND 2 (PRIMARY SIDE)

Seam No.	Weld Seam Nomenclature
CW 007	Primary Head to Stay Cylinder
CW 900	Tubesheet to Primary Head girth weld
CW 901	Tubesheet to Stay Cylinder
NZ 002	Primary Instrument Nozzle to Primary Head
NZ 003	Primary Head to Primary Inlet Nozzle
NZ 004	Primary Head to Primary Outlet Nozzle
NZ 035	Primary Inlet Nozzle Safe-End to Primary Inlet Nozzle

Table 5.2-24

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: STEAM GENERATOR NO. 1 PRIMARY SIDE

Component Weld Seam Number	Electrode Code	Electrode Lot Number	Drop Weight T_{NDT}(°F) [b]	RT_{NDT} [b] (°F)
NZ 003	SFA 5.5 E9018-G	1103838	-50	-50
NZ 003	SFA 5.5 E9018-G	101847	-65	-65
NZ 003	SFA 5.23 EF3N mod.	273046	-60	-60
NZ 004	SFA 5.5 E9018-G	1103838	-50	-50
NZ 004	SFA 5.5 E9018-G	101847	-65	-65
NZ 004	SFA 5.23 EF3N mod.	140596	-55	-55
NZ 004	SFA 5.23 EG	PG 312233720	-55	-55
CW 007	SFA 5.5 E9018-G	1103838	-50	-50
CW 007	SFA 5.23 EG	PG 312233720	-55	-55
NZ 035	SFA 5.5 E9018-G	6220179	-50	-50
NZ 035	SFA 5.5 E9018-G	1103838	-50	-50
NZ 035	SFA 5.23 EF3N mod.	140596	-55	-55
CW 900	SFA 5.5 E9018-G	4204001	-85	-85
CW 900	SFA 5.5 E9018-G	3122003	-55	-55
CW 900	SFA 5.23 EG	PG 312233720	-55	-55
CW 901	SFA 5.5 E9018-G	4204001	-85	-85
NZ 002	SFA 5.14 ER NiCrFe-7	93542	N.A.	N.A.

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-24A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: STEAM GENERATOR NO. 1 PRIMARY SIDE

Component Weld Seam Number	Electrode Code	Elec-trode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
SP 001	SFA 5.5 E9018-G	900630	-76	-76
SP 001	SFA 5.23 EF3N mod.	140596	-67	-67
NZ 003	SFA 5.5 E9018-G	805867	-58	-58
NZ 004	SFA 5.23 EF3N mod.	140596	-67	-67
CW 007	SFA 5.28 ER 80S-G	718288	Note 1	Note 1
CW 007	SFA 5.5 E9018-G	900630	-76	-76
CW 007	SFA 5.5 E9018-G	805867	-58	-58
CW 007	SFA 5.23 EF3N mod.	140596	-67	-67
NZ 035	SFA 5.5 E9018-G	900630	-76	-76
NZ 035	SFA 5.5 E9018-G	805867	-58	-58

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Note 1: Not requested as per ASME NB 2431 (c)

Table 5.2-24B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: STEAM GENERATOR NO. 1 PRIMARY SIDE

Component Weld Seam Number	Electrode Code	Electrode Lot Number	Drop Weight T_{NDT} (°F) [b]	RT_{NDT}(°F) [b]
NZ 003	SFA 5.5 E9018-G	4452004	-74	-74
NZ 003	SFA 5.23 F8P6-EG-F3	PG312233720	-85	-85
NZ 004	SFA 5.5 E9018-G	4452004	-74	-74
NZ 004	SFA 5.23 F8P6-EG-F3	PG312233720	-85	-85
CW 007	SFA 5.5 E9018-G	4452004	-74	-74
CW 007	SFA 5.23 F8P6-EG-F3	PG312233720	-85	-85
NZ 035	SFA 5.5 E9018-G	3122004	-76	-76
NZ 035	SFA 5.23 F8P6-EG-F3	PG312233720	-85	-85
CW 900	SFA 5.5 E9018-G	4204001	-85	-85
CW 900	SFA 5.5 E9018-G	4452004	-74	-74
CW 900	SFA 5.23 F8P6-EG-F3	PG504AR4809	-58	-58
CW 901 CW 901	SFA 5.23 F8P6-EG-F3 EN 760 A FB 1 55 AC	PG504AR4809 5047010	-58	-58
NZ 002	SFA 5.14 ER NiCrFe-7	93542/2390	N/A	N/A

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-25

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

STEAM GENERATORS 1 AND 2 PRIMARY SIDE

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
NZ 002	1507/E	Butter.	SB-166 N06690	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NZ 003	1627/E+Int+1829	SA 508 Cl. 3	SA 508 Cl. 3	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 004	1627/E+Int+1829	SA 508 Cl. 3	SA 508 Cl. 3	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 007	1627/E+Int+1829	SA 508 Cl. 3	SA 508 Cl. 3	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 900	1627/E+1814	SA 508 Cl. 3a	SA 508 Cl. 3	N.A.	N.A.	-65	-65	N.A.	N.A.
CW 901	1466/E+1814	SA 508 Cl. 3a	SA 508 Cl. 3	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 035	1698/E+1627/e	SA 508 Cl. 3	SA 508 Cl. 1a	N.A.	N.A.	-85	-85	N.A.	N.A.

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-25A

PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

STEAM GENERATORS 1 AND 2 PRIMARY SIDE

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
SP 001	1466/E + 1627/E	SA-508 Cl. 3	SA-508 Cl. 3	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 002	1507/E	Butter	SB-166 N06690	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NZ 003	1627/E	SA-508 Cl. 3	SA-508 Cl. 3	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 004	1627/E	SA-508 Cl. 3	SA-508 Cl. 3	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 007	1969/G + 1627/E	SA-508 Cl. 3	SA-508 Cl. 3	N.A.	N.A.	-31	-31	N.A.	N.A.

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-25B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]

STEAM GENERATORS 1 AND 2 PRIMARY SIDE

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
NZ 002	1507/E	Butter.	SB-166 N06690	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NZ 003	1627/E Int+1829	SA 508 Cl. 3	SA 508 Cl. 3	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 004	1627/E Int+1829	SA 508 Cl. 3	SA 508 Cl. 3	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 007	1627/E Int+1829	SA 508 Cl. 3	SA 508 Cl. 3	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 900	1627/E Int+1829	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-58	-58	N.A.	N.A.
CW 901	1627/E Int+1466/E	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-58	-58	N.A.	N.A.
NZ 035	1466/E+1829	SA 508 Cl. 3	SA 508 Cl. 1a	N.A.	N.A.	-76	-76	N.A.	N.A.

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-26

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 2 (PLATES AND FORGINGS)

Position	Reference Drawing No.	Material Specification	Location	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F)
3	PX-DWD-10-060	SA-508 Class 3	Primary Head	-50	-50
5	PX-DWD-10-060	SA-508 Class 3	Stay Cylinder	-35	-35
6	PX-DWD-10-061	SA-508 Class 3	Primary Inlet Nozzle	+1	+1
7	PX-DWD-10-061	SA-508 Class 1a	Primary Inlet Safe-End	-17	-17
8	PX-DWD-10-061	SA-508 Class 3	Primary Outlet Nozzle	+1	+1
11	PX-DWD-10-054	SB-166	Primary Instrument Nozzle	(a)	(a)
12	PX-DWD-11-051	SA-508 Class 3a	Tubesheet	-50	-50
45-2	PX-DWD-15-080	SA-533 Gr B Cl 1	Primary Manway Cover Plate	-39	-39

a. Not required as per ASME III NB 2311-6 and 7

Table 5.2-26A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 2 (PLATES AND FORGINGS) (Sheet 1 of 3)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	^{DW}NDT (°F)	$^{RT}NDT^{(a)}$ (°F)
1	PV-DWD-10-ABB065	-	SA-508 Cl. 3	Support Skirt	-20	-20
3	PV-DWD-10-ABB060	-	SA-508 Cl. 3	Primary Head	-50	-50
5	PV-DWD-10-ABB060	-	SA-508 Cl. 3	Stay Cylinder	-20	-20
6	PV-DWD-10-ABB061	-	SA-508 Cl. 3	Primary Inlet Nozzle	+10	+10
7	PV-DWD-10-ABB061	-	SA-508 Cl. 1a	Primary Inlet Safe-End	-8	-8
8	PV-DWD-10-ABB061	-	SA-508 Cl. 3	Primary Outlet Nozzle	+10	+10
11	PV-DWD-10-ABB054	-	SB-166	Primary Instrument Nozzle	Note 1	Note 1
12	PV-DWD-11-ABB051	-	SA-508 Cl. 3	Tubesheet	+1	+1
13	PV-DWD-11-ABB051	-	SA-508 Cl. 1a	Tubesheeet Drain Nozzle	-35	-26
14	PV-DWD-11-ABB051	-	SA-336 F 12	Tubesheet Blowdown Nozzle	-8	-8
15	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Stub Barrel	-47	-47
16	PV-DWD-11-ABB055	-	SA-508 Cl. 3	Feedwater Nozzle	-29	-29
17	PV-DWD-11-ABB055	-	SA-508 Cl. 1a	Feedwater Safe-End	-8	-8
18	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Lower Shell Level Nozzle	-35	-26
19	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Intermediate Shell	-47	-47
20	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Shell Cone	-25	-25
21	PV-DWD-12-ABB068	-	SA-336 F 12	Downcomer Blowdown Nozzle	+10	+10
22	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Shell Cone Level Nozzle	-35	-26
23	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Upper Shell	-8	-8

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331-(a-1, 2 ,3)

Note 1: Not requested as per ASME III NB 2311-6 and 7

Table 5.2-26A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 2 (PLATES AND FORGINGS) (Sheet 2 of 3)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	^{DW}NDT (°F)	^{RT}NDT[a] (°F)
24	PV-DWD-13-ABB058	-	SA-508 Cl. 3	Recirculation Nozzle	-17	-17
25	PV-DWD-13-ABB058	-	SA-508 Cl. 1a	Recirculation Nozzle Safe-End	-8	-8
26	PV-DWD-12-ABB057	-	SA-508 Cl. 3	Downcomer Feedwater Nozzle	-17	-17
27	PV-DWD-12-ABB057	-	Alloy 690	Downcomer Feedwater Nozzle Safe-End	Note 1	Note 1
28	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Upper Shell Level Nozzle	-35	-26
29	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Top Head Torus	-30	-30
30-1	PV-DWD-13-ABB059	-	SA-508 Cl. 1a	Steam Outlet Nozzle	-8	-8
30-2	PV-DWD-13-ABB059	-	SA-508 Cl. 1a	Pressure Tap Nozzle	-35	-26
31	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Pressure Test Nozzle	-35	-26
33	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Lower Shell	-35	-35
34	PV-DWD-00-ABB062	-	SA-533 Gr B Cl. 1	Top Head Dome	-30	-30
36-1	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Sampling Nozzle	-35	-26
37	PV-DWD-12-ABB057	-	SA-508 Cl. 1a	Downcomer FW Nozzle Transition Piece	-29	-29
41-1	PV-DWD-15-ABB081	-	SA-508 Cl. 3	Secondary Manway Nozzle	-8	-8
41-2	PV-DWD-15-ABB081	-	SA-533 Gr B Cl. 1	Secondary Manway Cover Plate	-29	-29
43-1	PV-DWD-11-ABB056	-	SFA 5.5 + SFA 5.23	Handhole (build-up)	-58	-49
43-2	PV-DWD-15-ABB081	-	SA-533 Gr B Cl. 1	Cover Plate	-29	-29
44-1	PV-DWD-11-ABB056	-	SFA 5.5 + SFA 5.23	Handhole (build-up)	-58	-49
44-2	**PV-DWD-23-ABB074**	**-**	**SA-106 Gr. B**	**Sleeve**	**Later**	**Later**
45-1	PV-DWD-10-ABB060		SFA 5.5	Primary Manway (build-up)	-31	-58
45-2	PV-DWD-15-ABB080		SA-533 Gr B Cl. 1	Cover Plate	-29	-29

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331-(a-1, 2 ,3)
Note 1: Not requested as per ASME III NB 2311-6 and 7

Table 5.2-26A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 2 (PLATES AND FORGINGS) (Sheet 3 of 3)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	^{DW}NDT (°F)	^{RT}NDT[a] (°F)
45-9	PV-DWD-10-ABB060	-	SB-163	Drain Tube	Note 1	Note 1
51-1	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Snubber Lug Arm	-35	-35
52	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Key Bracket	-8	-8
53	PV-DWD-10-ABB070		SB-168 or SB-564	Outlet Clamp Ring	Note 1	Note 1
55	PV-DWD-10-ABB070	-	SB-168 or SB-564	Inlet Clamp Ring	Note 1	Note 1
57-1	PV-DWD-10-ABB069	-	SB-168	Divider Plate	Note 1	Note 1
57-2	PV-DWD-10-ABB069	-	SB-168	Inner Patch Plate Assembly	Note 1	Note 1
57-3	PV-DWD-10-ABB069	-	SB-168	Divider Bars	Note 1	Note 1
57-6	PV-DWD-10-ABB069	-	SB-168	Outer Patch Plate Assembly	Note 1	Note 1
70-1	PV-DWD-11-ABB056	-	SA-508 Cl. 3	Handhole	-8	-8
70-2	PV-DWD-23-ABB092	-	SA-106 Gr. B	Sleeve	Not required	Not required
71	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Key Bracket	-8	-8
72	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Lug	+10	+10
78-1	PV-DWD-11-ABB056	-	SFA 5.5 + SFA 5.23	Handhole (build-up)	-58	-49
81	PV-DWD-23-ABB071	-	SA-516 Gr. 70	Upper Support Ring	-58	-58
85	PV-DWD-23-ABB071	-	SA-516 Gr. 70	Lower Support Ring	-58	-58
87	PV-DWD-23-ABB072	-	SA-516 Gr. 70	Divider Support Bar	-40	-40
107-1	PV-DWD-11-ABB056	-	SA-508 Cl. 3	Handhole	-8	-8
108	PV-DWD-24-ABB066	-	SA-516 Gr. 70	Shroud Lateral Support	-40	-40

a. Determined per applicable ASME B&PV Code, Section III, Subsection NB, Article NB-2331-(a-1, 2 ,3)

Note 1: Not requested as per ASME III NB 2311-6 and 7

Table 5.2-26B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

STEAM GENERATOR NO. 2 (PLATES AND FORGINGS)

Position	Reference Drawing Number	Material Specification	Location in Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F)
3	PX-DWD-10-060	SA-508 Class 3	Primary Head	-50	-50
5	PX-DWD-10-060	SA-508 Class 3	Stay Cylinder	-35	-35
6	PX-DWD-10-061	SA-508 Class 3	Primary Inlet Nozzle	+1	+1
7	PX-DWD-10-061	SA-508 Class 1a	Primary Inlet Safe-End	-17	-17
8	PX-DWD-10-061	SA-508 Class 3	Primary Outlet Nozzle	+1	+1
11	PX-DWD-10-054	SB-166	Primary Instrument Nozzle	(a)	(a)
12	PX-DWD-11-051	SA-508 Class 3a	Tubesheet	-50	-50
45-2	PX-DWD-15-080	SA-533 Gr B Cl 1	Primary Manway cover Plate	-39	-39

a. Not required as per ASME III NB 2311-6 and 7

Table 5.2-27

DELETED

Table 5.2-27A

DELETED

Table 5.2-27B

Deleted

Table 5.2-28

PVNGS UNIT 1 – STEAM GENERATOR No. 2 PRIMARY

SIDE WELD METAL CERTIFICATION TEST (a)

Component Weld Seam Number	Reference Drawing	Location in component	Electrode Code	Electrode Lot Number	Drop Weight T_{NDT} (°F) (b)	RT_{NDT} (°F) (b)
NZ 003	PX-DWF-10-010	Primary Head-Primary Inlet Nozzle	SFA 5.5 E9018-G	1103838	-50	-50
NZ 003	PX-DWF-10-010	Primary Head-Primary Inlet Nozzle	SFA 5.23 EG	PG 312233720	-55	-55
NZ 004	PX-DWF-10-010	Primary Head-Primary Outlet Nozzle	SFA 5.5 E9018-G	1103838	-50	-50
NZ 004	PX-DWF-10-010	Primary Head-Primary Outlet Nozzle	SFA 5.23 EG	PG 312233720	-55	-55
CW 007	PX-DWF-10-010	Primary Head-Stay Cylinder	SFA 5.5 E9018-G	312204	-60	-60
CW 007	PX-DWF-10-010	Primary Head-Stay Cylinder	SFA 5.23 EG	PG 312233720	-55	-55
NZ 035	PX-DWF-10-004	Prim. Inlet Nozzle-Prim. Inlet Safe-End	SFA 5.5 E9018-G	6220179	-50	-50
NZ 035	PX-DWF-10-004	Prim. Inlet Nozzle-Prim. Inlet Safe-End	SFA 5.5 E9018-G	1103838	-50	-50
NZ 035	PX-DWF-10-004	Prim. Inlet Nozzle-Prim. Inlet Safe-End	SFA 5.23 EF3N mod.	140596	-65	-65
CW 900	PX-DWF-33-001	Channel Head-Tubesheet	SFA 5.5 E9018-G	4204001	-85	-85
CW 900	PX-DWF-33-001	Channel Head Tubesheet	SFA 5.5 E9018-G	3122003	-55	-55
CW 900	PX-DWF-33-001	Channel Head Tubesheet	SFA 5.23 EG	PG 312233720	-55	-55
CW 901	PX-DWF-33-001	Stay Cylinder-Tubesheet	SFA 5.5 E9018-G	4204001	-85	-85
NZ 002	PX-DWF-10-009	Primary Instrument Nozzle-Buttering	SFA 5.14 ERNiCrFe-7	93542	N.A.	N.A.

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-28A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: STEAM GENERATOR NO. 2 PRIMARY SIDE

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
SP 001	SFA 5.5 E9018-G	900630	-76	-76
SP 001	SFA 5.23 EF3N mod.	140596	-67	-67
NZ 003	SFA 5.5 E9018-G	805867	-58	-58
NZ 004	SFA 5.23 EF3N mod.	140596	-67	-67
CW 007	SFA 5.28 ER 80S-G	718288	Note 1	Note 1
CW 007	SFA 5.5 E9018-G	900630	-76	-76
CW 007	SFA 5.5 E9018-G	805867	-58	-58
CW 007	SFA 5.23 EF3N mod.	140596	-67	-67
NZ 035	SFA 5.5 E9018-G	900630	-76	-76
NZ 035	SFA 5.5 E9018-G	805867	-58	-58

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Note 1: Not requested as per ASME NB 2431 (c)

Table 5.2-28B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[(a)]

COMPONENT: STEAM GENERATOR NO. 2 PRIMARY SIDE

Component Weld Seam Number	Reference Drawing	Location in component	Electrode Code	Electrode Lot Number	Drop Weight T_{NDT} (°F) [(b)]	RT_{NDT} (°F) [(b)]
NZ 003	PX-DWF-10-010	Primary Head-Primary Inlet Nozzle	SFA 5.5 E9018-G	1103838	-50	-50
NZ 003	PX-DWF-10-010	Primary Head-Primary Inlet Nozzle	SFA 5.23 EG	PG 312233720	-55	-55
NZ 004	PX-DWF-10-010	Primary Head-Primary Outlet Nozzle	SFA 5.5 E9018-G	1103838	-50	-50
NZ 004	PX-DWF-10-010	Primary Head-Primary Outlet Nozzle	SFA 5.23 EG	PG 312233720	-55	-55
CW 007	PX-DWF-10-010	Primary Head-Stay Cylinder	SFA 5.5 E9018-G	312204	-60	-60
CW 007	PX-DWF-10-010	Primary Head-Stay Cylinder	SFA 5.23 EG	PG 312233720	-55	-55
NZ 035	PX-DWF-10-004	Prim. Inlet Nozzle-Prim. Inlet Safe-End	SFA 5.5 E9018-G	6220179	-50	-50
NZ 035	PX-DWF-10-004	Prim. Inlet Nozzle-Prim. Inlet Safe-End	SFA 5.5 E9018-G	1103838	-50	-50
NZ 035	PX-DWF-10-004	Prim. Inlet Nozzle-Prim. Inlet Safe-End	SFA 5.23 EF3N mod.	140596	-65	-65
CW 900	PX-DWF-33-001	Channel Head-Tubesheet	SFA 5.5 E9018-G	4204001	-85	-85
CW 900	PX-DWF-33-001	Channel Head-Tubesheet	SFA 5.5 E9018-G	4452004	-74	-74
CW 900	PX-DWF-33-001	Channel Head-Tubesheet	SFA 5.23 F8P6-EG-F3	PG504AR4809	-58	-58
CW 901	PX-DWF-33-001	Stay Cylinder-Tubesheet	SFA 5.23 F8P6-EG-F3	PG504AR4809	-58	-58
CW 901	PX-DWF-33-001	Stay Cylinder-Tubesheet	EN 760 A FB 1 55 AC	5047010		
NZ 002	PX-DWF-10-009	Primary Instrument Nozzle -Buttering	SFA 5.14 ER NiCrFe-7	93542/2390	N/A	N/A

c. Per ASME B&PV Code, Section III, Article NB-2430

d. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-29

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 1 of 2)

Reference Drawing Number	Material Code Number	ASME Material Speci-fication	Location In Component	Drop Weight NDT (°F)		RT_{NDT}[a] (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 1							
78173-S/N1109-2A	U5	SA508-CL2	Pump Casing Disch Nozzle	40	40	40	40
78173-S/N1109-2A	V3	SA508-CL2	Top Pump Casing	40	40	40	40
78173-S/N1109-2A	V4	SA508-CL2	Bottom Pump Casing	40	40	40	40
78173-S/N1109-2A	W4	SA508-CL2	Bottom Flange	40	40	40	40
78173-S/N1109-2A	TS2720B-2[b]	SA508-CL2	Clamping Rings	40	40	40	40
78173-S/N1109-2A	V10	SA508-CL1	Casing Suction End	40	40	40	40
78173-S/N1109-2A	V18	SA508-CL1	Casing Discharge End	40	40	40	40
Reactor Coolant Pump No 2							
78173-S/N1109-1B	U9	SA508-CL2	Pump Casing Disch Nozzle	20	20	20	20
78173-S/N1109-1B	V5	SA508-CL3	Top Pump Casing	40	40	40	40
78173-S/N1109-1B	V8	SA508-CL3	Bottom Pump Casing	40	40	40	40
78173-S/N1109-1B	X4	SA508-CL2	Clamping Rings	40	40	40	40
78173-S/N1109-1B	V11	SA508-CL1	Casing Suction End	40	40	40	40
78173-S/N1109-1B	V19	SA508-CL1	Casing Discharge End	40	40	40	40
78173-S/N1109-1B	W26	SA508-CL2	Bottom Flange	30	30	30	30

a. ASME B&PV Code, Section III, Article NB-2331-(a-1, 2, 3)
b. Heat Number

Table 5.2-29

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 2 of 2)

Reference Drawing Number	Material Code Number	ASME Material Speci-fication	Location In Component	Drop Weight NDT (°F)		RT_{NDT} (a) (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 3							
78173-S/N1109-2B	V6	SA508-CL3	Top Pump Casing	40	40	40	40
78173-S/N1109-2B	V7	SA508-CL3	Bottom Pump Casing	40	40	40	40
78173-S/N1109-2B	W3	SA508-CL2	Bottom Flange	40	40	40	40
78173-S/N1109-2B	X1	SA508-CL2	Clamping Rings	40	40	40	40
78173-S/N1109-2B	U10	SA508-CL2	Pump Casing Disch Nozzle	20	20	20	20
78173-S/N1109-2B	V12	SA508-CL1	Casing Suction End	40	40	40	40
78173-S/N1109-2B	V21	SA508-CL1	Casing Discharge End	40	40	40	40
Reactor Coolant Pump No 4							
78173-S/N1109-1A	U2	SA508-CL2	Pump Casing Disch Nozzle	40	40	40	40
78173-S/N1109-1A	V1	SA508-CL2	Top Pump Casing	40	40	40	40
78173-S/N1109-1A	V2	SA508-CL2	Bottom Pump Casing	40	40	40	40
78173-S/N1109-1A	V9	SA508-CL1	Casing Suction End	40	40	40	40
78173-S/N1109-1A	W2	SA508-CL2	Bottom Flange	40	40	40	40
78173-S/N1109-1A	X3	SA508-CL2	Clamping Rings	40	40	40	40
78173-S/N1109-1A	V17	SA508-CL1	Casing Discharge End	40	40	40	40

Table 5.2-29A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 1 of 4)

Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Drop Weight NDT (°F)		RT_{NDT} (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 1A							
79173-S/N1110-1A	C001	SA508-CL2	Clamping Rings	-4	-11	-4[a]	-11[a]
79173-S/N1110-1A	V36	SA508-CL3	Pump Casing Discharge Nozzle	<40	<40	40[a]	40[a]
79173-S/N1110-1A	V45	SA508-CL3	Top Pump Casing	<40	<40	40[a]	40[a]
79173-S/N1110-1A	V58	SA508-CL3	Bottom Pump Casing	<40	<40	40[a]	40[a]
79173-S/N1110-1A	V69	SA508-CL1	Casing Suction End	<40	<40	40[a]	40[a]
79173-S/N1110-1A	V87	SA508-CL1	Casing Discharge End	<40	<40	40[a]	40[a]
79173-S/N1110-1A	W80	SA508-CL2	Bottom Flange	<40	<40	40[a]	40[a]

a. Determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2331-(a-1 ,2 ,3)

Table 5.2-29A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 2 of 4)

Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Drop Weight NDT (°F)		RT_{NDT} (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 1B							
79173-S/N1110-1B	B004	SA508-CL2	Clamping Rings	<40	<40	40[a]	40[a]
79173-S/N1110-1B	V38	SA508-CL3	Pump Casing Discharge Nozzle	<40	<40	40[a]	40[a]
79173-S/N1110-1B	V46	SA508-CL3	Top Pump Casing	<40	<40	40[a]	40[a]
79173-S/N1110-1B	V59	SA508-CL3	Bottom Pump Casing	<40	<40	40[a]	40[a]
79173-S/N1110-1B	V63	SA508-CL1	Casing Discharge End	<40	<40	40[a]	40[a]
79173-S/N1110-1B	V68	SA508-CL1	Casing Suction End	<40	<40	40[a]	40[a]
79173-S/N1110-1B	W78	SA508-CL2	Bottom Flange	<40	<40	40[a]	40[a]

Table 5.2-29A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 3 of 4)

Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Drop Weight NDT (°F)		RT_{NDT} (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 2A							
79173-S/N1110-2A	A008	SA508-CL2	Clamping Rings	<40	<40	40[a]	40[a]
79173-S/N1110-2A	V106	SA508-CL1	Casing Discharge End	<40	<40	40[a]	40[a]
79173-S/N1110-2A	V37	SA508-CL3	Pump Casing Discharge Nozzle	<40	<40	40[a]	40[a]
79173-S/N1110-2A	V57	SA508-CL3	Top Pump Casing	<40	<40	40[a]	40[a]
79173-S/N1110-2A	V64	SA508-CL3	Bottom Pump Casing	<40	<40	40[a]	40[a]
79173-S/N1110-2A	V84	SA508-CL1	Casing Suction End	<40	<40	40[a]	40[a]
79173-S/N1110-2A	W81	SA508-CL2	Bottom Flange	<40	<40	40[a]	40[a]

Table 5.2-29A

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 4 of 4)

Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Drop Weight NDT (°F)		RT_{NDT} (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 2B							
79173-S/N1110-2B	A005	SA508-CL2	Clamping Rings	<40	<40	40[a]	40[a]
79173-S/N1110-2B	V107	SA508-CL1	Casing Discharge End	<40	<40	40[a]	40[a]
79173-S/N1110-2B	V39	SA508-CL3	Pump Casing Discharge Nozzle	<40	<40	40[a]	40[a]
79173-S/N1110-2B	V71	SA508-CL3	Bottom Pump Casing	<40	<40	40[a]	40[a]
79173-S/N1110-2B	V72	SA508-CL3	Top Pump Casing	<40	<40	40[a]	40[a]
79173-S/N1110-2B	V85	SA508-CL1	Casing Suction End	<40	<40	40[a]	40[a]
79173-S/N1110-2B	W79	SA508-CL2	Bottom Flange	<40	<40	40[a]	40[a]

Table 5.2-29B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 1 of 4)

Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Drop Weight NDT (°F)		RT_{NDT} (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 1A							
65173-S/N1111-1A	BD-3	SA508-CL1	Casing Discharge End	+40	N/A	+40[a]	+40[b]
65173-S/N1111-1A	BD-5	SA508-CL1	Casing Suction End	+40	N/A	+40[a]	+40[b]
65173-S/N1111-1A	C003	SA508-CL2	Clamping Rings	-4	-13	-4[a]	-13[a]
65173-S/N1111-1A	V153	SA508-CL3	Pump Casing	-14	-5	-3[a]	+6[a]
65173-S/N1111-1A	W84	SA508-CL2	Bottom Flange	+30	+30	+30[a]	+30[a]

a. Determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2331-(a-1 ,2 ,3)

b. RT_{NDT} at 180F assumed to be the same as 0F

Table 5.2-29B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 2 of 4)

Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Drop Weight NDT (°F)		RT_{NDT} (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 1B							
65173-S/N1111-1B	BD-3	SA508-CL1	Casing Discharge End	+40	N/A	+40[a]	+40[b]
65173-S/N1111-1B	BD-7	SA508-CL1	Casing Suction End	+40	N/A	+40[a]	+40[b]
65173-S/N1111-1B	C002	SA508-CL2	Clamping Rings	+5	-22	+5[a]	-22[a]
65173-S/N1111-1B	V157	SA508-CL3	Pump Casing	+4	+4	+4[a]	+4[a]
65173-S/N1111-1B	W82	SA508-CL2	Bottom Flange	+30	+30	+30[a]	+30[a]

Table 5.2-29B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 3 of 4)

Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Drop Weight NDT (°F)		RT_{NDT} (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 2A							
65173-S/N1111-2A	BD-2	SA508-CL1	Casing Discharge End	+40	N/A	+40[a]	+40[b]
65173-S/N1111-2A	BD-4	SA508-CL1	Casing Suction End	+40	N/A	+40[a]	+40[b]
65173-S/N1111-2A	C004	SA508-CL2	Clamping Rings	-4	-31	-4[a]	-31[a]
65173-S/N1111-2A	V150	SA508-CL3	Pump Casing	+23	+14	+23[a]	+14[a]
65173-S/N1111-2A	W85	SA508-CL2	Bottom Flange	+30	+30	+30[a]	+30[a]

Table 5.2-29B

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA

REACTOR COOLANT PUMP (FORGING) (Sheet 4 of 4)

Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Drop Weight NDT (°F)		RT_{NDT} (°F)	
				0°	180°	0°	180°
Reactor Coolant Pump No. 2B							
65173-S/N1111-2B	BD-2	SA508-CL1	Casing Discharge End	+40	N/A	+40[(a)]	+40[(b)]
65173-S/N1111-2B	BD-6	SA508-CL1	Casing Suction End	+40	N/A	+40[(a)]	+40[(b)]
65173-S/N1111-2B	C005	SA508-CL2	Clamping Rings	-13	-13	-13[(a)]	-13[(a)]
65173-S/N1111-2B	V163	SA508-CL3	Pump Casing	-5	-14	-5[(a)]	-14[(a)]
65173-S/N1111-2B	W83	SA508-CL2	Bottom Flange	+30	+30	+30[(a)]	+30[(a)]

Table 5.2-30

PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS

COMPONENT: REACTOR COOLANT PUMPS

Component Weld Seam Number	Electrode Code	Rod Heat Number	Flux Type	Flux Lot	^{T}NDT (°F)	^{RT}NDT (°F)
158-0015	Flux Electrode Comb. (SAA)	4P7927	0091	1262	+40	+40
158-0016	Flux Electrode Comb. (SAA)	4P7927	0091	1262	+40	+40
158-0019	Flux Electrode Comb. (SAA)	4P7927	0091	1262	+40	+40
158-0162	Flux Electrode Comb. (SAA)	4P7927	0091	1262	+40	+40
223-0015	Flux Electrode Comb. (SAA)	4P7927	0091	1262	+40	+40
158-0015	Coated Electrode (MA)	KAOGE			-70	-70
158-0016	Coated Electrode (MA)	KAOGE			-70	-70
158-0019	Coated Electrode (MA)	KAOGE			-70	-70
158-0162	Coated Electrode (MA)	KAOGE			-70	-70
223-0015	Flux Electrode Comb. (SAA)	5P9029	0091	1262	+40	+40
158-0015	Coated Electrode (MA)	IAOCE			-80	-80
158-0016	Coated Electrode (MA)	IAOCE			-80	-80
158-0019	Coated Electrode (MA)	IAOCE			-80	-80
158-0162	Coated Electrode (MA)	IAOCE			-80	-80
223-0015	Coated Electrode (MA)	KAOGE			-70	-70
223-0015	Coated Electrode (MA)	IAOCE			-80	-80
223-0015	Coated Electrode (MA)	KAOGE			-70	-70

Table 5.2-30A

PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR COOLANT PUMPS

Component Weld Seam Number	Electrode Code	Rod Heat Number	Flux Type	Flux Lot	T_{NDT} (°F)	RT_{NDT} (°F)
158-0015	Coated Electrode (MA)	D813E			-140[b]	-140[b]
158-0015	Coated Electrode (MA)	IAOCE			- 80[b]	- 80[b]
158-0015	Coated Electrode (MA)	KAOGE			- 70[b]	- 70[b]
158-0016	Coated Electrode (MA)	IAOCE			- 80[b]	- 80[b]
158-0016	Coated Electrode (MA)	KAOGE			- 70[b]	- 70[b]
158-0019	Coated Electrode (MA)	IAOCE			- 80[b]	- 80[b]
158-0019	Coated Electrode (MA)	KAOGE			- 70[b]	- 70[b]
223-0015	Coated Electrode (MA)	IAOCE			- 80[b]	- 80[b]
223-0015	Coated Electrode (MA)	KAOGE			- 70[b]	- 70[b]
158-0015	Flux Electrode Comb. (SAA)	4P8632	0091	0383	< 40[b]	40[b]
158-0016	Flux Electrode Comb. (SAA)	4P8632	0091	0383	< 40[b]	40[b]
158-0016	Flux Electrode Comb. (SAA)	5P9744	0091	0383	< 40[b]	40[b]
158-0019	Flux Electrode Comb. (SAA)	2P8374	0091	0383	< 40[b]	40[b]
158-0019	Flux Electrode Comb. (SAA)	5P9744	0091	0383	< 40[b]	40[b]
223-0015	Flux Electrode Comb. (SAA)	4P8632	0091	0383	< 40[b]	40[b]
223-0015	Flux Electrode Comb. (SAA)	5P9744	0091	0383	< 40[b]	40[b]

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-30B

PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]

COMPONENT: REACTOR COOLANT PUMPS

Component Weld Seam Number	Electrode Code	Rod Heat Number	Flux Type	Flux Lot	T_{NDT} (°F)	RT_{NDT} (°F)
009-0009	Coated Electrode (MA)	D813E			-140[b]	-140[b]
009-0009	Coated Electrode (MA)	F827F			-140[b]	-140[b]
009-0009	Coated Electrode (MA)	G810D			-120[b]	-120[b]
223-0015	Coated Electrode (MA)	D813E			-140[b]	-140[b]
223-0015	Coated Electrode (MA)	F827F			-140[b]	-140[b]
223-0015	Coated Electrode (MA)	G810D			-120[b]	-120[b]
223-0016	Coated Electrode (MA)	D813E			-140[b]	-140[b]
223-0016	Coated Electrode (MA)	F827F			-140[b]	-140[b]
223-0016	Coated Electrode (MA)	G810D			-120[b]	-120[b]
009-0009	Flux Electrode Comb. (SAA)	2P8374	0091	0792	+40[b]	+40[b]
009-0009	Flux Electrode Comb. (SAA)	3P9030	0091	0604	+40[b]	+40[b]
009-0009	Flux Electrode Comb. (SAA)	3P9030	0091	0792	+40[b]	+40[b]
223-0015	Flux Electrode Comb. (SAA)	2P8374	0091	0792	+40[b]	+40[b]
223-0016	Flux Electrode Comb. (SAA)	2P8374	0091	0792	+40[b]	+40[b]
223-0016	Flux Electrode Comb. (SAA)	2P8374	124	0193	N/A	+60[c]

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

c. Determined by MTEB BTP 5-2

Table 5.2-31

PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA: REACTOR COOLANT PUMPS

Weld Seam Number	Weld Procedure Qualification Number	Material		Haz 1 DW_{NDT} (°F)	Haz 1 RT_{NDT} (°F)	Weld DW_{NDT} (°F)	Weld RT_{NDT} (°F)	Haz 2 DW_{NDT} (°F)	Haz 2 RT_{NDT} (°F)
		No. 1	No. 2						
158-0015	SMA-1.3-1G-1	516	302	+40	+40	+40	+40	+40	+40
158-0016	SMA-SA-3.3.1G2	5331	5331	+40	+40	+40	+40	+40	+40
158-0019	SMA-3.3-1G-3	5331	5331	+40	+40	+40	+40	+40	+40
158-0162	SMA-1.3-1G-1	516	302	+40	+40	+40	+40	+40	+40
223-0015	SMA-1.3-1G-1	516	302	+40	+40	+40	+40	+40	+40
158-0015	SA-1.3-1G-1	515	533	+40	+40	+40	+40	+40	+40
158-0019	SMA-SA-3.3-1G2	5331	5331	+40	+40	+40	+40	+40	+40
158-0162	SA-1.3-1G-1	515	533	+40	+40	+40	+40	+40	+40
223-0015	SA-1.3-1G-1	515	533	+40	+40	+40	+40	+40	+40

Table 5.2-31A

PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a] REACTOR COOLANT PUMPS

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
158-0015	SA -1.3-1G-1	5167	5082	<40	40	<40	40	<40	40
158-0015	SMA -1.3-1G-1	5167	5082	<40	40	<40	40	<40	40
158-0016	SA -1.3-1G-1	5167	5082	<40	40	<40	40	<40	40
158-0016	SMA -SA-3.3-1G2	5331	5331	<40	40	<40	40	<40	40
158-0016	SMA -1.3-1G-1	5167	5082	<40	40	<40	40	<40	40
158-0019	SMA -SA-3.3-1G2	5331	5331	<40	40	<40	40	<40	40
158-0019	SMA -3.3-1G-3	5331	5331	<40	40	<40	40	<40	40
223-0015	SA -1.3-1G-1	5167	5082	<40	40	<40	40	<40	40
223-0015	SMA -1.3-1G-1	5167	5082	<40	40	<40	40	<40	40

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

Table 5.2-31B

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a] REACTOR COOLANT PUMPS

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
				HAZ 1		Weld		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
009-0009	SA -1.3-1G-1	5167	5082	+40	+40	+40	+40	+40	+40
009-0009	SMA -1.3-1G-1	5167	5082	+40	+40	+40	+40	+40	+40
223-0015	SA -1.3-1G-1	5167	5082	+40	+40	+40	+40	+40	+40
223-0015	SMA -1.3-1G-1	5167	5082	+40	+40	+40	+40	+40	+40
223-0016	SA -1.3-1G-1	5167	5082	+40	+40	+40	+40	+40	+40
223-0016	SMA -1.3-1G-1	5167	5082	+40	+40	+40	+40	+40	+40

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

5.2.3.3.1.2 Components in the Doosan Scope of Supply

NSSS Components. Fracture toughness requirements for Reactor Coolant Pressure Boundary components, replacement Reactor Vessel Closure Heads (RVCH), replacement Control Element Drive Mechanisms (CEDM) and Reactor Vessel Level Monitoring System (RVLMS) pressure housings are established in accordance with the ASME Boiler and Pressure Vessel Code, Section III. Fracture toughness testing was performed in accordance with applicable ASME Code and Addenda.

Post-weld heat treatment of the test welds[a] is as follows:

Stress relief - 1150F ±50F for 40 hours

Furnace cool to 800F.

Plates used to fabricate test welds[a] are SA-533 Grade B, Class 1, quenched and tempered (12-inch thickness) on both sides of the weld. Test welds are made with the same P number classification for both base metals as used for the fabrication of the beltline region. The same type of filler material and welding conditions are also used.

Test specimen for the longitudinal seams are not removed from excess material and welds in the vessel shell course following completion of the longitudinal weld joint. However, the procedure utilized in fabricating these seams are qualified in

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a. All test welds are performed in accordance with ASME Boiler and Pressure Vessel Code, Section III, Article NB-4330 (General Requirements for Welding Procedure Qualification Tests).

accordance with ASME Boiler and Pressure Vessel Code, Section III, Article NB-4330 (General Requirements for Welding Procedure Qualification Tests). Fracture toughness data from these procedure qualification tests are given in table 5.2-7.

5.2.3.3.1.3 Components Not in the C-E Scope of Supply. All non-NSSS ASME Section III, Code Class 1, valves and piping are of austenitic stainless steel construction, and are, therefore, exempt from impact testing in accordance with Subsection NB-2311(a)(6).

5.2.3.3.2 Control of Welding

5.2.3.3.2.1 Avoidance of Cold Cracking. C-E complied with the recommendations of Regulatory Guide 1.50, Control of Preheat Temperature for Welding of Low Alloy Steel, May 1973, as discussed below.

Paragraph C.1.b implies that the qualification plates are an infinite heat sink that would instantaneously dissipate the heat input from the welding process. The qualification procedure consists of starting the welding at the minimum preheat temperature. Welding is continued until the maximum interpass temperature is reached. At this time, the test plate is permitted to cool to the minimum preheat temperature and the welding is restarted. Preheat temperatures utilized for low alloy steel are in accordance with Section III of the ASME Code. The maximum interpass temperature utilized is 500°F.

The Paragraph C.2 recommendation is considered an unnecessary extension of procedures which apply to low-alloy steel welds, meeting ASME Code Sections III and IX requirements. The recommendations of Regulatory Guide 1.50 are met by complying with Paragraph C.4. The soundness of all welds is verified by ASME Code acceptable examination procedures.

With regard to Regulatory Guide 1.43, major components are fabricated with corrosion resistant cladding on internal surfaces exposed to reactor coolant. The major portion of the material protected by cladding from exposure to reactor coolant is SA-533, Grade B, Class 1 plate which, as discussed in the Regulatory Guide, is immune to underclad cracking. Cladding of SA-508, Class 2 forging material is performed using low-heat-input welding processes controlled to minimize heating of the base metal. Low-heat-input welding processes are not known to induce underclad cracking. This discussion is also applicable to RCPB components not in the C-E scope of supply.

5.2.3.3.2.2 Regulatory Guide 1.34. Regulatory Guide 1.34 recommends controls to be applied during welding using the electroslag process. The electroslag process is not used in the fabrication of any RCPB components. Therefore, the recommendations of this guide are not applicable. This discussion is also applicable to RCPB components not in the C-E scope of supply.

5.2.3.3.2.3 Regulatory Guide 1.71. C-E complied with the recommendations of Regulatory Guide 1.71 except for the differences indicated below.

Performance qualifications for personnel welding under conditions of limited accessibility are conducted and maintained in accordance with the requirements of ASME B&PV Code Sections III and IX. A requalification is required when (1) any of the essential variables of Section IX is changed, or (2) when authorized personnel have reason to question the ability of the welder to satisfactorily comply with the applicable requirements. Production welding is monitored for compliance with the procedure parameters, and welding qualifications are certified in accordance with Sections III and IX. Further assurance of acceptable welds of limited accessibility is afforded by the welding supervisor assigning only the most highly skilled personnel to these tasks. Finally, weld quality, regardless of accessibility, is verified by the performance of the required non-destructive examinations. This discussion is also applicable to RCPB components not in the C-E scope of supply.

5.2.3.3.3 Nondestructive Examination of Tubular Products

5.2.3.3.3.1 Components in the C-E Scope of Supply. C-E complied with the requirements of Regulatory Guide 1.66 for steam generator tubing. The non-destructive examination requirements imposed by C-E for other tubular products are those specified by Section III of the ASME code rather than this guide.

5.2.3.3.3.2 Components Not in the C-E Scope of Supply. Tubular products for non-NSSS components of the RCPB are non-destructively examined in accordance with the requirements of ASME Code, Section III, Division 1, 1974 Edition and Addenda through Summer 1974.

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel

5.2.3.4.1 Avoidance of Stress Corrosion Cracking

5.2.3.4.1.1 Avoidance of Sensitization.

5.2.3.4.1.1.1 Components in the C-E Scope of Supply

NSSS Components. Fabrication of RCPB components is consistent with the recommendations of Regulatory Guide 1.44 as described in items A through D except for the criterion used to demonstrate freedom from sensitization. The ASTM A 708 Strauss Test is used in lieu of the ASTM A 262 Practice E, Modified Strauss Test, to demonstrate freedom from sensitization in fabricated, unstabilized, stainless steel.

A. Solution Heat Treatment Requirements

   All raw austenitic stainless steel material, both wrought and cast, used in the fabrication of the major NSSS components in the RCPB, is supplied in the annealed condition as specified by the pertinent ASTM or ASME Code; viz., 1900-2050F for 1/2 to 1 hour per inch of thickness and water quenched to below 700F. The time at temperature is determined by the size and type of component.

Solution heat treatment is not performed on completed or partially-fabricated components. Rather, the extent of chromium carbide precipitation is controlled during all stages of fabrication as described below.

B. Material Inspection Program

Extensive testing on stainless steel mockups, fabricated using production techniques, has been conducted to determine the effect of various welding procedures on the susceptibility of unstabilized 300 series stainless steels to sensitization-induced intergranular corrosion. Only those procedures and/or practices demonstrated not to produce a sensitized structure are used in the fabrication of RCPB components. The ASTM standard A 708 (Strauss Test) is the criterion used to determine susceptibility to inter-granular corrosion. This test has shown excellent correlation with a form of localized corrosion peculiar to sensitized stainless steels. As such, ASTM A 708 is utilized as a go/no-go standard for acceptability.

As a result of the above tests, a relationship was established between the carbon content of 304 stainless steel and weld heat input. This relationship is used to avoid weld heat-affected-zone sensitization as described below.

C. Unstabilized Austenitic Stainless Steel

The unstabilized grades of austenitic stainless steels with carbon content of more than 0.03% used for components of the RCPB are 304 and 316. These materials are furnished in the solution annealed condition. Exposure of completed or partially-fabricated components to temperatures ranging from 800F to 1500F is prohibited.

Duplex, austenitic stainless steels containing more than 5 FN delta ferrite (weld metal, cast metal, weld deposit overlay), are not considered unstabilized since these alloys do not sensitize, that is form a continuous network of chromium-iron carbides. Specifically, alloys in this category are:

CFM Cast stainless steel (delta ferrite 5FN to 33FN)

CF8 Cast stainless steel (delta ferrite 5FN to 33FN)

308, 309 Singly and combined stainless steel weld filler metals

312, 316 (delta ferrite controlled to 5FN-23FN depositied)

In duplex, austenitic/ferritic alloys, chromium-iron carbides are precipitated preferentially at the ferrite/austenite interfaces during exposure to temperatures ranging from 800-1500F. This precipate

morphology precludes intergranular penetrations associated with sensitized 300 series stainless steels exposed to oxygenated or fluoride environments.

D. Avoidance of Sensitization

Exposure of unstabilized austenitic 300 series stainless steels to temperatures ranging from 800 to 1500F will result in carbide precipitation. The degree of carbide precipitation, or sensitization, depends on the temperature, the time at that temperature, and also the carbon content. Severe sensitization is defined as a continuous grain boundary chromium-iron carbide network. This condition induces susceptibility to intergranular corrosion in oxygenated aqueous environments, as well as those containing fluorides. Such a metallurgical structure will rapidly fail the Strauss test ASTM A 708. Discontinuous precipitates (i.e., an intermittent grain boundary carbide network) are not susceptible to intergranular corrosion in a PWR environment.

Weld heat affected zone sensitized austenitic stainless steels (which will fail the Strauss Test, ASTM A 708) are avoided by careful control of:

- Weld heat input to less than 60 kJ/in
- Interpass temperature to 350F maximum
- Carbon content

Homogeneous or localized heat treatment in the temperature range 800-1500F is prohibited for unstabilized austenitic stainless steel with a carbon content greater than 0.03% used in components of the RCPB. When stainless steel safe ends are required on component nozzles, fabrication techniques and sequencing require that the stainless steel piece be welded to the component after final stress relief. This is accomplished by welding an Inconel overlay on the end of the nozzle. Following final stress relief of the component, the stainless steel safe end is welded to the Inconel overlay, using Inconel weld filler metal.

5.2.3.4.1.1.2 Components Not in the C-E Scope of Supply. Regulatory Guide 1.44 is discussed in section 1.8.

5.2.3.4.1.2 Avoidance of Contaminants Causing Stress Corrosion Cracking.

5.2.3.4.1.2.1 Components in C-E Scope of Supply.

NSSS Components. Specific requirements for cleanliness and contamination protection are included in the equipment specifications for components fabricated with austenitic stainless steel. The provisions described below indicate the type of procedures utilized for NSSS components to provide contamination control during fabrication, shipment, and storage as required by Regulatory Guide 1.37.

Contamination of austenitic stainless steels of the 300 type by compounds which can alter the physical or metallurgical structure and/or properties of the material is avoided during all stages of fabrication. Painting of 300 series stainless steels is prohibited. Grinding is accomplished with resin or rubber-bounded aluminum oxide or silicon carbide wheels which were not previously used on materials other than austenitic alloys. Outside storage of partially-fabricated components is avoided and in most cases prohibited. Exceptions are made for certain components provided they are dry, completely covered with a waterproof material, and kept above ground.

Internal surfaces of completed components are cleaned to produce an item which is clean to the extent that grit, scale, corrosion products, grease, oil, wax, gum, adhered or embedded dust or extraneous materials are not visible to the unaided eye. Cleaning is effected by either solvents (acetone or isopropyl alcohol) or inhibited water (hydrazine). Water will conform to the following requirements:

Halides	
Chloride (ppm)	<0.60
Fluoride (ppm)	<0.40
Conductivity (mmhos/cm)	<5.0
pH	6.0-8.0
Visual clarity	No turbidity, oil, or sediment

To prevent halide-induced intergranular corrosion which could occur in aqueous environment with significant quantities of

dissolved oxygen, flushing water is inhibited via additions of hydrazine. Results of tests have proven these inhibitors to be completely effective. Operational chemistry specifications restrict concentrations of halide and oxygen both prerequisites of intergranular attacks (Refer to Section 9.3.4).

5.2.3.4.1.2.2 Components Not in the C-E Scope of Supply. Requirements for cleanliness and contamination protection are included in the equipment specifications for components fabricated with austenitic stainless steel. Additionally, detailed vendor procedures are reviewed for acceptability of cleaning materials, cleaning equipment and procedures, and quality assurance provisions. The provisions described below indicate the type of criteria utilized for non-NSSS components to provide contamination control during fabrication, shipment, storage, and installation.

Contamination of austenitic stainless steels of the 300 type by compounds that can alter the physical or metallurgical structure and/or properties of the material was avoided during fabrication, shipment, storage, construction, testing, and operation. Grinding was accomplished with aluminum oxide or silicon-carbide grinding wheels that had not previously been used on ferritic materials.

Restrictions are placed on lubricants, marking materials, tapes, penetrants, water, solvents, and other materials used in the fabrication, marking, cleaning, examination, and testing.

Internal surfaces of completed components were cleaned to produce a clean item to the extent that grit, scale, corrosion

products, grease, oil, wax, gum, adhered or embedded dust, or extraneous materials were not visible to the unaided eye. Cleaning was effected by either solvents or water. Acetone, alcohol, or other organic solvents were specified to contain less than 200 ppm by weight of inorganic halogens and not more than 1% total halogens (organic and inorganic by weight). Water conformed to the following requirements:

pH at 25C	5.5 to 8.0
Inorganic halogen (ppm)	≤1
Sulfide (ppm)	≤1
Conductivity (μmho/cm)	≤3
Total dissolved solids (ppm)	≤5

Prior to shipment, RCPB components were packaged in such a manner that they were protected from the weather, dirt, wind, water spray, and any other extraneous conditions expected to be encountered during shipment and subsequent site storage. The environment within the package and/or component was maintained clean and dry. In some instances, dessicants were utilized.

Site-related activities for storage, construction, cleaning, and testing were governed by ANSI N45.2.1-1973 as interpreted by Regulatory Guide 1.37 and ANSI N45.2.2-1972 as interpreted by Regulatory Guide 1.38. Refer to section 1.8 for a discussion of these regulatory guides. Established procedures include:

A. Receiving and storage of materials in accordance with ANSI N45.2.2.

B. Vendor-supplied piping subassemblies and components were shop-cleaned, inspected, and sealed by the vendor per approved cleaning procedures. Source inspection verified and documented that cleaning was done in accordance with the approved cleaning procedure and that the cleanliness was achieved. Onsite quality control procedures monitored the vendor-installed seals up to the point at which the piping subassemblies or components were installed and openings were closed. Care was taken during installation of components and piping subassemblies to preclude introduction of foreign materials into the interiors of the piping subassemblies and components.

C. Field-fabricated austenitic stainless steel piping (2 inches and smaller) was fabricated from vendor-cleaned materials. During fabrication, care was taken to preclude the introduction of foreign materials into the interior of the subassemblies. After fabrication, the subassemblies were precleaned by blowing out with clean, dry, oil-free, compressed air and/or drawing clean, white, lint-free cloth through the interior of the subassembly. This precleaning was performed to minimize the flushing time required during the preoperational proof flush.

D. After erection completion, piping and components were pressure-tested as required by the code. Austenitic stainless steel systems were hydrostatically tested

with demineralized water as defined in ANSI N45.2.1. Specific water requirements are:

pH at 25C (corrected for N_2H_4 and CO_2)	5.5 to 8
Chloride (ppm)	<1
Fluoride (ppm)	<1
Sulfide (ppm)	<1
Conductivity at 25C (μmho/cm) (corrected for dissolved CO_2, NH_3, and N_2H_4)	<3
Silica (ppm)	<0.05
Turbidity (Jackson Turbidity Unit/Formazin Turbidity Unit)	<1

In addition, the water should be inhibited with 30-50 ppm hydrazine (N_2H_4) if testing is anticipated to take an extended period (>5 days) of time.

E. Preoperational proof flushes and final proof flushes were conducted in accordance with ANSI N45.2.1. Water quality for flushing is identical to that listed for pressure testing in listing D above.

F. Following proof flushes and hydrostatic testing, components were drained and placed in wet layup using water meeting the following requirements prior to hot functional testing:

Halides	
Chloride (ppm)	<0.15
Fluoride (ppm)	<0.10
Conductivity (μmho/cm) (corrected for dissolved CO_2, NH_3, and N_2H_4)	<2.00
pH (corrected for CO_2 and N_2H_4)	6.9-8.0
Visual Clarity	No turbidity, oil, or sediment

In addition, the water is inhibited with 30-50 ppm hydrazine (N_2H_4).

Leachable chlorides and fluorides in nonmetallic insulation materials in contact with stainless steel were controlled by inclusion of Regulatory Guide 1.36 requirements in the purchase specifications.

Operational chemical specifications restrict concentrations of halide and oxygen, both of which contribute to intergranular corrosion attacks (refer to subsection 10.3.5).

5.2.3.4.1.3 Characteristics and Mechanical Properties of Cold-Worked Austenitic Stainless Steels for RCPB Components. Cold-worked austenitic stainless steel is not utilized for components of the RCPB.

5.2.3.4.2 Control of Welding

5.2.3.4.2.1 Avoidance of Hot Cracking.

A. Components in C-E Scope of Supply

NSSS Components

1. Regulatory Guide 1.31

In order to preclude microfissuring in austenitic stainless steel welds, RCPB components are consistent with the recommendations of Regulatory Guide 1.31 as follows:

The delta ferrite content of A-No. 8 (Table QW-442 of the ASME Code, Section IX) austenitic stainless steel welding materials, except Type 16-8-2 and welding materials for weld metal overlay cladding, used in the fabrication of components of the reactor coolant system, is controlled to 5FN-23FN. The delta ferrite determination is carried out using a calibrated magnetic measuring instrument and undiluted weld deposits produced in accordance with the American Welding Society Specification AWSA.5.4 or another comparable procedure for other than coated electrodes. The ferrite requirement is met for each heat, lot or heat/lot combination of weld filler material. For submerged arc welding processes, the delta ferrite determination for each wire/flux combination may

be made on a production or simulated (qualification) production weld, and the delta ferrite content is controlled to 3FN-23FN.

"Delta ferrite contents of consumable inserts, rod or wire filler metal used with the gas tungsten and welding process, and deposits made with the plasma arc welding process may be determined from their chemical compositions using a constitutional diagram for austenitic stainless steel welding material."

As an alternative the delta ferrite determination may be carried out on production welds by magnetic measurement methods. The average delta ferrite content must be 3FN or more with no single reading less than 1FN when measured at four equally spaced positions. Each production weld greater than 1 inch in thickness is examined while welds of thicknesses 1 inch and less are tested in accordance with a sampling plan.

2. Regulatory Guide 1.34

   Regulatory Guide 1.34 is discussed in Section 5.2.3.3.2.2.

3. Regulatory Guide 1.71

   Regulatory Guide 1.71 is discussed in Paragraph 5.2.3.3.2.3.

B. Components Not in C-E Scope of Supply

In order to preclude microfissuring in austenitic stainless steel, PVNGS design is consistent with the recommendations of Regulatory Guide 1.31 except as noted in section 1.8.

5.2.4 INSERVICE INSPECTION AND TESTING OF REACTOR COOLANT PRESSURE BOUNDARY

Details of the inservice inspection program are included in the Technical Specifications.

Class I components and supports are designed to meet the access requirements of Section XI of the ASME Boiler and Pressure Vessel Code.

In the case of the reactor vessel, all internals except the flow baffle are removable. Their removal makes the entire inner surface of the vessel, as well as the weld zones of the internal load-carrying structural attachments, available for the surface and volumetric inspections. The closure head is available for inspection whenever it is removed, and its removal also makes available the vessel closure flange, closure stud holes and ligaments, and the closure studs and nuts. Each control element drive mechanism is removable as a unit through a closure at the top of its housing.

For interim inspections of the reactor vessel primary coolant nozzle to shell welds and inner radii, the two outlet nozzles are accessible from inside the reactor vessel without removal of the vessel internals. The outlet nozzles are accessible

either from outside the vessel or from inside after removal of the vessel internals.

Manways are provided for those inspections which must be made internally on the steam generators and pressurizer. Access holes are provided in the support skirt of the steam generators to allow examination of the tube sheet support stay cylinder welds. The steam generators are capable of being examined in accordance with the guidance of Regulatory Guide 1.83.

The reactor coolant pumps may be disassembled, if necessary, for inspection.

5.2.5 REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS

The reactor coolant system is constructed such that no leakage is expected to occur through the principal boundary members such as the pressure vessel walls, coolant piping walls, reactor coolant pump bowls, and valve bodies. However, a certain amount of coolant loss is expected through other pressure boundary components that cannot practically be made completely leak tight. The latter would include valve packing and stems, isolation valve seats, pump and valve seals as well as the steam generator tubes and tubesheet. To the extent practical, these potential leak pathways have been identified and routed to collection tanks or sumps so as not to obscure the presence of unanticipated reactor coolant pressure boundary leakage.

As required by 10CFR50, Appendix A, General Design Criterion 30, means have been provided for the detection of reactor coolant leakage from the reactor coolant system. The purpose of the reactor coolant leakage detection equipment is to alert operators to the existence of leakage above acceptable limits so that corrective actions, including reactor shutdown if necessary, may be taken to prevent further degradation of the boundary. Except as noted in this section, the leakage detection systems meet the criteria of Regulatory Guide 1.45.

The appropriate CESSAR and CESSAR SER commitments relative to RCS leakage detection equipment and methods have been incorporated into the following discussion. Therefore, the following description of the RCS leakage detection systems is the safety analysis report of record and supersedes any CESSAR text related to this topic.

5.2.5.1 Limits for Reactor Coolant Leakage

The terms pressure boundary leakage, unidentified leakage, identified leakage, and RCS pressure isolation valve leakage are all formally defined in the Technical Specifications. The Technical Specifications contain operational limits for these various types of leakage including separate limitations on steam generator tube leakage and pressure isolation valve leakage. These limits and bases are consistent with the positions of Regulatory Guide 1.45 as well as the assumptions used in the safety analyses and the interface requirements for RCS design and fabrication given in UFSAR 5.1.4.H.

Operability and testing requirements for equipment used to detect pressure boundary leakage and unidentified leakage shall also be provided in the Technical Specifications. The operability of leakage detection equipment and the associated surveillance requirements for RCS leakage provide reasonable assurance that the reactor can be shut down and depressurized before substantial degradation of the reactor pressure boundary occurs.

The surveillance requirements established in the Technical Specifications for operational leakage are commensurate with the safety significance of the leakage and comply with the applicable portions of the ASME Boiler and Pressure Vessel Code.

5.2.5.2 Identified Leakage

The amount of identified leakage from the Reactor Coolant System can be determined by adding up the individual contributions from the paths described below. Indicators and alarms associated with all of the identified leakage pathways are provided in the control room.

5.2.5.2.1 Pressurizer Safety Relief Valves

The relief from the primary safety valves located on the pressurizer is routed to the reactor drain tank. A temperature sensor with indication and alarm capability in the main control room is provided on each relief discharge line downstream of the valve. Safety valve leakage would be indicated by a pronounced temperature increase downstream of the leaking valve

accompanied by less severe increases in the other temperature indicators. Indirect indication of leakage may be evidenced by increased pressure, temperature and level in the reactor drain tank. Each relief discharge line also contains an acoustic monitor to provide indication of safety relief valve position as described in Section 18.II.D.3.

5.2.5.2.2 Reactor Coolant Pump Seals

As described in Section 5.4.1.2, the reactor coolant pumps are equipped with hydrodynamic seals containing three stages, each capable of retaining full RCS pressure. During normal operation, the reactor coolant system operating pressure is nominally decreased through the first two seals to within 330 psid of the pressure in CVCS volume control tank. The third seal, also known as the vapor seal or the backup seal, prevents leakage to the containment atmosphere and maintains sufficient pressure to direct the controlled seal bleed-off flow to the volume control tank. Leakage past the vapor seal would produce an increase in seal face leak-off into containment which is collected and routed to the reactor drain tank. Such leakage would be detected by a decrease in the second stage seal outlet pressure and an increased level in the reactor drain tank. Both parameters are indicated and alarmed in the control room.

Reactor coolant pump seal controlled-bleed off which returns to the volume control tank is not considered reactor coolant leakage. Loss of reactor coolant into the nuclear cooling water system via the high-pressure seal injection coolers is

classified as intersystem leakage and is discussed below in Section 5.2.5.4.

5.2.5.2.3 Component Vents and Drains

In addition to the pressurizer relief valve discharge and reactor coolant pump seal face leak-off described above, leakage of reactor coolant and connected systems is also possible from the following sources:

- Safety injection piping safety relief valve discharges
- RCP seal high-pressure filter drains
- Regenerative heat exchanger drain
- Pressurizer spray control and bypass valve drains
- Reactor coolant loop drains
- Auxiliary pressurizer spray valve drains
- Reactor vessel head seal leakage
- Reactor head and pressurizer vent valve discharge or leakage

The pressurizer relief is routed directly to the reactor drain tank and enters the tank via a submerged sparging nozzle. The rest of the identified leakages described above are collected in a header which goes to the reactor drain tank as well. Both the pressurizer relief sparger and the drain collection header enter the reactor drain tank below the normal water level in order to faciliatate condensate of two-phase fluids. Leakage of the component vents and drains would then be indicated by an

increase in reactor drain tank temperature, pressure, and level.

5.2.5.2.4 Leakage Through Steam Generator Tubes or Tubesheet

The increase in secondary side radioactivity concentrations produced by reactor coolant leakage through steam generator tubes/tubesheet would be indicated by radiation monitors located in the condenser air removal system, the steam generator blowdown, and the main steam system. Routine radiochemical analysis of steam generator water samples would also indicate leakage of reactor coolant into the secondary system. See Section 11.5 for radiation monitoring system details such as monitor range, sensitivity, communications, remote indication/control, and alarms. The magnitude of the identified leak rate through the steam generators is determined by calculation.

5.2.5.3 Detection of Unidentified Leakage

This section describes the four principal methods for detecting and quantifying unidentified leakage and pressure boundary leakage.

5.2.5.3.1 Inventory Method

The Reactor Coolant System (RCS) and the Chemical and Volume Control System (CVCS) together constitute a semi-closed system. Under roughly steady state power conditions, the net inventory of coolant contained in the RCS and the letdown and charging portions of the CVCS will be constant providing that:

- Reactor coolant pump seal controlled bleed-off flow is lined up to the volume control tank
- No makeup from the RWT/RMWT is added to the volume control tank or charging pump suction
- Letdown is not diverted to the CVCS Holdup Tank
- No RCS chemistry sampling is in progress.

In this configuration, coolant leakage will be seen as a deflection of level in the pressurizer and volume control tank. If this semi-closed RCS configuration is maintained for a sufficiently long period of time, nominally 2 hours, the sensitivity of the pressure and volume control tank level instrumentation will permit determination of reactor coolant leakage at rates much lower than 1 gpm. While the system is “isolated” as described above, transient changes in letdown flow rate or reactor coolant inventory can normally be accommodated by the capacitance in the pressurizer and volume control tank. The test will be discontinued if pressure or inventory control is jeopardized during its performance.

5.2.5.3.2 Sump Level Method

As described in section 9.3.3, leakage of liquid water and condensed liquid from steam leakage in the containment are collected and routed to the containment east and west radwaste sumps and to the reactor cavity sump. The levels of these three sumps in the reactor drain system are monitored continuously in the control room. A control room alarm will be generated on high level or if the rate of level increase

corresponds to a sump inflow greater than 1 gpm for one hour. Alarms may also result from other abnormal sump activity such as excessive sump pump run time. This sump level and flow monitoring equipment is qualified to perform its intended function following seismic events that do not require plant shutdown.

5.2.5.3.3 Containment Atmosphere Radiation Monitor Particulate Channel

Located in the auxiliary building, radiation monitor RU-1 provides the third and fourth methods of detecting unidentified pressure boundary leakage. This process monitor continuously draws a containment atmosphere sample into a closed loop that returns the sample back to containment. The sample flow passes through a particulate filter, an I-131 sampler (charcoal), and gaseous sample chamber in order to measure particulate, iodine, and gaseous radioactivity levels. The particulate and gaseous channels in particular are used to monitor RCS leakage. Section 11.5.2 provides a detailed description of the monitor including sampling assembly design, principle of detection, signal processing, communications, alarms, range, sensitivity, and accuracy. Both instrument channels are qualified to remain functional when subjected to a Safe Shutdown Earthquake (SSE).

In the event of reactor coolant leakage into the containment atmosphere, dissolved or otherwise entrained noble gases in the coolant will evolve out of solution. The particulate daughter products from these nuclides will be collected on the RU-1 filter paper, and the associated detector will use the increase

in count rate to indicate the activity concentration. The sensitivity of the particulate channel for reactor coolant leak rate detection depends on the magnitude of the normal baseline leakage into the containment and reactor coolant activity. Shortly after startup and also during steady operation with low levels of defect fuel, the concentration of radioactivity in the reactor coolant may not be sufficient to permit detection of a 1 gpm leak within 1 hour. Therefore, position C.5 of Regulatory Guide 1.45 has been exempted for this method of reactor coolant leak detection. The particulate setpoint given in Technical Specifications is established so that, in an isolated containment atmosphere at equilibrium concentration with an existing 1 gpm leak and 0.1% defect fuel, a 1 gpm increase in leak rate would roughly provide a 10% increase in indicated concentration within one hour. This method is further limited by the fact that large uncertainties are possible when determining the associated leak rate by calculation. Therefore, in the event of a high alarm or increasing trend on this channel, station procedures shall direct the operator to perform a water inventory balance within 1 hour in order to determine the equivalent RCS leak rate.

5.2.5.3.4 Containment Atmosphere Radiation Monitor Gas Channel

In radiation monitor RU-1 discussed above in the previous section, containment atmosphere is directed to the gaseous sampler assembly after the particulate matter and volatile halogens have been collected out of the stream by the particulate and I-131 samplers, respectively. The sample

stream is constantly mixed in a fixed, shielded volume where it is viewed by a beta scintillation detector located in a completely enclosed housing.

The gas channel setpoint given in Technical Specifications is established so that, in an isolated containment atmosphere at equilibrium concentration with an existing 0.5 gpm leak and 0.1% defect fuel, a 1 gpm increase in leak rate would roughly provide a 10% increase in indicated concentration within 9 hours. Because the noble gas channel has less sensitivity for detecting RCS leakage than the particulate channel, Regulatory Guide 1.45 position C.5 has also been exempted for this method of reactor coolant leak detection. The compensatory administrative controls described above apply for this method as well.

5.2.5.4 Intersystem Leakage

Intersystem leakage is loss of reactor coolant system inventory into an interfacing system through degradation of an engineering barrier such as heat exchanger tubes or closed reactor coolant isolation valves. Leakage from the reactor coolant system may occur into the following interfacing or auxiliary systems: safety injection system, nuclear cooling water system, essential cooling water system, nuclear sampling system, and chemical and volume control system. Leakage across the steam generator tubesheet or tubes is a special case of intersystem leakage which is discussed above.

Since intersystem leakage usually does not go to the containment atmosphere, it is not normally detected through

monitoring of the "identified" or "unidentified" leakage as described above. Instead, leakage into a particular system can be detected through various process instruments. Unless otherwise specified, the instruments described have indication and alarms in the main control room. The sensitivity of these indicators depends on a number of factors, and they are not required by Regulatory Guide 1.45 to be able to detect a 1gpm increase in leakage within 1 hour. If the instrumentation does not permit quantification of the intersystem leak rate, a water inventory material balance will be commenced within 1 hour to determine the extent of the leakage. Radiochemical analysis of grab samples taken from the system may be used to locate and quantify the leak.

Leakage of reactor coolant into the safety injection system via the cold leg injection lines is detected by pressure transmitters on the low pressure side of the first isolation check valves (SI-V217, V227, V237, V247). Pressure transmitters on the HPSI and LPSI pump discharge can detect leakage into those subsystems. Leakage of reactor coolant through the safety injection tank check valves is detected by monitoring the tank water level and pressure. Leakage past the hot leg injection check valves (SI-V522 and V532) can be detected by pressure transmitters on the low-pressure side of those valves.

Loss of reactor coolant to the shutdown cooling system may occur by leakage through two isolation valves arranged in series: SI-651 and SI-653 on the A train and SI-652 and SI-654 on the B train. The pressure relief valve positioned between

each pair of isolation valves is provided to prevent over-pressurization of that line segment due to thermal expansion resulting from heat conducted across the first (most inboard) valve. Since the nominal setpoint of the valve is 2485 psig, it should not lift in the event of leakage across the first valve. The pressure relief valve discharge is piped to the reactor drain tank. Should the first isolation valve and the relief valve both leak, the inflow to the reactor drain tank will be detected by increased tank pressure, temperature, and level. Leakage past both isolation valves in either train would pressurize the downstream portion of shutdown cooling line up to the outboard containment isolation valve (SI-655 or SI-656). When the line pressure exceeds the setpoint of the low temperature over-pressure (LTOP) relief valves, the valves will lift and discharge to the containment recirculation sumps. This leakage would eventually register on the containment atmosphere process radiation monitor RU-1 particulate and gas channels. A temperature sensor located on the wall of each recirculation sump may detect large leakage rates through the LTOPs.

When shutdown cooling is in service, reactor coolant may enter the essential cooling water (EW) system through material flaws in the shutdown cooling heat exchangers. The resulting influx of radioactivity and inventory will be detected by process radiation monitors RU-2 or RU-3 as well as the high level switches on the EW surge tank levels.

Reactor coolant leakage into the nuclear cooling water system through tube leaks in the letdown heat exchanger or the reactor

coolant pump high pressure seal coolers can be detected by process radiation monitor RU-6 and high level switches on the nuclear cooling water surge tank. Seal cooler leakage may also produce elevated seal temperatures.

Although chemistry sampling from the reactor coolant system and connected systems does represent a loss of inventory, the removal of sample aliquots and the associated purge volumes does not constitute coolant leakage because it involves no degradation of the boundary materials. When the sample line isolation valves are closed, flow past the isolation valve seats would result in intersystem leakage of reactor coolant into the nuclear sampling system. Such leakage can be detected by increased temperatures and pressures in the sampling system. These instrument readings are indicated on a local panel located in the Chemistry Hot Lab.

As design inputs of reactor coolant to the connecting chemical and volume control system (CVCS), letdown and controlled bleed-off from the reactor coolant pump seals are not considered to be reactor coolant leakage. When letdown is isolated, coolant leakage may be detected in a number of ways depending on the system configuration. Examples include increased equipment drain tank level from lifts of relief valve CH-PSV-345 when the downstream piping is isolated, indicated flow in the failed fuel monitor sample loop, or increasing volume control tank level. Depending on how controlled bleed-off is isolated, leakage through the isolation valves may be detected by level increases in the volume control tank or reactor drain tank.

5.2.5.5 Evaluation of Reactor Coolant Leakage Indication

Primary control room indication of reactor coolant leakage into the containment is provided by (1) abnormally high particulate and radioactive gas levels in the containment atmosphere and (2) high flow alarms if flow to any of the reactor drain (RD) system sumps increases to 1 gpm for 1 hour. Upon actuation of a high activity alarm or indication of an increasing activity trend on the containment atmosphere radioactive gas and particulate channels, the operator will commence a water inventory balance to determine coolant leakage rate within 1 hour. Upon actuation of the excessive sump leakage alarm in the control room, the operator will begin periodically recording sump levels. Based on the sump level increase during the intervals, the operator can determine the leak rate for comparison with the leakage limits.

Other indirect control room indications of significant reactor coolant leakage to the containment would include changes in pressurizer level; increased containment pressure, temperature, and humidity; increasing trends of containment area radiation monitor readings; and an increase in borated and dilute makeup water based on flow totalizer readings. Process instruments can also provide indirect indication of intersystem leakage as described above. Once potential reactor coolant leakage to the containment or to another system has been detected by process instruments, the operator will attempt to quantify the leak rate by direct measurement or by calculation. If this is not practical, then a water inventory balance should be conducted to determine the leak rate in common leakage equivalent units

(gpm evaluated at reactor standard operating temperature and pressure) in order to facilitate comparison with the Technical Specification limits.

For the purpose of leak detection, Regulatory Guide 1.45 and PVNGS Technical Specifications limit the definition of the “reactor coolant pressure boundary” to those portions of the reactor coolant system which are constructed so that no leakage is expected to occur. This refers to the principal boundary members such as the pressure vessel wall, coolant piping walls, reactor coolant pump bowls, and isolation valve bodies. Since leakage of the pressure boundary as defined in the Technical Specifications is a possible precursor to gross failure of the boundary, the reactor must shutdown and depressurized in a timely fashion if any “pressure boundary leakage” is detected.

Identified and unidentified leakage is expected through other pressure retaining components that cannot practically be made completely leak tight: isolation valve packing and stems, isolation valve seats, pump and valve seals as well as the steam generator tubes and tubesheet. The Technical Specifications limit identified leakage in order to prevent it from obscuring unidentified leakage. Due to inherent limitations of the containment leak detection systems, unidentified leakage is limited by the Technical Specifications because it is possibly “pressure boundary leakage.”

The water inventory balance determines the total reactor coolant leak rate. Leakage detected by this method is presumed to be unidentified until the source is determined and the leak

rate has been quantified. The overall identified leak rate shall be determined by summing all of the identified leak rate contributions together. By design, the RCS inputs to the reactor drain tank are identified, and therefore the leak rate for each input need not be identified individually. Inventory entering the reactor drain tank which did not originate from the reactor coolant or a connecting system may be subtracted from the identified leak rate if it can be quantified. Unidentified leakage is calculated as the difference between the total coolant leakage and the sum of all the identified leakages.

Planned flow of reactor coolant into a connecting system through open isolation valves for the purpose of reactor coolant process control or assessment is not leakage. In addition, inventory losses out of connecting systems through boundary degradation need not be considered reactor coolant leakage provided that the location is known, the leak rate can be quantified, and the leakage is known not to interfere with the leak detection methods described in the Technical Specifications. In this case, the leak rate out of the connecting system may be subtracted from the total leakage prior to calculating the identified and unidentified leak rates. Known leakage from a connecting system that interferes with or otherwise obscures the detection of unidentified leakage, however, must be considered identified leakage. Examples would include connecting system leakage into the containment atmosphere or containment sumps, or those connecting system leaks quantified with uncertainties that are

large in comparison with the unidentified leakage limit. If reactor coolant leakage out of a degraded connecting system exceeds limits in the Technical Specifications, then the isolation valves must be closed, or the reactor must be placed in a condition where the limit does not apply.

The Technical Specifications apply leak rate limits to RCS pressure isolation valves individually as added assurance against over-pressurization of low-pressure connecting systems due to valve failure. This requirement is normally surveilled on the refueling interval using in-service testing techniques. In operational modes 1-4, leakage through both RCS pressure isolation valves in series which is located and quantified shall be applied to the identified leak rate limit.

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5.3 REACTOR VESSEL

5.3.1 REACTOR VESSEL MATERIALS

5.3.1.1 Material Specifications

The principle ferritic materials used in the reactor vessel are listed in Table 5.1-2. These materials are in accordance with the ASME Boiler and Pressure Vessel Code, Section III.

5.3.1.2 Special Process Used for Manufacturing and Fabrication

The reactor vessel is fabricated in accordance with the ASME Boiler and Pressure Vessel Code, Section III. No special manufacturing methods that could compromise the integrity of the vessel are used.

The reactor vessel is a vertically mounted cylindrical vessel with a hemispherical lower head welded to the vessel and a removable hemispherical upper closure head. The construction of the vessel is basically that of formed plates welded into cylinders and hemispherical heads. The closure head, including the flange is a single forging having machined nozzles. The internal surfaces that are in contact with the reactor coolant are clad with austenitic stainless steel.

The reactor vessel consists basically of a vessel flange, three shell sections (upper, intermediate and lower) and a bottom head. The vessel flange is a forged ring with a machined ledge on the inside surface to support the core support barrel, which in turn supports the reactor internals and the core. The flange is drilled and tapped to receive the closure studs and is machined to provide a mating surface for the reactor vessel

closure seals. Each shell section consists of three 120°, or four 90° segments formed from plate material and welded together to form a cylindrical shell. The bottom head is constructed of two spherical sections formed from plate material and welded together to form a hemispherical head. These sections are joined together by welding, along with four inlet nozzles and two outlet nozzles, to form a complete vessel assembly.

The closure head is fabricated separately since it is joined to the reactor vessel by bolting. The flange is drilled to match the vessel flange stud hole locations, and the lower surface of the flange is machined to provide a mating surface for the vessel closure seals. The control element drive mechanism (CEDM) nozzles are welded into the head to complete the assembly.

The reactor vessel closure heads were purchased from Doosan Heavy Industries and Construction Company Limited, of South Korea. In a letter from the NRC to APS, dated January 3, 2007, the NRC specified that by accepting this equipment, installing it, and utilizing it at the plant, Arizona Public Service (APS) accepted responsibility for complying with certain peaceful use commitments undertaken on behalf of APS by the United States (U.S.) Government. The U.S. has agreed that this equipment will not be used for any purpose that would result in any nuclear explosive device. For example, this would preclude use of the Palo Verde reactors to produce tritium for the weapons program. Second, the U.S. Government has agreed that if this equipment is ever to be exported from PVNGS to a country other than Japan, the U.S. Government will obtain similar peaceful

use assurances from the proposed recipient country prior to approving its export. APS would be required to submit an application to the Nuclear Regulatory Commission for a license to export this equipment and these assurances would be obtained in the context of that review.

5.3.1.3 Special Methods for Nondestructive Examination

Prior to, during, and after fabrication of the reactor vessel, nondestructive tests based upon Section III of the ASME Boiler and Pressure Vessel Code are performed on all welds, forgings, and plates as indicated. The nondestructive examination requirements including calibration methods, instrumentation, sensitivity, reproducibility of data, and acceptance standards are in accordance with requirements of the ASME B&PV Code, Section III. (See Table 5.2-1). Strict quality control is maintained in critical areas such as calibration of test instruments.

All full-penetration, pressure-containing welds are 100% radiographed to the standards of Section III of the ASME Boiler and Pressure Vessel Code, Weld preparation areas, back-chip areas, and final weld surfaces are magnetic-particle or dye-penetrant examined. Other pressure-containing welds, such as used for the attachments of nonferrous nickel-chromium-iron mechanism housings, vents, and instrument housings to the reactor vessel and head, are inspected by liquid-penetrant tests of the root pass, the lesser of one-half of the thickness or each 1/2-inch of weld deposit, and the final surface. Additionally, the base metal weld preparation area is magnetic-

particle examined prior to overlay with nickel-chromium-iron weld metal.

All forgings are inspected by ultrasonic testing, using longitudinal beam techniques. In addition, ring forgings are tested using shear wave techniques.

All carbon-steel and low alloy forgings and ferritic welds are also subjected to magnetic-particle examination after stress relief.

Plates are subjected to ultrasonic examination using straight beam techniques.

All vessel bolting material receives ultrasonic and magnetic-particle examination during the manufacturing process.

The bolting material receives a straight-beam, radial-scan, ultrasonic examination with a search unit not exceeding 1 square-inch area. All hollow material receives a second ultrasonic examination using angle-beam, radial scan with a search unit not exceeding 1 square inch in area. A reference specimen of the same composition and thickness containing a notch (located on the inside surface) 1 inch in length and a depth of 3% of nominal section thickness, or 3/8-inch, whichever is less, is used for calibration. Use of these techniques ensures that no materials that have unacceptable flaws, observable cracks, or sharply defined linear defects are used.

The magnetic-particle inspection is performed both before and after threading of the studs.

Upon completion of all postweld heat treatments, the reactor vessel is hydrostatically tested, and all accessible ferritic weld surfaces, including those of welds used to repair material, are magnetic-particle inspected in accordance with Section III of the ASME Boiler and Pressure Vessel Code.

5.3.1.4 Special Controls for Ferritic and Austenitic Stainless Steels

are as follows:

Regulatory Guide 1.31, Control of Stainless Steel Welding, is addressed in Section 5.2.3.4.

- Regulatory Guide 1.34, Control of Electroslag Weld Properties is addressed in Paragraph 5.2.3.3.
- Regulatory Guide 1.43, Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components, is addressed in Paragraph 5.2.3.3.
- Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel, is addressed in Paragraph 5.2.3.4.
- Regulatory Guide, 1.50, Control of Preheat Temperature for Welding of Low-Alloy Steel, is addressed in Paragraph 5.2.3.3
- Regulatory Guide 1.71, Welder Qualification for Areas of Limited Accessibility, is addressed in Paragraph 5.2.3.3.

5.3.1.5 Fracture Toughness

In accordance with 10 CFR 50 Appendix G, Paragraph IV B, the reactor vessel beltline materials have minimum upper-shelf energy, as determined from Charpy V-notch tests on unirradiated

specimens in accordance with Paragraphs NB-2322.2 (a) of ASME Code, of 75 ft-lbs. Charpy impact tests were performed on transversely (weak direction) oriented specimens from the beltline plate materials to establish RT_{NDT} as required by 10CFR50, Appendix G.

Data from fracture toughness tests of base metal, weld metal, and heat affected zone (HAZ) material for Palo Verde Unit 1, Unit 2, and Unit 3 are presented in the tables of section 5.2.

Chemical analyses for the beltline plates and weld metal for Palo Verde Unit 1 are presented in tables 5.3-1 and 5.3-2, for Unit 2 in tables 5.3-3 and 5.3-4, and for Unit 3 in tables 5.3-5 and 5.3-6, respectively.

5.3.1.6 Reactor Vessel Material Surveillance Program

The surveillance program monitors the radiation induced changes in the strength and toughness properties of the reactor vessel beltline materials. These changes are determined by comparison of pre- and post-irradiation test results using uniaxial tension specimens, standard and precracked Charpy impact specimens, and compact tension specimens.

This surveillance program was established using the criteria presented in ASTM E185-79 for Unit 1 and ASTM E185-82 for Unit 2 & 3, Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessel. It also conforms to the requirements of 10CFR50, Appendix H (October 26, 1979), entitled, Reactor Vessel Material Surveillance Program Requirements. The material toughness requirements are determined in accordance with 10CFR50,

Table 5.3-1

PVNGS UNIT 1 REACTOR VESSEL BELTINE PLATES CHEMICAL ANALYSIS

(Sheet 1 of 2)

Material Code Number / Element	Intermediate Shell Plates			Lower Shell Plates		
	M-6701-1	M-6701-2	M-6701-3	M-4311-1	M-4311-1	M-4211-3
C	0.23	0.23	0.23	0.24	0.20	0.22
Mn	1.38	1.34	1.35	1.48	1.45	1.46
P	0.005	0.004	0.004	0.004	0.005	0.004
S	0.018	0.017	0.016	0.003	0.007	0.005
Si	0.24	0.28	0.28	0.22	0.19	0.19
Ni	0.66	0.61	0.61	0.65	0.62	0.64
Cr	0.06	0.05	0.05	0.07	0.04	0.05
Mo	0.52	0.53	0.53	0.51	0.53	0.53
V	0.003	0.003	0.003	0.003	0.001	0.001
Cb	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Ti	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Co	0.015	0.013	0.013	0.012	0.011	0.011
Cu	0.07	0.06	0.06	0.04	0.03	0.03
Al	0.032	0.035	0.037	0.026	0.022	0.022
B	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
W	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Sb	0.0024	0.0016	0.0015	-	-	-
As	<0.001	<0.001	<0.001	0.014	0.012	0.017

Table 5.3-1

PVNGS UNIT 1 REACTOR VESSEL BELTINE PLATES CHEMICAL ANALYSIS

(Sheet 2 of 2)

Material Code Number / Element	Intermediate Shell Plates			Lower Shell Plates		
	M-6701-1	M-6701-2	M-6701-3	M-4311-1	M-4311-1	M-4211-3
Sn	0.003	0.003	0.003	0.001	0.001	0.002
Zr	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
Pb	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
N_2	0.009	0.009	0.009	0.014	0.013	0.012

Table 5.3-2

PVNGS UNIT 1 REACTOR VESSEL BELTINE WELD METAL (AS DEPOSITED) CHEMICAL ANALYSIS

(Sheet 1 of 2)

Seam Number / Element	Lower Shell Long. Seams			Intermediate Shell Long. Seams			
	101-142C	101-142B	101-142A	101-124C	101-124B	101-124A	Girth Seam
C	0.15	0.15	0.15	0.13	0.14	0.12	0.11
Mn	1.29	1.32	1.36	1.21	1.20	1.24	1.51
P	0.005	0.005	0.006	0.009	0.01	0.012	0.013
S	0.006	0.006	0.006	0.007	0.008	0.009	0.009
Si	0.21	0.20	0.21	0.12	0.14	0.13	0.54
Ni	0.079	0.079	0.079	0.049	0.049	0.049	0.096
Cr	0.03	0.03	0.03	0.02	0.02	0.02	0.16
Mo	0.53	0.52	0.54	0.49	0.49	0.52	0.52
V	0.005	0.005	0.006	0.004	0.005	0.006	0.005
Cb	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Ti	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Co	0.015	0.015	0.016	0.005	0.005	0.006	0.008
Cu	0.035	0.035	0.035	0.047	0.047	0.047	0.031
Al	0.005	0.005	0.007	0.004	0.004	0.004	0.01
B	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
W	0.01	0.01	0.02	<0.01	<0.01	<0.01	<0.01
As	0.004	0.004	0.005	0.007	0.006	0.006	0.001
Sn	0.001	0.001	0.001	0.003	0.002	0.003	0.003

Table 5.3-2

PVNGS UNIT 1 REACTOR VESSEL BELTINE WELD METAL (AS DEPOSITED) CHEMICAL ANALYSIS

(Sheet 2 of 2)

Element \ Seam Number	Lower Shell Long. Seams			Intermediate Shell Long. Seams			
	101-142C	101-142B	101-142A	101-124C	101-124B	101-124A	Girth Seam
Zr	0.001	0.001	0.001	<0.001	<0.001	<0.001	<0.001
Pb	<0.001	<0.001	<0.001	-	-	-	<0.001
Sb	<0.001	<0.001	<0.001	-	-	-	0.009
N_2	0.005	0.005	0.006	0.01	0.006	0.008	0.013

Table 5.3-3

PVNGS UNIT 2 REACTOR VESSEL BELTINE PLATES CHEMICAL ANALYSIS

(Sheet 1 of 2)

Material Code Number / Element	Intermediate Shell Plates			Lower Shell Plates		
	F-765-4	F-765-5	F-765-6	F-773-1	F-773-2	F-773-3
C	0.25	0.26	0.25	0.23	0.22	0.22
Mn	1.47	1.49	1.49	1.49	1.48	1.44
P	0.003	0.004	0.002	0.003	0.003	0.004
S	0.005	0.007	0.004	0.008	0.008	0.009
Si	0.19	0.21	0.20	0.20	0.25	0.20
Ni	0.67	0.65	0.67	0.67	0.64	0.66
Cr	0.05	0.03	0.03	0.03	0.03	0.03
Mo	0.53	0.51	0.49	0.51	0.50	0.51
V	0.003	0.002	0.003	0.003	0.003	0.002
Cb	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Ti	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Co	0.011	0.011	0.013	0.012	0.018	0.017
Cu	0.03	0.03	0.04	0.03	0.04	0.05
Al	0.019	0.022	0.020	0.020	0.024	0.019
B	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
W	<0.001	<0.01	<0.01	<0.01	<0.01	<0.01
As	0.011	0.015	0.021	0.017	0.028	0.023

Table 5.3-3

PVNGS UNIT 2 REACTOR VESSEL BELTINE PLATES CHEMICAL ANALYSIS

(Sheet 2 of 2)

Material Code Number / Element	Intermediate Shell Plates			Lower Shell Plates		
	F-765-4	F-765-5	F-765-6	F-773-1	F-773-2	F-773-3
Sn	0.002	0.002	0.003	0.001	0.001	0.002
Zr	<0.001	<0.002	<0.001	<0.001	<0.001	<0.001
Pb	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
N_2	0.012	0.012	0.008	0.011	0.011	0.011

Table 5.3-4

PVNGS UNIT 2 REACTOR VESSEL BELTINE WELD METAL (AS DEPOSITED) CHEMICAL ANALYSIS

Seam Number / Element	Lower Shell Long. Seams			Intermediate Shell Long. Seams			
	101-142C	101-142B	101-142A	101-124C	101-124B	101-124A	Girth Seam
C	0.14	0.13	0.12	0.12	0.12	0.13	0.13
Mn	1.69	1.53	1.44	1.50	1.52	1.53	1.55
P	0.012	0.008	0.007	0.008	0.008	0.008	0.012
S	0.011	0.011	0.011	0.012	0.012	0.012	0.009
Si	0.49	0.41	0.42	0.40	0.42	0.39	0.39
Ni	0.067	0.067	0.067	0.059	0.059	0.059	0.096
Cr	0.11	0.10	0.10	0.04	0.05	0.04	0.15
Mo	0.44	0.48	0.48	0.59	0.60	0.59	0.51
V	0.05	0.005	0.004	0.006	0.004	0.004	0.005
Cb	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Ti	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Co	0.008	0.007	0.006	0.010	0.011	0.010	0.010
Cu	0.074	0.074	0.074	0.046	0.046	0.046	0.031
Al	0.004	0.004	0.004	0.009	0.010	0.009	0.006
B	0.001	0.001	0.001	0.001	0.001	0.001	0.001
W	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
As	0.006	0.002	0.002	0.020	0.020	0.020	0.006
Sn	0.004	0.003	0.003	0.005	0.004	0.004	0.004
Zr	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
Pb	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
Sb	0.0008	0.0008	0.0007	0.0011	0.0011	0.0012	0.0010
N_2	0.016	0.017	0.014	0.007	0.006	0.005	0.012

Table 5.3-5

PVNGS UNIT 3 REACTOR VESSEL BELTINE PLATES CHEMICAL ANALYSIS

Element \ Material Code Number	Intermediate Shell Plates			Lower Shell Plates		
	F-6407-4	F-6407-5	F-6407-6	F-6411-1	F-6411-2	F-6411-3
C	0.23	0.23	0.23	0.21	0.22	0.20
Mn	1.46	1.45	1.44	1.44	1.49	1.43
P	0.002	0.002	0.002	0.004	0.004	0.007
S	0.005	0.005	0.004	0.007	0.013	0.018
Si	0.22	0.22	0.22	0.22	0.23	0.17
Ni	0.62	0.61	0.61	0.64	0.65	0.66
Cr	0.02	0.02	0.03	0.15	0.03	0.04
Mo	0.50	0.52	0.54	0.53	0.53	0.52
V	0.003	0.003	0.003	0.004	0.003	0.003
Cb	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Ti	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Co	0.011	0.010	0.010	0.018	0.019	0.011
Cu	0.04	0.05	0.04	0.04	0.04	0.04
Al	0.024	0.017	0.021	0.021	0.021	0.018
B	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
W	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
As	0.009	0.010	0.007	0.016	0.008	0.010
Sn	<0.001	<0.001	<0.001	0.003	0.003	0.002
Zr	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
Pb	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
N_2	0.016	0.012	0.013	0.013	0.013	0.013

Table 5.3-6

PVNGS UNIT 3 REACTOR VESSEL BELTINE WELD METAL CHEMICAL ANALYSIS

Seam Number / Element	Lower Shell Long. Seams			Intermediate Shell Long. Seams			Lower to Intermediate Closing Girth Seam
	101-142 A	101-142 B	101-142 C	101-124 A	101-124 B	101-124 C	101-171
C	0.12	0.12	0.14	0.14	0.13	0.13	0.11
Mn	1.34	1.21	1.02	1.54	1.57	1.63	1.31
P	0.010	0.007	0.008	0.009	0.010	0.010	0.008
S	0.009	0.018	0.009	0.008	0.008	0.009	0.011
Si	0.33	0.27	0.14	0.41	0.43	0.43	0.40
Ni	0.096	0.096	0.096	0.096	0.096	0.096	0.096
Cr	0.15	0.10	0.04	0.17	0.18	0.19	0.16
Mo	0.36	0.30	0.09	0.49	0.52	0.54	0.51
V	0.004	0.003	0.002	0.004	0.004	0.005	0.003
Cb	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Ti	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Co	0.010	0.007	0.007	0.007	0.008	0.008	0.009
Cu	0.031	0.031	0.031	0.031	0.031	0.031	0.031
Al	0.007	0.003	0.006	0.009	0.007	0.007	0.006
B	0.001	<0.001	<0.001	0.001	0.001	0.001	<0.001
W	0.01	0.01	0.01	0.01	0.01	0.01	<0.01
As	0.003	0.003	0.003	0.002	0.002	0.002	0.005
Sn	0.004	0.003	0.003	0.003	0.003	0.003	0.004
Zr	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
Pb	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
Sb	0.0010	0.0009	0.0010	0.0019	0.0019	0.0016	0.0018
N_2	0.011	0.007	0.009	0.012	0.012	0.013	0.011

Appendix G, and ASME Boiler and Pressure Vessel Code (B&PV), Section III, Article NB-2300.

5.3.1.6.1 Test Material Selection

Three metallurgically different materials, representative of the reactor vessel, are investigated. These are base metal, weld metal, and heat-affected zone material. Base metal specimens for Unit 1 are fabricated from sections of two plates in the beltline region of the vessel which become the limiting plates with respect to reactor operation during its lifetime.

Selection was based on an evaluation of initial toughness (characterized by the reference temperature, RT_{NDT}), predicted effect of chemical composition (residual copper and phosphorus), and neutron fluence on the toughness (RT_{NDT} shift) during reactor operation. For Unit 1, a plate from the lower shell course had the highest predicted RT_{NDT} shift. A plate from the intermediate shell (nozzle) course had the highest adjusted RT_{NDT} (initial RT_{NDT} plus RT_{NDT} shift). Thus, for Unit 1, two plates were selected as base metal test material.

For Units 2 and 3, base metal test material was manufactured from one plate for each unit selected from the reactor vessel beltline. This plate from the lower shell course was predicted to have the highest predicted RT_{NDT} shift and the highest adjusted RT_{NDT}, and, therefore, was selected as the base metal test material.

Weld region test material was produced by welding together sections of lower shell course plates from the beltline of the

reactor vessel. The HAZ test material is manufactured from a section of the same plate used for lower shell course base metal surveillance test material. The weld metal test material is produced from the same heat of weld wire or rod and lot of flux used in the beltline of the reactor vessel. Welding parameters duplicated those used for the beltline welds.

Representative stock (archive material) to provide two additional sets of test specimens for each material was provided, with full documentation and identification.

In addition, material is included from a standard heat of ASTM A533, Grade B, Class 1, manganese-molybdenum-nickel steel made available by the USNRC-sponsored Heavy Section Steel Technology (HSST) Program. This standard reference material (SRM) was used as a monitor for Charpy impact tests, permitting comparisons among the irradiation data from operating power reactors and experimental reactors. Compilation of data generated from post-irradiation tests of these correlation monitors was carried out by the HSST program.

5.3.1.6.2 Test Specimens

5.3.1.6.2.1 Type and Quantity. The total quantity of specimens furnished in this program for baseline (unirradiated) and post-irradiation testing is presented in table 5.3-7 for Unit 1 and in table 5.3-8 for Units 2 and 3. The types of specimens are drop weight, tension, standard Charpy impact, pre-cracked Charpy, and compact tension for baseline testing; and tension, standard Charpy impact, precracked Charpy, and compact tension for post-irradiation testing.

Table 5.3-7

PVNGS UNIT 1 TOTAL QUANTITY OF SPECIMENS

Type of Specimen	Orientation	Base Metal		Quantity			Total
		Lower Shell	Intermediate Shell	Weld Metal	HAZ	SRM[a]	
Drop weight	Transverse	12	--	12	12	--	36
Standard Charpy	Longitudinal	42	36	--	--	69	147
	transverse	69	63	114	96	--	342
Precracked Charpy	Longitudinal	30	30	--	--	--	60
	transverse	30	30	48	--	--	108
Compact tension (1t)	Transverse	8	8	8	--	--	24
(1/2t	transverse	14	14	24	--	--	52
Tension	Longitudinal	12	--	--	--	--	12
	transverse	21	18	30	--	--	69
	Total	238	199	236	108	69	850

a. Standard reference material characterized by Heavy Section Steel Technology Program.

Table 5.3-8

PVNGS UNIT 2 AND 3 TOTAL QUANTITY OF SPECIMENS (IN EACH UNIT)

Type of Specimen	Orientation	Base Shell	Quantity[a]			Total
			Weld Metal	HAZ	SRM[b]	
Drop weight	Transverse	12	12	12	-	36
Standard Charpy	Longitudinal	51	-	-	69	120
	transverse	114	114	96	-	324
Precracked Charpy	Longitudinal	39	-	-	-	39
	transverse	39	39	-	-	78
Compact tension	1 t Transverse	8	8	-	-	16
	1/2 t Transverse	34	34	-	-	68
Tension	Longitudinal	12	-	-	-	12
	transverse	30	30	-	-	60
	Total	339	237	108	69	753

a. All specimens from lower shell, as noted in paragraph 5.3.1.6.1

b. Standard reference material characterized by Heavy Section Steel Technology Program.

5.3.1.6.2.2 Baseline Specimens. The type and quantity of test specimens provided for establishing the properties of the baseline (unirradiated) reactor vessel materials are presented in table 5.3-9 for Unit 1 and in table 5.3-10 for Units 2 and 3. The data from tests of these specimens provide the basis for determining the radiation-induced property changes of the reactor vessel materials.

Drop weight test specimens were provided to establish the nil-ductility transition temperatures (T_{NDT}) of the unirradiated lower shell course base metal (transverse orientation), weld metal, and HAZ material. Standard Charpy impact test specimens from the lower and intermediate shell (Unit 1) are provided to establish the initial Charpy impact energy transition curve and reference temperature (RT_{NDT}) of the base metals (longitudinal and transverse orientation), weld metal, and HAZ material. Uniaxial tension test specimens are provided to define the initial strength versus temperature relationship for the surveillance materials. For intermediate shell course base metal from Unit 1, no drop weight or longitudinal tension specimens are provided. Reactor vessel material qualification test results will be used instead.

Precracked Charpy impact and compact tension (1t and 1/2t) specimens from the base metals and weld metal are provided to determine the fracture toughness properties over the range extending from linear elastic to elastic-plastic fracture.

Table 5.3-9

PVNGS UNIT 1 TYPE AND QUANTITY OF SPECIMENS FOR BASELINE TESTS

		Base Metal		Quantity			
Type of Specimen	Orientation	Lower Shell	Intermediate Shell	Weld Metal	HAZ	SRM[a]	Total
Drop weight	Transverse	12	--	12	12	--	36
Standard Charpy	Longitudinal	24	18	--	--	15	57
	transverse	24	18	24	24	--	90
Precracked Charpy	Longitudinal	12	12	--	--	--	24
	transverse	12	12	12	--	--	36
Tension	Longitudinal	12	--	--	--	--	12
	transverse	12	9	12	--	--	33
Compact tension (1t)	Transverse	8	8	8	--	--	24
(1/2t	transverse	4	4	4			12
	Total	120	81	72	36	15	324

a. Standard reference material

Table 5.3-10

PVNGS UNIT 2 AND 3 TYPE AND QUANTITY OF TEST SPECIMENS (IN EACH UNIT)

FOR BASELINE TESTS

Type of Specimen	Orientation	Quantity[a]				
		Base Shell	Weld Metal	HAZ	SRM[b]	Total
Drop weight	Transverse	12	12	12	-	36
Standard Charpy	Longitudinal	24	-	-	15	39
	transverse	24	24	24	-	72
Precracked Charpy	Longitudinal	12	-	-	-	12
	transverse	12	12	-	-	24
Tension	Longitudinal	12	-	-	-	12
	transverse	12	12	-	-	24
Compact tension	1 t Transverse	8	8	-	-	16
	1/2 t Transverse	4	4	-	-	8
	Total	120	72	36	15	243

a. All specimens from lower shell, as noted in paragraph 5.3.1.6.1

b. Standard reference material

Table 5.3-11

PVNGS UNIT 1 TYPE AND QUANTITY OF SPECIMENS FOR IRRADIATION EXPOSURE AND IRRADIATED TESTS

		Base Metal		Quantity			
Type of Specimen	Orientation	Lower Shell	Intermediate Shell	Weld Metal	HAZ	SRM[(a)]	Total
Standard Charpy	Longitudinal	18	18	--	--	54	90
	transverse	45	45	90	72	--	252
Precracked Charpy	Longitudinal	18	18	--	--	--	36
	transverse	18	18	36	--	--	72
Tension	Transverse	9	9	18	--	--	36
1/2t Compact tension	Transverse	10	10	20	--	--	40
	Totals	118	118	164	72	54	526

a. Standard reference material

Table 5.3-12

PVNGS UNIT 2 AND 3 TYPE AND QUANTITY OF TEST SPECIMENS (IN EACH UNIT) FOR IRRADIATION EXPOSURE AND IRRADIATED TESTS

Type of Specimen	Orientation	Quantity[a]				
		Base Shell	Weld Metal	HAZ	SRM[b]	Total
Standard Charpy	Longitudinal	27	-	-	54	81
	transverse	90	90	72	-	252
Precracked Charpy	Longitudinal	27	-	-	-	27
	transverse	27	27	-	-	54
Tension	Transverse	18	18	-	-	36
Compact tension	1/2t Transverse	30	30	-	-	60
	Total	219	165	72	54	510

a. All specimens from lower shell, as noted in paragraph 5.3.1.6.1

b. Standard reference material.

5.3.1.6.2.3 Irradiated Specimens. The type and quantity of test specimens for monitoring the properties of the irradiated materials over the lifetime of the reactor vessel are presented in table 5.3-11 for Unit 1 and in table 5.3-12 for Units 2 and 3. Standard Charpy impact, precracked Charpy, 1/2t compact tension, and uniaxial tension specimens are used to measure changes in the strength and toughness of the surveillance materials.

Charpy impact test specimens are provided to establish the impact energy transition curve after irradiation for the base metals, weld metal, and HAZ material. Tension test specimens are provided to measure the strength and ductility of the base metals and weld metal following irradiation. The precracked Charpy and compact tension specimens are provided to measure the fracture toughness after irradiation.

5.3.1.6.3 Surveillance Capsules

The surveillance test specimens are placed in corrosion-resistant capsule assemblies for protection from the primary coolant during irradiation. The capsules also serve to physically locate the test specimens in selected positions within the reactor vessel and to facilitate the removal of a desired quantity of test specimens when a specified radiation exposure has been attained. Six surveillance capsule assemblies are provided for the reactor vessel. A summary of specimen type, origin, and quantity contained in each capsule assembly is presented in table 5.3-13 for Unit 1, in table 5.3-14 for Unit 2, and in table 5.3-15 for Unit 3.

A typical capsule assembly, illustrated in figure 5.3-1, consists of a series of three specimen compartments, connected by wedge couplings, and a lock assembly. Each compartment enclosure of the capsule assembly is internally supported by the surveillance specimens and is externally pressure tested to 3125 pounds per square inch during final fabrication. The wedge couplings also serve as end caps for the specimen compartments and position the compartments which are housed within the capsule holders attached to the reactor cladding. The lock assemblies fix the locations of the capsules within the holders by exerting axial forces on the wedge coupling assemblies which in turn cause these wedges to exert horizontal forces against the sides of the holders preventing relative motion. The lock assemblies also serve as a point of attachment for the tooling used to remove the capsules from the reactor.

Each capsule assembly consists of three compartments. Each compartment consists of two sections attached by a connecting spacer. Each capsule compartment section is assigned a unique identification so that a complete record of test specimen locations within each compartment section can be maintained.

Each Palo Verde Unit will have six surveillance capsule assemblies. For Unit 1 with two different base metal materials, there will be two precracked Charpy assemblies and one compact tension assembly for lower shell specimens and two precracked Charpy assemblies and one compact tension assembly for intermediate shell specimens. For Units 2 and 3, there will be three precracked Charpy assemblies and three compact tension assemblies. The types of specimens contained in each

Table 5.3-13

PVNGS UNIT 1 SURVEILLANCE PROGRAM (Sheet 1 of 4)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[f]	Lead Factor	Surveillance Material Origins	No.	Specimens	
						Type	Orientation
1 PC_V	38°	8-10	1.0<LF<1.5	Base metal lower shell plate M-4311-1[a]	15 9 9 3 9	C_V PC_V PC_V Tension C_V	Trans. Trans. Long. Trans. Long.
				Weld metal[b] M-4311-2/M-4311-3[c] weld wires B-4 heat/lot 90071 Flux Linde 0091/1054	3 15 9	Tension C_V PC_V	Trans. Trans. Trans.
				HAZ metal Lower shell plate M-4311-1[a]	12	C_V	Trans.
				SRM HSST plate 01[d]	9	C_V	Long.

a. See table 5.3-1 for chemistry of plate code No. M-4311-1 (lower shell plates).

b. See table 5.3-2 for chemistry of weld code No. 101-142 A-C (lower shell long seams).

c. Surveillance weld metal between plates m-4311-2 and M-4311-3 (long seams).

d. See ORNL-4315, dated February 1968 for chemistry of SRM (HSST-01 Ppate).

e. See table 5.3-1 for chemistry of plate code No. M-6701-2 (intermediate shell plate).

f. Effective full power years.

Table 5.3-13

PVNGS UNIT 1 SURVEILLANCE PROGRAM (Sheet 2 of 4)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY(f)	Lead Factor	Surveillance Material Origins	No.	Specimens	
						Type	Orientation
2	43°	Standby	1.0<LF<1.5	Base metal	15	C_V	Trans.
CT				Inter. shell plate	10	1/2t CT	Trans.
				M-6701-2(e)	3	Tension	Trans.
				Weld metal(b)	3	Tension	Trans.
				M-4311-2/M-4311-3(c)	15	C_V	Trans.
				Weld wires			
				B-4 heat lot 90071	10	1/2t CT	Trans.
				Flux Linde 0091/1054			
				HAZ metal	12	C_V	Trans.
				Lower shell plate M-4311-1(a)			
				SRM HSST plate 01(d)	9	C_V	Long.
3	137°	4-5	1.0<LF<1.5	Base metal	15	C_V	Trans.
PC_V				Inter shell plate	9	PC_V	Trans.
				M-6701-2(e)	9	PC_V	Long.
					3	Tension	Trans.
					9	C_V	Long.
				Weld metal(b)	3	Tension	Trans.
				M-4311-2/M-4311-3(c)	15	C_V	Trans.
				Weld wire			
				B-4 heat/lot 90071	9	PC_V	Trans.
				Flux Linde 0091/1054			
				HAZ metal	12	C_V	Trans.
				Lower shell plate M-4311-1(a)			
				SRM HSST plate 01(d)	9	C_V	Long.

Table 5.3-13

PVNGS UNIT 1 SURVEILLANCE PROGRAM (Sheet 3 of 4)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[f]	Lead Factor	Surveillance Material Origins	No.	Specimens	
						Type	Orientation
4	142°	Standby	1.0<LF<1.5	Base metal	15	C_V	Trans.
CT				Lower shell plate	10	1/2t CT	Trans.
				M-4311-1[a]	3	Tension	Trans.
				Weld metal[b]	3	Tension	Trans.
				M-4311-2/M-4311-3[c]	15	C_V	Trans.
				Weld wires			
				B-4 heat lot 90071	10	1/2t CT	Trans.
				Flux Linde 0091/1054	3	Tension	Trans.
				HAZ metal	12	C_V	Trans.
				Lower shell plate M-4311-1[a]			
				SRM HSST plate 01[d]	9	C_V	Long.
5	230°	12-15	1.0<LF<1.5	Base metal	15	C_V	Trans.
PC_V				Inter shell plate	9	PC_V	Trans.
				M-6701-2[e]	9	PC_V	Long.
					3	Tension	Trans.
					9	C_V	Long.
				Weld metal[b]	3	Tension	Trans.
				M-4311-2/M-4311-3[c]	15	C_V	Trans.
				Weld wire			
				B-4 heat/lot 90071	9	PC_V	Trans.
				Flux Linde 0091/1054			
				HAZ metal	12	C_V	Trans.
				Lower shell plate M-4311-1[a]	12	C_V	Trans.
				SRM HSST plate 01[d]	9	C_V	Long.

Table 5.3-13

PVNGS UNIT 1 SURVEILLANCE PROGRAM (Sheet 4 of 4)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[f]	Lead Factor	Surveillance Material Origins	No.	Specimens	
						Type	Orientation
6	310°	40-44	1.0<LF<1.5	Base metal	15	C_V	Trans.
PC_V				Lower shell plate	9	PC_V	Trans.
				M-4311-1[a]	9	PC_V	Long.
					3	Tension	Trans.
					9	C_V	Long.
				Weld metal[b]	3	Tension	Trans.
				M-4311-2/M-4311-3[c]	15	C_V	Trans.
				Weld wires			
				B-4 heat/lot 90071	9	PC_V	Trans.
				Flux Linde 0091/1054			
				HAZ metal	12	C_V	Trans.
				Lower shell plate M-4311-1[a]			
				SRM HSST plate 01[s]	9	C_V	Long.

Table 5.3-14
PVNGS UNIT 2 SURVEILLANCE PROGRAM (Sheet 1 of 3)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[a]	Lead Factor	Surveillance Material Origins	No.	Specimens Type	Specimens Orientation
1	38°	Standby	1.0<LF<1.5	Base metal	15	C_V	Trans
CT				Lower shell plate	10	1/2t CT	Trans
				F-773-1[b]	3	Tension	Trans
				Weld metal[c]	15	C_V	Trans
				F-773-2/F-773-3[d]	10	1/2t CT	Trans
				Weld wires	3	Tension	Trans
				B-4 heat/lot 3P7317			
				Flux Linde 124/0662			
				HAZ metal	12	C_V	Trans
				Lower shell plate			
				F-773-1[b]			
				SRM HSST plate 01[e]	9	C_V	Long.
2	43°	Standby	1.0<LF<1.5	Base metal	15	C_V	Trans
CT				Lower shell plate	10	1/2t CT	Trans
				F-773-1[b]	3	Tension	Trans
				Weld metal[c]	15	C_V	Trans
				F-773-2/F-773-3[d]	10	1/2t CT	Trans
				Weld wire	3	Tension	Trans
				B-4 heat/lot 3P7317			
				Flux Linde 124/0662			
				HAZ metal	12	C_V	Trans
				Lower shell plate			
				F-773-1[b]			
				SRM HSST plate 01	9	C_V	Trans
				01[e]			

a. Effective full power years.

b. See tables 5.3-3 for chemistry of plates.

c. See tables 5.3-4 for chemistry of weld code No. 101-142 A-C (lower shell long seams).

d. Surveillance weld metal formed between designated plates

e. See ORNL-4315 dated February 1968 for chemistry of SRM (HHST-01 plate).

Table 5.3-14
PVNGS UNIT 2 SURVEILLANCE PROGRAM (Sheet 2 of 3)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[a]	Lead Factor	Surveillance Material Origins	No.	Specimens Type	Specimens Orientation
3	137°	4-6	1.0<LF<1.5	Base metal	15	C_V	Trans
PC_V				Lower shell plate	9	PC_V	Trans
				F-773-1[b]	9	PC_V	Long.
					3	Tension	Trans
					9	C_V	Long.
				Weld metal[c]	15	C_V	Trans
				F-773-2/F-773-3[d]	9	PC_V	Trans
				Weld wires	3	Tension	Trans
				B-4 heat/lot 3P7317			
				Flux Linde 124/0662			
				HAZ metal	12	C_V	Trans
				Lower shell plate			
				F-773-1[b]			
				SRM HSST plate 01[e]	9	C_V	Long.
4	142°	Standby	1.0<LF<1.5	Base metal	15	C_V	Trans
CT				Lower shell plate	10	1/2T CT	Trans
				F-773-1[b]	3	Tension	Trans
				Weld metal[c]	15	C_V	Trans
				F-773-2/F-773-3[d]			
				Weld wire	10	1/2t CT	Trans
				B-4 heat/lot 3P7317			
				Flux Linde 124/0662	3	Tension	Trans
				HAZ metal	12	C_V	Trans
				Lower shell plate			
				F-773-1[b]			
				SRM HSST plate 01[e]	9	C_V	Long.

Table 5.3-14
PVNGS UNIT 2 SURVEILLANCE PROGRAM (Sheet 3 of 3)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[a]	Lead Factor	Surveillance Material Origins	No.	Specimens Type	Specimens Orientation
5 PC_V	230°	12-15	1.0<LF<1.5	Base metal	15	C_V	Trans
				Lower shell plate	9	PC_V	Trans
				F-773-1[b]	9	PC_V	Long.
					3	Tension	Trans
					9	C_V	Long.
				Weld metal[c]	15	C_V	Trans
				F-773-2/F-773-3[d]	9	PC_V	Trans
				Weld wires	3	Tension	Trans
				B-4 heat/lot 3P7317 Flux Linde 124/0662			
				HAZ material	12	C_V	Trans
				Lower shell plate F-773-1[b]			
				SRM HSST plate 01	9	C_V	Long.
6 PC_V	310°	39-43	1.0<LF<1.5	Base metal	15	C_V	Trans
				Lower shell plate	9	PC_V	Trans
				F-773-1[b]	9	PC_V	Long.
					3	Tension	Trans
					9	C_V	Long.
				Weld metal[c]	15	C_V	Trans
				F-773-2/F-773-3[d]		Tension	Trans
				Weld wire	9	PC_V	Trans
				B-4 heat/lot 3P7317 Flux Linde 124/0662			
				HAZ metal	12	C_V	Trans
				Lower shell plate F-773-1			
				SRM HSST plate 01[e]	9	C_V	Long.

Table 5.3-15

PVNGS UNIT 3 SURVEILLANCE PROGRAM (Sheet 1 of 4)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[e]	Lead Factor	Surveillance Material Origins	No.	Specimens	
						Type	Orientation
1 CT	38°	Standby	1.0<LF<1.5	Base metal Lower shell plate F-6411-2[a]	15 10 3	C_V 1/2t CT Tension	Trans. Trans. Trans.
				Weld metal[b] F-6411-1 to 3[c] Weld wires B-4 heat lot 4P7869 Flux Linde 124/0281	15 10 3	C_V 1/2t CT Tension	Trans. Trans. Trans.
				HAZ metal Lower shell plate F-6411-2[a]	12	C_V	Trans.
				SRM HSST plate 01[d]	9	C_V	Long.
2 CT	43°	Standby	1.0<LF<1.5	Base metal Lower shell plate F-6411-2[a]	15 10 3	C_V 1/2t CT Tension	Trans. Trans. Trans.

a. See table 5.3-5 for chemistry of plates.

b. See table 5.3-6 for chemistry of weld code No. 101-142 A-C (lower shell long seams).

c. Surveillance weld metal formed between designated plates.

d. See ORNL-4315 dated February 1968 for chemistry of SRM (HSST-01 plate).

e. Effective full power years.

Table 5.3-15

PVNGS UNIT 3 SURVEILLANCE PROGRAM (Sheet 2 of 4)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[e]	Lead Factor	Surveillance Material Origins	No.	Specimens Type	Specimens Orientation
2 CT (Cont.)				Weld metal[b]	15	C_V	Trans.
				F-6411-1 to 3[c]	10	1/2t CT	Trans.
				Weld wires	3	Tension	Trans.
				B-4 heat lot 4P7869			
				Flux Linde 124/0281			
				HAZ metal	12	C_V	Trans.
				Lower shell plate F-6411-2[a]			
				SRM HSST plate 01[d]	9	C_V	Long.
3 PC_V	137°	Standby	1.0<LF<1.5	Base metal	15	C_V	Trans.
				Lower shell plate	9	PC_V	Trans.
				F-6411-2[a]	9	PC_V	Long.
					3	Tension	Trans.
					9	C_V	Long.
				Weld metal[b]	15	C_V	Trans.
				F-6411-1 to 3[c]	9	PC_V	Trans.
				Weld wire	3	Tension	Trans.
				B-4 heat/lot 4P7869			
				Flux Linde 124/0281			
				HAZ metal	12	C_V	Trans.
				Lower shell plate F-6411-2[a]			
				SRM HSST plate 01[d]	9	C_V	Long.

Table 5.3-15

PVNGS UNIT 3 SURVEILLANCE PROGRAM (Sheet 3 of 4)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[e]	Lead Factor	Surveillance Material Origins	No.	Specimens	
						Type	Orientation
4	142°	4-6	1.0<LF<1.5	Base metal	15	C_V	Trans.
CT				Lower shell plate F-6411-2[a]	10	1/2t CT	Trans.
					3	Tension	Trans.
				Weld metal[b]	15	C_V	Trans.
				F-6411-1 to 3[c]			
				Weld wire	10	1/2t CT	Trans.
				B-4 heat lot 4P7869			
				Flux Linde 124/0281	3	Tension	Trans.
				HAZ metal	12	C_V	Trans.
				Lower shell plate F-6411-2[a]			
				SRM HSST plate 01[d]	9	C_V	Long.
5	230°	12-15	1.0<LF<1.5	Base metal	15	C_V	Trans.
PC_V				Lower shell plate	9	PC_V	Trans.
				F-6411-2[a]	9	PC_V	Long.
					3	Tension	Trans.
					9	C_V	Long.
				Weld metal[b]	15	C_V	Trans.
				F-6411-1 to 3[c]	9	PC_V	Trans.
				Weld wire	3	Tension	Trans.
				B-4 heat/lot 4P7869			
				Flux Linde 124/0281			
				HAZ material	12	C_V	Trans.
				Lower shell plate F-6411-2[a]			
				SRM HSST plate 01[d]	9	C_V	Long.

Table 5.3-15

PVNGS UNIT 3 SURVEILLANCE PROGRAM (Sheet 4 of 4)

Capsule Assembly No. and Type	Azimuthal Location	Withdrawal Schedule EFPY[f]	Lead Factor	Surveillance Material Origins	No.	Specimens Type	Specimens Orientation
6 PC_V	310°	42-46	1.0<LF<1.5	Base metal Lower shell plate F-6411-2[a]	15 9 9 3 9	C_V PC_V PC_V Tension C_V	Trans. Trans. Long. Trans. Long.
				Weld metal[b] F-6411-1 to 3[c] Weld wire B-4 heat/lot 4P7869 Flux Linde 124/0281	15 9 3	C_V Tension PC_V	Trans. Trans. Trans.
				HAZ metal Lower shell plate F-6411-2[a]	12	C_V	Trans.
				SRM HSST plate 01[d]	9	C_V	Long.

unit are given in tables 5.3-13, 5.3-14, and 5.3-15. In addition, each of the six capsules contains one set of nine flux monitors, two sets of five flux monitors, and one set of temperature monitors.

5.3.1.6.3.1 Precracked Charpy Capsule Assembly. The four Unit 1 and three Unit 2 precracked Charpy capsule assemblies consist of three capsule compartments, two Charpy and flux compartments, and one temperature, flux, tension, and Charpy compartment. The contents of each compartment are described below:

A. Charpy and Flux Compartment Assembly

   This assembly (figure 5.3-2) contains 15 base metal (transverse) impact test specimens and a set of five flux spectrum monitors in the top section. The bottom section contains nine precracked Charpy test specimens each of base metal (longitudinal and transverse). The Charpy test specimens are arranged vertically in 1 by 3 arrays and are oriented with the notch toward the reactor core. The temperature differential between the specimens and the reactor coolant is minimized by using spacers between the specimens and the compartment and by sealing both sections of the assembly in an atmosphere of helium.

B. Temperature, Flux, Tension, and Charpy Compartment Assembly

   This assembly (figure 5.3-3) contains three base metal (transverse) tension test specimens and 12 HAZ impact

test specimens in the top section. The tension specimens are placed in a housing machined to fit the compartment. Split spacers are placed around the gauge length of the specimens to minimize the temperature differential between the specimen gauge length and the coolant. The impact specimens are arranged vertically in 1 by 3 arrays and are oriented with the notch toward the reactor core. Spacers are utilized between the test specimens and the compartment. The bottom section contains a set of nine flux spectrum monitors, a set of temperature monitors, nine SRM impact test specimens, and three weld metal tension test specimens. Both compartment sections are sealed within an atmosphere of helium.

C. Charpy and Flux Compartment Assembly

This assembly (figure 5.3-2) contains 15 weld metal impact test specimens and a set of five flux spectrum monitors in the top section. The bottom section contains nine precracked weld metal and nine base metal (longitudinal) impact test specimens. The test specimens are arranged vertically in 1 by 3 arrays and are oriented with the notch toward the reactor core. The temperature differential between the specimens and the reactor coolant is minimized by using spacers between the specimens and the compartment and by sealing both sections of the assembly in an atmosphere of helium.

5.3.1.6.3.2 Compact Tension Capsule Assemblies. The two Unit 1 and three Unit 2 compact tension (CT) capsule assemblies consist of three capsule compartments; two Charpy, flux, and compact tension compartments, and one temperature, flux, tension, and Charpy compartment. The contents of each compartment are described below:

A. Charpy, Flux, and Compact Tension Compartment Assembly

   This assembly (figure 5.3-3A) contains 15 base metal (transverse) impact test specimens and set of five flux spectrum monitors in the top section. The bottom section contains 10 base metal (transverse) 1/2t compact tension test specimens. The 1/2t compact tension specimens are oriented so that opening of the crack starter notch is facing the top of the compartment. This orientation will result in a neutron flux gradient parallel to the crack front. The temperature differential between the specimens and the reactor coolant is minimized by using spacers between the specimens and the compartment and by sealing both sections of the assembly in an atmosphere of helium.

B. Temperature, Flux, Tension, and Charpy Compartment Assembly

   This assembly (figure 5.3-3) is the same as that in the precracked Charpy capsule.

C. Charpy, Flux, and Compact Tension Compartment Assembly

   This assembly (figure 5.3-3A) contains 15 weld metal impact test specimens and a set of five flux monitors in the top section. The bottom section contains ten weld

metal 1/2t compact tension test specimens. The Charpy and compact tension specimens are arranged in the same manner as in listing A and are surrounded by spacers to minimize temperature differentials between the specimens and the reactor coolant.

5.3.1.6.4 Neutron Irradiation and Temperature Exposure

Predicted changes in the properties of the reactor vessel materials are based on data from specimens irradiated to various fluence levels and in different neutron energy spectra. In order to permit accurate evaluations of the radiation-induced changes in the surveillance materials, complete information on the neutron flux, neutron energy spectra, and the irradiation temperature of the encapsulated specimens must be available.

5.3.1.6.4.1 Flux Measurements. Fast neutron flux measurements are obtained by insertion of threshold detectors into each of the six irradiation capsules. Such detectors are particularly suited for the proposed application, because their effective threshold energies lie in the range of interest (0.5 to 15 MeV).

These neutron threshold detectors and the thermal neutron detectors, presented in table 5.3-16, can be used to monitor the thermal and fast neutron spectra incident on the test specimens. These detectors possess reasonably long half-lives and activation cross-sections covering the desired neutron energy range. These neutron threshold detectors exceed the number required in ASTM E482.

Table 5.3-16

PVNGS UNITS 1, 2, AND 3 CANDIDATE MATERIALS FOR NEUTRON THRESHOLD DETECTORS

Material	Reaction	Threshold Energy (MeV)	Half-Life
Uranium	U^{238} (n,f) Cs^{137}	0.7	30.2 years
Sulfur	S^{32} (n,p) P^{32}	2.9	14.3 days
Iron	Fe^{54} (n,p) Mn^{54}	4.0	314 days
Nickel	Ni^{58} (n,p) Co^{58}	5.0	71 days
Copper	Cu^{63} (n,α) Co^{60}	7.0	5.3 years
Titanium	Ti^{46} (n,p) Sc^{46}	8.0	84 days
Cobalt	Co^{59} (n,γ) Co^{60}	Thermal	5.3 years

One set of nine flux spectrum monitors and two sets of five flux spectrum monitors are included in each surveillance capsule. Each detector is placed inside a sheath which identifies the material and facilitates handling. Cadmium covers are used for those materials (e.g., uranium, nickel, copper, and cobalt) which have competing neutron capture activities. The neutron threshold detectors are placed in holes drilled in stainless steel housings (figure 5.3-3).

In addition to these detectors, the program also includes correlation monitors (Charpy impact test specimens made from a reference heat of ASTM A533-B, Class 1, manganese-molybdenum-nickel steel) which are irradiated along with the specimens made from reactor vessel materials. The changes in impact

properties of the reference material provide a cross-check on the dosimetry in any given surveillance program. These changes also provide data for correlating the results from this surveillance program with the results from experimental irradiations and other reactor surveillance programs using specimens of the same reference material.

5.3.1.6.4.2 Temperature Estimates. Because the changes in mechanical and impact properties of irradiated specimens are highly dependent on the irradiation temperature, it is necessary to have knowledge of the specimen temperature as well as that of the pressure vessel. During irradiation, instrumented capsules are not practical for a surveillance program extending over the design lifetime of a power reactor. Thus, the maximum temperature of the irradiated specimens can be estimated with reasonable accuracy by including in the capsule assemblies small pieces of low melting point alloys or pure metals. The compositions of candidate materials with melting points in the operating range of power reactors are listed in table 5.3-17. The monitors are selected to bracket the operating temperature of the reactor vessel.

The temperature monitors consist of a helix of low melting alloy wire inside a sealed quartz tube. A stainless steel weight is provided to destroy the integrity of the wire when the melting point of the alloy is reached. The compositions and, therefore, the melting temperatures of the temperature monitors are differentiated by the physical lengths of the quartz tubes which contain the alloy wires.

A set of temperature monitors is included in each surveillance capsule. The temperature monitors are placed in holes drilled in stainless steel housings as shown in figure 5.3-3.

5.3.1.6.5 Irradiation Locations

The test specimens are enclosed within six capsule assemblies, the axial positions of which are bisected by the midplane of the active core. The capsules are positioned near the inside wall of the reactor vessel so that the irradiation conditions (fluence, flux spectrum, temperature) of the test specimens resemble as closely as possible the irradiation conditions of the reactor vessel. The neutron fluence of the test specimens is expected to be within 50% of that seen by the adjacent vessel wall, so the measured changes in properties of the surveillance materials will closely approximate the radiation-induced changes in the reactor vessel beltline materials.

Table 5.3-17

PVNGS UNITS 1, 2, AND 3 COMPOSITION AND MELTING POINTS OF CANDIDATE MATERIALS FOR TEMPERATURE MONITORS

Composition (wt%)	Melting Temperature (F)
80.0 Au, 20.0 Sn	536
90.0 Pb, 5.0 Sn, 5.0 Ag	558
97.5 Pb, 2.5 Ag	580
97.5 Pb, 0.75 Sn, 1.75 Ag	590

The capsule assemblies are placed in capsule holders positioned circumferentially about the core at locations which include the regions of maximum flux. Figure 5.3-4 presents the exposure locations for the capsule assemblies.

Capsule assemblies are inserted into their respective capsule holders during the final reactor assembly operation.

5.3.1.6.6 Withdrawal Schedule

The capsule assemblies remain within their capsule holders until the test specimens contained therein have been exposed to predetermined levels of fast neutron fluence. At that time, the capsule assembly is removed and the surveillance materials are evaluated. Detailed instructions for the removal of capsule assemblies are provided for each plant. The capsule assembly removal schedule for Unit 1 is presented in table 5.3-18 and for Units 2 and 3 is provided in table 5.3-19. Removal time is in terms of effective full power years (EFPYs). The capsule withdrawal schedule has been designed to periodically monitor the effects of neutron irradiation on the reactor vessel based on the magnitude of the predicted RT_{NDT} shift and the decrease in upper shelf energy. Sufficient standby capsules have been provided to enable monitoring the effects of any major core change, measure changes resulting from reactor vessel annealing or evaluating a flaw in the beltline materials. For Unit 1, four capsules are scheduled for withdrawal during the design lifetime of the reactor vessel. For Units 2 and 3, three capsules are scheduled for withdrawal during the design lifetime of the reactor vessels. The two remaining Unit 1 capsules and the three remaining

Units 2 and 3 capsules are designated as standby capsules. The schedule was established in accordance with 10CFR50, Appendix H, monitoring requirements for the base metal, weld, and HAZ materials.

Withdrawal schedules may be modified to coincide with those refueling outages or plant shutdowns most closely approaching the withdrawal schedule.

Changes to the reactor vessel surveillance specimen withdrawal schedule that meet the applicable ASTM standard must be submitted to the NRC with technical justification for approval prior to implementation (the NRC must verify compliance with the ASTM standard), in accordance with 10CFR50, Appendix H, paragraph III.B.3. Changes to the withdrawal schedule that do not meet the applicable ASTM standard must be submitted to the NRC for approval as a license amendment with information required by 10CFR50.91 and 50.92 (see NRC Administrative Letter 97-04 date September 30, 1997).

5.3.1.6.7 Irradiation Effects Prediction Basis

The design curve used to predict the radiation induced increase in transition temperature is shown in figure 5.3-5. Predicted changes in the transition temperature are used to select the surveillance materials (paragraph 5.3.1.6.1) and to formulate the initial heatup and cooldown limit curves for plant operation. Once actual post-irradiation surveillance data become available, these data will be used to adjust plant operating limit curves.

Table 5.3-18

PVNGS UNIT 1 CAPSULE ASSEMBLY REMOVAL SCHEDULE

Capsule	Azimuthal Locations	Removal Time	Base Metal Material Included
1	38°	8-10 EFPY	Lower shell PC_V
2	43°	Standby	Intermediate shell CT
3	137°	4-5 EFPY	Intermediate shell PC_V
4	142°	Standby	Lower shell CT
5	230°	12-15 EFPY	Intermediate shell PC_V
6	310°	40-44 EFPY	Lower shell PC_V

Note: Schedule may be modified to coincide with those refueling outages or scheduled shutdowns most closely approximating the withdrawal schedule.

Table 5.3-19

PVNGS UNIT 2
CAPSULE ASSEMBLY REMOVAL SCHEDULE

Capsule	Azimuthal Locations	Removal Time	Base Metal Material Included
1	38°	Standby	Lower shell CT
2	43°	Standby	Lower shell CT
3	137°	4-6 EFPY	Lower shell PC_V
4	142°	Standby	Lower shell CT
5	230°	12-15 EFPY	Lower shell PC_V
6	310°	39-43 EFPY	Lower shell PC_V

Note: Schedule may be modified to coincide with those refueling outages or scheduled shutdowns most closely approximating the withdrawal schedule.

Table 5.3-19A

PVNGS UNIT 3
CAPSULE ASSEMBLY REMOVAL SCHEDULE

Capsule	Azimuthal Locations	Removal Time	Base Metal Material Included
1	38°	Standby	Lower shell CT
2	43°	Standby	Lower shell CT
3	137°	Standby	Lower shell PC_v
4	142°	4-6 EFPY	Lower shell CT
5	230°	12-15 EFPY	Lower shell PC_v
6	310°	42-46 EFPY	Lower shell PC_v

Note: Schedule may be modified to coincide with those refueling outages or scheduled shutdowns most closely approximating the withdrawal schedule.

Figure 5.3-5 was conservatively drawn using the data given in table 5.3-20 including SA533B, Class 1, plate and weld zone material typical of that used in the fabrication of the Palo Verde reactor vessel beltline materials. The curve is applicable for materials with copper contents of 0.10 w/o or less, consistent with Palo Verde beltline material specifications, irradiated at 550F ±25F.

5.3.1.7 Reactor Vessel Fasteners

The bolting material for the reactor vessel closure head is fabricated from SA-540, B23 or B24, Class III material. This material conforms to the requirements of 10CFR50, Appendix G and Regulatory Guide 1.65, "Materials and Inspections for Reactor Vessel Closure Studs."

The reactor vessel vendor provided lubrication specifications for threads of studs, nuts and washers to improve the antigalling properties and resistance to corrosion of these components. These lubrication specifications are delineated in the vendor technical manual for the reactor vessel. Laboratory testing and field experience have determined that there is no evidence of deleterious breakdown of the specified lubricants when they are applied in accordance with the applicable instructions.

Fracture toughness and tensile test data for reactor vessel closure head bolting are presented for Palo Verde Unit 1 in Table 5.3-21, for Unit 2 in Tables 5.3-24 and 5.3-25, and for Unit 3 in Tables 5.3-33 and 5.3-34.

Fracture toughness and tensile test data for all other fasteners used in the reactor coolant pressure boundary (RCPB) for Palo Verde Unit 1 are presented in Tables 5.3-22 and 5.3-23, for Unit 2 in Tables 5.3-26 through 5.3-32, and Unit 3 in Tables 5.3-35 through 5.3-41.

5.3.2 PRESSURE-TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to reactor coolant system temperature and pressure changes. These cyclic loads are introduced by normal unit load transients, reactor trips and startup and shutdown operation.

During unit startup and shutdown, the rates of temperature and pressure changes are limited. The design number of cycles for heatup and cooldown is based upon a rate of 100F/h.

Table 5.3-20

PVNGS UNITS 1, 2, and 3 A533B-CL1 PLATE AND WELD MATERIAL WITH COPPER CONTENT LESS THAN OR EQUAL TO 0.10 w/o (Sheet 1 of 3)

Reference Data Point	Material	Fluence ($n/cm^2(10)^{19}$)		Transition Temperature Increase (F)	Selected Chemistry (w/o)		
		dfs[(a)]	dcs[(b)]		P	S	Cu
7.04	SA533B-weld	1.9	----	88	0.020	0.004	0.10
7.05	SA533B-weld	5.0	----	155	0.020	0.004	0.05
8.01	SA533B-weld	2.3	2.0	55	0.010	0.008	0.05
8.01	SA533B-weld	2.7	2.3	0	0.010	0.008	0.05
9.01	SA533B-plate	2.8	2.4	40	0.008	0.008	0.03
9.02	SA533B-plate	2.8	2.4	65	0.008	0.008	0.03
9.05	SA533B-plate	3.1	2.7	70	0.008	0.008	0.03
11.06	SA533B-weld	0.5	0.44	0	0.005	0.014	0.06
11.07	SA533B-weld	2.4	2.1	80	0.005	0.014	0.06
11.13	SA533B-plate	0.2	0.17	0	0.008	0.015	0.09
11.14	SA533B-plate	2.0	2.18	80	0.008	0.015	0.09
11.15	SA533B-plate	2.0	2.18	90	0.008	0.015	0.09
11.16	SA533B-plate	0.5	0.44	35	0.008	0.015	0.09
11.24	SA533B-plate	0.5	0.44	5	0.008	0.014	0.09
11.25	SA533B-plate	0.5	0.44	30	0.008	0.014	0.09
11.27	SA533B-plate	2.4	2.09	85	0.008	0.014	0.09
11.28	SA533B-plate	2.4	2.09	95	0.008	0.014	0.09

a. Fission spectrum

b. Calculated spectrum

Table 5.3-20

PVNGS UNITS 1, 2, and 3 A533B-CL1 PLATE AND WELD MATERIAL WITH COPPER CONTENT LESS THAN OR EQUAL TO 0.10 w/o (Sheet 2 of 3)

Reference Data Point	Material	Fluence ($n/cm^2(10)^{19}$)		Transition Temperature Increase (F)	Selected Chemistry (w/o)		
		dfs[(a)]	dcs[(b)]		P	S	Cu
23.07	SA533B-plate	4.4	3.8	35	0.009	0.017	0.09
23.08	SA533B-plate	5.7	5.0	55	0.009	0.017	0.09
23.09	SA533B-plate	4.0	3.5	45	0.011	0.018	0.09
23.10	SA533B-plate	5.4	4.7	85	0.011	0.018	0.09
23.11	SA533B-plate	5.3	4.6	65	0.009	0.017	0.02
23.19	SA533B-weld	4.9	4.2	35	0.010	0.010	0.07
23.20	SA533B-weld	5.0	4.3	50	0.010	0.010	0.07
23.21	SA533B-weld	4.9	4.2	15	0.004	0.010	0.05
23.22	SA533B-weld	5.0	4.3	15	0.004	0.010	0.05
37.01	SA533B-weld	2.5	----	100	0.002	0.008	0.09
37.02	SA533B-plate	2.5	----	60	0.003	0.014	0.09
49.11	SA533B-weld	---	0.15	0	0.012	0.017	0.01
49.12	SA533B-weld	---	0.37	18	0.012	0.017	0.01
59.01	SA533B-plate	2.3	1.6	75	0.008	0.008	0.03
60.04	SA533B-plate	6.1	5.3	75	0.010	0.012	0.04
60.06	SA533B-plate	5.4	4.7	65	0.007	0.011	0.05
60.07	SA533B-weld	5.4	4.7	15	0.005	0.010	0.03

Table 5.3-20

PVNGS UNITS 1, 2, and 3 A533B-CL1 PLATE AND WELD MATERIAL WITH COPPER CONTENT LESS THAN OR EQUAL TO 0.10 w/o (Sheet 3 of 3)

References for data points in table 5.3-20

7. HSST Semi-Annual Progress Report period ending February 29, 1972, ORNL-4816.

8. Hawthorne, Radiation Resistant Weld Metal for Fabricating A533-B Nuclear Reactor Vessels, Welding Journal, July 1982, p. 360-S.

9. Hawthorne, Demonstration of Improved Radiation Embrittlement Resistance of A533-B Steel Through Control of Selected Residual Elements, NRL Report 7121, January 1970.

11. Hawthorne, Trends in Charpy-V Shelf Energy Degradation and Yield Strength Increase of Neutron-Embrittled Pressure Vessel Steels, NRL Report 7011, December 22, 1969 and NRL Report 6772.

23. Hawthorne, Koziol, Evaluation of Commercial Production A533-B Plates and Weld Deposits Tailored for Improved Radiation Embrittlement Resistance", ASTM STP570, 1975, pp. 83-102.

37. Steele, Irradiation Effects on Reactor Structural Materials, NRL Report 2027, August 1969.

49. Kass, Radiation Effects in Boiling Water Reactor Pressure Vessel Steels NEDO-21708, October 1977.

59. Hawthorne, Further Observations on A533-B Steel Plate Tailored for Improved Radiation Embrittlement Resistance, NRL Report 7917, September 22, 1975.

60. Hawthorne, NRC-CE-NRL Cooperative Program: Series 3 (Extra Low Copper) Materials Evaluations, NRL/NUREG MR 3512, May 1977.

The maximum allowable reactor coolant system pressure at any temperature is based upon the stress limitations for brittle fracture considerations. These limitations are derived by using the rules contained in Section XI of the ASME Code, including Appendix G, Protection Against Nonductile Failure, and the rules contained in 10CFR50, Appendix G, Fracture Toughness Requirements. Compliance with the criteria in 10CFR50, Appendix H is discussed in Section 5.3.1.6.

5.3.2.1 Limit Curves

Limitations on pressurization are determined using material property test data, for Reactor Coolant Pressure Boundary material, as required by Appendix G to Section XI of the ASME Code. An initial RT_{NDT} of +40°F is assumed for the reactor vessel beltline material, as required by the reactor vessel equipment specifications. For the remaining pressure boundary materials in the reactor coolant system, a limiting RT_{NDT} of +60°F is assumed.

As a result of fast neutron irradiation in the region of the core, RT_{NDT} will increase with operation. The techniques used to analytically and experimentally predict the integrated fast neutron (E>1 MeV) fluxes of the reactor vessel are described in Section 5.3.1.6.

Since the neutron spectra and flux measured at the samples and reactor vessel inside radius should be nearly identical, the measured reference transition temperature shift for a sample can be applied to the adjacent section of the reactor vessel for later stages in plant life equivalent to the difference in

calculated flux magnitude. The maximum exposure of the reactor vessel will be obtained from the measured sample exposure by application of the calculated azimuthal neutron flux variation. The actual shift in RT_{NDT} will be established periodically during plant operation by testing of reactor vessel material samples which are irradiated cumulatively by securing them near the inside wall of the reactor vessel as described in Section 5.3.1.6 and shown in Figure 5.3-4. To compensate for any increase in the RT_{NDT} caused by irradiation, limits on the pressure-temperature relationship are periodically changed to stay within the stress limits during heatup and cooldown.

The limit lines identified are based on the following:

A. Heatup and Cooldown Curves (from Section XI of the ASME Code Appendix G-2215)

K_{IC} = $2\ K_{IM} + K_{IT}$

K_{IC} = Reference stress intensity factor as a function of coolant temperature.

K_{IM} = Membrane stress intensity factor due to pressure. (A safety factor of 2 is applied to membrane stress).

K_{IT} = Stress intensity factor for radial thermal gradient.

The above equation is applied to the reactor vessel beltline.

For plant heatup, the thermal stress at the vessel beltline I.D. is opposite in sign from the pressure

induced stress, thus tending to cancel each other out. These same stresses however, are similar in sign, and hence additive at the vessel O.D. This stress level variation across the wall, in conjunction with the fact that the neutron fluence (and hence RT_{NDT} shift) is higher at the inside wall, necessitates the investigation of crack locations on both the O.D. and I.D. surfaces.

For conservatism, therefore, the following areas are specifically analyzed:

1. An "isothermal" heatup (i.e., $K_{IT} = 0$) transient with a T/4 crack on the inside surface of the beltline
2. A conventional rate dependent heatup transient with a T/4 crack on the outside surface of the beltline.

For plant cooldown thermal and pressure stress are additive. The design cooldown rate of 100F/hr is used for calculation.

Thermal stress intensity factor is obtained through a detailed thermal analysis of the beltline wall using a computer code. A finite element heat transfer model is used to determine varying wall temperature as a function of radius, time, and thermal rate. Since a varying temperature profile is obtained, an alternate method for calculating K_{IT} was employed as suggested by Article G-2214.3 of ASME III. The alternate method uses a polynomial fit of the temperature profile and super position using influence coefficients to calculate K_{IT}.

K_{IC} is then varied as a function of temperature from Figure G-2110-1 of ASME XI and the allowable pressure calculated. Instrumentation errors are considered when plotting the curves. Whenever the core is critical, an additional 40F is added to these curves as required by 10CFR50, Appendix G.

B. System Hydrostatic Test

The system hydrostatic test curve is developed in the same manner as in A above, with the exception that a safety factor of 1.5 is used as allowed by ASME XI in lieu of 2.

C. Lowest Service Temperature

As indicated previously, an RT_{NDT} for all material with the exception of the reactor vessel beltline was +60F.

ASME III, Article NB-2332 (b) requires a lowest service temperature of RT_{NDT} + 100F for piping, pumps and valves. Below this temperature, a pressure of 20% of the system hydrostatic test pressure cannot be exceeded.

D. Maximum Pressure for Shutdown Cooling

This pressure is established by considering the design pressure of the shutdown cooling system, shutoff head of the low pressure safety injection (LPSI) pumps, elevation head from the pressurizer to the LPSI pumps, instrument and interlock tolerances, and the design temperature of the shutdown cooling system.

The pressure-temperature limitation curves are predicted for 60-year life. During plant life the surveillance capsules (refer to Section 5.3.3.7) will be removed from

their location in the reactor vessel for testing. The data obtained will be compared to that used to develop the pressure – temperature limit curves discussed in the Technical Specifications. If this information indicates anomolies to the existing predictions, the curves will be redrawn as previously indicated to reflect actual data.

5.3.2.2 Operating Procedures

Pressure-temperature limitations and additional information are discussed in the Technical Specifications and provided in the TRM. The pressure-temperature limit curves are prepared in accordance with Appendix G, ASME Code Section XI.

Maintenance of reactor coolant system (RCS) pressure and temperature within these prescribed limits ensures that the integrity of the reactor coolant pressure boundary (RCPB) is maintained.

5.3.3 REACTOR VESSEL INTEGRITY

C-E designs and fabricates the reactor vessels for System 80. C-E has been involved in reactor vessel design and fabrication since the late 1950's, and this proven expertise is reflected in the System 80 reactor vessels and the satisfactory performance of large numbers of reactor vessels in operating plants.

Vessel integrity is ensured because proven fabrication techniques are employed and because well characterized steels, which exhibit uniform properties and consistent behavior, are used. The characterization of these materials was established

through industrial and governmental studies which examined the prefabrication material properties through to irradiated service operation. Inservice inspection and material surveillance programs are also conducted during the service life of the vessel, which further ensures that vessel integrity is maintained.

5.3.3.1 Design

Applicable design codes are found in Table 5.2-1. A schematic of the reactor vessel is shown in Figure 4.1-1. Additional information on design may be found in Section 5.3.1.2.

The design permits all required inspections to be performed, and does not preclude access to areas requiring inservice inspection.

5.3.3.2 Materials of Construction

The materials used in the construction of the reactor vessel, as listed in Table 5.1-2, are in accordance with Section III of the ASME Boiler and Pressure Vessel Code.

5.3.3.3 Fabrication Methods

Fabrication of the reactor vessel is described in Section 5.3.1.2. Fabrication processes used in construction of the reactor vessel comply with Sections III and IX of the ASME B&PV Code.

5.3.3.4 Inspection Requirements

Inspection requirements of ASME Code, Section III are discussed in Section 5.3.1.3.

Table 5.3-21

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
REACTOR VESSEL FASTENERS[b] (Sheet 1 of 4)

Material Code No.	Material Specification	Location	Tube/Bar No:	PreLoad Temp (°F)	Yield STR (ksi)	Ultimate STR (ksi)
M-6720-1	SA540-GRB-24-CL3	Closure head studs	479-00	+10[a]	136.2	154.0
M-6720-1	SA540-GRB-24-CL3	Closure head studs	479-01	+10[a]	140.0	157.5
M-6720-1	SA540-GRB-24-CL3	Closure head studs	482-00	+10[a]	140.2	156.5
M-6720-1	SA540-GRB-24-CL3	Closure head studs	482-01	+10[a]	145.0	160.0
M-6720-0	SA540-GRB-24-CL3	Closure head studs	485-00	+10[a]	144.5	158.5
M-6720-1	SA540-GRB-24-CL3	Closure head studs	485-01	+10[a]	143.0	158.0
M-6720-2	SA540-GRB-24-CL3	Closure head studs	462-00	+10[a]	133.7	148.0
M-6720-2	SA540-GRB-24-CL3	Closure head studs	462-01	+10[a]	135.5	151.0
M-6720-2	SA540-GRB-24-CL3	Closure head studs	463-00	+10[a]	142.7	158.5
M-6720-2	SA540-GRB-24-CL3	Closure head studs	463-01	+10[a]	142.2	157.0
M-6720-2	SA540-GRB-24-CL3	Closure head studs	470-00	+10[a]	145.0	160.0

a. Determined per applicable ASMEB&PV Code and Addenda, Section III, Subsection NB, Article NB-2333-A (diameter over 4 inches)

b. Piece Numbers:

Studs	Nuts	Washers
(179-3301)	(179-3401)	(179-3402)

Reference drawing number: E-78173-161-004-02

Table 5.3-21

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
REACTOR VESSEL FASTENERS[b] (Sheet 2 of 4)

Material Code No.	Material Specification	Location	Tube/Bar No:	PreLoad Temp (°F)	Yield STR (ksi)	Ultimate STR (ksi)
M-6720-2	SA540-GRB-24-CL3	Closure head studs	470-01	+10[a]	141.2	156.0
M-6720-2	SA540-GRB-24-CL3	Closure head studs	472-00	+10[a]	141.0	156.0
M-6720-2	SA540-GRB-24-CL3	Closure head studs	472-01	+10[a]	133.2	149.0
M-6720-2	SA540-GRB-24-CL3	Closure head studs	475-00	+10[a]	141.0	155.0
M-6720-2	SA540-GRB-24-CL3	Closure head studs	475-01	+10[a]	137.0	152.0
M-6720-3	SA540-GRB-24-CL3	Closure head studs	623-00	+10[a]	142.5	156.0
M-6720-3	SA540-GRB-24-CL3	Closure head studs	623-01	+10[a]	143.5	157.5
M-6720-3	SA540-GRB-24-CL3	Closure head studs	624-00	+10[a]	135.0	150.0
M-6720-3	SA540-GRB-24-CL3	Closure head studs	624-01	+10[a]	137.5	152.0
M-6720-3	SA540-GRB-24-CL3	Closure head studs	628-00	+10[a]	135.3	150.0
M-6720-3	SA540-GRB-24-CL3	Closure head studs	628-01	+10[a]	139.5	155.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	633-00	+10[a]	130.0	147.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	633-01	+10[a]	137.5	154.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	635-00	+10[a]	132.0	149.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	635-01	+10[a]	132.5	149.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	639-00	+10[a]	131.5	148.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	639-01	+10[a]	134.8	150.0

Table 5.3-21

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
REACTOR VESSEL FASTENERS[b] (Sheet 3 of 4)

Material Code No.	Material Specification	Location	Tube/Bar No:	PreLoad Temp (°F)	Yield STR (ksi)	Ultimate STR (ksi)
M-6720-4	SA540-GRB-24-CL3	Closure head studs	643-00	+10[a]	131.3	148.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	643-01	+10[a]	131.0	149.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	649-00	+10[a]	131.5	149.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	649-01	+10[a]	132.0	149.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	650-00	+10[a]	134.2	150.0
M-6720-4	SA540-GRB-24-CL3	Closure head studs	650-01	+10[a]	133.5	150.0
M-6720-5	SA540-GRB-24-CL3	Closure head studs	556-00	+10[a]	138.3	154.0
M-6720-5	SA540-GRB-24-CL3	Closure head studs	556-01	+10[a]	136.0	153.0
M-6720-5	SA540-GRB-24-CL3	Closure head studs	557-00	+10[a]	139.7	155.0
M-6720-5	SA540-GRB-24-CL3	Closure head studs	557-01	+10[a]	140.0	156.0
M-6721-1	SA540-GRB-23-CL3	Closure head nuts and washers	156-00	+10[a]	143.0	156.0
M-6721-1	SA540-GRB-23-CL3	Closure head nuts and washers	156-01	+10[a]	146.0	158.5
M-672-1	SA540-GRB-23-CL3	Closure head nuts and washers	157-00	+10[a]	148.0	160.0
M-6721-1	SA540-GRB-23-CL3	Closure head nuts and washers	157-01	+10[a]	147.0	159.5

Table 5.3-21

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
REACTOR VESSEL FASTENERS[b] (Sheet 4 of 4)

Material Code No.	Material Specification	Location	Tube/Bar No:	PreLoad Temp (°F)	Yield STR (ksi)	Ultimate STR (ksi)
M-6721-1	SA540-GRB-23-CL3	Closure head nuts and washers	161-00	+10[a]	148.0	160.0
M-6721-1	SA540-GRB-23-CL3	Closure head nuts and washers	161-01	+10[a]	145.7	158.0
M-6721-1	SA540-GRB-23-CL3	Closure head nuts and washers	163-00	+10[a]	144.5	157.0
M-6721-1	SA540-GRB-23-CL3	Closure head nuts and washers	163-01	+10[a]	148.5	160.0
M-6721-1	SA540-GRB-23-CL3	Closure head nuts and washers	165-00	+10[a]	155.5	167.0
M-6721-1	SA540-GRB-23-CL3	Closure head nuts and washers	165-01	+10[a]	154.7	165.5

Table 5.3-22

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA[b]

PRESSURIZER[c] AND STEAM GENERATORS 1[d] AND 2[e] MANWAY FASTENERS (Sheet 1 of 2)

Material Code No.	Material Specification	Location	Tube/Bar No:	Preload Temp (°F)	Yield STR (ksi)	Ultimate STR (ksi)
MS-306-1	SA193-GRB7	Nuts and washers	1A	+40[a]	128.5	143.5
MS-306-1	SA193-GRB7	Nuts and washers	1B	+40[a]	135.0	151.0
MS-306-1	SA193-GRB7	Nuts and washers	1C	+40[a]	128.5	145.0
MS-314-1	SA540-GRB-24-CL3	Studs	-	+10[a]		
MS-314-1	SA540-GRB-24-CL3	Studs	71-00	+10[a]	150.0	162.5

a. Determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2333-A (diameter 1-4 incl)

b. Note: Since the same material lot was used for Units 1 and 2 pressurizer and Unit 2 steam generators primary manways, the respective piece numbers and reference drawing numbers are listed below.

	Piece Number		Reference Drawing
	Nuts and Washers	Studs	Number
c. Units 1 and 2 Pressurizer	676-3101	676-3301	E-78373-661-002-03
d. Unit 2 Steam Generator No. 1	276-3901	276-3501	E-78273-261-003-03
e. Unit 2 Steam Generator No. 2	276-3901	276-3501	E-78273-361-003-02

f. Not required

Table 5.3-22

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA[b]

PRESSURIZER[c] AND STEAM GENERATORS 1[d] AND 2[e] MANWAY FASTENERS (Sheet 2 of 2)

Material Code No.	Material Specification	Location	Tube/Bar No:	Preload Temp (°F)	Yield STR (ksi)	Ultimate STR (ksi)
MS-314-1	SA540-GRB-24-CL3	Studs	71-01	+10[a]	149.0	162.0
MS-314-1	SA540-GRB-24-CL3	Studs	217-00	+10[a]	150.7	161.0
MS-314-1	SA540-GRB-24-CL3	Studs	217-01	+10[a]	148.2	159.0
MS-314-1	SA540-GRB-24-CL3	Studs	237-00	+10[a]	147.2	159.0
MS-314-1	SA540-GRB-24-CL3	Studs	273-01	+10[a]	150.0	162.0
MS-314-1	SA540-GRB-24-CL3	Studs	43-00	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	43-01	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	70-00	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	70-01	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	69-00	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	69-01	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	204-00	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	204-01	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	208-00	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	208-01	+10[a]	N/R[f]	N/R[f]
MS-314-1	SA540-GRB-24-CL3	Studs	240-00	+10[a]	N/R[f]	N/R[f]

Table 5.3-22A

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
COMPONENT: STEAM GENERATOR No. 1 PRIMARY SIDE

PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS AND WASHERS												
					TENSILE TEST RESULTS				**IMPACT TEST RESULTS**			
Piece Number	Reference Drawing Number	ASME Material Specification	Location in Component	Preload Temp. (°F)	YS Mpa (Ksl)	UTS Mpa (Ksl)	RA (%)	Elong (%)	Temp. (°F)	Absorbed Energy (Average) J (ft/lbf)	Lateral Expansion (Average) mm (mils)	Sheer (%)
45-3	PX-DWD-15-080	SA-540 Gr B24 CL 3	Stud	10	943 (137)	1064 (154)	57.0	21.2	10	76.7 (56.6)	0.93 (36.6)	80
					972 (141)	1082 (157)	60.1	23.5	40	81.7 (60.2)	1.01 (39.8)	80
45-4	PX-DWD-15-080	SA-540 Gr B24 CL 3	Nut	10	1153 (167)	1215 (176)	50.4	16.3	10	60.0 (44.3)	0.63 (25.0)	80
					1160 (169)	1213 (176)	50.4	17.1	40	63.0 (46.5)	0.78 (30.9)	80

Table 5.3-22B

PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
COMPONENT: STEAM GENERATOR No. 2 PRIMARY SIDE

PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS AND WASHERS												
					TENSILE TEST RESULTS				**IMPACT TEST RESULTS**			
Piece Number	Reference Drawing Number	ASME Material Specification	Location in Component	Preload Temp. (°F)	YS Mpa (Ksl)	UTS Mpa (Ksl)	RA (%)	Elong (%)	Temp. (°F)	Absorbed Energy (Average) J (ft/lbf)	Lateral Expansion (Average) mm (mils)	Sheer (%)
45-3	PX-DWD-15-080	SA-540 Gr B24 CL 3	Stud	10	943 (137)	1064 (154)	57.0	21.2	10	76.7 (56.6)	0.93 (36.6)	80
					972 (141)	1082 (157)	60.1	23.5	40	81.7 (60.2)	1.01 (39.8)	80
45-4	PX-DWD-15-080	SA-540 Gr B24 CL 3	Nut	10	1153 (167)	1215 (176)	50.4	16.3	10	60.0 (44.3)	0.63 (25.0)	80
					1160 (169)	1213 (176)	50.4	17.1	40	63.0 (46.5)	0.78 (30.9)	80

Table 5.3-23

PVNGS UNIT 1

COMPONENT: REACTOR COOLANT PUMP
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS (Sheet 1 of 2)

Reference Number	Material Code Number	ASME Material Specification	Location In Component	Preload Temp (°F)[a]
Reactor coolant pump No. 1				
78173-S/N1109-2A	V112	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-2A	V113	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-2A	V41	SA540-GRB24-CL3	RCP Studs	70
78173-S/N1109-2A	V42	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-2A	86293[b]	SA540-GRB24-CL3	RCP Nuts	70
Reactor coolant pump No. 2				
78173-S/N1109-18	V110	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-1B	V111	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-1B	V52	SA540-GRB24-CL3	RCP Studs	70

a. Determined per applicable ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB233-A (diameter over 4 inches)

b. Heat Number

Table 5.3-23

PVNGS UNIT 1

COMPONENT: REACTOR COOLANT PUMP
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS (Sheet 2 of 2)

Reference Number	Material Code Number	ASME Material Specification	Location In Component	Preload Temp (°F)[a]
Reactor coolant pump No. 3				
78173-S/N1109-2B	V110	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-2B	V111	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-2B	V112	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-2B	V41	SA540-GRB24-CL3	RCP Studs	70
78173-S/N1109-2B	V42	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-2B	V43	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-2B	V44	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-2B	V52	SA540-GRB24-CL3	RCP Studs	70
Reactor coolant pump No. 4				
78173-S/N1109-1A	V111	SA540-GRB24-CL3	RCP Nuts	70
78173-S/N1109-1A	V41	SA540-GRB24-CL3	RCP Studs	70

Table 5.3-24

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
COMPONENT: REACTOR VESSEL
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS (Sheet 1 of 2)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Preload Temp (°F) [(a)]
179-3301	E-79173-161-004-02	F-776-1A	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1B	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1C	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1D	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1E	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1F	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1G	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1H	SA540-GRB24-CL3	Manway Studs	10

a. Preload temperature (diameter: over 4 inches) per ASME B&VP Code, Section III, Article NB-2333.

Table 5.3-24

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
COMPONENT: REACTOR VESSEL
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS (Sheet 2 of 2)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Preload Temp (°F) [(a)]
179-3301	E-79173-161-004-02	F-776-1I	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1J	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1K	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1L	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1M	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1N	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1O	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-1P	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-2A	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-2B	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-3A	SA540-GRB24-CL3	Manway Studs	10
179-3301	E-79173-161-004-02	F-776-3B	SA540-GRB24-CL3	Manway Studs	10

Table 5.3-25

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
COMPONENT: REACTOR VESSEL
PRODUCT FORM: FASTENERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Y S ksi	UTS ksi	R A (%)	Elong (%)
179-3301	E-79173-161-004-02	F-776-1A	SA540-GRB24-CL3	Manway Studs	141.3	156.0	54	17
179-3301	E-79173-161-004-02	F-776-1B	SA540-GRB24-CL3	Manway Studs	144.0	160.0	50	16
179-3301	E-79173-161-004-02	F-776-1C	SA540-GRB24-CL3	Manway Studs	147.8	162.5	55	17
179-3301	E-79173-161-004-02	F-776-1D	SA540-GRB24-CL3	Manway Studs	145.8	160.0	56	17
179-3301	E-79173-161-004-02	F-776-1E	SA540-GRB24-CL3	Manway Studs	157.0	169.0	50	15
179-3301	E-79173-161-004-02	F-776-1F	SA540-GRB24-CL3	Manway Studs	150.0	162.5	51	16
179-3301	E-79173-161-004-02	F-776-1G	SA540-GRB24-CL3	Manway Studs	150.0	165.0	50	16
179-3301	E-79173-161-004-02	F-776-1H	SA540-GRB24-CL3	Manway Studs	148.5	164.0	51	16
179-3301	E-79173-161-004-02	F-776-1I	SA540-GRB24-CL3	Manway Studs	147.5	161.5	51	16
179-3301	E-79173-161-004-02	F-776-1J	SA540-GRB24-CL3	Manway Studs	145.0	160.0	53	16
179-3301	E-79173-161-004-02	F-776-1K	SA540-GRB24-CL3	Manway Studs	145.0	160.0	50	16
179-3301	E-79173-161-004-02	F-776-1L	SA540-GRB24-CL3	Manway Studs	147.5	162.0	52	15
179-3301	E-79173-161-004-02	F-776-1M	SA540-GRB24-CL3	Manway Studs	145.0	159.3	53	16
179-3301	E-79173-161-004-02	F-776-1N	SA540-GRB24-CL3	Manway Studs	151.0	164.3	53	16
179-3301	E-79173-161-004-02	F-776-1O	SA540-GRB24-CL3	Manway Studs	143.8	158.0	48	16
179-3301	E-79173-161-004-02	F-776-1P	SA540-GRB24-CL3	Manway Studs	143.5	158.0	47	16
179-3301	E-79173-161-004-02	F-776-2A	SA540-GRB24-CL3	Manway Studs	148.5	162.0	57	17
179-3301	E-79173-161-004-02	F-776-2B	SA540-GRB24-CL3	Manway Studs	146.0	160.8	52	16
179-3301	E-79173-161-004-02	F-776-3A	SA540-GRB24-CL3	Manway Studs	146.0	159.0	48	15
179-3301	E-79173-161-004-02	F-776-3B	SA540-GRB24-CL3	Manway Studs	145.0	159.0	49	15

Table 5.3-26

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
COMPONENT: PRESSURIZER
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Preload Temp (°F) [a]
676-3101	E-79373-661-004-02	MS-306-1A	SA193-GRB7	Fastener Nuts	40
676-3101	E-79373-661-004-02	MS-306-1B	SA193-GRB7	Fastener Nuts	40
676-3101	E-79373-661-002-02	MS-306-1C	SA193-GRB7	Fastener Nuts	40
676-3301	E-79373-661-002-02	MS-314-1A	SA540-GRB24-CL3	Manway Studs	10
676-3301	E-79373-661-002-02	MS-314-AB	SA540-GRB24-CL3	Manway Studs	10
676-3301	E-79373-661-002-02	MS-314-1C	SA540-GRB24-CL3	Manway Studs	10
676-3301	E-79373-661-002-02	MS-314-1D	SA540-GRB24-CL3	Manway Studs	10
676-3301	E-79373-661-002-02	MS-314-1E	SA540-GRB24-CL3	Manway Studs	10
676-3301	E-79373-661-002-02	MS-314-1F	SA540-GRB24-CL3	Manway Studs	10

a. Preload temperature (diameter: under 4 inches) per ASME B&PV Code, Section III, Article NB-2333.

Table 5.3-27

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
COMPONENT: PRESSURIZER
PRODUCT FORM: FASTENERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Y S ksi	UTS ksi	R A (%)	Elong (%)
676-3101	E-79373-661-002-02	MS-306-1A	SA193-GRB7	Fastener Nuts	128.5	143.5	59	18
676-3101	E-79373-661-002-02	MS-306-1B	SA193-GRB7	Fastener Nuts	135.0	151.0	55	18
676-3101	E-79373-661-002-02	MS-306-1C	SA193-GRB7	Fastener Nuts	128.5	145.0	59	18
676-3301	E-79373-661-002-02	MS-314-1A	SA540-GRB24-CL3	Manway Studs	150.0	162.5	54	17
676-3301	E-79373-661-002-02	MS-314-1B	SA540-GRB24-CL3	Manway Studs	149.0	162.0	53	17
676-3301	E-79373-661-002-02	MS-314-1C	SA540-GRB24-CL3	Manway Studs	150.8	161.0	55	17
676-3301	E-79373-661-002-02	MS-314-1D	SA540-GRB24-CL3	Manway Studs	148.3	159.0	55	17
676-3301	E-79373-661-002-02	MS-314-1E	SA540-GRB24-CL3	Manway Studs	147.3	159.0	56	19
676-3301	E-79373-661-002-02	MS-314-1F	SA540-GRB24-CL3	Manway Studs	150.0	162.0	55	18

Table 5.3-28

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
COMPONENT: STEAM GENERATOR 1 PRIMARY SIDE
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHER

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Preload Temp (°F) [(a)]
276-3901	E-79273-261-003-03	MS-306-1A	SA193-GRB7	Fastener Nuts	40
276-3901	E-79273-261-003-03	MS-306-1B	SA193-GRB7	Fastener Nuts	40
276-3901	E-79273-261-003-03	MS-306-1C	SA193-GRB7	Fastener Nuts	40
276-4001	E-79273-261-003-03	MS-308-1A	SA193-GRB7	Fastener Nuts	40
276-3601	E-79273-261-003-03	MS-314-1A	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-261-003-03	MS-314-1B	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-261-003-03	MS-314-1C	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-261-003-03	MS-314-1D	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-261-003-03	MS-314-1E	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-261-003-03	MS-314-1F	SA540-GRB24-CL3	Manway Studs	10
276-3701	E-79273-261-003-03	MS-315-1A	SA193-GRB7	Manway Studs	10
276-3701	E-79273-261-003-03	MS-315-1B	SA193-GRB7	Manway Studs	10

a. Preload temperature (diameter: under 4 inches) per ASME B&PV Code, Section III, Article NB-2333.

Table 5.3-29

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
COMPONENT: STEAM GENERATOR 1 PRIMARY SIDE
PRODUCT FORM: FASTENERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Y S ksi	UTS ksi	R A (%)	Elong (%)
276-3901	E-79273-261-003-03	MS-306-1A	SA193-GRB7	Fastener Nuts	128.5	143.5	59	18
276-3901	E-79273-261-003-03	MS-306-1B	SA193-GRB7	Fastener Nuts	135.0	151.0	55	18
276-3901	E-79273-261-003-03	MS-306-1C	SA193-GRB7	Fastener Nuts	128.5	145.0	59	18
276-4001	E-79273-261-003-03	MS-308-1A	SA193-GRB7	Fastener Nuts	115.0	134.0	63	19
276-3601	E-79273-261-003-03	MS-314-1A	SA540-GRB24-CL3	Manway Studs	150.0	162.5	54	17
276-3601	E-79273-261-003-03	MS-314-1B	SA540-GRB24-CL3	Manway Studs	149.0	162.0	53	17
276-3601	E-79273-261-003-03	MS-314-1C	SA540-GRB24-CL3	Manway Studs	150.8	161.0	55	17
276-3601	E-79273-261-003-03	MS-314-1D	SA540-GRB24-CL3	Manway Studs	148.3	159.0	55	17
276-3601	E-79273-261-003-03	MS-314-1E	SA540-GRB24-CL3	Manway Studs	147.3	159.0	56	19
276-3601	E-79273-261-003-03	MS-314-1F	SA540-GRB24-CL3	Manway Studs	150.0	162.0	55	18
276-3701	E-79273-261-003-03	MS-315-1A	SA193-GRB7	Manway Studs	132.0	143.0	59	19
276-3701	E-79273-261-003-03	MS-315-1B	SA193-GRB7	Manway Studs	129.5	141.5	58	20

Table 5.3-30

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
COMPONENT: STEAM GENERATOR 2 PRIMARY SIDE
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHER

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Preload Temp (°F) [a]
276-3901	E-79273-361-003-03	MS-306-1A	SA193-GRB7	Fastener Nuts	40
276-3901	E-79273-361-003-03	MS-306-1B	SA193-GRB7	Fastener Nuts	40
276-3901	E-79273-361-003-03	MS-306-1C	SA193-GRB7	Fastener Nuts	40
276-4001	E-79273-361-003-03	MS-308-1A	SA193-GRB7	Fastener Nuts	40
276-3601	E-79273-361-003-03	MS-314-1A	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-361-003-03	MS-314-1B	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-361-003-03	MS-314-1C	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-361-003-03	MS-314-1D	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-361-003-03	MS-314-1E	SA540-GRB24-CL3	Manway Studs	10
276-3601	E-79273-361-003-03	MS-314-1F	SA540-GRB24-CL3	Manway Studs	10
276-3701	E-79273-361-003-03	MS-315-1A	SA193-GRB7	Manway Studs	10
276-3701	E-79273-361-003-03	MS-315-1B	SA193-GRB7	Manway Studs	10

a. Preload temperature (diameter: under 4 inches) per ASME B&PV Code, Section III, Article NB-2333.

Table 5.3-31

PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
COMPONENT: STEAM GENERATOR 2 PRIMARY SIDE
PRODUCT FORM: FASTENERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Y S ksi	UTS ksi	R A (%)	Elong (%)
276-3901	E-79273-361-003-03	MS-306-1A	SA193-GRB7	Fastener Nuts	128.5	143.5	59	18
276-3901	E-79273-361-003-03	MS-306-1B	SA193-GRB7	Fastener Nuts	135.0	151.0	55	18
276-3901	E-79273-361-003-03	MS-306-1C	SA193-GRB7	Fastener Nuts	128.5	145.0	59	18
276-4001	E-79273-361-003-03	MS-308-1A	SA193-GRB7	Fastener Nuts	115.0	134.0	63	19
276-3601	E-79273-361-003-03	MS-314-1A	SA540-GRB24-CL3	Manway Studs	150.0	162.5	54	17
276-3601	E-79273-361-003-03	MS-314-1B	SA540-GRB24-CL3	Manway Studs	149.5	162.0	53	17
276-3601	E-79273-361-003-03	MS-314-1C	SA540-GRB24-CL3	Manway Studs	150.8	161.0	55	17
276-3601	E-79273-361-003-03	MS-314-1D	SA540-GRB24-CL3	Manway Studs	148.3	159.0	55	17
276-3601	E-79273-361-003-03	MS-314-1E	SA540-GRB24-CL3	Manway Studs	147.3	159.0	56	19
276-3601	E-79273-361-003-03	MS-314-1F	SA540-GRB24-CL3	Manway Studs	150.0	162.0	55	18
276-3701	E-79273-361-003-03	MS-315-1A	SA193-GRB7	Manway Studs	132.0	143.0	59	19
276-3701	E-79273-361-003-03	MS-315-1B	SA193-GRB7	Manway Studs	129.5	141.5	58	20

Table 5.3-32

PVNGS UNIT 2

COMPONENT: REACTOR COOLANT PUMP
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS (Sheet 1 of 2)

Reference Number	Material Code Number	ASME Material Specification	Location In Component	Preload Temp (°F)
Reactor coolant pump No. 1A				
79173-S/N1110-1A	E17F	SA194-GR7	RCP Nuts	40[(a)]
79173-S/N1110-1A	E84D	SA540-GRB24-CL3	RCP Studs	10[(a)]
79173-S/N1110-1A	E86D	SA540-GRB24-CL3	RCP Studs	10[(a)]
Reactor coolant pump No. 1B				
79173-S/N1110-1B	C27L	SA540-GRB24-CL3	RCP Studs	10[(a)]
79173-S/N1110-1B	C94C	SA540-GRB24-CL3	RCP Studs	10[(a)]
79173-S/N1110-1B	E17F	SA194-GR7	RCP Nuts	40[(a)]

a. Preload temperature as per ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-233-A (diameter over 4-inches)

Table 5.3-32

PVNGS UNIT 2

COMPONENT: REACTOR COOLANT PUMP
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS (Sheet 2 of 2)

Reference Number	Material Code Number	ASME Material Specification	Location In Component	Preload Temp (°F)
Reactor coolant pump No. 2A				
79173-S/N1110-2A	E48A	SA194-GR7	RCP Nuts	40[a]
79173-S/N1110-2A	E68A	SA540-GRB24-CL3	RCP Studs	10[a]
Reactor coolant pump No. 2B				
79173-S/N1110-2B	C135 B	SA194-GR7	RCP Nuts	40[a]
79173-S/N1110-2B	E84D	SA540-GRB24-CL3	RCP Studs	10[a]
79173-S/N1110-2B	E86D	SA540-GRB24-CL3	RCP Studs	10[a]

Table 5.3-33

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
COMPONENT: REACTOR VESSEL
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHER

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Preload Temp (°F)
179-3301	E-65173-161-004-01	F-6422-1A	SA540-GRB24-CL3	Manway Studs	0[(a)]
179-3301	E-65173-161-004-01	F-6422-1B	SA540-GRB24-CL3	Manway Studs	0[(a)]
179-3301	E-65173-161-004-01	F-6422-2A	SA540-GRB24-CL3	Manway Studs	0[(a)]
179-3301	E-65173-161-004-01	F-6422-2B	SA540-GRB24-CL3	Manway Studs	0[(a)]
179-3401	E-65173-161-004-01	J-20 -1A	SA540-GRB24	Fastener Nuts	+10[(a)]
179-3401	E-65173-161-004-01	J-20 -1B	SA540-GRB24	Fastener Nuts	+10[(a)]
179-3401	E-65173-161-004-01	J-20 -1C	SA540-GRB24	Fastener Nuts	+10[(a)]
179-3401	E-65173-161-004-01	J-20 -1D	SA540-GRB24	Fastener Nuts	+10[(a)]
179-3401	E-65173-161-004-01	J-20 -1E	SA540-GRB24	Fastener Nuts	+10[(a)]
179-3401	E-65173-161-004-01	J-20 -1F	SA540-GRB24	Fastener Nuts	+10[(a)]
179-3401	E-65173-161-004-01	J-20 -1G	SA540-GRB24	Fastener Nuts	+10[(a)]
179-3401	E-65173-161-004-01	J-20 -1H	SA540-GRB24	Fastener Nuts	+10[(a)]

a. Preload temperature as per ASME B&PV Code, Section III, Article NB-2333.

Table 5.3-34

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
COMPONENT: REACTOR VESSEL
PRODUCT FORM: FASTENERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Y S ksi	UTS ksi	R A (%)	Elong (%)
179-3301	E-65173-161-004-01	F-6422-1A	SA540-GRB24-CL3	Manway Studs	137.5	156.9	55	21
179-3301	E-65173-161-004-01	F-6422-1B	SA540-GRB24-CL3	Manway Studs	136.3	156.9	59	20
179-3301	E-65173-161-004-01	F-6422-2A	SA540-GRB24-CL3	Manway Studs	141.0	158.1	57	20
179-3301	E-65173-161-004-01	F-6422-2B	SA540-GRB24-CL3	Manway Studs	139.9	156.9	57	21
179-3401	E-65173-161-004-01	J-20 -1A	SA540-GRB24	Fastener Nuts	150.5	164.0	56	16
179-3401	E-65173-161-004-01	J-20 -1B	SA540-GRB24	Fastener Nuts	151.0	165.0	55	16
179-3401	E-65173-161-004-01	J-20 -1C	SA540-GRB24	Fastener Nuts	147.0	161.0	56	17
179-3401	E-65173-161-004-01	J-20 -1D	SA540-GRB24	Fastener Nuts	149.3	164.0	55	17
179-3401	E-65173-161-004-01	J-20 -1E	SA540-GRB24	Fastener Nuts	144.5	159.0	56	17
179-3401	E-65173-161-004-01	J-20 -1F	SA540-GRB24	Fastener Nuts	146.0	160.0	57	16
179-3401	E-65173-161-004-01	J-20 -1G	SA540-GRB24	Fastener Nuts	145.3	159.0	56	17
179-3401	E-65173-161-004-01	J-20 -1H	SA540-GRB24	Fastener Nuts	143.5	157.3	58	17

Table 5.3-35

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
COMPONENT: PRESSURIZER
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Preload Temp (°F)
676-3601	E-65373-661-002-04	J-6391-1A	SA540-GRB24-CL3	Manway Studs	+10[a]
676-3601	E-65373-661-002-04	J-6391-1B	SA540-GRB24-CL3	Manway Studs	+10[a]
676-3601	E-65373-661-002-04	J-6391-1C	SA540-GRB24-CL3	Manway Studs	+10[a]
676-3601	E-65373-661-002-04	J-6391-1D	SA540-GRB24-CL3	Manway Studs	+10[a]
676-3101	E-65373-661-002-04	MS-306-1A	SA193-GRB7	Fastener Nuts	+40[a]
676-3101	E-65373-661-002-04	MS-306-1B	SA193-GRB7	Fastener Nuts	+40[a]
676-3101	E-65373-661-002-04	MS-306-1C	SA193-GRB7	Fastener Nuts	+40[a]

a. Preload temperature as per ASME B&PV Code, Section III, Article NB-2333-A.

Table 5.3-36

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
COMPONENT: PRESSURIZER
PRODUCT FORM: FASTENERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Y S ksi	UTS ksi	R A (%)	Elong (%)
676-3601	E-65373-661-002-04	J-6391-1A	SA540-GRB24-CL3	Manway Studs	151.0	161.5	59	16
676-3601	E-65373-661-002-04	J-6391-1B	SA540-GRB24-CL3	Manway Studs	153.0	163.5	60	15
676-3601	E-65373-661-002-04	J-6391-1C	SA540-GRB24-CL3	Manway Studs	152.5	162.3	58	16
676-3601	E-65373-661-002-04	J-6391-1D	SA540-GRB24-CL3	Manway Studs	151.0	161.0	57	16
676-3101	E-65373-661-002-04	MS-306-1A	SA193-GRB7	Fastener Nuts	128.5	143.5	59	18
676-3101	E-65373-661-002-04	MS-306-1B	SA193-GRB7	Fastener Nuts	135.0	151.0	55	18
676-3101	E-65373-661-002-04	MS-306-1C	SA193-GRB7	Fastener Nuts	128.5	145.0	59	18

Table 5.3-37

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
COMPONENT: STEAM GENERATOR No. 1 PRIMARY SIDE

PRODUCT FORM: FASTNERS INCLUDING STUDS, NUTS AND WASHERS

					TENSILE TEST RESULTS				IMPACT TEST RESULTS			
Piece Number	Reference Drawing Number	ASME Material Specification	Location In Component	Preload Temp. (°F)	YS Mpa (Ksi)	UTS Mpa (Ksi)	RA (%)	Elong (%)	Temp. (°F)	Absorbed Energy (Average) J (ft/lbf)	Lateral Expansion (Average) mm (mils)	Shear (%)
45-3	PX-DWD-15-080	SA-540 Gr B24 CL 3	Stud	10	1048 (152)	1158 (168)	54.9	19.3	10	69 (51)	0.81 (32)	70
					1032 (150)	1182 (172)	56.9	20.6	40	71 (52)	1.02 (40)	80
45-4	PX-DWD-15-080	SA-540 Gr B24 CL 3	Nut	10	936 (136)	1065 (154)	53.6	21.5	10	64 (47)	0.81 (32)	70
					942 (137)	1067 (155)	54.2	20.9	40	70 (52)	1.03 (41)	80

Table 5.3-38

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Table 5.3-39

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
COMPONENT: STEAM GENERATOR No. 2 PRIMARY SIDE

PRODUCT FORM: FASTNERS INCLUDING STUDS, NUTS AND WASHERS												
					TENSILE TEST RESULTS				IMPACT TEST RESULTS			
Piece Number	Reference Drawing Number	ASME Material Specification	Location In Component	Preload Temp. (°F)	YS Mpa (Ksi)	UTS Mpa (Ksi)	RA (%)	Elong (%)	Temp. (°F)	Absorbed Energy (Average) J (ft/lbf)	Lateral Expansion (Average) mm (mils)	Shear (%)
45-3	PX-DWD-15-080	SA-540 Gr B24 CL 3	Stud	10	1048 (152)	1158 (168)	54.9	19.3	10	69 (51)	0.81 (32)	70
					1032 (150)	1182 (172)	56.9	20.6	40	71 (52)	1.02 (40)	80
45-4	PX-DWD-15-080	SA-540 Gr B24 CL 3	Nut	10	936 (136)	1065 (154)	53.6	21.5	10	64 (47)	0.81 (32)	70
					942 (137)	1067 (155)	54.2	20.9	40	70 (52)	1.03 (41)	80

Table 5.3-40

DELETED

Table 5.3-41

PVNGS UNIT 3

COMPONENT: REACTOR COOLANT PUMP
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS (Sheet 1 of 2)

Reference Number	Material Code Number	ASME Material Specification	Location In Component	Preload Temp (°F)
Reactor coolant pump No. 1A				
65173-S/N1111-1A	E-48A	SA194-GR7	RCP Nuts	+40[a]
65173-S/N1111-1A	3-2288	SA540-GRB24-CL3	RCP Studs	+10[a]
Reactor coolant pump No. 1B				
65173-S/N1111-1B	E-48A	SA194-GR7	RCP Nuts	+40[a]
65173-S/N1111-1B	E-68A	SA540-GRB24-CL3	RCP Studs	+10[a]

a. Preload temperature as per ASME B&PV Code and Addenda, Section III, Subsection NB, Article NB-2333-A.

Table 5.3-41

PVNGS UNIT 3

COMPONENT: REACTOR COOLANT PUMP
PRODUCT FORM: FASTENERS INCLUDING STUDS, NUTS, AND WASHERS (Sheet 2 of 2)

Reference Number	Material Code Number	ASME Material Specification	Location In Component	Preload Temp (°F)
Reactor coolant pump No. 2A				
65173-S/N1111-2A	C-135B	SA194-GR7	RCP Nuts	+40[a]
65173-S/N1111-2A	F-1295	SA540-GRB24-CL3	RCP Studs	+10[a]
Reactor coolant pump No. 2B				
65173-S/N1111-2B	C-135B	SA194-GR7	RCP Nuts	+40[a]
65173-S/N1111-2B	F-1295	SA540-GRB24-CL3	RCP Studs	+10[a]

5.3.3.5 Shipment and Installation

The requirements of Regulatory Guide 1.38 were followed in the packaging and shipment of the reactor vessel. Regulatory Guide 1.37 and 1.39 address requirements during the construction phase.

The reactor vessels are prepared to be shipped by barge or rail to the site, while mounted on the shipping skid used for installation. The vessels are protected by closing all openings (including the top of the vessel) with wooden shipping covers. The closure heads are shipped with separate skids and covers. Vessel surfaces and covers are sprayed with a strippable coating for protection against corrosion during shipping and installation. Prior to the welding of interconnecting piping, and installation of insulation; the temporary protective coating is removed by peeling. For a discussion of compliance with Regulatory Guides 1.37 and 1.39 during installation, refer to section 1.8.

The replacement closure head and CEDMs were shipped to the site in accordance with the requirements of the Regulatory Guides 1.37, 1.38 and 1.39.

5.3.3.6 Operating Conditions

Refer to sections 3.9 and 4.4 for information on design transients and operating conditions, respectively.

5.3.3.7 Inservice Surveillance

The reactor vessel surveillance program is described in detail in Section 5.3.1.6. It is designed on the basis of 10CFR50,

Appendix H and ASTM E185-79 for Unit 1 and ASTM E185-82 for Unit 2 & 3. Standard reference material to corroborate the post-irradiation surveillance data and precracked Charpy impact specimens to enable determination of fracture toughness properties before and after irradiation are included in the program. Standard Charpy specimens in excess of the number required by E185-82 are included for key materials to increase the accuracy in defining post-irradiation index temperatures. When combined with the use of highly radiation resistant materials in the beltline of the reactor vessel, this surveillance program provides maximum assurance, consistent with commercial requirements, of the integrity of the reactor pressure vessel in terms of strength and fracture resistance.

For a discussion of the inservice inspection program, see subsection 5.2.4 and section 6.6, and the Technical Specifications.

5.3.4 REFERENCES

1. "C-E Procedure for Design, Fabrication, Installation and Inspection of Surveillance Specimen Holder Assemblies," Combustion Engineering Topical Report, CENPD-155P, Approved August 11, 1975.

2. "CE NPSD-1085," CEOG Response to NRC Generic Letter 97-01, Degradation of CEDM Nozzle and Other Vessel Closure Head Penetrations" Dated July 25, 1997.

3. Letter from NRC to PVNGS, subject "Closeout of Generic Letter 97-01, Degradation of CRDM/CEDM Nozzle and Other Vessel Closure Head Penetrations, for the Palo Verde Nuclear Generating Station, Units 1, 2, and 3 (TAC Nos. M98583, M98584 and M98585), Dated December 13, 1999.

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 REACTOR COOLANT PUMPS

The reactor coolant pumps provide sufficient forced circulation flow through the reactor coolant system to assure adequate heat removal from the reactor core during power operation. A low limit on reactor coolant pump flow rate (i.e., design flow) is established to assure that specified acceptable fuel design limits are not exceeded. Design flow is derived on the basis of the thermal-hydraulic considerations presented in Section 5.2.

The reactor coolant pump and motor assembly in conjunction with the flywheel, provide sufficient coastdown flow following loss of power to the pumps to assure adequate core cooling.

The reactor coolant pump pressure boundary is designed for the transients given in Section 3.9 so that the ASME Code Section III allowable stress limits are not exceeded for the specified number of cycles. Stress criteria concerning earthquake and pipe rupture conditions are presented in Section 3.9.3.

The design overspeed of the reactor coolant pump is 125 percent of normal speed.

5.4.1.1 Pump Flywheel Integrity

A. The material used to manufacture the flywheel of the reactor coolant pump motor will be produced by a commercially acceptable process that minimizes flaws, such as the vacuum melt and degassing process. This

provides adequate fracture toughness properties under reactor operating conditions. The acceptance criteria for flywheel design will be compatible with the safety philosophy of the PVRC primary coolant pressure boundary criteria as appropriate considering the inherent design and functional requirement differences between the pressure boundary and the flywheel.

1. The reference nil-ductility temperature (RT_{NDT}) of the material, as obtained from the drop-weight tests (DWT) performed in accordance with specification ASTM-E-208 will be no greater than 10F.

2. The Charpy V-notch (Cv) upper shelf energy level, in the "weak" (Wr) direction, as obtained per ASTM-A-370 will be no less than 50 ft-lb. A minimum of three Cv specimens will be tested from each plate or forging.

3. The minimum fracture toughness of the material at the normal operating temperature of the flywheel will be equivalent to a dynamic stress intensity factor (K_{IC} dynamic) of at least 100 ksi-in$^{1/2}$. Compliance will be demonstrated by either of the following:

   a. Testing of the actual material of the flywheel to establish the K_{IC} (dynamic) value at the normal operating temperature, or

b. Use of a lower bound fracture toughness curve obtained from tests on the same type of material. The curve will be translated along the temperature coordinate until the KIC (dynamic) value of 45 ksi-in$^{1/2}$ is indicated at the NDT of the material, as obtained from drop-weight tests.

4. Each finished flywheel will be subjected to a 100 percent volumetric ultrasonic inspection from the flat surface per ASME BPVC Section III.

   This inspection will be performed on the flywheel after final machining and overspeed test.

5. If the flywheel is flame cut, at least 1/2 inch of stock will be left on the outer and bore radii, for machining to final dimensions.

6. The flywheel will be subjected to a magnetic particle or liquid-penetrant examination per "Section III" before final assembly. The inspection will be performed on finished machined bores, keyways, and on both flat surfaces to a radial distance of 8 inches minimum beyond the final largest machined bore diameter but not including small drilled holes. There will be no stress concentrations such as stamp marks, center punch marks, or drilled or tapped holes within 8 inches of the edge of the largest flywheel bore.

B. The flywheels will be designed to withstand normal operating conditions, anticipated transients, and the largest mechanistic LOCA break size defined in CENPD-168 (Revision 1) combined with the Safe Shutdown Earthquake.

The following criteria will be satisfied:

1. The combined stress, both centrifugal and interference, at normal operating speed will not exceed one-third of the minimum specified yield strength for the material selected in the direction of maximum stress;

2. The design speed of the flywheel will be 125 percent of normal operating speed.

   The lowest of the critical speeds of the flywheel will be at least 10% above the highest anticipated overspeed of the pump. The highest anticipated overspeed is predicted for a discharge leg break of the largest break size defined in CENPD-168 (Revision 1).

3. The combined centrifugal and interference stresses at the design speed will be limited to two-thirds of the minimum specified yield strength. Design speed is defined as 125 percent of normal operating speed.

4. The motor and pump shaft or bearings and coupling will withstand any combination of normal operating loads or anticipated transients, and the design basis Loss-of-Coolant

Accident combined with the Safe Earthquake Shutdown.

Each flywheel will be tested at design speed, 125 percent of normal operating speed, as defined in Step B.2, above.

The flywheel will be accessible for 100 percent in-place volumetric ultrasonic inspection. The flywheel-motor assembly is designed to allow such inspection with a minimum of motor disassembly.

5.4.1.2 Description

Table 5.4-42 lists the principal parameters of the reactor coolant pumps and Figure 5.4-9 depicts the arrangement of the pump and motor. Reactor coolant pump supports are discussed in Section 5.4.14. The pump piping and instrument diagram is given in engineering drawings 01, 02, 03-M-RCP-001, -002 and -003.

The four reactor coolant pumps are vertical, single stage bottom suction, horizontal discharge, motor-driven centrifugal pumps. The pump impeller is keyed and locked to its shaft. Pump shaft alignment is maintained by a water lubricated radial bearing within the pump and by radial and thrust bearings located in the motor stand. The pump and motor shafts are directly connected by a coupling.

The shaft seal assembly consists of two face-type, mechanical seals in series, with controlled leakage bypass to provide the same pressure differential across each seal. The seal assembly is designed for 2500 psi differential and to reduce the leakage

pressure from Reactor Coolant System pressure to the volume control tank pressure. A third, face-type, low-pressure vapor seal at the top is designed to withstand system operating pressure when the pumps are not operating. The leakage past the second pressure seal and the controlled leakage is piped to the volume control tank in the Chemical and Volume Control System. Leakage past the low-pressure vapor seal is collected and piped to the reactor drain tank.

The temperature of the water in the seal assembly is maintained within acceptable limits by a watercooled heat exchanger. Water is also injected into the seal area from an external seal injection system. The performance of the shaft seal system is monitored by pressure and temperature sensing devices in the seal system. The seal assembly can be replaced without draining the pump casing or removing the shaft.

Nominal values for controlled bypass flow are given below. It is noted that actual RCP controlled bleed-off (CBO) flow may be different from these values and vary slightly from pump to pump and Unit to Unit. In addition, actual CBO flow may change for any given RCP over time as the pump seals wear. Bounding values for CBO flow are used in the accident analyses as described in UFSAR Chapter 15:

Controlled bypass flow, per pump:

(Normal) (All seals functioning)	3.0 +/- 1.0 gpm;
Alarm Setpoint (Hi)	6.0 gpm.

The motor is sized for continuous operation at the flows resulting from four-pump or one-pump operation with 1.0 to 0.74 specific gravity water. The motors are designed to start and

accelerate to speed under full load with a drop to 80 percent of normal rated voltage at the motor terminals.

Each motor is provided with an anti-reverse rotation device. The device is designed to prevent impeller rotation in the reverse direction due to each of the following conditions: motor starting torque, if the motor was incorrectly wired for reverse rotation; reactor coolant flow through the pump in the reverse direction due to a pump suction line LOCA.

5.4.1.3 Evaluation

The reactor coolant pumps are sized to deliver flow that equals or exceeds the design flow rate utilized in the thermal hydraulic analysis of the Reactor Coolant System. Analysis of steady-state and anticipated transients is performed assuming the minimum design flow rate. Tests are performed to evaluate reactor coolant pump performance during the post core load hot functional testing to verify adequate flow. Leakage from the pump via the pump shaft is controlled by the shaft seal assembly. Reactor coolant entering the seal chambers is cooled and collected in closed systems to prevent reactor coolant leakage to containment. Instrumentation is provided to monitor seal operation.

The design speed of the flywheel is 125 percent of normal speed. An overspeed test of each flywheel at the design speed is performed prior to assembly. Refer to pump flywheel integrity Section 5.4.1.1.

In the event of a break in the reactor coolant pump suction piping, the anti-reverse rotation device prevents impeller

rotation in the reverse direction. In the event of a discharge pipe break, increased flow through the pump tends to accelerate the pump impeller. The highest anticipated overspeed is predicted for a discharge leg break of the largest break size defined in CENPD-168. The highest predicted LOCA overspeed is less than the lowest critical speed of the flywheel.

The pump and motor oil lubricated bearings are lubricated by internal oil systems. Each bearing assembly has its own internal oil system consisting of either an oil bath type or force-feed type system. During normal operation, no external pumps will be required because pumping action is accomplished by internal pumping devices. Lubricating oil is cooled by cooling coils submerged in the oil sumps. Both sumps and cooling coils are internal to the motor structural frame and are designed for Seismic Category I operation, and use the intent of the ASME Boiler and Pressure Vessel Code, Section III, Class 3 as a guide for design and construction. This is established within the Combustion Engineering Topical Report, CENPD-201, which demonstrates the reactor coolant pump performance during a loss of component cooling water incident. Although the pump-motor assembly operation is not considered necessary for plant safety, this design minimizes the direct effects of seismic events on the reactor coolant pump and motor assembly oil lubricating systems so that adequate coast down characteristics are not detrimentally affected.

Bearing metal temperatures, oil flow and/or pressure oil levels, cooling water flow and/or pressure are continuously monitored and alarmed in the control room.

In the unlikely event that component cooling water to the reactor coolant pump and motor oil lubricating systems is not available or that an oil leak occurs during operation, the operator is alerted as soon as cooling water to the oil system is lost and has a time period of at least 30 minutes in which to reduce power, if necessary, isolate cooling water and shutdown the reactor coolant pump motor assembly to prevent bearing seizure. This time limit is established in the Topical Report CENPD-201. Combustion Engineering has performed a test to verify the analysis in Appendix A. The component cooling water was secured to the pump lubrication oil sumps and data taken so as to demonstrate the heat up rate of the oil sump up to a maximum sump temperature of 300°F. A test securing cooling water to the pump seals has been performed to demonstrate the seals operability. In the remote possibility of a simultaneous loss of component cooling water to all reactor coolant pump motor assemblies, 30 minutes is adequate to secure the plant and maintain the normal coast down capabilities of the reactor coolant pump motor assemblies.

During a loss of component cooling water event, it is unlikely that a shaft seizure due to bearing failure will occur for the following reasons:

A. The design is such that the heat generated in the bearing normally carried away by the cooling water, is transferred by alternate paths. The lube oil sump baths surrounding the bearings, the stagnant cooling water remaining in the heat exchanger coils, and the bearing and sump assembly metal masses, all act as heat sinks.

Also conduction down the pump shaft and outer sump shell radiation help to reduce the temperature rise.

B. The rotation of the bearing assemblies insures adequate oil flow and mixing of heated oil to insure the heat transfer as described in A.

C. In the event that the oil temperature rises such that the viscosity degrades significantly, the design of the thrust bearing continues to produce a hydrodynamic film so as to preclude metal to metal contact.

D. Operation and test experience has demonstrated that the reactor coolant pump motor assembly will operate without cooling water to the lubricating oil system for at least the calculated 30 minute time period.

Should an oil leak occur, redundant instrumentation will alert the operator to shut down the reactor coolant pump motor assembly and thereby avoid bearing damage.

In the event of an oil leak, the separation of lubrication systems would limit the problem to a single reactor coolant pump.

The loss of the oil in the bearing oil reservoir would not result in bearing seizure for the following reasons:

A. Temperature and oil level monitors will provide appropriate indication of an abnormal condition.

B. The vibration monitoring device furnished on the pump will respond to bearing degradation and allow the operator to shutdown the pump.

C. If the above protective measures fail, the high torque produced by the motor will cause a slow breakdown of the bearings and not a rapid shaft seizure. Industry experience indicates that the babbitt bearing surfaces wear away and the bearing pads and sleeves will be badly worn but the shaft will continue to rotate.

If the extremely remote possibility of bearing seizure occurs while the reactor coolant pump motor assembly is in operation, adequate flow to the core is available from the other reactor coolant pump motor assemblies as demonstrated by the one pump loss of flow study.

Engineering drawings 01, 02, 03-M-RCP-001, -002 and -003 show a separate oil lift system which is required for start-up of the pump assembly. The oil lift system furnishes high pressure oil to the pump assembly thrust bearings, thereby lifting the rotor and reducing bearing friction during pump start-up. Interlocking devices are furnished which prevent pump start-up until oil lift flow is established. The oil lift system is automatically shutdown when the pump reaches full speed. Since oil lift is not required during normal operation, an oil leak in this system will not cause a bearing failure.

5.4.1.4 Tests and Inspections

The reactor coolant pump pressure boundary is nondestructively inspected as required by ASME Section III for Class 1 components. The pump casing inspections include complete radiography and liquid penetrant or ultrasonic testing. The pump receives a hydrostatic pressure test in the vendor's shop

and with the Reactor Coolant System. Inservice inspection of the pump pressure boundary will be performed during plant life in accordance with ASME Section XI.

The pump assembly is performance tested in the vendor's shop over at least the normal operating range in accordance with the Standards of the Hydraulic Institute. The tests also demonstrate ability of the pumps to function under the various operating conditions specified. Tests commonly performed are hot and cold performance and stop-start cycling. Special testing will also be performed on one pump. Such testing will include loss of cooling and/or seal injection water. Vibrations are monitored at several places on the pump during shop testing.

In addition to meeting an absolute criterion for vibration amplitude, the test results are examined for evidence of critical speed problems.

The pump motors undergo a "routine" test in accordance with NEMA MG-1. This test also confirms that the motors are within their vibration limits. At least one motor is tested by being used as the driver for the pump assemblies, during the pump manufacturer's shop testing.

The following testing may also be performed where significant seal experience is lacking to develop confidence in the sealing system.

Seal materials testing for suitability in reactor coolant environment.

Long term testing of an entire seal assembly.

To the greatest extent practicable, all conditions of operation within the reactor coolant pump will be duplicated.

Reactor coolant pump flywheel inspections and testing are described in Section 5.4.1.1.

The reactor coolant pump anti-reverse rotation device is tested in the motor vendor's shop by reversing the power leads to the motor and applying power at rated voltage. This test subjects the anti-reverse rotation device to maximum motor starting torque and duplicates what would occur if the power leads were accidentally reversed in the plant.

In response to an RCP shaft cracking issue, the original shafts have been replaced. A vibration monitoring system has been installed such that the RCPs are continuously monitored using a Programmable Logic Controller (PLC) type with solid state I/O modules for vibration monitoring system. The system monitors the critical vibration related to parameters, such as overall vibration, synchronous 1XRPM and 2XRPM amplitude, and phase angle.

The PLC have setpoints, which sound an alarm and flash an alarm window in the control room. In addition to the alarm, a computer system is installed which provides the Man-Machine-Interface (MMI) and performs the data acquisition and trending for further vibration analysis and evaluation.

5.4.2 STEAM GENERATORS

5.4.2.1 Design Bases

The steam generators are designed to transfer 4013 MWt from the RCS to the secondary system, producing approximately 18.0 x 10^6

lb/h of 1030 psia saturated steam, when provided with 450F feedwater. Moisture content of the steam for steam generators is limited to less 0.1%. The steam generator design parameters are listed in Table 5.4.2-1. The steam generators, including the tubes, are designed for the RCS transients listed in Section 3.9.1 so that the code allowable stress limits are not exceeded for the specified number of cycles. All transients have been established based on conservative assumptions of operating conditions in consideration of supportive system design capabilities. The steam generators are capable of sustaining the following additional design transients without exceeding code allowable stress limits:

A. Ten secondary side hydrostatic tests with secondary side pressurized to 1-1/4 times the design pressure and the primary side pressurized so that the tube differential pressure does not exceed 820 psid (test condition);

B. Two hundred secondary side leak tests with the secondary side pressurized from 820 psia to design pressure, with the primary side pressurized so that tube differential pressure (secondary to primary) does not exceed 820 psid (test condition);

C. Fifteen thousand cycles of adding 40F feedwater at 875 gpm to the steam generator through the downcomer feedwater nozzle when at hot standby conditions (normal condition);

D. Five hundred cycles of adding 40F feedwater at 875 gpm to the steam generator through the downcomer feedwater nozzle during loading conditions (normal condition);

E. Five hundred cycles of adding 100F feedwater at 875 gpm to the steam generator through the downcomer feedwater nozzle during loading conditions (normal condition);

F. Seven cycles of adding 40F feedwater at 1750 gpm to the steam generator through the downcomer feedwater nozzles during a steam line break. This provides for one steam line break incident with the auxiliary feedwater cycled to a maximum of seven times (faulted condition);

G. Two hundred and eighty cycles of adding 40F feedwater at 1750 gpm to the steam generator through the downcomer feedwater nozzles with the flow initiated 30 seconds after a loss of normal feedwater. This provides for 40 loss of normal feedwater incidents with the auxiliary feedwater cycled at a maximum of seven times (upset condition);

H. Four thousand pressure transients of 85 psi across the primary divider plate in either direction caused by starting and stopping reactor coolant pumps (normal condition).

The steam generator are designed to ensure that critical vibration frequencies are well out of the range expected during normal operation and during abnormal conditions. The tubing and tubing supports are designed and fabricated with considerations given to both secondary side flow induced vibration and reactor coolant pump induced vibrations. In addition, the steam generator assemblies are designed to withstand the blowdown forces resulting from the severance of a steam nozzle. The steam generator assemblies are also designed to withstand the severance of any one of the feedwater nozzles. The two accidents are not considered simultaneously.

The steam generator tubes are ¾” OD with 0.042-inch nominal wall thickness and are constructed of thermally treated Inconel 690 alloy.

A steam generator tube rupture incident is a penetration of the barrier between the reactor coolant system and the main steam system. The integrity of this barrier is significant from the standpoint of radiological safety in that a leaking steam generator tube allows the transfer of reactor coolant into the main steam system. Radioactivity contained in the reactor coolant would mix with water in the shell side of the affected steam generator. This radioactivity would be transported by steam to the turbine and then to the condenser, or directly to the condenser via the Turbine Bypass System. Noncondensable radioactive gases in the condenser are removed by the main condenser's evacuation system and discharged to the plant ventilation system.

Experience with nuclear steam generators indicates that the probability of complete severance of a tube is remote. A double-ended rupture has never occurred in a steam generator of this design. The more probable modes of failure, which result in smaller penetrations, are those involving the occurrence of pinholes or small cracks in the tubes, and of cracks in the seal welds between the tubes and tube sheet. Detection and control of steam generator tube leakage is described in Section 5.2.

The concentration of radioactivity in the secondary side of the steam generators is dependent upon the concentration of the radionuclides in the reactor coolant, the primary-to-secondary

leak rate, and the rate of steam generator blowdown. The expected specific activities in the secondary side of the steam generators during periods of normal operation are given in Section 11.2.

The recirculation water within the steam generators will contain volatile additives necessary for proper chemistry control. These and other chemistry considerations of the main steam system are discussed in Section 10.3.5.

Table 5.4.2-1
STEAM GENERATORS DESIGN PARAMETERS[(a)]

Parameter	Value
Number of Units	2
Heat transfer rate, each, Btu/h	6.848×10^9
Primary Side	
Design pressure/temperature (lb. in.^{2}g/°F	2485/650
Coolant inlet temperature, °F	618.8
Coolant outlet temperature, °F	560.4
Coolant flow rate, each, lb/h	84.43×10^6
Coolant volume at 68F each, ft^3	2947
Tube size, OD, in.	¾
Tube thickness, nominal, in.	0.042
Secondary Side	
Design pressure/temperature (lb in. ^{2}a/°F	1270/575
Steam pressure, lb/in.^{2}a	1030
Steam flowrate (at 0.1% moisture) each nozzle, lb/h	4.5×10^6
Feedwater temperature at full power, °F	450
Moisture carryover, weight maximum, %	0.1
Primary inlet nozzle, No/ID, in.	1/42
Primary outlet nozzle, No/ID, in.	2/30
Steam nozzle, No./ID, in.	2/28
Feedwater nozzles, No./size/schedule (Economizer)	2/1480
Feedwater nozzles, No./size/schedule (Downcomer)	1/6/80
Overall heat transfer coefficient (estimated), Btu/h-Ft^2-°F	1238

(a) Unit 2 values are shown and are representative for all three PVNGS Units. Unit specific differences are minor.

5.4.2.2 Description

The steam generators are illustrated in Figure 5.4-8. Moisture-separating equipment in the shell side of the steam generators limits moisture content of the exit steam. Manways and handholes are provided for access to the steam generator internals. Reactor coolant enters at the bottom of each steam generator through the single inlet nozzle, flows through the U-tubes, and leaves through the two outlet nozzles. A vertical divider plate separates the inlet and outlet plenums in the lower head. The steam generator with integral economizer is in most respects similar to earlier U-tube recirculating steam generators. The basic difference is that instead of introducing feedwater only through a sparger ring to mix with the recirculating water flow in the downcomer channel, feedwater is also introduced into a separate, but integral section of the steam generator. A semi-cylindrical section of the tube bundle, at the cold leg or exit end of the U-tubes, is separated from the remainder of the tube bundle by vertical divider plates. Feedwater is introduced directly into this section and pre-heated before discharge into the evaporator section.

The lower portion of the evaporator section and the downcomer channel occupy only one-half of the steam generator cross-section. The effect of this non-symmetry is considered in calculation of recirculation ratio, internal flow considerations, and in design of tube support structures.

The steam-water mixture leaving the vertical U-tube heat transfer surface enters the separators which impart a

centrifugal motion to the mixture and separate the water particles from the steam. The water exits from the perforated separator housing and recirculates through the downcomer channel to repeat the cycle. Final drying of the steam is accomplished by passage of the steam through Peerless Hook-vane type dryers.

The pressure drop from the steam generator feedwater nozzles to the steam outlet nozzle including the economizer is approximately 41 psi. The steam generators include design enhancement features to improve blowdown system performance. A six inch nozzle is provided in the hot side downcomer region. This makes it possible to take recirculating water not only at the tubesheet level, but also from the downcomer.

Features to enhance wet layup recirculation chemistry control during outages are also provided. A nozzle is provided in the upper shell and is connected to a distribution ring located inside the shroud above the tube bundle.

The steam generator supports are described in Section 5.4.14.

5.4.2.3 Economizer Integrity

The economizer section is designed in full consideration of operating transients, startup and standby operation, and accident conditions such as loss of feedwater flow and feedwater line break. The structural design of the various parts is adequate to withstand the thermal and pressure loadings from these various conditions, consistent with the appropriate load classifications and design rules in the ASME Code, Section III, see Appendix G.

The components of the steam generator economizer section have been designed for the primary stresses which occur due to the blowdown associated with a feedline break. The divider plates, which separate the economizer region from the evaporator region of the secondary side, are supported from the vessel shell and the central cylindrical support welded to the tubesheet. This divider cylinder becomes an extension of the primary tubesheet stay cylinder, though less massive, and extends the full height of the economizer. The tube support/flow baffle plates are supported from the vessel shell, the divider cylinder and the tubesheet via an array of support rods. The support rods, which also serve as support plate spacers are solid and designed for either tensile or buckling loads. An effort has been made to avoid the use of thin plates which may collapse when subjected to differential pressure.

5.4.2.4 Steam Generator Materials

The pressure boundary materials used in the construction of the steam generator are listed in the Fracture Toughness tables. These materials are in accordance with the ASME Boiler and Pressure Vessel Code, Section III. Code cases used in the fabrication of the steam generator are discussed in Section 5.2.1.

The Class 1 components of the steam generator will meet the fracture toughness requirements of the ASME code. An additional discussion of fracture toughness testing is included in Section 5.2.3.

Discussion of the techniques used to maintain cleanliness during final assembly and shipment are discussed in Section 5.2.3.

5.4.2.4.1 Steam Generator Tubes

The method of fastening tubes to the tube sheet conforms with the requirements of Section III and IX of the ASME Code. Tube expansion into the tube sheet is total with no voids or crevices occurring along the length of the tube in the tube sheet.

Localized corrosion of tubing material has led to steam generator tube leakage in some operating reactor plants. Examination of tube defects that have resulted in leakage has shown that two mechanisms are primarily responsible. These localized corrosion mechanisms are referred to as (1) stress assisted caustic cracking, and (2) wastage or beavering. Both of these types of corrosion have been related to steam generators that have operated on phosphate chemistry. The caustic stress corrosion type of failure is precluded by controlling bulk water chemistry to the specification limits shown in Section 10.3.5. Removal of solids from the secondary side of the steam generator is discussed in Section 10.4.8.

Localized wastage or beavering has been eliminated by removing phosphates from the chemistry control program.

Volatile chemistry (discussed in Section 10.3.5) has been successfully used in all C-E steam generators that have gone into operation since 1972.

Fracture toughness data for the primary side of steam generators 1 and 2 for Palo Verde Units 1, 2, and 3 are presented in paragraph 5.2.3.3.1.

Fracture toughness data for the secondary side of steam generators 1 and 2 are presented for Palo Verde Unit 1 in tables 5.4-1 to 5.4-12, for Unit 2 in tables 5.4-13 to 5.4-24, and for Unit 3 in tables 5.4-25 to 5.4-36.

Onsite cleaning and cleanliness control for the steam generators is in accordance with the recommendations of ANSI Standard N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants, and Regulatory Guide 1.37 as discussed in section 1.8.

5.4.2.5 Tests and Inspections

Prior to, during and after fabrication of the steam generator, nondestructive tests based upon Section III of the ASME Code are performed.

Initial hydrostatic tests of the primary and secondary sides of the steam generator were conducted in accordance with ASME Code, Section III. Following satisfactory performance of the hydrostatic tests, magnetic-particle inspections are made on all accessible welds.

Inservice inspection of the steam generator is described in Section 5.2.4.

Table 5.4-1
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE (PLATES)

Position	Reference Drawing Number	Material Specification	Location In Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F)[(a)]
19	PX-DWD-00-062	SA-533Gr B Cl 2	Intermediate Shell	-17	-17
23	PX-DWD-00-062	SA-533 Gr B Cl 1	Upper Shell	-8	-8
29	PX-DWD-00-062	SA-533 Gr B Cl 1	Top Head Torus	-35	-35
33	PX-DWD-00-062	SA-533 Gr B Cl 2	Lower Shell	-26	-26
34	PX-DWD-00-062	SA-533 Gr B Cl 1	Top Head Dome	-26	-26
41-2	PX-DWD-15-081	SA-533 Gr B Cl 1	Secondary Manway Cover Plate	-39	-39
43-2	PX-DWD-15-081	SA-533 Gr B Cl 1	Handhole Cover Plate	-39	-39
78-2	PX-DWD-15-081	SA-533 Gr B Cl 1	Flow Blocker Cover Plate	-39	-39
81	PX-DWD-23-071	SA-516 Gr 70	Upper Support Ring	-40	-40
85	PX-DWD-23-071	SA-516 Gr 70	Lower Support Ring	-40	-40
87	PX-DWD-23-072	SA-516 Gr 70	Divider Support Bar	-35	-35
108	PX-DWD-24-066	SA-516 Gr 70	Shroud Lateral Support	-45	-45

a. ASME B&PV Code, Section III, Article NB 2331-A-1, 2, 3

b. Not required as per ASME III NB 2311-6 and 7

Table 5.4-2
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE (FORGINGS)

Position	Reference Drawing Number	Material Specification	Location In Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F)[(a)]
12	PX-DWD-11-051	SA-508 Class 3a	Tubesheet	-50	-50
13	PX-DWD-11-051	DELETED	Tubesheet Drain Nozzle	-	-
14	PX-DWD-11-051	SA-336 Class F12	Tubesheet Blowdown Nozzle	-40	-40
15	PX-DWD-00-062	SA-508 Class 3a	Stub Barrel	-47	-47
16	PX-DWD-11-055	SA-508 Class 3a	Feedwater Nozzle	-20	-20
17	PX-DWD-11-055	SA-508 Class 1a	Feedwater Safe-End	-26	-26
18	PX-DWD-00-054	SA-508 Class 1a	Lower Shell Level Nozzle	-26	-26
20	PX-DWD-00-062	SA-508 Class 3a	Shell Cone	-30	-30
21	PX-DWD-12-068	SA-336 Class F12	Downcomer Blowdown Nozzle	+1	+1
22	PX-DWD-00-054	SA-508 Class 1a	Shell Cone Level Nozzle	-26	-26
24	PX-DWD-13-058	SA-508 Class 3	Recirculation Nozzle	-35	-35
25	PX-DWD-13-058	SA-508 Class 1a	Recirculation Nozzle Safe-End	-8	-8
26	PX-DWD-12-057	SA-508 Class 3a	Downcomer Feedwater Nozzle	-35	-35
28	PX-DWD-00-054	SA-508 Class 1a	Upper Shell Level Nozzle	-26	-26
30-1	PX-DWD-13-059	SA-508 Class 1a	Steam Outlet Nozzle	-8	-8
30-2	PX-DWD-13-059	SA-508 Class 1a	Pressure Tap Nozzle	-26	-26
31	PX-DWD-00-054	SA-508 Class 1a	Pressure Test Nozzle	-26	-26
36-1	PX-DWD-00-054	SA-508 Class 1a	Sampling Nozzle	-26	-26
37	PX-DWD-12-057	SA-508 Class 1a	Downcomber FW Nozzle Transition Piece	-8	-8
41-1	PX-DWD-15-081	SA-508 Class 3	Secondary Manway Nozzle	-26	-26
43-1	PX-DWD-11-056	SA-508 Cl.3a (Integral with stub barrel)	Handhole	-47	-47
44-1	PX-DWD-11-056	SA-508 Cl.3a (Integral with stub barrel)	Handhole	-47	-47
70-1	PX-DWD-11-056	SA-508 Cl.3a	Handhole	-35	-35
72	PX-DWD-00-067	SA-508 Class 3	Snubber Lug	-17	-17
78-1	PX-DWD-11-056	SA-508 Cl.3a (Integral with stub barrel)	Handhole	-47	-47
107-1	PX-DWD-11-056	SA-508 Class 3a	Handhole	-35	-35

a. ASME B&PV Code, Section III, Article NB 2331-A-1, 2, 3
b. Not required as per ASME III NB 2311-6 and 7

Table 5.4-2A
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE (BARS AND TUBES)

Position	Reference Drawing Number	Material Specification	Location In Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F) [(a)]
44-2	PX-DWD-23-074	SA-106 Gr B	Sleeve	N.R.	N.R.
70-2	PX-DWD-12-092	SA-106 Gr B	Sleeve	N.R.	N.R.

a. ASME B&PV Code, Section III, Article NB-2331-A-1, 2, 3

Table 5.4-3A
UNIT 2 STEAM GENERATOR SECONDARY SIDE WELD SEAMS IDENTIFICATION
STEAM GENERATORS 1 AND 2 (Sheet 1 OF 2)

Seam No.	Weld Seam Nomenclature
CW115	Lower shell course to tubesheet girth seam
CW203	Lower shell course to intermediate shell course girth seam
CW221	Lug to shell cone
CW224	Downcomer feedwater nozzle to downcomer feedwater nozzle thermal liner
CW303	Top head dome to top head torus girth seam
CW317	Recirculation nozzle safe end to recirculation nozzle thermal liner
LW108	Lower shell long seam
LW201	Intermediate shell long seam
LW202	Intermediate shell long seam
LW207	Shell cone segment long seam
LW208	Shell cone segment long seam
LW209 LW311	Shell cone segment long seam Top head torus assembly welds
FN110	Feedwater nozzle to lower shell course
FN111	Feedwater nozzle to safe end
NZ105	Bottom blowdown nozzle to lower shell course
NZ114	Tubesheet drain nozzle to buildup
NZ204	Hand hole to lower shell
NZ205	Hand hole to intermediate shell
NZ210	Lower shell level nozzle to lower shell
NZ211	Downcomer feedwater nozzle to shell cone

Table 5.4-3A
UNIT 2 STEAM GENERATOR SECONDARY SIDE WELD SEAMS IDENTIFICATION
STEAM GENERATORS 1 AND 2 (Sheet 2 OF 2)

Seam No.	Weld Seam Nomenclature
NZ212	Shell cone level nozzle to shell cone
NZ213	Sampling nozzle to shell cone
NZ214	Recirculation nozzle to upper shell course
NZ216	Downcomer feedwater nozzle to downcomer feedwater nozzle transition piece
NZ305	Recirculation nozzle to upper shell
NZ306	Upper shell level nozzle to upper shell
NZ307	Secondary manways to upper shell
NZ308	Steam outlet nozzle to top head dome
NZ313	Recirculation nozzle to recirculation nozzle safe end
BT104	Tubesheet drain nozzle buildup to tubesheet
BT109	Hand hole to lower shell course buildup

TABLE 5.4-3B
PVNGS UNIT 1 STEAM GENERATOR SECONDARY SIDE WELD SEAMS IDENTIFICATION STEAM GENERATORS 1 AND 2

Seam No.	Weld Seam Nomenclature
CW 115	Stub Barrel Forging to Tubesheet girth seam
CW 203	Intermediate Shell course to Lower Shell course girth seam
CW 206	Shell cone forging to Intermediate Shell course girth seam
CW 221	Lug to Shell Cone
CW 302	Top Head Torus to Upper Shell course girth seam
CW 303	Tope Head Dome to Top Head Torus girth seam
CW 902	Lower Shell course to Stub Barrel girth seam
CW 903	Upper Shell course to Shell Cone forging girth seam
IB 223	Downcomer FW Nozzle Safe-End Buttering
LW 201	Intermediate Shell long seam
LW 202	Lower Shell long seam
LW 301	Upper Shell long seam
LW 311	Top Head Torus assembly welds
LW 321	Upper Shell long seam
NZ 204	Lower Shell Handhole to Lower Shell
NZ 205	Intermediate Shell Handhole to Intermediate Shell
NZ 210	Lower Shell Level Nozzles to Lower Shell
NZ 211	Downcomer Feedwater Nozzle to Shell Cone
NZ 212	Shell Cone Level Nozzles to Shell Cone
NZ 213	Sampling Nozzle to Shell Cone
NZ 214	Downcomer Blowdown Nozzle to Lower Shell
NZ 216	Downcomer FW Nozzle Safe-End to Downcomer FW Nozzle
NZ 305	Recirculation Nozzle to Upper Shell
NZ 306	Upper Shell Level Nozzles to Upper Shell
NZ 307	Secondary Manways to Upper Shell
NZ 308	Steam Outlet Nozzle to Top Head Dome
NZ 309	Pressure Test Nozzle to Top Head Dome
NZ 313	Recirculation Nozzle Safe-End to Recirculation Nozzle
NZ 323	Pressure Tap Nozzle to Steam Outlet Nozzle
FN 110	Economizer FW Nozzle Transition Piece to Stub Barrel
FN 111	Economizer FW Nozzle Safe-End to Economizer FW Nozzle Transition Piece
NZ 114	Tubesheet Blowdown Nozzle to Tubesheet

Table 5.4-4
PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: STEAM GENERATOR No. 1 SECONDARY SIDE (Sheet 1 of 2)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	Drop Weight T_{NDT} (°F)[b]	RT_{NDT} (°F)[b]
FN 110	SFA 5.5 E9018-G	6220179	-50	-50
FN 110	SFA 5.5 E9018-G	1103838	-50	-50
FN 111	SFA 5.5 E9018-G	1103838	-50	-50
CW 115	SFA 5.5 E9018-G	1103838	-50	-50
CW 115	SFA 5.23 EF3N mod.	273046	-60	-60
CW 115	SFA 5.23 EF3N mod.	140596	-55	-55
NZ 210	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 210	SFA 5.5 E9018-G	6220179	-50	-50
NZ 211	SFA 5.5 E9018-G	1103838	-50	-50
NZ 211	SFA 5.5 E9018-G	101847	-65	-65
NZ 211	SFA 5.23 EF3N mod.	140596	-55	-55
NZ 211	SFA 5.5 E9018-G	6220179	-50	-50
NZ 212	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 212	SFA 5.5 E9018-G	701896	-65	-65
NZ 212	SFA 5.5 E9018-G	6220179	-50	-50
NZ 213	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 213	SFA 5.5 E9018-G	701896	-65	-65
NZ 213	SFA 5.5 E9018-G	6220179	-50	-50
NZ 214	SFA 5.5 E9018-G	1103838	-50	-50
NZ 214	SFA 5.5 E9018-G	101847	-65	-65
NZ 214	SFA 5.23 EF3N mod.	140596	-55	-55
NZ 216	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 216	SFA 5.5 E9018-G	6220179	-50	-50
NZ 216	SFA 5.5 E9018-G	1103838	-50	-50
CW 221	SFA 5.5 E9018-G	1103838	-50	-50
CW 221	SFA 5.5 E9018-G	6220179	-50	-50
CW 221	SFA 5.23 EF3N mod.	140596	-55	-55
IB 223	SFA 5.11 ENiCrFe-7	85019	(c)	(c)
LW 301	SFA 5.5 E9018-G	1103838	-50	-50
LW 301	SFA 5.5 E9018-G	101847	-65	-65
LW 301	SFA 5.5 E9018-G	6220179	-50	-50
LW 301	SFA 5.23 EG	PG 312233720	-55	-55
LW 301	SFA 5.5 E9018-G	3134001	-65	-65
LW 311	SFA 5.5 E9018-G	6220179	-50	-50

Table 5.4-4
PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: STEAM GENERATOR No. 1 SECONDARY SIDE (Sheet 2 of 2)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	Drop Weight T_{NDT} (°F) [b]	RT_{NDT}(°F) [b]
LW 311	SFA 5.5 E9018-G	3134001	-65	-65
LW 321	SFA 5.5 E9018-G	101847	-65	-65
LW 321	SFA 5.23 EG	PG 312233720	-55	-55

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

c. Not required as per ASME NB 2431 (c)

Table 5.4-5
PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE (Sheet 1 of 2)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness					
				HAZ1		Weld		HAZ2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
CW 106	1698/E	SA 508 Cl.3a	SA-508 Cl. 1a	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 115/1	1466/E + 1627/E+Int	SA 508 Cl,3a	SA-508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
FN 110	1627/E+Int+1466/E	SA 508 Gr. B Cl.3a	SA-508 Cl. 3a	N.A.	N.A.	-49	49	N.A.	N.A.
FN 111	1698/E	SA 508 Cl. 3a	SA-508 Cl. 1a	N.A.	N.A.	-58	-58	N.A.	N.A.
SF 112	1627/E+Int+1466/E	SA 508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 113	1698/E	SA 508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 114	1507/E	SFA 5.11 ENiCrFe-7	SFA 5.11 ENiCrFe-7	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
CW 115	1627/E+Int+1814	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
SF 116	1627/E+Int+1466/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 123	1698/E	SA 508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-76	-76	N.A.	N.A.
SW 113	1698/E	SA 508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-76	-76	N.A.	N.A.
LW 201	1627/E+Int.	SA 533 Gr. B Cl. 2	SA 533 Gr. B Cl. 2	N.A.	N.A.	-49	-49	N.A.	N.A.
LW 202	1627/E+Int.	SA 533 Gr. B Cl. 2	SA 533 Gr. B Cl. 2	N.A.	N.A.	-49	-49	N.A.	N.A.
CW 203	1466/E & 1627/E+Int.	SA 533 Gr. B Cl. 2	SA 533 Gr. B Cl. 2	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 204	1627/E+Int.	SA 533 Gr. B Cl. 2	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 205	1627/E+Int.	SA 533 Gr. B Cl. 2	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
CW 206	1466/E&1627/E+Int.+1829	SA 533 Gr. B Cl. 2	SA-508 Cl. 3a	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 210	1698/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 2	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 211	1627/E+Int.	SA 508 Cl. 3a	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 212	1698/E	SA 508 Cl. 1a	SA-508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 213	1698/E	SA 508 Cl. 1a	SA-508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 214	1753/G	SA 366 Cl. F12	SA 533 Gr. B Cl. 2	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 216	1698/E	SA 508 Cl. 1a	SA-508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 221	1627/E+Int.	SA 508 Cl. 3a	SA-508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
IB 223	1052/E	SA 508 Cl. 1a	Inconel 600 UNS W86182	N.A.	N.A.	N.R.(A)	N.R.(A)	N.A.	N.A.

Table 5.4-5
PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA
REPLACEMENT STEAM GENERATOR 1 SECONDARY SIDE (Sheet 2 of 2)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness					
				HAZ1		Weld		HAZ2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
LW 301	1627/E+Int.+1426/E+1829	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 303	1627/E+Int.+1829	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 305	1627/E+Int.+1829	SA 508 Cl.3	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 306	1698/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 307	1627/E+Int.+1829	SA 508 Cl. 3	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 308	1698/E - 1627/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 309	1698/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
LW 311	1627/E+Int.+1829	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
LW 321	1627/E+Int.	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 323	1664/E	SA 508 Cl. 1a	SA 508 Cl. 1a	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 324	1698/E	SA 516 Gr. 70	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 325	1698/E	SA 516 Gr. 70	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 302	1627/E+Int.+1829	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.

a. As per ASME Section III NB 2430

TABLE 5.4-5A
PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SENCODARY SIDE (SHEET 1 of 2)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness					
				HAZ1		Weld		HAZ2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
CW 106	1698/E	SA 508 Cl. 3a	SA 508 Cl. 1a	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 115/1	1466/E + 1627/E+Int.	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
FN 110	1627/E+Int.+1466/E	SA 508 Gr. B Cl.3a	SA 508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
FN 111	1698/E	SA 508 Cl. 3a	SA 508 Cl. 1a	N.A.	N.A.	-58	-58	N.A.	N.A.
SF 112	1627/E+Int.+ 1466/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 113	1698/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 114	1507/E	SFA 5.11 ENiCrFe-7	SFA 5.11 ENiCrFe-7	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
CW 115	1627/E+Int.+1814	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
SF 116	1627/E+Int + 1466/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 123	1698/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-76	-76	N.A.	N.A.
SW 113	1698/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-76	-76	N.A.	N.A.
LW 201	1627/E+Int.	SA 533 Gr. B Cl. 2	SA 533 Gr. B Cl. 2	N.A.	N.A.	-49	-49	N.A.	N.A.
LW 202	1627/E+Int.	SA 533 Gr. B Cl. 2	SA 533 Gr. B Cl. 2	N.A.	N.A.	-49	-49	N.A.	N.A.
CW 203	1466/E & 1627/E+Int.	SA 533 Gr. B Cl. 2	SA 533 Gr. B Cl. 2	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 204	1627/E+Int.	SA 533 Gr. B Cl. 2	SA 508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 205	1627/E+Int.	SA 533 Gr. B Cl. 2	SA 508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
CW 206	1466/E & 1627/E+Int.+1829	SA 533 Gr. B Cl. 2	SA 508 Cl. 3a	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 210	1698/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 2	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 211	1627/E+Int.	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 212	1698/E	SA 508 Cl. 1a	SA 508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 213	1698/E	SA 508 Cl. 1a	SA 508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 214	1753/G	SA 366 Cl. F12	SA 533 Gr. B Cl. 2	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 216	1698/E	SA 508 Cl. 1a	SA 508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 221	1627/E+Int.	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
IB 223	1052/E	SA 508 Cl. 1a	Inconel 600 UNS W86182	N.A.	N.A.	N.R.[a]	N.R.[a]	N.A.	N.A.

TABLE 5.4-5A
PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SENCODARY SIDE (SHEET 2 of 2)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness					
				HAZ1		Weld		HAZ2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
LW 301	1627/E+Int.+1426/E+1829	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 303	1627/E+Int.+1829	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 305	1627/E+Int.+1829	SA 508 Cl. 3	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 306	1698/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 307	1627/E+Int.+1829	SA 508 Cl. 3	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 308	1698/E - 1627/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 309	1698/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
LW 311	1627/E+Int.+1829	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 313	1698/E	SA 508 Cl. 3	SA 508 Cl. 1a	N.A.	N.A.	-31	-31	N.A.	N.A.
LW 321	1627/E+Int.	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 323	1664/E	SA 508 Cl. 1a	SA 508 Cl. 1a	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 324	1698/E	SA 516 Gr. 70	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 325	1698/E	SA 516 Gr. 70	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 302	1627E+Int.+1829	SA 533 Gr. B Cl. 2	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.

a. As per ASME Section III NB 2430

Table 5.4-6
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (PLATES)

Position	Reference Drawing Number	Material Specification	Location in Component	Drop Weight T_{NDT}(°F)	RT_{NDT} (°F)[(a)]
19	PX-DWD-00-062	SA 533 Gr. B Cl. 2	Intermediate Shell	-17	-17
23	PX-DWD-00-062	SA 533 Gr. B Cl. 1	Upper Shell	-8	-8
29	PX-DWD-00-062	SA 533 Gr. B Cl. 1	Top Head Torus	-44	-44
33	PX-DWD-00-062	SA 533 Gr. B Cl. 2	Lower Shell	-26	-26
34	PX-DWD-00-062	SA 533 Gr. B Cl. 1	Top Head Dome	-26	-26
41-2	PX-DWD-15-081	SA 533 Gr. B Cl. 1	Secondary Manway Cover Plate	-39	-39
43-2	PX-DWD-15-081	SA 533 Gr. B Cl. 1	Handhole Cover Plate	-39	-39
78-2	PX-DWD-15-081	SA 533 Gr. B Cl. 1	Flow Blocker Cover Plate	-39	-39
81	PX-DWD-23-071	SA 516 Gr. 70	Upper Support Ring	-40	-40
85	PX-DWD-23-071	SA 516 Gr. 70	Lower Support Ring	-40	-40
87	PX-DWD-23-072	SA 516 Gr. 70	Divider Support Bar	-34	-34
108	PX-DWD-24-066	SA 516 Gr. 70	Shroud Lateral Support	-45	-45

a. ASME B&PV Code, Section III, Article NB 2331-A-1, 2, 3

b. Not required as per ASME III NB 2311-6 and 7

Table 5.4-7
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (FORGINGS)

Position	Reference Drawing Number	Material Specification	Location in Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F)[a]
12	PX-DWD-11-051	SA 508 Class 3a	Tubesheet	-50	-50
13	PX-DWD-11-051	DELETED	Tubesheet Drain Nozzle	-	-
14	PX-DWD-11-051	SA 336 Class F12	Tubesheet Blowndown Nozzle	-40	-40
15	PX-DWD-00-062	SA 508 Class 3a	Stub Barrel	-47	-47
16	PX-DWD-11-055	SA 508 Class 3a	Feedwater Nozzle	-47	-38
17	PX-DWD-11-055	SA 508 Class 1a	Feedwater Safe-End	-26	-26
18	PX-DWD-00-054	SA 508 Class 1a	Lower Shell Level Nozzle	-26	-26
20	PX-DWD-00-062	SA 508 Class 3a	Shell Cone	-30	-30
21	PX-DWD-12-068	SA 336 Class F12	Downcomer Blowdown Nozzle	+1	+1
22	PX-DWD-00-054	SA 508 Class 1a	Shell Cone Level Nozzle	-26	-26
24	PX-DWD-13-058	SA 508 Class 3	Recirculation Nozzle	-35	-35
25	PX-DWD-13-058	SA 508 Class 1a	Recirculation Nozzle Safe-End	-8	-8
26	PX-DWD-12-057	SA 508 Class 3a	Downcomer Feedwater Nozzle	-35	-35
28	PX-DWD-00-054	SA 508 Class 1a	Upper Shell Level Nozzle	-26	-26
30-1	PX-DWD-13-059	SA 508 Class 1a	Steam Outlet Nozzle	-8	-8
30-2	PX-DWD-13-059	SA 508 Class 1a	Pressure Tap Nozzle	-26	-26
31	PX-DWD-00-054	SA 508 Class 1a	Pressure Test Nozzle	-26	-26
36-1	PX-DWD-00-054	SA 508 Class 1a	Sampling Nozzle	-26	-26
37	PX-DWD-12-057	SA 508 Class 1a	Downcomer FW Nozzle Transition Piece	-8	-8
41-1	PX-DWD-15-081	SA 508 Class 3	Secondary Manway Nozzle	-17	-17
43-1	PX-DWD-11-056	SA 508 Cl. 3a (integral with stub barrel)	Handhole	-29	-29
44-1	PX-DWD-11-056	SA 508 Cl. 3a (integral with stub barrel)	Handhole	-29	-29
70-1	PX-DWD-11-056	SA 508 Cl. 3a	Handhole	-35	-35
72	PX-DWD-00-067	SA 508 Class 3	Snubber Lug	-17	-17
78-1	PX-DWD-11-056	SA 508 Cl. 3a (integral with stub barrel)	Handhole	-29	-29
107-1	PX-DWD-11-056	SA 508 Class 3a	Handhole	-35	-35

a. ASME B&PV Code, Section III, Article NB-2331-A-1, 2, 3

b. Not required as per ASME III NB 2311-6 and 7

TABLE 5.4-7A
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (BARS AND TUBES)

Position	Reference Drawing Number	Material Specification	Location in Component	Drop Weight T_{NDT}(°F)	RT_{NDT} (°F)[(a)]
44-2	PX-DWD-23-074	SA 106 Gr. B	Sleeve	N.R.	N.R.
70-2	PX-DWD-12-092	SA 106 Gr. B	Sleeve	N.R.	N.R.

a. ASME B&PV Code, Section III, Article NB 2331-A-1, 2, 3

b. Not required as per ASME III NB 2311-6 and 7

Table 5.4-8
PVNGS UNIT 1 WELD METAL CERTIFICATION TESTS[(a)]
STEAM GENERATOR No. 2 SECONDARY SIDE

Component Weld Seam Number	Electrode Code	Electrode Lot Number	Drop Weight T_{NDT} [(b)] (°F)	RT_{NDT} (°F) [(b)]
FN 110	SFA 5.5 E9018-G	6220179	-50	-50
FN 110	SFA 5.5 E9018-G	1103838	-50	-50
FN 111	SFA 5.5 E9018-G	6220179	-50	-50
FN 111	SFA 5.5 E9018-G	1103838	-50	-50
CW 115	SFA 5.5 E9018-G	1103838	-50	-50
CW 115	SFA 5.23 EF3N mod.	273046	-60	-60
CW 115	SFA 5.5 E9018-G	6220179	-50	-50
NZ 210	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 210	SFA 5.5 E9018-G	6220179	-50	-50
NZ 211	SFA 5.5 E9018-G	101847	-65	-65
NZ 211	SFA 5.5 E9018-G	6220179	-50	-50
NZ 211	SFA 5.5 E9018-G	1103838	-50	-50
NZ 211	SFA 5.23 EF3N mod.	140596	-65	-65
NZ 212	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 212	SFA 5.5 E9018-G	6220179	-50	-50
NZ 213	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 213	SFA 5.5 E9018-G	6220179	-50	-50
NZ 214	SFA 5.5 E9018-G	1103838	-50	-50
NZ 214	SFA 5.5 E9018-G	101847	-65	-65
NZ 214	SFA 5.23 EF3N mod.	140596	-85	-65
NZ 216	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 216	SFA 5.5 E9018-G	6220179	-50	-50
NZ 216	SFA 5.5 E9018-G	1103838	-50	-50
CW 221	SFA 5.5 E9018-G	6220179	-50	-50
CW 221	SFA 5.5 E9018-G	1103838	-50	-50
CW 221	SFA 5.23 EF3N mod.	140596	-65	-65
IB 223	SFA 5.11 ENiCrFe-7	85019	N.R.	N.R.
LW 301	SFA 5.5 E9018-G	1103838	-50	-50
LW 301	SFA 5.23 EG	PG 312233720	-55	-55
LW 311	SFA 5.5 E9018-G	3134001	-65	-65
LW 321	SFA 5.5 E9018-G	1103838	-50	-50
LW 321	SFA 5.23 EG	PG 312233720	-55	-55

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

C. Not required as per ASME NB 2431 (c)

TABLE 5.4-8A
PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (SHEET 1 OF 2)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness					
				HAZ1		Weld		HAZ2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
CW 106	1698/E	SA 508 Cl. 3a	SA 508 Cl. 1a	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 115/1	1466/E+1627/E+Int.	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
FN 110	1627/E+Int+1466/E	SA 508 Gr. B Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
FN 111	1698/E	SA 508 Cl. 3a	SA 508 Cl. 1a	N.A.	N.A.	-58	-58	N.A.	N.A.
SF 112	1627/E+Int.+1466/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 113	1698/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 114	1507/E	SFA 5.11 ENiCrFe-7	SFA 5.11 ENiCrFe-7	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
CW 115	1627/E+Int.+1814	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
SF 116	1627/E+Int.+1466/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 123	1698/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-76	-76	N.A.	N.A.
SW 113	1698/E	SA 508 Cl. 3a	SA 516 Gr. 70	N.A.	N.A.	-76	-76	N.A.	N.A.
LW 201	1627/E+Int.	SA 533 Gr. B Cl.2	SA 533 Gr. B Cl.2	N.A.	N.A.	-49	-49	N.A.	N.A.
LW 202	1627/E+Int.	SA 533 Gr. B Cl.2	SA 533 Gr. B Cl.2	N.A.	N.A.	-49	-49	N.A.	N.A.
CW 203	1466/E & 1627/E+Int.	SA 533 Gr. B Cl.2	SA 533 Gr. B Cl.2	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 204	1627/E+Int.	SA 533 Gr. B Cl.2	SA 508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 205	1627/E+Int.	SA 533 Gr. B Cl.2	SA 508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
CW 206	1466/E & 1627/E+Int.+1829	SA 533 Gr. B Cl.2	SA 508 Cl. 3a	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 210	1698/E	SA 508 Cl. 1a	SA 533 Gr. B Cl.2	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 211	1627/E+Int.	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 212	1698/E	SA 508 Cl. 1a	SA 508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 213	1698/E	SA 508 Cl. 1a	SA 508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 214	1753/G	SA 366 Cl. F12	SA 533 Gr. B Cl.2	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 216	1698/E	SA 508 Cl. 1a	SA 508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 221	1627/E+Int.	SA 508 Cl. 3a	SA 508 Cl. 3a	N.A.	N.A.	-49	-49	N.A.	N.A.
IB 223	1052/E	SA 508 Cl. 1a	Inconel 600 UNS W86182	N.A.	N.A.	N.R.[(a)]	N.R.[(a)]	N.A.	N.A.

TABLE 5.4-8A
PVNGS UNIT 1 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (SHEET 2 OF 2)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness					
				HAZ1		Weld		HAZ2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
LW 301	1627/E+Int+1426/E+1829	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 303	1627/E+Int.+1829	SA 533 Gr. B Cl. 1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 305	1627/E+Int.+1829	SA 508 Cl. 3	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 306	1698/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 307	1627/E+Int.+1829	SA 508 Cl. 3	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 308	1698/E - 1627/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 309	1698/E	SA 508 Cl. 1a	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
LW 311	1627/E+Int.+1829	SA 533 Gr. B Cl.1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 313	1698/E	SA 508 Cl. 3	SA 508 Cl. 1a	N.A.	N.A.	-31	-31	N.A.	N.A.
LW 321	1627/E+Int.	SA 533 Gr. B Cl.1	SA 533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 323	1664/E	SA 508 Cl. 1a	SA 508 Cl. 1a	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 324	1698/E	SA 516 Gr. 70	SA 533 Gr. B Cl.1	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 325	1698/E	SA 516 Gr. 70	SA 533 Gr. B Cl.1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 302	1627/E+Int.+1829	SA 533 Gr. B Cl.1	SA 533 Gr. B Cl.1	N.A.	N.A.	-31	-31	N.A.	N.A.

a. As per ASME Section III NB 2430

Table 5.4-9
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE FASTENERS

					TENSILE TEST RESULTS				IMPACT TEST RESULTS			
Piece Number	Reference Drawing Number	ASME Material Specification	Location In Component	Preload Temp. (°F)	YS Mpa (Ksi)	UTS Mpa (ksi)	RA (%)	Elong (%)	Temp. (°F)	Absorbed Energy (Average) J (ft/lbf)	Lateral Expansion (Average) mm (mils)	Sheer (%)
41-3	PX-DWF-15-025	SA 540 Gr. B24 CL 3	Manway Stud	10	991 (142)	1120 (162)	50.6	16.7	10	54,2 (40)	0,6 (23,7)	80
					1009 (146)	1118 (162)	50.2	17	40	63,7 (47)	0,7 (27,7)	80
41-4	PX-DWF-15-025	SA 540 Gr. B24 CL 3	Manway Nut	10	1070 (155)	1165 (169)	48.3	17.4	10	60 (43,5)	0,65 (25,8)	80
					1074 (156)	1170 (169)	49.1	17.8	40	64,8 (50)	0,75 (29,6)	80
43-3	PX-DWF-15-025	SA 193 Gr. B7	Handhole Stud	10	862 (125)	925 (134)	21.7	(a)	(a)	(a)	(a)	(a)
43-4	PX-DWF-15-025	SA 194 Gr. 7	Handhole Nut	10	886 (128)	984 (143)	22.2	(a)	(a)	(a)	(a)	(a)

a. Not required

Table 5.4-10
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE FASTENERS

DELETED

Table 5.4-11
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE FASTENERS

					TENSILE TEST RESULTS				IMPACT TEST RESULTS			
Piece Number	Reference Drawing Number	ASME Material Specification	Location In Component	Preload Temp. (°F)	YS Mpa (Ksi)	UTS Mpa (ksi)	RA (%)	Elong (%)	Temp. (°F)	Absorbed Energy (Average) J (ft/lbf)	Lateral Expansion (Average) mm (mils)	Sheer (%)
41-3	PX-DWF-15-025	SA 540 Gr. B24 CL 3	Manway Stud	10	991 (142)	1120 (162)	50.6	16.7	10	54,2 (40)	0,6 (23,7)	80
					1009 (146)	1118 (162)	50.2	17	40	63,7 (47)	0,7 (27,7)	80
41-4	PX-DWF-15-025	SA 540 Gr. B24 CL 3	Manway Nut	10	1070 (155)	1165 (169)	48.3	17.4	10	60 (43,5)	0,65 (25,8)	80
					1074 (156)	1170 (169)	49.1	17.8	40	67,8 (50)	0,75 (29,6)	80
43-3	PX-DWF-15-025	SA 193 Gr. B7	Handhole Stud	10	862 (125)	925 (134)	21.7	(a)	(a)	(a)	(a)	(a)
43-4	PX-DWF-15-025	SA 194 Gr. 7	Handhole Nut	10	886 (128)	984 (143)	22.2	(a)	(a)	(a)	(a)	(a)

a. Not required

Table 5.4-12
PVNGS UNIT 1 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE FASTENERS

DELETED

Table 5.4-13
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE (PLATES)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	DW_{NDT} (°F)	RT_{NDT} [(a)] (°F)
19	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Intermediate Shell	-47	-47
23	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Upper Shell	+10	+10
29	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Top Head Torus	-31	-31
33	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Lower Shell	-35	-35
34	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Top Head Dome	-31	-31
41-2	PV-DWD-15-ABB081	-	SA-533 Gr. B Cl. 1	Secondary Manway Cover Plate	-29	-29
43-2	PV-DWD-15-ABB081	-	SA-533 Gr. B Cl. 1	Cover Plate	-29	-29
81	PV-DWD-23-ABB071	-	SA-516 Gr. 70	Upper Support Ring	-58	-58
85	PV-DWD-23-ABB071	-	SA-516 Gr. 70	Lower Support Ring	-58	-58
87	PV-DWD-23-ABB072	-	SA-516 Gr. 70	Divider Support Bar	-40	-40
108	PV-DWD-24-ABB066	-	SA-516 Gr. 70	Shroud Lateral Support	-40	-40

a. ASME B&PV Code, Section III, Article NB-2331-A-1, 2, 3

Note 1: Not requested as per ASME III NB 2311-6 and 7.

Table 5.4-14
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE (FORGINGS) (Sheet 1 of 1)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location In Component	DW_{NDT} (°F)	RW_{NDT} (°F)
26	PV-DWD-12-ABB057	-	SA-508 Cl. 3	Downcomer Feedwater Nozzle	-17	-17
28	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Upper Shell Level Nozzle	-35	-26
30-1	PV-DWD-13-ABB059	-	SA-508 Cl. 1a	Steam Outlet Nozzle	-8	-8
30-2	PV-DWD-13-ABB059	-	SA-508 Cl. 1a	Pressure Tap Nozzle	-35	-26
31	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Pressure Test Nozzle	-35	-26
36-1	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Sampling Nozzle	-35	-26
37	PV-DWD-12-ABB057	-	SA-508 Cl. 1a	Downcomer FW Nozzle Transition Piece	-29	-29
41-1	PV-DWD-15-ABB081	-	SA-508 Cl. 3	Secondary Manway Nozzle	-8	-8
51-1	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Snubber Lug Arm	-35	-35
52	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Key Bracket	-8	-8
53	PV-DWD-10-ABB070	-	SB-564	Outlet Clamp Ring	Note 1	Note 1
55	PV-DWD-10-ABB070	-	SB-564	Inlet Clamp Rimg	Note 1	Note 1
71	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Key Bracket	-8	-8
72	PV-DWD-00-ABB067	-	SA-508 Cl. 3	Lug	+10	+10
107-1	PV-DWD-11-ABB056	-	SA-508 Cl. 3	Handhole	-8	-8

a. ASME B&PV Code, Section III, Article NB 2331-A-1, 2, 3

b. ASME B&PV Code, Section III, Article NB 2331-A-4

Note 1: Not requested per ASME III NB 2311-6 and 7.

Table 5.4-14A
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE (BARS & TUBES)

Piece Number	Reference Drawing Number	ASME Material Specification	Location In Component	DW_{NDT} (°F)	RW_{NDT} (°F)
44-2	PV-DWD-23-ABB074	SA-106 Gr. B	Sleeve	Not Required	Not Required
70-2	PV-DWD-23-ABB092	SA-106 Gr. B	Sleeve	Not Required	Not Required

a. ASME B&PV Code, Section III, Article NB 2331-A-1, 2, 3

Note 1: Not requested per ASME III NB 2311-6 and 7.

Table 5.4-15
PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: STEAM GENERATOR 1 SECONDARY SIDE (Sheet 1 of 3)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
LW 108	SFA 5.5 E9018-G	705350	-58	-58
LW 108	SFA 5.23 EF3N mod.	913872	-49	-49
FN 110	SFA 5.5 E9018-G	805867	-58	-58
FN 110	SFA 5.5 E9018-G	900630	-60	-60
FN 110	SFA 5.23 EF3N mod.	913872	-49	-49
FN 110	SFA 5.23 EF3N mod.	140596	-55	-55
FN 111	SFA 5.5 E9018-G	0476. 01	-85	-85
FN 111	SFA 5.5 E9018-G	805867	-58	-58
CW 115	SFA 5.5 E9018-G	900630	-76	-76
CW 115	SFA 5.5 E9018-G	805867	-58	-58
CW 115	SFA 5.5 E9018-G	900262	-85	-85
CW 115	SFA 5.23 EF3N mod.	140596	-55	-55
LW 209	SFA 5.23 EF3N mod.	140596	-67	-67
LW 209	SFA 5.5 E9018-G	900630	-76	-76
LW 209	SFA 5.23 EF3N mod.	913872	-49	-49
LW 210	SFA 5.28 ER 80S-G	718288	Note 1	Note 1

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

Note 1: Not requested as per ASME NB 2431 (c).

Table 5.4-15
PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: STEAM GENERATOR 1 SECONDARY SIDE (Sheet 2 of 3)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
LW 210	SFA 5.5 E9018-G	0476. 01	-85	-85
LW 210	SFA 5.5 E9018-G	900262	-85	-85
NZ 211	SFA 5.5 E9018-G	900630	-76	-76
NZ 211	SFA 5.5 E9018-G	900262	-85	-85
NZ 211	SFA 5.5 E9018-G	805867	-58	-58
NZ 211	SFA 5.23 EF3N mod.	140596	-67	-67
NZ 212	SFA 5.28 ER 80S-G	718288	Note 1	Note 1
NZ 212	SFA 5.5 E9018-G	0476. 01	-85	-85
NZ 212	SFA 5.5 E9018-G	900262	-85	-85
NZ 212	SFA 5.5 E9018-G	900630	-76	-76
NZ 212	SFA 5.5 E9018-G	6219509	-35	-35
NZ 213	SFA 5.28 ER 80S-G	718288	Note 1	Note 1
NZ 213	SFA 5.5 E9018-G	0476. 01	-85	-85
NZ 213	SFA 5.5 E9018-G	900262	-85	-85
NZ 213	SFA 5.5 E9018-G	6219509	-35	-35
NZ 213	SFA 5.5 E9018-G	900630	-76	

Table 5.4-15
PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: STEAM GENERATOR 1 SECONDARY SIDE (Sheet 3 of 3)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
NZ 214	SFA 5.5 E9018-G	900630	-76	-76
NZ 214	SFA 5.5 E9018-G	900262	-85	-85
NZ 214	SFA 5.23 EF3N mod.	140596	-67	-67
NZ 216	SFA 5.28 ER 80S-G	718288	Note 2	Note 2
NZ 216	SFA 5.5 E9018-G	900262	-85	-85
NZ 216	SFA 5.5 E9018-G	900630	-76	-76
CW 221	SFA 5.5 E9018-G	900630	-76	-76
CW 221	SFA 5.23 EF3N mod.	140596	-67	-67
IB 223	SFA 5.11 EniCrFe 3	7481005	Note 2	Note 2
IB 223	SFA 5.11 EniCrFe 3	7421003	Note 2	Note 2
IB 223	SFA 5.11 EniCrFe 3	8241003	Note 2	Note 2
LW 301	SFA 5.5 E9018-G	6219509	-35	-35
LW 301	SFA 5.5 E9018-G	805867	-58	-58
LW 301	SFA 5.23 EF3N mod.	140596	-67	-67
LW 311	SFA 5.5 E9018-G	6219509	-35	-35
LW 311	SFA 5.5 E9018-G	900262	-85	-85
LW 311	SFA 5.5 E9018-G	805867	-58	-58
LW 311	SFA 5.23 EF3N mod.	140596	-67	-67
LW 321	SFA 5.5 E9018-G	6219509	-35	-35
LW 321	SFA 5.5 E9018-G	805867	-58	-58
LW 321	SFA 5.23 EF3N mod.	140596	-67	-67

Table 5.4-16
PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]
STEAM GENERATORS 1 SECONDARY SIDE (Sheet 1 of 3)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness[b]					
				HAZ 1		WELD		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
BT 104	1700/E	SA-508 Cl. 3	E 7015-A1	N.A.	N.A.	-22	-22	N.A.	N.A.
NZ 105	1692/F + 1627/E	SA-508 Cl. 3	SA-336 Cl. F12	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 106	1698/E	SA-508 Cl. 3	SA-508 Cl. 1a	N.A.	N.A.	-76	-76	N.A.	N.A.
LW 108	1627/E	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
BT 109	1466/E+1627/E+ 1627/E	SA-533 Gr. B Cl. 1	E9018-G+F8P6-EF3	N.A.	N.A.	-49	-49	N.A.	N.A.
FN 110	1627/E	SA-533 Gr. B Cl. 1	SA-508 Cl. 3	N.A.	N.A.	-49	-49	N.A.	N.A.
FN 111	1698/E	SA-508 Cl. 3	SA-508 Cl. 1a	N.A.	N.A.	-58	-58	N.A.	N.A.
SF 112	1627/E+1466/E	SA-533 Gr. B Cl. 1	SA-516 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 113	1698/E	SA-533 Gr. B Cl. 1	SA-516 Gr. 70	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 114	1788	SA-058 Cl. 1a	E 7015-A1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 115	1627/E+1466/E	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
SF 116	1627/E+1466/E	SA-533 Gr. B Cl. 1	SA-515 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 123	1698/E	SA-533 Gr. B Cl. 1	SA-516 Gr. 70	N.A.	N.A.	-76	-76	N.A.	N.A.
SW 128	1774 & 1796	Fn 43 - butter	SB168 & none 690	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
AP 129	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
HP 132	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 113	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
LW 201	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
LW 202	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
CW 203	1466/E & 1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 204	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-508 Cl. 3	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 205	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-508 Cl. 3	N.A.	N.A.	-67	-67	N.A.	N.A.

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV code, Section III, Article NB-2330

Note 1: Not required as per ASME Section III NB Paragraph NB 2430.

Table 5.4-16
PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]
STEAM GENERATORS 1 SECONDARY SIDE (Sheet 2 of 3)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness[b]					
				HAZ 1		WELD		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
CW 206	1466/E & 1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
LW 207	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
LW 208	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
LW 209	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
NZ 210	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 211	1627/E+Int.	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 212	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 213	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 214	1753/G	SA-366 Cl. F12	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
SP 215	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 216	1698/E	SA-508 Cl. 1a	SA-508 Cl. 3	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 221	1627/E+Int.	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
IB 223	1052/E	SA-508 Cl. 1a	Inconel 600 UNS W86182	N.A.	N.A.	Note 1	Note 1	N.A.	N.A.
HP 226	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-22	-22	N.A.	N.A.
AP 227	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-22	-22	N.A.	N.A.
LW 301	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 303	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 305	1627/E+Int.	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 306	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 307	1627/E+Int.	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 308	1698/E – 1627/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.

Table 5.4-16
PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]
STEAM GENERATORS 1 SECONDARY SIDE (Sheet 3 of 3)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness[b]					
				HAZ 1		WELD		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
NZ 309	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
LW 311	1466/E & 1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 312	**1482/D**	**Fn 43 – Buttering**	**Fn 43 - Buttering**	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NZ 313	1698/E	SA-508 Cl. 3	SA-508 Cl. 1a	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
IB 315	1482/D + 1769	Inconel 600	SA-533 Gr. B Cl. 1	N.A.	N.A.	Note 1	Note 1	N.A.	N.A.
DS 316	1698/E	SA-533 Gr. B Cl. 1	A 36	N.A.	N.A.	-85	-85	N.A.	N.A.
LW 321	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
HP 322	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 323	1664/E	SA-508 Cl. 1a	SA-508 Cl. 1a	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 324	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 325	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 302	**1627/e & Int. - 1814**	**533 Gr. B Cl. 1**	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.

Table 5.4-17
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (PLATES)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	DW_{NDT} (°F)	RT_{NDT}[a] (°F)
19	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Intermediate Shell	-47	-47
23	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Upper Shell	- 8	- 8
29	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Top Head Torus	-30	-30
33	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Lower Shell	-35	-35
34	PV-DWD-00-ABB062	-	SA-533 Gr. B Cl. 1	Top Head Dome	-30	-30
41-2	PV-DWD-15-ABB081	-	SA-533 Gr. B Cl. 1	Secondary Manway Cover Plate	-29	-29
43-2	PV-DWD-15-ABB081	-	SA-533 Gr. B Cl. 1	Cover Plate	-29	-29
81	PV-DWD-23-ABB071	-	SA-516 Gr. 70	Upper Support Ring	-58	-58
85	PV-DWD-23-ABB071	-	SA-516 Gr. 70	Lower Support Ring	-58	-58
87	PV-DWD-23-ABB072	-	SA-516 Gr. 70	Divider Support Bar	-40	-40
108	PV-DWD-24-ABB066	-	SA-516 Gr. 70	Shroud Lateral Support	-40	-40

a. ASME B&PV Code, Section III, Article NB 2331-A-1, 2, 3

Note 1: Not requested as per ASME III NB 2311-6 and 7

Table 5.4-18
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (FORGINGS)

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location In Component	DW_{NDT} (°F)	RT_{NDT} OR LST (°F)
12	PV-DWD-11-ABB051	-	SA-508 Cl. 3	Tubesheet	+1	+1
13	PV-DWD-11-ABB051	-	SA-508 Cl. 1a	Tubesheet Drain Nozzle	-35	-26
14	PV-DWD-11-ABB051	-	SA-336 F 12	Tubesheet Blowdown Nozzle	-8	-8
16	PV-DWD-11-ABB055	-	SA-508 Cl. 3	Feedwater Nozzle	-29	-29
17	PV-DWD-11-ABB055	-	SA-508 Cl. 1a	Feedwater Safe-End	-8	-8
18	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Lower Shell Level Nozzle	-35	-26
21	PV-DWD-12-ABB068	-	SA-336 Cl. F 12	Downcomer Blowdown Nozzle	+10	+10
22	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Shell Cone Level Nozzle	-35	-26
24	PV-DWD-13-ABB058	-	SA-508 Cl. 3	Recirculation Nozzle	-17	-17
25	PV-DWD-13-ABB058	-	SA-508 Cl. 1a	Recirculation Nozzle Safe-End	-8	-8
26	PV-DWD-12-ABB057	-	SA-508 Cl. 3	Downcomer Feedwater Nozzle	-17	-17
28	PV-DWD-00-ABB054	-	SA-508 Cl. 1a	Upper Shell Level Nozzle	-35	-26

a. ASME B&PV Code, Section III, Article NB 2331-A-1, 2, 3

b, ASME B&PV Code, Section III, Article NB 2331-A-4

Table 5.4-18A
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (BARS & TUBES)

Piece Number	Reference Drawing Number	ASME Material Specification	Location In Component	DW_{NDT} (°F)	RT_{NDT} OR LST (°F)
44-2	PV-DWD-23-ABB074	SB-106 Gr. B	Sleeve	Not required	Not required
70-2	PV-DWD-23-ABB092	SB-106 Gr. B	Sleeve	Not required	Not required

a. ASME B&PV Code, Section III, Article NB 2331-A-1, 2, 3

Note 1: Not requested as per ASME III NB 2311 - 6 and 7

Table 5.4-19
PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: STEAM GENERATOR 2 SECONDARY SIDE (Sheet 1 of 3)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
LW 108	SFA 5.5 E9018-G	705350	-58	-58
LW 108	SFA 5.23 EF3N mod.	913872	-49	-49
FN 110	SFA 5.5 E9018-G	805867	-58	-58
FN 110	SFA 5.5 E9018-G	900630	-60	-60
FN 110	SFA 5.23 EF3N mod.	913872	-49	-49
FN 110	SFA 5.23 EF3N mod.	140596	-55	-55
FN 111	SFA 5.5 E9018-G	0476. 01	-85	-85
FN 111	SFA 5.5 E9018-G	805867	-58	-58
CW 115	SFA 5.5 E9018-G	900630	-76	-76
CW 115	SFA 5.5 E9018-G	805867	-58	-58
CW 115	SFA 5.5 E9018-G	900262	-85	-85
CW 115	SFA 5.23 EF3N mod.	140596	-55	-55

a. Per ASME B&PV Code, Section III Article NB-2430

b. Per ASME B&PV Code, Section III Article NB-2330

Note 2: Not requested as per ASME NB 2431(c)

Table 5.4-19
PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: STEAM GENERATOR 2 SECONDARY SIDE (Sheet 2 of 3)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
LW 209	SFA 5.23 EF3N mod.	140596	-67	-67
LW 209	SFA 5.5 E9018-G	900630	-76	-76
LW 209	SFA 5.23 EF3N mod.	913872	-49	-49
LW 210	SFA 5.28 ER 80S-G	718288	Note 2	Note 2
LW 210	SFA 5.5 E9018-G	0476. 01	-85	-85
LW 210	SFA 5.5 E9018-G	900262	-85	-85
NZ 211	SFA 5.5 E9018-G	900630	-76	-76
NZ 211	SFA 5.5 E9018-G	900262	-85	-85
NZ 211	SFA 5.5 E9018-G	805867	-58	-58
NZ 211	SFA 5.23 EF3N mod.	140596	-67	-67
NZ 212	SFA 5.28 ER 80S-G	718288	Note 2	Note 2
NZ 212	SFA 5.5 E9018-G	0476. 01	-85	-85
NZ 212	SFA 5.5 E9018-G	900262	-85	-85
NZ 212	SFA 5.5 E9018-G	900630	-76	-76
NZ 212	SFA 5.5 E9018-G	6219509	-35	-35
NZ 213	SFA 5.28 ER 80S-G	718288	Note 2	Note 2
NZ 213	SFA 5.5 E9018-G	0476. 01	-85	-85
NZ 213	SFA 5.5 E9018-G	900262	-85	-85
NZ 213	SFA 5.5 E9018-G	6219509	-35	-35
NZ 213	SFA 5.5 E9018-G	900630	-76	-76
NZ 214	SFA 5.5 E9018-G	900630	-76	-76
NZ 214	SFA 5.5 E9018-G	900262	-85	-85
NZ 214	SFA 5.23 EF3N mod.	140596	-67	-67
NZ 216	SFA 5.28 ER 80S-G	718288	Note 2	Note 2
NZ 216	SFA 5.5 E9018-G	900262	-85	-85
NZ 216	SFA 5.5 E9018-G	900630	-76	-76
CW 221	SFA 5.5 E9018-G	900630	-76	-76
CW 221	SFA 5.23 EF3N mod.	140596	-67	-67
IB 223	SFA 5.11 EniCrFe 3	7481005	Note 2	Note 2
IB 223	SFA 5.11 EniCrFe 3	7421003	Note 2	Note 2
IB 223	SFA 5.11 EniCrFe 3	8241003	Note 2	Note 2

Table 5.4-19
PVNGS UNIT 2 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: STEAM GENERATOR 2 SECONDARY SIDE (Sheet 3 of 3)

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT}[b] (°F)	RT_{NDT}[b] (°F)
LW 301	SFA 5.5 E9018-G	6219509	-35	-35
LW 301	SFA 5.5 E9018-G	805867	-58	-58
LW 301	SFA 5.23 EF3N mod.	140596	-67	-67
LW 311	SFA 5.5 E9018-G	6219509	-35	-35
LW 311	SFA 5.5 E9018-G	900262	-85	-85
LW 311	SFA 5.5 E9018-G	805867	-58	-58
LW 311	SFA 5.23 EF3N mod.	140596	-67	-67
LW 321	SFA 5.5 E9018-G	6219509	-35	-35
LW 321	SFA 5.5 E9018-G	805867	-58	-58
LW 321	SFA 5.23 EF3N mod.	140596	-67	-67

Table 5.4-20
PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]
COMPONENT: STEAM GENERATOR 2 SECONDARY SIDE (Sheet 1 of 3)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness[b]					
				HAZ 1		WELD		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
BT 104	1700/E	SA-508 Cl. 3	E 7015-A1	N.A.	N.A.	-22	-22	N.A.	N.A.
NZ 105	1692/F + 1627/E	SA-508 Cl. 3	SA-336 Cl. F12	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 106	1698/E	SA-508 Cl. 3	SA-508 Cl. 1a	N.A.	N.A.	-76	-76	N.A.	N.A.
LW 108	1627/E	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
BT 109	1466/E+1627/E+1627/E	SA-533 Gr. B Cl. 1	E9018-G+F8P6-EP3	N.A.	N.A.	-49	-49	N.A.	N.A.
FN 110	1627/E	SA-533 Gr. B Cl. 1	SA-508 Cl. 3	N.A.	N.A.	-49	-49	N.A.	N.A.
FN 111	1698/E	SA-508 Cl. 3	SA-508 Cl. 1a	N.A.	N.A.	-58	-58	N.A.	N.A.
SF 112	1627/E+1466/E	SA-533 Gr. B Cl. 1	SA-516 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 113	1698/E	SA-533 Gr. B Cl. 1	SA-516 Gr. 70	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 114	1788	SA-508 Cl. 1a	E 7015-A1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 115	1627/E+1466/E	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
SF 116	1627/E+1466/E	SA-533 Gr. B Cl. 1	SA-515 Gr. 70	N.A.	N.A.	-49	-49	N.A.	N.A.
SW 123	1698/E	SA-533 Gr. B Cl. 1	SA-516 Gr. 70	N.A.	N.A.	-76	-76	N.A.	N.A.
SW 128	1774 & 1769	**Fn 43 – Butter**	**SB-168 & None 690**	**N.A.**	**N.A.**	**N.A.**	**N.A.**	**N.A.**	**N.A.**
AP 129	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
HP 132	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 113	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
LW 201	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
LW 202	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
CW 203	1466/E & 1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 204	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-508 Cl. 3	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 205	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-508 Cl. 3	N.A.	N.A.	-67	-67	N.A.	N.A.

a. Per ASME B&PV Code, Section III, Article NB-4330

b. Fracture toughness determined per ASME B&PV Code, Section III, Article NB-2330

NOTE 1: Not required as per ASME, Section III NB Paragraph NB 2430

Table 5.4-20
PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]
COMPONENT: STEAM GENERATOR 2 SECONDARY SIDE (Sheet 2 of 3)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness[b]					
				HAZ 1		WELD		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
CW 206	1466/E & 1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
LW 207	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
LW 208	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
LW 209	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
NZ 210	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 211	1627/E+Int.	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 212	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 213	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 214	1753/G	SA-366 Cl. F12	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.
SP 215	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 216	1698/E	SA-508 Cl. 1a	SA-508 Cl. 3	N.A.	N.A.	-76	-76	N.A.	N.A.
CW 221	1627/E+Int.	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-49	-49	N.A.	N.A.
IB 223	1052/E	SA-508 Cl. 1a	Inconel 600 UNS W86182	N.A.	N.A.	Note 1	Note 1	N.A.	N.A.
HP 226	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-22	-22	N.A.	N.A.
AP 227	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-22	-22	N.A.	N.A.
LW 301	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 303	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 305	1627/E+Int.	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 306	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 307	1627/E+Int.	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 308	1698/E - 1627/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-67	-67	N.A.	N.A.

Table 5.4-20
PVNGS UNIT 2 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[a]
COMPONENT: STEAM GENERATOR 2 SECONDARY SIDE (Sheet 3 of 3)

Weld Seam Number	Weld Procedure Qualification No.	Material Joined		Fracture Toughness[b]					
				HAZ 1		WELD		HAZ 2	
		Material 1	Material 2	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
NZ 309	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
LW 311	1466/E & 1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 312	**1482/D**	**Fn 43 - Buttering**	**Fn 43 - Buttering**	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NZ 313	1698/E	SA-508 Cl. 3	SA-508 Cl. 1a	N.A.	N.A.	-31	-31	N.A.	N.A.
IB 315	1482/D + 1769	Inconel 600	SA-533 Gr. B Cl. 1	N.A.	N.A.	Note 1	Note 1	N.A.	N.A.
DS 316	1698/E	SA-533 Gr. B Cl. 1	A 36	N.A.	N.A.	-85	-85	N.A.	N.A.
LW 321	1627/E+Int.	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
HP 322	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
NZ 323	1664/E	SA-508 Cl. 1a	SA-508 Cl. 1a	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 324	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
SW 325	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.
CW 302	**1627/e & int. - 1814**	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-31	-31	N.A.	N.A.

Table 5.4-21
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE FASTENERS[a][b]

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Preload Temp (°F)
41-3	PV-DWD-15-ABB081	-	SA-540 Gr. B24 Cl. 3	Stud	10
41-4	PV-DWD-15-ABB081	-	SA-540 Gr. B24 Cl. 3[c]	Nut	10
43-3	PV-DWD-15-ABB081	-	SA-193 Gr. B7	Stud	10
43-4	PV-DWD-15-ABB081	-	SA-194 Gr. B7	Nut	10

a. Preload temperature (diameter less than 4 inches) per ASME B&PV Code, Section III, Article NB 2333.

b. Includes studs, nuts, and washers.

c. For Unit 2, cycle 12 only, SA-540 material may be replaced by SA-194, Gr 7 material for the secondary manway nuts (MEE 03689).

Table 5.4-22
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE FASTENERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location Component	Y S Mpa(ksi)	UTS Mpa(ksi)	R A (%)	Elong (%)
41-3	PV-DWD-15-ABB081	-	SA-540 Gr. B24 Cl. 3	Stud	1141(165)	1197(169)	52.7	18.2
41-4	PV-DWD-15-ABB081	-	SA-540 Gr. B24 Cl. 3[a]	Nut	1110(161)	1184(167)	54.8	19.2
43-3	PV-DWD-15-ABB081	-	SA-193 Gr. B7	Stud	821(119)	907(128)	58.0	18.8
43-4	PV-DWD-15-ABB081	-	SA-194 Gr. B7	Nut	842(122)	961(136)	58.4	19.8

a. For Unit 2, cycle 12 only, SA-540 material may be replaced by SA-194, Gr 7 material for the secondary manway nuts (MEE 03689).

Table 5.4-23
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE FASTENERS[a][b]

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location in Component	Preload Temp (°F)
41-3	PV-DWD-15-ABB081	-	SA-540 Gr. B24 Cl. 3	Stud	10
41-4	PV-DWD-15-ABB081	-	SA-540 Gr. B24 Cl. 3[c]	Nut	10
43-3	PV-DWD-15-ABB081	-	SA-193 Gr. B7	Stud	10
43-4	PV-DWD-15-ABB081	-	SA-194 Gr. B7	Nut	10

a. Preload temperature (diameter 1-4 inches) per ASME B&PV Code, Section III, Article NB-2333

b. Includes studs, nuts, and washers.

c. For Unit 2, cycle 12 only, SA-540 material may be replaced by SA-194, Gr 7 material for the secondary manway nuts (MEE 03689).

Table 5.4-24
PVNGS UNIT 2 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE FASTENERS

Piece Number	Reference Drawing Number	Material Code Number	ASME Material Specification	Location Component	Y S Mpa(ksi)	UTS Mpa(ksi)	R A (%)	Elong (%)
41-3	PV-DWD-15-ABB081	-	SA-540 Gr. B24 Cl. 3	Stud	1141(165)	1197(169)	52.7	18.2
41-4	PV-DWD-15-ABB081	-	SA-540 Gr. B24 Cl. 3[a]	Nut	1110(161)	1184(167)	54.8	19.2
43-3	PV-DWD-15-ABB081	-	SA-193 Gr. B7	Stud	821(119)	907(128)	58.0	18.8
43-4	PV-DWD-15-ABB081	-	SA-194 Gr. B7	Nut	842(122)	961(136)	58.4	19.8

a. For Unit 2, cycle 12 only, SA-540 material may be replaced by SA-194, Gr 7 material for the secondary manway nuts (MEE 03689)

Table 5.4-25
PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE (PLATES)

Position	Reference Drawing Number	Material Specification	Location in Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F) [(a)]
19	PX-DWD-00-062	SA-533 Gr B Cl 2	Intermediate Shell	-17	-17
23	PX-DWD-00-062	SA-533 Gr B Cl 1	Upper Shell	-8	-8
29	PX-DWD-00-062	SA-533 Gr B Cl 1	Top Head Torus	-35	-35
33	PX-DWD-00-062	SA-533 Gr B Cl 2	Lower Shell	-26	-26
34	PX-DWD-00-062	SA-533 Gr B Cl 1	Top Head Dome	-26	-26
41-2	PX-DWD-15-081	SA-533 Gr B Cl 1	Secondary Manway Cover Plate	-39	-39
43-2	PX-DWD-15-081	SA-533 Gr B Cl 1	Handhole Cover Plate	-39	-39
78-2	PX-DWD-15-081	SA-533 Gr B Cl 1	Flow Blocker Cover Plate	-39	-39
81	PX-DWD-23-071	SA-516 Gr 70	Upper Support Ring	-40	-40
85	PX-DWD-23-071	SA-516 Gr 70	Lower Support Ring	-40	-40
87	PX-DWD-23-072	SA-516 Gr 70	Divider Support Bar	-35	-35
108	PX-DWD-24-066	SA-516 Gr 70	Shroud Lateral Support	-45	-45

Table 5.4-26
PVNGS UNIT 3 FRACTURE TOUGHNESS DATA STEAM GENERATOR 1 SECONDARY SIDE (FORGINGS)

Position	Reference Drawing Number	Material Specification	Location in Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F) (a)
12	PX-DWD-11-051	SA-508 Class 3	Tubesheet	-50	-50
13	PX-DWD-11-051	DELETED	Tubesheet Drain Nozzle	-	-
14	PX-DWD-11-051	SA-336 Class F12	Tubesheet Blowdown Nozzle	-40	-40
15	PX-DWD-00-062	SA-508 Class 3a	Stub Barrel	-47	-47
16	PX-DWD-11-055	SA-508 Class 3a	Feedwater Nozzle	-20	-20
17	PX-DWD-11-055	SA-508 Class 1a	Feedwater Safe-End	-26	-26
18	PX-DWD-00-054	SA-508 Class 1a	Lower Shell Level Nozzle	-26	-26
20	PX-DWD-00-062	SA-508 Class 3a	Shell Cone	-30	-30
21	PX-DWD-12-068	SA-336 Class F12	Downcomer Blowdown Nozzle	+1	+1
22	PX-DWD-00-054	SA-508 Class 1a	Shell Cone Level Nozzle	-26	-26
24	PX-DWD-13-058	SA-508 Class 3	Recirculation Nozzle	-35	-35
25	PX-DWD-13-058	SA-508 Class 1a	Recirculation Nozzle Safe-End	-8	-8
26	PX-DWD-12-057	SA-508 Class 3a	Downcomer Feedwater Nozzle	-35	-35
28	PX-DWD-00-054	SA-508 Class 1a	Upper Shell Level Nozzle	-26	-26
30-1	PX-DWD-13-059	SA-508 Class 1a	Steam Outlet Nozzle	-8	-8
30-2	PX-DWD-13-059	SA-508 Class 1a	Pressure Tap Nozzle	-26	-26
31	PX-DWD-00-054	SA-508 Class 1a	Pressure Test Nozzle	-26	-26
36-1	PX-DWD-00-054	SA-508 Class 1a	Sampling Nozzle	-26	-26
37	PX-DWD-12-057	Sa-508 Class 1a	Downcomer FW Nozzle Transition Piece	-8	-8
41-1	PX-DWD-15-081	SA-508 Class 3	Secondary Manyway Nozzle	-26	-26
43-1	PX-DWD-11-056	SA-508 Cl. 3a (Integral with stub barrel)	Handhole	-47	-47
44-1	PX-DWD-11-056	SA-508 Cl. 3a (Integral with stub barrel	Handhole	-47	-47
70-1	PX-DWD-11-056	SA-508 Class 3a	Handhole	-35	-35
72	PX-DWD-00-067	SA-508 Class 3	Snubber Lug	-17	-17
78-1	PX-DWD-11-056	SA-508 Cl.3a (Intergral with stub barrel)	Handhole	-47	-47
107-1	PX-DWD-11-056	SA-508 Class 3a	Handhole	-35	-35

a. ASME B&PP Code, Section III, Article NB-2331-A-1, 2, 3

Table 5.4-26A

PVNGS UNIT 3 FRACTURE TOUGHNESS DATA STEAM GENERATOR 1 SECONDARY SIDE (BARS & TUBES)

Position	Reference Drawing Number	Material Specification	Location in Component	Drop Weight T_{NDT} (°F)	RT_{NDT} (°F)[(a)]
44-2	PX-DWD-23-074	SA-106 Gr B	Sleeve	N.R.	N.R.
70-2	PX-DWD-12-092	SA-106 Gr B	Sleeve	N.R.	N.R.

a. ASME B&PP Code, Section III, Article NB-2331-A-1, 2, 3

Table 5.4-27
PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]
COMPONENT: STEAM GENERATOR No. 1 SECONDARY SIDE

Component Weld Seam Number	Electrode Code	Electrode Lot Number	T_{NDT} [b] (F)	RT_{NDT} [b] (F)
FN 110	SFA 5.5 E9018-G	3134001	-85	-85
FN 110	SFA 5.5 E9018-G	3122003	-94	-94
FN 111	SFA 5.5 E9018-G	3134001	-85	-85
FN 111	SFA 5.5 E9018-G	1103838	-58	-58
CW 115	SFA 5.5 E9018-G	3122003	-94	-94
CW 115	SFA 5.23 F8P6-EG-F3	PG312233720	-67	-67
NZ 210	SFA 5.28 ER 80S-G	4/1701-10438N	(c)	(c)
NZ 210	SFA 5.5 E9018-G	3122003	-94	-94
NZ 211	SFA 5.5 E9018-G	3122003	-94	-94
NZ 211	SFA 5.23 F8P6-EG-F3	PG312233720	-67	-67
NZ 212	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 212	SFA 5.5 E9018-G	4204001	-85	-85
NZ 213	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 213	SFA 5.5 E9018-G	4204001	-85	-85
NZ 214	SFA 5.5 E901E-G	3122003	-94	-94
NZ 214	SFA 5.23 F8P6-EG-F3	PG312233720	-67	-67
NZ 216	SFA 5.5 E9018-G	4374003	-76	-76
NZ 216	SFA 5.28 ER 80S-G	4/1701-10438N	(c)	(c)
DW 221	SFA 5.5 E9018-G	3122003	-94	-94
CW 221	SFA 5.23 F8P6-EG-F3	PG312233720	-67	-67
IB 223	SFA 5.11 E NiCrFe-3	4100683	(c)	(c)
LW 301	SFA 5.5 E9018-G	4452004	-74	-74
LW 301	SFA 535 E9018-G	4374003	-76	-76
LW 311	SFA 5.5 E9018-G	4374003	-76	-76
LW 311	SFA 5.5 E9018-G	4452004	-74	-74
LW 321	SFA 5.5 E-018-G	4374003	-76	-76
LW 321	SFA 5.5 E9018-G	4452004	-74	-74
LW 321	SFA 5.23 F8P6-FG-F3	PG312233720	-67	-67

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

c. Not required as per ASME NB 2431 (c)

Table 5.4-28
PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA
STEAM GENERATORS 1 SECONDARY SIDE

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[b]					
		Material 1	Material 2	HAZ 1		WELD		HAZ 2	
				DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
CW 106	1689-E	SA-508 Cl. 3a	SA-508 Cl. 1a	N.A.	N.A.	-85	-85	N.A.	N.A.
CW 115	1466/E+1627/E Int+1829	SA-508 Cl. 3a	SA-508-Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
FN 110	1627/E Int+1466/E	SA-508 Cl. 3a	SA-508 Cl. 3a	N.A.	N.A.	-85	-85	N.A.	N.A.
FN 111	1698/E	SA-508 Cl. 3a	SA-508 Cl. 1a	N.A.	N.A.	-58	-58	N.A.	N.A.
SF 112	1698/E	SA-508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-85	-85	N.A.	N.A.
SW 113	1698/E	SA-508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-94	-94	N.A.	N.A.
NZ 114	1507/E	ER NiCr-3	ER NiCrFe-7	N.A.	N.A.	-60	-60	N.A.	N.A.
CW 115	1627/E Int+1829	SA-508 Cl. 3a	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
SF 116	1698/E	SA-508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-85	-85	N.A.	N.A.
SW 123	1698/E	SA-508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-58	-58	N.A.	N.A.
LW 201	1627/E Int+1466/E+1829	SA-533 Gr. B Cl. 2	SA-533 Gr. B Cl. 2	N.A.	N.A.	-67	-67	N.A.	N.A.
LW 202	1627/E Int+1829	SA-533 Gr. B Cl. 2	SA-533 Gr. B Cl. 2	N.A.	N.A.	-67	-67	N.A.	N.A.
CW 203	1466/E+1627/E Int+1829	SA-533 Gr. B Cl. 2	SA-533 Gr. B Cl. 2	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 204	1627/E+1829	SA-533 Gr. B Cl. 2	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 205	1627/E+1829	SA-533 Gr. B Cl. 2	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
CW 206	1466/E+1627/E+1829	SA-533 Gr. B Cl. 2	SA-508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 210	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 2	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 211	1627/E Int+1829	SA-508 Cl. 3a	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 212	1698/E	SA-508 Cl. 1a	SA-508 Cl. 3a	N.A.	N.A.	-85	-85	N.A.	N.A.
NZ 213	1698/E	SA-508 Cl. 1a	SA-508 Cl. 3a	N.A.	N.A.	-85	-85	N.A.	N.A.
NZ 214	1753/G	SA-366 Cl. F12	SA-533 Gr. B Cl. 2	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 216	1698/E	SA-508 Cl. 1a	SA-508 Cl. 3a	N.A.	N.A.	-74	-74	N.A.	N.A.
CW 221	1627/E Int+1829	SA-508 Cl. 3	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
IB 223	1052/E	SA-508 Cl. 1a	Inconel 600 UNS W86182	N.A.	N.A.	N.R.[a]	N.R.[a]	N.A.	N.A.
LW 301	1627/E Int+1466/E+1829	SA-533 Gr. B Cl. 2	SA-533 Gr. B Cl. 2	N.A.	N.A.	-74	-74	N.A.	N.A.
CW 303	1627/E Int+1829+1846	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-35	-35	N.A.	N.A.
NZ 305	1627/E Int+1829	SA-508 Cl. 3	SA 533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
NZ 306	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 307	1627/E Int+1829	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
NZ 308	1698/E+1829	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
NZ 309	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
LW 311	1627/E Int+1829	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-59	-59	N.A.	N.A.
NZ 312	1482/D	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NZ 313	1698/E	SA-508 Cl. 3	SA-508 Cl. 1a	N.A.	N.A.	-74	-74	N.A.	N.A.
LW 321	1627/E Int+1466/E+1829	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
NZ 323	1664/E	SA-508 Cl. 1a	SA-508 Cl. 1a	N.A.	N.A.	-13	-13	N.A.	N.A.
SW 324	1689/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
SW 325	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
CW 302	1627/E Int+1829	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-50	-50	N.A.	N.A.

a. As per ASME Sect. III NB 2430

Table 5.4-29
PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (PLATES)

Position	Reference Drawing Number	Material Specification	Location in Component	DW_{NDT} (°F)	RT_{NDT} (°F)
19	PX-DWD-00-062	SA-533 Gr B Cl 2	Intermediate Shell	-17	-17
23	PX-DWD-00-062	SA-533-Gr B-Cl 1	Upper Shell	-8	-8
29	PX-DWD-00-062	SA-533-Gr B-Cl 1	Top Head Torus	-44	-44
33	PX-DWD-00-062	SA-533 Gr B Cl 2	Lower Shell	-26	-26
34	PX-DWD-00-062	SA-533-Gr B-Cl 1	Top Head Dome	-26	-26
41-2	PX-DWD-15-081	SA-533 Gr B Cl 1	Secondary Manway Cover Plate	-39	-39
43-2	PX-DWD-15-081	SA-533 Gr B Cl 1	Handhole Cover Plate	-39	-39
78-2	PX-DWD-15-081	SA-533-Gr B-Cl 1	Flow Blocker Cover Plate	-39	-39
81	PX-DWD-23-071	SA-516 Gr 70	Upper Support Ring	-40	-40
85	PX-DWD-23-071	SA-516-Gr 70	Lower Support Ring	-40	-40
87	PX-DWD-23-072	SA-516-Gr 70	Divider Support Bar	-34	-34
108	PX-DWD-24-066	SA-516 Gr 70	Shroud Lateral Support	-45	-45

a. ASME B&PV Code, Section III, Article NB-2331-A-1, 2, 3)

Table 5.4-30
PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (FORGINGS)

Position	Reference Drawing Number	Material Specification	Location In Component	Drop Weight T_{NDT} (°F)	RT_{NDT} 180-Deg (°F)
12	PX-DWD-11-051	SA-508 Class 3a	Tubesheet	-50	-50
13	PX-DWD-11-051	DELETED	Tubesheet Drain Nozzle	-	-
14	PX-DWD-11-051	SA-336 Class F12	Tubesheet Blowdown Nozzle	-40	-40
15	PX-DWD-00-062	SA-508 Class 3a	Stub Barrel	-47	-47
16	PX-DWD-11-055	SA-508 Class 3a	Feedwater Nozzle	-47	-38
17	PX-DWD-11-055	SA-508 Class 1a	Feedwater Safe-End	-26	-26
18	PX-DWD-00-054	SA-508 Class 1a	Lower Shell Level Nozzle	-26	-26
20	PX-DWD-00-062	SA-508 Class 3a	Shell Cone	-30	-30
21	PX-DWD-12-068	SA-336 Class F12	Downcomer Blowdown Nozzle	+1	+1
22	PX-DWD-00-054	SA-5608 Class 1a	Shell Cone Level Nozzle	-26	-26
24	PX-DWD-13-058	SA-508 Class 3	Recircultion Nozzle	-35	-35
25	PX-DWD-13-058	SA-508 Class 1a	Recirculation Nozzle Safe-End	-8	-8
26	PX-DWD-12-067	SA-508 Class 3a	Downcomer Feedwater Nozzle	-35	-35
28	PX-DWD-00-054	SA-508 Class 1a	Upper Shell Level Nozzle	-26	-26
30-1	PX-DWD-13-059	SA-508 Class 1a	Steam Outlet Nozzle	-8	-8
30-2	PX-DWD-13-059	SA-508 Class 1a	Pressure Tap Nozzle	-26	-26
31	PX DWD-00-054	SA-508 Class 1a	Pressure Test Nozzle	-26	-26
36-1	PX-DWD-00-054	SA-508 Class 1a	Sampling Nozzle	-26	-26
37	PX-DWD-12-057	SA-508 Class 1a	Downcomer FW Nozzle Transition Piece	-8	-8
41-1	PX-DWD-11-056	SA-508 Class 3	Secondary Mayway Nozzle	-17	-17
43-1	PX-DWD-11-056	DA-508 Cl 3a(Integral with stub barrel)	Handhole	-29	-29
44-1	PX DWD-11-056	DA-508 Cl 3a(Integral with stub barrel)	Handhole	-29	-29
70-1	PX-DWD-11-056	SA-508 Class 3a	Handhole	-35	-35
72	PX-DWD-00-067	SA-508 Class 3	Lug	-17	-17
76-1	PX-DWD-11-056	DA-508 Cl 3a(Integral with stub barrel)	Handhole	-29	-29
107-1	PX-DWD-11-056	SA-508 Class 3a	Handhole	-35	-35

a. ASME B&PV Code, Section III, Article NB-2331-A-1, 2, 3

Table 5.4-30A
PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE (BARS AND TUBES)

Position	Reference Drawing Number	Material Specification	Location In Component	Drop Weight T_{NDT} (°F)	RT_{NDT} 180-Deg (°F)
44-2	PX-DWD-23-074	SA-106 Gr B	Sleeve	N.R.	N.R.
70-2	PX-DWD-12-092	SA-106 Gr B	Sleeve	N.R.	N.R.

a. ASME B&PV Code, Section III, Article 11B-2331-A-1, 2, 3

Table 5.4-31
PVNGS UNIT 3 WELD METAL CERTIFICATION TESTS[a]
STEAM GENERATOR 2 SECONDARY SIDE

Component Weld Seam Number	Electrode Code	Electrode Lot Number	Drop Weight T_{NDT} (°F)[b]	RT_{NDT}(°F)[b]
FN 110	SFA 5.5 E9018-G	3134001	-85	-85
FN 110	SFA 5.5 E9018-G	3122003	-94	-94
FN 111	SFA 5.5 E9018-G	3134001	-85	-85
FN 111	SFA 5.5 E9018-G	1103838	-58	-58
CW 115	SFA 5.5 E9018-G	3122003	-94	-94
CW 115	SFA 5.23 F8P6-EG-F3	PG312233720	-67	-67
NZ 210	SFA 5.28 ER 80S-G	4/1701-10438N	(c)	(c)
NZ 210	SFA 5.5 E9018-G	3122003	-94	-64
NZ 211	SFA 5.5 E9018-G	3122003	-94	-94
NZ 211	SFA 5.23 F8P6-EG-F3	PG312233720	-67	-67
NZ 212	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 212	SFA 5.5 E9018-G	4204001	-85	-85
NZ 213	SFA 5.28 ER 80S-G	401748	(c)	(c)
NZ 213	SFA 5.5 E9018-G	4204001	-85	-85
NZ 214	SFA 5.5 E9018-G	3122003	-94	-94
NZ 214	SFA 5.23 F8P6-EG-F3	PG312233720	-67	-67
NZ 216	SFA 5.5 E9018-G	4374003	-76	-76
NZ 216	SFA 5.28 ER 80S-G	4/1701-10438N	(c)	(c)
CW 221	SFA 5.5 E9018-G	3122003	-94	-94
CW 221	SFA 5.23 F8P6-EG-F3	PG312233720	-67	-67
IB 223	SFA 5.11 E NiCrFe-3	4100683	(c)	(c)
LW 301	SFA 5.5 E9018-G	4452004	-74	-74
LW 301	SFA 5.5 E9018-G	4374003	-76	-76
LW 311	SFA 5.5 E9018-G	4374003	-76	-76
LW 311	SFA 5.5 E9018-G	4452004	-74	-74
LW 321	SFA 5.5 E9018-G	4374003	-76	-76
LW 321	SFA 5.5 E9018-G	4452004	-74	-74
LW 321	SFA 5.23 F8P6-EG-F3	PG312233720	-67	-67

a. Per ASME B&PV Code, Section III, Article NB-2430

b. Per ASME B&PV Code, Section III, Article NB-2330

c. Not required as per ASME NB 2431 (c)

Table 5.4-32

PVNGS UNIT 3 WELD PROCEDURE QUALIFICATION FRACTURE TOUGHNESS DATA[(a)]

STEAM GENERATORS 2 SECONDARY SIDE

Weld Seam Number	Weld Procedure Qualification No.	Materials Joined		Fracture Toughness[(b)]					
		Material 1	Material 2	HAZ 1		WELD		HAZ 2	
				DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)	DW_{NDT} (°F)	RT_{NDT} (°F)
CW 106	1689-E	SA-508 Cl. 3a	SA-508 Cl. 1a	N.A.	N.A.	-85	-85	N.A.	N.A.
CW 115	1466/E+1627/E Int+1829	SA-508 Cl. 3a	SA-508-Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
FN 110	1627/E Int+1466/E	SA-508 Cl. 3a	SA-508 Cl. 3a	N.A.	N.A.	-85	-85	N.A.	N.A.
FN 111	1698/E	SA-508 Cl. 3a	SA-508 Cl. 1a	N.A.	N.A.	-58	-58	N.A.	N.A.
SF 112	1698/E	SA-508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-85	-85	N.A.	N.A.
SW 113	1698/E	SA-508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-94	-94	N.A.	N.A.
NZ 114	1507/E	ER NiCr-3	ER NiCrFe-7	N.A.	N.A.	-60	-60	N.A.	N.A.
CW 115	1627/E Int+1829	SA-508 Cl. 3a	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
SF 116	1698/E	SA-508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-85	-85	N.A.	N.A.
SW 123	1698/E	SA-508 Cl. 3a	SA-516 Gr. 70	N.A.	N.A.	-58	-58	N.A.	N.A.
LW 201	1627/E Int+1466/E+1829	SA-533 Gr. B Cl. 2	SA-533 Gr. B Cl. 2	N.A.	N.A.	-67	-67	N.A.	N.A.
LW 202	1627/E Int+1829	SA-533 Gr. B Cl. 2	SA-533 Gr. B Cl. 2	N.A.	N.A.	-67	-67	N.A.	N.A.
CW 203	1466/E+1627/E Int+1829	SA-533 Gr. B Cl. 2	SA-533 Gr. B Cl. 2	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 204	1627/E+1829	SA-533 Gr. B Cl. 2	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 205	1627/E+1829	SA-533 Gr. B Cl. 2	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
CW 206	1466/E+1627/E+1829	SA-533 Gr. B Cl. 2	SA-508 Cl. 3a	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 210	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 2	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 211	1627/E Int+1829	SA-508 Cl. 3a	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
NZ 212	1698/E	SA-508 Cl. 1a	SA-508 Cl. 3a	N.A.	N.A.	-85	-85	N.A.	N.A.
NZ 213	1698/E	SA-508 Cl. 1a	SA-508 Cl. 3a	N.A.	N.A.	-85	-85	N.A.	N.A.
NZ 214	1753/G	SA-366 Cl. F12	SA-533 Gr. B Cl. 2	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 216	1698/E	SA-508 Cl. 1a	SA-508 Cl. 3a	N.A.	N.A.	-74	-74	N.A.	N.A.
CW 221	1627/E Int+1829	SA-508 Cl. 3	SA-508 Cl. 3a	N.A.	N.A.	-67	-67	N.A.	N.A.
IB 223	1052/E	SA-508 Cl. 1a	Inconel 600 UNS W86182	N.A.	N.A.	N.R.[(a)]	N.R.[(a)]	N.A.	N.A.
LW 301	1627/E Int+1466/E+1829	SA-533 Gr. B Cl. 2	SA-533 Gr. B Cl. 2	N.A.	N.A.	-74	-74	N.A.	N.A.
CW 303	1627/E Int+1829+1846	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-35	-35	N.A.	N.A.
NZ 305	1627/E Int+1829	SA-508 Cl. 3	SA 533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
NZ 306	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-76	-76	N.A.	N.A.
NZ 307	1627/E Int+1829	SA-508 Cl. 3	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
NZ 308	1698/E+1829	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
NZ 309	1698/E	SA-508 Cl. 1a	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
LW 311	1627/E Int+1829	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-59	-59	N.A.	N.A.
NZ 312	1482/D	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
NZ 313	1698/E	SA-508 Cl. 3	SA-508 Cl. 1a	N.A.	N.A.	-74	-74	N.A.	N.A.
LW 321	1627/E Int+1466/E+1829	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
NZ 323	1664/E	SA-508 Cl. 1a	SA-508 Cl. 1a	N.A.	N.A.	-13	-13	N.A.	N.A.
SW 324	1689/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
SW 325	1698/E	SA-516 Gr. 70	SA-533 Gr. B Cl. 1	N.A.	N.A.	-74	-74	N.A.	N.A.
CW 302	1627/E Int+1829	SA-533 Gr. B Cl. 1	SA-533 Gr. B Cl. 1	N.A.	N.A.	-50	-50	N.A.	N.A.

a. As per ASME Sect. III NB 2430

Table 5.4-33
PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 1 SECONDARY SIDE FASTENERS

					TENSILE TEST RESULTS				IMPACT TEST RESULTS			
Piece Number	Reference Drawing Number	ASME Material Specification	Location in Component	Preload Temp. (°F)	YS Mpa (KsI)	UTS Mpa (KsI)	RA (%)	Elong (%)	Temp. (°F)	Absorbed Energy (Average) J (ft/lbf)	Lateral Expansion (Average) mm (mils)	Sheer (%)
41-3	PX-DWF-15-025	SA-540 Gr B24 CL 3	Stud	10	991 (142)	1120 (162)	50.6	16.7	10	54.2 (40)	0.6 (23.7)	80
					1009 (146)	1118 (162)	50.2	17	40	63.7 (47)	0.7 (27.7)	80
41-4	PX-DWF-15-025	SA-540 Gr B24 CL 3	Nut	10	1070 (155)	1165 (169)	48.3	17.4	10	60 (43.5)	0.65 (25.8)	80
					1074 (156)	1170 (169)	49.1	17.8	40	67.8 (50)	0.75 (29.6)	80
43-3	PX-DWF-15-025	SA-193 Gr B7	Stud	10	862 (125)	925 (134)	21.7	(a)	(a)	(a)	(a)	(a)
43-4	PX-DWF-15-025	SA-194 Gr 7	Nut	10	886 (128)	984 (143)	22.2	(a)	(a)	(a)	(a)	(a)

a. Not required

Table 5.4-34

DELETED

Table 5.4-35
PVNGS UNIT 3 FRACTURE TOUGHNESS DATA
STEAM GENERATOR 2 SECONDARY SIDE FASTENERS

					TENSILE TEST RESULTS				IMPACT TEST RESULTS			
Piece Number	Reference Drawing Number	ASME Material Specification	Location in Component	Preload Temp. (°F)	YS Mpa (Ksl)	UTS Mpa (Ksl)	RA (%)	Elong (%)	Temp. (°F)	Absorbed Energy (Average) J (ft/lbf)	Lateral Expansion (Average) mm (mils)	Sheer (%)
41-3	PX-DWF-15-025	SA-540 Gr B24 CL 3	Stud	10	991 (142)	1120 (162)	50.6	16.7	10	54.2 (40)	0.6 (23.7)	80
					1009 (146)	1118 (162)	50.2	17	40	63.7 (47)	0.7 (27.7)	80
41-4	PX-DWF-15-025	SA-540 Gr B24 CL 3	Nut	10	1070 (155)	1165 (169)	48.3	17.4	10	60 (43.5)	0.65 (25.8)	80
					1074 (156)	1170 (169)	49.1	17.8	40	67.8 (50)	0.75 (29.6)	80
43-3	PX-DWF-15-025	SA-193 Gr B7	Stud	10	862 (125)	925 (134)	21.7	(a)	(a)	(a)	(a)	(a)
43-4	PX-DWF-15-025	SA-194 Gr 7	Nut	10	886 (128)	984 (143)	22.2	(a)	(a)	(a)	(a)	(a)

a. Not required

Table 5.4-36

DELETED

5.4.3 REACTOR COOLANT PIPING

5.4.3.1 Design Basis

Applicable design codes are found in Table 5.2-1. The reactor coolant loop piping is designed and analyzed for all transients specified in Section 3.9.1. In addition, certain nozzles are subjected to local transients which are included in the design and analysis of the areas affected. Thermal sleeves are installed in the charging nozzle to accommodate these additional transients.

In addition to being specified as Seismic Category I, the piping is designed to ensure that critical vibration frequencies are well out of the range expected during normal operation and during abnormal conditions. Additional presentations relating to seismic and dynamic analysis and criteria for the reactor coolant piping is contained in Sections 3.7.2 and 3.9.2, respectively.

5.4.3.2 Description

Each of the two heat transfer loops contains five sections of pipe: one 42-in. internal diameter pipe between the reactor vessel outlet nozzle and steam generator inlet nozzle, two 30-in. internal diameter pipes from the steam generator's two outlet nozzles to the reactor coolant pumps suction nozzle, and two 30-in. internal diameter pipes from the pumps discharge nozzle to the reactor vessel inlet nozzles. These pipes are referred to as the hot leg, the suction legs, and the cold legs, respectively. The other major pieces of reactor coolant piping are the surge line, a 12-in. pipe between the

pressurizer and the hot leg, and the spray line, a 4-inch pipe at the pressurizer end reduced to a 3-inch pipe and connected to two (2) cold legs.

The 42-in. and 30-in. pipe diameter are selected to obtain coolant velocities which provide a reasonable balance between erosion-corrosion, pressure drop, and system volume. The surge line is sized to limit the frictional pressure loss through it during the maximum in-surge so that the pressure differential between the pressurizer and the heat transfer loops is no more than 5 percent of the system design pressure. The spray line sizing is discussed in Section 5.4.10.

To reduce the amount of field welding during plant fabrication, the 42-in. and 30-in. pipes are supplied in major pieces, complete with shop-installed instrumentation nozzles and connecting nozzles to the auxiliary systems. Where required, the nozzles are supplied with safe ends to facilitate field welding of the connecting piping.

Flow restricting orifices (7/32" dia. x 1" long) are provided in the nozzles for the RCS instrumentation and sampling lines to limit flow in the event of a break downstream of a nozzle.

The flow restricting orifice in the reactor head vent line limits flow in the event of a downstream pipe break. This orifice is 1/4" dia. x 1.25" long and is functionally equivalent to the 7/32" dia. x 1" long orifices serving the RCS instrument and sample lines.

5.4.3.3 Materials

The materials used in the fabrication of the piping are listed in Table 5.2-2. These materials are in accordance with the ASME Code, Section III. The provisions taken to control those factors that contribute to stress corrosion cracking are discussed in Section 5.2.3.

Fracture toughness of the reactor coolant piping is discussed in Section 5.2.3.

5.4.3.4 Tests and Inspections

Prior to, during and after fabrication of the reactor coolant piping, nondestructive tests based upon Section III of the ASME Code were performed. In addition, the fully assembled reactor coolant system is hydrostatically tested in accordance with the Code.

Inservice inspection of the reactor coolant system piping is discussed in Section 5.2.4.

5.4.4 MAIN STEAM LINE FLOW RESTRICTIONS

The steam generator outlet nozzles are one piece forgings with an integral venturi type flow restrictor. The venturi section of the nozzle is designed to reduce the flow area by 70%.

5.4.5 MAIN STEAM LINE ISOLATION SYSTEM

The main steam line isolation system is composed of portions of the main steam system and the engineered safety features actuation system. Discussed here are those portions of these systems that respond to a Main Steam Isolation Signal, as

defined in Section 7.3. A discussion of radiological considerations is provided in Section 12.3.

In addition, the main steam system valves and arrangement are described in subsection 10.3.2. Main steam line isolation system operability is discussed in section 3.9.

5.4.5.1 Design Bases

A. The main steam line isolation valves are designed to isolate the steam generators and the main steam lines in the event of a main steam line rupture.

B. The main steam line isolation valves are designed to perform containment isolation functions for the main steam lines in the event of a design basis accident, as discussed in Section 6.2.4. In the event of a steam line break outside the containment, the isolation function serves to reduce the potential leakage of radioactivity to the environment.

C. The main steam isolation valves are designed to isolate the main steam lines and the steam generators as required for maintenance.

   C-E interface requirements for the main steam isolation valves are listed in Subsection 5.1.4.

5.4.5.2 System Design

5.4.5.2.1 General Description

Each of the four main steam lines is provided with a power-actuated main steam isolation valve designed to stop flow from either direction when it is tripped closed. Each valve is

located outside containment and is provided with means of actuation from the engineered safety features actuation system, meeting the requirements of IEEE Standard 279.

The logic circuitry required to isolate the main steam lines is discussed in Section 7.3. The main steam system valves and arrangement are discussed in Section 10.3.2.2.2.

5.4.5.2.2 Component Description

The main steam isolation system consists of the main steam isolation valves and their associated controls and instrumentation. The main steam isolation valves are remotely operated valves designed to either fail closed or be guaranteed to close upon receipt of Main Steam Isolation Signal. The main steam isolation valves can be monitored and controlled locally and in the control room.

5.4.5.2.3 System Operation

The main steam isolation valves are designed to isolate the main steam lines and the steam generators as required during operation and under accident conditions.

A steam line break inside containment would result in a pressure rise in the containment. Reverse flow protection is also achieved through the main steam isolation valves. To achieve reverse flow protection in the case of the main steam pipe rupture, the valve is fully closed within 5 seconds from receipt of the initiating signal.

The main steam line isolation system components are qualified to serve in the environment specified in Section 3.11.

5.4.5.3 Design Evaluation

Design evaluations are listed to correspond with the design bases listing.

A. The main steam isolation valves are capable of isolating the steam generators within 4.6 seconds after receiving a signal from the engineered safety features actuation system. In the event of a steam line break, this action prevents continuous uncontrolled steam release from more than one steam generator. Protection is offered for breaks inside or outside the containment.

B. The main steam isolation valves, their operators, and associated circuitry are Seismic Category I, and are protected against missiles and the effect of high-energy line breaks.

   All main steam isolation valves are designed, fabricated, tested, and installed in accordance with the codes and standards identified in the interface requirements described in Section 5.1.4. Assurance of operability is discussed in Section 3.9.3.

5.4.6 REACTOR CORE ISOLATION COOLING SYSTEM

This system is not applicable to a pressurized water reactor.

5.4.7 RESIDUAL HEAT REMOVAL SYSTEM

5.4.7.1 Design Bases

5.4.7.1.1 Summary Description

The Shutdown Cooling System (SCS) is used in conjunction with the Main Steam and Main or Emergency Feedwater Systems (see Sections 10.1 and 10.4.7) to reduce the temperature of the Reactor Coolant System (RCS) in post shutdown periods from normal operating temperature to the refueling temperature. The initial phase of the cooldown is accomplished by heat rejection from the steam generators (SG) to the condenser or atmosphere. After the reactor coolant temperature and pressure have been reduced to approximately 350°F and 400 psia, the SCS is put into operation to reduce the reactor coolant temperature to the refueling temperature and to maintain this temperature during refueling.

The Shutdown Cooling Heat Exchangers (SDCHX) are also used during the recirculation mode following a Loss-Of-Coolant Accident (LOCA) or Main Steam Line Break (MSLB) for containment spray purposes as described in Section 6.3.

The SCS is used in addition to the S.G. atmospheric steam release capability and the Auxiliary Feedwater System to cooldown the RCS following a small break LOCA (see Section 6.3). The SCS would also be used subsequent to steam and feedline breaks, steam generator tube ruptures, and is used to maintain flow through the core during plant startup.

5.4.7.1.2 Functional Design Bases

The following functional design bases apply to the Shutdown Cooling System:

A. No single active failure prevents at least one complete train of the SCS from being brought on line from the control room, whether this is during normal plant cooldown or following a Design Basis Event.

B. The functional requirements defined in Paragraph 5.4.7.1.1 are met assuming the failure of a single active component during shutdown cooling or a single active or limited leakage passive failure of a component during the recirculation mode following a Design Basis Event.

C. No single failure allows the SCS to be overpressurized by the RCS. Shutdown Cooling System components whose design pressure is less than the Reactor Coolant System design pressure are provided with overpressure protection by use of interlocks, valve arrangement, and relief valves.

D. The PVNGS Shutdown Cooling System was originally designed and sized to provide sufficient cooling capacity to cool the RCS from 350°F to a refueling temperature of 125°F in less than 27.5 hours following reactor shutdown using two trains of SCS. Note that, although the PVNGS SCS was designed based on a final refueling temperature of 125°F, PVNGS has established the refueling temperature at 135°F. Two trains of shutdown cooling are capable of attaining refueling temperature in less than 27.5 hours following reactor shutdown.

A single train of SCS provides sufficient cooling capacity to cool and maintain the RCS temperature below 200°F in less than 36 hours after reactor shutdown. The PVNGS SCS cooling capacity is based on a component cooling water temperature of 105°F and the decay heat associated with a 4000 MWth APR Core.

Typical cooldown curves are shown in Figures 5.4-10 and 5.4-11.

E. The components of the shutdown cooling system are designed in accordance with Section 5.4.7.3.4.

F. Materials are selected to preclude system performance degradation due to the effects of short and long term corrosion.

G. Deleted

H. Pressure and temperature of the reactor coolant system (RCS) vary from 410 psia and 350F at initiation of shutdown cooling to atmospheric pressure and 135F at refueling conditions.

I. Each train of the SCS may be initiated and operated with one injection nozzle isolated as long as SCS flow through a nozzle does not exceed 6000 gpm.

J. Shutdown cooling system suction line relief valves have a set pressure of 467 psig with a capacity of 5635(@ 10% accumulation) gallons per minute each.

K. Shutdown cooling system heat exchanger relief valves have a set pressure of 650 psig with a capacity of 120 gallons per minute each.

L. Shutdown cooling system thermal relief valves have a set pressure of 650 psig with a capacity of 10 gallons per minute per valve, except for relief valves SI-141/150 which have a set point of 485 psig and a capacity of 10 gallons per minute (as described in paragraph 6.3.2.2.5.a.9) and valves SI-194/191 which have a set point of 650 psig and a capacity of 120 gallons per minute (as described in paragraph 5.4.7.1.2.K, above.

M. When the RCS temperature is below 200F and pressurizer pressure less than 250 psia, the containment spray pumps may be realigned and started to provide additional flow through the heat exchangers.

N. Interlocks associated with the shutdown cooling suction isolation valves prevent the valves from being opened if RCS pressure exceeds 410 psia. Visual and audible alarms are provided in the main control room to inform the operator that the shutdown cooling suction isolation valves are not fully closed when RCS pressure is above the shutdown cooling system operating pressure. These alarms are tested at each refueling outage. An interlock for automatic closure of the isolation valves is not provided. The instrumentation and controls which implement this are discussed in section 7.6.

O. Shutdown cooling isolation valves UV-653 (train A) and UV-654 (train B) are deenergized during plant operation. These valves are deenergized due to findings from the 10CFR50, Appendix R, spurious actuation analysis.

P. Interlocks supplied by independent power supplies are provided to isolate the low-pressure portion of the shutdown cooling system.

Q. When RCS pressure is less than 430 psia, the safety injection tank isolation valves may be closed.

In addition pressure, temperature, flow indication, and SDC isolation valve position (SI-UV-651 through UV-656) are provided in the control room.

5.4.7.2 CESSAR Interface Requirements

Provided below are interface requirements repeated from CESSAR Section 5.4.7.1.3.

Below are detailed the interface requirements that the Shutdown Cooling System (SCS) places on certain aspects of the BOP, listed by categories. In addition, applicable GDC and Regulatory Guides which C-E utilizes in its design of the SCS are presented. These GDC and Regulatory Guides are listed only to show what C-E considers to be relevant, and are not imposed as interface requirements unless specifically called out as such in a particular interface requirement.

Relevant GDC-	1, 2, 3, 4, 10, 34, 35, 36, 37, 38, 39, 40, 50, 54, 56, 57
Relevant -	1.1, 1.4, 1.26, 1.28, 1.29, 1.31, 1.34, 1.36,
Reg. Guides	1.44, 1.46, 1.37, 1.48, 1.50, 1.51, 1.61, 1.64, 1.68, 1.73, 1.74, 1.75, 1.79, 1.84, 1.85, 8.8.

A. Power

1. Electrical power requirements for the motor-operated valves in the Shutdown Cooling System as contained in CESSAR Table 8.3.1-1 are met in the PVNGS design as discussed in Section 8.3.

2. The electrical supplies for Shutdown Cooling System pumps, valves and instruments shall be as follows:

    a. The Shutdown Cooling System pumps and valves shall be capable of being powered from the plant's normal and emergency power sources. Power connections shall be through independent power trains so that in the event of a LOCA, in conjunction with the loss of normal power and a single failure in the emergency electrical supply, the capability of initiating shutdown cooling with a minimum of one subsystem exists.

    b. An independent electrical bus shall supply one LPSI pump and the valves in the associated heat exchanger train.

    c. The shutdown cooling suction line isolation valves (SI-651 through SI-656 on engineering drawing 01, 02, 03-M-SIP-002) shall receive electrical power such that no fault to a single power supply could open the valves to connect the RCS and Shutdown Cooling System inadvertently, nor could a fault to a single power supply prevent opening all the valves of

at least one suction line during initiation of shutdown cooling.

The power supply to the shutdown cooling isolation valves is shown below. The numbers adjacent to valves indicate the source of power.

	Valve	Source of Power[a]
Train A	UV655	1
	UV653	3
	UV651	1
Train B	UV656	2
	UV654	4
	UV652	2

a. Sources of Power

(1) Fed from Class 1E MCC E-PHA-M35

(2) Fed from Class 1E MCC E-PHB-M36

(3) Fed from Class 1E, Channel C, battery through Class 1E inverter E-PKC-N43

(4) Fed from Class 1E, Channel D, battery through Class 1E inverter E-PKD-N44

d. Two independent instrument power supplies shall be provided for the Shutdown Cooling System Instrumentation.

B. Protection From the Effects of Natural Phenomena

1. The location, arrangement, and installation of the Shutdown Cooling System components shall be such that floods (and tsunami and seiches for applicable sites) or the effects thereof, per the requirements of General Design Criteria (GDC) 2 of 10CFR50, will not prevent them from performing their safety functions.

2. The location, arrangement, and installation of the SCS components shall be such that winds and tornadoes or the effects thereof, per the requirements of GDC 2 of 10CFR50, will not prevent them from performing their safety functions.

3. The location, arrangement, and installation of the SCS components shall be such that they will withstand the effects of earthquakes, per the requirements of GDC 2 of 10CFR50, without loss of the capability to perform their safety functions.

   Failure of nonseismic systems and structures shall not cause loss of either SCS train.

C. Protection From Pipe Failure

1. Pipe Break Considerations

   The Shutdown Cooling System both inside and outside containment shall be protected from the

effects of postulated high and moderate energy pipe rupture.

2. Pipe Leakage Considerations

No limited leakage passive failure or the effects thereof (such as flooding, spray impingement, steam, temperature, pressure, radiation, or loss of NPSH) in a connecting system (e.g., Safety Injection System or Containment Spray System) shall preclude the availability of minimum acceptable shutdown cooling capability. Minimum acceptable shutdown cooling capability is defined as that provided by one LPSI pump and its associated heat exchanger train.

All SCS instruments and associated instrument lines, root valves, and isolation valves, shall be designed to maintain pressure boundary integrity following a seismic event.

3. Design Requirements for Protection from Pipe Break

For all parts of the SCS appropriate design procedures shall be employed to ensure that a postulated pipe failure does not result in a loss of function of the SCS.

a. Protection of the SCS from the consequences of a postulated pipe failure shall be by (1) separation via physical plant layout, (2) pipe restraints, (3) protective

structures, (4) watertight rooms, (5) isolation capability, or (6) other suitable means.

b. Isolation valves (system and/or containment) used to contain leakage shall be protected from the adverse effects of a pipe failure which might preclude their operation when required.

D. Missiles

1. For the portion of the SCS located inside containment, appropriate missile barrier design procedures shall be used to insure that the impact of any potential missile will not lead to a Loss-Of-Coolant Accident (LOCA) or preclude the system from carrying out its specified safety functions.

2. For the portion of the SCS located outside containment, appropriate design procedures (e.g., proper turbine orientation, physical separation, or missile barriers) shall be used to insure that the impact of any potential missile does not prevent the system or equipment from carrying out its specified safety functions.

3. Appropriate design procedures shall be used to insure that the impact of any potential missile does not prevent the conduct of a safe plant

shutdown, or prevent the plant from remaining in a safe shutdown condition.

E. Separation

1. Concrete compartments within containment shall serve as protection for that portion of the SCS which is inside the containment and thus could be subjected to credible dynamic effects originating within the containment under the conditions of accidents the SCS is required to mitigate. Separation via physical plant layout, pipe restraints, isolation capability, or other suitable means shall be provided as necessary to guard against damage to the components of the SCS inside the containment from these dynamic effects.

2. Containment isolation valves, operators, and associated power and control systems located outside the containment that are part of the SCS shall be protected from dynamic effects and loss of function resulting from equipment failures and pipe ruptures originating in adjacent areas. Protection from such failure and rupture effects shall be by separation, enclosure, restraint, water-tight rooms or other suitable means.

3. Adequate physical separation shall be maintained between the redundant piping paths and containment penetrations of the Shutdown Cooling System such that the Shutdown Cooling System

will meet its functional requirements even with a single active failure or a limited leakage passive failure.

F. Independence

1. Electrical - See Section 5.4.7.1.3 (A.2.b.)

2. Environmental - See Section 5.4.7.1.3 (Q)

3. Mechanical - See Section 5.4.7.1.3 (C, D, E)

G. Thermal Limitations

1. Component Cooling Water - See Section 5.4.7.1.3 (P)

2. Environmental - See Section 5.4.7.1.3 (Q)

H. Monitoring

1. The safety related instrumentation of the SCS is identified in Table 7.5-2.

I. Operational/Controls

1. The SCS components shall be powered such that the operational and control requirements of Section 5.4.7.1.3 (A) are met.

2. The SCS shall meet the operation and control requirements of Section 5.4.7.1.2.

J. Inspection and Testing

1. All SCS ASME, Section III components shall be arranged to provide adequate clearances to permit inservice inspection.

2. Manually operated valves which contain reactor coolant or other potentially radioactive liquids during normal plant operations shall be provided with handwheel extensions and shielding, to allow periodic actuation.

3. SCS components which contain reactor coolant or other potentially radioactive liquids during normal plant operations, and which require access for periodic pressure tests and nondestructive examination, shall be capable of being flushed prior to testing. The low pressure safety injection pumps shall provide the driving head for flushing.

4. System components not designed to ASME, Section III, should be located such that the access for periodic visual inspection for leakage, structural distress, and corrosion is possible.

5. System and component arrangement shall allow adequate clearances for performance of inspections identified in the Technical Specifications.

K. Chemistry/Sampling

1. The component cooling water shall contain corrosion inhibitors. The water shall not contain scale-forming compounds. The cooling water chemistry control program is the same as that described in Section 9.2.2.1.4.

2. The Sampling System shall provide a means of obtaining remote liquid samples from the Shutdown Cooling System for chemical and radiochemical laboratory analysis.

3. The sample lines in contact with reactor coolant shall be austenitic stainless steel that is compatible with the fluid chemistry.

4. The sample lines shall be sized such that the fluid velocity allows a representative sample and the purge flowrate is high enough to remove crud from the sample lines.

L. Materials

1. Piping and all metallic parts in contact with the system fluid, with the exception of some component internals as required, shall be of austenitic stainless steel.

   Selection shall be on the basis of compatibility with design pressure and temperature stress considerations and with the chemistry of the system fluid.

   Valve packing, gaskets, and diaphragm materials forpackless valves shall also be compatible with the radiation dose and the chemistry of the system fluid.

2. Fabrication and erection of system materials shall be consistent with the quality standards

of General Design Criteria 1 of 10CFR50, Appendix A.

3. Care shall be taken to prevent sensitization and to control the delta ferrite content of (1) the welds which join any system fabricated of austenitic stainless steel to the SCS, and (2) the field welds of the SCS.

4. Controls shall be exercised during system construction to assure that contaminants do not significantly contribute to stress corrosion of stainless steel.

M. System/Component Arrangement

1. The first isolation valve on the shutdown cooling suction lines shall be located as close to the Reactor Coolant System as practical. The volume of the shutdown cooling suction piping between the RCS and the first isolation valve shall be as small as possible. This requirement minimizes the amount of piping exposed to normal RCS pressure.

2. The maximum allowable distance of the low pressure safety injection pump suctions below the pressurizer upper pressure sensor nozzle shall be 115 feet. This ensures that the SCS design pressures will not be exceeded.

3. The low pressure safety injection pumps shall be located as close as practical to the containment.

a. The elevation of these pumps shall be low enough such that adequate NPSH is available during shutdown cooling when the pumps take a suction on the RCS. The required NPSH during shutdown cooling is 20 feet.

b. The elevation of these pumps shall be low enough such that adequate NPSH is available during the recirculation mode of safety injection when the pumps take a suction on the containment sump.

4. The Shutdown Cooling System piping and components shall be arranged such that straight piping runs upstream and downstream of the flow measurement device orifices are provides of sufficient length to comply with: ASME Fluid Meters; their theory and application, Parts 1 & 2.

5. The SCS suction lines shall be arranged such that no portion is physically above the lowest point of the RCS hot leg piping.

6. If the shutdown cooling suction line overpressure relief valves are located at a higher elevation than the LPSIP suction centerline, their set pressure shall be reduced to adequately compensate. An elevation difference greater than 50 feet will invalidate the valve setpoint.

7. Physical identification for safety related RCS equipment shall be provided to allow recognition of safety status by plant personnel.

8. The elevation difference from the bottom discharge nozzle of the SIT's to the centerline of the LPSI pump suctions shall not exceed 85 feet. This ensures that the SCS design pressure will not be exceeded.

9. In the event of a limited leakage passive failure in one SCS train during long term cooling, personnel access to the intact train shall be possible.

10. Protection shall be provided from internally generated flooding that could prevent performance of safety-related functions.

N. Radiological Waste

1. The containment sump shall be designed to accept relief valve discharge from the shutdown cooling suction line overpressure relief valves at temperatures up to 400F and at flows up to 4000 gal/min.

O. Overpressure Protection

1. Thermal relief valves shall be provided in isolated sections of piping in the system to prevent over-pressurization due to thermal transients.

P. Related Service

1. A fire protection system shall be provided to protect the SCS and shall include, as a minimum, the following features:

   a. Facilities for fire detection and alarming;

   b. Facilities or methods to minimize the probability of fire and its associated effects;

   c. Facilities for fire extinguishment;

   d. Methods of fire prevention such as use of fire resistant and non-combustible materials whenever practical, and minimizing exposure of combustible materials to fire hazards;

   e. Assurance that fire protection systems do not diversely affect the functional and structural integrity of safety related structures, systems, and components;

   f. Assurance that fire protection systems are designed to assure that their rupture or inadvertent operation does not significantly impair the capability of safety related structures, systems, and components;

   g. The fire protection system piping design and arrangement shall be such as to assure that the functional and structural

integrity of the Shutdown Cooling System is adequately protected against the effects of pipe whip, jet impingement, and environmental effects resulting from postulated piping ruptures in the fire protection system.

2. Cooling Water System Requirements

   a. The cooling water system design shall be such that cooling water consistent with the requirements of b. below is available to supply the shutdown cooling heat exchangers when an irradiated core is present in the reactor vessel or the spent fuel pool.

   b. Cooling water shall be supplied at the following temperatures and be able to remove the heat loads listed for the given conditions.

SHUTDOWN COOLING HEAT EXCHANGERS

Situation	Cooling Water Inlet Temperature	Design Heat Load (Million Btu/ hour) (includes both heat exchangers)
Post-LOCA	65 - 120F	290
Shutdown Cooling:		
3-1/2 hours after Shutdown	65 - 120F	247
27-1/2 hours after Shutdown	65 - 105F	87.6

c. For all conditions, cooling water shall be supplied as follows:

Parameter	Required Value Per Heat Exchanger
Normal Allowable Delivery Pressure	100 psig
Maximum Allowable Delivery Pressure	150 psig
Required Flowrate	11,000 gal/min
Maximum Allowable Flowrate	13,000 gal/min

d. Cooling water piping supplying the shutdown cooling heat exchangers shall be designed and fabricated in accordance with ASME B&PVC, Section III, Class 3, as a minimum, and shall be designed as Seismic Category I, Safety Class 3, as a minimum.

e. The cooling water system which services the SCS shall be designed with sufficient redundancy and diversity such that one SCS heat exchanger train will always be supplied cooling water.

f. The cooling water system which services the SCS shall be designed consistent with the cooling water chemistry.

3. Containment Spray System (CSS)

a. The CSS shall be designed to allow use of the containment spray pumps can augment the SCS during the later stage of plant cooldown when plant temperature is less

than 200F. The spray system shall provide 4000 gal/min per train at a head which can be set between 250-300 feet.

b. The CSS shall be designed such that the containment spray pumps can be aligned for automatic spray initiation concurrent with shutdown cooling operation of the LPSI pumps. When shutdown cooling is in operation and the containment spray pumps are aligned for automatic initiation, the containment spray alignment shall bypass the shutdown cooling heat exchangers.

Q. Environmental

1. The proper operating environmental conditions for the equipment of one train of the SCS shall be maintained independently of the environment of the other train of the SCS, e.g., failure or isolation of the ventilation capability to one train of the SCS shall not cause the environmental limits of the other SCS train to be exceeded.

2. The auxiliary building ventilation system shall control ambient air conditions in the proximity of all C-E supplied motor driven or diaphragm operated equipment in the SCS in accordance with the requirements of Section 3.11.

5.4.7.3 CESSAR Interface Evaluation

The CESSAR interface requirements listed in paragraph 5.4.7.1 are met by the PVNGS design as follows:

A. Power

1. Electrical power requirements for the motor-operated valves in the SCS as contained in CESSAR Table 8.3.1-1 are met in the PVNGS design as discussed in section 8.3.

2. The electrical supplies for Shutdown Cooling System pumps, valves, and instruments are as follows:

   a. The SCS pumps and valves are capable of being powered from the plant's normal and emergency power sources. Power connections are through independent power trains so that in the event of a LOCA, in conjunction with the loss of normal power and a single failure in the emergency electrical supply, the capability of initiating shutdown cooling with a minimum of one subsystem exists. Refer to section 8.3 for a detailed description of the electrical supply system.

   b. An independent train-oriented power supply to each LPSI pump and valves in the associated heat exchanger train is provided.

c. The shutdown cooling suction line isolation valves (SI-651 through SI-656 on CESSAR Figure 6.3-1B) receive electrical power such that no fault to a single power supply can open the valves to connect the RCS and SCS inadvertently, nor can a fault to a single power supply prevent opening all the valves of at least one suction line during initiation of shutdown cooling.

The power supplies to the shutdown cooling isolation valves are given below. Valve arrangement is shown in engineering drawings 01, 02, 03-M-SIP-001, -002 and -003.

Train A:	UV-655	(Note 1)
	UV-653	(Note 3)
	UV-651	(Note 1)
Train B:	UV-656	(Note 2)
	UV-654	(Note 4)
	UV-652	(Note 2)

NOTES:

1. Fed from train A Class 1E MCC E-PHA-M35
2. Fed from train B Class 1E MCC E-PHB-M36
3. Fed from Class 1E, Channel C, battery through Class 1E inverter E-PKC-N43
4. Fed from Class 1E, Channel D, battery through Class 1E inverter E-PKD-N44

The power supplies indicated provide power to the valve operator (motor). Train A valves are completely independent from train B valves, each train providing a redundant parallel shutdown cooling path. Each train consists of three valves in series powered from two separate channels. Therefore, no single or common failure can result in loss of shutdown cooling capability, either due to failure of a valve to open or failure of a valve to close. Thus, PVNGS meets the single failure criterion.

d. Two independent instrument power supplies are provided for the shutdown cooling system Instrumentation.

B. Protection From the Effects of Natural Phenomena

1. Design provisions for maintaining functional capability of the safety-related systems during a flood, earthquake, a tornado, or high winds as defined in GDC 2 are discussed in subsection 3.1.2. The SCS is located inside Seismic Category I structures. The protection of Seismic Category I structures against natural phenomena is presented in sections 3.3 and 3.4.

2. See paragraph 5.4.7.2, listing B.1.

3. Design provisions for maintaining functional capability of the safety-related systems during

an earthquake or other natural phenomena as defined in GDC 2 are discussed in subsection 3.1.2. All components of the SCS are located in Seismic Category I structures in accordance with Regulatory Guides 1.29 and 1.48. Assessment of the geologic and seismic characteristics of the site was accomplished in accordance with 10CFR100, Appendix A.

Failure of nonseismic systems and structures will not cause loss of either SCS train.

C. Protection from Pipe Failure

1. Pipe Break Considerations

The SCS, both inside and outside containment, is protected from the effects of postulated high and moderate energy pipe rupture (See Subsection C.3 below). During SCS operation, the piping system is considered a moderate energy system per Branch Technical Position MEB 3-1 because it operates in the high-energy range for less than 2% of system operation. In accordance with MEB 3-1, the largest crack is based on a circular opening whose area is equal to a rectangle one-half pipe diameter in length and one-half pipe wall thickness in width.

Maximum expected leakage from a moderate energy pipe rupture postulated in the SCS is defined by the methods of Subsection 3.6.2. At the NRC’s request, a line break is postulated downstream

of the Shutdown Cooling System (SCS) heat exchanger while in the shutdown cooling mode. The purposes of evaluating this break are to ensure that (1) the RCS piping system can sustain the resulting loss of inventory while maintaining core cooling (i.e., the core remains covered) and (2) at least one SCS train remains operable. This postulated break will flood the heat exchanger compartment. Flooding from this line break is enveloped by the worst case (design bases) flood scenario (See Subsection C.3 below).

The maximum discharge rate during SCS operation is approximately 990 gallons per minute based on the upper limits of 275 psig and 200°F for a moderate energy system. The rate is calculated using a 2.5-square inch crack in the shutdown cooling heat exchanger (SDCHX) discharge line since this line is a 20-inch line. The crack location is in the SDCHX room on the 70-foot level of the auxiliary building. Assuming no operator action for 30 minutes, the total loss of RCS inventory is approximately 30,000 gallons. This loss of RCS inventory will not adversely affect core cooling as the redundant train can provide full heat removal capability, and sufficient RCS inventory remains to provide core cooling. The water level will be well above the midpoint of the RCS hot leg

when the operator isolates the break and places the redundant train into service.

Alarms are provided in the control room on low-low pressurizer level (25%). In addition to these alarms, control room indication of room level alarms is provided to alert the operator of a leak and to assist the operator in locating the affected train which then can be isolated. Room sump level instrumentation is provided in each ECCS pump room, pipe chase room, SDCHX room, valve gallery area, and piping penetration room for both train A and train B piping which is separated from each other. The above mentioned rooms are also separated so that a leak in one train is specifically identified with that train. Sump volumes are relatively small so that a leak of 990 gallons per minute would be alarmed very quickly (high level alarm corresponds to approximately 3.5 gallons). The room sump level alarms and instrumentation for the ECCS pump rooms are Class 1E.

2. Pipe Leakage Considerations

No limited leakage passive failure or the effects thereof (such as flooding, spray impingement, steam, temperature, pressure, radiation, or loss of NPSH) in a connecting system (e.g., safety injection system or containment spray system) precludes the

availability of minimum acceptable shutdown cooling capability. Minimum acceptable shutdown cooling capability is defined as that provided by one LPSI pump and its associated heat exchanger train.

All SCS instruments and associated instrument lines, root valves, and isolation valves are designed to maintain pressure boundary integrity following a seismic event.

3. Design Requirements for Protection from Pipe Break

   The SCS, both inside and outside containment, is protected from the effects of postulated high and moderate energy pipe rupture. Appropriate design procedures are employed to ensure that postulated failures do not result in a loss of SCS function. The SCS design includes the following features:

   a. Protection from the consequences of a postulated pipe failure by: (1) separation via physical plant layout, (2) pipe restraints, (3) protective structures, (4) isolation capability, or (5) other suitable means (see UFSAR Table 3.6-3);

   b. Isolation valves (system and/or containment) used to contain leakage are protected from the adverse effects of a

pipe failure which might preclude their operation when required.

These design features protect the redundant SCS train and other plant equipment from the effects of a pipe break (pressurization, pipe whip, impingement, and flooding). The design basis flood for specific rooms and compartments is based on the line break with the largest spillage per Section 3.6.2.1.

Flood protection for the ECCS pumps is provided by train separation and drainage system design. Each HPSI, LPSI, and CS pump is located in a separate compartment. The compartment walls serve as flood barriers so that flooding within or outside of the ESF pump room of one train will not jeopardize the operation of the pump of the redundant train. Water in the ECCS compartments is routed to the Radioactive Waste Drain System, which includes two ESF drain subsystems, one serving Train A equipment and the other serving Train B equipment. A drain header from each ECCS pump room is routed directly to the appropriate ESF sump and is equipped with a check valve to prevent backflow. These check valves are included in the ISI/IST Program. The two ESF drain subsystems are

included in the Maintenance Rule, and the two ESF drain subsystems are physically separate from drains serving the non-ESF equipment rooms (reference engineering drawings 01, 02, 03-M-RDP-002). Thus, the worst case (design basis) flooding of one ESF pump room, will not affect the operation of redundant safety-related equipment that is required to perform protective actions to mitigate the consequences of the postulated break or place the plant in a safe shutdown condition.

D. Missiles

1. Design provisions for protecting the SCS from missiles inside the containment are discussed in subsection 3.5.2.

2. Design provisions for protecting the SCS from missiles outside the containment are discussed in subsection 3.5.2.

3. Appropriate design procedures which ensure that the impact of any potential missile does not prevent the conduct or maintenance of a safe plant shutdown are discussed in section 3.5.

E. Separation

1. Protection of redundant safety systems inside containment is discussed in section 3.6.

2. Protection of redundant safety systems outside containment is discussed in section 3.6.

3. Adequate physical separation is maintained between the redundant piping paths and containment penetrations of the SCS such that the shutdown cooling system will meet its functional requirements even with a single active failure or a limited leakage passive failure.

F. Independence

1. Electrical - See paragraph 5.4.7.2, sublisting A.2.b.

2. Environmental - See paragraph 5.4.7.2, listing Q.

3. Mechanical - See paragraph 5.4.7.2, listings C, D, and E.

G. Thermal Limitations

1. Essential cooling water - See paragraph 5.4.7.2, listing P.

2. Environmental - See paragraph 5.4.7.2, listing Q.

H. Monitoring

Instrumentation used for monitoring of SCS performance is provided as discussed in section 7.5.

I. Operational/Controls

1. The SCS components are powered such that the operational and control requirements of CESSAR interface requirements stated in paragraph 5.4.7.1, listing A, are met.

2. The SCS is designed to meet the operation and control requirements of CESSAR Section 5.4.7.1.2.

J. Inspection and Testing

1. All SCS ASME, Section III, components are arranged to provide adequate clearances to permit inservice inspection. Refer to subsection 5.2.4 and section 6.6.

2. Manually-operated valves which contain reactor coolant or other potentially radioactive liquids during normal plant operations are provided with handwheel extensions or shielding, to allow periodic actuation, unless they are operated less frequently than once a year. Refer to paragraph 12.3.1.1.

3. Shutdown cooling system components that contain reactor coolant or other potentially radioactive liquids during normal plant operations, and that require access for periodic pressure tests and nondestructive examination, are capable of being flushed prior to testing. The low-pressure safety injection pumps can provide the driving head for flushing.

4. System components not designed to ASME, Section III, are located such that the access for periodic visual inspection for leakage, structural distress, and corrosion is possible.

5. System and component arrangement allows adequate clearances for performance of inspections identified in CESSAR Technical Specification 16.4.0.5.

K. Chemistry/Sampling

1. The essential cooling water makeup conductivity will be 2.0 micromhos/cm or less. The cooling water will not contain scale-forming compounds. The cooling water chemistry control program is described in Section 9.2.2.1.4.

2. The sampling system provides a means of obtaining remote liquid samples from the shutdown cooling system for chemical and radiochemical laboratory analysis. Refer to subsection 9.3.2.

3. The sample lines in contact with reactor coolant are of austenitic stainless steel.

4. The sample lines are sized such that the fluid velocity allows a representative sample and the purge flowrate is high enough to remove crud from the sample lines. Refer to subsection 9.3.2.

L. Materials

1. Piping and metallic parts in contact with the system fluid, with the exception of some component internals as required, are of austenitic stainless steel.

   Selection is made on the basis of compatibility with design pressure and temperature stress considerations and with the chemistry of the system fluid.

   Valve packing, gaskets, and diaphragm materials for packless valves are also compatible with the radiation dose and the chemistry of the system fluid.

2. Fabrication and erection of system materials were consistent with the quality standards of GDC 1 and Regulatory Guide 1.26. Refer to subsection 3.1.1 and section 1.8.

3. Methods used to avoid severe sensitization of unstabilized austenitic stainless steels as the result of welding are listed in section 5.2. Regulatory Guides 1.31 and 1.44 are used as discussed in section 1.8.

4. Controls will be exercised to assure that contaminants do not significantly contribute to stress corrosion of stainless steel. Refer to section 5.2. Regulatory Guides 1.36 and 1.37 are used as discussed in section 1.8.

M. System Component Arrangement

It is noted that some of the Interface Requirements described in this section were provided for original piping and component design/selection to ensure that the as-built system would support required design functions. For the operating plant, the adequacy of the design to support required design functions is maintained and demonstrated by current design basis calculations and surveillance tests that evaluate the as-built systems, and the values specified by the original interface requirements are no longer relevant. The specific interface requirements in this section for which this applies and that provide historical information are: M.2, M.8.

1. The first isolation valve on the shutdown cooling suction lines is located as close as practical to the RCS. The volume of water in the pipe between the first isolation valve and the RCS is less than 16 cubic feet for A train for all three units and less than 44 cubic feet for B train for all three units.

2. The distance between the pressurizer upper pressure sensor nozzle and the LPSI pump suction piping is less than 112 feet. This interface requirement describes an aspect of the plant's physical configuration upon which the system design limits were originally established and is historical.

3. The LPSI pumps are located as close as practical to the containment. In addition, the LPSI pumps' NPSH requirements are satisfied as follows:

   a. The available NPSH during shutdown cooling, when both the LPSI and CS pumps take suction from the RCS, is greater than 25 feet. The CESSAR Interface Requirement for required NPSH is 20 feet. The actual required NPSH based on the specific PVNGS design requirements is 22 feet. The available NPSH exceeds the CESSAR Interface Requirement and the PVNGS specific required NPSH.

   b. The available NPSH during the recirculation mode of safety injection, when the pumps take a suction on the containment emergency recirculation sumps, is greater than 25 feet, which is adequate.

4. The SCS flow measuring orifices are installed in compliance with ASME Publication, ASME Fluid Meters; Their Theory and Application, Parts 1 and 2.

5. The SCS suction lines are arranged such that no portion is physically above the lowest point of the RCS hot leg piping.

6. The setpoint for the Shutdown Cooling suction relief valves is compensated for elevation

differences from the LPSI/CS pump centerline. This setpoint is 467 psig. The original CE requirement established a 50 ft. maximum elevation difference based on a relief valve setpoint of 435 psig. However, the relief valve setpoint was subsequently increased to 467 psig at PVNGS and, therefore, the original CE interface requirement no longer applies. This requirement was changed by CE for PVNGS to simply state that the setpoint for the Shutdown Cooling suction relief valves is compensated for elevation differences from the LPSI/CS pump centerline, and the setpoint is 467 psig.

7. RCS components are provided with equipment tags which include a designator, A, B, C, D, or E, for safety-related components, or N for nonsafety-related components.

8. The elevation difference between the bottom discharge nozzles of the SITs and the centerline of the LPSI pump suctions is less than 70 feet. This interface requirement describes an aspect of the plant's physical configuration upon which the system design limits were originally established and is historical.

9. In the event of a limited leakage passive failure in one SCS train during long-term cooling, personnel access to the intact train will not be prevented by flooding. However,

access will be limited by the dose rate at the intact train.

10. Protection is provided from internally generated flooding that could prevent performance of safety-related functions. Also refer to section 3.6 and subsection 9.3.3.

N. Radiological Waste

1. The containment emergency recirculation sump is designed to accept relief valve discharge from the shutdown cooling suction line overpressure relief valves at temperatures up to 400F and at flows up to 4000 gallons per minute.

O. Overpressure Protection

1. Thermal relief valves and overpressure protection is provided in isolated sections of piping and valves (in accordance with responses to Generic Letter 96-07) in the system to prevent overpressurization due to thermal transients.

P. Related Services

1. The fire protection system provided to protect the SCS is discussed in subsection 9.5.1.

2. Cooling Water System Requirements

   a. The cooling water system is designed as shown in the listing below, to supply cooling water to the shutdown cooling heat exchangers when an irradiated core is

present in the reactor vessel or the spent fuel pool.

b. Cooling water will be supplied at the following temperatures and will be able to remove the heat loads listed for the given conditions.

SHUTDOWN COOLING HEAT EXCHANGERS

Situation	Cooling Water Inlet Temperature °F	Design Heat Load (Million Btu/hour) (includes both heat exchangers)
Post-LOCA & Forced Shutdown	65 - 135	*
Normal Shutdown Cooling:		
3-1/2 hours after Shutdown	65 - 120	245.1
27-1/2 hours after Shutdown	65 - 105	86.56

* Heat load is variable and discussed in Section 6.2.1

c. For all conditions, cooling water will be supplied as follows:

Parameter	Nominal Value Per Heat Exchanger
Normal delivery pressure	96 psig
Maximum delivery pressure	116 psig
Minimum flow range	12,000 - 12,600 gal/min

d. Cooling water a piping supplying the shutdown cooling heat exchangers is designed and fabricated in accordance with

ASME B&PV Code, Section III, Class 3, and is designed as Seismic Category I, Safety Class 3.

e. The cooling water system which services the SCS is designed with sufficient redundancy and diversity such that one SCS heat exchanger train will always be supplied with cooling water.

f. The cooling water system which services the SCS is designed consistent with the cooling water chemistry control program described in Section 9.2.2.1.4.

3. Containment Spray System (CSS)

a. The CSS is designed to allow the containment spray pumps to augment the SCS during the later stages of plant cooldown when plant temperature is less than 200F. The spray system will provide approximately 4000 gallons per minute per train at a head which can be set between 250 and 300 feet.

b. The CSS is designed to allow the containment spray pumps to be aligned for automatic spray initiation concurrent with shutdown cooling operation of the LPSI pumps. This can be achieved by aligning the containment spray pumps discharge path to bypass the shutdown cooling heat exchangers.

Q. Environmental

1. The proper operating environmental conditions for the equipment of one train of the SCS will be maintained independently of the environment of the other train of the SCS, e.g., failure or isolation of the ventilation capability to one train of the SCS: will not cause the environmental limits of the other SCS train to be exceeded.

2. The auxiliary building ventilation system described in subsection 9.4.2 will control ambient air conditions in the proximity of C-E-supplied motor-driven or diaphragm-operated equipment in the SCS to between 50 and 104F under normal operating conditions.

   Following a LOCA, including the subsequent recirculation mode of operation, auxiliary building ambient air conditions are controlled in accordance with the requirements of section 3.11.

5.4.7.4 System Design

5.4.7.4.1 System Schematic

The SCS is shown on the RCS engineering drawing 01, 02, 03-M-RCP-001, -002 and -003 and on the SIS engineering drawing 01, 02, 03-M-SIP-001, -002 and -003. Figures 6.3-2G through 6.3-2J show flow rates at various locations during system operation. The pressure and temperature of the RCS system vary

from 410 psia and 350°F at initiation of shutdown cooling to atmospheric pressure and 135°F at refueling conditions. SCS design parameters are given in Table 5.4-43. The SCS suction side pressure and temperature follow RCS conditions. The discharge side pressure is higher by an amount equal to the pump head and the temperature is lower at the shutdown cooling heat exchanger outlet.

The SCS contains two shutdown cooling heat exchangers and employs the two low pressure safety injection pumps throughout shutdown cooling. The applicant may utilize the flow of the containment spray pumps through the shutdown cooling heat exchangers to achieve an increased cooldown rate during the latter stages of shutdown cooling. During initial shutdown cooling, a portion of the reactor coolant flows out the shutdown cooling nozzles located on the reactor vessel outlet (hot leg) pipes and is circulated through the shutdown cooling heat exchangers by the LPSI pumps. The return to the RCS is through the four LPSI lines.

The SCS suction line isolation valves are interlocked to prevent overpressurization of the SCS by the RCS. These interlocks are described in Sections 5.4.7.3.3 and 7.6.

Shutdown cooling and LPSI flow are measured by orifice meters installed in each LPSI header. The information provided by these flow elements is used by the operator for flow control during shutdown cooling operation.

The cooldown rate is controlled by adjusting flow through the heat exchangers with throttle valves on the discharge of each heat exchanger. The operator maintains a constant total

shutdown cooling flow to the core by adjusting the heat exchanger bypass flow to compensate for changes in flow through the heat exchangers.

5.4.7.4.2 Component Description

A. Shutdown Cooling Heat Exchangers

The shutdown cooling heat exchangers are used to remove decay, sensible and safeguards pump heat during cooldown, and decay and pump heat during cold shutdown. The units are sized to maintain a refueling water temperature of 125°F with the design component cooling water temperature 105°F at 27-1/2 hours after shutdown following an assumed reactor core average burnup of two years. A conservative fouling resistance is assumed, resulting in an additional area margin for the heat exchangers.

Shutdown cooling heat exchanger characteristics are given in Tables 5.4-43 and 5.4-44.

The design pressure of the heat exchanger is based on the suction line design pressure plus the shutoff head of the LPSI pump.

The design temperature is based upon the temperature of the reactor coolant at the initiation of shutdown cooling plus a design tolerance.

B. Instrumentation

The operation of the SCS is controlled and monitored through the use of installed instrumentation. The

instrumentation provides the capability to determine heat removal, cooldown rate, shutdown cooling flow, and the capability to detect degradation in flow or heat removal capacity. The instrumentation provided for the SCS is discussed in Section 6.3.5.

C. Piping

All SCS piping is austenitic stainless steel. All piping joints and connections are welded, except for a minimum number of flanged connections that are used to facilitate equipment maintenance or accommodate component design.

D. Valves

The location of valves, along with the type and size, type of operator, position (during the normal operating mode of the plant), type of position indication, and failure position is shown in engineering drawing 01, 02, 03-M-SIP-001, -002 and -003. Pressure design rating and code design classification are also shown.

Throttle valves (SI-306, 657, 307, 658) are provided for remote control of the heat exchanger tube side and bypass flow.

1. Relief Valves

Protection against overpressure of components within the SCS is provided by conservative design of the system piping, appropriate valving between high pressure sources and low pressure

piping, and by relief valves. The shutdown cooling suction lines up to and including SI-653 and SI-654 are designed for full RCS pressure. Relief valves are provided as required by the applicable codes. All relief valves are of the totally enclosed, pressure tight type, with suitable provisions for gagging. A tabulation of relief valves is provided below:

a. SI-169 and 469

   Shutdown cooling suction isolation valve thermal relief valves. These valves are sized to protect the piping between the shutdown cooling isolation valves of each shutdown cooling suction line from the pressure developed due to a temperature increase. The valves are located inside the containment and discharge into the reactor drain tank. The set pressure is 2485 psig with a capacity of 15 gpm each.

b. SI-179 and 189

   Shutdown cooling suction line relief valves. These valves are sized to protect the SCS from operation of the pressurizer heaters, operation of the HPSI pumps, and operation of the charging pumps during shutdown cooling. The valves are located inside the containment and discharge into the containment sump. The set pressure is

467 psig with a capacity of 5635 (@ 10% accumulation) gpm each.

c. SI-191 and 194

Shutdown cooling heat exchanger reliefs. These valves are sized to protect an isolated heat exchanger from the pressure developed due to a component cooling water temperature increase. The valves discharge into the equipment drain tank. The set pressure is 650 psig with a capacity of 120 gpm each.

d. SI-161 and 193

Thermal relief valves. These valves are sized to protect the isolated piping from the pressure developed due to a temperature increase. The valves discharge to the equipment drain tank. The set pressure is 650 psig with a capacity of 10 gpm each.

2. Actuator Operated Throttling and Stop Valves

The failure position of each valve on loss of actuating signal or power supply is selected to ensure safe operation. System redundancy is considered when defining the failure position of any given valve. Valve position indication is provided at the main control panel, as indicated in engineering drawings 01, 02, 03-M-SIP-001, -002 and -003. A locking type control switch on the main control panel and/or manual override

handwheel is provided where necessary for efficient and safe plant operation. All actuator operated valves were supplied with a double packing with a lantern ring leakoff connection. During original plant design, an evalution determined that leakoffs piped to the equipment drain tank present a greater ALARA concern than capping the valve leakoff. The cap has been designed as part of the SIS pressure boundary.

E. Pumps Used During Shutdown Cooling

The LPSI pumps are used as part of the SCS. During shutdown cooling, these pumps take suction from the reactor hot leg pipes and discharge through the shutdown cooling heat exchangers. The flow is then returned to the RCS through the LPSI header to the four cold legs. One LPSI pump is aligned to each shutdown cooling heat exchanger. At the start of shutdown cooling, both of the LPSI pumps are in service. When the RCS temperature is below 200°F, the containment spray pumps may be realigned and started to provide additional flow through the heat exchangers. The LPSI pumps are described in Section 6.3.2.2.2.

5.4.7.4.3 Overpressure Prevention

A. Overpressurization of the SCS by the RCS is prevented in the following ways:

1. The shutdown cooling suction isolation valves (SI-651, 652, 653, and 654) are powered by four independent power supplies such that a fault in one power supply or valve will neither line up the RCS to either of the two SCS trains inadvertently nor prevent the initiation of shutdown cooling with at least one train when pressure permits.

2. Interlocks associated with the shutdown cooling suction isolation valves prevent the valves from being opened if RCS pressure exceeds 410 psia. The instrumentation and controls which implement this are discussed in Section 7.6.

3. The SCS suction valves inside the containment are designed for full RCS pressure with the second valve forming the pressure boundary and class change.

4. Alarms on SI-651, 652, 653 and 654 annunciate when the shutdown cooling system suction isolation valves are not fully closed. Also, if SI-651 and 653 or SI-652 and 654 valves are open and RCS pressure exceeds the maximum pressure for SCS operation, an alarm will notify the operator that a pressurization transient is occurring during low temperature conditions.

5. Relief valves are provided as discussed in Section 5.4.7.4.2.

   The effects of inadvertent operation are discussed in Table 5.1-4.

5.4.7.4.4 Applicable Codes and Classifications

A. The SCS is a Safety Class 2 System, except for that portion discussed in B. below, which is Safety Class 1.

B. The piping and valves from the RCS up to and including SI-653 and 654 are designed to ASME B&PVC Section III, Class 1.

C. The piping, valves, and components of the SCS, with the exception of those in Section 5.4.7.4.4 B. are designed to ASME B&PVC Section III, Class 2.

D. The component cooling water side of the shutdown cooling heat exchanger is designed to ASME B&PVC Section III, Class 3.

E. The power operated valves are designed to the applicable IEEE Standards.

F. The SCS is a Seismic Category 1 System.

5.4.7.4.5 System Reliability Considerations

The SCS is designed to perform its design function assuming a single failure, as described in Section 5.4.7.1.2.

To assure availability of the SCS when required, redundant components and power supplies are utilized. The RCS can be

brought to refueling temperature utilizing one of the two redundant SCS trains. However, with the design heat load, the cooldown would be considerably longer than the specified 27-1/2 hour time period.

A loss of instrument air to the shutdown cooling system will not result in a loss of cooling ability.

Inadvertent overpressurization of the SCS is precluded by the use of pressure relief valves and interlocks installed on the shutdown cooling suction line isolation valves and safety injection tank isolation valves (see Section 7.6 and 5.4.7.4.3).

The instrumentation, control, and electric equipment pertaining to the SCS was designed to applicable portions of IEEE Standards 279 and 308.

In addition to normal offsite power sources, physically and electrically separated and redundant emergency power supply systems are provided to power safety-related components. See Chapter 8 for further discussion.

Since the SCS is essential for a safe shutdown of the reactor, it is a Seismic Category I system and designed to remain functional in the event of a design basis earthquake.

For long-term performance of the SCS without degradation due to corrosion, only materials compatible with the pumped fluid are used.

Environmental conditions are specified for system components to ensure acceptable performance in normal and applicable accident environments (see Section 3.11).

In the event of a limited leakage passive failure in one train of the SCS, continued core cooling is assured by the two independent train design of the SCS. Make-up of the leakage is provided by the manual alignment of the SIS to the refueling water tank or by opening the Safety Injection Tank isolation valves. The affected SCS train can then be isolated and core cooling continued with the other train.

A limited leakage passive failure is defined as the failure of a pump seal or valve packing, whichever is greater. The maximum leakage is expected to be from a failed LPSI pump seal.

This leakage to the pump compartment will normally drain to the room sump. From there it is pumped to the water management system. The sump pumps in each room will handle expected amounts of leakage. If leakages are greater than the sump pump capacity, the room will be isolated.

5.4.7.4.6 Manual Actions

A. Plant Cooldown

   Plant cooldown is the series of manual operations which bring the reactor from hot shutdown to cold shutdown. Cooldown to approximately 350°F is accomplished by releasing steam from the secondary side of the steam generators. When the RCS pressure falls below 2150 psia, the Safety Injection Actuation Signal (SIAS) setpoint can be manually decreased as discussed in Section 7.2.1.1.1.6. When RCS pressure reaches 750 psia, the safety injection tank pressure is reduced to 300 psig. When RCS pressure is between 380 and

400 psia, the safety injection tank isolation valves are closed.

When RCS temperature and pressure decrease below 350°F and the maximum pressure for SCS operation, the SCS may be used. If the SCS is not aligned to the RCS before cold leg temperature is reduced to below the maximum RCS cold leg temperature requiring LTOP, an alarm will notify the operator to open the SCS isolation valves (SI-651, 652, 653, 654). The maximum temperature requiring LTOP is based upon the evaluation of the applicable P-T curves. This operator action requires that the RCS be depressurized to below the maximum pressure for SCS operation, in order to clear the permissive SCS interlock (see paragraph 5.4.7.4.3, item A.2). Interlocks associated with the six valves on the two SCS suction lines prevent overpressurization of the SCS. See Section 7.6 and 5.4.7.4.3 for details. Also, if SI-651 and 653 or SI-652 and 654 SCS suction isolation valves are open and RCS pressure exceeds the maximum pressure for SCS operation, an alarm will notify the operator that a pressurization transient is occurring during low temperature conditions.

Shutdown cooling is initiated using only the LPSI pumps (LPSIP), with the CSS lined up for automatic initiation of spray, bypassing the shutdown cooling heat exchanger. The SCS is warmed up and placed in operation as follows (refer to engineering drawings 01, 02, 03-M-SIP-001, -002 and -003):

1. The containment spray isolation valves for the shutdown cooling heat exchangers (SI-684*, 687*, 689, 695) are shut.
2. The containment spray valves bypassing the shutdown heat exchangers (SI-688*, 693) are opened.
3. The LPSI pump minimum flow recirculation isolation valves (SI-668, 669*) are shut.
4. The LPSI pump suction valves (SI-683*, 692) from the RWT and containment sump are shut.
5. The shutdown cooling suction line isolation valves (SI-651*, 652, 653*, 654, 655*, 656) in the two suction lines are opened.
6. The crossover valves between the LPSI pump discharge and the shutdown cooling heat exchangers (SI-685*, 694) are opened.
7. The SDCHX Discharge valves between the shutdown cooling heat exchanger outlet and the LPSI header (SI-686*, 696) are opened and the shutdown cooling throttle valves (SI-657*, 658) are cracked open.
8. The SCS warmup line isolation valves (SI-690, 691*) are opened and the LPSI pumps are started to induce recirculation flow through the SCS (flow is limited to 5000 gpm per pump).
9. Once flow has been induced in the SCS, the LPSI isolation valves (SI-615, 625, 635*, 645*) are

cracked open to allow a small amount of flow from the RCS to heat up SCS valves and piping.

10. The LPSI header isolation valves (SI-615, 625, 635*, 645*) are then gradually opened, while the warmup line isolation valves (SI-690, 691*) are gradually closed to maintain a constant flow of 5000 gpm per pump. When the LPSI header isolation valves (SI-615, 625, 635*, 645*) are open to their preset positions and the SCS warmup line isolation valves (SI-690, 691*) are closed, the SCS is aligned in its operating mode.

11. The shutdown cooling throttle valves (SI-657*, 658) and the SCS bypass flow control valves (SI-306*, 307) are adjusted as necessary to maintain the RCS cooldown rate at 75°F/hour or less, at a SCS flow of 5000 gpm through each heat exchanger.

When reactor coolant temperature decreases below 200°F (typically 170°F), the containment spray pumps are aligned to provide additional shutdown cooling flow. The SCS is realigned to the following line-up (refer to engineering drawings 01, 02, 03-M-SIP-001, -002 and -003):

1. The containment spray pump suction valves (SI-104, 105*) from the RWT and containment sump are closed.

2. The containment spray pump minimum flow recirculation line isolation valves (SI-664*, 665) are shut.

3. The containment spray bypass around the shutdown cooling heat exchanger valves (SI-688*, 693) are shut.

4. The containment spray pump suction valves (SI-184*, 185) from shutdown cooling suction lines are opened.

5. The containment spray pump discharge to the shutdown cooling heat exchanger valves (SI-684*, 689) are opened.

6. The containment spray pump discharge valves (SI-678*, 679) are opened to the position determined by preoperational testing.

7. The CSS pumps are started, and the shutdown cooling throttle valves (SI-657*, 658) are opened to give a total shutdown cooling flow of 9000 gpm per train.

Shutdown cooling is then continued using the containment spray pumps in parallel with the LPSI pumps until the refueling temperature of 135°F is attained.

A maximum rate of cooldown (not to exceed 75°F/hour) is maintained by adjusting the flowrate of reactor coolant through the shutdown cooling heat exchangers with the throttle valves on the discharge of the heat

exchangers. With the shutdown cooling flow indicators, the operator maintains a total shutdown cooling flowrate by adjusting the amount of coolant which bypasses the shutdown cooling heat exchangers.

When the system is first put into operation, the temperature difference for heat transfer is large and only a portion of the total flow from the LPSIP's is diverted through the heat exchangers. As cooldown proceeds, the temperature differential decreases and the flowrate through the heat exchangers is increased to maintain the cooldown rate.

The flow to the shutdown cooling heat exchangers is increased periodically until full LPSIP flow through the heat exchangers is reached, at which time the rate of cooldown begins a decline, which continues until the RCS is below 200°F (typically 170°F). At this point, the containment spray pumps (CSP) are realigned to provide additional shutdown cooling flow. With the combined flow of the LPSIP's and CSP's, the cooldown rate will rise. As cooldown proceeds, the rate will again go into a decline lasting until the RCS reaches refueling temperature at about 27-1/2 hours after shutdown.

A graph of RCS temp. vs. time after shutdown for a typical cooldown is presented in Figure 5.4-10 and 5.4-11.

Shutdown cooling is continued throughout the entire period of plant shutdown to maintain a refueling

water temperature of 135°F or less. Whenever shutdown cooling is in operation, shutdown purification flow may be initiated to purify the circulating coolant in the CVCS.

B. Plant Heatup

Plant heatup is a series of manual operations which bring the RCS from cold shutdown to hot standby. The SCS is used during cold shutdown to control reactor coolant temperature. Prior to plant heatup above 200°F, the CSS is aligned for automatic initiation. The SCS heat exchangers are bypassed to maintain flow through the core without the heat removal effect of the heat exchangers. Flow can be initiated to the heat exchangers if necessary to control the heatup rate. When the reactor coolant pumps can be run and prior to reaching 350°F or 400 psia, the LPSI pumps are stopped and the shutdown cooling heat exchangers are aligned for their containment spray function.

C. Abnormal Operation

1. The shutdown cooling heat exchangers may be used to supplement the spent fuel pool cooling heat exchangers when more than one-third of a spent core is stored in the spent fuel pool. Normally this would be done during refueling when both shutdown cooling heat exchangers are no longer needed to maintain reactor coolant at the refueling temperature. The SCS would be aligned with one heat exchanger train lined up to the

spent fuel pool cooling system and the other shutdown cooling heat exchanger train lined up for shutdown cooling of the RCS. The SCS heat exchanger train aligned to the spent fuel pool would be in a normal shutdown cooling lineup for use of either the LPSI or CS pump, except the pump takes suction on the spent fuel pool vice the RCS, and the discharge of the shutdown cooling heat exchanger goes to the spent fuel pool, vice the RCS.

2. Initiation of shutdown cooling with the most limiting single failure (loss of one shutdown cooling train) can be accomplished using the procedure under plant cooldown for the operable train (i.e., operating the valves with (*) for train number 1 or the valves without (*) for train number 2).

3. Following a loss of offsite power, natural circulation provides the primary method of core heat removal during hot standby and the subsequent cooldown to shutdown cooling entry conditions. As described in the natural circulation cooldown analysis, shutdown cooling is initiated to continue the cooldown and stabilize the plant in cold shutdown. A summary of the analysis is included at the end of this chapter as Appendix 5C.

D. Design Bases Event Operations

Following Design Bases Events, Shutdown Cooling may be initiated in the same manner as a normal shutdown as described in Paragraph A of Section 5.4.7.4.6.

5.4.8 REACTOR COOLANT CLEANUP SYSTEM

One function of the Chemical and Volume Control System (CVCS) is to provide radiological and chemical cleanup of the Reactor Coolant System. A description of the CVCS is given in Section 9.3.4. Radiological considerations are described in Chapters 11 and 12.

5.4.9 MAIN STEAM LINE AND FEEDWATER PIPING

The main steam line is described in section 10.3. The feedwater piping is described in subsection 10.4.7.

5.4.10 PRESSURIZER

5.4.10.1 Design Basis

The pressurizer is designed to:

A. Maintain RCS operating pressure such that the minimum pressure observed during operating transients is above the setpoint for the Safety Injection Actuation Signal and that the maximum pressure is below the high pressure reactor trip.

B. Meet the design transients specified in Section 3.9.1 except that the maximum allowable rate of change in pressurizer temperature during plant heatup and cooldown is 200°F/hr.

C. Provide sufficient water volume to prevent draining the pressurizer as a result of a reactor trip.

D. Provide sufficient water volume to prevent pressurizer heaters from being uncovered by the outsurge following a step load decrease of 10% from 25% to 15% or a 5% per minute ramp decrease from 100% to 15%.

E. Provide sufficient steam volume to yield an acceptable pressure response to normal system volume changes, during all design load change transients.

F. Provide sufficient steam volume to allow acceptance of the insurge resulting from load reduction from any load to any load without the vessel water level reaching the primary safety valve nozzles.

G. Minimize the total reactor coolant mass change and associated charging and letdown flow rates in order to reduce the quantity of wastes generated by load follow operations.

H. Provide sufficient pressurizer heater capacity to heat up the pressurizer, filled with water at the zero power level, at a rate that ensures a pressurizer temperature (and thus pressure) which will maintain an adequate degree of subcooling of the water in the reactor coolant loop as it is heated by core decay heat and/or pump work from the reactor coolant pumps.

I. Contain a total water volume that does not adversely affect the total mass and energy released to the containment during the maximum hypothetical accident.

J. Ensure that, in addition to being specified as Seismic Category I, the pressurizer vessel, including heaters, baffles, and supports shall be designed such that no damage to the equipment is caused by the frequency ranges of 19-20 cps and 95-100 cps. The lower frequency is defined as for the reactor vessel. The design basis for the higher frequency consists of a pressure pulse of 5 psi which diminishes internally within the vessel.

5.4.10.2 Description

The pressurizer, as shown in Figure 5.4-5, is a vertically mounted, bottom supported, cylindrical pressure vessel. Replaceable direct immersion electric heaters are vertically mounted in the bottom head. The pressurizer is furnished with nozzles for spray, surge, safety, and pressure and level instrumentation. A manway is provided in the top head for access for inspection of the pressurizer internals. The pressurizer surge line is connected to one of the reactor coolant hot legs and the spray lines are connected to two of the cold legs at the reactor coolant pump discharge. The pressurizer spray and surge nozzles are furnished with a thermal sleeve to withstand specified plant transients during the design life. Heaters are supported inside the pressurizer to preclude damage from vibration and seismic loadings. Principal design parameters are listed in Table 5.4-37.

The pressurizer is designed and fabricated in accordance with the ASME Code listed in Table 5.2-1. The interior surface is clad with weld deposited stainless steel.

The total volume of the pressurizer is established by consideration of the factors given in Section 5.4.10.1. To account for these factors and to provide adequate margin at all power levels, the water level in the pressurizer is programmed as a function of average coolant temperature as shown in Figure 5.4-2, in conjunction with Figure 5.4-3. High or low water level error signals result in the control actions shown in Figure 5.4-4. The pressurizer surge line is sized to accommodate the flow rates associated with the RCS expansion and contraction due to the transients specified in Section 3.9.1.

The pressurizer maintains Reactor Coolant System operating pressure and, in conjunction with the Chemical and Volume Control System (CVCS), Section 9.3.4, compensates for changes in reactor coolant volume during load changes, heatup, and cooldown. During full-power operation, the pressurizer is about one-half full of saturated steam. Reactor Coolant System pressure may be controlled automatically or manually by maintaining the temperature of the pressurizer fluid at the saturation temperature corresponding to the desired system pressure. A small continuous spray flow is maintained to the pressurizer to avoid stratification of pressurizer boron concentration and to maintain the temperature in the surge and spray lines, thereby reducing thermal shock as the spray control valves open. An auxiliary spray line is provided from the charging pumps to permit pressurizer spray during plant heatup, or to allow cooling if the reactor coolant pumps are shut down. The pressurizer spray nozzle usage factor is calculated and limited as described in Table 5.4-38.

During load changes, the pressurizer limits pressure variations caused by expansion or contraction of the reactor coolant. The average reactor coolant temperature is programmed to vary as a function of load as shown in Figure 5.4-3. A reduction in load is followed by a decrease in the average reactor coolant temperature to the programmed value for the lower power level. The resulting contraction of the coolant lowers the pressurizer water level, causing the reactor system pressure to decrease. This pressure reduction is partially compensated by flashing of pressurizer water into steam. All pressurizer heaters are automatically energized on low system pressure, generating steam and further limiting pressure decrease. Should the water level in the pressurizer drop sufficiently below its setpoint, the letdown control valves close to a minimum value, and additional charging pumps in the chemical and volume control system are automatically started to add coolant to the system and restore pressurizer level.

When steam demand is increased, the average reactor coolant temperature is raised in accordance with the coolant temperature program. The expanding coolant from the reactor coolant piping hot leg enters the bottom of the pressurizer through the surge line, compressing the steam and raising system pressure. The increase in pressure is moderated by the condensation of steam during compression and by the decrease in bulk temperature in the liquid phase. Should the pressure increase be large enough, the pressurizer spray valves open, spraying coolant from the reactor coolant pump discharge (cold leg) into the pressurizer steam space. The relatively cold spray water condenses some of the steam in the steam space,

limiting the system pressure increase. The programmed pressurizer water level is a temperature dependent function. A high level error signal, produced by an in-surge, causes the letdown control valves to open, releasing coolant to the chemical and volume control system and restoring the pressurizer to the programmed level. Small pressure and primary coolant volume variations are accommodated by the steam volume that absorbs flow into the pressurizer and by the water volume that allows flow out of the pressurizer.

The pressurizer heaters are single unit, direct immersion heaters that protrude vertically into the pressurizer through sleeves welded in the lower head. Each heater is internally restrained from high amplitude vibrations and can be individually removed for maintenance during plant shutdown. There are 35 pressurizer heaters in Unit 1 (1 abandoned in place), 34 pressurizer heaters in Unit 2 (2 abandoned in place), and 36 pressurizer heaters in Unit 3.

A number of the heaters are connected to proportional controllers, which adjust the heat input to account for steady-state losses and to maintain the desired steam pressure in the pressurizer. The remaining heaters are connected to on-off controllers. These heaters are normally deenergized except those required to compensate for main spray bypass flow. The backup heaters are automatically turned on by a low pressurizer pressure signal or a high level error signal. This latter feature is provided since load increases result in an in-surge of relatively cold coolant into the pressurizer, thereby decreasing the bulk water temperature. The CVCS acts to restore level, resulting in a transient pressure below normal

operating pressure. To minimize the extent of this transient, the backup heaters are energized, contributing more heat to the water. Backup heaters are deenergized in the event of concurrent high-level error and high-pressurizer pressure signals. A low-low pressurizer water level signal deenergizes all heaters before they are uncovered to prevent heater damage. The pressure control program is shown in Figure 5.4.-1.

5.4.10.3 Evaluation

It is demonstrated by analysis in accordance with requirements for ASME Code, Section III, Class 1 vessels that the pressurizer is adequate for all normal operating and transient conditions expected during the life of the facility. Following completion of fabrication, the pressurizer is subjected to the required ASME Code, Section III hydrostatic test and post-hydrostatic test non-destructive testing.

During hot functional testing, the transient performance of the pressurizer is checked by determining its normal heat losses and maximum pressurization and depressurization rates. This information is used in setting the pressure controllers.

Further assurance of the structural integrity of the pressurizer during plant life will be obtained from the inservice inspections performed in accordance with ASME Code, Section XI, and described in Section 5.2.

Overpressure protection of the Reactor Coolant System is provided by four ASME Code spring-loaded safety valves. Refer to Section 5.4.12 and 5.4.13.

5.4.10.4 Tests and Inspections

Prior to and during fabrication of the pressurizer, non-destructive testing is performed in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code. Table 5.4-39 summarizes the pressurizer inspection program, which also includes tests not required by the Code. Refer to Section 5.2.1 for inservice inspections of the pressurizer.

5.4.11 PRESSURIZER RELIEF DISCHARGE SYSTEM

The reactor drain tank is used as the pressurizer relief tank. The design and description of this tank are given in Section 9.3.4.

5.4.12 VALVES

5.4.12.1 Design Basis

The safety related functions of valves within the RCS pressure boundary are to act as pressure retaining vessels and leak-tight barriers during normal operation, accidents and seismic events.

The valves are designed and fabricated in accordance with ASME B&PV Code, Section III, Class I requirements. These valves must withstand the affects of system design transients (Section 3.9.1) and any other transients associated with the individual valve's location or service requirements. The valves are designed to meet Seismic Category I requirements. Backseats are specified on manual and motor operated gate and globe valves to minimize valve stem leakage.

TABLE 5.4-37
PRESSURIZER PARAMETERS

Property	Parameter
Design pressure, psia	2500
Design temperature, °F	700
Normal operating pressure, psia	2250
Normal operating temperature, °F	652.7
Internal free volume, ft^3	1800
Normal (full power) operating water volume, ft^3	900
Normal (full power) steam volume, ft^3	900
Installed heater capacity, KW	1800[(1)(4)]
Heater type	Immersion
Spray flow, maximum, gal/min	525[(2)]
Spray flow, continuous, gal/min	~1[(3)]
Nozzles	
Surge, in. (nominal)	12, schedule 160
Spray, in. (nominal)	4, schedule 160
Safety valves, in. (nominal)	6, schedule 160
Instrument	
Level, in. (nominal)	3/4, schedule 160
Temperature, in. (nominal)	1, schedule 160
Pressure, in. (nominal)	3/4, schedule 160
Heater, O.D., in.	1-1/4

(1) Unit 2 has 1700 KW of installed heater capacity. This difference is due to the failure of two heaters, which have been abandoned in place.

(2) The nominal main pressurizer spray flow rate is approximately 475 gpm including the bypass flow assuming that both main spray valves are full open under typical RCS conditions (core ΔP = 70 psid and average spray fluid temperature = 565°F). The table value includes a 10% margin to account for method and process uncertainties.

(3) The table value represents the estimated flow rate through each bypass valve at nominal RCS conditions. Individual bypass valve positions have been adjusted so that each valve provides sufficient flow to maintain the fluid temperature difference between the cold legs and the spray nozzle inlet piping less than 70°F.

(4) Unit 1 has 1750 KW of installed capacity. This difference is due to the failure of one heater which has been abandoned in place.

Table 5.4-38
PRESSURIZER SPRAY NOZZLE USAGE FACTOR
(Sheet 1 of 2)

The pressurizer spray nozzle usage factor is calculated as shown below for conditions when the main spray (less than four RCPs operating ΔT_m[(a)] >200F, and/or auxiliary spray ΔT_a[(b)] >200 F.

Main Spray				Auxiliary Spray			
ΔT_m	N_A	N	N/N_A	ΔT_a	N_A	N	N/N_A
201-250	33,400			201-250	26,900		
251-300	13,100			251-300	10,800		
301-350	6,700			301-350	5,200		
351-400	4,100			351-400	2,900		
401-450	2,900			401-450	1,800		
451-500	2,400			451-500	1,200		
501-550	2,100			501-550	890		
				551-600	680		
				601-650	540		
		$\Sigma N/N_A$ = ______	________			$\Sigma N/N_A$ =	____________

Cumulative Usage Factor

$\Sigma N/N_A$(Main Spray) ____________

$\Sigma N/N_A$(Aux. Spray) ____________

Total ____________ = Cumulative Usage Factor

Where:

$\Delta T_a = (T_{101} - T_{229}) + 60$

$\Delta T_m = (T_{103*} \text{ or } _{104*}) + 70$

N_A = Allowable number of spray cycles

N = Number of cycles in ΔT range indicated

Table 5.4-38
Pressurizer Spray Nozzle Usage Factor
(Sheet 2 of 2)

Calculational Method:

1. The spray cycle is defined as any initiation and termination of main or auxiliary spray flow throughout the pressurizer spray nozzle.

2. If the difference between pressurizer water temperature and the spray water temperature exceeds 200F each spray cycle and the corresponding temperature difference is logged. These are the controlling pressurizer spray transients. The non-controlling pressurizer spray transients include plant heatup/cooldown, system hydrostatic/leak test, and spray cycle events where ΔTm or ΔTa less than 200°F. The non-controlling cumulative usage factor is accounted for in the 0.65 limit.

3. The spray nozzle usage factor shall be calculated as follows:

   A. Fill in Column "N" above

   B. Calculate "N/N_A" (Divide N by N_A)

   C. Add column "N/N_A" to find Σ N/N_A

   Σ N/N_A is the cumulative spray nozzle usage factor. If the cumulative usage factor is equal to or less than 0.65 no further action is required.

4. If the cumulative usage factor exceeds 0.65, subsequent pressurizer spray operation shall continue to be monitored and an engineering evaluation of nozzle fatigue shall be performed within 90 days. The evaluation shall determine that the nozzle remains acceptable for additional service beyond the 90 day period or subsequent spray operation shall be restricted so that the difference between the pressurizer water temperature and the spray water temperature shall be limited to less than or equal to 200F when spray is operated.

*Use lower temperatures

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a. ΔT_m = The difference in temperature between the pressurizer and main spray water as adjusted by the instrument correction factor.

b. ΔT_a = The difference in temperature between the pressurizer and auxiliary spray water as adjusted by the instrument correction factor.

TABLE 5.4-39
PRESSURIZER TESTS

Component	Tests[a]
Heads	
Plates	UT, MT
Cladding	
Shell	
Plates	UT, MT
Cladding	UT, PT
Heaters	
Tubing	UT, PT
Centering of elements	RT
End Plug	UT, PT
Nozzle (Forgings)	UT, MT
Studs	UT, MT
Welds	
Shell, longitudinal	RT, MT
Shell, circumferential	RT, MT
Cladding	UT, PT
Nozzles	RT, MT
Nozzle safe ends	RT, PT
Instrument connections	PT
Support Skirt	MT, RT
Temporary attachment after removal	MT
All welds after hydrostatic test	MT or PT
Heater assembly, end plug weld	PT

(a) Key:

UT= ultrasonic testing

MT= magnetic particle testing

PT= dye-penetrant testing

RT= radiographic testing

Control of valve stem leakage for valves used in the RCS pressure boundary is accomplished through several different methods depending on the design of the individual valve. All valves use valve packing. Some valves have a conventional packing design. Other valves may have double packing with a leak-off connection at the lantern ring. The leak-off connection provides a method of collecting any leakage that may occur around the valve stem.

During original plant design, an evaluation determined that leakoffs piped to the reactor drain tank present a greater ALARA concern than capping the valve leakoff. The cap has been designed as part of the RCS pressure boundary. The leakoffs for all RCS valves are capped except for the pressurizer spray control (RC-100E and 100F) and bypass (RC-236 and 237) valves.

Manual globe valves with a bellows seal are also utilized as RCS pressure boundary valves. These valves are designed and fabricated in accordance with ASME B&PV Code, Section III, Division I, Class NB requirements. The bellows seal valves also employ a packing set as a backup to the bellows to prevent leakage.

5.4.12.2 Design Description

All valves in the RCS are constructed primarily of stainless steel. Other materials in contact with the reactor coolant, such as hard facing and packing, are fabricated from materials that are compatible with the RCS and reactor coolant. Yoke and other miscellaneous fasteners and packing gland assemblies are constructed of stainless steel to eliminate corrosion concerns.

5.4.12.3 Design Evaluation

Stress analyses that take into consideration cyclic loadings have been performed for all valves within the RCS pressure boundary. These analyses are performed in accordance with ASME B&PV Code, Section III, Class I requirements.

5.4.12.4 Tests and Inspections

The valves are hydrostatic and leak tested in accordance with ASME B&PV Code as specified in Table 5.2-1. The leak tests include testing for leakage across the valve seats and across the valve packing.

5.4.13 SAFETY AND RELIEF VALVES

5.4.13.1 Design Basis

The safety valves on the pressurizer are designed to protect the system, as required by the ASME B&PV Code, Section III.

The design basis for establishing the relieving capacity of the pressurizer safety valves is presented in Appendix 5B. For the postulated transients presented in Chapter 15, the results indicate that relieving capacity of the safety valves is sufficient to provide overpressure protection in accordance with Section III of the ASME Code.

Safety valves on the steam side of each steam generator are designed to protect the steam system, as required by the ASME Code, Section III. They are conservatively sized to pass a steady flow equivalent to the maximum expected power level at the design pressure of the steam system.

5.4.13.2 Description

The RCS has four safety valves to provide overpressure protection. A typical safety valve is illustrated in Figure 5.4-6. The design parameters are given in Table 5.4-40. These valves are connected by piping to the top of the pressurizer. They are direct acting, spring-loaded safety valves meeting ASME Code requirements. They have an enclosed bonnet and have a balanced bellows to compensate for back pressure. The safety valves pass sufficient pressurizer steam to limit the reactor coolant system pressure to 110% of design pressure (2750 psig) following a complete loss of turbine generator load without simultaneous reactor trip. A delayed reactor trip is assumed on a high-pressurizer pressure signal. To determine maximum steam flow through the pressurizer safety valves, the main steam safety valves are assumed to be operational. Values for the system parameters, delay times, and core moderator coefficient are given in Chapter 15.

Overpressure protection for the shell side of the steam generators and the main steam line up to the inlet of the turbine stop valves is provided by the secondary safety valves. A typical main steam safety valve is illustrated in Figure 5.4-7.

These valves (20 total) are sized to a minimum steam flow capacity of $19x10^6$ lb/hr at accumulation pressure (see Table 5.4-41). This limits steam generator pressure to less than 110% of steam generator design pressure during worst case transients. The secondary safety valves consist of 10 valves per steam generator (5 valves per steam line) with staggered

set pressures. The valves are spring-loaded safety valves procured in accordance with ASME Boiler and Pressure Vessel Code, Section III (see Table 5.2-1). Parameters for the secondary safety valves are given in Table 5.4-41.

5.4.13.3 Evaluation

Overpressure protection is discussed in Section 5.2.2. The ASME Code report on Overpressure Protection is provided in Appendix 5B.

5.4.13.4 Tests and Inspections

The safety valves are inspected during fabrication in accordance with ASME B&PV Code, Section III, requirements.

5.4.13.4.1 Pressurizer Safety Valves

The inlet and outlet portions of the safety valves are hydrostatically tested with water at the appropriate pressures in accordance with the applicable section of the ASME B&PV Code. The set pressure of each safety valve is verified using steam and restricted lift of the valve. The set pressure is adjusted as needed and shall be made by selecting a valve ring setting combination that provides stable valve operation. The selection of the valve ring setting combination is based on the results from the EPRI Safety Valve Test Program[1]. The final set pressure is then verified using steam. Steam is also utilized to check for seat leakage.

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(1) CEN-227 "Summary Report on the Operability of Pressurizer Safety Relief Valve in C-E Designed Plants," December 1982.

TABLE 5.4-40

PRESSURIZER SAFETY VALVE PARAMETERS

Property	Parameter
Design pressure, lb/in.^{2}a	2500
Design temperature, °F	700
Fluid	Saturated Steam, 4400 ppm, boron, pH = 4.5 to 10.6
Set pressure, lb/in.^{2}a	2475 + 3%, -1%
Min. capacity, lb/h at accumulation pressure, each	473,300
Type	Spring loaded safety-balanced bellows. Enclosed bonnet.
Orifice area, in.^{2}	4.34
Accumulation, %	3
Backpressure	
Max. buildup/max superimposed, lb/in.^{2}g	700/340
Minimum blowdown, %	5
Typical materials	
Body	ASME SA 182, GR. F316
Disc	ASTM A637, GR. 688
Nozzle	ASME SA 182, GR. 347

TABLE 5.4-41
MAIN STEAM SAFETY VALVE PARAMETERS

Property	Parameter
Design pressure, lb/in.^{2}g	1375
Design temperature, °F	575
Fluid	Saturated Steam
Set pressure, lb/in.^{2}g	1250, 1290, 1315
Min. capacity, lb/h at accumulation pressure	19 x 10^6 Total (20 Valves)
Type	Spring loaded
Orifice area, in.^{2}	16
Accumulation, %	3
Backpressure	
Max. buildup/max superimposed, lb/in.^{2}g	125/0
Approx. dry weight, lbs.	1545
Minimum blowdown pressure, psig	1175
Typical materials	
Body	ASME SA 105
Disc	ASTM A565, GR. 616 or ASTM B637, Alloy X-750
Nozzle	ASME SA 182, GR. F316

5.4.13.4.2 Main Steam Safety Valves

The inlet and outlet portions of the safety valves are hydrostatically tested with water at the appropriate pressures in accordance with the applicable section of the ASME B&PV Code. The set pressure of each safety valve is verified using steam and restricted lift of the valve. The set pressure is adjusted as needed. The final set-pressure and seat leakage are verified using steam. Another acceptable method of testing each safety valve is to test the valve while it is installed on the main steam line using steam produced by the plant and a hydraulic assist device. Seat leakage may also be verified using steam produced by the plant and a hydraulic assist device.

5.4.14 COMPONENT SUPPORTS

5.4.14.1 Design Basis

The criteria applied in the design of the Reactor Coolant System supports are that the specific function of the supported equipment be achieved during all normal, earthquake, and Loss-of-Coolant Accident (LOCA) conditions. Specifically, the supports are designed to support and restrain the Reactor Coolant System components under the combined Safe Shutdown Earthquake and Loss-of-Coolant Accident loadings in accordance with the stress and deflection limits of Section III, ASME Code.

5.4.14.2 Description

Figure 5.4-12 illustrates the Reactor Coolant System support points. A description of the supports for each supported component follows:

A. Reactor Vessel Supports

The reactor vessel is supported by four vertical columns located under the vessel inlet nozzles. These columns are designed to flex in the direction of horizontal thermal expansion and thus allow unrestrained heatup and cooldown. They also act as holddown devices for the vessel.

Horizontal keyways located alongside the upper portion of the column guide the vessel during thermal expansion and contraction of the Reactor Coolant System and maintain the vessel centerline.

Four horizontal keys are welded to the bottom vessel head. The column base plate acts as a keyway for these keys to restrain the bottom of the vessel.

The supports are designed to accept normal loads and seismic and pipe rupture accident loads.

Reactor vessel supports are shown in Figure 5.4-13.

B. Steam Generator Supports

The steam generator is supported at the bottom by a sliding base bolted to an integrally attached conical skirt. The sliding base rests on low friction bearings which allow unrestrained thermal expansion of the Reactor Coolant System. Two keyways within

the sliding base mate with embedded keys to guide the movement of the steam generator during expansion and contraction of the Reactor Coolant System and, together with a stop and anchor bolts, limit movement of the bottom of the steam generator during seismic events and following a LOCA.

A system of keys and snubbers located on the steam drum guide the top of the steam generator during expansion and contraction of the Reactor Coolant System and provide support during seismic events and following a LOCA or a steam line break.

Typical steam generator supports are shown in Figure 5.4-14.

C. Reactor Coolant Pump Supports

Each reactor coolant pump is provided with four vertical support columns, four horizontal support columns, and two horizontal snubbers. The rigid structural columns provide support for the pumps during normal operation, earthquake conditions, and any Design Basis Pipe breaks in either the pump suction or discharge line. An illustration of the pumps supports is shown in Figure 5.4-15.

For the case of pipe break in the pump discharge line, a structural stop is provided to limit the pump motion. Pipe stop structures which limit pipe motion also prevent overloading of the pump support columns due to a pipe rupture at either the steam generator or reactor vessel nozzles.

D. Pressurizer Supports

The pressurizer is supported by a cylindrical skirt welded to the pressurizer and bolted to the support structure. The skirt is designed to withstand deadweight and normal operating loads as well as the loads due to earthquakes and LOCA. Four keys welded to the upper shell provide additional restraint during a postulated seismic event.

E. Where appropriate, load limiting devices are used to reapportion the loading applied to elements of redundant supports.

5.4.14.3 Evaluation

The structural integrity of the reactor coolant system support components is ensured by quality assurance inspections in accordance with Section III of the ASME Code during fabrication. The non-integral supports are procured by individual equipment specifications which impose appropriate quality assurance requirements commensurate with the respective component's functions.

During pre-operational testing of the Reactor Coolant System, the support displacements will be monitored for concurrence with calculated displacements and/or clearances. Subsequent inspections of supports which are integral with Reactor Coolant System components will be in accordance with Section XI of the ASME Code.

5.4.15 REACTOR COOLANT REDUCED INVENTORY OPERATIONS

There are limited periods during plant operation when the reactor coolant system may be operated with reduced inventory while irradiated fuel is in the reactor vessel. Examples include refueling outages or maintenance evolutions. A reduced inventory condition, which includes mid loop conditions, exists whenever the reactor coolant system level is lower than the 111 ft elevation, which is three feet below the vessel flange. This section describes the administrative controls and instrumentation relied upon during reduced inventory operations.

Generic Letter 88-17, Loss of Decay Heat Removal, was issued to address continuing problems that were occurring throughout the industry with respect to maintaining decay heat removal capability.

5.4.15.1 Generic Letter 88-17, Loss Of Decay Heat Removal

The following measures have been implemented to address the potential for the loss of decay heat removal when fuel is in the core and the head is located on the reactor vessel during RCS reduced inventory operations:

- At least two core exit thermocouples (CETs) are manintained except during the short period of time immediately following reactor head placement and prior to head removal. Shutdown cooling heat exchanger inlet temperature is credited for monitoring RCS temperatures during this period.
- An RCS hot side vent (e.g., pressurizer manway removal) is established to prevent core uncovery due to pressurization of

the hot leg side from any potential boiling of the core coolant. The vent is established prior to establishing cold leg RCS openings in excess of one square inch or blocking both hot legs with nozzle dams.

- At least two available means for adding inventory to the RCS are provided. The available paths ensure that makeup water will not bypass the reactor vessel (e.g., gravity feed from the RWT, HPSI, and/or charging).

- Administrative controls provide for timely containment closure should a loss of shutdown cooling occur.

In response to Generic Letter 88-17, and to address pump protection issues, a low flow alarm for the pumps used for shutdown cooling (i.e., LPSI and CS) provides visible and audible indication in the control room if flow decreases below the low flow set point during shutdown cooling operations. Administrative controls are also provided to preclude CS pump operation for normal operations when the RCS water level is at or below the top of the hot-leg (elevation 103’-1”) to protect against possible surface vortexing and consequential air entrainment into the CS pumps suction.

5.4.15.2 Refueling Water Level Indication System

A permanent refueling water level indication system (RWLIS) was installed in each of the units and is used to monitor RCS inventory. The installation of this system was a commitment from Generic Letter 88-17 and replaced reliance upon temporary level indication devices and related procedures.

This permanent system was designed as a non-safety grade system that would provide a high degree of reliability. This system is shown in engineering drawings 01, 02, 03-M—SIP-001, and -002 and is referred to as the refueling water level monitoring system.

The RWLIS provides continuous refueling water level indication for each reactor coolant system hot leg to the control room. The control room indications consists of narrow and wide range level indication for each hot leg and a common level recorder. The level signals are inputted into the plant computer for trending and into the plant annunciator system for control room alarms. The control room alarms provide visible and audible indication to the operator in the event of a low or low-low refueling water level condition.

In accordance with the recommendations of Generic Letter 88-17, the RWLIS provides an independent level monitoring channel for each reactor coolant system hot leg. Channel independence is maintained up to the common reference leg isolation valve and tap, and up to the control room alarm input selector switch. Channel independence is not maintained in the instrument reference legs due to the very low probability that this small section of tubing and associated valve would become plugged. Channel independence also is not maintained in the RCS low level alarm input circuitry to give the operator the flexibility to select the appropriate alarm inputs such that spurious or nuisance alarms may be reduced or eliminated, as described below.

The RWLIS is provided with flow compensation from the shutdown cooling system. This compensation is required due to the location of the RWLIS instrument taps on the shutdown cooling system and due to the effects of shutdown cooling flow. As the shutdown cooling system flow increases, the pressure at the RWLIS instrument taps decreases, which results in the indicated level being lower than the actual level. Each shutdown cooling loop provides flow information to the respective RWLIS channels. This information is used to modify the actual level signals such that accurate refueling water levels are indicated in the control room.

During periods of reduced inventory operation in the reactor coolant system, the RWLIS associated with the operating shutdown cooling loop may experience nuisance low and low-low level alarms. These alarms result from the reduced inventory in the reactor coolant system and the minor flow oscillations that occur in the shutdown cooling line as a result of the lowered inventory condition. In order to maximize control room operator awareness, a selector switch is provided in the main control room that will allow the operator to select the non-operating shutdown cooling loop RWLIS for control room alarm input. This action essentially removes all nuisance alarms and ensures that the operator will not be distracted from responding to an actual low or low-low refueling water level condition. Both channels of level indication, however, will still provide control room level indication regardless of this selector switch's position.

A rapid vent connection is provided upstream of the flow restricting orifice in the reactor head vent piping. This

connection increases the venting area for the system in order to minimize lags between RWLIS indication and level in the reactor vessel at reduced inventory conditions.

TABLE 5.4-42
REACTOR COOLANT PUMP PARAMETERS

Number of Units	4
Type	Vertical, single stage centrifugal
Design Total Dynamic Head, ft*	365
Design Flow, gpm	111,400
Design Pressure, psia	2500
Design Temperature, F	650
Normal Operating Pressure, psia	2250
Normal Operating Temperature, F*	565
NPSH Required (at design flow), ft*	220
Suction Temperature, F*	564.5
Water Volume, each, ft^3	134
Weight (including motor), dry, lbs.	279,000
Shaft Seals	Mechanical Face Seals
Pump Speed, rpm*	1190
Motor Synchronous Speed, rpm	1200
Motor Type	AC Induction
Horsepower, hot*	9000
cold	12,000
Rated Brake Horsepower	12,000
Voltage	13,200
Phase	3
Frequency	60 Hz
Insulation Class	F
Starting Current, at 100% Voltage, amps	3,000

____

*Parameters are related to four-pump, full power operating conditions.

TABLE 5.4-43
SHUTDOWN COOLING DESIGN PARAMETERS (CESSAR TABLE 5.4.7-1)

System Design Parameters

Shutdown cooling system startup	Approximately 3.5 hours after reactor shutdown or trip
Reactor coolant system maximum cooldown rate (at initiation of shutdown cooling)	75°F/hr
Refueling water temperature	135°F
Nominal shutdown cooling flow	9000 gpm per HX

Component Design Parameters
Shutdown Cooling Heat Exchanger Data

Quantity	2
Type	Shell and tube, horizontal U-tube
Service transfer rate, Btu/hr-°F-ft^2	378.8
Heat Transfer area (ft^2/Hx)	7515
Tube Side	
Fluid	Reactor coolant
Design pressure, psig	650
Design temperature, °F	450
Material	Austenitic stainless steel
Code	ASME Section III, Class 2
Fouling resistance (hr-ft^2-°F/Btu)	0.00025
Shell Side	
Fluid	Component cooling water
Design pressure, psig	150
Design temperature °F	250
Material	Carbon Steel
Code	ASME Section III, Class 3
Fouling resistance (hr-ft^2-°F/Btu)	0.0005

At 27-1/2 hours after shutdown: (if containment spray pumps are used)

Tube Side	
Flow, million lb/hr.	4.44
Inlet temperature, °F	125.0
Outlet temperature, °F	115.1
Shell Side	
Flow, million lb/hr.	6.96
Inlet temperature, °F	105.0
Outlet temperature, °F	111.3
Heat load, million Btu/hr	43.8

TABLE 5.4-44
INTERFACE REQUIREMENTS FOR COMPONENT COOLING WATER
(CESSAR TABLE 5.4.7-2)

Mode	Shutdown Cooling (3.5 hrs.)	Shutdown Cooling (27.5 hrs)	Recirculation Following LOCA (Large Break)
Supply Temp °F (Max)(1)	120°	105°	120°
Outlet Temp °F	144.6°	114.5°	(Note 2)
Flow per SDCHX (gpm)(3)	11,000 min.	11,000 min.	11,000 min.
Total Heat Load (10^6 $\frac{Btu}{hr}$) For Both SDCHX	268	87.6	(Note 2)

NOTES: (1) For maximum supply temperatures lower than those listed, the minimum flow listed may be reduced provided that the heat removal capability of the Shutdown Cooling System is not adversely affected. Conversely, for Component Cooling Water supply temperatures lower than those listed, it may be necessary to reduce flow, so that the heat capacity of the ultimate heat sink is not exceeded.

(2) This outlet temperature and heat load are dependent upon the Applicant’s containment design and are a function of sump water temperature. For example, for shell side parameters of 11,000 gpm at 120°F, the heat load for a tube side temperature of 270° and flow rate of 3500 gpm is 164 x 10^6 Btu/hr per SDCHX. See Applicant’s SAR for details.

(3) Maximum allowable component cooling water flow through each shutdown cooling heat exchanger is 13,000 gpm.

APPENDIX 5A

RESPONSES TO NRC REQUESTS FOR INFORMATION

CONTENTS

APPENDIX 5A

<u>QUESTION 5A.1</u> (NRC comment on subsection 5.2.4) (6/18/80) (5.2.4)

Only addresses accessibility of inspection areas.

RESPONSE: The response is given in amended subsection 5.2.4.

<u>QUESTION 5A.2</u> (NRC comment on paragraph 5.3.1.6) (6/18/80) (5.3.1.6)

Only addresses Unit 1 reactor vessel.

RESPONSE: The response is given in amended paragraph 5.3.1.6.

<u>QUESTION 5A.3</u> (NRC Question 410.6) (5.2.5)

Provide the following additional information concerning leakage from the reactor coolant pressure boundary:

a) Provide further detail of how the reactor drain tank (RDT) can be used to detect leakage of primary coolant to the shutdown cooling system as identified in FSAR paragraph 5.2.5.1.5.

b) Describe the means of detection of leakage of primary coolant from the CVCS, reactor coolant pump seals, and other radioactive fluid sources to normally nonradioactive systems such as the nuclear cooling water system.

c) Verify that the containment radioactive gas and air particulate monitor has a sensitivity for detecting a 1 gallon per minute RCPB leak in 1 hour in accordance with the guidelines of Regulatory Guide 1.45.

RESPONSE:

a) The response is given in amended paragraph 5.2.5.1.5.

b) The response is given in amended paragraph 5.2.5.1.5.

c) The response is given in Section 1.8, Regulatory Guide 1.45.

QUESTION 5A.4 (NRC Question 121.1)

Information supplied in FSAR Technical Specifications Section 16.3/4.4.5 concerning steam generator tube inspection is either incomplete or inadequate. In order to demonstrate compliance with NRC requirements, revise the following areas of this FSAR section to be consistent with NUREG-0212, Revision 1, "Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors":

1. Change the wording with regard to the first tube samples in Section 4.4.5.2.b to be consistent with the corresponding section in NUREG-0212;

2. Change the wording with regard to the second and third tube samples in Section 4.4.5.2.c to be consistent with the corresponding section in NUREG-0212;

3. Include the additional requirements listed in NUREG-0212 regarding eddy current testing in Section 4.4.5.2.b.3;

4. Change the wording in Section 4.4.5.3.b to be consistent with the corresponding in NUREG-0212;
5. Include additional requirement listed in NUREG-0212 regarding preservice inspection in Section 4.4.5.4.a.9;
6. Include additional requirement listed in NUREG-0212 with regard to the reporting requirements in Sections 4.4.5.5.a, 4.4.5.5.b, 4.4.5.5.c.

RESPONSE: Refer to Technical Specifications for steam generator tube inspection requirements.

QUESTION 5A.5 (NRC Question 251.1) (5.2)

Specify the edition and addenda to which all reactor coolant pressure boundary components were fabricated.

RESPONSE: The response is provided in amended table 5.2-2.

QUESTION 5A.6 (NRC Question 251.2)

To demonstrate compliance with the beltline material test requirements of Paragraph III.C.2 of Appendix G, 10CFR Part 50:

a) Provide a schematic of the reactor vessel showing all welds, plates, and/or forgings in the beltline. Welds should be identified by shop control number, weld procedure qualification number, the heat of filler metal, and type and batch of flux. Provide the chemical composition for these welds (particularly Cu, P, and S content). Identify material specification, type, and grade of all base metal.

b) Provide dropweight NDT and complete CVN curves of energy and lateral expansion versus temperature for the weld metal(s) in the beltline.

c) Provide dropweight NDT and complete CVN curves of energy and lateral expansion versus temperature for the base metal in the beltline.

d) If beltline welds were fabricated using submerged arc or shielded metal arc electrode, the heat affected zones are considered acceptable and no additional data is required; otherwise fracture toughness data in accordance with Paragraph NB-2330 of the ASME Code must be provided.

e) Indicate the post-weld heat treatment used in the fabrication of the test welds.

f) Identify the plates used to fabricate the test welds.

g) Indicate whether the test specimen for the longitudinal seams were removed from excess material and welds in the vessel shell course following completion of the longitudinal weld joint.

RESPONSE:

a) A schematic of the reactor vessel beltline region showing weldseam numbers and plate code numbers is shown in figure 5.2-6.

Weld procedure qualification numbers and associated fracture toughness data from weld procedure

qualification tests for the reactor vessel are given in tables 5.2-10, 5.2-10A, and 5.2-10B.

Weld metal used in the fabrication of the reactor vessel beltline and its fracture toughness properties from weld metal certification tests is given in tables 5.2-9, 5.2-9A, and 5.2-9B.

Chemical composition of welds in the reactor vessel beltline is given in tables 5.3-2, 5.3-4, and 5.3-6.

Chemical composition of plates in the beltline is given in tables 5.3-1, 5.3-3, and 5.3-5.

b) Dropweight NDT and RT_{NDT} for weld metal used in the beltline of the reactor vessel are given in tables 5.2-9, 5.2-9A, and 5.2-9B.

Full CVN curves for the weld metals in the beltline are given in figure 5.2-1 (sheets 7 through 20).

c) Dropweight NDT and RT_{NDT} for the base metal used in the beltline of the reactor vessel are given in table 5.2-5.

Full CVN curves for the base metal in the reactor vessel beltline are given in figure 5.2-1 (sheets 1 through 6).

d) The response is given in amended paragraph 5.2.3.3.1.1.

e) The response is given in amended paragraph 5.2.3.3.1.1.

f) The response is given in amended paragraph 5.2.3.3.1.1.

g) The response is given in amended paragraph 5.2.3.3.1.1.

QUESTION 5A.7 (NRC Question 251.3)

To demonstrate compliance with the fracture toughness requirements of Paragraph IV.A.1 of Appendix G, 10CFR Part 50:

a) Provide the RT_{NDT} for all RCPB welds and ferritic base metals which may be limiting for operation of the reactor vessel. If the RT_{NDT} has been determined by methods other than that specified in Paragraph NB-2330 of the ASME Code, identify the method and provide technical justification.

b) Indicate whether there are any RCPB heat affected zones which require CVN impact testing per Paragraph NB-4335.7 of the ASME Code. Provide CVN impact test data for these heat affected zones which may be limiting for operation of the reactor vessel.

RESPONSE:

a) Limiting RT_{NDT} values for the RCPB base metals and weld metals which may be limiting for operation of the reactor vessel was provided along with the pressure temperature limit curves (NRC Question 251.6).

b) All base metal used in the fabrication of the reactor vessel are of P number 3 classification. The heat affected zone CVN impact test data obtained from weld procedure qualification tests (NB-4335.2) is given in tables 5.2-10, 5.2-10A, and 5.2-10B.

   The RT_{NDT} in the reactor vessel heat affected zone that may be limiting for operation of the reactor vessel was

provided along with the pressure temperature limit curves (NRC Question 251.6).

<u>QUESTION 5A.8</u> (NRC Question 251.4)

Demonstrate compliance with ASME Code, Paragraphs NB-2332 and NB-2333, on the following ferritic reactor coolant pressure boundary components: ferritic piping, pumps, valves, and bolts and fastening materials.

a) Provide the ASME Code and Addenda which the applicant utilized for fabrication of the above materials.

b) If the applicant's RCPB materials do not comply with the requirements of Section 50.55a, 10CFR Part 50, submit CVN impact data for each heat and lot of material.

RESPONSE:

a) The response is given in amended table 5.2-1.

b) The RCPB materials comply with the requirements of 10CFR50, Section 50.55a.

<u>QUESTION 5A.9</u> (NRC Question 251.5)

Provide data on the qualifications of the personnel performing the fracture toughness tests to demonstrate compliance with Paragraph III.B.4 of Appendix G, 10CFR Part 50.

RESPONSE: The response is given in amended paragraph 5.2.3.3.1.1.

<u>QUESTION 5A.10</u> (NRC Question 251.6)

Provide pressure-temperature limit curves for the reactor pressure vessel.

RESPONSE: Pressure-temperature limit curves are provided in the Pressure-Temperatures Limits Report in the TRM.

<u>QUESTION 5A.11</u> (NRC Question 251.7)

Provide the following data on the surveillance materials:

a) Origin of heat affected zone and base materials (heat number, plate identification number, and chemical composition),

b) Origin of weld metal (weld wire type, heat of filler metal, production welding process, plate material used to make weld specimens, chemical composition of deposited weld metal),

c) The lead factor of each surveillance capsule with respect vessel inner wall.

RESPONSE: The response is given in amended paragraph 5.3.1.6 and table 5.3-16.

<u>QUESTION 5A.12</u> (NRC Question 440.1) (5.2.2)

A description of the design features which will be used to mitigate the consequences of overpressurization events while operating at low temperatures is not provided in the CESSAR System 80 FSAR. Provide a description of the features which will be provided on the CESSAR System 80. Specific design criteria

regarding overpressurization protection while operating at low temperatures are as follows:

1. <u>Operator Action</u>: No credit can be taken for operator action for 10 minutes after the operator is aware of the transient.

2. <u>Single Failure</u>: The system must be designed to relieve the pressure transient given a single failure in addition to the failure that initiated the pressure transient.

3. <u>Testability</u>: The system must be testable on a periodic basis consistent with the system's employment.

4. <u>Seismic and IEEE 279 Criteria</u>: Ideally, the system should meet Seismic Category I and IEEE 279 criteria. The basic objective is that the system should not be vulnerable to a common failure that would both initiate a pressure transient and disable the overpressure mitigating system. Such events as loss of instrument air and loss of offsite power must be considered.

An alarm must be provided to monitor the position of the pressurizer relief valve isolation valves to assure that the over-pressure mitigating system is properly aligned for shutdown conditions.

In demonstrating that the mitigation system meets these criteria, the applicant should include the following information in his submittal:

1. Identify and justify the most limiting pressure transients caused by mass input and heat input.

2. Show that overpressure protection is provided (do not violate Appendix G limits) over the range of conditions applicable to shutdown/heatup operation.

3. Identify and justify that the equipment will meet pertinent parameters assumed in the analyses (e.g., valve opening times, signal delay, valve capacity).

4. Provide a description of the system including relevant P&I drawings.

5. Discuss how the system meets the criteria.

6. Discuss all administrative controls required to implement the protection system.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR responses to NRC questions.

QUESTION 5A.13 (NRC Question 440.2) (5.2.2)

Provide details of your proposed preoperational and initial startup test program to show that they are consistent with the requirements of Regulatory Guide 1.68.

RESPONSE: The response was provided on the CESSAR docket for those tests in the CESSAR scope. See CESSAR FSAR responses to NRC questions. For remaining tests not in CESSAR scope, the response is provided in sections 1.8 and 14B.11.

APPENDIX 5A

QUESTION 5A.14 (NRC Question 440.3) (5.2.2)

Check valves in the discharge side of the high-pressure safety injection, low-pressure safety injection, RHR, and charging systems perform an isolation function in that they protect low pressure systems from full reactor pressure. The staff will require that these check valves be classified ASME IWV-2000 Category AC, with the leaktesting for this class of valve being performed to code specifications. It should be noted that a testing program which simply draws a suction on the low-pressure side of the outermost check valves will not be acceptable. This only verifies that one of the series check valves is fulfilling an isolation function. The necessary frequency will be that specified in the ASME Code, except in cases where only one or two check valves separate high- to low-pressure systems. In these cases, leaktesting will be performed at each refueling after the valves have been exercised. Identify all check valves which should be classified Category AC as per the position discussed above. Verify that you have the necessary test lines to leak test each valve. Provide the leak detection criteria that will be in the Technical Specifications.

RESPONSE: The response was provided on the CESSAR docket for check valves classified Category AC, which are leaktested. See CESSAR FSAR responses to NRC questions. The PVNGS design differences from the CESSAR design modifies the list as follows:

Safety Injection (SI) Valves

SI V-215	SI V-522
SI V-217	SI V-523
SI V-225	SI V-532
SI V-227	SI V-533
SI V-235	SI V-540
SI V-237	SI V-541
SI V-245	SI V-542
SI V-247	SI V-543

Adequate test connections and lines, as shown in engineering drawings 01, 02, 03-M-SIP-001, -002 and -003 have been provided to facilitate testing of the above-listed valves to ASME IWV-2000 Category AC requirements. The leak detection criteria of 1/2 gallon per minute per 1 inch of nominal valve diameter, not to exceed 5 gallons per minute, has been included in the Technical Specifications.

<u>QUESTION 5A.15</u> (NRC Question 440.4) (5A)

On page 5A-2, it is indicated that a negative Doppler coefficient of -0.8×10^{-5} $\Delta k/k/F$ is assumed in the bounding overpressure transient (loss of load). It is our position that overpressure protection of system be demonstrated without taken credit for either Doppler or moderator temperature reactivity feedback (SRP 5.2.2, Section III.6). Reanalyze the bounding overpressure transient without credit for Doppler feedback, demonstrating that

primary system pressure does not exceed 110% of the design pressure.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR responses to NRC questions.

<u>QUESTION 5A.16</u> (NRC Question 440.5) (5A)

On page 5A-1, it is indicated that the worst case transient, loss of load, in conjunction with a delayed reactor trip, is the design basis for the primary safety valves. It is our position that the high-pressure reactor trip or second safety grade trip signal, whichever occurs later, should be used for sizing the primary system safety valves. Confirm that the CESSAR System 80 safety valves are sized sufficiently to accommodate a reactor trip on the second safety grade trip signal.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR responses to NRC questions.

<u>QUESTION 5A.17</u> (NRC Question 440.6) (5.4.7)

Palo Verde must have the capability to take the plant from full power to a cold shutdown using only safety grade equipment, per the requirements of BTP RSB 5-1. Address your compliance with all provisions of that position and respond to the detailed question below.

Question 1. Describe the sequence for achieving a cold shutdown condition within 36 hours, assuming the most limiting single failure with only onsite power availability. Identify all manual actions inside

or outside containment that must be performed and discuss the capability of remaining at hot standby until manual actions (or repairs) can be performed.

1a. If the steam generator dump valves, operators, air and power supplies are not safety grade, justify how you would cool down the primary system in the event of loss of offsite power and an SSE.

1b. Describe the sequence for depressurizing the primary system using only safety grade systems, assuming a single failure. Identify all manual actions inside or outside containment that must be performed.

1c. Discuss the boration capability using only safety grade systems, assuming a single failure. Identify all manual actions inside or outside containment that must be performed. If the proposed boration method utilizes the charging pumps (assuming a letdown line failure is proposed), provide an evaluation of this approach with regard to concentration of boron source and liquid volume in primary system.

Question 2. Discuss the provisions for collection and containment of RHR pressure relief valves discharge.

Question 3. Describe tests which will demonstrate adequate mixing of the added borated water and cooldown under natural circulation conditions with and without a single

failure of a steam generator atmospheric dump valve. Specific procedures for plant cooldown under natural circulation conditions must be available to the operator. Summarize these procedures.

Question 4. Discuss the availability of the Seismic Category I auxiliary feedwater supply for at least 4 hours at hot shutdown plus cooldown to the RHR system cut-in based on longest time for the availability of only onsite or only offsite power and assuming a single failure. If this cannot be achieved, discuss the availability of an adequate alternate Seismic Category I water source.

Question 5. What provisions in natural circulation cooldown methods have been made to account for possible upper head void formation?

RESPONSE: The response will be provided on the CESSAR docket. Additional clarification is provided as follows:

1a. PVNGS provides, as a backup to the instrument air system, safety grade nitrogen accumulators to operate the steam generator atmospheric dump valves (ADVs). The remaining response is given in amended paragraph 10.3.2.2.4.

1b. The response is given in amended subsection 5.4.7 and paragraph 6.3.1.3. There is no single failure which could result in the opening of all SIT isolation valves or could preclude RCS depressurization.

1c. The response is given in amended paragraph 9.3.4.1.

2. Residual heat removal pressure relief discharge piping is provided with a sparger that is located at the bottom of the containment emergency sump. On that basis, no direct steam flow would be directed toward any personnel.

3. Cooldown under natural circulation conditions was analytically modeled and positively confirmed following two events at an operating C-E reactorplant. St. Lucie Unit 1 (Docket No. 50-335) performed two natural circulation cooldowns following a reactor trip from full power conditions in 1977 and in 1980. Natural circulation for System 80 was conducted as part of power ascension testing. Testing was also conducted to verify adequate boron mixing under natural circulation conditions and the ability to perform a natural circulation cooldown and a plant depressurization to shutdown cooling initiation conditions.[a]

a. Letter from E. E. Van Brunt, Jr., APS, to G. W. Knighton, NRC, dated January 31, 1985, (ANPP-31829), provided a description of the PVNGS Natural Circulation Test Program.

4. The CST tank is designed to provide sufficient auxiliary feedwater supply for 4 hours at hot standby plus 6.5 hours of operation to reach cold shutdown under natural circulation conditions[a].

   Refer to subsection 9.2.6 for a discussion on single failure analysis.

   PVNGS meets C-E's interface requirements for a water volume as described in subsection 9.2.6. Other non-Seismic Category I supplies are also provided:

   - A 550,000-gallon reactor makeup water tank at each unit which can be manually aligned to provide water to the auxiliary feedwater system.

   - Refer to subsection 9.2.3 for a discussion on the demineralized water system.

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a. Letter 102-03578-WLS/AKK/GAM, Dated January 5, 1996, to the NRC, provided a revised Report on Natural Circulation Cooldown for the Palo Verde increase in Licensed Reactor Power to 3876 MWt. This report verifies the CST design is adequate.

   The adequacy of the CST design (volume of condensate required and duration required) with respect to compliance with the requirements of Branch Technical Position RSB 5-1 are currently docketed in Amendments 108 (NPF-41), 100 (NPF-51) and 80 (NPF-74) for plant changes implemented under the power uprate project. The values for the volume of condensate required and duration of use of the CST for power uprate remain bounded by the natural circulation cooldown testing and reconciliation analyses performed under the submittal of PVNGS' report to demonstrate compliance with the testing requirements of Branch Technical Position RSB 5-1 (ANPP-40069-JGH/BJA/98.05; Letter from J. G. Haynes, PVNGS to G. W. Knighton, NRC, dated February 9,1987).

5. Specific natural circulation and natural circulation cooldown operator guidelines have been prepared by C-E for the C-E Owner's Group. These guidelines were transmitted in CEN-152 to the NRC for review (June 1981). These guidelines provide instruction to avoid void formation in the reactor vessel upper head that could occur during natural circulation conditions. Also included are instructions that deal with the symptoms and followup actions for a condensable reactor vessel void if one should occur.

QUESTION 5A.18 (NRC Question 440.7) (5.4.7)

Provide detailed information on the sizing criteria used to determine the relief capacity of the SDCS suction line pressure relief valves.

Did the version of the ASME Code that the SDCS relief valves were sized to require establishing liquid or two-phase relief capacity with testing? If so, describe in detail the test program and results. If the liquid or two-phase relief capacity was not established by test, show that the difference between the rated and maximum required relief capacity is more than sufficient to bound liquid and two-phase relief rate uncertainties.

Provide details on the alarms and indications which would inform the operators that a SDC suction line isolation valve has closed while the plant is in shutdown cooling. Is there any common failure which would result in both valves being closed while in shutdown cooling.

When LPSI pump miniflow isolation valves are closed during shutdown cooling, what would prevent pump damage if a pressure transient were to occur which caused RCS pressure to exceed LPSI deadhead pressure.

When the plant is in the SDCS mode, is there any single failure which could cause the suction of both SDC pumps to be switched from the hot leg piping to the dry sumps?

RESPONSE: Detailed information on relief valve sizing criteria and ASME Code requirements will be provided on the CESSAR docket.

A discussion of alarms and indications which would inform the operators that a SDC suction line isolation valve has closed will be provided on the CESSAR docket.

Refer to subsection 5.4.7 for a discussion on interlocks and control room indication.

<u>QUESTION 5A.19</u> (NRC Question 440.8) (5.4.7)

Provide the following information related to pipe breaks or leaks in high or moderate energy lines outside containment associated with the RHR system when the plant is in a shutdown cooling mode:

1. Determine the maximum discharge rate from a pipe break in the systems outside containment used to maintain core cooling.

2. Determine the time available for recovery based on these discharge rates and their effect on core cooling.

3. Describe the alarms available to alert the operator to the event, the recovery procedures to be utilized by the operator, and the time available for operator action.

A single failure criterion consistent with Standard Review Plan 3.6.1 and Branch Technical Position APCSB 3-1 should be applied in the evaluation of the recovery procedures utilized.

RESPONSE: The response is given in amended paragraph 5.4.7.2(c).

QUESTION 5A.20 (NRC Question 440.9) (5.4.7)

Indicate whether there are any systems or components needed for shutdown cooling which are deenergized or have power locked out during plant operation. If so, indicate what actions have to be taken to restore operability to the components or systems.

It is the staff's position that all operator actions necessary to take the plant from normal operation to SDCS entry should be performed from the control room. If the present design does not meet this position, please commit to revise it accordingly.

RESPONSE: The response is given in amended subsection 5.4.7. Additional information is provided on the CESSAR docket.

QUESTION 5A.21 (NRC Question 440.10) (5.4.7)

Provide additional information regarding the power sources supplied to the SDCS isolation valves. The staff's position is that a single failure of a power supply will not prevent isolation of the SDCS when RCS pressure exceeds its design pressure. Additionally, loss of a single power supply cannot

result in the inability to initiate at least one 100% shutdown cooling train.

RESPONSE: The response is given in amended paragraph 5.4.7.2(c). Additional response is provided on the CESSAR docket.

QUESTION 5A.22 (NRC Question 440.83) (18.II.B.1)

Your response to Item II.B.1 of NUREG-0737 requirements is not sufficient. Provide the following:

1. Provide diagrams and description of the vent discharge vicinity. Verify that adequate ventilation is provided and that equipment in this area is capable of withstanding discharge of gases and liquids from the vents.

2. What size are the flow limiting orifices and what are the calculated flow rates through the vent system for both gas mixtures and liquids at operating pressures?

3. Provide drawings of the piping system from the vessel head and pressurizer through the discharge paths. In particular, show the location of the solenoid-operated valves and consider potential missile hazards from them.

RESPONSE: Refer to the revised response to NUREG-0737, Item II.B.1, provided in subsection 18.II.B.1.

QUESTION 5A.23 (NRC Question 440.87) (5.4.1 and 9.2.2)

If the RCP tests demonstrate that the RCPs are not able to operate with loss of component cooling water supply for longer than 30 minutes without loss of function and the need for

operator protective action, safety grade instrumentation to detect the loss of component cooling water to the RCPs and to alarm the operator in the control room should be provided.

The entire instrumentation system, including audible and visual status indicators for loss of component cooling water should meet the requirements of IEEE Std. 279-1971/1974. The above requirements should be specified in the applicable section (e.g., Section 5.4.1 or 9.2.2) of CESSAR System 80 FSAR as interface requirements.

RESPONSE: The response was provided in the CESSAR response to NRC Question 440.82 on the CESSAR docket. Refer to paragraph 9.2.2.2.8 for a discussion on NCWS instrumentation, and section 7.6 for a discussion on annunciators and how they meet the requirements of IEEE Standard 279-1971.

APPENDIX 5B

OVERPRESSURE PROTECTION FOR COMBUSTION ENGINEERING SYSTEM 80 - PRESSURIZED WATER REACTORS

APPENDIX 5B

OVERPRESSURE PROTECTION FOR COMBUSTION ENGINEERING SYSTEM 80 - PRESSURIZED WATER REACTORS

ABSTRACT

This Appendix documents the adequacy of overpressure protection provided for Combustion Engineering's (C-E's) System 80 pressurized water reactor, steam generators, and Reactor Coolant System.

Overpressurization of the Reactor Coolant System and steam generators is precluded by means of primary safety valves, secondary safety valves and the Reactor Protective System. Pressure relief capacity for the steam generators and Reactor Coolant System is conservatively sized to satisfy the overpressure requirements of the ASME Boiler and Pressure Vessel Code, Section III. The safety valves in conjunction with the Reactor Protective System, are designed to provide overpressure protection for a loss-of-load incident with a delayed reactor trip.

The loss of load transient used to size the primary safety valves is not intended to be used as a design transient for any other NSSS equipment.

APPENDIX 5B

OVERPRESSURE PROTECTION FOR COMBUSTION ENGINEERING SYSTEM 80 - PRESSURIZED WATER REACTORS

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APPENDIX 5B

1.0 INTRODUCTION

Overpressure protection for C-E's System 80 pressurized water reactor, steam generators, and Reactor Coolant System is in accordance with the requirements set forth in the ASME Boiler and Pressure Vessel Code, Section III. Overpressure protection is considered by means of primary safety valves, secondary safety valves, and the Reactor Protective System. Analysis of all reactor and steam plant transients causing pressure excursions is conducted. The worst case transient, loss-of-load, in conjunction with a delayed reactor trip, is the design basis for the primary safety valves. The primary safety valves, secondary safety valves, and Reactor Protective System maintain the Reactor Coolant System below 110% of design pressure during worst case transients. The secondary safety valves are sized conservatively to pass steam flow at greater than the proposed licensed power level of 3817 Mwt. Steam generator pressure is limited to less than 110% of steam generator design pressure during worst case transients.

2.0 ANALYSIS

2.1 METHOD

C-E has performed a parametric study to determine the design basis incident for sizing the primary safety valves. The design basis incident is a loss-of-load with a delayed reactor trip. The analysis is performed using digital computer codes which accurately model the thermal, hydraulic, and nuclear performances of the Reactor Coolant and Steam Systems. The digital codes used in the transient analysis include reactor

kinetics, thermal and hydraulic performance of the Reactor Coolant System, and the thermal and hydraulic performance of the steam generators. The computer simulation includes effects of reactor coolant pump performance, elevation heads, inertia of surge line water and friction drop in the surge line. Worst case initial conditions and nuclear parameters are assumed for the parametric analysis. The reactor is assumed to trip at a RCS pressure of 2450 psia, while the primary safety valves are assumed to lift at a pressure of 2525 psia, which is 25 psi above the system design pressure. During the analysis, the throat area associated with these valves is increased parametrically until the above design basis incident analysis indicates that a further increase in throat area will not result in a significant decrease in RCS peak pressure. The performance of the digital codes employed in the analysis have been verified by transient data from operating plants.

2.2 ASSUMPTIONS

a. At the onset of the loss-of-load transient, the Reactor Coolant and Main Steam Systems are at maximum rated output plus a two percent uncertainty. By choosing the highest possible power output, the heatup rate of the primary loop is maximized, hence the rate of pressurization is also maximized.

b. Moderator temperature coefficient is zero. Analytical studies supported by core data show that the moderator temperature coefficient can vary between zero and -3.5×10^{-4} for various phases of core life.

Therefore, a coefficient of zero is chosen to maximize the power/pressure transient.

c. Doppler coefficient of $-.8 \times 10^{-5}$ $\Delta K/K/F$ is used in the loss-of-load analysis. Actual operating coefficients can be expected to range from -1.4×10^{-5} at zero power to $-1. \times 10^{-5}$ $\Delta K/K?F$ at full power. By choosing a relatively small Doppler coefficient, the reduction in reactivity with increasing fuel temperature is minimized, thereby maximizing the rate of power rise.

d. No credit is taken for letdown, charging, pressurizer spray, turbine bypass, or feedwater addition after turbine trip in the loss-of-load analysis. Letdown and pressurizer spray both act to reduce primary pressure. By not taking credit for these systems, the rate of pressurization is increased. By not taking credit for the addition of feedwater, the steam generator secondary inventory will be depleted at a faster rate. This in turn reduces the capability of the steam generator to remove heat from the primary loop, thereby maximizing the rate of primary pressurization.

e. The analysis reflects consideration of plant instrumentation error and safety valve setpoint errors. For example, all safety valves are assumed to open at their maximum popping pressure. This extends the period of time before energy can be removed from the system. The reactor trip setpoint errors are

always assumed to act in such a manner that they delay reactor trip, again resulting in maximum pressurization.

f. Pressurizer pressure at the onset of the incident is 2200 psi. By using the lower limit of the normal plant operating pressure, the time required to trip the plant on high pressure is increased.

2.2.1 SECONDARY SAFETY VALVE SIZING

The discharge piping serving the secondary safety valves is designed to accommodate rated relief capacity without imposing unacceptable backpressure on the safety valves.

The secondary safety valves are conservatively sized to pass excess steam flow. This limits steam generator pressure to less than 110% of steam generator design pressure during worst case transients. A plant's secondary safety valves consist of three banks of valves with staggered set pressures. The valves are spring loaded type safety valves procured in accordance with ASME Boiler and Pressure Vessel Code, Section III.

Figure 5B-2 depicts the steam generator pressure transient for this worst case loss-of-load incident. As can be seen in Figure 5B-2, the steam generator pressure remains below 110 percent of design pressure during the incident.

2.2.2 PRIMARY SAFETY VALVE SIZING

The reactor drain tank, inlet and discharge piping are sized to preclude unacceptable pressure drops and backpressure which would adversely affect valve operation.

Primary safety valve backpressure is limited by the design pressure of the valve bellows. These bellows prevent any accumulated backpressure from being imposed on the valve spring, thus allowing valve operation at its design setpoint rather than at its setpoint plus backpressure.

The design basis incident for sizing the primary safety valves is a loss of turbine-generator load in which the reactor is not immediately tripped. No credit is taken for any pressure-reducing devices except the primary and secondary safety valves. In reality, the incident would be terminated by a number of reactor trips. These include:

a. Steam generator low level trip;

b. High pressurizer pressure trip;

c. Manual trip.

If the high primary pressure trip were to become inoperative, other reactor trips would proceed to shut the reactor down as their setpoints are exceeded.

A series of loss-of-load studies are run with various sizes of primary safety valves. As can be seen in Figure 5B-1, after the safety valve capacity increases to a certain size, additional increase in capacity has negligible effect in reducing the maximum system pressure experiences during the loss-of-load transient. C-E's primary safety valves are chosen so as to minimize the maximum pressure experienced during the loss-of-load transient. The minimum specified safety valve capacity is identified on Figure 5B-1.

Figures 5B-2, 5B-3 and 5B-4 present curves of steam generator pressure, maximum Reactor Coolant System pressure and core power versus time for the worst case loss of turbine-generator load. As can be seen on Figures 5B-2 and 5B-3, the maximum steam generator pressure and reactor coolant loop pressures remain below 110% of design during this worst case transient.

The first, second, and third banks of secondary safety valves open at approximately 3.7, 5, and 6.2 seconds, respectively. The secondary safety valves remove energy from the Reactor Coolant System and thus mitigate the pressure surge. The primary safety valves are conservatively assumed to open at 1 percent above the normal Reactor Coolant System design pressure 5.7 seconds after the initiation of the upset condition.

The analysis of a complete loss of load incident is described in Chapter 15, Section 15.2. As demonstrated in this analysis, if a complete loss of load occurs without a simultaneous reactor trip, the protection provided by the high pressurizer pressure trip, primary safety valves and secondary safety valves is sufficient to assure that the integrity of the RCS and main steam system is maintained and that the minimum DNB ratio is not less than the SAFDL.

2.2.3 ACCEPTABILITY OF SAFETY VALVE BLOWDOWN

2.2.3.1 Background

Full scale, full pressure prototypical testing of pressurizer safety valves was performed by EPRI in 1981.[1] The blowdown settings required to insure stable valve operation during the blowdown from the set pressure were above the 5% setting

specified in the ASME Code. In order to insure that the extended blowdown would not adversely affect overpressure protection or plant operation, analyses were performed to evaluate the NSSS response. The analyses described below demonstrate that a blowdown setting, including associated uncertainties, of 14.0% is acceptable.

2.2.3.2 Results of Evaluation

An extended blowdown of the safety valves could result in swelling of the pressurizer liquid level due to flashing and possible liquid carryover through the safety valves. Since the safety valve design specification specifies dry saturated steam flow conditions, it is desirable to show that these conditions are maintained during the extended blowdown. It is also desirable to verify that the RCS remains in a subcooled condition in order that the steam bubble formation in the RCS is precluded.

A computer analysis was performed of the Loss-of-load event with delayed reactor trip, similar to that used in safety valve sizing, except that a conservative 20% safety valve blowdown and initial conditions biased to maximize pressurizer liquid level were assumed. The purpose of this analysis was to determine the pressurizer liquid level response and the RCS subcooling under these conservative conditions. For additional conservatism, an additive adjustment was made to the computer-calculated pressurizer levels on the basis of a very conservative pressurizer model. This model assumed that the initial saturated pressurizer liquid did not mix with the cooler insurge liquid, that the initial liquid remained in the

equilibrium with the pressurizer steam space, and that the steam which flashed during blowdown remained dispersed in the liquid phase and caused the liquid level to swell. The adjusted pressurizer water level vs time curve showed a maximum of 98%(2) (1730 ft^3), below the safety valve nozzle elevation of 100%, so that dry saturated steam flow to the safety valves is assured throughout the blowdown. The computer analysis also showed that adequate subcooling was maintained in the RCS during the blowdown, so that steam bubble formation is precluded.

(1) CEN-227, "Summary Report on the Operability or Pressurizer Safety Relief Valves in C-E Designed Plants", December 1982.

(2) Water level expressed as the percentage of the distance from the lower level nozzle to the upper level nozzle.

In addition, the System 80 safety analyses of pressurization events were re-evaluated to determine the impact of assuming an 18.5% blowdown below the original nominal set pressure of 2500 psia for the pressurizer safety valves in lieu of the 5% specified by the ASME Code. The evaluation indicated that, for the FWLB event analysis, which produces the greatest increase in pressurizer level, the increased blowdown would not result in the pressurizer liquid level reaching the safety valve nozzle elevation and thus normal safety valve operation would be assured. Further, subcooling in the RCS wars maintained during the blowdown.

Since the performance of CEN-227 and PSV setpoint tolerance changes, PVNGS changed some plant operating conditions (i.e.,

10°F reduction in the core inlet temperature, and 2% increase in nominal power level to 3876 MWt combined with 2°F additional reduction in the core inlet temperature) which affected the initial conditions used in the CEN-227 analysis. Increased initial power level and lower RCS temperature result in larger swelling of the RCS during a heatup transient. Therefore, an analysis was performed by PVNGS using a blowdown of 14% below the minimum PSV set pressure of 2450 psia (2475 psia - 1% tolerance) and initial conditions set to maximize the pressurizer liquid level. The analysis demonstrates that, for the limiting transient (LFWLB with LOP), the maximum pressurizer liquid level for PVNGS unit's remains below the PSV nozzles and subcooling is maintained during the period when the PSVs are open.

Power has been increased by an additional 3% (3990 MWt) with installation of replacement steam generators. This configuration also affects the initial conditions used in CEN-227. Accordingly, an analysis was also performed with a 14% blowdown and bounding initial conditions given a core power of 3990 MWt with replacement steam generators. This analysis also confirms that, for the limiting transient (LFWLB with LOP and single failure), the maximum pressurizer liquid level for PVNGS units remains below the PSV nozzles and subcooling is maintained during the period when the PSV's are open.

In summary, analyses show that adequate plant overpressure protection and RCS subcooling are ensured during a blowdown of 14.0% below the minimum pressurizer safety valve set pressure.

3.0 CONCLUSIONS

C-E's System 80 pressurized water reactor, steam generators, and Reactor Coolant System are protected from overpressurization in accordance with the guidelines set forth in the ASME Boiler and Pressure Vessel Code, Section III. Peak Reactor Coolant System and Secondary System pressures are limited to 110% of design pressures during worst case loss of turbine-generator load. Overpressure protection is afforded by primary safety valves, secondary safety valves, and the Reactor Protective System.

APPENDIX 5C

NATURAL CIRCULATION COOLDOWN ANALYSIS

APPENDIX 5C

NATURAL CIRCULATION COOLDOWN ANALYSIS

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APPENDIX 5C

1.0 INTRODUCTION

In the PVNGS System 80 design, residual heat removal is provided by the Shutdown Cooling (SDC) System. As described in UFSAR 5.4.7, the SDC system is typically placed in service when reactor coolant temperature is below 350°F and pressurizer pressure is less than 410 psia. Since shutdown cooling cannot be initiated with the unit in Hot Standby, additional systems are required to cool and depressurize the primary system down to shutdown cooling entry conditions.

Per the NRC Standard Review Plan, systems used to take the reactor from normal operating temperature and pressure down to cold shutdown conditions are expected to meet the requirements of Branch Technical Position (BTP) Reactor System Branch (RSB) 5-1. The functional requirements of BTP RSB 5-1 ensure that the cooldown can be accomplished within a reasonable time after reactor shutdown using only safety-grade systems that satisfy General Design Criteria 1 through 5. Following reactor trip, the plant must have the capability to maintain Hot Standby conditions for at least 4 hours prior to commencement of the cooldown. The credited systems must function using either onsite electrical power system operation (assuming offsite power is not available) or offsite electrical power system operation (assuming onsite power is not available) and assuming a single failure. Systems must be capable of remote operation from the control room although limited operator action outside of the control room is acceptable to mitigate the effects of postulated single failures.

Since the PVNGS design was complete and the construction permit was docketed before the original issue of BTP RSB 5-1, partial implementation of the functional requirements was permitted for PVNGS as a "Class 2" plant. Exceptions were taken for portions of the Chemical and Volume Control System (CVCS), which constitutes the primary method for reactivity control, reactor coolant makeup, and RCS pressure control during the cooldown to SDC entry conditions. The CVCS did not fully meet BTP RSB 5-1 criteria because (1) two of the three credited gravity-fed boration pathways cannot be aligned from the control room, (2) not all required components were safety grade, (3) the system was not tolerant of all credible faults, and (4) more than "limited" action outside the control room is needed to recover from some postulated failures.

To achieve an acceptable level of reliability, PVNGS committed to a number of engineering and administrative controls, which are described in UFSAR 9.3.4.4.5. In addition, supplemental engineering analysis was performed to demonstrate that the safety-grade High Pressure Safety Injection (HPSI) and the Reactor Coolant Gas Vent System (RCGVS) provided a diverse and redundant method for taking the unit from Hot Standby to SDC entry conditions. In March 1999, the NRC accepted the PVNGS design with respect to natural circulation cooldown based in part on probabilistic risk assessment submitted by PVNGS to show that the safety benefits afforded by further modification of the CVCS were not commensurate with their costs.

The capability of the CVCS for supporting a natural circulation cooldown was demonstrated by an in-plant test conducted in January 1986. Although the HPSI/RCGVS method has been

demonstrated analytically, the method has not been verified by field test at PVNGS. Therefore, the HPSI/RCGVS method has only been approved as a backup means of RCS cooldown and depressurization. Neither the CVCS nor the HPSI/RCGVS methods individually can satisfy the BTP RSB 5-1 requirements fully.

2.0 METHODS

Specific requirements for the method of analysis are not contained in BTP RSB 5-1. Although a natural circulation cooldown may occur during the recovery and long term plant stabilization after accidents analyzed in UFSAR Chapter 15, natural circulation cooldown is not required to mitigate the transients themselves. Consequently, NRC has accepted conservative analysis in lieu of the bounding type safety analysis conventionally employed to evaluate Chapter 15 events.

The natural circulation cooldown analysis has been performed using computer codes that have been previously reviewed and approved by NRC for the purposes of licensing activities. The codes are maintained and used in accordance with a software quality assurance program that meets the requirements of 10 CFR 50 Appendix B. Use of computer codes is consistent with their intended scope as well as any limitations specified in the accompanying safety evaluation reports.

Given the licensing position of PVNGS as a Class 2 plant with respect to BTP RSB 5-1, the natural circulation cooldown analysis involves three parts:

1. Cooldown from Hot Standby to SDC entry conditions with CVCS

2. Cooldown from Hot Standby to SDC entry conditions using HPSI/RCGVS

3. Cooldown from SDC entry to Cold Shutdown using the SDC system

The cooldown to SDC entry was analyzed with a "full scope" NSSS simulation code capable of accurately modeling the principal dynamics of the primary system performance:

- Reactor coolant heat removal using main steam safety relief valves (initially) and atmospheric dump valves to steam the steam generators
- Reactor coolant heat removal and steam generator inventory recovery using auxiliary feedwater pumps taking suction from the condensate storage tank
- Core cooling flow rate established by thermal driving head (difference in hot and cold leg temperatures)
- Variation in pressurizer level due to coolant temperature change, mass addition by charging or high pressure injection, and coolant losses by leakage and controlled bleed-off
- Pressurizer pressure response to level changes and operation of auxiliary spray or head vents
- Steam bubble formation, expansion, and contraction in the reactor vessel upper head

The cooldown to mode 5 entry conditions was analyzed using a code capable of modeling the heat transfer capability of the shutdown cooling heat exchanger. The overall heat exchanger

performance is determined with a standard analysis technique such as Log Mean Temperature Difference (LMTD) or the Number of Transfer Units (NTU) methods. The temperature of Essential Cooling Water (EW) on the shell inlet may be treated as a boundary condition provided the values are conservative with respect to the anticipated plant conditions. The temperature of the reactor coolant system is time-dependent and varies principally as a function of thermal input from core decay heat, heat removal by the shutdown cooling heat exchanger, and the heat capacity of the reactor coolant and primary system metal.

Use of nominal input data instead of worst-case values has historically been accepted as long as the overall plant performance is not overestimated. Given the conservatism of the design scenario itself, application of instrument uncertainty has not been required, nor has parametric study to determine the worst combination of initial conditions been required to demonstrate compliance.

3.0 INPUT AND ASSUMPTIONS

The natural circulation cooldown analysis has been performed for reactor power of 3990 MWt and reactor coolant volume of approximately 14,250 ft^3 (assumes nominal pressurizer level at full power). These parameters bound the limiting reactor plant design.

The anticipated response of plant systems is consistent with a loss of offsite electrical power followed by a failure of one emergency diesel generator (DG) to start and load one vital

4160 VAC bus. Unless otherwise specified, the loss of the DG is taken as the postulated single failure. Except as described below, only safety grade equipment is assumed to function during the cooldown. Per BTP RSB 5-1, cooldown may not commence until 4 hours after reactor trip to allow operators time to prepare for cooldown.

Analysis indicates that local loss of subcooling in the reactor vessel upper head during cooldown and de-pressurization will result in formation of a steam bubble there. In both the CVCS and HPSI cases, operation of the reactor head vents is expected to restrict the steam bubble size so that natural circulation flow is not impeded.

The initial cooldown ends when the shutdown cooling system has been placed in service. Manual alignment of shutdown cooling requires approximately 1 hour to accomplish once entry conditions are established.

All assumed operator actions described in this appendix, including contingencies, are supported by station procedures and operator training. The response times include reasonable delays for communication, preparation, transit, and device manipulation. Consistent with the requirements of BTP RSB 5-1, operator actions outside the control are considered "limited" in extent.

3.1 Cooldown with CVCS

At the start of the event, the minimum number of charging pumps required by the Technical Requirements Manual are operating. Following a loss of offsite power and failure of one emergency

diesel generator, only one charging pump is available to perform the cooldown.

Once the vital 4160 VAC buses are de-energized, the charging pump breakers are "anti-pumped" and must be manually reset and restarted from the control room. Therefore, no charging flow is assumed for 30 minutes after the time of trip to allow for resetting the breaker and performing manual alignment of one of three gravity-fed boration pathways to the charging pump suction. When operating, the charging pump delivers a nominal flow of 42 gpm.

The Technical Requirements Manual requires that only two of three boration flowpaths be available. In the event that the gravity feed path from the RWT bottom is nonfunctional, the useful borated water inventory located above the high suction nozzle must provide sufficient reactor coolant makeup during the cooldown. The useful water volume is based on the minimum required by the Technical Requirements Manual and does not include that located below the level where vortexing could entrain air to the charging pump suction.

The loss of offsite power results in a loss of non-class instrument and control power. In addition, the instrument air system is also lost because the compressors are powered from a non-class power supply, and neither instrument air nor its nitrogen backup are safety grade equipment. With no instrument air, the charging backpressure control valve fails closed, and the main RCS return flow is diverted through spring-loaded check valve CH-435. The loss of instrument air also causes the reactor coolant pump seal injection flow control valves to fail

open. In the analysis, the assumed auxiliary spray flow from one valve is consistent with these postulated hydraulic conditions.

The net makeup to the reactor coolant system is the total charging pump discharge flow minus losses to RCP controlled bleed-off (CBO) and RCS leakage. Due to loss of offsite power, the individual CBO isolation valves, which are non-class and motor-operated, fail "as-is" in the open position. Although the containment isolation valves on the CBO header will close due either to the loss of instrument air or by operator action, CH-507 fails in the open position. Thus, CBO flow will continue via relief valve CH-199 to the reactor drain tank (RDT) and cannot be terminated without containment entry for local operation of isolation valves. Although this operation is possible, the analysis assumes that CBO losses persist for the duration of the cooldown with the magnitude decreasing as a function of reactor coolant pressure. Based on historical data, nominal reactor coolant leakage of 1 gpm at normal operating pressure and temperature may also be assumed during the cooldown.

3.2 Cooldown with HPSI

The credited HPSI discharge flow rate is consistent with the pump curves for minimum design flow specified in UFSAR section 6.3. Since the flow instruments on the cold leg injection lines contain square root extractors that do not register flow below approximately 75 gpm, this value may be used as a minimum flow.

The mass flow rate of steam out of the pressurizer vent is determined considering the limiting flow path, the A train line containing the 7/32"x1" flow orifice. Estimates of mass flow are based correlations that are consistent with prevailing thermodynamic conditions of the steam in the pressurizer.

Use of auxiliary feedwater and ADVs for RCS heat removal are the same as for cooldown using CVCS. This is also the case for assumptions regarding inventory losses through RCP controlled bleed-off flow and coolant leakage. In addition, other operator actions such as control of voids in the reactor vessel upper head and alignment of SDC will also be the same.

However, without charging flow, there is no auxiliary spray or seal injection flow. Since HPSI takes suction from the bottom of the RWT, the available coolant makeup is not limited to the upper portion of the tank.

3.3 Cooldown with SDCHX

The last portion of the analysis consists of shutdown cooling operation to reach cold shutdown. The essential cooling water (EW) temperature entering the SDCHX is consistent with the essential cooling and spray pond system thermal performance analysis, which is conservative for the expected conditions during natural circulation. After the loss of offsite power, EW must carry heat loads from spent fuel pool cooling heat exchangers, the diesel generators, and the essential chillers. Since the limiting single failure in the analysis is the loss of one emergency diesel generator, only one train of essential cooling water and associated spray pond may be assumed to be in operation. Design values for spray pond temperature and

essential cooling water pump flow rate have historically been used.

The heat transfer coefficient for the SDCHX includes mechanical effects of fouling and tube plugging and is conservative with respect to the expected fluid temperatures and flow rates.

During the cooldown, makeup for contraction and system losses is normally provided by the boration systems in CVCS. With nominal assumptions, there is sufficient inventory above the high suction nozzle to support the cooldown all the way to mode 5. If this inventory is depleted, charging suction can be aligned via CH-327 from the bottom of the RWT. If the CH-327 pathway is not functional, then, as described in the emergency operating procedures, HPSI, which also takes suction from the bottom of the RWT, may be used for inventory control.

3.4 Operator Action Outside the Control Room

In accordance with the provisions of BTP RSB 5-1, NRC has accepted "limited" operator action outside of the control room to mitigate the consequences of postulated single active failures, considering that only onsite or offsite power is available. The Failure Modes and Effects Analysis for CVCS is contained in UFSAR 9.3.4.8. The following discussion summarizes those failures related to natural circulation for which operator action outside the control room may be required.

As described above, operators must manually reset the charging pump breaker following LOP and restoration of power to a vital 4160 VAC bus. If the Train E pump is nonfunctional because its power supply is de-energized, power may be realigned to the

pump motor from the opposite train. This contingency requires local operator actions in the Control Building (Switchgear Room) and the Auxiliary Building (100' elevation).

If A train power is available, the charging pump suction can be lined up to the RWT from the control room via CH-536. In the event that A train is not available or CH-536 is failed in the closed position, a gravity-fed boration pathway may be aligned through either CH-514 or CH-327. Both of the latter pathways require operator action outside the control room to establish flow. None of the motor-operated valves involved (including the associated VCT outlet valve CH-501) are fully safety-grade components.

In the unlikely event that gas binding may result from entrainment of VCT cover gas or evolution of dissolved gas out of solution at low pressure conditions, the charging pumps will trip on low suction pressure. Once adequate NPSH has been re-established, the auxiliary operators can vent the charging pumps prior to restart. The current plant design permits the venting of charging pumps to the vent receiver tank on the 88' foot level of the Auxiliary Building following a loss of offsite power. Venting can be achieved without radiological or industrial safety hazard for the operator, creation of a flammable or explosive atmosphere, or an unmonitored release of radioactive materials to the environment. This capability was physically demonstrated to NRC staff in 1986.

The Nuclear Cooling (NC) Water System provides the normal cooling for the spent fuel pool. Since the NC pumps are powered from the non-class electrical distribution, NC flow

will be lost upon a loss of offsite power. In this case, either train of Essential Cooling Water (EW) can be cross-connected through safety grade piping to provide cooling for the associated Fuel Pool Heat Exchanger (FPHX). Since the EW also provides cooling for the shutdown cooling heat exchanger used during the second portion of natural circulation, the assumed EW temperatures include effects of the added FPHX heat load.

Administrative controls have been established to maintain the RWT outlet valve CH-532 in the high suction line and the charging pump discharge valve CH-524 locked open with their actuators de-energized. In this passive configuration, spurious closure is not a credible malfunction.

Once shutdown cooling conditions are established, some actions outside the control room are required as part of normal operations to place a train of shutdown cooling and supporting systems in service.

3.5 Supplemental Design Features

The Palo Verde units were designed before the guidance in BTP RSB 5-1 was issued and do not meet all of its requirements. As permitted by the SRP, exceptions to the requirements have been granted to Palo Verde as a Class 2 plant in part because the overall design provides an acceptable level of reliability. Reliability is provided by some non-safety design features that are not directly credited in the analysis.

Although the motors for emergency boration valve CH-536 and VCT outlet valve CH-501 are not seismically qualified, both motor-

operated valves are energized from a class power supply to enhance their availability. In addition, both have provisions that allow the valves to be locally operated by hand, if necessary.

Following a loss of offsite power, letdown will isolate automatically due to the loss of nuclear cooling water to the letdown heat exchanger or by operator action. When charging is restarted, the resulting mismatch between letdown and charging will cause VCT level to decrease. To reduce the chance of losing suction to the charging pumps, VCT level is monitored by two non-safety grade instrument channels. Alarms are provided on low level and if the two channels differ significantly. The use of two channels of different types (one has a wet reference leg and the other is dry) decreases the probability of operator error in aligning the boration systems should one channels fail.

On VCT lo-lo level on LT-227, a non-safety grade interlock is provided to automatically open CH-514, start the boric acid makeup pumps (BAMPs), close the BAMP recirc valve CH-510, and close VCT outlet valve CH-501. The BAMPs are started because gravity feed to the charging pump suction through CH-514 cannot provide adequate NPSH unless the boric acid filters are bypassed, and this requires operator action outside the control room. Thus, if offsite power is available, no operator action outside the control room is needed to realign charging pump suction via CH-514.

With a loss of offsite power, neither the BAMPs nor the motor for CH-514 will be available should a VCT lo-lo level occur.

Therefore, an additional non-safety grade interlock is provided to automatically open CH-536 if VCT has a lo-lo level and the CH-514 motor is de-energized. This automatic alignment following a loss of offsite power and successful operation of Diesel Generator A reduces the chance of the operator failing to realign charging pump suction before the VCT empties.

The Train E charging pump is capable of being energized from either train of vital 4160 VAC emergency buses. Thus, the available charging flow would likely be double that assumed in the cooldown analysis. The E Train pump provides additional assurance that shutdown cooling entry conditions can be achieved under some conditions not necessarily bounded by the analysis. Examples would include reactor coolant leakage up to Technical Specification limits, elevated RCP controlled bleed-off or leak-off due to pre-existing seal degradation, and consideration of worst-case instrument uncertainty.

In order for the pressurizer to be considered operable per Technical Specifications, two back-up banks of pressurizer heaters capable of being energized from vital power supplies must also be operable. Although the heaters themselves are not seismically qualified and analysis shows they are not required during natural circulation cooldown, the availability of heaters following a loss of offsite power enhances pressure control and reduces the chance of losing subcooling margin by operator error.

Notwithstanding these design enhancements, some credible CVCS malfunctions cannot be mitigated under the BTP RSB 5-1 guidelines without extensive operator action or repair. In

these unlikely cases, cooldown will be accomplished using HPSI and RCGVS.

4.0 RESULTS

The analyses demonstrate that natural circulation flow provides adequate core cooling. Throughout the cooldown to shutdown cooling entry conditions:

- Power-to-flow ratio remained less than unity.
- The temperature difference across the core less stayed less than that at full power.
- Subcooling margin was maintained within the limits specified in the emergency operating procedures.
- Volume of steam formed in the reactor vessel was limited to the upper head and never obstructed flow by extending into the outlet plenum of the hot leg.

Plant systems are capable of supporting a natural circulation cooldown to shutdown cooling entry conditions conducted using only the Technical Specification minimum values of:

- Nitrogen gas contained in the atmospheric dump valve accumulators
- Condensate available in the condensate storage tank.
- Borated makeup water available above the RWT high suction line nozzle

Pressure and inventory control during a natural circulation cooldown to shutdown entry conditions may be accomplished with

either (1) charging and auxiliary spray or (2) HPSI and the reactor head vent system. Both methods are capable of:

- Complying with the RCS P/T limits
- Maintaining pressurizer level within the band specified by the emergency operations procedures
- Restricting thermal conditions of the RCP seal packages below values that would result in excessive controlled bleed-off or face seal leak-off
- Establishing shutdown cooling entry conditions within 13.33 hours, including a 4 hour hold in hot standby prior to commencement of cooldown

Once shutdown cooling was placed into service, cold shutdown conditions can be established within 36 hours from the time of reactor trip.

Adequate reactivity control is demonstrated in separate design calculations used to substantiate the bases for the Technical Specifications and Technical Requirements Manual. The capability of the reactor coolant system to provide sufficient mixing of boric acid solution was verified experimentally during the 1986 functional testing.

5.0 CONCLUSION

With the assumptions described, plant systems can support a natural circulation cooldown to cold shutdown conditions within a reasonable time without jeopardizing critical safety functions. The initial portion of the analysis relies in part on non-safety grade equipment and does not provide for

mitigation of every credible malfunction. To compensate for these limitations, design features have been added to CVCS to enhance reliability, and the availability of a redundant, safety-grade, alternate method for cooling to shutdown cooling entry conditions has been demonstrated by analysis. Therefore, the overall design has been accepted for meeting the provisions of Branch Technical Position RSB 5-1 as a Class 2 plant.

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21. NRC Letter, "Charging System Commitments for the Palo Verde Nuclear Generating Station, 3/23/99.

22. SDOC MN725-A00128, "RSB 5-1 Natural Circulation Cooldown Analysis following U2 RSG/PU," 8/1/00. This APS tracking number is used as a cover for CE Calculation 25/26/27-AS95-C-016, "RSB 5-1 Natural Circulation Cooldown Analysis at Uprated Power Conditions (3876 MWt Core Power) for Palo Verde Nuclear Generating Stations Units 1, 2, and 3," Rev. 1, 5/5/00

23. SDOC MN725-A00129, "RSB 5-1 Shutdown Cooling Analysis following U2 RSG/PU," 8/1/00. This APS tracking number is used as a cover for CE Calculation V-PENG-CALC-007, "RSB 5-1 Shutdown Cooling Analysis for 102% Stretch Power Using the DESCENT Code -- Palo Verde Nuclear Generating Units 1, 2, & 3," Rev. 02, 5/5/00.

24. ANSI/ANS-58.8-1984, "Time Response Design Criteria for Operator Actions."

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APPENDIX 5D

STRUCTURAL EVALUATION OF STEAM LINE RUPTURE FOR THE STEAM GENERATOR INTERNALS

APPENDIX 5D

STRUCTURAL EVALUATION OF STEAM LINE RUPTURE FOR THE STEAM GENERATOR INTERNALS

ABSTRACT

This report documents the adequacy of the steam generator internals to steam line rupture conditions.

The separator deck, shroud and tubes are subjected to a hypothetical large pipe break accident. The resulting stresses in the structures are compared to ASME Boiler and Pressure Vessel Code, Section III allowables to determine the adequacy of the structure.

APPENDIX 5D

STRUCTURAL EVALUATION OF STEAM LINE RUPTURE FOR THE STEAM GENERATOR INTERNALS

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1.0 INTRODUCTION

The hydraulic loading on the steam generator internals has been postulated by a complete rupture at the main steam line nozzle. This condition is defined as a Main Steam Line Break (MSLB) accident. A one-dimensional, two-phase flow model of the steam generator was formulated and its blowdown characteristics were simulated using the CEFLASH-4B computer code. The FLASH model is shown in Figures 5D-1A and 5D-1B. The MSLB accident loads obtained from the FLASH run are presented in Table 5D-1 of this report. These loads are used to establish the adequacy of the tube bundle, separator deck, and shroud. ANSYS structural models were developed to determine the maximum stresses due to MSLB loads. The resulting stresses were compared to elastic allowables defined in ASME Code, Section III (Reference 1).

2.0 ANALYSIS

2.1 MODEL DESCRIPTION

2.1.1 STEAM SEPARATOR DECK

The steam separator deck and shroud were modeled on the ANSYS finite element program (Reference 2). Since the structure is symmetrical, only 90 degree segment of the structure was required. The appropriate boundary conditions were applied to maintain symmetry. The deck is modeled as an effective plate with modified material properties. The deck stiffeners are modeled with holes. In the ANSYS model, shell elements are used for all structural members. The F.E. model is shown in Figure 5D-2.

2.1.2 TUBE BUNDLE

The analysis of the tube bundle upper region was performed using ANSYS. The tube bundle was modeled as a 3-D structure (straight and curved pipe elements for the tubes and 3-D beam elements for the vertical strips and batwings); the finite element model is shown in Figure 5D-3.

The model was composed by 66 equivalent tubes, representing all the 171 tube rows. In fact, to reduce the model dimensions, a single tube model represented three adjacent tube rows. Also the vertical strips and batwings were modeled by the same approach, properly accounting for the in-plane and out-of-plane support to the tubes.

2.2 ASSUMPTIONS

a. Structure is symmetrical, therefore only a 90 degree section was modeled.

b. Peak pressure load was applied across the separator deck and shroud.

c. For 0%, 15%, and 100% load cases a break opening time of 0.001 seconds was assumed for the rupture of the 28 inch steam line (ANSI/ANS-58.2-1988, paragraph 6.2.3).

d. The Henry-Fauske/Moody critical flow correlation was used with discharge coefficient of 1.0 (ANSI/ANS-58.2-1988, paragraph 6.2.5).

e. Operating pressure of 2250 psi was used as primary pressure and the secondary pressure was assumed to decay to zero.

2.3 HYDRAULIC FLOW LOADS

Main Steam Line Break (MSLB) accident loads are shown in Table 5D-1. For 15%¯ load, a maximum pressure differential of 18.78 psi at 0.17 seconds is the peak pressure applied upward across the separator deck. An outward pressure of 24.05 psi is applied across the shroud. For the tube bend region the flow forces per unit length of tube are determined using the equation below:

$$F = C_F * d * (g * V_g^2/2 * g)$$

where:

C_F = .14 drag coefficient

d = .75 in tube outer diameter

g = 42.28 lbs/ft^3 = 0.0245 lbs/in^3 specific weight (Ref. 3)

V_g = 8.08 * 1.797 = 14.44 ft/s = 173.28 in/s gap velocity (Ref. 3)

g = gravity acceleration

The resulting force per unit length on a single tube is 0.1000 lbs/in.

This force, multiplied by the number of tubes in each equivalent row, is applied on the bend and horizontal part of the tubes in the model.

The loads defined are used to determine the maximum stresses in the separator deck and shroud, and tube bundle models developed.

2.4 PRESSURE LOAD

During the MSLB event, the tube differential pressure was conservatively considered to be 2250 psi. This is based on the operating primary pressure with the assumption that the secondary pressure has decayed to zero.

2.5 STRESS RESULTS

2.5.1 SEPARATOR DECK

In the finite element model, the separator deck is treated as a perforated plate with modified elastic constants ν^* and E^*. The maximum membrane stress is 4.9 ksi, which is less than the allowable of 0.7 x S_u = 49 ksi for SA-515 Gr.70 material. The membrane plus bending stress is 45.5 ksi, which is less than 1.5 x (0.7 x S_u) = 73.5 ksi.

2.5.2 DECK STIFFENERS

The separator deck stiffeners are loaded by the uniform pressure applied across the deck. Stress in the plane of the stiffeners is membrane plus bending and is 19.9 ksi, which is less than the allowable of 1.5 x (0.7 x S_u) = 73.5 ksi for SA-515 Gr.70 material.

2.5.3 SHROUD

The shroud stresses due to an outward pressure result in a maximum local membrane stress intensity of 5.4 Ksi at the junction with the separator deck whereas the maximum primary membrane plus bending stress intensity (close to the same location) is 26.6 Ksi. Both stresses are less than the allowable of 1.5 x (0.7 x S_u) = 73.5 ksi for SA-515 Gr.70 material.

2.5.4 TUBES

The maximum membrane plus bending stress in the tubes due to hydraulic flow loads is 11.7 ksi.

2.6 PRESSURE STRESS

As a consequence of the main steam line break, the differential pressure inside the tubes rises to a value which was conservatively assumed equal to the full operating pressure in the primary circuit, i.e., 2250 psia, concomitant with a secondary pressure = 0.

The stress due to pressure are:

$$\sigma_x = (p_i - p_o) * \frac{r}{2 * t} = 9.5\ Ksi$$

$$\sigma_\theta = (p_i - p_o) * \frac{r}{t} = 19.0\ Ksi$$

$$\sigma_r = \frac{(p_i + p_o)}{2} = -1.1\ Ksi$$

where:

p_i = internal pressure = 2250 psia

p_o = external pressure = 0

s_x = axial stress

s_q = hoop stress

s_r = radial stress

r = mean radius of tube = (.75 - .042)/2 = .354 in

t = tube thickness = .042 in

3.0 CONCLUSIONS

The results show that the separator deck and shroud are within the elastic allowable limits.

The resultant tube stress intensity due to hydraulic flow loads and pressure differential is 22.3 Ksi, which is less than the membrane plus bending allowable of 84 ksi.

4.0 REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III, Rules for Construction of Nuclear Power Plant Components, 1989 Edition, no Addenda.
2. Computer Code, ANSYS, Revision 5.4 - ANSYS Engineering Analysis System User's Manual, Revision 5.4, by G. J. De Salvo and J. A. Swanson.
3. PV-RPH-00-000005, Rev. 1 - Steam Line Break
4. PV-RPM-00-000022, Rev. 1 - Steam Line Break Analysis

TABLE 5D-1

PEAK PRESSURE LOADS

Nodes	Regions	0% Power		15%- Power		15%+ Power		100% Power	
		Time(s)	DP (psi)	Time(s)	DP (psi)	Time(s)	DP (psi)	Time(s)	DP (psi)
N 2-3	Dryers	0.00614	-4.9	0.37715	-5.8	0.3573	**-6.11**	0.00626	-3.7
N 4-5	Separator Deck	0.2499	-17.59	0.16515	**-18.78**	0.2184	-16.19	0.13455	-15.1
N 5-32	Shroud Upper Part Hot Side	0.19205	23.48	0.11605	**24.05**	0.18755	22.25	0.08855	23.51
N 5-33	Shroud Upper Part Cold Side	0.19205	**23.48**	0.11455	23.06	0.1893	20.74	0.0858	20.59
N 24-26	Shroud Lower Part Hot Side	0.39055	**24.98**	0.12705	10.29	0.4153	10.58	2.2225	-74.32(*)
N 5-14	U Bend Hot Side	0.1458	**-18.92**	0.0788	-13.67	0.0774	-13.78	0.04015	-10.68
N 5-15	U Bend Cold Side	0.14565	**-18.93**	0.08605	-13.79	0.08505	-14.37	0.0528	-11.34
N 5-25	Evaporator Hot Side	0.23815	**-31.32**	0.16665	-22.97	0.1628	-22.9	4.1163	-26.84
N 5-36	Evaporator Cold Side	0.20605	**-25.96**	0.0728	-16.15	0.03465	-22.2	0.04455	-14.23
N 14-12	Top Eggcrate Hot Side	0.1694	**4.35**	0.1054	3.16	0.1023	3.07	0.0794	1.71
N 15-13	Top Eggcrate Cold Side	0.16915	**4.35**	0.1054	3.33	0.10705	3.41	0.0738	3.13

(*) This value is due to an effect of numerical 'water packing' occurring in the lower part of the DC. The duration of the effect is about 0.005 sec. and is due to the disappearing of the steam in the node 26. The effect of level oscillation occurring during the transient is responsible of the appearing and disappearing of the steam in the lower part of the DC that provides to generate numerical water packing. The maximum physical value occurs in the first second of transient and is less than 20 psi.

APPENDIX 5E

STRUCTURAL EVALUATION OF FEEDWATER LINE RUPTURE FOR THE STEAM GENERATOR INTERNALS

APPENDIX 5E

STRUCTURAL EVALUATION OF FEEDWATER LINE RUPTURE FOR THE STEAM GENERATOR INTERNALS

ABSTRACT

This report documents the structural adequacy of the steam generator internals to withstand a feedwater line rupture.

The steam generator economizer divider plate, support cylinder, cold leg flow distribution plate and feedwater box are subjected to a hypothetical feedwater line break during 100% power operation. The resulting stresses in the structures are compared to ASME Boiler and Pressure Vessel Code, Section III allowables to determine their acceptance.

APPENDIX 5E

STRUCTURAL EVALUATION OF FEEDWATER LINE RUPTURE FOR THE STEAM GENERATOR INTERNALS

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1.0 INTRODUCTION

The hydraulic loading on the steam generator internals resulting from the double-ended guillotine break of one 12.5 inch ID feedwater nozzle were calculated. The CEFLASH-4B computer code was employed to perform the thermohydrodynamic analysis of this condition defined as Feedwater Line Break (FWLB) accident. The FLASH model is shown in Figures 5E-1A and 5E-1B. The FWLB accident peak pressure loads obtained from the FLASH run are presented in Table 5E-1 of this report. These loads were used to establish the adequacy of the economizer divider plate, support cylinder, blowdown duct, cold leg flow distribution plate and feedwater box. ANSYS structural models were appropriately developed to determine the maximum stresses due to FWLB loads. The resulting stresses were then compared to the faulted (Service Level D) allowables as specified in the ASME Code, Section III (Reference 1).

2.0 ANALYSIS

2.1 MODEL DESCRIPTION

2.1.1 ECONOMIZER DIVIDER PLATE

The ANSYS computer program (Reference 2) was used to set up a finite element model of the economizer divider plate, support cylinder and blowdown assembly, using 3-D shell elements with four nodes and six d.o.f each. The divider plate, support cylinder and blowdown rectangular tube were modeled taking advantage of the symmetry to the plane through the steam generator axis and perpendicular to the divider plate. Appropriate boundary conditions were selected to simulate the

symmetry and the support provided by adjacent structures. The model is shown in Figure 5E-2.

2.1.2 COLD LEG FLOW DISTRIBUTION PLATE

The flow distribution plate was modeled using 3-D shell elements which, taking again advantage of the symmetry, simulated half of the 180° plate. The perforated region of the plate was modeled as an equivalent solid plate with modified properties (i.e., modulus of elasticity and Poisson's ratio) except in the area of the solid rim near the support cylinder. Vertical out-of-plane displacements were fixed at the tie rod locations and along the outer edge of the plate, whereas appropriate symmetry conditions were imposed on the nodes at the x=0 plane (see Figure 5E-3).

2.1.3 FEEDWATER BOX

The finite element model used 3-D shell elements for the box parts (inner cylinder, intermediate and lower rings, ending plates) and 3-D beam elements for the set screws. The z-axis is along the SG axis, the x-axis is along the divider plate and the y-axis is perpendicular to the plate, right-hand-rule oriented. By symmetry considerations only one of the two segments of the structure was modeled. The model, depicted in Figure 5E-4, extended over a 84° amplitude arc starting from 3.5° from the xz plane up to 2.5° to the plane yz.

2.2 ASSUMPTIONS

2.2.1 HYDRODYNAMIC ANALYSIS

a. A double-ended guillotine break at the safe-end of one FW nozzle was considered.

b. A downcomer FW split of 50/50 (hot/cold) was assumed for the 100% power.

c. The break opening time of 0.001 seconds was assumed for the rupture of the 12.5 inch FW line, according to ANSI/ANS-58.2-1988, paragraph 6.2.3.

d. The Henry-Fauske/Moody critical flow correlation was used with discharge coefficient of 1.0 (ANSI/ANS 58.2-1988, paragraph 6.2.5).

2.2.2 STRUCTURAL ANALYSIS

a. Linear elastic behavior was assumed.

b. Peak pressure loads were assumed to occur simultaneously on each structural model.

c. These peak pressures were applied as static loadings.

2.3 HYDRAULIC FLOW LOADS

Feedwater Line Break (FWLB) accident loads are shown in Table 5E-1. The 15%+- load gives the more severe conditions in terms of maximum differential pressure across the structures analyzed.

Pressure differences were applied across the divider plate, across the support cylinder walls and across of the lateral

walls of the blowdown tube. The plate, divided into 10 rectangular regions (5 horizontal overlain belts divided by a vertical line) was loaded with 10 different pressure values. The support cylinder was likewise divided into 10 regions. The blowdown tube was divided by a vertical line into 2 different pressure regions. Pressure grows from the top (cylinder and plate upper ends) to the bottom (near the tubesheet) and the region of maximum pressure was located at the plate base near the shell.

A pressure difference directed inward on the FW box, equal to 958.1 psi was applied on the box inner cylinder and on the two ending plates.

Different values of pressure were applied on three concentric areas of the flow distribution plate. In fact, the pressures applied to the equivalent solid plate region were corrected to account for the presence of the holes.

2.4 STRESS RESULTS

Since the FWLB is a faulted (Service Level D) condition, the membrane stress allowables for elastic analysis are 0.7 x Su.

2.4.1 ECONOMIZER DIVIDER PLATE

The primary stress of concern in the divider plate are membrane plus bending. The maximum primary membrane plus bending stress intensity occurs at the junction of the plate with the stay cylinder and is 51.3 Ksi, which is less than the allowable of 1.5 x 0.7 x Su = 73.5 ksi for SA-516 Gr.70 material. The blowdown duct has maximum membrane plus bending stress of 59.6

Ksi compared to the allowable of 1.5 x 0.7 x Su = 60.9 ksi for the A 500 Gr. B material.

2.4.2 SUPPORT CYLINDER

The maximum stress on the support cylinder occurs at the junction with the tubesheet, where the structure has all the degrees of freedom restrained, and is 50.6 Ksi, which is lower than the allowable of 1.5 x (0.7 x Su) = 73.5 ksi for the SA 508 Cl 1A material.

2.4.3 COLD LEG FLOW DISTRIBUTION PLATE

The max membrane + bending stress intensity in the solid region of the plate is 52.51 ksi. The maximum ligament membrane plus bending stress intensity in the perforated region occur at the boundary with the inner ring and is 53.42 Ksi.

The allowable for the SA-540 Type 405 material is 1.5 x (0.7 x Su) = 58.7 ksi.

For the most loaded tie rod, the maximum stress intensity (categorized as Pm) is 32.1 Ksi which is lower than the allowable of (0.7 x Su) = 40.7 ksi for the SA-36 material.

2.4.4 FEEDWATER DISTRIBUTION BOX

The highest primary membrane plus bending stress intensity (72.9 Ksi) occurs at the box inner wall. The allowable limit is 1.5 x (0.7 x Su) = 73.5 ksi for the SA-516 Gr.70 material.

The highest primary membrane plus bending stress intensity at the box junction with the upper support ring is 71.9 Ksi, less than the above allowable limit.

The highest shear stress in the threaded connection between box wall and set screws is 26.1 Ksi, less than the allowable limit of 0.6 x (0.7 x Su) = 29.4 ksi.

3.0 CONCLUSIONS

The results show that the economizer divider plate, support cylinder, cold leg flow distribution plate and feedwater box are adequately designed to withstand a hypothetical Feedwater Line Break Accident.

4.0 REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III, Rules for Construction of Nuclear Power Plant Components, 1989 Edition, no Addenda.

2. Computer Code, ANSYS, Revision 5.4 - ANSYS Engineering Analysis System User's Manual, Revision 5.4, by G. J. De Salvo and J. A. Swanson.

3. PV-RPH-00-000004, Rev. 1 - Feedline Break

4. PV-RPM-00-000021, Rev. 0 - Secondary Side Internal Structural Analysis Under Feedline Break Accident Condition

TABLE 5E-1

PEAK PRESSURE LOADS

NODES	REGIONS	15%+ POWER - ORIGINAL	
		Time (sec)	$\Delta\rho$ (psi)
NODES 27,50	DC-FW Ring	0.00102	990.94
NODES 47,50	Economizer - FW Ring	0.00088	958.10
NODES 49,50	Economizer - FW Ring	0.00088	891.77
NODES 47,49	FDP External Part	.068050	136.92
NODES 46,48	FDP Internal Part	.101400	96.44
NODES 22,36	Hot/Cold Side, Top SC	0.01740	-66.40
NODES 22,39	Hot Side/Econ, Internal	0.00402	136.72
NODES 22,40	Hot Side/Econ, External	0.00352	96.98
NODES 23,39	Hot Side/Econ, Internal	0.00402	137.50
NODES 23,40	Hot Side/Econ, External	0.00352	97.76
NODES 23,43	Hot Side/Econ, Internal	0.00388	176.57
NODES 23,44	Hot Side/Econ, External	0.00452	129.57
NODES 24,43	Hot Side/Econ, Internal	0.00388	177.35
NODES 24,44	Hot Side/Econ, External	0.00452	130.34
NODES 24,46	Hot Side/Econ, Internal	0.00364	198.58
NODES 24,47	Hot Side/Econ, External	0.00202	164.45
NODES 25,46	Hot Side/Econ, Internal	0.00364	199.16
NODES 25,47	Hot Side/Econ, External	0.00202	165.09
NODES 25,48	Hot Side/Econ, Internal	0.00364	227.61
NODES 25,49	Hot Side/Econ, External	0.00214	243.01
NODES 49,51	Economizer - FW Ring	0.09915	522.47
NODES 45,46	Flow Deflector - Econ.	0.00288	-19.53
NODES 41,43	Flow Deflector - Econ.	0.01365	26.35
NODES 37,39	Flow Deflector - Econ.	0.00426	-44.21
NODES 38,40	Flow Deflector - Econ.	0.01280	5.79
NODES 42,44	Flow Deflector - Econ.	0.00252	-4.47
NODES 56,36	SC-Economizer	0.01740	-79.93
NODES 56,39	SC-Economizer	0.00402	135.79
NODES 56,43	SC-Economizer	0.00388	175.34
NODES 56,46	SC-Economizer	0.00364	197.14
NODES 56,48	SC-Economizer	0.00352	225.73

CHAPTER 6

ENGINEERED SAFETY FEATURES

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6. ENGINEERED SAFETY FEATURES

6.1 ENGINEERED SAFETY FEATURE MATERIALS

See CESSAR Section 6.1 for ESF materials within the C-E scope of supply.

6.1.1 METALLIC MATERIALS

6.1.1.1 Materials Selection and Fabrication

6.1.1.1.1 Specifications for Principal ESF Pressure-Retaining Materials

Principal ESF pressure-retaining materials are listed in table 6.1-1.

6.1.1.1.2 Engineered Safety Features Construction Materials

Materials located inside containment potentially exposed to boric acid spray and the containment spray solution following a LOCA are indicated in table 6.1-2. These materials are chosen to be compatible with these chemical solutions.

Material corrosion within the containment is minimized by restricting the use of zinc, aluminum, and mercury. Since aluminum can be degraded in a high temperature, high moisture environment (i.e., post-LOCA), the amount of aluminum present inside the containment is the lowest practical amount. The use of zinc in the containment is controlled to minimize the generation of hydrogen due to the zinc-boric acid oxidation-reduction reaction. Because mercury and mercuric compounds adversely affect aluminum, stainless steel, NiCrFe Alloy 600, and alloys containing copper, mercury is not utilized within the containment for permanent equipment.

ENGINEERED SAFETY

FEATURE MATERIALS

Table 6.1-1

PRINCIPAL ESF PRESSURE-RETAINING MATERIALS (Sheet 1 of 2)

Product Form	ASME Specification
Plate	SA 515 GR 70 SA 516 GR 70 SA 240 TP 304, TP 304L SA 240 TP 316, TP 316L Inconel 600 (ASME SB 168)
Forgings	SA 105 GR 2 SA 182 F304, F304L SA 182 F316, F316L SA 508 CL 2 SA 336 F 8 SA 403 F316
Castings	SA 351 CF 3M, CF8, CF8M SA 216 WCB SA 351 GR CA6NM ASTM A296 CF8
Pipe	SA 106 GR B SA 312 TP 304, TP 316 SA 358 TP 304 Class 1 SA 376 TP 304, TP 316 ASME SB 111
Tube	SA 249 TP 304/316 SA 213 316 SS/304
Bar	SA 479 TP 304, TP 316, 304H, 304L SB 166 SA 276 TP 316, SA 564, TP 630 SA 193 GR B7, B6,

Table 6.1-1

PRINCIPAL ESF PRESSURE-RETAINING MATERIALS (Sheet 2 of 2)

Product Form	ASME Specification
Bolting	SA 193 GR B7, B8 SA 193 GR B8M SA 453 GR 660 SA 307 GR B SA 540 B 24 CL.3,
Nuts	SA 194 GR 2H, GR 8, 6 SA 194 GR 8F, GR 8M, GR 7, GR 8T, GR 8C
Weld Rod	SFA 5.1 Class E 7018 SFA 5.4 Class E 308-15 308-16 308L-15 308L-16 SFA 5.9 Class ER 308 ER 308L ER 309 ER 309L SFA 5.11 Class E Ni Cr Fe-3 SFA 5.14 Class ER Ni Cr Fe-3 SA 298 F4 SA 233 F4 SA 371 ER 308

Table 6.1-2

ENGINEERED SAFETY FEATURES STRUCTURAL MATERIALS
THAT COULD BE EXPOSED TO CORE COOLING WATER
OR CONTAINMENT SPRAY IN THE EVENT OF A LOCA

Product Form	ASME Specification
Plate	SA 516 GR 70 (Painted)
	SA 36 (Painted)
	SA 533 GR B CL.2
	SA-264
	SA-572, GR.50
Forgings	ASTM A105 GR 2 (Painted)
	SA 182 F316L
	SA 182 F316
Castings	SA 351 DF8M CF8, SA 508 CL.2,
	SA 320 L43, SA 487 CA 6M,
	ASTM A148 GR 90-60
Pipe	SA 312 TP 316
	SA 53 (Painted)
	SA 358 TP 304 Class 1
	SA 312 TP 304
	SA 376 TP 304, TP 316
Bar	SB-166
Bolting	SA 193 GR B6, B7
	SA 193 B8M
	SA 453 GR 660
	SA 307
	SA 564 GR 630, H 1100
Nuts	SA 194 2H
	SA 194 8F
	SA 194 GR B8

Section 6.2.5.3.A.3 discusses the amounts of aluminum and zinc that are assumed to be present in the containment and that could potentially be exposed to a corrosive environment. An estimate of their expected corrosion rate is given in Table 6.2.5-5.

6.1.1.1.3 Integrity of ESF Components During Manufacture and Construction

6.1.1.1.3.1 Control of Sensitized Stainless Steel. The NSSS ESF components comply with the recommendations of Regulatory Guide 1.44 in the following manner.

All raw austenitic stainless steel, both wrought and cast, used to fabricate pressure retaining components of the engineering safety features, is supplied in the annealed condition as specified in the pertinent ASME Specification; viz, 1900-2050F for 1/2 to 1 hr/in. of thickness and rapidly cooled below 700F. The time at temperature is determined by the size and type of component. In addition, vendor fabrication procedures have been reviewed to assure that unstablized austenitic stainless steel with a carbon content greater than 0.03% is not exposed to the temperature range of 800 to 1500F other than during welding.

Duplex, austenitic stainless steels, containing >5 FN delta ferrite (weld metal, cast metal, weld deposit overlay), are not considered unstablized, since these alloys do not sensitize; i.e., form a continuous network of chromium-iron carbides. Specifically, alloys in this category are:

CF 8M	Cast stainless steels (delta ferrite controlled
CF 8	to 5 FN to 33FN)
Type 308	Singly and combined
Type 309	stainless steel weld filler
Type 312	metals (Delta ferrite
Type 316	controlled to 5 FN to 23FN deposited)

In duplex austenitic/ferritic alloys, chromium-iron carbides are precipitated preferentially at the ferrite/austenite interface during exposure to temperatures ranging from 800 to 1500F. This precipitate morphology precludes intergranular penetrations associated with sensitized 300 series stainless steels exposed to oxygenated or otherwise fault environments.

The non-NSSS ESF components are consistent with the recommendations of Regulatory Guide 1.44, except as indicated in section 1.8.

6.1.1.1.3.2 Cleaning and Contamination Protection Procedures.

Specific requirements for cleanliness and contamination protection are provided for NSSS components which provide contamination control during fabrication, shipment, and storage as recommended in Regulatory Guide 1.37.

Contamination of austenitic stainless steels of the 300 type by compounds that can alter the physical or metallurgical structure and/or properties of the material was avoided during all stages of fabrication. Painting of 300 series stainless steels is prohibited. Grinding is accomplished with resin or

rubber bonded aluminum oxide or silicon carbine wheels that have not previously been used on materials other than 300 series stainless alloys.

Internal surfaces of completed components are cleaned to produce an item that is clean to the extent that grit, scale, corrosion products, grease, oil, wax, gum, adhered or embedded dirt, or extraneous material are not visible to the unaided eye.

Degreasing solvents, acetone or isoprophyl alcohol, may be used on metallic surfaces. Water used for cleaning is inhibited with 30-100 ppm hydrazine.

The specifications for water quality is:

Halides	
Chlorine, ppm	<0.60
Fluoride, ppm	<0.40
Conductivity, μmhos/cm	<5.0
pH	6.0-8.0
Visual clarity	No turbidity, oil or sediment

To prevent halide-induced intergranular corrosion which could occur in aqueous environment with significant quantities of dissolved oxygen, flushing water is inhibited via additions of hydrazine. Many experiments conducted by C-E have proven this inhibitor to be effective.

Onsite and preoperational cleaning of ESF components is in accordance with the recommendations of Regulatory Guide 1.37 as discussed in section 1.8.

Non-NSSS ESF components are suitably cleaned and suitably protected against contaminants capable of causing stress corrosion cracking during fabrication, shipment, storage, construction, testing, and operation.

6.1.1.1.3.3 Cold Worked Stainless Steel. Cold worked austenitic stainless steel is not utilized for ESF components.

6.1.1.1.3.4 Nonmetallic Insulation. All non-metallic insulation materials installed on stainless steel piping and equipment of the ESF are made of calcium silicate, expanded pearlite, fiberglass fiber, or similar materials (ASTM C533, C547, C553, C610, C612) and are consistent with the recommendations of Regulatory Guide 1.36.

6.1.1.1.4 Weld Fabrication and Assembly of Stainless Steel ESF Components

The recommendations of Regulatory Guide 1.31 are followed as discussed in section 1.8.

6.1.1.2 Composition, Compatibility, and Stability of Containment and Core Spray Coolants

Borated water is stored in the austenitic (type 304L) stainless steel-lined safety injection tanks and the refueling water tank. Extensive tests and operating experience show that this coolant will not produce significant corrosion of the tank lining material.

The initial containment spray is borated water taken from the refueling water tank. With a concentration of 4000 to 4400 ppm boron as boric acid and a temperature of 60°F to 120°F, the solution has a pH of about 4.2.

Long-term chemistry control of the recirculated sump solution is accomplished by the containment spray system (subsection 6.2.2).

The long-term recirculation sump fluid pH is controlled by dissolution of anhydrous trisodium phosphate (TSP), which is stored in side-screened baskets located in the vicinity of the containment sumps. Each unit has installed nine baskets of dimensions 2-feet x 2-feet x 2-feet and eight baskets of 4-feet x 4-feet x 4-feet for a total capacity of approximately 580 cubic feet. PVNGS utilizes a minimum of 524 cubic feet (approximately 25,325 pounds) per unit of bulk anhydrous TSP to raise the containment sump pH. In granular form, TSP has a lower bulk density of approximately 48.4 pounds per cubic foot. Its solubility in water at 122°F is 330 grams per kilogram (liter).

As the baskets are submerged in break flow and containment spray, the TSP dissolves into solution. Within 4 hours after a Recirculation Actuation Signal (RAS), the sump solution will reach neutral pH conditions. The sump fluid will have a nominal chemical composition of approximately 4200 ppm boron as boric acid and 3.2 grams per liter of TSP.

The TSP ensures that the final recirculation sump fluid pH will be greater than or equal to 7.0 and less than or equal to 8.5.

This sump solution promotes the long-term retention of iodine. The pH is also sufficient to avoid the stress-corrosion cracking of austenitic stainless steel and to avoid excessive generation of hydrogen by the corrosion of containment metals.

The quantity, solubility, and buffering capability of the trisodium phosphate is periodically verified as described in the Technical Specifications and bases.

The analysis of post-LOCA hydrogen generation is discussed in subsection 6.2.5.

6.1.2 ORGANIC MATERIALS

6.1.2.1 Protective Coatings

Protective coatings used inside the containment, excluding components limited by size and/or exposed surface area, meet the intent of ANSI N101.2 (1972), Protective Coatings (Paints) for Light-Water Nuclear Reactor Containment Facilities, and recommendations of Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants. Refer to subsection 6.2.2 for a discussion of the sump design and consideration given to screen clogging.

A list of surface coatings and applicable conditions for their use inside containment is given in table 6.1-3.

Approximate paint film thickness and exposed surface area for major components and structures inside containment is given in the containment passive heat sink table 6.2.1-8. The painted

areas of valve operators, miscellaneous parts on the reactor coolant pump drives, and instrumentation are considered insignificant.

6.1.2.2 Other Materials

A listing of other materials in the containment is included in table 6.1-4.

Table 6.1-3

COATING MATERIALS USED IN CONTAINMENT

Surface to be Coated	Type of Coating
Steel surfaces at temperature of less than 300F	Epoxy Inorganic zinc
Uninsulated steel surfaces at temperature more than 300F	Inorganic zinc
Decontaminable concrete wall surfaces	Epoxy
Concrete floors	Epoxy

Table 6.1-4

OTHER ORGANIC MATERIALS IN CONTAINMENT

Item	Material	Amount
Reactor coolant pumps lubricant	Petroleum base oil	1600 gallons (400 gallons per pump)
Cable insulation	EP/Hypalon XLPE/Neoprene XLPE/Hypalon FR-ER/CPE	39,500 pounds[(a)] (37,600 + 5%)
UGS Storage Area alignment pins (6)	Delrin 150 SA Acetal Homo-polymer	160 lbs.

a. The major organic polymer in the cable insulation is flame-retardant ethylene propylene rubber and chlorinated polyethylene.

b. Reference DMWO 752491 (Unit 1 6th Refueling Outage.

6.1.3 REFERENCES

6.2 CONTAINMENT SYSTEMS

The containment systems include the containment structure, the containment heat removal systems, the containment air purification and cleanup systems, the containment isolation system, and the containment combustible gas control system.

This section provides the design criteria and evaluations necessary to demonstrate that the systems listed above will function within the specified limits throughout the station operating lifetime.

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

A physical description of the containment and the design criteria relating to the construction techniques, static loads, and seismic loads are provided or referenced in section 3.8. This section pertains to those aspects of containment design, testing, and evaluation that relate to the accident mitigation function.

6.2.1.1 Containment Structure

6.2.1.1.1 Design Bases

The containment design basis is to limit release of radioactive materials, subsequent to postulated accidents, such that resulting calculated offsite doses are less than the guideline values of 10CFR100. In order to meet this requirement, a design (maximum) containment leakage rate has been defined in conjunction with performance requirements placed on the engineered safety features (ESF) systems.

The capability of the containment structure to maintain design leaktight integrity and to provide a predictable environment for operation of ESF systems is ensured by a comprehensive design, analysis, and testing program that includes consideration of:

A. The peak containment pressure and temperature associated with the most severe postulated accident coincident with the operating basis earthquake (OBE) or safe shutdown earthquake (SSE).

B. Maximum external pressure loading condition to which the containment may be subjected as a result of inadvertent containment systems operations that potentially reduce containment internal pressure below outside atmospheric pressure.

6.2.1.1.1.1 Containment Structure Accident Conditions. The postulated accidents considered in determining design containment peak pressure (and temperature) and external pressure are summarized in table 6.2.1-1. These analyses were performed at 102% of Licensed power, i.e., at 4070 MWt.

For the containment structure peak pressure analysis, it is assumed that each postulated accident is concurrent with the most limiting single active failure in systems required to mitigate the consequence of the accident or to shut down the plant. In addition, if the postulated accident causes a turbine or reactor trip, loss of offsite power is also assumed. Main steam line breaks are evaluated with offsite power available since secondary side breaks are more severe with no loss of offsite power. No two accidents are postulated to

occur simultaneously or consecutively. For conservatism, containment leakage is not incorporated into the PVNGS containment peak pressure analysis.

The design basis accident (DBA) for each of the categories of containment peak pressure (and temperature) and containment maximum external pressure is defined as the most severe accident postulated for each case. The DBAs and calculated pressures are given in table 6.2.1-2. In the event of a postulated LOCA or MSLB, the release of coolant from the rupture area will cause the high temperature, high pressure fluid to flash to steam. The release of mass and energy raises the temperature and pressure of the containment atmosphere. The severity of the resulting temperature and pressure peaks developed depends upon the nature, location, and size of the postulated rupture, as well as the containment design.

In order to establish the controlling rupture for containment design, a spectrum of primary and secondary breaks, described in Table 6.2.1-1, are analyzed to determine their effects. Mass/energy source terms for hot leg cases and MSLB cases are not generated after the end of blowdown. For hot leg cases, most of the reflood fluid does not pass through a steam generator prior to being released to the containment; hence, in contrast to a cold leg break, there is no physical mechanism to rapidly remove the residual steam generator secondary energy during or after reflood. For a MSLB, following blowdown of the affected generator, the decay heat is transferred to the unaffected generator which, in turn, will vent to the atmosphere when its safety valves open. For both cases, then,

there is no mechanism for the release of significant amounts of mass or energy to the containment after the end of blowdown.

Breaks in the main feedwater piping would result in blowdown that is less limiting than the MSLB. Effective break areas for the main feedwater line break (MFLB) are limited by the steam generator internals design. Fluid enthalpy for the MFLB is less than the enthalpy of the fluid in the MSLB; therefore, MFLB's are not analyzed. Blowdown data for the spectrum of breaks shown in Table 6.2.1-1 are evaluated to determine the most limiting mass and energy release rates with respect to containment peak pressure analysis. These cases, and their results, are presented in this chapter. The most limiting of these accidents are identified in table 6.2.1-4. Containment design parameters are given in table 6.2.1-3. The difference between the design pressure (60 psig) and the calculated peak pressure of the as-constructed design (57.9 psig) results in a design margin of approximately 3.5%.

6.2.1.1.1.2 Containment Internal Structures Accident Conditions. The reactor coolant system (RCS) breaks defined in Section 3.6.2 are analyzed and form the design basis for the loads on containment internal structures and equipment. The simultaneous occurrences are the same as discussed in paragraph 6.2.1.1.1.1. The design pressures for the steam generator and pressurizer compartments are given in table 6.2.1-3. The currently calculated values for the as-built design are listed in table 6.2.1-2.

6.2.1.1.2 Design Features

The design features of the containment structure and internal structures are provided in subsections 3.8.1 and 3.8.3, respectively.

6.2.1.1.2.1 Protection From the Dynamic Effects of Postulated Accidents. The containment structure, subcompartments, and engineered safety feature systems are protected from loss of safety function due to the dynamic effects of postulated accidents. Containment design has provided separation and inclusion of barriers, restraints and supports when required to protect essential structures, systems, and components from accident generated missile, pipe whip, and jet impingement forces. The detailed criteria, locations, and descriptions of devices used for protection are given in section 3.6.

6.2.1.1.2.2 Codes and Standards. Codes and standards applied to the design, fabrication, and erection of the containment and internal structures are given in table 3.2-1 and in paragraph 3.8.1.2. In each case, the codes and standards used are consistent with the equipment safety function.

6.2.1.1.2.3 Protection Against External Pressure Loads. The containment system is designed to maintain its structural and functional integrity during and after the most extreme loading conditions due to inadvertent operation of containment heat removal systems and other possible modes of plant operation (e.g., containment purging as listed in table 6.2.1-1) that could potentially result in significant external structural

Table 6.2.1-1

POSTULATED ACCIDENTS FOR CONTAINMENT DESIGN (Sheet 1 of 2)

Containment Design Parameter	Postulated Accidents Considered
Peak pressure/temperature	Loss-of-coolant accidents (LOCAs) Double-ended hot leg slot (DEHLS), 19.24-square foot area Double-ended suction leg slot (DESLS), 9.82-square foot area, maximum emergency core cooling system (ECCS) flow Double-ended suction leg slot (DESLS), 9.82-square foot area, minimum ECCS flow Double-ended discharge leg slot (DEDLS), 9.82-square foot area, maximum ECCS flow Double-ended discharge leg slot (DEDLS), 9.82-square foot area, minimum ECCS flow Main steam line breaks (MSLB) 7.16-square foot slot area MSLB, 102% power with cooling train failure 7.16-square foot slot area MSLB, 75% power with cooling train failure 7.16-square foot slot area MSLB, 50% power with cooling train failure 7.16-square foot slot area MSLB, 0.0% power with cooling train failure

Table 6.2.1-1

POSTULATED ACCIDENTS FOR CONTAINMENT DESIGN (Sheet 2 of 2)

Containment Design Parameter	Postulated Accidents Considered
Subcompartment peak pressure/temperature	Reactor cavity
	N/A
	N/A
	Steam generator compartment
	98-square inch SI-A or B line
	129-square inch SDC line
	123-square inch FW Guillotine
	Pressurizer compartment
	161-square inch pressurizer surge line guillotine break
External pressure	Inadvertent operation of the containment heat removal systems[a]
	Misoperation of the containment normal purging system

a. Calculated by simple ideal gas law relationship.

Table 6.2.1-2

CALCULATED VALUES FOR CONTAINMENT PRESSURE PARAMETERS

Parameter	Design Basis Accident[a]	Calculated Value (PSIG)
Peak Pressure (4070 MWt)	DEDL slot, max. ECCS	57.9
Peak subcompartment pressure	Reactor cavity	
	N/A	N/A
	Steam generator compartment	
	129-square inch SDC line (3990 MWt)	19.5
	Pressurizer compartment wall	
	161-square inch surge line guillotine	72.4
External pressure loading	Inadvertent operation of the containment spray system	3.5[b]

a. See table 6.2.1-1 for definition of abbreviations used.

b. The maximum external pressure that would occur as a result of this transient is 3.5 psig based on an initial containment pressure of −1.0 psig (the lower Technical Specification limit plus instrument uncertainty) and the calculated pressure drop of 2.5 psig.

Table 6.2.1-3

PRINCIPAL CONTAINMENT DESIGN PARAMETERS

Parameter	Peak Value
Containment	
Internal design pressure, psig	60.0
Design temperature, °F	
High mean during normal operation	120.0
Maximum, DBA	300.0
External design pressure loading, psig	4.0
Net free volume, ft^3	2.62×10^6
Design leak rate, percent free volume per day at 60.0 psig	0.1
Subcompartments	
Reactor cavity design wall loading, psid	110[a]
Steam generator compartment design wall loading, psid	30[a]
Pressurizer compartment design wall loading, psid	73[a]

a. This value does not include the dynamic load factors which were used in the design as described in paragraph 3.8.3.3.1.4.

loadings. The resulting pressures are lower than the design containment external pressure. Details of this evaluation are provided in paragraph 6.2.1.1.3.6.

6.2.1.1.2.4 Potential Water Traps Inside Containment. The design of the containment minimizes potential trapping of safety injection and containment spray water which might otherwise prevent return and subsequent recirculation via the containment emergency sump. The reactor cavity and associated ventilation ducts are the only locations that trap significant quantities of water. These locations are shown in Engineering drawings 13-P-OOB-002, 13-P-OOB-007, and 13-P-OOB-008. As a result of a LOCA and subsequent safety injection system operation, the reactor cavity and the ventilation ducts that penetrate the lower portion of the cavity shield wall could fill with water to an elevation of 96.8 feet (to a depth of approximately 42 feet above the reactor cavity floor). At this elevation, water will overflow to the surrounding floor of the containment. The quantity of water trapped by the cavity and ducts is 18,452 ft^3 (approximately 138,000) gallons.

Based on initial availability of 104,730 ft^3 (approximately 783,400 gallons) from the refueling water tank (maximum capacity), the contribution of the RCS inventory, and the four safety injection tank volumes, the resulting maximum water level will be approximately 91 ft, or 11 feet above the containment floor.

For net positive suction head (NPSH) calculations, the minimum required RWT volume, less a specified volume of water diverted to the chemical volume and control system and water postulated

to be held on wetted surfaces and delayed in containment, results in a minimum containment volume outside the reactor cavity corresponding to an approximate containment water level of 84.5 feet (4.5 feet above the containment floor).

The safety injection and containment spray pumps are located in the auxiliary building and are placed low enough below containment emergency sump elevation to assure the availability of the NPSH requirements listed in table 6.3.2-1.

During normal plant operation, drains from the refueling canal floor (elevation 98.5 feet and elevation 90.5 feet) to the containment floor (elevation 80 feet) are open with flange removed to preclude trapping of water. The drain line consists of approximately 10 feet of 10-inch diameter piping. Plugging of the drain line is precluded by its large diameter. No water will be permanently contained by the refueling canal.

Since the expected maximum pumped fluid temperature will exceed 212F, NPSH for the safeguards pumps was calculated by assuming that the temperature of the pumped liquid is at saturation for the containment pressure, and that the vapor pressure is equal to the containment pressure. These assumptions ensure that no credit is taken for containment pressure since the containment and vapor pressure terms cancel out of the NPSH equation which then reduces to:

$$NPSH_{available} = \Delta Z - h_L$$

ΔZ = elevation head

h_L = suction line loss

6.2.1.1.2.5 Containment Cooling and Ventilation Systems. During normal reactor operation, the containment atmosphere is maintained below 120F by continuous operation of the containment normal ventilation system.

Only one-half of the cooling units installed are required to remove the normal plant operating heat load, the remaining one half is used as a standby. Temperature is thermostatically controlled.

Before entering, the containment is purged, if necessary, to permit occupancy. All air supplied is taken from outside, filtered, and delivered through the purge supply system. The exhaust unit discharges through a filter to the plant vent stack and maintains stack velocity at a rate that ensures adequate dispersion in the atmosphere against design wind pressures.

Containment normal ventilation systems are described in detail in subsection 9.4.6.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 Containment Peak Pressure and Temperature Analysis. In the event of a postulated loss-of-coolant accident (LOCA), or main steam line break (MSLB), the release of coolant from the rupture area will cause the high-temperature, high-pressure fluid to flash to steam. This release of mass and energy raises the temperature and pressure of the containment atmosphere. The severity of the resulting temperature and pressure peaks developed depends upon the nature, location, and size of the postulated rupture.

A. Pipe Break

In order to establish the controlling rupture for containment design, the primary and secondary breaks, described in table 6.2.1-1, were analyzed to determine their significance in selecting a containment design basis. Mass/energy source terms for the hot leg case and MSLB cases were not generated after the end of blowdown. For the hot leg case, most of the reflood fluid does not pass through a steam generator prior to being released to the containment; hence, in contrast to a cold leg break, there is no physical mechanism to rapidly remove the residual steam generator secondary energy during or after reflood and the mass/energy release rate from the break will be less than for a cold leg break. For a MSLB, following isolation and blowdown of the ruptured unit, the decay heat is transferred to the intact unit which, in turn, will vent to the atmosphere when its safety valves open. For the MSLB, then, there is no mechanism for the release of significant amounts of mass or energy to the containment after the end of blowdown. Effective break areas for the main feedwater line break (MFWLB) are limited by the steam generator internals design and fluid enthalpy for the MFWLB is less than the enthalpy of the fluid in the MSLB. Consequently, breaks in the main feedwater piping would result in blowdown that is less limiting than the MSLB; therefore, MFWLBs are not analyzed. Blowdown data for the spectrum of breaks shown in table 6.2.1-1 are evaluated to determine the

most limiting mass and energy release rates with respect to containment peak pressure analysis. Those limiting cases for an analyzed core power of 4070 MWt are presented in tables 6.2.1-4 and 6.2.1-5. The most severe of these accidents, identified in listing D is the controlling containment DBA.

B.1 Initial Conditions and Input Data

The containment pressure analysis input data are based upon the final plant design as shown in tables 6.2.1-3 and 6.2.1-6. A conservative prediction of LOCA and MSLB consequences was assured by determining upper and lower bounding values of containment initial conditions, geometric parameters, and thermodynamic properties, and by applying these values in the manner producing maximum pressure results.

The initial conditions within the containment system and the reactor coolant system prior to accident initiation are given in table 6.2.1-6. The maximum containment normal pressure is assumed to be at 2.5 psig, design maximum inside and maximum outside temperature are used to minimize calculated heat transfer during the postulated accident. The reactor coolant system is assumed to be at 102% of Licensed Power.

For the purpose of the containment peak pressure and temperature analysis, the safety injection system and the containment heat removal systems (i.e., containment spray system) were assumed to operate in the mode that

maximizes the containment peak pressure as shown in table 6.2.1-7. For the safety injection system, both maximum and minimum ECCS performances were evaluated. For the containment heat removal systems, minimum system capacity is conservative for calculating containment peak pressures.

Passive heat sink data is provided in table 6.2.1-8. Part A of the heat sink table is a detailed list of the geometry of each heat sink and part B describes the resulting simplified heat sink models used for computer input. Node spacing used for concrete, steel, and steel-lined concrete heat sinks is fine enough to ensure an accurate representation of the thermal gradient in each slab. In concrete, the node spacing varies from 0.003274 to 0.004233 foot depending on the total thickness of the slab. In the steel, node spacing varies from 0.000455 to 0.006943 foot. For composite steel (liner)-concrete heat sinks, the node spacing used is the same as that given above for individual steel and concrete slabs. A 0.0087 foot air gap, equivalent to a thermal conductance of 20 Btu/h-ft^2-F, is assumed to exist between the containment steel liner and concrete wall for peak pressure calculations. It is further assumed that heat is transferred only by conduction across the air gap. The same gap conductance is presumed for the interface between the stainless steel refueling canal liner and the concrete.

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 1 of 18)

A. RCS RCP Discharge leg break

Break Type: Double-ended discharge leg slot break (DEDLS)
Pipe ID: 30 inches
Break area: 9.82 square feet
ECCS: Maximum

A.1: BLOWDOWN MASS AND ENERGY RELEASE DATA

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
0.00	0.00000E+00	0.00000E+00	565.31
0.01	2.85051E+08	1.61143E+11	565.31
0.02	2.82343E+08	1.59386E+11	564.51
0.03	2.83133E+08	1.59728E+11	564.14
0.04	2.85732E+08	1.61190E+11	564.13
0.05	2.88377E+08	1.62721E+11	564.27
0.06	3.01921E+08	1.70410E+11	564.42
0.07	2.94592E+08	1.66291E+11	564.48
0.08	2.99242E+08	1.68875E+11	564.34
0.09	4.68059E+08	2.64422E+11	564.93
0.10	4.42910E+08	2.50371E+11	565.29
0.15	4.63273E+08	2.62547E+11	566.72
0.20	4.34348E+08	2.46504E+11	567.53
0.25	4.46826E+08	2.53784E+11	567.97
0.30	4.32850E+08	2.45930E+11	568.16
0.35	4.36275E+08	2.47902E+11	568.23
0.40	4.28639E+08	2.43546E+11	568.19
0.45	4.33702E+08	2.46417E+11	568.17
0.50	4.26589E+08	2.42354E+11	568.12
0.60	4.22271E+08	2.39860E+11	568.02
0.70	4.20711E+08	2.39023E+11	568.14
0.80	4.12837E+08	2.34625E+11	568.32
0.90	4.09663E+08	2.32982E+11	568.72
1.00	4.06057E+08	2.31244E+11	569.49
1.50	3.60263E+08	2.08245E+11	578.04
2.00	3.00554E+08	1.76705E+11	587.93
2.50	2.69094E+08	1.58869E+11	590.38
3.00	2.36632E+08	1.39496E+11	589.51
3.50	2.19011E+08	1.28889E+11	588.50
4.00	2.10110E+08	1.23631E+11	588.41

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 2 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
5.00	1.84618E+08	1.14148E+11	618.29
6.00	1.29529E+08	9.24680E+10	713.88
7.00	1.23988E+08	8.69023E+10	700.89
8.00	1.08135E+08	7.81967E+10	723.14
9.00	9.04002E+07	6.94123E+10	767.83
10.00	7.19805E+07	6.03395E+10	838.28
11.00	5.50213E+07	5.09172E+10	925.41
12.00	3.23437E+07	3.50072E+10	1082.35
13.00	3.18199E+07	2.88930E+10	908.02
14.00	5.37833E+07	3.15424E+10	586.47
15.00	5.06775E+07	2.16670E+10	427.55
16.00	3.93638E+07	1.46646E+10	372.54
16.50	4.27465E+07	1.54686E+10	361.87
16.60	1.78056E+07	6.44829E+09	362.15
16.70	1.64299E+07	5.99800E+09	365.07
16.80	1.45180E+07	5.34982E+09	368.50
16.90	1.33387E+07	4.92406E+09	369.16
17.00	1.22485E+07	4.51611E+09	368.71
17.10	1.11330E+07	4.10017E+09	368.29
17.11	0.00000E+00	0.00000E+00	368.29

A.2: CORE REFLOOD & POST REFLOOD MASS AND ENERGY RELEASE DATA

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
17.11	0.00000E+00	0.00000E+00	1306.44
17.20	5.56020E+05	7.26408E+08	1306.44
20.20	3.16375E+06	4.09720E+09	1295.04
21.00	3.30674E+06	4.27039E+09	1291.42
21.01	1.91791E+06	2.47683E+09	1291.42
23.10	1.92885E+06	2.47702E+09	1284.19
26.00	1.93543E+06	2.47192E+09	1277.19
28.90	1.93570E+06	2.46282E+09	1272.31
31.80	1.93198E+06	2.45112E+09	1268.71
34.70	1.92555E+06	2.43772E+09	1265.98
37.60	1.91731E+06	2.42314E+09	1263.83
40.50	1.90785E+06	2.40780E+09	1262.05
43.40	1.89760E+06	2.39195E+09	1260.52

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 3 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
46.40	1.88642E+06	2.37520E+09	1259.10
49.30	1.87525E+06	2.35881E+09	1257.86
52.20	1.86387E+06	2.34232E+09	1256.69
55.10	1.85233E+06	2.32574E+09	1255.58
58.00	1.84074E+06	2.30914E+09	1254.46
60.79	1.82953E+06	2.29313E+09	1253.40
60.80	3.15436E+06	3.95366E+09	1253.40
68.10	3.10183E+06	3.87950E+09	1250.71
75.30	3.05219E+06	3.80934E+09	1248.07
82.60	3.00164E+06	3.73838E+09	1245.45
89.80	2.95153E+06	3.66854E+09	1242.93
97.00	2.90020E+06	3.59820E+09	1240.67
104.30	2.84944E+06	3.52800E+09	1238.14
111.50	2.79918E+06	3.45892E+09	1235.69
118.80	2.74774E+06	3.38918E+09	1233.45
126.00	2.65568E+06	3.14291E+09	1183.46
133.20	2.46388E+06	2.90869E+09	1180.54
140.50	2.29057E+06	2.70410E+09	1180.54
147.70	2.13250E+06	2.51748E+09	1180.53
155.00	1.98306E+06	2.34108E+09	1180.54
162.20	1.84460E+06	2.17760E+09	1180.53
169.40	1.71367E+06	2.02306E+09	1180.54
169.50	1.74212E+06	2.08012E+09	1194.02
170.40	1.68099E+06	1.96910E+09	1171.39
172.40	1.67421E+06	1.99090E+09	1189.16
175.40	1.60028E+06	1.88352E+09	1177.00
179.40	1.54432E+06	1.82808E+09	1183.74
184.40	1.44080E+06	1.69704E+09	1177.85
190.40	1.26062E+06	1.48954E+09	1181.59
197.30	1.28129E+06	1.51150E+09	1179.67
205.30	1.01395E+06	1.19761E+09	1181.13
214.30	9.86046E+05	1.16371E+09	1180.17
224.20	7.38977E+05	8.72393E+08	1180.54
235.20	6.94826E+05	8.20353E+08	1180.66
247.10	7.43358E+05	8.77393E+08	1180.31
260.10	5.61909E+05	6.63585E+08	1180.95
274.00	5.33631E+05	6.29821E+08	1180.26
288.90	4.10696E+05	4.84835E+08	1180.52
288.91	0.00000E+00	0.00000E+00	1180.52

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 4 of 18)

A.3: VESSEL CONDENSATION AND SPILLAGE MASS AND ENERGY RELEASE DATA

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
17.11	0.00000E+00	0.00000E+00	93.79
20.99	0.00000E+00	0.00000E+00	93.79
21.00	4.42722E+07	4.15248E+09	93.79
23.00	3.98212E+07	3.76220E+09	94.48
25.00	3.61624E+07	3.44096E+09	95.15
31.90	2.72557E+07	2.65688E+09	97.48
35.90	2.35676E+07	2.33105E+09	98.91
41.90	1.91248E+07	1.93751E+09	101.31
45.90	1.66474E+07	1.71753E+09	103.17
51.90	1.34244E+07	1.43080E+09	106.58
55.90	1.15244E+07	1.26147E+09	109.46
59.90	9.78345E+06	1.10612E+09	113.06
61.90	3.73464E+05	3.28648E+07	88.00
71.90	4.72464E+05	4.15768E+07	88.00
81.90	5.71608E+05	5.03015E+07	88.00
91.90	6.71112E+05	5.90579E+07	88.00
99.90	7.52220E+05	6.61954E+07	88.00
115.90	9.11484E+05	8.02106E+07	88.00
125.00	9.87084E+05	1.19931E+08	121.50
135.00	1.20064E+06	2.12513E+08	177.00
145.00	1.38478E+06	2.98811E+08	215.78
155.00	1.54595E+06	3.79598E+08	245.54
165.00	1.69150E+06	4.55529E+08	269.31
169.40	1.79615E+06	4.89624E+08	272.60
184.40	2.40966E+06	6.56861E+08	272.59
194.40	1.93194E+06	5.26643E+08	272.60
210.00	1.30928E+06	3.56908E+08	272.60
230.00	1.19542E+06	3.25868E+08	272.60
250.00	9.54432E+05	2.60172E+08	272.59
270.00	4.78224E+05	1.30358E+08	272.59
288.91	0.00000E+00	0.00000E+00	272.59

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 5 of 18)

B. RCS RCP Suction leg break

Break Type: Double-ended suction leg slot break (DESLS)
Pipe ID: 30 inches
Break area: 9.82 square feet
ECCS: Maximum

B.1: BLOWDOWN MASS AND ENERGY RELEASE DATA

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
0.00	0.00000E+00	0.00000E+00	566.01
0.01	2.86642E+08	1.62242E+11	566.01
0.02	2.82425E+08	1.59639E+11	565.25
0.03	2.80586E+08	1.58439E+11	564.67
0.04	2.80194E+08	1.58140E+11	564.39
0.05	2.80086E+08	1.58065E+11	564.35
0.06	2.79377E+08	1.57679E+11	564.39
0.07	2.77696E+08	1.56741E+11	564.43
0.08	2.75302E+08	1.55392E+11	564.44
0.09	2.73111E+08	1.54164E+11	564.47
0.10	2.71881E+08	1.53491E+11	564.55
0.15	2.74434E+08	1.55302E+11	565.90
0.20	2.71292E+08	1.53745E+11	566.71
0.25	2.73267E+08	1.55130E+11	567.69
0.30	2.71316E+08	1.54150E+11	568.16
0.35	2.71845E+08	1.54620E+11	568.78
0.40	2.70055E+08	1.53695E+11	569.12
0.45	2.70016E+08	1.53824E+11	569.69
0.50	2.68763E+08	1.53190E+11	569.98
0.60	2.67216E+08	1.52528E+11	570.80
0.70	2.65698E+08	1.51883E+11	571.64
0.80	2.64521E+08	1.51454E+11	572.56
0.90	2.63330E+08	1.51022E+11	573.51
1.00	2.62314E+08	1.50712E+11	574.55
1.50	2.56446E+08	1.48858E+11	580.47
2.00	2.43094E+08	1.42282E+11	585.29
2.50	2.25346E+08	1.32729E+11	589.00
3.00	2.09166E+08	1.24148E+11	593.54
3.50	1.86241E+08	1.12263E+11	602.78
4.00	1.59363E+08	9.88852E+10	620.50

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 6 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
5.00	1.23140E+08	8.11070E+10	658.66
6.00	1.12334E+08	7.44097E+10	662.40
7.00	1.06542E+08	7.04639E+10	661.37
8.00	9.86203E+07	6.61333E+10	670.58
9.00	9.36966E+07	6.31155E+10	673.62
10.00	8.86283E+07	6.01565E+10	678.75
11.00	8.31655E+07	5.71518E+10	687.21
12.00	7.76489E+07	5.42702E+10	698.92
13.00	7.43751E+07	5.23831E+10	704.31
14.00	6.68921E+07	4.92980E+10	736.98
15.00	5.64399E+07	4.51446E+10	799.87
16.00	4.63633E+07	4.04256E+10	871.93
17.00	3.92003E+07	3.60630E+10	919.97
18.00	3.37968E+07	3.06900E+10	908.08
19.00	3.49090E+07	2.62350E+10	751.52
20.00	3.46231E+07	2.41939E+10	698.78
20.60	3.23395E+07	2.12615E+10	657.45
20.70	3.22187E+07	2.08081E+10	645.84
20.80	3.19554E+07	2.03099E+10	635.57
20.81	0.00000E+00	0.00000E+00	635.57

B.2: CORE REFLOOD & POST REFLOOD MASS AND ENERGY RELEASE DATA[a]

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
20.81	0.00000E+00	0.00000E+00	1295.06
20.90	8.66520E+05	1.12219E+09	1295.06
22.70	5.69106E+06	7.29439E+09	1281.73
22.71	3.30081E+06	4.23075E+09	1281.73
27.10	3.55302E+06	4.47033E+09	1258.17
33.20	3.45466E+06	4.31247E+09	1248.31
39.30	3.33930E+06	4.14750E+09	1242.03
45.40	3.22765E+06	3.98875E+09	1235.81
51.50	3.11928E+06	3.83543E+09	1229.59
57.60	3.01664E+06	3.69273E+09	1224.12
63.70	2.61111E+06	3.14492E+09	1204.44

[a] 70 psia containment back pressure

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 7 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
69.80	2.22343E+06	2.68389E+09	1207.10
75.90	1.88123E+06	2.27665E+09	1210.20
82.00	1.58126E+06	1.91925E+09	1213.74
88.10	1.30579E+06	1.59068E+09	1218.17
94.20	2.74466E+06	3.27945E+09	1194.85
100.30	5.00723E+05	6.24750E+08	1247.70
106.40	2.64299E+05	3.35124E+08	1267.97
112.39	1.78253E+05	2.27049E+08	1273.75
112.40	3.07332E+05	3.91464E+08	1273.75
112.50	3.05316E+05	3.88908E+08	1273.79
112.60	2.82388E+05	3.52859E+08	1249.55
112.61	0.00000E+00	0.00000E+00	1249.55

B.3: VESSEL CONDENSATION AND SPILLAGE MASS AND ENERGY RELEASE DATA[a, b]

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
20.81	0.00000E+00	0.00000E+00	95.97
23.69	0.00000E+00	0.00000E+00	95.97
23.70	5.97064E+07	5.72973E+09	95.97
25.70	4.89556E+07	4.78471E+09	97.74
31.90	2.90300E+07	3.01991E+09	104.03
35.90	2.11250E+07	2.31424E+09	109.55
41.90	1.30929E+07	1.59235E+09	121.62
45.90	9.77309E+06	1.29053E+09	132.05
51.90	7.38277E+06	1.06586E+09	144.37
55.90	6.77946E+06	1.00379E+09	148.06
59.90	6.71634E+06	9.89517E+08	147.33
61.90	7.79416E+06	1.21631E+09	156.05

[a] 70 psia containment back pressure

[b] Direct ECCS Spillage is the ECCS flow which goes directly to the containment without entering the NSSS. Vessel Spillage is the sum of all liquid leaving the break. For the double ended suction leg break, there is no spillage since the water fed to the cold leg would not spill out of break against the RCP inertia and high flow resistance.

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 8 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
65.90	7.81299E+06	1.33133E+09	170.40
71.90	8.44839E+06	1.55219E+09	183.73
81.90	1.00232E+07	1.99283E+09	198.82
91.90	1.14244E+07	2.63992E+09	231.08
93.90	1.64886E+07	4.49497E+09	272.61
99.90	1.87553E+07	5.11266E+09	272.60
101.90	2.15196E+07	5.20525E+09	241.88
103.90	2.23582E+07	5.05876E+09	226.26
105.90	2.27700E+07	4.81495E+09	211.46
107.90	2.29040E+07	4.48718E+09	195.91
109.90	2.28546E+07	4.10270E+09	179.51
112.61	0.00000E+00	0.00000E+00	179.51

C. Hot leg break

Break Type: Double-ended hot leg slot break (DEHLS)
Pipe ID 42 inches
Break area: 19.24 square feet

C.1: BLOWDOWN MASS AND ENERGY RELEASE DATA

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
0.00	0.00000E+00	0.00000E+00	653.27
0.01	6.25782E+08	4.08806E+11	653.27
0.02	6.09098E+08	3.96762E+11	651.39
0.03	6.12653E+08	3.99998E+11	652.89
0.04	5.22239E+08	3.39712E+11	650.49
0.05	4.76734E+08	3.08305E+11	646.70
0.06	5.22618E+08	3.39608E+11	649.82
0.07	5.22104E+08	3.39981E+11	651.17
0.08	5.02273E+08	3.26158E+11	649.36
0.09	5.30094E+08	3.44672E+11	650.21
0.10	5.53012E+08	3.60512E+11	651.91
0.15	5.26827E+08	3.43248E+11	651.54
0.20	5.03500E+08	3.28434E+11	652.30
0.25	4.90827E+08	3.20398E+11	652.77
0.30	4.62032E+08	3.01285E+11	652.09
0.35	4.48029E+08	2.92190E+11	652.17

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 9 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
0.40	4.41604E+08	2.87805E+11	651.73
0.45	4.31104E+08	2.80543E+11	650.76
0.50	4.23569E+08	2.75303E+11	649.96
0.60	4.07482E+08	2.64480E+11	649.06
0.70	3.98281E+08	2.58334E+11	648.62
0.80	3.85579E+08	2.50588E+11	649.90
0.90	3.68922E+08	2.40562E+11	652.07
1.00	3.55832E+08	2.32589E+11	653.65
1.50	3.11656E+08	2.05107E+11	658.12
2.00	2.93674E+08	1.90662E+11	649.23
2.50	2.79900E+08	1.79671E+11	641.91
3.00	2.76715E+08	1.73941E+11	628.59
3.50	2.63436E+08	1.65188E+11	627.05
4.00	2.37326E+08	1.52799E+11	643.84
5.00	2.00125E+08	1.32500E+11	662.09
6.00	1.69927E+08	1.16089E+11	683.17
7.00	1.39703E+08	1.00423E+11	718.84
8.00	1.09540E+08	8.54954E+10	780.50
9.00	7.01908E+07	6.18124E+10	880.63
10.00	4.17911E+07	4.56412E+10	1092.13
11.00	2.12768E+07	2.24885E+10	1056.95
11.10	1.95816E+07	2.07220E+10	1058.24
11.20	1.81921E+07	1.92556E+10	1058.46
11.30	1.66420E+07	1.76113E+10	1058.25
11.40	1.52148E+07	1.61240E+10	1059.76
11.50	1.38377E+07	1.47176E+10	1063.59
11.60	1.25084E+07	1.33579E+10	1067.91
11.70	1.11831E+07	1.19787E+10	1071.14
11.80	9.71821E+06	1.04298E+10	1073.22
11.90	8.14924E+06	8.89625E+09	1091.67
12.00	7.22817E+06	7.97833E+09	1103.78
12.10	6.43526E+06	7.18148E+09	1115.96
12.20	5.73897E+06	6.51920E+09	1135.95
12.21	0.00000E+00	0.00000E+00	1135.95

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 10 of 18)

C.2: CORE REFLOOD & POST REFLOOD MASS AND ENERGY RELEASE DATA

For the hot leg break, there is no viable path for the steam in the reactor vessel to go through the steam generators. Therefore, the reflood and post-reflood mass and energy releases are zero.

C.3: VESSEL CONDENSATION AND SPILLAGE MASS AND ENERGY RELEASE DATE

Direct ECCS Spillage is the ECCS flow which goes directly to the containment without entering the NSSS. Vessel Spillage is the sum of all liquid leaving the break. For the double ended hot leg break, spillage is zero since all ECCS injection flow would be induced into the core before it would be discharged into the containment.

D. Most severe secondary system break

Break Type: Main steam line Double ended guillotine break
Pipe ID: 24.459 inches
Break area: 6.526 square feet (plus expansion)
Reactor Power: 0%

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
0.00	3.25378E+07	3.85006E+10	1183.25
0.10	3.18314E+07	3.76992E+10	1184.34
0.20	3.15536E+07	3.73838E+10	1184.77
0.30	3.13568E+07	3.71603E+10	1185.08
0.40	3.11894E+07	3.69702E+10	1185.34
0.50	3.10326E+07	3.67920E+10	1185.59
0.60	3.08809E+07	3.66192E+10	1185.82
0.70	3.07327E+07	3.64507E+10	1186.05
0.80	3.05873E+07	3.62851E+10	1186.28
0.90	3.04443E+07	3.61220E+10	1186.50
1.00	3.03037E+07	6.59619E+10	1186.71
1.99	2.90287E+07	3.45048E+10	1188.64
2.99	2.79400E+07	3.32566E+10	1190.29
3.99	2.65639E+07	3.16693E+10	1192.19
4.99	2.26258E+07	2.70396E+10	1195.08

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 11 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
5.99	1.95679E+07	2.33952E+10	1195.60
6.99	1.61693E+07	1.93352E+10	1195.80
7.99	1.24966E+07	1.49453E+10	1195.94
8.99	8.89114E+06	1.06338E+10	1196.01
9.99	8.82727E+06	1.05593E+10	1196.22
10.99	8.75308E+06	1.04727E+10	1196.46
11.99	8.66509E+06	1.03699E+10	1196.74
12.99	8.56346E+06	1.02510E+10	1197.06
13.99	8.45168E+06	1.01201E+10	1197.41
14.99	8.33688E+06	9.98564E+09	1197.76
15.99	8.22316E+06	9.85223E+09	1198.11
16.99	8.11537E+06	9.72569E+09	1198.43
17.99	8.01623E+06	9.60919E+09	1198.71
18.99	7.92608E+06	9.50317E+09	1198.97
19.99	7.84357E+06	9.40601E+09	1199.20
24.99	7.47234E+06	8.96832E+09	1200.20
29.99	7.14528E+06	8.58161E+09	1201.02
34.99	6.88684E+06	8.27543E+09	1201.63
39.99	6.65413E+06	7.99927E+09	1202.15
44.99	6.44278E+06	7.74806E+09	1202.59
49.99	6.24391E+06	7.51126E+09	1202.97
54.99	6.05678E+06	7.28813E+09	1203.30
59.99	5.87905E+06	7.07591E+09	1203.58
64.99	5.70967E+06	6.87344E+09	1203.82
69.99	5.54792E+06	6.67984E+09	1204.03
74.99	5.39309E+06	6.49433E+09	1204.19
79.99	5.24477E+06	6.31645E+09	1204.33
84.99	5.04925E+06	6.08166E+09	1204.47
89.99	4.88052E+06	5.87880E+09	1204.54
94.99	4.71132E+06	5.67518E+09	1204.59
99.99	4.47988E+06	5.39636E+09	1204.59
104.99	4.31651E+06	5.19937E+09	1204.54
109.99	4.26290E+06	5.13472E+09	1204.51
114.99	4.15415E+06	5.00346E+09	1204.45
119.99	4.03675E+06	4.86169E+09	1204.36
124.99	3.91576E+06	4.71550E+09	1204.24
129.99	3.79328E+06	4.56746E+09	1204.09

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 12 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
134.99	3.67254E+06	4.42141E+09	1203.91
139.99	3.55236E+06	4.27601E+09	1203.71
144.99	3.43333E+06	4.13190E+09	1203.47
149.99	3.31444E+06	3.98794E+09	1203.20
154.99	3.19526E+06	3.84354E+09	1202.89
159.99	3.07473E+06	3.69745E+09	1202.53
164.99	2.95511E+06	3.55245E+09	1202.14
169.99	2.84165E+06	3.41487E+09	1201.72
174.99	2.71213E+06	3.25778E+09	1201.19
179.99	2.57271E+06	3.08863E+09	1200.54
180.99	2.54397E+06	3.05376E+09	1200.39
181.99	2.51486E+06	3.01845E+09	1200.24
182.99	2.48534E+06	2.98263E+09	1200.09
183.99	2.45536E+06	2.94625E+09	1199.93
184.99	2.42491E+06	2.90930E+09	1199.76
185.99	2.39398E+06	2.87177E+09	1199.58
186.99	2.36257E+06	2.83366E+09	1199.40
187.99	2.33070E+06	2.79499E+09	1199.20
188.99	2.29838E+06	2.75576E+09	1199.00
189.99	2.26558E+06	2.71597E+09	1198.79
190.99	2.23231E+06	2.67559E+09	1198.57
191.99	2.19849E+06	2.63455E+09	1198.35
192.99	2.16264E+06	2.59107E+09	1198.11
193.99	2.12634E+06	2.54705E+09	1197.86
194.99	2.08957E+06	2.50246E+09	1197.60
195.99	2.05231E+06	2.45727E+09	1197.32
196.99	2.01455E+06	2.41149E+09	1197.04
197.99	1.97630E+06	2.36512E+09	1196.74
198.99	1.93757E+06	2.31817E+09	1196.43
199.99	1.89838E+06	2.27065E+09	1196.10
200.99	1.85874E+06	2.22260E+09	1195.76
201.99	1.81866E+06	2.17401E+09	1195.40
202.99	1.77817E+06	2.12495E+09	1195.02
203.99	1.73728E+06	2.07540E+09	1194.63
204.99	1.69601E+06	2.02539E+09	1194.21
205.99	1.65440E+06	1.97499E+09	1193.78
206.99	1.61250E+06	1.92424E+09	1193.33

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 13 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
207.99	1.57038E+06	1.87323E+09	1192.85
208.99	1.52810E+06	1.82204E+09	1192.36
209.99	1.48569E+06	1.77071E+09	1191.84
210.99	1.44324E+06	1.71933E+09	1191.30
211.99	1.40080E+06	1.66797E+09	1190.73
212.99	1.35844E+06	1.61673E+09	1190.14
213.99	1.31623E+06	1.56569E+09	1189.53
214.99	1.27425E+06	1.51495E+09	1188.89
215.99	1.23258E+06	1.46459E+09	1188.23
216.99	1.19130E+06	1.41471E+09	1187.54
217.99	1.15221E+06	1.36747E+09	1186.82
218.99	1.11527E+06	1.32279E+09	1186.08
219.99	1.07861E+06	1.27847E+09	1185.30
220.99	1.04235E+06	1.23465E+09	1184.49
221.99	1.00667E+06	1.19155E+09	1183.65
222.99	9.71528E+05	1.14910E+09	1182.78
223.99	9.37145E+05	1.10759E+09	1181.88
224.99	9.03924E+05	1.06750E+09	1180.96
225.99	8.71650E+05	1.02857E+09	1180.02
226.99	8.69702E+05	1.05639E+09	1214.66
227.99	7.55046E+05	9.30046E+08	1231.77
228.99	1.94053E+05	2.40909E+08	1241.46
229.99	3.82763E+04	4.77306E+07	1247.01
239.81	6.01402E+03	7.51237E+06	1249.14
249.81	6.08836E+03	7.60684E+06	1249.41
259.81	5.63126E+03	7.03681E+06	1249.60
269.81	5.13342E+03	6.41563E+06	1249.78
279.81	4.97030E+03	6.21256E+06	1249.94
289.81	4.63165E+03	5.79006E+06	1250.11
299.81	4.33638E+03	5.42164E+06	1250.27
309.81	4.30790E+03	5.38664E+06	1250.42
319.81	4.05781E+03	5.07460E+06	1250.57
329.81	3.86125E+03	4.82933E+06	1250.72
339.81	3.68129E+03	4.60480E+06	1250.87
349.81	3.47246E+03	4.34412E+06	1251.02
359.81	3.37424E+03	4.22172E+06	1251.16
369.81	3.35728E+03	4.20098E+06	1251.30

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 14 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
379.81	3.12284E+03	3.90809E+06	1251.45
389.81	3.05607E+03	3.82493E+06	1251.59
399.81	2.96382E+03	3.70987E+06	1251.73
409.81	2.89163E+03	3.61991E+06	1251.86
419.81	2.81970E+03	3.53025E+06	1252.00
429.81	2.73347E+03	3.42265E+06	1252.13
439.81	2.53686E+03	3.17683E+06	1252.27
449.81	2.50988E+03	3.14337E+06	1252.40
459.81	2.30716E+03	2.88980E+06	1252.54
469.81	2.24789E+03	2.81586E+06	1252.67
479.81	2.34066E+03	2.93235E+06	1252.79
489.81	2.13948E+03	2.68061E+06	1252.92
499.81	2.08047E+03	2.60693E+06	1253.05
500.01	2.20053E+03	2.75737E+06	1253.05

E. Most severe secondary system break

Break Type: Main steam line Double ended guillotine break
Pipe ID: 24.459 inches
Break area: 6.526 square feet (plus expansion)
Reactor Power: 102%

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
0.00	2.75891E+07	3.28531E+10	1190.80
0.10	2.65258E+07	3.16244E+10	1192.21
0.20	2.60088E+07	3.10247E+10	1192.85
0.30	2.56908E+07	3.06554E+10	1193.24
0.40	2.54656E+07	3.03939E+10	1193.53
0.50	2.52871E+07	3.01865E+10	1193.75
0.60	2.51333E+07	3.00079E+10	1193.95
0.70	2.49951E+07	2.98475E+10	1194.13
0.80	2.48669E+07	2.96987E+10	1194.30
0.90	2.47441E+07	2.95560E+10	1194.47
1.00	2.46237E+07	2.94161E+10	1194.62
1.99	2.35570E+07	2.81735E+10	1195.97
2.99	2.26720E+07	2.71392E+10	1197.03

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 15 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
3.99	2.19502E+07	2.62934E+10	1197.87
4.99	2.01408E+07	2.41373E+10	1198.42
5.99	1.80279E+07	2.16000E+10	1198.14
6.99	1.53908E+07	1.84325E+10	1197.63
7.99	1.22916E+07	1.47139E+10	1197.07
8.99	8.91212E+06	1.06626E+10	1196.42
9.99	8.85805E+06	1.05953E+10	1196.11
10.99	8.90845E+06	1.06541E+10	1195.95
11.99	8.90507E+06	1.06501E+10	1195.96
12.99	8.85647E+06	1.05934E+10	1196.12
13.99	8.77813E+06	1.05020E+10	1196.38
14.99	8.74966E+06	1.04687E+10	1196.47
15.99	8.71463E+06	1.04278E+10	1196.58
16.99	8.68129E+06	1.03888E+10	1196.69
17.99	8.65364E+06	1.03564E+10	1196.78
18.99	8.62931E+06	1.03280E+10	1196.85
19.99	8.60260E+06	1.02968E+10	1196.94
24.99	8.33141E+06	9.97920E+09	1197.78
29.99	8.05280E+06	9.65218E+09	1198.61
34.99	7.78871E+06	9.34142E+09	1199.36
39.99	7.54222E+06	9.05080E+09	1200.02
44.99	7.31192E+06	8.77878E+09	1200.61
49.99	7.08790E+06	8.51364E+09	1201.15
54.99	6.88295E+06	8.27078E+09	1201.64
59.99	6.68542E+06	8.03646E+09	1202.09
64.99	6.40400E+06	7.70188E+09	1202.67
69.99	6.03454E+06	7.26160E+09	1203.34
74.99	5.76504E+06	6.93965E+09	1203.75
79.99	5.62338E+06	6.77020E+09	1203.93
84.99	5.47607E+06	6.59376E+09	1204.11
89.99	5.28714E+06	6.36725E+09	1204.29
94.99	5.08219E+06	6.12122E+09	1204.45
99.99	4.86061E+06	5.85486E+09	1204.55
104.99	4.63705E+06	5.58576E+09	1204.59
109.99	4.40888E+06	5.31083E+09	1204.57
114.99	4.22417E+06	5.08799E+09	1204.49
119.99	4.10454E+06	4.94356E+09	1204.41

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 16 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
124.99	3.98070E+06	4.79398E+09	1204.31
129.99	3.84430E+06	4.62910E+09	1204.15
134.99	3.69986E+06	4.45450E+09	1203.95
139.99	3.55649E+06	4.28101E+09	1203.71
144.99	3.40523E+06	4.09788E+09	1203.41
149.99	3.23389E+06	3.89034E+09	1202.99
154.99	3.05169E+06	3.66955E+09	1202.46
159.99	2.85988E+06	3.43698E+09	1201.79
164.99	2.65877E+06	3.19305E+09	1200.95
169.99	2.44943E+06	2.93905E+09	1199.89
174.99	2.23312E+06	2.67657E+09	1198.58
179.99	2.00490E+06	2.39979E+09	1196.96
180.99	1.95899E+06	2.34413E+09	1196.60
181.99	1.91317E+06	2.28858E+09	1196.22
182.99	1.86745E+06	2.23316E+09	1195.83
183.99	1.82188E+06	2.17792E+09	1195.43
184.99	1.77648E+06	2.12290E+09	1195.00
185.99	1.73128E+06	2.06812E+09	1194.57
186.99	1.68629E+06	2.01362E+09	1194.11
187.99	1.64156E+06	1.95944E+09	1193.64
188.99	1.59715E+06	1.90565E+09	1193.16
189.99	1.55309E+06	1.85230E+09	1192.65
190.99	1.50943E+06	1.79944E+09	1192.13
191.99	1.46620E+06	1.74712E+09	1191.59
192.99	1.42345E+06	1.69538E+09	1191.04
193.99	1.38122E+06	1.64429E+09	1190.46
194.99	1.33953E+06	1.59387E+09	1189.87
195.99	1.29844E+06	1.54419E+09	1189.26
196.99	1.25798E+06	1.49527E+09	1188.64
197.99	1.21817E+06	1.44717E+09	1187.99
198.99	1.17906E+06	1.39993E+09	1187.33
199.99	1.14325E+06	1.35663E+09	1186.65
200.99	1.10867E+06	1.31482E+09	1185.94
201.99	1.07457E+06	1.27359E+09	1185.21
202.99	1.04101E+06	1.23303E+09	1184.46
203.99	1.00804E+06	1.19320E+09	1183.68
204.99	9.75715E+05	1.15416E+09	1182.89

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 17 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
205.99	9.44089E+05	1.11597E+09	1182.07
206.99	9.13248E+05	1.07875E+09	1181.23
207.99	8.83220E+05	1.04252E+09	1180.37
208.99	8.54291E+05	1.00763E+09	1179.50
209.99	8.26312E+05	9.73901E+08	1178.61
210.99	7.47050E+05	8.79847E+08	1177.76
211.99	7.99722E+05	9.73591E+08	1217.41
212.99	4.11793E+05	5.11488E+08	1242.10
213.99	1.78411E+05	2.24209E+08	1256.70
214.99	6.88770E+04	8.71060E+07	1264.66
215.99	2.82648E+04	3.58376E+07	1267.92
216.99	1.45531E+04	1.84694E+07	1269.10
217.99	9.95245E+03	1.26348E+07	1269.51
218.99	8.44848E+03	1.07268E+07	1269.67
219.99	8.12876E+03	1.03216E+07	1269.76
220.99	8.27352E+03	1.05061E+07	1269.84
221.99	8.54233E+03	1.08484E+07	1269.96
222.99	8.72982E+03	1.10877E+07	1270.10
223.99	8.72528E+03	1.10833E+07	1270.25
224.99	8.51119E+03	1.08126E+07	1270.40
225.99	8.15044E+03	1.03554E+07	1270.53
226.99	7.75339E+03	9.85165E+06	1270.62
227.99	7.43393E+03	9.44618E+06	1270.68
228.99	7.26941E+03	9.23746E+06	1270.73
229.99	7.27783E+03	9.24847E+06	1270.77
239.81	6.97968E+03	8.87515E+06	1271.57
249.81	6.70486E+03	8.53074E+06	1272.32
259.81	6.42780E+03	8.18294E+06	1273.05
269.81	6.15762E+03	7.84339E+06	1273.77
279.81	5.89986E+03	7.51925E+06	1274.48
289.81	5.65823E+03	7.21526E+06	1275.18
299.81	5.43352E+03	6.93248E+06	1275.87
309.81	5.22522E+03	6.67026E+06	1276.56
319.81	5.03212E+03	6.42715E+06	1277.23
329.81	4.85291E+03	6.20158E+06	1277.90
339.81	4.68680E+03	5.99238E+06	1278.57
349.81	4.53906E+03	5.80648E+06	1279.23

Table 6.2.1-4
MOST SEVERE MASS AND ENERGY RELEASE FOR CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS - ANALYZED AT 102% OF 3990 MWt (Sheet 18 of 18)

TIME (sec)	MASS RATE (lbm/hr)	ENERGY RATE (Btu/hr)	ENTHALPY (Btu/lbm)
359.81	4.39949E+03	5.63080E+06	1279.88
369.81	4.26726E+03	5.46437E+06	1280.52
379.81	4.14122E+03	5.30557E+06	1281.17
389.81	4.02167E+03	5.15498E+06	1281.80
399.81	3.90823E+03	5.01203E+06	1282.44
409.81	3.80048E+03	4.87627E+06	1283.07
419.81	3.69814E+03	4.74725E+06	1283.69
429.81	3.60371E+03	4.62827E+06	1284.31
439.81	3.51475E+03	4.51620E+06	1284.93
449.81	3.42923E+03	4.40842E+06	1285.54
459.81	3.34711E+03	4.30488E+06	1286.15
469.81	3.26830E+03	4.20552E+06	1286.76
479.81	3.19269E+03	4.11016E+06	1287.36
489.81	3.11977E+03	4.01814E+06	1287.96
499.71	2.78001E+03	3.58222E+06	1288.56
500.01	2.77852E+03	3.58035E+06	1288.58

Table 6.2.1-5

MASS AND ENERGY RELEASE FOR SUBCOMPARTMENT
PEAK PRESSURE ANALYSIS

A. 100-square inch hot leg guillotine break

Pipe ID: 42 inches

Refer to CESSAR Tables 6.2.1-25A and 6.2.1-25B

B. 350-square inch discharge leg guillotine break

Pipe ID: 30 inches

Refer to CESSAR Tables 6.2.1-27A and 6.2.1-27B

C. 600-square inch hot leg guillotine break

Pipe ID: 42 inches

Refer to CESSAR Tables 6.2.1-26A and 6.2.1-26B

D. 480-square inch discharge leg guillotine break

Pipe ID: 30 inches

Refer to CESSAR Tables 6.2.1-28A and 6.2.1-28B

E. 430-square inch suction leg guillotine

Pipe ID: 30 inches

Refer to CESSAR Tables 6.2.1-29A and 6.2.1-29B

F. 592-square inch suction leg guillotine break

Pipe ID: 30 inches

Refer to CESSAR Tables 6.2.1-31A and 6.2.1-31B

G. 161-square inch pressurizer surge line guillotine break

Pipe ID: 10.1 inches

Refer to CESSAR Tables 6.2.1-32A and 6.2.1-32B

Table 6.2.1-6
INITIAL CONDITIONS FOR CONTAINMENT PEAK PRESSURE ANALYSIS – ANALYZED AT 102% OF 3990 MWt (Sheet 1 of 2)

Parameter	Value
Reactor coolant system	
Reactor power level, MWt[(a)]	4070
Assumed Tcold °F	568.2
Mass of reactor coolant system liquid, lbm	626,310
Mass of reactor coolant system steam, lbm	6173
Liquid plus steam energy, 10^6 Btu[(b)]	541.221
Containment	
Pressure, psia (worst case)	
a. MSLB	13.2
b. LOCA	16.7
Temperature, °F (maximum normal)	120
Relative humidity, %	
a. MSLB	0
b. LOCA	0
Essential cooling water temperature assumed constant for 24 hr., °F	135
Refueling water temperature °F (maximum) (nominal 90°F)	120
Outside air temperature, °F	130
Net free volume, ft^3	2.62×10^6
Stored water (as applicable)	
Refueling water storage tank, gal (minimum)	400,000
All accumulators (safety injection tanks), ft^3 @ PSIA	7656 @ 652
Condensate storage tank temperature, (F)	120
Nitrogen from Accumulators, ft^3	1968

Continued on next page

a. At design overpower of 102%.
b. All energies are relative to 32F.

Table 6.2.1-6
INITIAL CONDITIONS FOR CONTAINMENT PEAK PRESSURE ANALYSIS – ANALYZED AT 102% OF 3990 MWt (Sheet 2 of 2)

Parameter	Value
Primary Parameters	
Initial RCS cold leg temperature (F)	
a. LOCA	568.2
b. MSLB @ zero power	572.0
c. MSLB @ 102% power	568.2
Initial RCS pressure (PSIA)	2325.0
Total RCS Flow rate (lbm/hr)	
a. LOCA	161.0E+6
b. MSLB	192.2E+6
RCS Expansion Multiplier	
a. LOCA	2%
b. MSLB	2%
Secondary Parameters	
Steam Generator initial pressure (PSIA)	
a. LOCA	1051.4
b. MSLB Zero power	1220.0
c. MSLB 102% power	1051.4
Steam Generator Inventory (lbm) incl 2% vol exp	
a. LOCA	196443
b. MSLB Zero power	287706
c. MSLB 102% power	195493
Feed water Temperature (°F) Enthalpy (Btu/lbm)	
a. LOCA	450.0/430.6
b. MSLB Zero power	120.0/91.1
c. MSLB 102% power	450.0/430.5
Secondary Expansion Multiplier	2%

Table 6.2.1-7
ENGINEERED SAFETY SYSTEMS OPERATING ASSUMPTIONS FOR CONTAINMENT PEAK PRESSURE ANALYSIS – AT 102% OF 3990 (Sheet 1 of 4)

System/Item	Value
Passive safety injection system	
Number of safety injection tanks	4
Pressure setpoint, psig	637.8
Volume, ft^3/tank	1914
Active safety injection systems	
High-pressure safety injection	
Number of lines	2
Number of pumps	1/2
Max flowrate, gal/min/pump	Case Dependent
Low-pressure safety injection	
Number of lines	2
Number of pumps	1/2
Max flowrate, gal/min/pump	Case Dependent
Containment spray system	
Number of lines	1
Number of pumps	1
Number of headers	1

Table 6.2.1-7
ENGINEERED SAFETY SYSTEMS OPERATING ASSUMPTIONS FOR CONTAINMENT PEAK PRESSURE ANALYSIS – AT 102% OF 3990 MWt (Sheet 2 of 4)

System/Item	Value
Analyzed flowrate, gal/min/pump	
Injection Mode	3500
Recirculation Mode	3500
Time to rated flow, seconds after event initiation, loss of offsite power	
Loss-of-coolant accident (loss of offsite power)	95
Main steam line break accident (offsite power available)	85
Heat exchangers	
Shutdown heat exchangers	
Type	Shell and U-tube
Number	1
Heat transfer area, ft^2	9756 (10% plugging)
Overall heat transfer coefficient, $Btu/h-ft^2-°F$	310
Flowrates	
Exterior side, gal/min	12,000 - 12,600
Source of cooling water	Essential cooling water

Continued on next page

Table 6.2.1-7
ENGINEERED SAFETY SYSTEMS OPERATING ASSUMPTIONS FOR CONTAINMENT PEAK PRESSURE ANALYSIS - AT 102% OF 3990 MWt (Sheet 3 of 4)

System/Item	Value
Credited Set points to generate a signal during;	
1. LOCA	
a. SIAS due to generation of CIAS (psig)	Note (a)
b. CSAS due to high pressure in containment (psig)	10.00
2. MSLB	
a. Main steam Isolation due to generation of CIAS (psig).	19.2
b. Reactor trip due to generation of CIAS (psia),	19.2
c. Reactor trip due to Low SG pressure. (psia)	915
d. Differential Pressure between SGs (lock out signal). (PSID)	325
f. AFAS actuation on Low SG Level. (Percent of wide range)	32
e. CSAS due to high pressure in containment (psig)	10.00
Closure time during MSLB	
a. Main steam isolation valve closure time. (sec)	5.0
b. Main feed water isolation valve closure time. (sec)	10.0

(a): SI flow is not credited during blowdown phase of the event, but SIAS is assumed to occur prior to end of blowdown.

Table 6.2.1-7

ENGINEERED SAFETY SYSTEMS OPERATING ASSUMPTIONS FOR CONTAINMENT PEAK PRESSURE ANALYSIS – AT 102% OF 3990 MWt (Sheet 4 of 4)

System/Item	Value
Delay times	
c. Signal delay time for MSIS / FWIS. (sec)	1.0
e. Delay time from SG delta P setpoint until all flow is directed to the intact SG (lock out). (sec)	18.0
f. Delay time from AFAS until AFW flow reaches steam generators. (sec)	7.0
Physical system parameters used for MSLB	
a. Auxiliary feed water flow rate (run-out per two pump). (gpm)	3200
b. MSIV Area per valve. (ft^2)	2.127
c. Main Steam Safety valves	
MSIV / steam line	5/4
Maximum Opening setpoint (PSIG)	1287.5
Maximum Full open pressure. (PSIG)	1394
Total flow Area of MSSV. (ft^2)	1.11184
Steam line volume from MSIV to SG outlet. (ft^2/SG)	1850
Steam line volume from MSIV to Turbine stop valves. (ft^3)	3390
Volume of fluid between the upstream MFIV and each steam generator. (ft^3/SG)	<537[b]

b: Includes 2% Expansion Factor

The containment building dome, containment building cylinder (above grade), and containment building wall area with buttress sections detailed in heat sink table 6.2.1-8, part B, are exposed to the containment atmosphere on their inside surfaces and ambient air on their outside surfaces. The initial temperature distribution in these three heat sinks is established by assuming a heat-transfer coefficient of 2 Btu/h-ft^2-F exists at inside and outside surfaces. Following the LOCA or MSLB, Tagami or Uchida condensing heat-transfer coefficients apply to the inside surfaces which a value of 2 Btu/h-ft^2-F continues to be used on the outside surface. Other heat sinks are either entirely within the containment building envelope or are bounded by the earth at their outside surface where thermal insulation is conservatively assumed. Consequently, these other heat sinks are initialized at the initial containment temperature prior to the MSLB or LOCA. The initial containment temperature is the design maximum for reactor power operation. Most of the building structure and cold components would be cooler than the design maximum temperature; a few regions, notably the reactor cavity walls, may be warmer. The warmer heat sinks comprise a small area and, as a result, the average heat sink temperatures would initially be less than the design maximum.

Table 6.2.1-8
PASSIVE HEAT SINKS FOR CONTAINMENT MAXIMUM
PRESSURE-TEMPERATURE ANALYSIS (Sheet 1 of 7)
A. Detailed Listing

Item	Paint Type and Thickness (in.)	Material	Thickness (in.)	Surface Area (ft^2)	Uncertainty in Area (±%)
Containment building					
Liner plate	Inorg 0.004	Carbon steel	0.25	96,600	5
Dome walls	NA	Concrete	41.75	33,500	5
Cylinder walls	NA	Concrete	47.75	58,200	5
Cylinder walls (buttress section)	NA	Concrete	77.75	4,900	5
Basemat	Org 0.010	Concrete	159	11,000	10
Containment equipment hatch and personnel locks					
Equipment hatch	Inorg 0.004	Carbon steel	1.50	900	15
Flange	Inorg 0.004	Carbon steel	2.00	105	15
Ring plates	Inorg 0.004	Carbon steel	3.50	160	15
Guide beam plates	Inorg 0.004	Carbon steel	0.50	1,000	15
Personnel locks	Inorg 0.004	Carbon steel	4.00	460	15
Internal structures, concrete					
Sealed walls	Sealer Neglected	Concrete	6	4,200	15
	Sealer neglected	Concrete	12	6,000	15
	Sealer neglected	Concrete	18	12,000	15
	Sealer neglected	Concrete	24	43,000	15
	Sealer neglected	Concrete	33	1,600	15
	Sealer neglected	Concrete	60	2,800	15
Refueling pool					
Liner plate	NA	Stainless steel	0.1875	12,500	5
Sealed walls and floor	Sealer Neglected	Concrete	24	9,600	5
	Sealer Neglected	Concrete	36	1,000	5
	Sealer Neglected	Concrete	60	1,200	5
	Sealer Neglected	Concrete	200	700	5
Sealed floor slabs above steel decking	Sealer Neglected	Concrete	18	1,760	15
	Sealer Neglected	Concrete	30	1,200	15
	Sealer Neglected	Concrete	36	3,200	15

Table 6.2.1-8
PASSIVE HEAT SINKS FOR CONTAINMENT MAXIMUM
PRESSURE-TEMPERATURE ANALYSIS (Sheet 2 of 7)
A. Detailed Listing (continued)

Item	Paint Type and Thickness (in.)	Material	Thickness (in.)	Surface Area (ft^2)	Uncertainty in Area (±%)
Internal structures, concrete (cont)					
Floor slab decking	Inorg 0.004	Carbon steel	0.0478	6,160[a]	15
NSSS supports					
Steam gen foundations	NA	Concrete	72	3,000	5
Reactor vessel shield plugs					
Liner plate	Inorg 0.004	Carbon steel	0.25	450	5
Plug	NA	Concrete	20.75	450	5
SI tank pads	NA	Concrete			5
Pressurizer beams	NA	Concrete	20	450	5
Misc pads, brackets, missile shields, etc.	NA	Concrete	12	2,000	10
Internal structures, metal					
Gratings (galvanized)	Galv neglected	Carbon steel	0.10	50,000	15
	Galv neglected	Carbon steel	0.20	22,000	15
Uninsulated structural internals					
Columns	Inorg 0.004	Carbon steel	0.75	9,900	15
Stops	Inorg 0.004	Carbon steel	1.50	3,000	30
Polar crane bridges	Inorg[b] 0.004	Carbon steel	0.5	17,544	20
Girders and brackets	Inorg 0.004	Carbon steel	2.0	15,500	20
Cable tray supports	Inorg 0.004	Carbon steel	0.053	15,800	20

a. Conservatively, area of concrete floor slabs above decking is used.

b. Although the containment peak pressure analysis assumes inorganic coating on the polar crane and polar crane bridges, the actual coating is epoxy. Evaluation has determined that the use of epoxy coating on these items has an insignificant effect on the analysis.

Table 6.2.1-8
PASSIVE HEAT SINKS FOR CONTAINMENT MAXIMUM
PRESSURE-TEMPERATURE ANALYSIS (Sheet 3 of 7)
A. Detailed Listing (continued)

Item	Paint Type and Thickness (in.)	Material	Thickness (in.)	Surface Area (ft^2)	Uncertainty in Area (±%)
Internal structures, metal (cont)					
Uninsulated structural internals (cont)					
Misc structural steels	Inorg 0.004	Carbon Steel	0.15	19,000	20
	Inorg 0.004	Carbon Steel	0.25	22,000	20
	Inorg 0.004	Carbon Steel	0.50	9,600	20
	Inorg 0.004	Carbon Steel	0.80	2,100	20
Work platforms, stairs, ladders	Inorg 0.004	Carbon Steel	0.20	3,800	20
HVAC Ducting 18 ga	Galv neglected	Carbon steel	0.050	4,850	20
16 ga	Galv neglected	Carbon steel	0.063	9,950	20
14 ga	Galv neglected	Carbon steel	0.080	5,600	20
12 ga	Galv neglected	Carbon steel	0.100	6,200	20
11 ga	Galv neglected	Carbon steel	0.125	377	20
Larger	Galv neglected	Carbon steel	0.25	2,100	20
Electrical equipment					
Conduit	Galv neglected	Carbon steel	0.154	30,980	15
Trays, supports, fixtures	Galv neglected	Carbon steel	0.0374	55,465	20
boxes, panels, etc.	Galv neglected	Carbon steel	0.0525	106,502	20
Piping, uninsulated					
1 in. Sched. 80	Inorg 0.004	Carbon steel	0.25 (avg)	3,000	20
1 in. Sched. 160	Inorg 0.004	Carbon steel			
2 in. Sched. 40	Inorg 0.004	Carbon steel			
2 in. Sched. 160	Inorg 0.004	Carbon steel			
2-1/2 in. Sched. 40	Inorg 0.004	Carbon steel	0.12	120	20

Table 6.2.1-8
PASSIVE HEAT SINKS FOR CONTAINMENT MAXIMUM PRESSURE-TEMPERATURE ANALYSIS (Sheet 4 of 7)
A. Detailed Listing (continued)

Item	Paint Type and Thickness (in.)	Material	Thickness (in.)	Surface Area (ft^2)	Uncertainty in Area (±%)
Internal structures, metal (cont)					
Piping, uninsulated (cont)					
3 in. Sched. 160	Inorg 0.004	Carbon Steel	0.438	90	20
4 in. Sched. 40	Inorg 0.004	Carbon Steel	0.237	1,350	20
6 in. Sched. 40	Inorg 0.004	Carbon Steel	0.28	520	20
8 in. Sched. 20	Inorg 0.004	Carbon Steel	0.25	300	20
8 in. Sched. 40	Inorg 0.004	Carbon Steel	0.322	450	20
10 in. Sched. 20	NA	Stainless steel	0.25	1,550	20
10 in. Sched. 40	NA	Stainless steel	0.365	890	20
14 in. Sched. 20	NA	Stainless steel	0.312	400	20
Miscellaneous metal components					
Polar crane					
Reactor cavity sump pumps					
Radwaste sump pumps (cont'm't)					
SG wet layup recirc pump					
Containment bldg monohoist					
CEDM normal ACU units					
Containment normal ACU					
Containment normal duct heaters	Inorg[b] 0.004	Carbon steel	1.0 (assumed)	29,000	20
Containment tendon gallery exhaust fan					
Damper - motors					
Containment recirc sump screen					
Rx cavity normal CCU fan					
Man Basket Test Weight	Inorg[b]	Carbon Steel	No change from existing table values	No change from existing table values	No change from existing table values
Associated Rigging	Inorg[b]	Carbon Steel			
Crane Man Basket	N/A	Stainless Steel	3/8"	58	No change from existing table values
Safety injection tanks	Inorg 0.004	Carbon Steel	1.865	5,735	5 (est)

Table 6.2.1-8
PASSIVE HEAT SINKS FOR CONTAINMENT MAXIMUM
PRESSURE-TEMPERATURE ANALYSIS (Sheet 5 of 7)
B. Modeling of Heat Sinks for Computer Input

Passive Heat Sink	Material	Thickness (ft)	Exposed Surface Area (ft^2)	Mass (lb)	Boundary Condition
1. Reactor containment building dome	Inorg paint Carbon steel Concrete	0.00033 0.02083 3.47917	31,825	1.79×10^3 3.25×10^5 1.58×10^7	Inside surface exposed to cont. atmosphere; outside surface exposed to amb. atmosphere
2. Reactor containment building cylinder walls	Inorg paint Carbon steel Concrete	0.00033 0.02083 3.97917	55,290	3.10×10^3 5.64×10^5 3.15×10^7	Inside surface exposed to cont. atmosphere; outside surface exposed to amb. atmosphere
3. Reactor containment buttress sections	Inorg paint Carbon steel Concrete	0.00033 0.02083 6.47917	4,655	2.61×10^2 4.75×10^4 4.31×10^6	Inside surface exposed to cont. atmosphere; outside surface exposed to amb. atmosphere
4. Containment basemat and filler slab	Org paint Concrete Carbon steel Concrete	0.00083 2.25 0.02083 10.97917	9,900	4.93×10^2 3.19×10^6 1.01×10^5 1.55×10^7	Inside surface exposed to cont. sump water; outside surface assumed insulated
5. Internal concrete structures 0 to 3 feet thick	Concrete	2.346[(b)]	20,998	3.52×10^6	Total surface exposed to cont. atmosphere
6. Internal concrete structures greater than 3 feet thick	Concrete	4.831[(b)]	43,065	1.50×10^7	Total surface exposed to cont. atmosphere
7. Refueling pool	Stainless steel Concrete	0.01562 5.44531	11,875[(a)]	9.09×10^4 9.25×10^6	Inner SS face and outer concrete face exposed to cont. atmosphere
8. Internal concrete with steel decking	Concrete Carbon steel Inorg paint	2.47403[(b)] 0.00398 0.00033	5,236[(c)]	1.85×10^6 1.02×10^4 2.94×10^3	Unpainted and inorganic painted faces each exposed to cont. atmosphere

a. Stainless steel face area; outer concrete face assumed of equal area.
b. Portions of these structures has Epoxy coating.
c. Unpainted floor slab surface area; inorganic painted steel decking face assumed of equal area.

Table 6.2.1-8
PASSIVE HEAT SINKS FOR CONTAINMENT MAXIMUM
PRESSURE-TEMPERATURE ANALYSIS (Sheet 6 of 7)
B. Modeling of Heat Sinks for Computer Input (continued)

Passive Heat Sink	Material	Thickness (ft)	Exposed Surface Area (ft^2)	Mass (lb)	Boundary Condition
9. Carbon steel grating (galvanizing neglected)	Carbon steel	0.01088	61,200	1.63×10^5	Total surface exposed to cont. atmosphere
10. HVAC ducting (galvanizing neglected)	Carbon steel	0.00719	23,262	8.20×10^4	Outside surface exposed to cont. atmos.; no heat transfer to inside surface
11. Electrical equipment (galvanizing neglected)	Carbon steel	0.00872	155,907	6.66×10^5	Outside surface exposed to cont. atmos.; no heat transfer to inside surface
12. Stainless steel piping	Stainless steel	0.02456	2,272	2.73×10^4	Outside surface exposed to cont. atmos.; no heat transfer to inside surface
13. Coated carbon steel (thickness 0 to 0.125 inch)	Inorg paint Carbon steel	0.00033 0.00446	12,736	7.14×10^2 2.78×10^4	Outside surface exposed to cont. atmos.; no heat transfer to inside surface
14. Coated carbon steel (0.125 inch < thickness $\leq$ 0.25 inch)	Inorg paint Carbon steel	0.00033 0.01709	63,720	3.57×10^3 5.34×10^5	Outside surface exposed to cont. atmos.; no heat transfer to inside surface
15. Coated carbon steel (0.25 inch < thickness $\leq$ 0.50 inch)	Inorg paint Carbon steel	0.00033 0.04113	26,933	1.51×10^3 5.43×10^5	Outside surface exposed to cont. atmos.; no heat transfer to inside surface
16. Coated carbon steel (0.50 inch < thickness $\leq$ 1.0 inch)	Inorg paint Carbon steel	0.00033 0.07641	44,150	2.48×10^3 1.65×10^6	Outside surface exposed to cont. atmos.; no heat transfer to inside surface

Table 6.2.1-8
PASSIVE HEAT SINKS FOR CONTAINMENT MAXIMUM
PRESSURE-TEMPERATURE ANALYSIS (Sheet 7 of 7)
B. Modeling of Heat Sinks for Computer Input (continued)

Passive Heat Sink	Material	Thickness (ft)	Exposed Surface Area (ft^2)	Mass (lb)	Boundary Condition
17. Coated carbon steel (1.0 inch < thickness ≤ 2.5 inches)	Inorg paint Carbon steel	0.00033 0.15798	20,802	1.17×10^3 1.61×10^6	Outside surface exposed to cont. atmos.; no heat transfer to inside surface
18. Coated carbon steel (thickness < 2.5 inches)	Inorg paint Carbon steel	0.00033 0.31580	332	1.9×10^1 5.14×10^4	Outside surface exposed to cont. atmos.; no heat transfer to inside surface

C. Thermal Physical Properties

Material	Density (lb_m/ft^3)	Specific Heat ($Btu/lb_m\ °F$)	Thermal Conductivity (Btu/hr ft °F)	Volumetric Heat Capacity ($Btu/ft^3\ °F$)
Inorganic paint	170	0.12	1.0	20
Carbon steel	490	0.11	25.0	54
Concrete	143	0.21	0.8	30
Organic paint	60	0.33	0.1	20
Stainless steel	490	0.11	10.0	54

Minimum heat sink areas (i.e., nominal minus tolerance given in table 6.2.1-8) are used for the short-term and long-term containment pressure-temperature transient analysis of primary or secondary pipe ruptures inside containment. Most individual structural or component heat sinks have some uncertainty associated with the exposed surface area. The minimum area was used to provide the most conservative assumptions.

Table 6.2.1-8, part C, lists the thermophysical properties used in analyses. Metal, concrete, and protective coating properties are typical values for the temperature range observed.

B.2 Mass and Energy Release Analyses for Postulated Loss of Coolant Accidents

LOCA mass/energy release analyses can be classified into the following phases: blowdown, refill, reflood, post reflood, and long term. The blowdown period extends from time zero until the primary system depressurizes to essentially the containment pressure. During blowdown, most of the initial primary coolant is released to the containment as a two phase mixture. Following blowdown, the water for releases is provided by the ECCS.

There is an important distinction between hot leg breaks and cold leg breaks for LOCA post blowdown analyses. For a hot leg break, the majority of the ECCS supplied water leaving the core can vent directly to the containment without passing through a steam

generator. Therefore, since there is no mechanism for releasing the steam generator energy to the containment for a hot leg break, only the blowdown period must be considered. Conversely, for cold leg breaks, the water must pass through a steam generator before reaching the containment so that post blowdown releases to the containment must be considered for cold leg breaks.

The first post blowdown period is refill. During refill, the ECCS water refills the bottom of the reactor vessel to the bottom of the core. This period is conservatively omitted from the analysis.

The second post blowdown period is the reflood period. During reflood, ECCS water floods the core. Reflood is assumed to end when the liquid level in the core is 2 feet below the top of the active core. During reflood, a significant amount of the ECCS water entering the core is postulated to be carried out of the core by the steaming action of the core to coolant heat transfer process. This fluid then passes through a steam generator where reverse (i.e., secondary to primary) heat transfer heats it before it reaches the containment. The residual steam generator secondary energy is sufficient to convert all of this fluid to superheated steam during the initial part of the reflood period. Subsequently, as the generators are cooled by this process, there is not enough heat transfer to boil all of the fluid passing through the tubes. This causes the break flow to change from pure steam to two phase. In time, as the entire NSSS cools,

the flow to the containment will be subcooled since the safety injection water is subcooled. The onset of the two phase release to the containment may or may not occur before the end of reflood; typically, this occurs close to the end of reflood. The potential release of subcooled fluid to the containment does not occur during reflood when conservative system parameters are utilized.

The third post blowdown period is the post reflood period. During this time frame, the dominant process is the continued cooling of the steam generators by the ECCS water leaving the core. The release to the containment during this time frame is generally two phase due to the cooling of the steam generators. The post reflood ends when the affected steam generator has essentially reached the containment temperature.

The final post blowdown period is the long term period, which begins at the end of post reflood. During long term, the dominant mechanisms for release rates are the decay heat and the cooling of all NSSS metal. Long term ends when the containment pressure and the environment pressure are essentially equal.

B.2.1 Mass and Energy Release Data

Mass and energy release data for most severe breaks (the suction leg, discharge leg and hot leg) break cases analyzed. For cold leg breaks (pump suction and discharge), some of the post blowdown ECCS water is postulated to spill directly to the containment

floor whenever the reactor vessel annulus is full. The data associated with these breaks are given in Table 6.2.1-4. Additionally, for discharge leg breaks, some of the ECCS water is postulated to spill directly to the containment floor without first entering the reactor vessel. This direct spillage is in addition to the vessel spillage discussed above.

Also, for the discharge leg breaks, 1 out of the 4 available safety injection tanks is assumed to be unavailable due to the break; accordingly, the discharge leg break energy balances show the inventory of this tank in the sump category. Direct flow spillage data for each discharge leg break is given in Table 6.2.1-4.

B.2.2 Energy Sources

The following sources of generated and stored energy in the reactor coolant system and secondary coolant system are considered:

- primary coolant
- primary walls (including reactor internals),
- secondary coolant,
- secondary walls,
- safety injection water,
- core power transient and decay heat,
- steam generator forward and reverse heat transfer.

- Decay heat
- Metal water reaction energy

The initial reactor coolant system water volumes are conservatively calculated based on maximum manufacturing tolerances for the reactor vessel and steam generator tubes. Expansion of the loop components from cold to hot operating conditions is also considered. The pressurizer water volume includes an allowance for level instrumentation error.

The initial conditions in the reactor coolant system are given in table 6.2.1-6. The decay heat utilized in the preparation of mass and energy release and sensible heat for this analysis is provided in Table 6.2.1-21 and is based on the 1979 ANS 5.1 Standard plus a two sigma uncertainty and modified implementation of the actinide correction factor. The containment analysis model (COPATTA) also employs this decay heat. This decay heat standard is used during the blowdown, reflood/post-reflood and long term cooldown phases of a postulated LOCA event (ABB CENP Codes; CEFLASH-4A, FLOOD3 Mod 2 and CONTRANS2). The initial core power assumed in this analysis is 4070 MWt (3990 MWt plus 2% for instrumentation uncertainty). A tabulation of sources and amounts of stored energy for this plant configuration is given in table 6.2.1-11.

Metal-Water Reaction

Energy addition to the containment atmosphere resulting from the maximum allowable 1% zirconium water reaction is based on a zirconium mass in the active core of 58498 lbm. Using a molecular weight of 91.22 for zirconium and a reaction energy of 252900 Btu/lbm mole, the 1% metal-water reaction produces 1.622 x 10^6 Btu. This energy is added directly to the containment. This energy is not included in the mass/energy source terms of Table 6.2.1-4, since this energy will have a very small effect on the rate of blow down.

B.2.3 Single failure

Assuming the loss of non-emergency power is conservative for the LOCAs, since it results in a longer time to actuation of ECCS and injection. The most severe random single failure for the containment peak pressure analyses is failure of a active component in containment spray system (CSS), which it would result in loss of a train of CSS. This minimizes the rate of heat removal from containment structure and would result in maximum peak pressure.

B.3 Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures Inside Containment

Following a postulated main steam line break (MSLB) or a main feedwater line break (MFLB) inside the containment, the contents of one steam generator (affected) will be released to the containment. The

contents of the other steam generator (unaffected) will be isolated by the main steam isolation valves (MSIV) and main feedwater isolation valves (MFIV).

Containment pressurization following a secondary side rupture depends on how much of the break fluid enters the containment atmosphere as steam. MSLB break flows can be pure steam or two-phase. MFLB flows are two-phase. With a pure steam blowdown, all of the break flow enters the containment atmosphere. With two-phase blowdown, part of the liquid in the break flow boils off in the containment and is also added to the atmosphere, while the rest falls to the sump and contributes nothing to containment pressurization. For MSLB cases with large break areas, steam cannot escape fast enough from the two-phase region of the affected steam generator, and the two-phase level rises rapidly to the steam line nozzle. A two-phase blowdown results. The duration of this blowdown is short; therefore little primary-to-secondary heat transfer takes place and the break flow is largely liquid.

For MSLB cases with small break areas, steam can escape fast enough from the two-phase region of the affected steam generator so that the level swell does not reach the steam line nozzle. A pure steam blowdown results. Because of the pressure reducing effects of active and passive containment heat sinks, the highest peak containment pressure resulting from a MSLB for a given set of initial steam generator conditions occurs for that case where the break area is the maximum at which

a pure steam blowdown can occur. The potential for steam generator two-phase level swell following a MSLB increases as power level decreases; therefore, a spectrum of power levels must be analyzed to determine which one results in the peak MSLB containment pressures.

The feedwater distribution box is below the steam generator water level; therefore, MFLB cases always result in two-phase blow downs and do not produce peak containment pressures as severe as MSLB cases.

To permit a determination of the effect of MSLB upon containment pressure, analyses are performed at an analyzed core power of 4070 MWt using ABB-CE computer code SGNIII at 102, 75, and 0 percent power[1]. The largest slot and guillotine breaks at which a pure steam blowdown can occur are determined. The breaks are conservatively assumed to be at the nozzle of one of the steam generators. The cases analyzed for this plant configuration are listed in Table 6.2.1-1.

The Palo Verde plants have integral flow restrictors in the nozzles of the steam generators. Credit for the flow restrictors is taken in the analysis. In the plant, the main steam isolation signal (MSIS) of the engineered safety features actuation system (ESFAS)

[1]LOCA blowdowns provide limiting parameters for consideration of peak containment pressure. The power level cases were selected to identify peak MSLB containment temperature. A review of prior analyses of record indicated that neither a 25% nor a 50% power case would provide limiting containment temperature conditions for MSLB.

closes the MSIV's, MFIV's and the emergency feedwater isolation valves. MSIS is generated by a steam generator low pressure signal or a containment high pressure signal high steam generator level signal. The MSIV's close in 5 seconds. The valve closures have been considered in the analysis.

The auxiliary feedwater system functions automatically during MSLB to ensure that a heat sink is always available to the reactor coolant system by supplying cold feedwater to maintain an adequate water inventory in the unaffected steam generator. The affected steam generator is identified and isolated while a controlled flow path is provided to the unaffected steam generator.

B.3.1 Mass and Energy Release Data

Mass/energy release data for limiting MSLB cases listed in Table 6.2.1-4.

B.3.2 Energy Sources

For the MSLB analysis, the following sources of heat generation and stored energy are addressed.

- Primary Coolant,
- Primary wall (including reactor vessel internals),
- SG inventory on unaffected unit prior to MSIV closure,

- SG inventory on affected unit including main feed water addition from both trains,
- Auxiliary feedwater flow to affected unit,
- SG secondary walls on the affected unit,
- Core power transient and decay heat,
- Steam line inventory to turbine stop valves and steam line inventory up to MSIVs after valve closure.
- Feed water line inventory to MFIVs on the affected SG.
- RCP heat
- Fuel Decay heat

Expansion of the primary loop components from cold to hot operating conditions is considered. This maximizes the RCS volume and therefore stored energy to be transferred to the affected SG during the blowdown to containment. A similar volumetric expansion of secondary side inventory, including the main steam and feedwater lines is also assumed. Identical values for initial core power and decay heat described for LOCA are assumed for MSLB (refer to table 6.2.1-25).

B.3.3 Single Failure

Assuming the availability of non-emergency power is conservative since it allows the continuation of reactor coolant pump operation. This maximizes the

rate of heat transfer to the affected steam generator which maximizes the rate of mass/energy release. With non-emergency power, a diesel failure need not be postulated.

There is an MSIV in each main steam line. The MSIV's have been designed to close based on a conservative calculation which maximizes the dynamic pressure loading on the valve for all possible flow rates and qualities. Each valve has dual solenoid valves to assure closure even with a single failure in the control system. Single failure of the actuation signal will not prevent valve closure since both trains of MSIS actuation are provided to each MSIV. Any failure would result in the valve going to the closed position so that no additional steam could be added to the containment. The other MSIV isolates the unaffected steam generator. Each valve is tested periodically. However, conservatively, the random failure is assumed to be a failure of an MSIV in the broken steam line this would maximize the forward and reverse flow to the break and it would maximize the consequences of the event.

There are two MFIV's in series in each main feedwater line. If one MFIV fails, the second MFIV would provide isolation. All cases analyzed considered the flashing of the fluid in the lines from the upstream MFIV's to the affected steam generator; therefore, there is no need to do a separate analysis assuming MFIV failure.

C.1 Method of Mass and Energy release analysis

C.1.1 Loss of Coolant Accident

The analytical simulation of the LOCA event is divided into four distinct phases. These are blowdown, reflood, post-reflood and long term cooldown and explained below,

C.1.2.1 Blowdown:

Blowdown mass and energy release rates are calculated using the CEFLASH-4 A computer code (NRC approved in 1985). A description of the CEFLASH4 code including the conservatism's in modeling is given below. These analyses are performed in accordance with the Appendix K of 10CFR50. Additional conservatism has been include as required by Standard Review Plan (NUREG-087) to maximize the release of mass and energy to containment.

1. The appendix K prediction of fuel clad swelling and rupture is not considered. This will maximize the energy available for release from the core.

2. Calculation of heat transfer from core to coolant assume nucleate boiling. This will maximize the energy transfer to the exiting RCS coolant. While nucleate boiling is assumed for a portion of appendix K transient, as core conditions change, different heat transfer correlation may be selected by the code. To maximize fuel/cladding temperature, once an

alternate means of heat transfer is selected, the model will not go back to this high heat transfer regime.

3. The initial mass of water in the RCS is based on the temperature and pressure condition existing at 102% of full licensed power. This defers from the appendix K assumption of using nominal (cold) volume without inclusion of P/T expansion.

4. Some typical appendix K assumptions are to isolate the steam generators at the initiation of the event and include the addition of main feed water during the blowdown. For containment analyses calculation, steam flow was conservatively isolated at initiation of the event, however, a time dependent main feedwater addition to steam generators is assumed.

5. Containment pressure temperature analysis conservatively assumes that there are no degradation of steam generators and all steam generator tubes are available for secondary to primary heat transfer.

Since the refill phase (the time period during which the reactor vessel fills with SI liquid from the bottom of reactor vessel to the bottom of active core) is conservatively omitted from containment calculation, the next phase of the transient simulation is reflood.

C.1.2.2 Description of Core Reflood Model;

Reflood (applicable to cold leg breaks) is defined as the time period during which the reactor vessel level reaches an elevation of two feet below the top of the active core. At this point, the core is quenched. Reflood mass and energy release rates are calculated using the FLOOD-MOD2 computer code (ABB-CE). Heat transfer is conservatively modeled for core, vessel walls, vessel internals, loop metal, steam generator tubes, steam generator secondary, and steam generator secondary walls. The FLOOD3 (updated version of FLOOD-MOD2 NRC approved methodology) code hydraulics calculates flow rates and pressure. The heat transfer process predicts fluid enthalpies. Fluid densities are calculated as functions of pressures and enthalpies. The conservatisms in the model are as follows:

1. Depending on containment design, reflood containment pressures on System 80 plants are typically 55 psia or 70 psia.

2. A one-dimensional heat transfer model is used for all wall heat transfer calculations. It has been demonstrated that one dimensional models yield a more conservative result than identical two-dimensional models.

3. A nucleate boiling heat transfer coefficient of 10000 Btu/hr-ft^2-°F is used to model the heat

transfer from the steam generator tubes to the fluid. This coefficient represents an upper limit, and is conservatively used at all times throughout the tubes.

4. During reflood, calculations are made on the steam generator secondaries to predict the liquid levels. These calculations show that a conservatively calculated fraction (~25%) of the tube heat transfer area is in contact with the secondary steam; the remainder of the tubes is in contact with the secondary liquid. A conservative Nusselt condensation heat transfer coefficient of 2250 Btu/hr-ft^2-°F is used in conjunction with the tube 2 area exposed to steam; a natural circulation coefficient of 5 Btu/hr-ft^2-°F is used for the rest of the tube area.

5. The thermal resistance corresponding to the steam generator tubes is 0.00034 (Btu/hr-ft^2-°F)$^{-1}$. This value is also used in calculating secondary to primary heat transfer.

6. The carryover rate fraction (CRF) used during reflood is 0.05 up to the 18 inch core level, increases to 0.80 at the 24 inch core level, and is kept at 0.80 until the 10.5 foot level is reached. 10.5 feet is 2 feet below the level of the top of the active core. Other variables, such as core inlet temperature, pressure, flow rate,

linear heat rate, or other experimental data are not used to determine the CRF.

7. Reflood is assumed to terminate when the 10.5 foot quench level in the core is reached.

8. The decay heat utilized in the preparation of mass and energy release and sensible heat is based on the 1979 ANS 5.1 Standard plus a two sigma uncertainty and modified implementation of actinide correction factor without any further conservatism. The decay heat standard used is shown to be conservative enough for this application.

9. During reflood, credit is taken for the condensation of steam in the discharge legs by the cold ECCS water. As a conservatism, credit is not taken unless the reactor vessel annulus is full since the computer code assumes that the ECCS flow is injected directly into the annulus. Also, as an additional conservatism, credit is not taken when the ECCS rate is too low to thermodynamically condense all of the steam in the discharge legs. The percentage of the total steam flow condensed varies slightly with time for each case. For suction leg cases, credit is taken for the condensation of approximately 42% of the total steam flow when the annulus full and the thermodynamic criteria are simultaneously met; for discharge leg cases, the percentage varies from 42% to 50%.

C.1.2.3 Description of Post Reflood Model

This Post Reflood Model is identical to the reflood model, including the carryout rate fraction (CRF), which is kept at 0.8 for the remainder of the event. The flow rates are further enhanced by the fact that the core liquid height is now constrained at the 10.5 foot level, which maximizes the available driving head between the annulus level and the core in the FLOOD3 flooding equation. All heat transfer coefficients are kept at the values used for the reflood analysis. Condensation is analyzed as previously described; however, there is not sufficient spillage to completely thermodynamically condense the steam so that credit for condensation has not been taken.

C.1.2.4 Description of Long Term Cooling Model

The heat generation rate from shutdown fissions, heavy isotope decay, and fission product decay is shown in table 6.2.1-21. For conservatism the long-term analysis assumes that decay heat is added to the reactor vessel water at two standard deviation greater rate than that predicted by the decay heat curve.

Following the post reflood period outlined above, the mass/energy source terms for long-term containment analysis are computed concurrently with the containment back pressure in the

containment code. The steam flows out the break will be a function of the depressurization of the containment (and the variable ECCS inlet enthalpy when in the recirculation mode), decay heat (plus margin) and primary metal-to-primary fluid heat transfer. The steam generator secondary fluid, tube, thick and thin metal stored energy are used to superheat the steam prior to discharge into the containment.

The reactor coolant system is assumed to be a vessel containing a constant mass of saturated water. The pressure in the vessel is assumed to be the containment pressure. ECCS water is injected into the vessel. Steam is formed at a rate determined by decay heat, RCS metal-to-coolant heat transfer, and the rate of containment depressurization. Since the water in the vessel is saturated, boiling will occur even without decay heat or metal heat transfer as the containment pressure decreases. The difference between the ECCS injection rate and the steaming rate is the spillage rate to the sump.

The long-term decay heat and primary and secondary energy input was prepared using ABB CENP’s NRC-approved containment analysis code CONTRANS (Ref. 12). The time dependent energy addition due to this sensible heat, as calculated by CONTRANS, was input to the COPATTA mass & energy release

calculation. The decay heat and sensible energy addition data are presented in Table 6.2.1-11.

C.2 Main Steam line Break

C.2.1 Description of Blowdown Model

The secondary system pipe break analysis was performed using SGNIII version sgn 3.898 ml digital computer code (Reference 8). The version used for analysis is essentially equivalent to those used during the original plant design calculation. Some differences include a feed water expansion calculation (down stream of the affected side MFIV) which is now an integral part of the SGNIII computer model and a plant specific main steam line arrangement in the blowdown calculation.

The contribution to containment pressure due to feedwater flow is handled by feedwater flow addition to the affected steam generator and the boiling off of the feedwater by primary to secondary heat transfer. The feedwater flow is the sum of the pumped feedwater flow prior to isolation plus the isentropic expansion of the fluid in the feedwater line between the affected steam generator and its MFIV. No degradation of the feedwater flow occurs until the closure of the MFIV's. For consistency, no feedwater is added to the unaffected steam generator. Following closure of the MFIV's, there is an inventory of feedwater between the MFIV and the affected steam generator. As the affected steam

generator depressurizes, this inventory starts to boil. As steam in the line expands this feedwater inventory is pushed into the steam generator and is boiled off by primary to secondary heat transfer. The expansion of the feedwater inventory into the affected steam generator has been considered in the analysis. The expansion is assumed to be isentropic.

The isentropic expansion of the feedwater downstream of the MFIV is determined in a calculation separate from SGNIII. Since it is assumed that the pressure in the feedwater line downstream of the MFIV is the same as the affected steam generator pressure, iteration with SGNIII is required. As the affected steam generator depressurizes, the feedwater expands. At first the feedwater is subcooled and the fluid which expands into the affected steam generator is liquid. Once the steam generator pressure drops below the saturation pressure of the feedwater, flashing starts to occur and then the fluid which expands into the steam generator is two-phase.

The feedwater flow from isentropic expansion is added to the pumped feedwater flow. The pumped feedwater flow is conservatively assumed to be a constant 200% of the initial feedwater flow until the MFIVs close.

The MSLB mass/energy data given in Table 6.2.1-4 represent the total release from the NSSS - steam generator and secondary to the containment.

C.3 Containment Response Analysis

The containment pressure analyses are performed using the Bechtel COPATTA computer program that was derived from the CONTEMPT program written for the AEC loss-of-fluid test (LOFT) program.

The COPATTA model predicts both the pressure and temperature within the containment regions and the temperatures in the containment structures. Separate blowdown and core thermal behavior studies were made by ABB C-E to determine mass and/or energy input rates from sources such as: the release of reactor coolant, chemical reactions, decay energy, and sensible heat release, which may cause heating or boil-off of residual water in the reactor vessel or super-heating of steam as it passes through the steam generator and enters the containment through the postulated point of RCS rupture.

The COPATTA model treats the containment and the heat transfer surfaces following a DBA. Included in this model are ESF system parameters and analytical techniques that enable calculation of their effects upon the containment. Several options are incorporated in the model to facilitate use of these features.

COPATTA calculates a pressure-time transient with stepwise iteration between the thermodynamic state points. The iterations are based on the laws of the conservation of mass and energy together with their thermodynamic relationships. Superposition of heat

input functions is assumed so that any combination of coolant release, decay heat generation, and sensible heat release can be used with appropriate ESF features to determine the containment pressure-time-history associated with a DBA.

The program uses a three-region containment model consisting of the containment atmosphere (vapor region), the sump (liquid region), and the water contained in the reactor vessel. Mass and energy are transferred between the liquid and vapor regions by boiling, condensation, or liquid dropout. Evaporation is not considered. A convective heat transfer coefficient can be specified between the sump liquid and atmosphere vapor regions. However, since any heat transfer in this mode is small, a conservative coefficient of zero is generally assumed. Each region is assumed homogeneous, but a temperature difference can exist between regions. Any moisture condensed in the vapor region during a time increment is assumed to fall immediately into the liquid region. Noncondensable gases are included in the vapor region.

D. Accident Identification and Results

The containment pressure and temperature response and sump water temperature response versus time are given in figures 6.2.1-1 through 6.2.1-6 for the most severe LOCA breaks and the most severe MSLBs. It has been demonstrated in reference 1 where main steam line breaks produced a high degree of superheat that typical safety-related equipment surface temperatures remained

at or near the containment saturation temperature as a result of the short time frame at superheat conditions due to spray actuation.

Pipe break locations, break areas, peak pressures and temperatures, times of peak pressure, and total energy released to containment are summarized in table 6.2.1-9 for each LOCA and MSLB analyzed. Based on the results presented in table 6.2.1-9, the double-ended discharge leg slot break LOCA with maximum ECCS was identified as the pipe break with the highest peak pressure for an analyzed core power of 4070 MWt. The calculated value is 57.85 psig (72.05 psia)[1], which is below the design pressure value of 60 psig.

Figures 6.2.1-7 through 6.2.1-9 are plots of the containment condensing heat transfer coefficient versus time for the most severe RCS discharge and suction leg breaks and secondary coolant system breaks.

6.2.1.1.3.2 Long-Term Containment Performance. Long-term analyses of the worst case pump discharge leg break, and the worst case pump suction leg break were performed to verify the ability of the containment heat removal system (CHRS) to maintain the containment below the design conditions. These evaluations were based upon conservatively assumed performance of the engineered safety features. The CHRS long-term operating mode is assumed to include one containment spray train.

[1]Includes the effect of SIT Nitrogen discharge

The containment pressure-time responses for the DBA for the pumps discharge leg and the pump suction leg cases out to 8.64E+4 seconds (24 hours) are shown in figures 6.2.1-3 and 6.2.1-4 for the ESF performance mode outlined in table 6.2.1-7.

The containment pressure-time response for the highest pressure MSLB case (102% power) is shown in figure 6.2.1-6. The analysis shows that within 24 hours the containment pressure is reduced to 1/2 of peak containment pressure. No further analysis is performed for the MSLB since, after isolation and blowdown, there is no further energy input to containment. The maximum pressure of 55.2 psia occurs at 199.5 seconds in 102% power MSLB case. The energy distributions in the containment versus time are shown in figures 6.2.1-10 through 6.2.1-12 for DBA LOCAs and MSLBs. Mechanisms of energy removal from and transfer within the containment are addressed. Included are the vapor energy (steam plus air), sump (liquid) energy, energy contained in heat sinks, energy removed by the shutdown cooling heat exchangers, and energy transferred by sprays from the vapor to the sump.

6.2.1.1.3.3 Accident Chronology. Accident chronologies for the most severe reactor coolant system breaks and MSLBs are provided in table 6.2.1-10. It is assumed that time equals zero at the start of each accident.

6.2.1.1.3.4 Energy Balance. For the most severe reactor coolant system pipe breaks and the most severe secondary coolant system pipe break, a detailed energy balance is presented in table 6.2.1-11.

Table 6.2.1-9

SUMMARY OF CALCULATED CONTAINMENT PRESSURE AND TEMPERATURES

ANALYZED AT 102% OF 3990 MWt[1]

Loss-of-Coolant Accident Results	DEHLS 19.24 ft^2	DESLS 9.82 ft^2 Max ECCS	DESLS 9.82 ft^2 Min ECCS	DEDLS 9.82 ft^2 Max ECCS	DEDLS 9.82 ft^2 Min ECCS
Peak pressure, psia	67.06	68.65	68.31	72.05	69.62
Peak temperature, °F	276.6	300.55	299.64	308.41	304.07
Time of peak pressure, seconds	11.4	95.0	90.4	204.0	340
Energy released to containment up to the end of blowdown, 10^6 Btu	412.82	397.34	397.34	409.44	409.44
Main Steam Line Break Results	**102% Power 6.526 ft^2 Guillotine with Cooling Failure**	**75% Power 6.526 ft^2 Guillotine with Cooling Failure**	**0% Power 6.526 ft^2 Guillotine with Cooling Failure**		
Peak pressure, psia	55.19	55.54	55.27		
Peak temperature, °F	405.55	404.03	400.11		
Time of peak pressure, seconds	199.5	210.5	219		
Energy released to containment up to the end of blowdown, 10^6 Btu	375.7	380.9	380.6		

[1] Limiting containment peak pressure is based on LOCA. Peak containment temperature is based on MSLB. A review of prior analyses of record indicated that neither a 25% nor a 50% power case would provide limiting containment temperature conditions for MSLB.

Table 6.2.1-10

ACCIDENT CHRONOLOGIES - ANALYZED AT 102% OF 3990 MWt

(Sheet 1 of 7)

A. Worst case hot leg break

Break type: Double-ended hot leg slot break

Time (s)	Event
0.0	Break occurs
8.2	Start core flood tank injection
11.4	Peak containment pressure 67.06 psia (52.86 psig) (blowdown)
12.2	Start ECCS injection phase
12.2	End of blowdown
95	Start spray injection

Table 6.2.1-10

ACCIDENT CHRONOLOGIES - ANALYZED AT 102% OF 3990 MWt

(Sheet 2 of 7)

B. Worst case suction leg break

Break type: Double-ended suction leg slot break minimum ECCS

Time (s)	Event
0.0	Break occurs
17.5	Start core flood tank injection
20.8	Start ECCS injection phase
20.8	End of blowdown
94.6	End of core reflood
90.4	Peak containment pressure, 68.0 psia (53.8 psig)
95	Start spray injection
114.1	End of steam generator energy release: post reflood
3003	End of ECCS injection; start ECCS recirculation
3003	End of spray injection; start spray recirculation
5400	ECCS realigned: 50% to hot leg and 50% to cold leg
86400	Addition of RCS sensible heat completed
86400	Depressurization of containments, 36.62 psia, (22.42 psig). Containment Pressure is Less Than 1/2 containment peak pressure.

Table 6.2.1-10

ACCIDENT CHRONOLOGIES - ANALYZED AT 102% OF 3990 MWt

(Sheet 3 of 7)

C. Worst case discharge leg break

Break type: Double-ended discharge leg slot break maximum ECCS

Time (s)	Event
0.0	Break occurs
11.4	Start core flood tank injection
17.1	Start ECCS injection phase
17.1	End blowdown
95	Start spray injection
169.4	End of core reflood
204	Peak containment pressure subsequent to end of blowdown, 72.05 psia (57.85 psig)
288.9	End of steam generator energy release: post-reflood
1403	End of ECCS injection; start ECCS recirculation
1403	End of spray injection; start spray recirculation
5400	ECCS realigned: 50% to hot leg and 50% to cold leg
86400	Addition of RCS sensible heat completed
86400	Depressurization of containment, 35.59 psia (21.39 psig). Containment pressure is less than 1/2 of peak containment pressure.

Table 6.2.1-10

ACCIDENT CHRONOLOGIES - ANALYZED AT 102% OF 3990 MWt

(Sheet 4 of 7)

D. Worst case steam line break (pressure)

Break type: 0% power MSL slot break – loss of cooling train

Time (s)	Event
0.0	Break occurs
2.95	Containment pressure reaches safety injection actuation signal (SIAS) analysis setpoint of 19.2 psia
2.95	Containment pressure reaches reactor trip analysis setpoint of 19.2 psia
2.95	Containment pressure reaches main steam isolation signal (MSIS) analysis setpoint of 19.2 psia
3.95	High containment pressure reactor trip signal and MSIS generated
3.95	SIAS generated
3.95	Turbine admission valves closed
4.10	Reactor trip breakers open
6.4	Containment pressure reaches containment spray actuation signal (CSAS) analysis setpoint of 24.2 psia

Table 6.2.1-10

ACCIDENT CHRONOLOGIES - ANALYZED AT 102% OF 3990 MWt

(Sheet 5 of 7)

D. Worst case main steam line break (pressure)

Break type: 0% power MSL slot break loss of cooling train (cont)

Time (s)	Event
8.95	Main steam isolation valves closed
13.95	Main feedwater isolation valves closed (see paragraph 1.9.2.4.10)
94.25	AFW actuates
105.25	AFW to the affected SG is isolated
88.4	Containment spray at full flow initiated inside containment building
88.4	Peak containment temperature of 400.11°F occurs
219	Peak containment pressure of 55.27 psia occurs
500	Blowdown ends

Table 6.2.1-10

ACCIDENT CHRONOLOGIES - ANALYZED AT 102% OF 3990 MWt

(Sheet 6 of 7)

E. Worst case main steam line break temperature

Break type: 102% power MSL slot break loss of cooling train

Time (s)	Event
0.0	Break occurs
3.03	Containment pressure reaches safety injection actuation signal (SIAS) analysis setpoint of 19.2 psia
3.03	Containment pressure reaches reactor trip analysis setpoint of 19.2 psia
3.03	Containment pressure reaches main steam isolation signal (MSIS) analysis setpoint of 19.2 psia
4.03	High containment pressure reactor trip signal and MSIS generated
4.03	SIAS generated
4.03	Turbine admission valves closed
4.18	Reactor trip breakers open
8.0	Containment pressure reaches containment spray actuation signal (CSAS) analysis setpoint of 24.2 psia

Table 6.2.1-10

ACCIDENT CHRONOLOGIES - ANALYZED AT 102% OF 3990 MWt

(Sheet 7 of 7)

F. Worst case main steam line break (temperature)

Break type: 102% power MSL slot break Loss of cooling train (cont)

Time (s)	Event
9.03	Main steam isolation valves closed
14.03	Main feedwater isolation valves closed (see paragraph 1.9.2.4.10)
66.11	AFW Actuates
77.11	AFW to the affected SG is isolated
90.0	Containment spray at full flow initiated inside containment building
90	Peak containment temperature of 405.55°F occurs
199.5	Peak containment pressure of 55.19 psia occurs
500	Blowdown ends

6.2.1.1.3.5 Functional Capability of Containment Normal Ventilation Systems. Containment maximum and minimum design pressures are based on conservative assumptions of initial atmospheric pressures and temperatures within the containment. The functional capability of the containment normal ventilation systems to maintain initial containment atmospheric conditions within the range of temperature and pressure defined for normal plant operation is discussed in section 9.4. The Technical Specifications give the limiting conditions of containment temperature and pressure for normal plant operation and describe the action that will be taken if these conditions are exceeded.

6.2.1.1.3.6 Protection Against Severe External Loading. The DBA for containment external pressure design has been determined to be inadvertent actuation of the containment spray system. Consideration was also given to misoperation of the containment normal purging system (i.e., operation of the exhaust train with the supply train isolated), but the maximum feasible differential pressure for this case is limited to a few inches of water (gauge) based on the exhaust fan operating curve.

As a conservative estimate of the consequences of an inadvertent spray actuation, a calculation of the minimum containment pressure has been made assuming ideal gas behavior, Dalton's laws, and a reduction in containment air temperature to the minimum spray water temperature. The assumptions used in the analysis of an inadvertent containment spray system actuation are listed in table 6.2.1-12. The maximum external

pressure that would occur as a result of this transient is 3.5 psig based on an initial containment pressure of –1.0 psig (the lower Technical Specification limit plus instrument uncertainty) and the calculated pressure drop of 2.5 psig. This calculated value is less than the 4.0 psi value used in the containment design. Measures taken to prevent inadvertent actuation are covered in paragraph 6.2.2.2.

6.2.1.1.3.7 Post-Accident Containment Pressure/Temperature Monitoring. One channel each of containment pressure and temperature instrumentation will be recorded in the main control room. Containment emergency sump temperature is not recorded since it is not required to mitigate the consequences of a DBA. Section 7.5 contains a detailed discussion of range, accuracy, and response of the instrumentation used and the type and accessibility of recorders provided. The tests conducted to qualify the instruments for use in the post-accident containment environment are discussed in section 3.11.

Table 6.2.1-11
REACTOR CONTAINMENT BUILDING ENERGY DISTRIBUTION[1]
AT 102% OF 3990 MWt (Sheet 1 of 7)

A. WORST CASE HOT LEG BREAK

BREAK TYPE: DOUBLE - ENDED HOT LEG SLOT BREAK
BREAK AREA: 19.24 SQUARE FEET

Energy Description	Energy [(10 E+6) Btu]	
	Prior to LOCA	End of blow down
Reactor Coolant system water internal energy	541.221	53.860
Safety Injection Tank Water internal energy	41.657	35.315
Energy Stored in core	33.747	13.430
Energy Stored in RV Internals	34.854	30.583
Energy Stored in RV walls	89.234	88.446
Integrated core power including decay heat	0.000	5.570
Energy stored in primary system metal including SG tubes	136.863	126.558
Energy stored in steam generator secondary walls	128.995	<128.995
Secondary coolant internal energy (in steam generators)[2]	270.276	235.680
Energy content of Containment Building[3]	Refer to figure 6.2.1-10 sheet 1	
Energy content of Containment Building internal structures[4]		
Energy of recirculation intake water (sump)		

[1] The datum temperature is 32 F unless otherwise noted.
[2] Includes steam line energy.
[3] Atmospheric constituent datum are 120 F for air and 32F for water vapor.
[4] Datum for energy content of reactor containment building and internal structures is 120 F.

Table 6.2.1-11
REACTOR CONTAINMENT BUILDING ENERGY DISTRIBUTION[1]
AT 102% OF 3990 MWt (Sheet 2 of 7)

B. WORST CASE SUCTION LEG BREAK

BREAK TYPE: DOUBLE-ENDED SUCTION LEG SLOT BREAK
BREAK AREA: 9.82 SQUARE FEET
ECCS FLOW: MINIMUM

Energy Description	Energy [(10 E+6) Btu]		
	Prior to LOCA	End of blow down	24 HR AFTER LOCA
Reactor Coolant system water internal energy	541.221	17.463	41
Safety Injection Tank Water internal energy	41.657	0.000	0.000
Energy Stored in core	33.747	3.042	0.000
Energy Stored in RV Internals	34.854	25.672	0.000
Energy Stored in RV walls	89.234	88.142	0.000
Integrated core power including decay heat	0.000	13.563	3049
Energy stored in primary system metal including SG tubes	136.863	108.013	0.000
Energy stored in steam generator secondary walls	128.995	127.726	0.000
Secondary coolant internal energy (in steam generators)[2]	270.276	158.585	0.000
Energy content of Containment Building[3]	Refer to figure 6.2.1-11		

1 The datum temperature is 32 F unless otherwise noted.
2 Includes steam line energy.
3 Atmospheric constituent datum are 120 F for air and 32F for water vapor.

Table 6.2.1-11
REACTOR CONTAINMENT BUILDING ENERGY DISTRIBUTION[1]
AT 102% OF 3990 MWt (Sheet 3 of 7)

B. WORST CASE SUCTION LEG BREAK

BREAK TYPE: DOUBLE-ENDED SUCTION LEG SLOT BREAK
BREAK AREA: 9.82 SQUARE FEET
ECCS FLOW: MINIMUM

Energy Description	Energy [(10 E+6) Btu]		
	Prior to LOCA	End of blow down	24 HR AFTER LOCA
Energy content of Containment Building internal structures[2]	Refer to figure 6.2.1-11		
Energy of recirculation intake water (sump)			
Energy removed by shutdown heat exchanges (containment spray system)			

[1] The datum temperature is 32 F unless otherwise noted.
[2] Datum for energy content of reactor containment building and internal structures is 120 F.

Table 6.2.1-11
REACTOR CONTAINMENT BUILDING ENERGY DISTRIBUTION[1]
AT 102% OF 3990 MWt (Sheet 4 of 7)

C. WORST CASE DISCHARGE LEG BREAK

BREAK TYPE: DOUBLE-ENDED DISCHARGE LEG SLOT BREAK
BREAK AREA: 9.82 SQUARE FEET
ECCS FLOW: MAXIMUM

Energy Description	Energy [(10 E+6) Btu]		
	Prior to LOCA	End of blow down	24 HR AFTER LOCA
Reactor Coolant system water internal energy	541.221	26.204	41.0
Safety Injection Tank Water internal energy	41.657	0.000	0.000
Energy Stored in core	33.747	6.585	0.000
Energy Stored in RV Internals	34.854	24.3967	0.000
Energy Stored in RV walls	89.234	87.343	0.000
Integrated core power including decay heat	0.000	34.508	3049
Energy stored in primary system metal including SG tubes	136.863	100.231	0.000
Energy stored in steam generator secondary walls	128.995	125.087	0.000
Secondary coolant internal energy (in steam generators)[2]	270.276	133.115	0.000
Energy content of Containment Building[3]	Refer to figure 6.2.1-10 sheet 2		

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[1] The datum temperature is 32 F unless otherwise noted.
[2] Includes steam line energy.
[3] Atmospheric constituent datum are 120 F for air and 32F for water vapor.

Table 6.2.1-11
REACTOR CONTAINMENT BUILDING ENERGY DISTRIBUTION[1]
AT 102% OF 3990 MWt (Sheet 5 of 7)

C. WORST CASE DISCHARGE LEG BREAK

BREAK TYPE: DOUBLE-ENDED DISCHARGE LEG SLOT BREAK
BREAK AREA: 9.82 SQUARE FEET
ECCS FLOW: MAXIMUM

Energy Description	Energy [(10 E+6) Btu]		
	Prior to LOCA	End of blow down	24 HR AFTER LOCA
Energy content of Containment Building internal structures[2]	Refer to figure 6.2.1-10A sheet 2		
Energy of recirculation intake water (sump)			
Energy removed by shutdown heat exchanges (containment spray system)			

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[1] The datum temperature is 32 F unless otherwise noted.
[2] Datum for energy content of reactor containment building and internal structures is 120 F.

Table 6.2.1-11
REACTOR CONTAINMENT BUILDING ENERGY DISTRIBUTION[1]
AT 102% OF 3990 MWt (Sheet 6 of 7)

D. WORST CASE SECONDARY SYSTEM BREAK (CONTAINMENT TEMPERATURE)

BREAK TYPE: DOUBLE-ENDED SLOT BREAK
BREAK AREA: 7.16 SQUARE FEET
POWER: 102% OF LICENSED POWER

Energy Description	Energy [(10 E+6) Btu]	
	Prior to MSLB	End of blow down
Reactor Coolant system water internal energy	541.221	471.622
Energy Stored in core	33.747	11.008
Integrated core power including decay heat	0.000	97.945
Energy stored in primary system metal including SG tubes (RCS vessel, RV walls, piping pumps)	260.951	246.715
Energy stored in steam generator secondary walls	399.271	258.501
Feed water to SG No. 1	0.000	0.000
Feed water to SG No. 2	0.000	43.061
Energy content of Containment Building[2]	Refer to figure 6.2.1-10 sheet 2	
Energy content of Containment Building internal structures[3]		
Energy of recirculation intake water (sump)		

[1] The datum temperature is 32 F unless otherwise noted.
[2] Atmospheric constituent datum are 120 F for air and 32F for water vapor.
[3] Datum for energy content of reactor containment building and internal structures is 120 F.

Table 6.2.1-11
REACTOR CONTAINMENT BUILDING ENERGY DISTRIBUTION[1]
AT 102% OF 3990 MWt (Sheet 7 of 7)

D. WORST CASE SECONDARY SYSTEM BREAK (CONTAINMENT TEMPERATURE)

BREAK TYPE: DOUBLE-ENDED SLOT BREAK
BREAK AREA: 7.16 SQUARE FEET
POWER: 000% OF LICENSED POWER

Energy Description	Energy [(10 E+6) Btu]	
	Prior to MSLB	End of blow down
Reactor Coolant system water internal energy	498.781	389.248
Energy Stored in core	12.977	9.446
Integrated core power including decay heat	0.000	0.02508
Energy stored in primary system metal including SG tubes (RCS vessel, RV walls, piping pumps)	222.900	189.968
Energy stored in steam generator secondary walls	592.336	363.044
Feed water to SG No. 1	0.000	0.000
Feed water to SG No. 2	0.000	0.485
Energy content of Containment Building[2]	Refer to figure 6.2.1-12 sheet 2	
Energy content of Containment Building internal structures[3]		
Energy of recirculation intake water (sump)		

[1] The datum temperature is 32 F unless otherwise noted.
[2] Atmospheric constituent datum are 120 F for air and 32F for water vapor.
[3] Datum for energy content of reactor containment building and internal structures is 120 F.

Table 6.2.1-12

ASSUMPTIONS USED IN ANALYSIS OF INADVERTENT CONTAINMENT SPRAY SYSTEM ACTUATION

Item	Assumed Value
Initial temperature, F (max)	120
Initial pressure, psia (min)	13.2
Relative humidity, %	90
Refueling water temperature, F	60
No heat input to containment from structure or primary and secondary system components	-
Ideal gas behavior of air in containment	-

6.2.1.2 Containment Subcompartments

6.2.1.2.1 Design Bases

Subcompartments within containment, principally the reactor cavity, the steam generator compartments, and the pressurizer compartment, are designed to withstand the transient differential pressures and jet impingement forces of a postulated pipe break. Venting of these chambers is employed to keep the differential pressures within structural limits. In addition, restraints on the coolant pipes, reactor vessel, and steam generators are designed so that neither pipe whip nor forces transmitted through component supports threatened the integrity of the subcompartments or of the containment structure.

The spectrum of pipe breaks analyzed for each subcompartment are listed in table 6.2.1-1. The characteristics of the main coolant pipe ruptures were determined in accordance with the methods and criteria of subsection 3.6.2. The accident that results in the maximum differential pressure across the walls of the respective compartment is designated as the subcompartment DBA. Calculated DBA differential pressures are compared to the design differential pressure values used in the structural design of subcompartment walls and equipment to ensure that calculated values are less than design values.

The application of Leak-before-Break (LBB) to sub-compartment analysis require that the requirement be met.

a. A confirmation is made that the as-built facility design substantially agrees with the design described in the CE submittal of December 23, 1983; specifically, the piping

loads should be no greater than those cited in that submittal.

b. A confirmation that a leak detection system that is consistent with the guidelines of RG 1.45 so that it can detect leakage of 1 gpm in 1 hour.

6.2.1.2.2 Design Features

6.2.1.2.2.1 Reactor Cavity. No high energy line breaks are postulated in the Reactor Cavity due to application of Leak Before Break Criteria.

6.2.1.2.2.2 Steam Generator Compartment. The walls of the steam generator compartment are constructed of reinforced concrete that serves to support the equipment enclosed and provides radiation shielding. Engineering drawings 13-P-OOB-002 through -005 and 13-P-OOB-008 present views of the steam generator compartment arrangement.

The steam generator compartment encloses the steam generator vessel, two reactor coolant pumps and other smaller equipment. The compartment is very nearly symmetrical about the vertical plane through the two generators and the reactor vessel. The nodal model of the steam generator compartment is provided in figure 6.2.1-15. The control volume and vent path descriptions are given in Tables 6.2.1-15 and 6.2.1-16.

6.2.1.2.2.3 Pressurizer Compartment. The pressurizer compartment consists of a small, nearly square compartment that completely encloses the pressurizer vessel, as shown in engineering drawing 13-P-OOB-003 and -007. The pressurizer

vessel is supported on a pair of concrete beams which form a partial slab at elevation 110 feet. The most severe accident in this compartment is the surge line break at the vessel nozzle. This break is located within the vessel mounting skirt and produces the largest vessel uplift force. It also produces the largest compartment wall loads due to differential pressures.

The model of the pressurizer compartment used for the analysis of the surge line break consists of nine nodes and is depicted in figure 6.2.1-16. The control volume and vent path descriptions are given in tables 6.2.1-17 and 6.2.1-18.

6.2.1.2.3 Design Evaluation

6.2.1.2.3.1 Computer Codes. The computer codes used to calculate mass and energy release from postulated pipe breaks and to calculate the subsequent pressure transient response of the subcompartment are discussed below.

A. Blowdown Code: Mass and energy release rates from a postulated pipe break were calculated with the CEFLASH-4A computer program. See sections 6.2.1.1.3.B.3 and 6.2.1.1.3.C.2.

B. Pressure Transient Code

   Analysis of the pressure transients in the reactor cavity, steam generator compartments, and pressurizer compartment were performed using the COPDA computer program. Refer to BN-TOP-4.[2]

Table 6.2.1-13

REACTOR CAVITY NODAL DESCRIPTION (Sheet 1 of 8)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

Volume No.[(a)]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions[(b)]			Peak Calculated Differential Pressure (psig)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
1	Cavity above shield plug between adjacent to broken pipe and excore detector	14.1	13.3	120	14.4	25	16	198
2	Adjacent to node 1 and hot leg at plant north	14.1	15.7	120	14.4	25	27	229
3	Adjacent to node 2 and the excore detector	14.1	15.7	120	14.4	25	27	229
4	Adjacent to node 3 and the next cold leg	14.1	13.3	120	14.4	25	16	198
5	Adjacent to node 4 and the next cold leg	14.1	29.0	120	14.4	25	7	439
6	Adjacent to node 1 and the next cold leg	14.1	29.0	120	14.4	25	7	439
7	Adjacent to node 6 and the next excore detector	14.1	13.3	120	14.4	25	4	198
8	Adjacent to node 7 and the hot leg at plant south	14.1	15.7	120	14.4	25	4	229

a. Refer to figure 6.2.1-13.

b. The NRC Standard Review Plan indicates that as low as possible initial relative humidity and pressure should be used in subcompartment analysis.

Paragraph 2.3.1.1.4 shows that the average atmosphere relative humidity is 36%. The value of 25% as used in the subcompartment analysis is, therefore, conservatively low.

Subsection 2.4.3 gives plant (Unit 3 nominal) elevation as 951 feet (msl). This corresponds to an atmospheric pressure of 14.2 psia. By including the effect of humidity on the containment atmosphere, a total pressure of 14.6 psia is realized. This is conservatively lowered to 14.4 psia in the subcompartment analysis.

Table 6.2.1-13

REACTOR CAVITY NODAL DESCRIPTION (Sheet 2 of 8)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

Volume No.[a]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions[b]			Peak Calculated Differential Pressure (psig)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
9	Adjacent to node 8 and the next excore detector	14.1	15.7	120	14.4	25	4	229
10	Adjacent to nodes 9 and 5	14.1	13.3	120	14.4	25	4	198
11	Between shield plug and bottom of reactor cavity, below node 1	18.2	9.6	120	14.4	25	<2	159
12	Between shield plug and bottom of reactor cavity, below nodes 2 and 3	18.2	29.7	120	14.4	25	<2	500
13	Between shield plug and bottom of reactor cavity, below node 4	18.2	9.6	120	14.4	25	<2	159
14	Between shield plug and bottom of reactor cavity, below node 5	18.2	33.4	120	14.4	25	<2	571
15	Between shield plug and bottom of reactor cavity, below node 6	18.2	33.4	120	14.4	25	<2	571
16	Between shield plug and bottom of reactor cavity, below node 7	18.2	9.6	120	14.4	25	<2	159
17	Between shield plug and bottom of reactor cavity below nodes 8 and 9	18.2	29.7	120	14.4	25	<2	500
18	Between shield plug and bottom of reactor cavity below node 10	18.2	9.6	120	14.4	25	<2	159

Table 6.2.1-13

REACTOR CAVITY NODAL DESCRIPTION (Sheet 3 of 8)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

Volume No.[a]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions[b] Temperature (°F)	Pressure (psia)	Humidity (%)	Peak Calculated Differential Pressure (psig)	Net Free Volume (ft^3)
19	Region below reactor cavity, above ICI guide tube support plate 1	10.8	200	120	14.4	25	<2	1782
20	Region between plates 1 and 2	14.2	125	120	14.4	25	<2	2334
21	Region between plates 2 and 3	7.0	120	120	14.4	25	<2	1032
22	Region between plates 3 and 4	6.5	120	120	14.4	25	<2	733
23	Region between plates 4 and 5	10.5	165	120	14.4	25	<2	916
24	Region between plates 5 and 6	10.9	148	120	14.4	25	<2	1125
25	Region between plates 6 and 7	22.4	62.9	120	14.4	25	<2	1135
26	Region between plates 7 and 8	10.8	102	120	14.4	25	<2	1050
27	Region between plates 8 and 9	10.0	102	120	14.4	25	<2	970
28	Region between plates 9 and 10	9.6	102	120	14.4	25	<2	930
29	Region between plates 10 and the seal table	2.9	102	120	14.4	25	<2	278
30	Volume of reactor cavity cooling system ductwork	-	-	120	14.4	25	<2	1990
31	Hot leg pipe tunnel at plant north adjacent to nodes 2 and 3	11.5	14.9	120	14.4	25	12	89

Table 6.2.1-13

REACTOR CAVITY NODAL DESCRIPTION (Sheet 4 of 8)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

Volume No.[a]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions[b]			Peak Calculated Differential Pressure (psig)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
32	Cold leg tunnel adjacent to nodes 4 and 5	6.0	18.3	120	14.4	25	6	212
33	Cold leg tunnel adjacent to nodes 5 and 10	11.5	18.3	120	14.4	25	4	212
34	Hot leg tunnel adjacent to nodes 8 and 9	6.0	14.9	120	14.4	25	<2	89
35	Cold leg tunnel adjacent to nodes 1 and 6	11.5	18.3	120	14.4	25	6	212
36	Cold leg tunnel adjacent to nodes 6 and 7	11.5	18.3	120	14.4	25	4	212
37	Reactor containment	-	-	120	14.4	25	-	$2.6x10^6$

Table 6.2.1-13

REACTOR CAVITY NODAL DESCRIPTION (Sheet 5 of 8)

B. 350 Square Inches Cold Leg Guillotine Break
Break location: volume numbers 1 and 6

Volume No.[(a)]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions[(b)] Temperature (°F)	Pressure (psia)	Humidity (%)	Peak Calculated Differential Pressure (psig)	Net Free Volume (ft^3)
1	Cavity above shield plug between adjacent to broken pipe and excore detector	14.1	13.3	120	14.4	25	100	198
2	Adjacent to node 1 and hot leg at plant north	14.1	15.7	120	14.4	25	61	229
3	Adjacent to node 2 and the excore detector	14.1	15.7	120	14.4	25	3	229
4	Adjacent to node 3 and the next cold leg	14.1	13.3	120	14.4	25	19	198
5	Adjacent to node 4 and the next cold leg	14.1	29.0	120	14.4	25	97	439
6	Adjacent to node 1 and the next cold leg	14.1	29.0	120	14.4	25	97	439
7	Adjacent to node 6 and the next excore detector	14.1	13.3	120	14.4	25	57	198
8	Adjacent to node 7 and the hot leg at plant south	14.1	15.7	120	14.4	25	32	229
9	Adjacent to node 8 and the next excore detector	14.1	15.7	120	14.4	25	19	229
10	Adjacent to nodes 9 and 5	14.1	13.3	120	14.4	25	15	198

Table 6.2.1-13

REACTOR CAVITY NODAL DESCRIPTION (Sheet 6 of 8)

B. 350 Square Inches Cold Leg Guillotine Break
Break location: volume numbers 1 and 6

Volume No.[(a)]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions[(b)]			Peak Calculated Differential Pressure (psig)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
11	Between shield plug and bottom of reactor cavity, below node 1	18.2	9.6	120	14.4	25	18	159
12	Between shield plug and bottom of reactor cavity, below nodes 2 and 3	18.2	29.7	120	14.4	25	15	500
13	Between shield plug and bottom of reactor cavity, below node 4	18.2	9.6	120	14.4	25	15	159
14	Between shield plug and bottom of reactor cavity, below node 5	18.2	33.4	120	14.4	25	15	571
15	Between shield plug and bottom of reactor cavity, below node 6	18.2	33.4	120	14.4	25	18	571
16	Between shield plug and bottom of reactor cavity, below node 7	18.2	9.6	120	14.4	25	18	159
17	Between shield plug and bottom of reactor cavity below nodes 8 and 9	18.2	29.7	120	14.4	25	15	500
18	Between shield plug and bottom of reactor cavity below node 10	18.2	9.6	120	14.4	25	15	159
19	Region below reactor cavity, above ICI guide tube support plate 1	10.8	200	120	14.4	25	14	1782

Table 6.2.1-13

REACTOR CAVITY NODAL DESCRIPTION (Sheet 7 of 8)

B. 350 Square Inches Cold Leg Guillotine Break
Break location: volume numbers 1 and 6

Volume No.[a]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions[b]			Peak Calculated Differential Pressure (psig)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
20	Region between plates 1 and 2	14.2	125	120	14.4	25	14	2334
21	Region between plates 2 and 3	7.0	120	120	14.4	25	14	1032
22	Region between plates 3 and 4	6.5	120	120	14.4	25	1	733
23	Region between plates 4 and 5	10.5	165	120	14.4	25	13	916
24	Region between plates 5 and 6	10.9	148	120	14.4	25	13	1125
25	Region between plates 6 and 7	22.4	62.9	120	14.4	25	12	1135
26	Region between plates 7 and 8	10.8	102	120	14.4	25	10	1050
27	Region between plates 8 and 9	10.0	102	120	14.4	25	7	970
28	Region between plates 9 and 10	9.6	102	120	14.4	25	6	930
29	Region between plates 10 and the seal table	2.9	102	120	14.4	25	6	278
30	Volume of reactor cavity cooling system ductwork	-	-	120	14.4	25	12	1990
31	Hot leg pipe tunnel at plant north adjacent to nodes 2 and 3	11.5	14.9	120	14.4	25	27	89
32	Cold leg tunnel adjacent to nodes 4 and 5	6.0	18.3	120	14.4	25	7	212

Table 6.2.1-13

REACTOR CAVITY NODAL DESCRIPTION (Sheet 8 of 8)

B. 350 Square Inches Cold Leg Guillotine Break
Break location: volume numbers 1 and 6

Volume No.[a]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions[b] Temperature (°F)	Pressure (psia)	Humidity (%)	Peak Calculated Differential Pressure (psig)	Net Free Volume (ft^3)
33	Cold leg tunnel adjacent to nodes 5 and 10	11.5	18.3	120	14.4	25	7	212
34	Hot leg tunnel adjacent to nodes 8 and 9	6.0	14.9	120	14.4	25	10	89
35	Cold leg tunnel adjacent to nodes 1 and 6	11.5	18.3	120	14.4	25	57	212
36	Cold leg tunnel adjacent to nodes 6 and 7	11.5	18.3	120	14.4	25	42	212
37	Reactor containment	-	-	120	14.4	25	-	$2.6X10^6$

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 1 of 12)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning and Obstruction Loss, K	Expansion, K	Contraction, K	Total K_t	
1	1	6		X	32.6	-	-	-	.081	1	-	1.081	.210
2	1	11	X		1.86	3.5	1.55	.02	-	1	.5	1.52	3.33
3	1	12	X		.402	-	-	-	.72	1	.5	2.22	9.52
4	1	35		X	6.56	-	-	-	-	1	.5	1.5	.340
5	1	36	X		11.3	-	-	← Modeled as an orifice →					.540
6	2	1		X	17.2	-	-	-	.220	1	-	1.22	.130
7	2	3		X	31.2	-	-	-	.093	1	-	1.093	.179
8	2	12	X		.602	-	-	-	1.14	1	.5	2.64	4.20
9	2	31		X	5.8	-	-	-	-	1	.5	1.5	.220
10	2	37	X		13.7	-	-	← Modeled as an orifice →					.460
11	3	4		X	34.1	-	-	-	.220	1	-	1.22	.130
12	3	12	X		.602	-	-	-	1.14	1	.5	2.64	4.20
13	3	31		X	5.8	-	-	-	-	1	.5	1.5	.220
14	3	37	X		13.7	-	-	← Modeled as an orifice →					.460
15	4	5		X	32.6	-	-	-	.081	1	-	1.081	.210
16	4	12	X		.402	-	-	-	.72	1	.5	2.22	9.52
17	4	13	X		1.86	3.5	1.55	.02	-	1	.5	1.52	3.33
18	4	32		X	7.56	-	-	-	-	1	.5	1.5	.340

(-) Means this value is negligible

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 2 of 12)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

Vent Path Number	Vol. Node Number From	Vol. Node Number To	Description of Vent Path Flow: Choked	Description of Vent Path Flow: Unchoked	Vent Area (ft^2)	Friction Factors: Length (ft)	Friction Factors: Hydraulic Diameter (ft)	Head Loss, K: Friction K, fl/d	Head Loss, K: Turning and Obstruction Loss, K	Head Loss, K: Expansion, K	Head Loss, K: Contraction, K	Head Loss, K: Total K_t	L/A (ft^{-1})
19	4	37	X		11.3	-	-	← Modeled as an orifice →					.540
20	10	5		X	32.6	-	-	-	.081	1	.5	1.081	.210
21	5	14		X	.402	-	-	-	.72	1	.5	2.22	1.33
22	5	32		X	7.56	-	-	-	-	1	.5	1.5	.340
23	5	33		X	7.56	-	-		-	1	.5	1.5	.340
24	5	37		X	29.0	-	-	← Modeled as an orifice →					.240
25	6	7		X	32.6	-	-	-	.081	1	-	1.081	.210
26	6	15		X	.402	-	-	-	.72	1	.5	2.22	1.33
27	6	35		X	7.56	-	-	-	-	1	.5	1.5	.340
28	6	36		X	7.56	-	-		-	1	.5	1.5	.340
29	6	37		X	29.0	-	-	← Modeled as an orifice →					.240
30	7	8		X	34.1	-	-	-	.220	1	-	1.22	.130
31	7	16		X	1.86	3.5	1.55	.02	-	1	.5	1.52	3.33
32	7	17		X	.402	-	-		.72	1	.5	2.22	9.52
33	7	36		X	7.56	-	-	-	-	1	.5	1.5	.340
34	7	37		X	11.3	-	-	← Modeled as an orifice →					.540
35	8	9		X	31.2	-	-	-	.093	1	-	1.093	.179
36	8	17		X	.602	-	-	-	1.14	1	.5	2.64	4.20

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 3 of 12)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

Vent Path Number	Vol. Node Number From	Vol. Node Number To	Description of Vent Path Flow: Choked	Description of Vent Path Flow: Unchoked	Vent Area (ft^2)	Friction Factors: Length (ft)	Friction Factors: Hydraulic Diameter (ft)	Head Loss, K: Friction K, fl/d	Head Loss, K: Turning and Obstruction Loss, K	Head Loss, K: Expansion, K	Head Loss, K: Contraction, K	Head Loss, K: Total K^t	L/A (ft^{-1})
37	8	34		X	5.80	-	-			1	.5	1.5	.619
38	8	37		X	15.3	-	-	Modeled as an orifice					.460
39	9	10		X	34.1	-	-	-	.220	1	-	1.22	.130
40	9	17		X	.602	-	-	-	1.14	1	.5	2.64	4.20
41	9	34		X	5.80	-	-		-	1	.5	1.5	.220
42	9	37		X	13.7	-	-	Modeled as an orifice					.460
43	10	17		X	.402	-	-	-	.72	1	.5	2.22	9.52
44	10	18		X	1.86	3.5	1.55	.02	.72	1	.5	1.52	3.33
45	10	33		X	7.56	-	-	-	-	1	.5	1.5	.340
46	10	37		X	11.3	-	-	Modeled as an orifice					.540
47	11	12		X	9.10	4	3.98	.02	.42	1	-	1.44	.390
48	11	15		X	37.2	-	-	-	1.72	1	-	2.72	.160
49	11	19		X	2.28	-	-	-	-	1	.5	1.78	6.25
50	11	30		X	1.10	13.64	1.67	.08	.2	1	.5	1.78	6.25
51	12	13		X	9.10	4	3.98	.02	.42	1	-	1.44	.390
52	12	19		X	15.3	-	-	-	-	1	.20	1.20	.359
53	13	14		X	37.2	-	-	-	1.72	1	-	2.72	.160
54	13	19		X	2.28	-	-	-	-	1	.38	1.38	1.00

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 4 of 12)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

	Vol. Node Number		Description of Vent Path Flow			Friction Factors		Head Loss, K					
Vent Path Number	From	To	Choked	Unchoked	Vent Area (ft^2)	Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning and Obstruction Loss, K	Expansion, K	Contraction, K	Total K_t	L/A (ft^{-1})
55	13	30		X	1.10	13.64	1.67	.08	.2	1	.5	1.78	6.25
56	14	18		X	37.2	-	-	-	1.72	1	-	2.72	.160
57	14	19		X	4.56	-	-	-	-	1	.42	1.42	.325
58	14	30		X	2.20	13.64	1.67	.08	.2	1	.5	1.78	6.25
59	15	16		X	37.2	-	-	-	1.72	1	-	2.72	.160
60	15	19		X	4.56	-	-	-	-	1	.42	1.42	.325
61	15	30		X	2.20	13.64	1.67	.08	.2	1	.5	1.78	6.25
62	16	17		X	9.10	4	3.98	.02	.42	1	-	1.44	.390
63	16	19		X	2.28	-	-	-	-	1	.38	1.38	1.00
64	16	30		X	1.10	13.64	1.67	.08	.2	1	.5	1.78	6.25
65	17	18		X	9.10	4	3.98	.02	.42	1	-	1.44	.390
66	17	19		X	15.3	-	-	-	-	1	.20	1.20	.359
67	18	19		X	2.28	-	-	-	-	1	.38	1.38	1.00
68	18	30		X	1.10	13.64	1.67	.08	.2	1	.5	1.78	6.25
69	19	20		X	126.7	-	-	Modeled as an orifice					.084
70	19	30		X	13.1	5.5	1.67	.05	-	1	.5	1.55	2.52
71	20	21		X	135.1	-	-	Modeled as an orifice					.058
72	221	22		X	74.0	-	-	Modeled as an orifice					.056

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 5 of 12)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

	Vol. Node Number		Description of Vent Path Flow			Friction Factors		Head Loss, K					
Vent Path Number	From	To	Choked	Unchoked	Vent Area (ft^2)	Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning and Obstruction Loss, K	Expansion, K	Contraction, K	Total K_t	L/A (ft^{-1})
73	22	23		X	64.1	-	-	Modeled as an orifice					.068
74	23	24		X	104.6	-	-	Modeled as an orifice					.076
75	24	25		X	68.7	-	-	Modeled as an orifice					.091
76	25	26		X	27.2	-	-	Modeled as an orifice					.110
77	26	27		X	24.7	-	-	Modeled as an orifice					.102
78	27	28		X	36.4	-	-	Modeled as an orifice					.096
79	28	29		X	50.8	-	-	Modeled as an orifice					.062
80	28	37		X	21.0	-	-	Modeled as an orifice					.110
81	30	37		X	15.1	82.8	4	Modeled as an orifice					6.57
82	31	37	X		14.9	-	-	.21	-	1	.5	1.71	.201
83	32	37		X	18.3	-	-	-	-	1	-	1	.317
84	33	37		X	18.3	-	-	-	-	1	-	1	.317
85	34	37		X	14.9	-	-	-	-	1	-	1	.201
86	35	37		X	18.3	-	-	-	-	1	-	1	.317
87	36	37		X	18.3	-	-	-	-	1	-	1	.317
88	2	12	X		.41	3.5	.17	.212	-	1	.5	1.71	4.20
89	3	12	X		.41	3.5	.17	.21	-	1	.5	1.71	4.20
90	8	17		X	.41	3.5	.17	.21	-	1	.5	1.71	4.20

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 6 of 12)

A. 100 Square Inches Hot Leg Guillotine Break
Break location: volume numbers 2 and 3

	Vol. Node Number		Description of Vent Path Flow			Friction Factors		Head Loss, K					
Vent Path Number	From	To	Choked	Unchoked	Vent Area (ft^2)	Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning and Obstruction Loss, K	Expansion, K	Contraction, K	Total K_t	L/A (ft^{-1})
91	9	17		X	.41	3.5	.17	.21	-	1	.5	1.71	4.20
92	5	14		X	3.79	3.5	.65	.05	-	1	.5	1.55	1.33
93	6	15		X	3.79	3.5	.65	.05	-	1	.5	1.55	1.33

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 7 of 12)

B. 350 Square Inches Cold Leg Guillotine Break
Break location: volume numbers 1 and 6

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning and Obstruction Loss, K	Expansion, K	Contraction, K	Total K_t	
1	1	6		X	32.6	-	-	-	.081	1	-	1.081	.210
2	1	11	X		1.86	3.5	1.55	.02	-	1	.5	1.52	3.33
3	1	12	X		.402	-	-	-	.72	1	.5	2.22	9.52
4	1	35	X		6.56	-	-	-	-	1	.5	1.5	.340
5	1	36	X		11.3	-	-	← Modeled as an orifice →					.540
6	2	1		X	17.2	-	-	-	.220	1	-	1.22	.130
7	2	3	X		31.2	-	-	-	.093	1	-	1.093	.179
8	2	12	X		.602	-	-	-	1.14	1	.5	2.64	4.20
9	2	31	X		5.8	-	-	-	-	1	.5	1.5	.220
10	2	37	X		13.7	-	-	← Modeled as an orifice →					.460
11	3	4		X	34.1	-	-	-	.220	1	-	1.22	.130
12	3	12	X		.602	-	-	-	1.14	1	.5	2.64	4.20
13	3	31		X	5.8	-	-	-	-	1	.5	1.5	.220
14	3	37	X		13.7	-	-	← Modeled as an orifice →					.460
15	4	5		X	32.6	-	-	-	.081	1	-	1.081	.210
16	4	12		X	.402	-	-	-	.72	1	.5	2.22	9.52
17	4	13		X	1.86	3.5	1.55	.02	-	1	.5	1.52	3.33
18	4	32		X	7.56	-	-	-	-	1	.5	1.5	.340

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 8 of 12)

B. 350 Square Inches Hot Cold Guillotine Break
Break location: volume numbers 1 and 6

Vent Path Number	Vol. Node Number From	Vol. Node Number To	Description of Vent Path Flow: Choked	Description of Vent Path Flow: Unchoked	Vent Area (ft^2)	Friction FactorS: Length (ft)	Friction FactorS: Hydraulic Diameter (ft)	Head Loss, K: Friction K, fl/d	Head Loss, K: Turning and Obstruc-tion Loss, K	Head Loss, K: Expansion, K	Head Loss, K: Contrac-tion, K	Head Loss, K: Total K_t	L/A (ft^{-1})
19	4	37	X		11.3	-	-	Modeled as an orifice					.540
20	10	5		X	32.6	-	-	-	0.81	1	.5	1.081	.210
21	5	14		X	.402	-	-	-	.72	1	.5	2.22	1.33
22	5	32		X	7.56	-	-	-	-	1	.5	1.5	.340
23	5	33		X	7.56	-	-		-	1	.5	1.5	.340
24	5	37		X	29.0	-	-	Modeled as an orifice					.240
25	6	7	X		32.6	-	-	-	.081	1	-	1.081	.210
26	6	15	X		.402	-	-	-	.72	1	.5	2.22	1.33
27	6	35	X		7.56	-	-	-	-	1	.5	1.5	.340
28	6	36	X		7.56	-	-		-	1	.5	1.5	.340
29	6	37	X		29.0	-	-	Modeled as an orifice					.240
30	7	8	X		34.1	-	-	-	.220	1	-	1.22	.130
31	7	16	X		1.86	3.5	1.55	.02	-	1	.5	1.52	3.33
32	7	17	X		.402	-	-		.72	1	.5	2.22	9.52
33	7	36		X	7.56	-	-	-	-	1	.5	1.5	.340
34	7	37	X		11.3	-	-	Modeled as an orifice					.540
35	8	9		X	31.2	-	-	-	.093	1	-	1.093	.179
36	8	17	X		.602	-	-	-	1.14	1	.5	2.64	4.20

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 9 of 12)

B. 350 Square Inches Cold Leg Guillotine Break
Break location: volume numbers 1 and 6

Vent Path Number	Vol. Node Number From	Vol. Node Number To	Description of Vent Path Flow: Choked	Description of Vent Path Flow: Unchoked	Vent Area (ft^2)	Friction Factors: Length (ft)	Friction Factors: Hydraulic Diameter (ft)	Head Loss, K: Friction K, fl/d	Head Loss, K: Turning and Obstruction Loss, K	Head Loss, K: Expansion, K	Head Loss, K: Contraction, K	Head Loss, K: Total K_t	L/A (ft^{-1})
37	8	34	X		5.80	-	-			1	.5	1.5	.619
38	8	37	X		15.3	-	-	← Modeled as an orifice →					.460
39	9	10		X	34.1	-	-	-	.220	1	-	1.22	.130
40	9	17		X	.602	-	-	-	1.14	1	.5	2.64	4.20
41	9	34		X	5.80	-	-		-	1	.5	1.5	.220
42	9	37	X		13.7	-	-	← Modeled as an orifice →					.460
43	10	17		X	.402	-	-	-	.72	1	.5	2.22	9.52
44	10	18		X	1.86	3.5	1.55	.02	.72	1	.5	1.52	3.33
45	10	33		X	7.56	-	-	-	-	1	.5	1.5	.340
46	10	37		X	11.3	-	-	← Modeled as an orifice →					.540
47	11	12		X	9.10	4	3.98	.02	.42	1	-	1.44	.390
48	11	15		X	37.2	-	-	-	1.72	1	-	2.72	.160
49	11	19		X	2.28	-	-	-	-	1	.5	1.78	6.25
50	11	30		X	1.10	13.64	1.67	.08	.2	1	.5	1.78	6.25
51	12	13		X	9.10	4	3.98	.02	.42	1	-	1.44	.390
52	12	19		X	15.3	-	-	-	-	1	.20	1.20	.359
53	13	14		X	37.2	-	-	-	1.72	1	-	2.72	.160
54	13	19		X	2.28	-	-	-	-	1	.38	1.38	1.00

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 10 of 12)

B. 350 Square Inches Cold Leg Guillotine Break
Break location: volume numbers 1 and 6

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning and Obstruction Loss, K	Expansion, K	Contraction, K	Total K_t	
55	13	30		X	1.10	13.64	1.67	.08	.2	1	.5	1.78	6.25
56	14	18		X	37.2	-	-	-	1.72	1	-	2.72	.160
57	14	19		X	4.56	-	-	-	-	1	.42	1.42	.325
58	14	30		X	2.20	13.64	1.67	.08	.2	1	.5	1.78	6.25
59	15	16		X	37.2	-	-	-	1.72	1	-	2.72	.160
60	15	19		X	4.56	-	-	-	-	1	.42	1.42	.325
61	15	30		X	2.20	13.64	1.67	.08	.2	1	-	1.78	6.25
62	16	17		X	9.10	4	3.98	.02	.42	1	.38	1.44	.390
63	16	19		X	2.28	-	-	-	-	1	.5	1.38	1.00
64	16	30		X	1.10	13.64	1.67	.08	.2	1	-	1.78	6.25
65	17	18		X	9.10	4	3.98	.02	.42	1	.20	1.44	.390
66	17	19		X	15.3	-	-	-	-	1	.38	1.20	.359
67	18	19		X	2.28	-	-	-	-	1		1.38	1.00
68	18	30		X	1.10	13.64	1.67	.08	.2	1	.5	1.78	6.25
69	19	20		X	126.7	-	-	← Modeled as an orifice →					.084
70	19	30		X	13.1	5.5	1.67	.05	-	1	.5	1.55	2.52
71	20	21		X	135.1	-	-	← Modeled as an orifice →					.058
72	221	22		X	74.0	-	-	← Modeled as an orifice →					.056

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 11 of 12)

B. 350 Square Inches Cold Leg Guillotine Break
Break location: volume numbers 1 and 6

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning and Obstruction Loss, K	Expansion, K	Contraction, K	Total K_t	
73	22	23		X	64.1	-	-	Modeled as an orifice					.068
74	23	24		X	104.6	-	-	Modeled as an orifice					.076
75	24	25		X	68.7	-	-	Modeled as an orifice					.091
76	25	26		X	27.2	-	-	Modeled as an orifice					.110
77	26	27		X	24.7	-	-	Modeled as an orifice					.102
78	27	28		X	36.4	-	-	Modeled as an orifice					.096
79	28	29		X	50.8	-	-	Modeled as an orifice					.062
80	28	37		X	21.0	-	-	Modeled as an orifice					.110
81	30	37		X	15.1	82.8	4	Modeled as an orifice					6.57
82	31	37	X		14.9	-	-	.21	-	1	.5	1.71	.201
83	32	37		X	18.3	-	-	-	-	1	-	1	.317
84	33	37		X	18.3	-	-	-	-	1	-	1	.317
85	34	37		X	14.9	-	-	-	-	1	-	1	.201
86	35	37	X		18.3	-	-	-	-	1	-	1	.317
87	36	37	X		18.3	-	-	-	-	1	-	1	.317
88	2	12	X		.41	3.5	.17	.21	-	1	.5	1.71	4.20
89	3	12	X		.41	3.5	.17	.21	-	1	.5	1.71	4.20
90	8	17	X		.41	3.5	.17	.21	-	1	.5	1.71	4.20

Table 6.2.1-14

REACTOR CAVITY VENT PATH DESCRIPTION (Sheet 12 of 12)

B. 350 Square Inches Cold Leg Guillotine Break
Break location: volume numbers 1 and 6

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning and Obstruction Loss, K	Expansion, K	Contraction, K	Total K_t	
91	9	17		X	.41	3.5	.17	.21	-	1	.5	1.71	4.20
92	5	14		X	3.79	3.5	.65	.05	-	1	.5	1.55	1.33
93	6	15	X		3.79	3.5	.65	.05	-	1	.5	1.55	1.33

6.2.1.2.3.2 Subcompartment Modeling. Subcompartment nodalization models are determined by physical flow restrictions within each compartment. These flow restrictions include consideration of concrete obstructions, doorways, vent shafts, grating, piping, the reactor cavity shield plug, and major equipment component. By choosing nodal boundaries at the various primary system components and physical flow restrictions, the calculated differential pressures and consequent vessel loads are maximized. A further increase in the number of subcompartment nodes modeled is not feasible unless additional physical flow restrictions are present. The subcompartment models, discussed below, take into account all physical flow restrictions present. Vent loss coefficients are categorized as either orifices or miscellaneous. Orifice coefficients are calculated by the COPDA computer code (see paragraph 6.2.1.2.3.1). For flow restrictions which cannot be adequately modeled as orifices, a miscellaneous flow coefficient is determined. References 3 and 4 are used in determining miscellaneous flow coefficients. The miscellaneous flow coefficients include friction losses; objects in flow paths; grating; and expansion, contraction, and turning losses.

A. Reactor Vessel Cavity

   There are no postulated breaks in the Reactor Vessel Cavity as a result of application of Leak Before Break Criteria.

Table 6.2.1-15
STEAM GENERATOR COMPARTMENT NODAL DESCRIPTION (Sheet 1 of 7)[a]

Volume No.[b]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions Temperature (°F)	Initial Conditions Pressure (psia)	Initial Conditions Humidity (%)	Peak Calculated Differential Pressure (psid)	Net Free Volume (ft^3)
1	Adjacent to and east of hot leg east to reactor cavity cooling fan and south to primary shield wall, below 100.6'	13.6	47	120	16.7	0	(c)	283
2	Adjacent to and symmetric to 1	13.6	47	120	16.7	0	(c)	269
3	Between 1 and steam generator (S.G.)	13.6	40	120	16.7	0	(c)	108
4	Adjacent to and symmetric to 3	13.6	40	120	16.7	0	(c)	108
5	Between S.G. and reactor coolant pump (RCP) north to pump suction leg and south to cavity cooling fan	13.6	115	120	16.7	0	(c)	792
6	Same as 5 only west of steam generator	13.6	115	120	16.7	0	(c)	792

a. NRC Generic Letter 87-11 has been implemented.

b. Refer to figure 6.2.1-15.

c. Volume is not adjacent to shield wall.

Table 6.2.1-15

STEAM GENERATOR COMPARTMENT NODAL DESCRIPTION (Sheet 2 of 7)[a]

Volume No.[b]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Condition			Peak Calculated Differential Pressure (psid)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
7	North of east RCP between pump suction leg and north east wall	13.6	142	120	16.7	0	5.0	1321
8	North of west RCP between pump suction leg and north west wall	13.6	142	120	16.7	0	4.8	1321
9	Northeast of steam gen. and adjacent to secondary shield wall	13.6	93	120	16.7	0	3.9	792
10	Adjacent to and west of node 9	13.6	93	120	16.7	0	4.8	792
11	East of cavity cooling fan and south of east RCP	13.6	87	120	16.7	0	6.4	922
12	West of 2 and south of west RCP	13.6	87	120	16.7	0	5.1	705
13	East of 11 and south of east RCP	13.6	103	120	16.7	0	5.5	1002

Table 6.2.1-15

STEAM GENERATOR COMPARTMENT NODAL DESCRIPTION (Sheet 3 of 7)[a]

Volume No.[b]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions Temperature (°F)	Initial Conditions Pressure (psia)	Initial Conditions Humidity (%)	Peak Calculated Differential Pressure (psid)	Net Free Volume (ft^3)
14	West of 12 and south of west RCP	13.6	103	120	16.7	0	5.5	1251
15	Between 7 and 13, east of east RCP	13.6	150	120	16.7	0	5.0	2437
16	Between 8 and 14, west of west RCP	13.6	150	120	16.7	0	4.8	2437
17	Tunnel between north and south steam generator compartments	12	297	120	16.7	0	2.8	2918
18	South and west of steam generator between 100.6’ and 107.7’	7.2	239	120	16.7	0	6.2	736
19	South and east of steam generator between 100.6’ and 107.7’	7.2	239	120	16.7	0	9.4	736
20	West of 18 and southwest of west RCP between 100.6’ and 100.7’	7.2	171	120	16.7	0	6.5	951

Table 6.2.1-15

STEAM GENERATOR COMPARTMENT NODAL DESCRIPTION (Sheet 4 of 7)[a]

Volume No.[b]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions: Temperature (°F)	Initial Conditions: Pressure (psia)	Initial Conditions: Humidity (%)	Peak Calculated Differential Pressure (psid)	Net Free Volume (ft^3)
21	East of 19 and south-east of east RCP between 100.6′ and 107.7′	7.2	171	120	16.7	0	6.5	951
22	North of 20 and north-west of west RCP between 100.6′ and 107.7′	7.2	77	120	16.7	0	6.4	455
23	North of 21 and north-east of east RCP between 100.6′ and 107.7′	7.2	77	120	16.7	0	6.6	455
24	North of 18 and east of 22 between 100.6′ and 107.7′	7.2	300	120	16.7	0	6.2	1174
25	North of 19 east of 24 between 100.6′ and 107.7′	7.2	300	120	16.7	0	3.9	1174
26	Above 18 between 107.7′ and 117.8′	10.1	195	120	16.7	0	4.7	1497
27	Above 19 between 107.7′ and 117.8′	10.1	195	120	16.7	0	5.1	1497

Table 6.2.1-15

STEAM GENERATOR COMPARTMENT NODAL DESCRIPTION (Sheet 5 of 7)[(a)]

Volume No.[(b)]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions			Peak Calculated Differential Pressure (psid)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
28	Above 24 between 107.7' and 117.8'	10.1	300	120	16.7	0	11.9	1939
29	Above 25 between 107.7' and 117.8'	10.1	300	120	16.7	0	3.5)	1939
30	Above 20 between 107.7' and 117.8'	10.1	151	120	16.7	0	6.0)	1122
31	Above 21 between 107.7' and 117.8'	10.1	151	120	16.7	0	6.0	1122
32	Above 22 between 107.7' and 117.8'	10.1	77	120	16.7	0	6.0	631
33	Above 23 between 107.7' and 117.8'	10.1	77	120	16.7	0	4.9	631
34	Above 26 between 117.8' and 128'	10.2	195	120	16.7	0	3.0	1522
35	Above 27 between 117.8' and 128'	10.2	195	120	16.7	0	3.0	1522
36	Above 28 between 117.8' and 128'	10.2	300	120	16.7	0	6.3	1886
37	Above 29 between 117.8' and 128'	10.2	300	120	16.7	0	2.7	1886

Table 6.2.1-15

STEAM GENERATOR COMPARTMENT NODAL DESCRIPTION (Sheet 6 of 7)[(a)]

Volume No.[(b)]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions			Peak Calculated Differential Pressure (psid)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
38	Above 30 between 117.8' and 128'	10.2	151	120	16.7	0	4.3	1218
39	Above 31 between 117.8' and 128'	10.2	151	120	16.7	0	2.5	1218
40	Above 32 between 117.8' and 128'	10.2	77	120	16.7	0	4.1	598
41	Above 33 between 117.8' and 128'	10.2	77	120	16.7	0	2.8	598
42	Above 34 between 128' and 133.6'	5.6	242	120	16.7	0	2.6	952)
43	Above 35 between 128' and 133.6'	5.6	242	120	16.7	0	1.8	952)
44	Above 36 between 128' and 133.6'	5.6	300	120	16.7	0	2.9	1177
45	Above 37 between 128' and 133.6'	5.6	300	120	16.7	0	2.1	1177
46	Above 38 between 128' and 133.6'	5.6	152	120	16.7	0	2.5	757
47	Above 39 between 128' and 133.6'	5.6	152	120	16.7	0	1.9	757

Table 6.2.1-15

STEAM GENERATOR COMPARTMENT NODAL DESCRIPTION (Sheet 7 of 7)[(a)]

Volume No.[(b)]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions			Peak Calculated Differential Pressure (psid)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
48	Above 40 between 128' and 133.6'	5.6	77	120	16.7	0	2.6	375
49	Above 41 between 128' and 133.6'	5.6	77	120	16.7	0	2.0	375
50	West side of north steam generator compt. between 140.9' and 133.6'	7.3	1650	120	16.7	0	2.1	3624
51	Ease side of north generator compt. adjacent to node 50	7.3	1650	120	16.7	0	1.7	3624
52	Between 155' and 140.9' above node 50	14.1	1650	120	16.7	0	1.0	6715
53	Above node 51 and adjacent to node 52	14.1	1650	120	16.7	0	1.0	6715
54	Remainder of containment	-	-	120	16.7	0	1.0	2.5×10^6
55	Region below east reactor coolant pump	11.25	36.5	120	16.7	0	(c)	301

Table 6.2.1-16

STEAM GENERATOR COMPARTMENT VENT PATH DESCRIPTION (Sheet 1 of 9)[a]

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning Loss, K	Expansion, K	Contraction, K	Total K_t	
1	1	2		X	8	-	-	← Modeled as an orifice →					.940
2	1	3		X	45.4	-	-	-	-	1.0		1.0	.136
3	1	11		X	69.6	-	-	-	-	1.0	.073	1.073	.125
4	1	19		X	23.4	-	-	-	-	1.0	.397	1.397	.109
5	1	54	X		0.0	-	-	← Modeled as an orifice →					3.18
6	2	4		X	45.4	-	-	-	-	1.0		1.0	.136
7	2	12		X	56.6	-	-	-	-	1.0	.073	1.073	.125
8	2	18		X	23.4	-	-	-	-	1.0	.397	1.397	.109
9	2	54		X	0.0	-	-	← Modeled as an orifice →					3.18
10	3	4		X	5.8	-	-	-	-	1.0	.322	1.322	1.022
11	3	5		X	40.2	-	-	-	-	1.0	.208	1.208	.148
12	3	19		X	11.4	-	-	-	-	1.0	.162	1.62	.145
13	4	6		X	40.2	-	-	-	-	1.0	.208	1.208	.198
14	4	18		X	11.4	-	-	-	-	1.0	.162	1.62	.145
15	5	7		X	120.0	-	-	-	-	1.0	.305	1.305	.100
16	5	9		X	14.4	-	-	-	-	1.0	.407	1.407	.511
17	5	11		X	81.7	-	-	-	-	1.0	.208	1.208	.145

a. NRC Generic Letter 87-11 has been implemented

(-) Means this value is negligible.

Table 6.2.1-16

STEAM GENERATOR COMPARTMENT VENT PATH DESCRIPTION (Sheet 2 of 9)[a]

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning Loss, K	Expansion, K	Contrac-tion, K	Total K_t	
18	5	19		X	11.2	-	-	Modeled as an orifice					.272
19	5	25		X	11.2	-	-	Modeled as an orifice					.272
20	6	8		X	120.0	-	-	-	-	1.0	.305	1.305	.100
21	6	10		X	14.4	-	-	-	-	1.0	.407	1.407	.511
22	6	12		X	81.7	-	-	-	-	1.0	.208	1.208	.145
23	6	18		X	11.2	-	-	Modeled as an orifice					.272
24	6	24		X	11.2	-	-	Modeled as an orifice					.259
25	7	9		X	13.6	-	-	-	-	1.0	.338	1.338	.115
26	7	15		X	100.8	-	-	-	-	1.0	.171	1.171	.087
27	7	25		X	83.0	-	-	-	.344	1.0	.178	1.192	.087
28	8	10		X	13.6	-	-	-	-	1.0	.338	1.338	.115
29	8	16		X	100.8	-	-	-	-	1.0	.171	1.171	.087
30	8	24		X	83.0	-	-	-	.344	1.0	.178	1.192	.087
31	9	10		X	38.7	-	-	-	-	1.0	.336	1.336	.116
32	9	25		X	38.0	-	-	-	-	1.0	.120	1.120	.100
33	10	24		X	38.0	-	-	-	-	1.0	.120	1.120	.099
34	11	13		X	100	-	-	-	-	1.0	.193	1.193	.079

Table 6.2.1-16

STEAM GENERATOR COMPARTMENT VENT PATH DESCRIPTION (Sheet 3 of 9)[(a)]

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning Loss, K	Expansion, K	Contraction, K	Total K_t	
35	11	19		X	60	-	-	-	-	1.0	.157	1.157	.135
37	11	54	X		0.0	-	-	← Modeled as an orifice →					.676
38	12	14		X	100	-	-	-	-	1.0	.193	1.193	.079
39	12	18		X	60	-	-	-	-	1.0	.157	1.157	.135
41	12	54		X	0.0	-	-	← Modeled as an orifice →					.676
42	13	15		X	123	-	-	-	-	1.0	.194	1.194	.081
43	13	21		X	26.2	-	-	← Modeled as an orifice →					.284
44	14	16		X	123	-	-	-	-	1.0	.194	1.194	.081
45	14	17		X	91.8	-	-	-	-	1.0	.075	1.075	.253
46	14	20		X	28.4	-	-	← Modeled as an orifice →					.264
47	15	21		X	12.7	-	-	-	.344	1.0	.370	1.714	.164
48	15	23		X	121.7	-	-	-	.344	1.0	.193	1.527	.085
49	15	25		X	7.1	-	-	-	.344	1.0	.264	1.598	.053
50	15	54	X		43.2	-	-	-	3.194	1.0	.417	4.611	.724
51	16	20		X	12.7	-	-	-	.344	1.0	.370	1.714	.164
52	16	22		X	121.7	-	-	-	.344	1.0	.193	1.527	.085
53	16	24		X	7.1	-	-	-	.344	1.0	.264	1.598	.053

Table 6.2.1-16

STEAM GENERATOR COMPARTMENT VENT PATH DESCRIPTION (Sheet 4 of 9)[a]

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning Loss, K	Expansion, K	Contraction, K	Total K_t	
54	16	54		X	18.9	18.0	4.2	.086	1.22	1.0	.464	2.77	.884
55	17	54		X	91.8	33.0	9.56	.069	-	1.0	-	1.069	.153
56	18	19		X	11.5	-	-	-	-	1.0	.383	1.383	.454
57	18	20		X	21.7	-	-	-	-	1.0	.321	1.321	.271
58	18	24		X	33.6	-	-	-	-	1.0	.325	1.325	.206
59	18	26		X	105.8	-	-	-	.344	1.0	-	1.344	.061
60	18	54		X	0.0	-	-	Modeled as an orifice					.974
61	19	21		X	21.7	-	-	-	-	1.0	.321	1.321	.271
62	19	25		X	22.6	-	-	-	-	1.0	.325	1.325	.205
63	19	27		X	120.8	-	-	-	.344	1.0	-	1.344	.061
64	19	54	X		0.0	-	-	Modeled as an orifice					.974
65	20	22		X	55.1	-	-	-	-	1.0	.153	1.153	.149
66	20	26		X	3.6	-	-	-	-	1.0	.366	1.366	.051
67	20	30		X	104.8	-	-	-	.344	1.0	-	1.344	.062
68	20	54		X	0.0	-	-	Modeled as an orifice					.793
69	21	23		X	62.1	-	-	-	-	1.0	.153	1.153	.149
70	21	27		X	3.6	-	-	-	-	1.0	.366	1.366	.051

Table 6.2.1-16

STEAM GENERATOR COMPARTMENT VENT PATH DESCRIPTION (Sheet 5 of 9)[(a)]

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning Loss, K	Expansion, K	Contraction, K	Total K_t	
71	21	31		X	104.8	-	-	-	.344	1.0	-	1.344	.062
72	21	54	X		0.0	-	-	← Modeled as an orifice →					.493
73	21	54		X	0.0	-	-	-	2.919	1.0	.253	1.172	.833
74	22	24		X	145.1	-	-	-	-	1.0	.163	1.163	.260
75	22	32		X	50.1	-	-	-	-	1.0	.174	1.174	.140
76	23	25		X	45.1	-	-	-	-	1.0	.163	1.163	.260
77	23	33		X	50.1	-	-	-	-	1.0	.174	1.174	.140
78	24	25		X	19.5	-	-	-	1.08	1.0	.283	1.363	.444
79	24	28		X	147.9	-	-	-	-	1.0	.134	1.134	.041
80	25	29		X	147.9	-	-	-	-	1.0	.134	1.134	.041
81	26	27		X	66.1	-	-	-	-	1.0	.261	1.261	.215
82	26	28		X	30.9	-	-	-	-	1.0	.358	1.358	.149
83	26	30		X	71.2	-	-	-	-	1.0	.191	1.191	.188
84	26	34		X	103.5	-	-	-	-	1.0	.262	1.262	.098
85	27	29		X	34.9	-	-	-	-	1.0	.358	1.358	.149
86	27	31		X	71.2	-	-	-	-	1.0	.191	1.191	.188
87	27	35		X	103.5	-	-	-	-	1.0	.262	1.262	.098

Table 6.2.1-16

STEAM GENERATOR COMPARTMENT VENT PATH DESCRIPTION (Sheet 6 of 9)[a]

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning Loss, K	Expansion, K	Contraction, K	Total K_t	
88	28	29		X	57.9	-	-	-	-	1.0	.294	1.294	.296
89	28	32		X	69.7	-	-	-	-	1.0	.213	1.213	.266
90	28	36		X	150.4	-	-	-	-	1.0	.192	1.192	.046
91	29	33		X	69.7	-	-	-	-	1.0	.213	1.213	.266
92	29	37		X	150.4	-	-	-	-	1.0	.193	1.192	.046
93	30	32		X	77.3	-	-	-	-	1.0	.197	1.197	.337
94	30	38		X	51.4	-	-	Modeled as an orifice					.104
95	31	33		X	77.3	-	-	-	-	1.0	.197	1.197	.337
96	31	39		X	51.4	-	-	Modeled as an orifice					.104
97	32	40		X	33.7	-	-	Modeled as an orifice					.162
98	33	41		X	33.7	-	-	Modeled as an orifice					.162
99	34	35		X	77.0	-	-	-	-	1.0	.262	1.262	.205
100	34	36		X	50.8	-	-	-	-	1.0	.360	1.360	.815
101	34	38		X	58.2	-	-	-	-	1.0	.262	1.262	.202
102	34	42		X	137.2	-	-	-	-	1.0	.120	1.120	.044
103	35	37		X	50.8	-	-	-	-	1.0	.360	1.360	.815
104	35	39		X	58.2	-	-	-	-	1.0	.262	1.262	.202

Table 6.2.1-16

STEAM GENERATOR COMPARTMENT VENT PATH DESCRIPTION (Sheet 7 of 9)[(a)]

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning Loss, K	Expansion, K	Contrac-tion, K	Total K_t	
105	35	43		X	125.6	-	-	-	-	1.0	.120	1.120	.047
106	36	37		X	45.5	-	-	-	-	1.0	.305	1.305	.303
107	36	40		X	71.4	-	-	-	-	1.0	.198	1.198	.159
108	36	44		X	138.6	-	-	-	.344	1.0	-	1.344	.038
109	37	41		X	71.4	-	-	-	-	1.0	.198	1.198	.159
110	37	45		X	143.8	-	-	-	.344	1.0	-	1.344	.038
111	38	40		X	74.9	-	-	-	-	1.0	.210	1.210	.105
112	38	46		X	128.5	-	-	-	-	1.0	.025	1.025	.101
113	39	41		X	74.9	-	-	-	-	1.0	.210	1.210	.105
114	39	47		X	128.5	-	-	-	-	1.0	.195	1.195	.101
115	40	48		X	67.0	-	-	-	-	1.0	-	1.0	.118
116	41	49		X	67.0	-	-	-	-	1.0	.244	1.244	.118
117	42	43		X	36.5	-	-	-	-	1.0	.262	1.262	.387
118	42	44		X	23.8	-	-	-	-	1.0	.350	1.350	.260
119	42	46		X	41.5	-	-	-	-	1.0	.191	1.191	.338
120	42	50		X	168.5	-	-	-	-	1.0	-	1.0	.023
121	43	45		X	23.8	-	-	-	-	1.0	.350	1.350	.260

Table 6.2.1-16

STEAM GENERATOR COMPARTMENT VENT PATH DESCRIPTION (Sheet 8 of 9)[a]

Vent Path Number	Vol. Node Number From	Vol. Node Number To	Description of Vent Path Flow: Choked	Description of Vent Path Flow: Unchoked	Vent Area (ft^2)	Friction Factors: Length (ft)	Friction Factors: Hydraulic Diameter (ft)	Head Loss, K: Friction K, fl/d	Head Loss, K: Turning Loss, K	Head Loss, K: Expansion, K	Head Loss, K: Contraction, K	Head Loss, K: Total K_t	L/A (ft^{-1})
122	43	47		X	41.5	-	-	-	-	1.0	.191	1.191	.338
123	43	51		X	168.5	-	-	-	-	1.0	-	1.0	.023
124	44	45		X	26.5	-	-	-	-	1.0	.294	1.294	.552
125	44	48		X	34.3	-	-	-	-	1.0	.236	1.236	.481
126	44	50		X	197.3	-	-	-	-	1.0	-	1.0	.020
127	45	49		X	34.3	-	-	-	-	1.0	.236	1.236	.481
128	45	51		X	197.3	-	-	-	-	1.0	-	1.0	.020
129	46	48		X	45.1	-	-	-	-	1.0	.181	1.181	.189
130	46	50		X	135.2	-	-	-	-	1.0	-	1.0	.027
131	47	49		X	45.1	-	-	-	-	1.0	.181	1.181	.189
132	47	51		X	135.2	-	-	-	-	1.0	-	1.0	.027
133	48	50		X	67.0	-	-	-	-	1.0	-	1.0	.048
134	49	51		X	67.0	-	-	-	-	1.0	-	1.0	.048
135	50	51		X	66.2	-	-	-	2.725	-	-	2.725	1.089
136	50	52		X	551.6	-	-	-	-	1.0	.157	1.157	.019
137	51	53		X	551.6	-	-	-	-	1.0	.157	1.157	.019
138	52	53		X	86.1	-	-	-	4.38	-	-	4.38	.433

Table 6.2.1-16

STEAM GENERATOR COMPARTMENT VENT PATH DESCRIPTION (Sheet 9 of 9)[a]

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Vent Area (ft^2)	Friction Factors		Head Loss, K					L/A (ft^{-1})
	From	To	Choked	Unchoked		Length (ft)	Hydraulic Diameter (ft)	Friction K, fl/d	Turning Loss, K	Expansion, K	Contraction, K	Total K_t	
139	52	54		X	521.9	-	-	-	-	1.0	-	1.0	.013
140	53	54		X	521.9	-	-	-	-	1.0	-	1.0	.013
141	55	5		X	31.1	-	-	-	-	1.0	.130	1.130	.208
142	55	7		X	17.7	-	-	-	-	1.0	.288	1.288	.205
143	55	11		X	25.8	-	-	-	-	1.0	.130	1.130	.222
144	55	13		X	24.8	-	-	-	-	1.0	.173	1.173	.220
145	55	15		X	53.9	-	-	-	-	1.0	.098	1.098	.132

Table 6.2.1-17

PRESSURIZER COMPARTMENT NODAL DESCRIPTION[(a)]

Volume No.[(b)]	Description	Height (ft)	Cross-Sectional Area (ft^2)	Initial Conditions			Peak Calculated Differential Pressure (psig)	Net Free Volume (ft^3)
				Temperature (°F)	Pressure (psia)	Humidity (%)		
1	Pressurizer skirt and region above 105.5'	8.8	46	120	14.4	25	131.6[(c)]	315
2	Below pressurizer between 100' and 105.5'	5.5	115	120	14.4	25	72.4	601
3	Adjacent to 2 and between 100' and 110'	10.0	68	120	14.4	25	61.7	643
4	Pressurizer compartment between 110' and 120'	10.0	315	120	14.4	25	10.8	2316
5	Above 4, between 120' and 140'	20.0	306	120	14.4	25	10.0	4394
6	Above 5, between 140' and 146.5'	6.5	290	120	14.4	25	9.0	1274
7	Above 6, between 146.5' and 153'	6.5	286	120	14.4	25	7.7	1528
8	Above 7, between 153' and 161.5'	8.5	288	120	14.4	25	7.0	2253
9	Free containment	-	-	120	14.4	25	-	$2.7x10^6$

a. Double-ended surge line break

b. Refer to figure 6.2.1-16

c. Pressure across the skirt not the pressurizer compartment wall

Table 6.2.1-18

PRESSURIZER COMPARTMENT VENT PATH DESCRIPTION[a]

Vent Path Number	Vol. Node Number		Description of Vent Path Flow		Area (ft^2)	Head Loss, K						L/A (ft^{-1})
						Forward Flow			Reverse Flow			
	From	To	Choked	Unchoked		$K_{Entrance}$	K_{Exit}	Total, K_t	$K_{entrance}$	K_{exit}	Total, K_t	
1	1	2	X		38.8	0.313	1.0	1.313	0.313	1.0	1.313	0.132
2	1	4	X		2.36	0.496	1.0	1.496	0.496	1.0	1.496	0.155
3	2	3	X		71.0	1.381	1.0	2.381	1.208	1.0	2.208	0.250
4	2	9	X		33	1.191	1.0	2.191	1.191	1.0	2.191	0.233
5	3	4	X		37.8	2.093	1.0	3.093	1.068	1.0	2.068	0.192
6	3	9	X		21	0.5	1.0	1.5	0.5	1.0	1.5	0.215
7	4	5		X	186	0.112	1.0	1.112	0.091	1.0	1.091	0.067
8	5	6		X	147.8	0.164	1.0	1.164	0.164	1.0	1.164	0.062
9	5	9		X	13.6	0.5	1.0	1.5	0.5	1.0	1.5	0.180
10	6	7		X	130	0.204	1.0	1.204	0.315	1.0	1.315	0.030
11	7	8		X	186	0.050	1.0	1.050	0.149	1.0	1.149	0.030
12	7	9		X	10.73	0.5	1.0	1.5	0.5	1.0	1.5	0.281
13	8	9		X	5.03	0.5	1.0	1.5	0.5	1.0	1.5	1.17
14	8	9		X	62.6	0.385	1.0	1.385	0.5	1.0	1.5	0.068

a. Double-ended surge line break

Table 6.2.1-19

DIFFERENTIAL PRESSURE LOADS ON REACTOR VESSEL

(NODAL SENSITIVITY STUDY)

Total number of nodes	37	45
Number of cavity nodes	18	26
Peak cavity pressure (psig)	114.2	114.2
Lateral force (lb_f)	2.78(6)[a]	2.72(6)
Uplift force (lb_f)	6.9(5)	6.9(5)
Moment about x-axis (ft-lb_f)	4.57(6)	4.45(5)
Moment about y-axis (ft-lb_f)	-1.26(7)	-1.28(7)
Moment about z-axis (ft-lb_f)	-8.18(5)	-8.18(5)

a. ( ) denotes power of ten.

Table 6.2.1-20

STEAM GENERATOR NODAL SENSITIVITY STUDY

592-SQUARE INCH SUCTION LEG BREAK

	Sensitivity Study	Models	Present Model
Total number of nodes	41	47	55
Maximum primary wall pressure (psia)	38.4	38.8	38.8
Maximum secondary wall pressure (psia)	44.0	44.1	43.9
X-Axis moment (10^6 ft-lb)	2.80	2.79	2.79
Y-Axis moment (10^6 ft-lb)	-6.77	-6.93	-7.18
Lateral load (10^5 lb_f)	4.73	4.89	4.98
Uplift load (10^5 lb_f)	5.86	5.93	5.92

B. Steam Generator Compartments

For the steam generator compartment, the worst case break was determined to be the 129-square inch shutdown cooling line break. The pressure transient response is presented in figure 6.2.1-18. The peak differential pressures acting across the primary and secondary shield walls are summarized in table 6.2.1-15. Based on the results of nodal sensitivity studies performed for other plants, the nodalization of the steam generator compartment was increased from a maximum of 15 nodes at the construction permit stage to the current 55 nodes. These nodal boundaries were located radially and axially at all positions that could have significant pressure differentials or could contribute significantly to the loads on a piece of equipment. A nodal sensitivity study was performed on the present 55-node model. Pressure, force, and moment values from the 55-node model were compared to the values obtained from 41 and 47 node models. This study indicates negligible difference between the values in each model. The results are summarized in table 6.2.1-20. The inertial version of COPDA was used in the analysis.

C. Pressurizer Compartment

The response of the pressurizer compartment to postulated surge line break is presented in figure 6.2.1-19.

6.2.1.3 Mass and Energy Release Analysis for Postulated Loss-of-Coolant Accidents

A. The design basis LOCA is the double-ended discharge leg slot break. The mass/energy releases used in conjunction with the COPATTA computer code are as follows:

1. Decay heat (see table 6.2.1-21).
   4070 MWt analyzed core power:

   1979 ANS 5-1 decay heat with 2σ added for entire analyzed transient.

2. Metal water reaction included in blowdown containment P/T calculation. (See table 6.2.1-22)

3. Mass energy release data Table 6.2.1-4. (See table 6.2.1-23)

4. Spillage data (See table 6.2.1-24)

5. Miscellaneous energies (See table 6.2.1-25)

   (a) Energy stored in core

   (b) Energy stored in R.V. internals

   (c) Energy stored in R.V metal

   (d) Energy stored in pressurizer, primary piping, valves, and pumps

   (e) Energy stored in steam generator tubes

   (f) Energy stored in steam generator secondary walls

(g) Secondary coolant internal energy in Steam Generators No. 1 and No. 2

B. Additional energy releases:
Energy of steam in main steam line up to the MSIVs

4070 MWt analyzed core power:

= 9.8974×10^6 Btu (included in table 6.2.1-25).

6.2.1.4 Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures Inside Containment

The MSLB methodology used for the PVNGS analysis is discussed in section 6.2.1.1.3.B.3 and 6.2.1.1.3.C.2 as follows. The PVNGS specific steam line arrangement was used for determining flow from the intact steam generator to the containment prior to isolation. The steam line model considered choking at the MSIV throat and cross-connect piping as well as at the venturi throat. The MSIV and MFIV closure times were 4.6 and 9.6 seconds, respectively.

The PVNGS specific mass and energy release data for the most severe MSLB containment pressure and temperature cases are given in table 6.2.1-4.

Table 6.2.1-21
DECAY HEAT
3990 MWt CORE POWER
Decay heat used for calculation of containment pressure / temperature during LOCA
Based on 1979 ANS 5.1 Standard plus two sigma uncertainty
(used in Bechtel computer codes ; COPATTA)

Time	Decay heat
(sec)	BTU / Hr
1.00E+02	4.74E+08
2.00E+02	4.14E+08
3.00E+02	3.83E+08
4.00E+02	3.63E+08
6.00E+02	3.34E+08
8.00E+02	3.12E+08
1.00E+03	2.96E+08
2.00E+03	2.42E+08
4.00E+03	1.94E+08
6.00E+03	1.70E+08
8.00E+03	1.57E+08
1.00E+04	1.47E+08
2.00E+04	1.29E+08
4.00E+04	1.08E+08
6.00E+04	9.73E+07
8.00E+04	8.98E+07
1.00E+05	9.33E+07
2.00E+05	7.80E+07
4.00E+05	6.54E+07
6.00E+05	5.29E+07
8.00E+05	4.44E+07
1.00E+06	3.79E+07
2.00E+06	2.80E+07

Table 6.2.1-22

METAL-WATER REACTION[a] AT 102% OF 3990 MWt CORE POWER

Time (sec)	Energy (Btu/h)
0	4.166 E8
24	4.166 E8
24	0
1E6	0

a. All metal-water reaction energy is assumed to be input to the reactor water during initial blowdown.

Table 6.2.1-23
MASS AND ENERGY RELEASES AT 102% OF 3990 MWt CORE POWER
(Sheet 1 of 3)

TIME (SEC)	MASS (LBM/HR)	ENERGY (BTU/HR)	COMMENTS
0.00	0.00E+00	0.00E+00	start of blow down
0.01	2.85E+08	1.61E+11	
0.02	2.82E+08	1.59E+11	
0.03	2.83E+08	1.60E+11	
0.04	2.86E+08	1.61E+11	
0.05	2.88E+08	1.63E+11	
0.06	3.02E+08	1.70E+11	
0.07	2.95E+08	1.66E+11	
0.08	2.99E+08	1.69E+11	
0.09	4.68E+08	2.64E+11	
0.10	4.43E+08	2.50E+11	
0.15	4.63E+08	2.63E+11	
0.20	4.34E+08	2.47E+11	
0.25	4.47E+08	2.54E+11	
0.30	4.33E+08	2.46E+11	
0.35	4.36E+08	2.48E+11	
0.40	4.29E+08	2.44E+11	
0.45	4.34E+08	2.46E+11	
0.50	4.27E+08	2.42E+11	
0.60	4.22E+08	2.40E+11	
0.70	4.21E+08	2.39E+11	
0.80	4.13E+08	2.35E+11	
0.90	4.10E+08	2.33E+11	
1.00	4.06E+08	2.31E+11	
1.50	3.60E+08	2.08E+11	
2.00	3.01E+08	1.77E+11	
2.50	2.69E+08	1.59E+11	
3.00	2.37E+08	1.39E+11	
3.50	2.19E+08	1.29E+11	
4.00	2.10E+08	1.24E+11	
5.00	1.85E+08	1.14E+11	
6.00	1.30E+08	9.25E+10	
7.00	1.24E+08	8.69E+10	
8.00	1.08E+08	7.82E+10	
9.00	9.04E+07	6.94E+10	
10.00	7.20E+07	6.03E+10	
11.00	5.50E+07	5.09E+10	

Table 6.2.1-23
MASS AND ENERGY RELEASES AT 102% OF 3990 MWt CORE POWER
(Sheet 2 of 3)

TIME (SEC)	MASS (LBM/HR)	ENERGY (BTU/HR)	COMMENTS
12.00	3.23E+07	3.50E+10	
13.00	3.18E+07	2.89E+10	
14.00	5.38E+07	3.15E+10	
15.00	5.07E+07	2.17E+10	
16.00	3.94E+07	1.47E+10	
16.50	4.27E+07	1.55E+10	
16.60	1.78E+07	6.45E+09	
16.70	1.64E+07	6.00E+09	
16.80	1.45E+07	5.35E+09	
16.90	1.33E+07	4.92E+09	
17.00	1.22E+07	4.52E+09	
17.10	1.11E+07	4.10E+09	
17.11	0.00E+00	0.00E+00	End of blow down
1.711E+01	0.00E+00	0.00E+00	Start of reflood
17.11	0.00E+00	0.00E+00	
17.20	5.56E+05	7.26E+08	
20.20	3.16E+06	4.10E+09	
21.00	3.31E+06	4.27E+09	
21.01	1.92E+06	2.48E+09	
23.10	1.93E+06	2.48E+09	
26.00	1.94E+06	2.47E+09	
28.90	1.94E+06	2.46E+09	
31.80	1.93E+06	2.45E+09	
34.70	1.93E+06	2.44E+09	
37.60	1.92E+06	2.42E+09	
40.50	1.91E+06	2.41E+09	
43.40	1.90E+06	2.39E+09	
46.40	1.89E+06	2.38E+09	
49.30	1.88E+06	2.36E+09	
52.20	1.86E+06	2.34E+09	
55.10	1.85E+06	2.33E+09	
58.00	1.84E+06	2.31E+09	
60.79	1.83E+06	2.29E+09	
60.80	3.15E+06	3.95E+09	
68.10	3.10E+06	3.88E+09	

Table 6.2.1-23
MASS AND ENERGY RELEASES AT 102% OF 3990 MWt CORE POWER
(Sheet 3 of 3)

TIME (SEC)	MASS (LBM/HR)	ENERGY (BTU/HR)	COMMENTS
75.30	3.05E+06	3.81E+09	
82.60	3.00E+06	3.74E+09	
89.80	2.95E+06	3.67E+09	
97.00	2.90E+06	3.60E+09	
104.30	2.85E+06	3.53E+09	
111.50	2.80E+06	3.46E+09	
118.80	2.75E+06	3.39E+09	
126.00	2.66E+06	3.14E+09	
133.20	2.46E+06	2.91E+09	
140.50	2.29E+06	2.70E+09	
147.70	2.13E+06	2.52E+09	
155.00	1.98E+06	2.34E+09	
162.20	1.84E+06	2.18E+09	
169.40	1.71E+06	2.02E+09	End of reflood and start of post reflood
169.50	1.74E+06	2.08E+09	
170.40	1.68E+06	1.97E+09	
172.40	1.67E+06	1.99E+09	
175.40	1.60E+06	1.88E+09	
179.40	1.54E+06	1.83E+09	
184.40	1.44E+06	1.70E+09	
190.40	1.26E+06	1.49E+09	
197.30	1.28E+06	1.51E+09	
205.30	1.01E+06	1.20E+09	
214.30	9.86E+05	1.16E+09	
224.20	7.39E+05	8.72E+08	
235.20	6.95E+05	8.20E+08	
247.10	7.43E+05	8.77E+08	
260.10	5.62E+05	6.64E+08	
274.00	5.34E+05	6.30E+08	
288.90	4.11E+05	4.85E+08	End of post reflood

Table 6.2.1-24
SPILLAGE - AT 102% OF 3990 MWt CORE POWER

TIME Sec	MASS LBM/HR	ENERGY BTU/ HR
0	1.42E+07	1.27E+09
17.1	1.42E+07	1.27E+09
17.11	1.60E+07	1.43E+09
21.0	1.60E+07	1.43E+09
21.0	6.02E+07	5.58E+09
23.0	5.58E+07	5.19E+09
25.0	5.21E+07	4.87E+09
30.0	4.57E+07	4.30E+09
30.0	3.15E+07	3.03E+09
31.9	2.90E+07	2.81E+09
35.9	2.53E+07	2.49E+09
41.9	2.09E+07	2.09E+09
45.9	1.84E+07	1.87E+09
51.9	1.52E+07	1.59E+09
55.9	1.33E+07	1.42E+09
59.9	1.15E+07	1.26E+09
61.9	2.14E+06	1.88E+08
71.9	2.24E+06	1.97E+08
81.9	2.34E+06	2.06E+08
91.9	2.44E+06	2.14E+08
99.9	2.52E+06	2.22E+08
115.9	2.68E+06	2.36E+08
125.0	2.75E+06	2.75E+08
135.0	2.97E+06	3.68E+08
145.0	3.15E+06	4.54E+08
155.0	3.31E+06	5.35E+08
165.0	3.46E+06	6.11E+08
169.4	3.56E+06	6.45E+08
169.4	5.69E+06	1.22E+09
184.4	6.30E+06	1.39E+09
194.4	5.82E+06	1.26E+09
210.0	5.20E+06	1.09E+09
230.0	5.09E+06	1.06E+09
250.0	4.84E+06	9.95E+08
270.0	4.37E+06	8.65E+08
288.9[1]	3.89E+06	7.35E+08
288.9+[2]	4.61E+06[3]	4.05E+08
1403[4]	4.61E+06[3]	4.05E+08
1403+[2]	7.38E+05[5]	1.08E+08
5400	7.38E+05[5]	1.36E+08

Table 6.2.1-25

MISCELLANEOUS AND ADDITIONAL ENERGY RELEASES[a]
At 102% OF 3990 MWt CORE POWER

Time (sec)	Energy (Btu/h)
0	0
289	0
289	4.83E+06
36,000	4.83E+06
36,000	2.01E+06
86,400	2.01E+06
86,400	1.80E+06
216,000	1.80E+06
216,000	0
2.6E6	0

a. All miscellaneous energy added after blowdown ends, up to 2.5 days (216,000 seconds).

6.2.1.5 Minimum Containment Pressure Analysis for ECCS Performance Analysis

6.2.1.5.1 Introduction and Summary

Appendix K to 10 CFR 50[8] lists the required and acceptable features of Emergency Core Cooling System (ECCS) evaluation models. Included in the list is the requirement that the containment pressure used in the evaluation of ECCS performance not exceed a pressure calculated conservatively for that purpose. This section describes the analyses that determined the minimum containment pressure used in the Palo Verde 1, 2 and 3 ECCS performance analyses presented in subsection 6.3.3.

6.2.1.5.2 Method of Calculation

The calculations reported in this section used the NRC-approved 1999EM version of the Westinghouse Electric Company LLC large break LOCA evaluation model for Combustion Engineering designed PWRs[9, Supplement 4-P-A]. In the evaluation model, the CEFLASH-4A computer program[10] determines the mass and energy released to the containment during the blowdown phase of the postulated LOCA. The COMPERC-II computer program[11] determines both the mass and energy released to the containment during the refill/reflood phase of the LOCA and the minimum containment pressure response used in the ECCS performance analysis.

A minimum containment pressure analysis was completed to support an "ECCS break spectrum analysis" for implementation of replacement steam generators with 10% tube plugging and simplified head assembly for ZIRLO™ clad fuel rods for a

thermal power of 4070 MWt. This analysis bounds PVNGS units utilizing Zircaloy-4 clad material.

6.2.1.5.3 Input Parameters

The input for the minimum containment pressure analysis for Palo Verde 1, 2 and 3 presented herein is consistent with the input used in the ECCS performance analyses described in UFSAR section 6.3.3.

6.2.1.5.3.1 Mass and Energy Release Data. The mass and energy released to the containment for the limiting large break LOCA for peak clad temperature, the 0.6 DEG/PD break (Double Ended Guillotine break in Pump Discharge), are listed as a function of time in Table 6.2.1-26. The mass and energy released to the containment for the limiting large break LOCA for maximum clad oxidation and core-wide cladding oxidation, 0.8 DEG/PD, are similar in nature. The quantity of safety injection fluid that spills from the break is discussed in paragraph 6.2.1.5.3.5.

6.2.1.5.3.2 Initial Containment Internal Conditions. The initial containment internal conditions used in the "break spectrum" are:

Temperature	50°F (minimum)
Pressure	13.2 psia (minimum)[a]
Relative Humidity	100% (maximum)

For each parameter, the conservative direction with respect to minimizing the containment pressure appears in parentheses.

a. This pressure is less than Technical Specification minimum. Minimum pressure is conservative.

Table 6.2.1-26

(Page 1 of 4)

MASS AND ENERGY RELEASE DATA FOR THE
MINIMUM CONTAINMENT PRESSURE ANALYSES FOR ECCS PERFORMANCE
BREAK SPECTRUM ANALYSIS RESULTS FOR THE 0.6 DEG/PD BREAK

A. BLOWDOWN PHASE

Time, sec	Mass Flow Rate, lbm/sec	Energy Release Rate, BTU/sec	Integral of Mass Flow Rate, lbm	Integral of Energy Release Rate, BTU
0.00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00
0.13	7.6266E+04	4.0259E+07	9.0885E+03	4.7605E+06
0.25	7.5029E+04	3.9819E+07	1.8125E+04	9.5464E+06
0.51	7.3108E+04	3.8924E+07	3.7194E+04	1.9687E+07
1.01	7.2082E+04	3.8426E+07	7.3442E+04	3.9002E+07
2.01	6.5486E+04	3.5044E+07	1.4298E+05	7.6126E+07
3.01	5.4975E+04	2.9657E+07	2.0250E+05	1.0809E+08
4.01	4.7688E+04	2.5980E+07	2.5426E+05	1.3616E+08
5.01	4.3001E+04	2.3806E+07	2.9977E+05	1.6113E+08
6.00	3.6207E+04	2.0735E+07	3.3920E+05	1.8329E+08
7.00	3.2078E+04	1.9057E+07	3.7296E+05	2.0302E+08
8.00	2.9558E+04	1.7959E+07	4.0372E+05	2.2151E+08
9.00	2.6837E+04	1.6600E+07	4.3193E+05	2.3881E+08
10.00	2.5112E+04	1.5609E+07	4.5772E+05	2.5483E+08
11.00	2.3986E+04	1.4960E+07	4.8225E+05	2.7010E+08
12.00	2.2763E+04	1.4284E+07	5.0562E+05	2.8471E+08
13.00	2.1021E+04	1.3469E+07	5.2756E+05	2.9859E+08
14.00	1.6996E+04	1.1935E+07	5.4687E+05	3.1141E+08
15.00	1.1046E+04	9.7825E+06	5.6069E+05	3.2221E+08
16.00	8.6026E+03	8.6155E+06	5.7030E+05	3.3135E+08
17.00	7.0548E+03	7.6845E+06	5.7812E+05	3.3950E+08
18.00	4.7825E+03	5.4596E+06	5.8411E+05	3.4624E+08
19.00	6.5719E+03	5.8528E+06	5.8939E+05	3.5165E+08
20.01	8.8766E+03	5.9361E+06	5.9756E+05	3.5783E+08
21.00	6.2404E+03	3.3906E+06	6.0526E+05	3.6251E+08
21.76	3.8759E+03	1.9283E+06	6.0893E+05	3.6442E+08

Table 6.2.1-26

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MASS AND ENERGY RELEASE DATA FOR THE
MINIMUM CONTAINMENT PRESSURE ANALYSES FOR ECCS PERFORMANCE
BREAK SPECTRUM ANALYSIS RESULTS FOR THE 0.6 DEG/PD BREAK

B. REFLOOD PHASE (Values are for steam only)

Time, sec	Mass Flow Rate, lbm/sec	Energy Release Rate, BTU/sec	Integral of Mass Flow Rate, lbm	Integral of Energy Release Rate, BTU
21.76	0.0000E+00	0.0000E+00	6.0893E+05	3.6442E+08
26.76	0.0000E+00	0.0000E+00	6.0893E+05	3.6442E+08
31.76	0.0000E+00	0.0000E+00	6.0893E+05	3.6442E+08
36.76	0.0000E+00	0.0000E+00	6.0893E+05	3.6442E+08
41.76	2.4537E+02	3.2091E+05	6.0949E+05	3.6516E+08
46.76	2.3519E+02	3.0759E+05	6.1069E+05	3.6672E+08
51.76	2.3988E+02	3.1374E+05	6.1188E+05	3.6828E+08
56.76	2.3873E+02	3.1224E+05	6.1307E+05	3.6984E+08
61.76	2.3484E+02	3.0715E+05	6.1425E+05	3.7139E+08
66.76	2.3176E+02	3.0313E+05	6.1542E+05	3.7291E+08
71.76	2.2942E+02	3.0008E+05	6.1657E+05	3.7442E+08
76.76	2.2730E+02	2.9730E+05	6.1772E+05	3.7591E+08
81.76	2.2685E+02	2.9671E+05	6.1885E+05	3.7740E+08
86.76	2.2434E+02	2.9343E+05	6.1998E+05	3.7887E+08
91.76	2.2265E+02	2.9123E+05	6.2110E+05	3.8033E+08
96.76	2.2150E+02	2.8972E+05	6.2221E+05	3.8179E+08
101.76	2.2046E+02	2.8836E+05	6.2331E+05	3.8323E+08
106.76	2.1933E+02	2.8688E+05	6.2441E+05	3.8467E+08
111.76	2.1833E+02	2.8557E+05	6.2550E+05	3.8610E+08
116.76	2.1932E+02	2.8686E+05	6.2660E+05	3.8753E+08
121.76	2.1754E+02	2.8454E+05	6.2769E+05	3.8896E+08
126.76	2.1649E+02	2.8316E+05	6.2877E+05	3.9038E+08
131.76	2.1598E+02	2.8250E+05	6.2985E+05	3.9179E+08
136.76	2.1557E+02	2.8195E+05	6.3093E+05	3.9320E+08
141.76	2.1519E+02	2.8146E+05	6.3201E+05	3.9461E+08
146.76	2.1485E+02	2.8102E+05	6.3309E+05	3.9602E+08
151.76	2.1453E+02	2.8059E+05	6.3416E+05	3.9742E+08
156.76	2.1420E+02	2.8017E+05	6.3523E+05	3.9882E+08
161.76	2.1405E+02	2.7997E+05	6.3630E+05	4.0022E+08
166.76	2.1474E+02	2.8085E+05	6.3738E+05	4.0163E+08
171.76	2.1413E+02	2.8006E+05	6.3845E+05	4.0303E+08
176.76	2.1355E+02	2.7930E+05	6.3952E+05	4.0443E+08
181.76	2.1345E+02	2.7915E+05	6.4059E+05	4.0583E+08
186.76	2.1332E+02	2.7899E+05	6.4165E+05	4.0722E+08
191.76	2.1320E+02	2.7882E+05	6.4272E+05	4.0862E+08

Table 6.2.1-26

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MASS AND ENERGY RELEASE DATA FOR THE
MINIMUM CONTAINMENT PRESSURE ANALYSES FOR ECCS PERFORMANCE
BREAK SPECTRUM ANALYSIS RESULTS FOR THE 0.6 DEG/PD BREAK

B. REFLOOD PHASE (Values are for steam only)

Time, sec	Mass Flow Rate, lbm/sec	Energy Release Rate, BTU/sec	Integral of Mass Flow Rate, lbm	Integral of Energy Release Rate, BTU
196.76	2.1308E+02	2.7866E+05	6.4379E+05	4.1001E+08
201.76	2.1296E+02	2.7851E+05	6.4485E+05	4.1140E+08
206.76	2.1285E+02	2.7836E+05	6.4592E+05	4.1280E+08
211.76	2.1274E+02	2.7822E+05	6.4698E+05	4.1419E+08
216.76	2.1263E+02	2.7807E+05	6.4804E+05	4.1558E+08
221.76	2.1253E+02	2.7793E+05	6.4911E+05	4.1697E+08
226.76	2.1242E+02	2.7779E+05	6.5017E+05	4.1836E+08
231.76	2.1230E+02	2.7763E+05	6.5123E+05	4.1975E+08
236.76	2.1339E+02	2.7905E+05	6.5229E+05	4.2114E+08
241.76	2.1284E+02	2.7833E+05	6.5336E+05	4.2253E+08
246.76	2.1263E+02	2.7795E+05	6.5442E+05	4.2392E+08
251.76	2.1240E+02	2.7765E+05	6.5548E+05	4.2531E+08
256.76	2.1216E+02	2.7733E+05	6.5655E+05	4.2670E+08
261.76	2.1186E+02	2.7693E+05	6.5761E+05	4.2808E+08
266.76	2.1172E+02	2.7675E+05	6.5866E+05	4.2947E+08
271.76	2.1171E+02	2.7672E+05	6.5972E+05	4.3085E+08
276.76	2.1167E+02	2.7667E+05	6.6078E+05	4.3223E+08
281.76	2.1162E+02	2.7660E+05	6.6184E+05	4.3362E+08
286.76	2.1157E+02	2.7653E+05	6.6290E+05	4.3500E+08
291.76	2.1151E+02	2.7644E+05	6.6396E+05	4.3638E+08
296.76	2.1144E+02	2.7635E+05	6.6501E+05	4.3776E+08
301.76	2.1137E+02	2.7625E+05	6.6607E+05	4.3915E+08
306.76	2.1130E+02	2.7615E+05	6.6713E+05	4.4053E+08
311.76	2.1123E+02	2.7606E+05	6.6818E+05	4.4191E+08
316.76	2.1117E+02	2.7596E+05	6.6924E+05	4.4329E+08
321.76	2.1109E+02	2.7587E+05	6.7030E+05	4.4467E+08
326.76	2.1102E+02	2.7577E+05	6.7135E+05	4.4605E+08
331.76	2.1096E+02	2.7568E+05	6.7241E+05	4.4743E+08
336.76	2.1089E+02	2.7558E+05	6.7346E+05	4.4880E+08
341.76	2.1081E+02	2.7548E+05	6.7451E+05	4.5018E+08
346.76	2.1074E+02	2.7538E+05	6.7557E+05	4.5156E+08
351.76	2.1066E+02	2.7527E+05	6.7662E+05	4.5293E+08
356.76	2.1058E+02	2.7516E+05	6.7767E+05	4.5431E+08
361.76	2.1050E+02	2.7504E+05	6.7873E+05	4.5569E+08
366.76	2.1042E+02	2.7493E+05	6.7978E+05	4.5706E+08

Table 6.2.1-26

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MASS AND ENERGY RELEASE DATA FOR THE
MINIMUM CONTAINMENT PRESSURE ANALYSIS FOR ECCS PERFORMANCE
BREAK SPECTRUM ANALYSIS RESULTS FOR THE 0.6 DEG/PD BREAK

B. REFLOOD PHASE (Values are for steam only)

Time, sec	Mass Flow Rate, lbm/sec	Energy Release Rate, BTU/sec	Integral of Mass Flow Rate, lbm	Integral of Energy Release Rate, BTU
371.76	2.1084E+02	2.7547E+05	6.8083E+05	4.5844E+08
376.76	2.1064E+02	2.7521E+05	6.8189E+05	4.5982E+08
381.76	2.1052E+02	2.7504E+05	6.8294E+05	4.6119E+08
386.76	2.1041E+02	2.7489E+05	6.8399E+05	4.6257E+08
391.76	2.1030E+02	2.7474E+05	6.8504E+05	4.6394E+08
396.76	2.1019E+02	2.7459E+05	6.8610E+05	4.6532E+08
401.76	2.1008E+02	2.7443E+05	6.8715E+05	4.6669E+08
406.76	2.0996E+02	2.7427E+05	6.8820E+05	4.6806E+08
411.76	2.0982E+02	2.7408E+05	6.8925E+05	4.6943E+08
416.76	2.0966E+02	2.7386E+05	6.9030E+05	4.7080E+08
421.76	2.0946E+02	2.7360E+05	6.9134E+05	4.7217E+08
426.76	2.0922E+02	2.7328E+05	6.9239E+05	4.7354E+08
431.76	2.0906E+02	2.7305E+05	6.9344E+05	4.7490E+08
436.76	2.0905E+02	2.7304E+05	6.9448E+05	4.7627E+08
441.76	2.0903E+02	2.7300E+05	6.9553E+05	4.7763E+08
446.76	2.0898E+02	2.7293E+05	6.9657E+05	4.7900E+08
451.76	2.0892E+02	2.7284E+05	6.9762E+05	4.8036E+08
456.76	2.0885E+02	2.7274E+05	6.9866E+05	4.8173E+08
461.76	2.0878E+02	2.7264E+05	6.9970E+05	4.8309E+08
466.76	2.0870E+02	2.7254E+05	7.0075E+05	4.8445E+08
471.76	2.0863E+02	2.7243E+05	7.0179E+05	4.8582E+08
476.76	2.0856E+02	2.7233E+05	7.0283E+05	4.8718E+08
481.76	2.0848E+02	2.7222E+05	7.0388E+05	4.8854E+08
486.76	2.0840E+02	2.7211E+05	7.0492E+05	4.8990E+08
491.76	2.0833E+02	2.7200E+05	7.0596E+05	4.9126E+08
496.76	2.0824E+02	2.7189E+05	7.0700E+05	4.9262E+08
501.76	2.0816E+02	2.7176E+05	7.0804E+05	4.9398E+08
506.76	2.0807E+02	2.7164E+05	7.0909E+05	4.9534E+08
511.76	2.0799E+02	2.7153E+05	7.1013E+05	4.9670E+08
516.76	2.0791E+02	2.7141E+05	7.1117E+05	4.9805E+08
521.76	2.0783E+02	2.7130E+05	7.1221E+05	4.9941E+08

6.2.1.5.3.3 Containment Volume. The net free containment volume used in the analysis is 3,000,000 ft^3 which is the maximum value including all uncertainties.

6.2.1.5.3.4 Active Heat Sinks. In order to conservatively maximize the heat removal capacity of the containment active heat sinks, the containment sprays were modeled with a minimum actuation time following the LOCA and to operate at their maximum capacity.

The operating parameters used for the containment sprays in the "break spectrum analysis" are as follows:

Number of pumps	2
Flow rate	5250 gpm/pump
Actuation time	30 sec after LOCA
Temperature	60°F

6.2.1.5.3.5 Steam Water Mixing. The effect on containment pressure due to condensing containment steam with spilled ECCS water was calculated in the manner described in Section III.D.2 of reference 9 (CENPD-132P, Volumes I and II). The effective ECCS spillage rate is shown as a function of time in Figure 6.2.1-21 for the "break spectrum analysis." The spillage rate was conservatively determined using the maximum flow rate from two high pressure and two low pressure safety injection pumps and initiating the safety injection pump flow when the downcomer was refilled by the safety injection tanks.

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 1 of 15)
A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
Containment Building					
Liner Plate	Inorganic (0.004)	Carbon Steel	0.25	96,600	5
Dome Walls	N/A	Concrete	41.75	33,500	5
Cylinder Walls	N/A	Concrete	47.75	58,200	5
Cylinder Walls (Buttress Section)	N/A	Concrete	77.75	4,900	5
Basemat	Organic (0.010)	Concrete	159.00	11,000	10
Containment Equipment Hatch and Personnel Locks					
Equipment Hatch, Flange, Ring	Inorganic (0.004)	Carbon Steel	0.50	1,000	15
Plates, Guide Beam Plates	Inorganic (0.004)	Carbon Steel	1.50	900	15
	Inorganic (0.004)	Carbon Steel	2.00	105	15
Personnel Locks: (Normal, 140 ft. el and Emergency, (100 ft. el)	Inorganic (0.004)	Carbon Steel	3.00	95	15
	Inorganic (0.004)	Carbon Steel	3.50	160	15
	Inorganic (0.004)	Carbon Steel	4.00	230	15
Internal Structures, Concrete					
Sealed Walls	Sealer Neglected	Concrete	6*	4,200	15
	Sealer Neglected	Concrete	12*	6,000	15
	Sealer Neglected	Concrete	18*	12,000	15

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 2 of 15)
A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
	Sealer Neglected	Concrete	24*	43,000	15
	Sealer Neglected	Concrete	33*	1,600	15
	Sealer Neglected	Concrete	47.14*	2,800	15
Refueling Pool					
Liner Plate	N/A	Stainless Steel	0.1875	11,265	5
Sealed Walls and Floor	Sealer Neglected	Concrete	24*	9,600	5
	Sealer Neglected	Concrete	60	265	5
	Sealer Neglected	Concrete	78	700	5
	Sealer Neglected	Concrete	35*	14,615**	5
Sealed Floor Slabs above Steel Decking	Sealer Neglected	Concrete	18.00	1,760	15
	Sealer Neglected	Concrete	30.00	1,200	15
	Sealer Neglected	Concrete	36.00	3,200	15
Internal Steel Decking (w/coating), Floor Slab Decking (18 Gauge)	Inorganic (0.004)	Carbon Steel	0.0478	14,000	15
NSSS Supports					
Steam Generator foundations	N/A	Concrete	72.00	1,300	5
Reactor Vessel Shield Plugs					

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 3 of 15)
A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
1) Liner Plate	Inorganic (0.004)	Carbon Steel	0.50	450	5
2) Plug	N/A	Concrete	21.00	450	5
SI Tank pads	N/A	Concrete	78.00	970	5
Pressurizer beams	N/A	Concrete	20.00	450	5
Miscellaneous Pads, Brackets, Missile Shields, etc.	N/A	Concrete	12.00	2,000	10
Internal Structures, Metal					
Gratings (galvanized)	Galvanize neglected	Carbon Steel	0.0835	62,500	5
	Galvanize neglected	Carbon Steel	0.1373	17,000	5
Uninsulated Structural Internals					
Columns and RSG Aux Crane	Inorganic (0.004)	Carbon Steel	0.75 (avg)*	8,600	5
Stops	Inorganic (0.004)	Carbon Steel	1.50*	2,700	5
RSG Runway Supports (N1)	Inorganic (0.004)	Carbon Steel	2.00	67	20
RSG Runway Supports	Inorganic (0.004)	Carbon Steel	1.00*	30	20
RSG Runway Supports	Inorganic (0.004)	Carbon Steel	0.75*	53	20
Polar Crane Bridge	Epoxy (assume no paint)	Carbon Steel	0.50	17,544	20
Girders and Brackets	Inorganic (0.004)	Carbon Steel	2.0*	15,500	5
Cable Tray Supports	Inorganic (0.004)	Carbon Steel	0.053*	18,512	10
	Inorganic (0.004)	Carbon Steel	0.25	3	10
Conduit Supports	Inorganic (0.004)	Carbon Steel	0.053*	13,745	10

Table 6.2.1-27

PASSIVE HEAT SINKS

FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 4 of 15)

A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
	Inorganic (0.004)	Carbon Steel	0.125*	6	20
	Inorganic (0.004)	Carbon Steel	0.25*	1	20
HVAC Support	Inorganic (0.004)	Carbon Steel	0.15*	2,200	10
	Inorganic (0.004)	Carbon Steel	0.25*	700	10
Miscellaneous Structural Steel (including work platforms, stairs, ladders, etc.)	Inorganic (0.004)	Carbon Steel	0.15*	53,646	20
	Inorganic (0.004)	Carbon Steel	0.25*	45,011	20
	Inorganic (0.004)	Carbon Steel	0.44*	-4	20
	Inorganic (0.004)	Carbon Steel	0.50*	9859	10
	Inorganic (0.004)	Carbon Steel	0.56*	8	20
	Inorganic (0.004)	Carbon Steel	0.80*	8,207	10
	Inorganic (0.004)	Carbon Steel	1.00*	21	20
	Inorganic (0.004)	Carbon Steel	1.25*	-1	10
	Inorganic (0.004)	Carbon Steel	1.375*	-2	10
	Inorganic (0.004)	Carbon Steel	2.0*	-1	10
	Inorganic (0.004)	Carbon Steel	0.15	28	20
	Inorganic (0.004)	Carbon Steel	0.25	128	20
	Inorganic (0.004)	Carbon Steel	0.38	8	20
	Inorganic (0.004)	Carbon Steel	0.50	1	20
	Inorganic (0.004)	Carbon Steel	0.70*	198	20
	Inorganic (0.004)	Carbon Steel	0.75	743	20

Table 6.2.1-27

PASSIVE HEAT SINKS

FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 5 of 15)

A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
	Inorganic (0.004)	Carbon Steel	1.00	68	20
	Inorganic (0.004)	Carbon Steel	0.09	7	20
Cold Leg Bumper Block Removed	Inorganic (0.004)	Carbon Settl	4.00	-19	20
Sheet Metal Seals (DMWO 2822654)	None	Stainless Steel	0.075	375	25
Others					
HVAC Ducting					
1) 18 ga	Galvanize neglected	Carbon Steel	0.050	2,028	20
2) 16 ga	Galvanize neglected	Carbon Steel	0.063	9,950	20
3) 14 ga	Galvanize neglected	Carbon Steel	0.080	5,600	20
4) 13 ga	Galvanize neglected	Carbon Steel	0.10	6,200	20
5) 12 ga	Galvanize neglected	Carbon Steel	0.125	377	20
6) Larger	Galvanize neglected	Carbon Steel	0.250	2,100	20
Electrical Equipment					
1) Conduit (N2, N3)	Galvanize neglected	Carbon Steel	0.154	31,072	15
	Galvanize neglected	Carbon Steel	0.13	62	20
	Galvanize neglected	Carbon Steel	0.11	9	20
	Galvanize neglected	Carbon Steel	0.24	-2	20

Table 6.2.1-27

PASSIVE HEAT SINKS

FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 6 of 15)

A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
2) Tray Supports, Fixture Boxes, Panels, Wireway etc. (N2, N3)	Galvanize neglected	Carbon Steel	0.0747	55,465	20
	Galvanize neglected	Carbon Steel	0.105	106,572	20
	Galvanize neglected	Carbon Steel	0.05	20	20
3) Cable Tray Supports	Assume neglected	Carbon Steel	0.25	3	20
Piping, Uninsulated					
1″ sch 80, 160 & 2″ sch 40, 160	Inorganic (0.004)	Carbon Steel	0.25 (avg)	3,000	20
2 ½″ sch 40	Inorganic (0.004)	Carbon Steel	0.12	120	20
3″ sch 160	Inorganic (0.004)	Carbon Steel	0.438	92	20
4″ sch 40	Inorganic (0.004)	Carbon Steel	0.237	1,350	20
6″ sch 40	Inorganic (0.004)	Carbon Steel	0.28	520	20
8″ sch 20	Inorganic (0.004)	Carbon Steel	0.25	300	20
8″ sch 40	Inorganic (0.004)	Carbon Steel	0.322	450	20
10″ sch 20	N/A	Stainless Steel	0.25	1,562	20
10″ sch 40	N/A	Stainless Steel	0.365	890	20
14″ sch 20	N/A	Stainless Steel	0.312	400	20
Misc	N/A	Stainless Steel	0.13	-6	20
Misc	N/A	Stainless Steel	0.15	-2	20
Tubing	N/A	Stainless Steel	0.07	22	20

Table 6.2.1-27

PASSIVE HEAT SINKS

FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 7 of 15)

A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
Pipe Supports (other)	Inorganic (0.004)	Carbon Steel	0.25*	6	5
Pipe Supports (other)	Inorganic (0.004)	Carbon Steel	0.375*	2	5
Pipe Supports (other)	Inorganic (0.004)	Carbon Steel	0.63	1	5
Pipe/Tubing Supports (other)	Inorganic (0.004)	Carbon Steel	0.38	-70	5
Pipe/Tubing Supports (other)	Inorganic (0.004)	Carbon Steel	0.31	2	5
Pipe/Tubing Supports (other)	Inorganic (0.004)	Carbon Steel	0.25	87	5
Pipe/Tubing Supports (other)	Inorganic (0.004)	Carbon Steel	0.19	9	5
Pipe Supports (other)	N/A	Carbon Steel	0.13	-8	5
Pipe/Tubing Supports (other)	Inorganic (0.004)	Carbon Steel	0.09	-1	5
Pipe/Tubing Supports (other)	Inorganic (0.004)	Carbon Steel	0.11	8	10
Pipe/Tubing Supports (other)	Inorganic (0.004)	Carbon Steel	0.50	20	10

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 8 of 15)
A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
Misc. Metal Components					
Polar Cranes, Reactor Cavity Sump Pumps, Radwaste Sump Pumps, SG Wet Lay Up Recirc Pumps, Containment Bldg. Momo-Hoist, CEDM Normal ACU Units, Containment Normal Duct Heaters, Containment Tendon Gallery, Exhaust Fan, Damper Motors, Rx. Cavity Normal CCU Fan; Man Basket Test Weight Associated Rigging	N/A (assumed)	Carbon Steel	1.0 (assumed)	28,682	20
Polar Crane	N/A	Carbon Steel	1.0	500	20
Crane Man Basket	N/A	Stainless Steel	0.375	58	20
Safety Injection Tanks	N/A	Stainless Steel	1.865	5,735	5
RCP Motor	Assume No Paint	Stainless Steel	0.5 (assumed)	5,264	5
RCP Air-Water Heat Exchanger	Assume No Paint	Stainless Steel	0.5 (assumed)	901	5
RCP Air-Water Heat Exchanger Coil Assembly Housing	Assume No Paint	Stainless Steel	0.5 (assumed)	397	5
RCP Air-Water Heat Exchanger Coil Assembly Coils	Assume No Paint	Stainless Steel	0.5 (assumed)	0.4	5

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 9 of 15)
A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
RCP Upper Bearing Oil Cooler Coil Assembly	Copper Tubing, Filled w/Water	Copper	0.5 (assumed)	50	5
RCP Lower Bearing Oil Cooler Coil Assembly	Copper Tubing, Filled w/Water	Copper	0.5 (assumed)	21	5
Pre-Access Normal AFU	Assume No Paint	Carbon Steel	0.25	2,677	5
UGS Lift Rig	No	Stainless Steel	0.41*	2,076	20
Core Support Barrel Lift Rig	No	Stainless Steel	0.41*	43	20
Multi Stud Tensioner	Yes	Carbon Steel	1.14*	1,236	20
Single Stud Tensioner	Yes	Carbon Steel	2.15*	87	20
Reactor Drain Tank	N/A	Stainless Steel, Water Filled	0.19	354	10
Refueling Machine	Yes	Carbon Steel	0.30*	3,285	20
Recirc. Strainer Cartridges & End Seals	N/A	Stainless Steel	0.023*	18,466	5
Recirc. Strainer Side Supports	N/A	Stainless Steel	0.15*	792	5
Recirc. Strainer Duct Assemblies	N/A	Stainless Steel	0.09*	709	5
Recirc. Strainer Floor Plate	N/A	Stainless Steel	0.15*	1,097	5
Recirc. Strainer 6WF Frame	N/A	Carbon Steel	0.20	759	5

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 10 of 15)
A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
Recirc. Strainer Floor Joists	N/A	Stainless Steel	0.23	1,051	5
D Ring Penetration Seals	N/A	Stainless Steel	0.075	128	20
CEA Indicator Rods	N/A	Stainless Steel	0.13	123	10
Component Tags	N/A	Stainless Steel	0.0625*	300	0
Refueling Machine Upender Drive Handrail	N/A	Stainless Steel	0.15	29	5
GraviGate & CEDM Grease Lines	N/A	Stainless Steel	0.15	16	20
DMWO 2314788					
Containment Shielding Lead Storage Boxes	No	Stainless Steel Boxes Filled w/Lead	5.8	930	5
Scaffold Material	Galvanized	Carbon steel	0.097	7,740	5
DMWO 3095435 Changes for SHA Modifications*					
ACU Fan Casing Extensions	Inorganic	Carbon Steel	0.375	-403	15
Collector Ring Support Structure & Spreader/Lift Rig	Inorganic	Carbon Steel	0.47	-1,910	15
Support Structure at 181 ft Elevation Collector Ring Storage Platform	Inorganic	Carbon Steel	0.69	-1,462	15

* The results are also applicable to the Palo Verde plant configuration without SHA implementation. Also, the associated DMWO 2992340 for the Replacement Reactor Vessel Closure Head (RRVCH) has been determined to have no impact on the ECCS Performance Analysis.

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 11 of 15)
A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
Structural Angles for 181 ft Collector Ring Platform	Inorganic	Carbon Steel	0.33	-438	15
Grating (floor) for 181 ft Collector Ring Platform	Inorganic	Carbon Steel	0.19	-400	15
Support Knee Braces (4) for East and West Vertical Ducts	Inorganic	Carbon Steel	0.34	-140	15
Top Head Manifold/Cooling Plenum/Insulation Quads	Inorganic	Stainless Steel	0.13	-983	15
ORVCH Tripod (including Delta Beam)	Inorganic	Carbon Steel	1.88	-265	15
HLR lifting shroud and work platform	Inorganic	Carbon Steel	0.83	-1,134	15
ACU Lifting Frame	Inorganic	Carbon Steel	0.79	-1,208	15
Platform Extension on Concrete Missile Shield	Inorganic	Carbon Steel	0.27	-4,865	15
Miscellaneous Removed from Cable Support Structure	Inorganic	Carbon Steel	0.31	-80	15
ACU/MS Lifting Rig	Inorganic	Carbon Steel	1.19	1,341	5
Modifications to ACU	Inorganic	Carbon Steel	0.22	426	5
ACU Support Steel	Inorganic	Carbon Steel	0.77	5,060	5

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 12 of 15)
A. Detailed Listing

Item	**Paint Type and Thickness (in.)**	**Material**	**Thickness (in)**	**Surface Area (ft^2)**	**Uncertainty in Area (+/-%)**
Head Lifting Rig	Inorganic	Carbon Steel	1.67	683	5
Top & Middle Shrouds	Inorganic	Stainless Steel	0.27	776	5
Lower Shroud	Inorganic	Stainless Steel	1.5	213	5
Duct & Platform Assembly	Inorganic	Carbon Steel	0.33	2,050	5
Duct Assembly (Riser Ducts)	Inorganic	Stainless Steel	0.16	929	5
Miscellaneous Hardware	Inorganic	Carbon Steel	0.45	71	5
Assemblies added to the Reactor Vessel Missile Shield Relocated Storage Area and Riser Duct Storage Area	Inorganic	Carbon Steel	1.28	184	5
Assemblies added to the Reactor Vessel Missile Shield Relocated Storage Area and Rise Duct Storage Area	Inorganic	Carbon Steel	0.54	17	5

Notes:

* Half thickness

** For modeling purposes, 700 ft^2 of this heat sink is lined with 0.1875” stainless steel

Table 6.2.1-27

PASSIVE HEAT SINKS

FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 13 of 15)

B. Modeling of Heat Sinks for Computer Input

Wall No.	Description and Boundary Condition(3)	Material	Thickness(1) (ft)	Exposed Surface Area(2) (ft^2)
1	Containment Cylinder and Dome Inside surface exposed to containment atmosphere. Outside surface exposed to ambient atmosphere.	Concrete Carbon Steel	3.862 0.0208	101430
2	Internal Concrete, Unlined Total surface exposed to containment atmosphere.	Concrete	1.622	107804
3	Internal Concrete, Carbon Steel Lined Total surface exposed to containment atmosphere.	Concrete Carbon Steel	1.158 0.00409	7557
4	Internal Concrete, Stainless Steel Lined Total surface exposed to containment atmosphere.	Concrete Stainless Steel	2.101 0.01563	11828
5	Galvanized Steel Total surface exposed to containment atmosphere.	Galvanized Steel	0.00785	358096
6	Stainless Steel Total surface exposed to containment atmosphere.	Stainless Steel	0.00501	58141
7	Carbon Steel, less than 0.5 inch thick Total surface exposed to containment atmosphere.	Carbon Steel	0.00987	161720
8	Carbon Steel, greater than or equal to 0.5 inch thick Total surface exposed to containment atmosphere.	Carbon Steel	0.07230	57669
9	Basemat Inside surface exposed to containment sump water. Outside surface exposed to earth.	Concrete	13.25	12100
10	Unpainted Carbon Steel Total surface exposed to containment atmosphere.	Carbon Steel	0.042	73078

Notes:

(1) Thickness is effective thickness as a result of combining similar thickness walls.
(2) As modeled surface area which includes uncertainty.
(3) Modeling of inorganic painted heat sinks for computer input uses 0.003 inches for conservatism.

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 14 of 15)
C. Bank Account Information

Bank Account Listing	**Item**	**Exposed Surface Area (ft^2)**	**Thickness (in)**	**Uncertainty**	**Max Exposed Surface Area (ft^2)**
Wall 6 Stainless Steel	BA 6.1	2000	015	0.2	2400
	BA 6.2	4500	0.25	0.2	5400
	BA 6.3	2000	0.5	0.2	2400
	BA 6.4	2000	1	0.2	2400
Wall 7 Carbon Steel < 0.5 in. with paint	BA 7.1	3500	0.15	0.2	4200
	BA 7.2	1000	0.25	0.2	1200
Wall 8 Carbon Steel > 0.5 in. with paint	BA 8.1	1000	0.5	0.2	1200
	BA 8.2	1000	1	0.2	1200
Wall 10 Carbon Steel unpainted	BA 10.1	3500	0.15	0.2	4200
	BA 10.2	1000	0.25	0.2	1200
	BA 10.3	1000	0.5	0.2	1200
	BA 10.4	1000	1	0.2	1200
Wall 5 Galvanized Steel	BA 5.1	4480	0.096	0.05	4704

Table 6.2.1-27
PASSIVE HEAT SINKS
FOR ECCS PERFORMANCE MINIMUM CONTAINMENT PRESSURE ANALYSIS (Sheet 15 of 15)
D. Thermal Physical Properties

Material	Density (lb_m/ft^3)	Specific Heat (Btu/lb_m °F)	Thermal Conductivity (Btu/hr ft °F)	Volumetric Heat Capacity (Btu/ft^3 °F)
Inorganic paint	170	0.12	1.0	20
Carbon steel	490	0.11	25.0	54
Concrete	143	0.21	0.8	30
Organic paint	60	0.33	0.1	20
Stainless steel	490	0.11	10.0	54

6.2.1.5.3.6 Passive Heat Sinks. For the "break spectrum analysis," the surface areas and thickness of all exposed containment passive heat sinks are listed in Table 6.2.1-27. To maximize the heat transfer to the passive heat sinks, the surface areas were modeled at the maximum of their uncertainty ranges and their thermal properties (conductivity and heat capacity) were maximized. Table 6.2.1-27 also describes how they were modeled into ten equivalent walls for the COMPERC-II computer code.

6.2.1.5.3.7 Heat Transfer to Passive Heat Sinks. The condensing heat transfer coefficient between the containment atmosphere and the passive heat sinks was calculated in the manner described in Section III.D.2 and Figure III.D.2-2 of reference 9 (CENPD-132P, Volumes I and II). The variation of the condensing heat transfer coefficient is shown as a function of time in Figure 6.2.1-25, for the "break spectrum analysis."

6.2.1.5.3.8 Containment Purge System. The effects of the 8-inch power access purge system was evaluated in an earlier minimum containment analysis. The power access purge system was assumed to be operating at the time of the postulated LOCA. The purge system isolation valves are fully closed 8.0 seconds after a containment isolation actuation signal generated by high containment pressure (5.0 psig). It is assumed that only dry air is removed from the containment atmosphere through the purge system. This conservatively minimized the calculated containment pressure. Analysis has shown operation of containment purge system has negligible effect on results. This conclusion remains applicable to the latest analysis.

6.2.1.5.4 Results

For the limiting large break LOCA, the 0.6 DEG/PD break, the minimum containment pressure response for the ECCS "break spectrum" analysis is shown in Figure 6.2.1-22 and Figure 6.3.3.2-3F. The responses of the containment atmosphere and containment sump temperatures are shown in Figures 6.2.1-23 and 6.2.1-24 respectively, for the "break spectrum analysis" limiting break size.

The containment response is used in the ECCS performance analyses presented in Section 6.3.3.

6.2.1.6 Testing and Inspection

Testing and inspection requirements for the containment are discussed in subsection 6.2.6. No other testing of the containment structure is planned or required. Testing and inspection requirements for other engineered safety features that interface with the containment structure are discussed along with the applicable system descriptions.

6.2.1.7 Instrumentation Applications

The containment pressure is measured by independent pressure transmitters located at widely separated points outside the containment. Refer to section 7.3 for a discussion of pressure as an input to the engineered safety features actuation system (ESFAS). Refer to section 7.5 for a discussion of the display instrumentation associated with pressure.

The containment airborne radioactivity is monitored by the airborne radioactivity monitoring system, discussed in

section 11.5. Hydrogen concentration is monitored in the containment by the hydrogen monitoring system, discussed in subsection 6.2.5. Temperature sensors are positioned at appropriate locations throughout the containment. The temperature is displayed in the main control room along with high-temperature alarms.

6.2.1.8 Qualification Parameters for In-Containment, Safety-Related Equipment

In-containment, safety-related equipment required to operate post-MSLB is qualified to the main steam line break design basis accident environment as specified in Appendix A of the Equipment Qualification Program Manual. The results shown in Appendix A of the Equipment Qualification Program Manual are of a containment analysis for a 102% power, 7.16-square foot, slot-type main steam line break, with the loss of one containment spray train and no loss of offsite power. It differs from the analysis of the main steam line break of paragraph 6.2.1.1.3.1 in that the equipment qualification analysis utilizes 8% condensate reevaporation as allowed by Appendix B of NUREG-0588[5].

In-containment, safety-related equipment required to operate post-LOCA is qualified to the LOCA design basis accident environment as specified in Appendix A of the Equipment Qualification Program Manual. This environment bounds the calculated pressure-time and temperature-time response of figure 6.2.1-3 which shows the worst case LOCA transient as discussed in paragraph 6.2.1.1.3.1, listing D.

6.2.1.9 References

1. Shoenhoff, H. M. and Braddy, R. W., "Containment and Safety-Related Equipment Transient Temperature Analysis Following a Main Steam Line Break," Bechtel Power Corporation, May 1975.

2. BN-TOP-4, Rev. 1, Oct. 1977, Subcompartment Pressure and Temperature Transient Analysis, Bechtel Power Corporation, San Francisco, CA.

3. Idel'chik, I. E., Handbook of Hydraulic Resistance (AEC-TR-6630), 1966.

4. ASHRAE Handbook of Fundamentals, 1972.

5. Interim Staff Position of Environmental Qualification of Safety-Related Electrical Equipment (NUREG-0588), December 1979.

6. Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Cooled Nuclear Power Reactors, Federal Register, Vol. 39, No. 3 - Friday, January 4, 1974.

7. "Calculative Methods for the C-E Large Break LOCA Evaluation Model for the Analysis of CE and W designed NSSS," CENPD-132, Supplement 3-PA, June 1985 (Proprietary)

8. Code of Federal Regulations, Title 10, Part 50, Appendix K, "ECCS Evaluation Models."

   ABB-CE Software verification and validation Report #00000 –AS95- cc – 010, Rev 0. Computer Code SGN III. Dated 12/17/1995

9. CENPD-132P, Volumes I and II, "Calculative Methods for the C-E Large Break LOCA Evaluation Model," August 1974.

CENPD-132P, Supplement 1, "Calculational Methods for the C-E Large Break LOCA Evaluation Model," February 1975.

CENPD-132P, Supplement 2-P, "Calculational Methods for the C-E Large Break LOCA Evaluation Model," July 1975.

CENPD-132, Supplement 3-P-A, "Calculative Methods for the C-E Large Break LOCA Evaluation Model for the Analysis of C-E and W Designed NSSS," June 1985.

CENPD-132, Supplement 4-P-A, "Calculative Methods for the CE Engineering Technology Large Break LOCA Evaluation Model," March 2001.

10. CENPD-133P, "CEFLASH-4A, A FORTRAN-IV Digital Computer Program for Reactor Blowdown Analysis," August 1974.

CENPD-133P, Supplement 2, "CEFLASH-4A, A FORTRAN-IV Digital Computer Program for Reactor Blowdown Analysis (Modifications)," February 1975.

CENPD-133, Supplement 4-P, "CEFLASH-4A, A FORTRAN-IV Digital Computer Program for Reactor Blowdown Analysis," April 1977.

CENPD-133, Supplement 5-A, "CEFLASH-4A, A FORTRAN77 Digital Computer Program for Reactor Blowdown Analysis," June 1985.

11. CENPD-134P, "COMPERC-II, A Program for Emergency Refill-Reflood of the Core," August 1974.

CENPD-134P, Supplement 1, "COMPERC-II, A Program for Emergency Refill-Reflood of the Core (Modifications)," February 1975.

CENPD-134, Supplement 2-A, "COMPERC-II, A Program for Emergency Refill-Reflood of the Core," June 1985.

12. CENPD-140A, “Description of the CONTRANS Digital Computer Code for Containment Pressure and Temperature Transient Analysis,” June 1976.

13. ABB CENP Calculation No. 00000-ST99-CC-013, Rev. 00, “Software Verification and Validation Report – CONTRANS2 version ctn2ml.0699,” July 20, 1999.

14. WESTINGHOUSE Software Verification and Validation Report, 00000-ST98-CC-021, Rev. 001, Computer Code SGN III. July 30, 1999.

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6.2.2 CONTAINMENT HEAT REMOVAL SYSTEMS

The functional performance objective of the containment spray system (CSS) as an engineered safety feature system is to reduce the containment temperature and pressure following a LOCA, MSLB accident, by removing thermal energy from the containment atmosphere. This cooling system also serves to limit offsite radiation levels by reducing the pressure differential between the containment atmosphere and the external environment, thereby diminishing the driving force for leakage of fission products from the containment to the environment.

6.2.2.1 Design Bases

The design bases for the containment spray system are:

A. The CSS shall be designed to rapidly reduce the containment pressure and temperature following a LOCA or MSLB, and maintain these parameters at acceptably low levels as required by NRC General Design Criterion 38. The sources and amounts of energy released to the containment that were used as the basis for the sizing of the containment spray system are given as functions of time in subsection 6.2.1.

B. The spray system shall consist of two redundant and independent trains each of which provides 100% of the required heat removal capability and 100% of the required iodine removal capability.

C. The heat removal capacity of the system shall be sufficient to keep the containment pressure and

temperature below design conditions for any size break in the reactor coolant system piping up to and including a double-ended break of the largest reactor coolant pipe. The system also is designed to mitigate the consequences of any size break in the main steam line piping, up to and including a double-ended break of the main steam line from a single steam generator. During recirculation, the system shall continue to reduce containment pressure and temperature and maintain them at acceptable levels. For the containment design basis accident, the containment spray system shall be designed to reduce containment pressure from peak value to one-half peak value in less than 24 hours.

D. The portions of the containment heat removal system located inside containment shall be designed to remain operable in the containment accident environment.

E. The CSS shall be designed such that a single failure of any active component will not degrade the system ability to fulfill design objectives.

Each train of the CSS shall receive power from a separate emergency diesel generator in the event that off-site power is unavailable during an accident. The two trains shall be physically separated from each other so that a failure in one train will not result in failure of the other train due to fire, flooding, jet impingement, or missiles.

Each train shall receive separate actuation signals. Critical plant parameters shall be monitored and the actuation signals shall be produced in the ESFAS.

F. The CSS shall be designed to Seismic Category I requirements.

G. The CSS shall be protected against dynamic effects associated with postulated rupture of piping as discussed in section 3.6.

H. The CSS is designed to permit the periodic inspection and testing as described in the plant Technical Specifications and Technical Requirements Manual.

I. The CSS shall be designed rapidly reduce fission product iodine concentration in the containment atmosphere.

J. System sizing shall be based on the long-term heat rejection function of the system. The CSS shall use the shutdown cooling heat exchangers to reject heat from the containment.

Protection of the CSS from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Principal design codes and standards are given in table 3.2-1.

6.2.2.2 System Design

Piping and instrumentation diagrams and spray header arrangements of the CSS are provided in engineering drawings 01, 02, 03-M-SIP-001, -002, and –003 and 13-P-ZCG-114. A table of the design and performance data for the system is provided below.

CONTAINMENT SPRAY PUMPS

Quantity	2
Type	Centrifugal, vertical single stage
Safety Class	2
Code	ASME III, Class 2
Design Pressure, psig	650
Design Temperature, °F	400
Design Flow Rate, gpm	3890
Design Head, feet	505
Maximum Flow Rate, gpm	5200
Head at Maximum Flow Rate, feet	473 max/380 min
Shutoff Head, feet	690 max/640 min
NPSH Required, feet	20 at 5200 gal/min
Design Suction Pressure, psig	485
Maximum Suction Operating Pressure, psig	320
Material	Stainless Steel
Pumped Fluid	2.5% w/o boric acid (4400 ppmB)
Rated Motor Horsepower/Pump	800

Motor Voltage, volts	4000, 3 phase
SPRAY NOZZLES	(Reference Section 6.5.2.3)
Number (for two spray headers)	460 (primary) 80 (auxiliary)
Type	Non-clogging
Flow, per nozzle	15.2 gpm at 40 psid 3 gpm at 40 psid

Table 7.3-11A shows plant protection signals and setpoints that actuate the CSS.

The assumed delay times following postulated accidents are tabulated in Table 6.2.1-10. A discussion of the delay times following receipt of the actuation signals is provided in section 7.3.

A description of the qualification tests performed on system components is provided in CESSAR Sections 3.10 and 3.11. Environmental test conditions, as shown in CESSAR Figure 3.11A-1, are representative of post-accident conditions as described in subsection 6.2.1.

Fan systems for post-accident containment heat removal are not employed at PVNGS.

6.2.2.2.1 CONTAINMENT RECIRCULATION SUMP SCREENS

The general guidance of NEI 04-07, Pressurized Water Reactor Sump Performance Evaluation Methodology, is used to comply with requirements of GL 2004-02 for strainer sizing evaluations for

the replacement sump strainers installed under DMWO 2822654. The guidance document, NEI 04-07, has been reviewed by the NRC for use in sump strainer sizing evaluations for Pressurized Water Reactors, with the review documented in an SE dated December 6, 2004. The assumption of 50 percent blockage and approximate coolant velocity of 6cm/sec (0.2 ft/sec) described in Regulatory Guide 1.82 are no longer used for strainer sizing evaluations. The vertical and horizontal surfaces of the strainer is accounted for in the determination of total available surface area(this is an exception to Regulatory Guide 1.82). The design features of the recirculation intake structures (sumps) comply with Regulatory Guide 1.82, with the exceptions noted above, and include the following features:

A. Two independent sumps and screens are provided, one for each safety-related train.

B. Physically separated sumps preclude simultaneous damage to both strainers.

C. Sumps located in the lowest floor of the containment building, at elevation 80 feet 0 inch, are protected by cassette strainer assemblies with integral trash rack. The strainers are placed within a 3-inch high curb and atop a sub-floor covering the sump opening at elevation 80 feet 0 inch.

D. The floor level in the sump vicinity slopes toward local floor drains. In addition, to preclude surface waste from plugging the screens, a 3-inch curb is provided around the perimeter of the sub-floor.

E. The 3-inch curb around the sumps also provides protection from surface drains. No drains from upper regions impinge on the screen assemblies.

F. The strainer assemblies consist of horizontal cassette pockets made of perforated plate that provide the screen area. Each pocket is approximately 3 inches wide by 5 inches high, and the leading edge is solid plate, which acts as an integral trash rack to protect the perforated portion of the pocket from debris. See figure 6A-5

G. With the horizontal cassette pocket (specialty) design, the strainers consist of both vertical and horizontal flow paths through the screening elements. All pockets are submerged at the minimum post-LOCA flood level. Since the new strainers are approximately 3,142 ft^2 vs. the original 210 ft^2 screens, design coolant velocity at the new strainer is less than that for the original screens.

H. The top of the strainer assemblies is a solid (non-perforated) plate and will be submerged during the recirculation mode of operation at minimum water level conditions.

I. The strainer cassettes (with integral trash rack) are designed to withstand the vibrating motion of seismic events without loss of structural integrity.

J. The holes in the perforated plate of the strainers are 0.083 inches in diameter, which satisfies original C-E requirements on sump screen design (0.09 inches

maximum). No flow blockage will occur beyond the screen as all openings are larger than the minimum screen size.

K. The pump intake is designed to minimize vortexing and other degrading effects on pump inlets.

L. The strainer assemblies are fabricated from austenitic stainless steel and zinc-coated carbon steel. Both materials have a low sensitivity to spray-induced corrosion and will not be adversely affected by periods of inactivity.

M. A manhole is provided in the strainer assembly sub-floor to facilitate access into the sump and suction intake structures.

N. The manhole facilitates access for inspection of strainer parts accessible from below the sub-floor. Adequate space is provided around the strainers to facilitate unobstructed inspection of the outside strainers.

O. There are no high energy lines located in the vicinity of the emergency sumps which could interfere with the successful operation when required.

6.2.2.2.2 INSULATION IN CONTAINMENT

Identification of the reflective piping insulation and quantities used within the containment are listed in table 6.2.2-1.

The insulation is designed to be non-reactive under the following LOCA conditions:

Ambient temperature	140 to 350F
Relative humidity	Saturated steam/air mixture
Air velocity	0 to 300 ft/min
Radiation	3.3 x 107 rads integrated dosage
Chemical	Up to 4400 ppm boron, pH 4-10
Pressure	60 psig

Metallic, reflective-type insulation type 304, stainless steel is attached to the piping and components as two half-segments with quick release latches or by expansion-type metal bands. Mirror and reflective insulation is by Diamond Power Corporation and TRANSCO, respectively.

NUKON nonmetallic thermal insulation is used for the pressurizer. NUKON insulation is also installed on portions of the pressurizer spray line, the main feedwater line, and the blowdown line at pipe support locations. Table 6.2.2-2 indicates the location and quantity of NUKON insulation used in containment. NUKON insulation consists of high temperature fibrous glass insulation, enclosed in woven fibrous glass fabric. The fabric completely encloses the wool insulation, and its seams are sewn with fibrous glass thread. The blanket is enclosed in stainless steel wire mesh and the NUKON insulation is attached with heavy-duty Velcro fasteners. The uninsulated portion of piping at the support locations for the pressurizer spray line and selected uninsulated support locations for the blowdown line and main feedwater line are also wrapped with NUKON thermal insulation to avoid heat loss

at the junction of metallic insulation and the pipe supports. Due to this composition, density of the system varies with thickness. Therefore, a more accurate representation of density is in pounds per square foot. A 4-inch thick NUKON blanket will weigh an average of 1.8 to 2.2 pounds per square foot (with knitted wire mesh, add 0.2 to 0.3 pound per square foot). NUKON insulation is manufactured by Owens-Corning Fiberglass Corporation.

Table 6.2.2-1

REFLECTIVE PIPING INSULATION USED WITHIN CONTAINMENT IN UNITS WITH ORIGINAL STEAM GENERATORS

Nominal Pipe Dia (in.)	Length (ft)	Use	Attachment Method
28	710	Main Steam	Quick release latches or expansion type metal bands
24	290	Main Feedwater	Quick release latches or expansion type metal bands
14	60	Main Feedwater	Quick release latches or expansion type metal bands
6	280	Steam Generator Blowdown	Quick release latches or expansion-type metal bands
4[b]	130	Downcomer Blowdown	Quick release latches or expansion-type metal bands
4	60	Feedwater Recirculation	Quick release latches or expansive-type metal bands
12	540	Safety Injection	Quick release latches or expansive-type metal bands
14	160	Safety Injection	Quick release latches or expansive-type metal bands
16	290	Shutdown cooling	Quick release latches or expansive-type metal bands

a. 4-inch thick insulation is assumed for listed pipes.

b. Line size is 6-inch in Unit 2 only.

Table 6.2.2-2

NUKON INSULATION USED IN CONTAINMENT

Nominal Pipe Dia. (in.)	Quantity[(a)] (ft^3)	Use
NA	48	Top head area of the pressurizer
4	22	Pressurizer spray line
24	74	Main feedwater line
4[(c)]	24[(b)]	Blowdown lines

a. 4-inch thick insulation is assumed for all listed pipes.

b. Quantity includes NUKON installed on SG blowdown lines and Transco THERMAL-WRAPS® insulation system installed on downcomer blowdown lines. Unit 2 volume is 21ft^3.

c. Unit 2 only is 6-inch

The NUKON system will not be reduced to fine fiber because of the spray or radiation conditions of a LOCA. This has been demonstrated in the Owens-Corning Fiberglass Corporation Topical Report OCF-1: Nuclear Containment Insulation System (Final NRC Staff Evaluation, dated December 8, 1978).

Transco THERMAL-WRAP® insulation system consists of a lightweight fiberglass blanket. The THERMAL-WRAP® insulation system is designed for use in nuclear power plant containments

and uses materials that have been fully tested and qualified for use in nuclear power plants. It is similar in design and construction to the NUKON nonmetallic insulation systems and will not be reduced to fine fiber because of the spray or radiation conditions of a LOCA.

TEMP-MAT nonmetallic thermal insulation is used for the reactor vessel, and pressurizer as spacers between these components and their reflective insulation. The TEMP-MAT insulation is composed of needle-type, porous, fiberglass material that will not disintegrate to a powder form. As such, it is not expected that TEMP-MAT insulation material will form particles small enough to pass through the sump screens. TEMP-MAT is a type of fiberglass insulation enclosed in fiberglass cloth material and attached by pop rivets to the reflective insulation. The 1-1/2-inch thick TEMP-MAT insulation has a density of approximately 1.4 pounds per square foot. The TEMP-MAT insulation is manufactured by Pittsburgh-Corning Corporation. A total of 500 square foot of 1-1/2-inch thick TEMP-Mat insulation is installed on the reactor vessel and pressurizer in quantities of 200, and 300 square feet, respectively.

Nonmetallic insulation on nonreactor coolant pressure boundary components is limited to the normal chilled water system piping with a density of 4 pounds per cubic foot. Four hundred feet of fiberglass insulation is used on 10-inch, 8-inch, and 6-inch chilled water pipe. Nonmetallic insulation (fiberglass) is enclosed in stainless steel sheet and strapped to the component. The fiberglass insulation is manufactured by the CERTAINTEE Company.

6.2.2.3 Design Evaluation

A. The CSS is designed to rapidly reduce the containment pressure and temperature following a LOCA or MSLB. Figures 6.2.1-1 through 6.2.1-6 show the effect of containment spray in event of these accidents. Plan and elevation drawings of the containment showing expected spray coverage are provided in figures 6.5-1 through 6.5-6.

A discussion of containment sprayed volume and spray overlap is provided in paragraph 6.5.2.2. A discussion of the system's heat removal effectiveness is found in Section 3.1.34 Response.

Performance testing of the spray nozzles has verified that they will function as predicted, in terms of flow rate, spray angle, drop size spectrum, and mean drop size as a function of the pressure drop across the nozzles.

A detailed description of the SPRACO nozzle parameters was submitted earlier to the NRC for the Waterford Steam Electric Station, Unit No. 3, Docket No. 50-382.

Analysis of the NPSH of the recirculation pumps in accordance with Regulatory Guide 1.1 is provided in section 6.3 (the same analysis as for high-pressure safety injection (HPSI) pumps). Pump data are tabulated in UFSAR section 6.2.2.2.

B. The containment spray system consists of two redundant and independent trains, each of which is capable of

providing 100% of the required heat removal capability and 100% of the required iodine removal capability.

C. The heat removal capacity of the CSS is discussed in subsection 6.2.1.

D. The containment heat removal system is designed to remain operable in the containment accident environment as discussed in section 3.11.

E. The CSS is designed such that single failure of any active component will not degrade system abilities as shown in the failure modes and effects analyses Table 6.2.2-4 (for further discussion of system actuation, see section 7.3).

F. The entire CSS is designed to Seismic Category I requirements. System components as appropriate are designed to meet ASME Code, Section III, Class 2 requirements.

G. The CSS is protected against dynamic effects associated with postulated rupture of piping as discussed in section 3.6.

H. The CSS is designed to permit the periodic inspections and tests described in the Technical Specifications and the Technical Requirements Manual.

I. The CSS is designed to reduce fission product iodine concentration in the containment atmosphere as discussed in section 6.5.

J. The CSS is sized based on the long-term heat rejection function of the system. The shutdown cooling heat

exchangers used for rejecting heat from the containment are sized by the shutdown cooling function discussed in subsection 5.4.7.

PVNGS does not employ a fan system as part of the containment heat removal system during post-accident conditions.

Graphs of the integrated energy content of the containment atmosphere and recirculation water as functions of time are provided in figures 6.2.l-10, 6.2.1-11, and 6.2.1-12.

6.2.2.4 Test and Inspections

As part of the overall testing program, hydraulic model tests were performed in order to determine the effect of the sump design on vortex phenomena and on entrance and line losses relative to the required NPSH for ESF pumps. The hydraulic testing included taking suction from the original design model sump to verify vortex control and acceptable pressure drops across screening and suction lines and valves.

The preoperational testing of ESF pumps in accordance with Regulatory Guide 1.79 verified operability of the ESF pumps.

In evaluating the net positive suction head available (NPSHA) of safety-related pumps taking suction from the containment recirculation sumps, the head losses obtained from hydraulic model tests performed on the original recirculation sumps and suction piping were combined with conservative analytically calculated head losses of portions of pipe that were not modeled.

In evaluating the NPSHA of safety-related pumps taking suction from the refueling water tank (RWT), the data obtained during the preoperational pump tests was used in conjunction with analytical calculations.

The program for initial performance testing is covered in section 14.2 and CESSAR Appendix 6A, Section 9.0.

6.2.2.5 Instrumentation Requirements

6.2.2.5.1 ACTUATION SIGNALS

The Containment Spray System is automatically actuated by a Containment Spray Actuation Signal from the Engineered Safety Features Actuation System. The CSAS is initiated by a coincidence of two-out-of-four high-high containment pressure signals, or two remote manual signals from the control room, or by loss of power to two-out-of-four actuation logic channels.

The Containment Spray System’s supportive systems are automatically actuated by a Safety Injection Actuation Signal from the Engineered Safety Features Actuation System. The SIAS is generated prior to or coincident with the CSAS by a two-out-of-four high containment pressure signals, or remote manual signals from the control room, or by loss of power to two-out-of-four actuation logic channels. The SIAS is also actuated by low pressurizer pressure signals. Any SIAS will automatically start the containment spray pumps. The Containment Spray System’s suction is automatically changed from the Refueling Water Tank to the Containment Sump by a Recirculation Actuation Signal from the Engineered Safety Features Actuation System. The RAS is generated by two-out-of-four low Refueling Water

Tank level signals, or two remote manual signals in the control room, or by loss of power to two-out-of-four actuation logic channels. Following the RAS, timely operator action is required to isolate the RWT using valves CH-530 and CH-531 to prevent ingress of air in the ESF pump suction piping during switchover to recirculation.

The ESFAS trains are redundant, separate, and diverse. Details of the system are contained in Sections 7.3 and 7.4.

CSS ACTUATION

	SIAS Initiated CSAS Not Initiated	CSAS Initiated
CSP 1, 2	START / RUN	START / RUN
SI-671, 672	CLOSED	OPEN

A SIAS or CSAS starts the Containment Spray Pumps but only a CSAS opens the Spray Header Isolation Valves (SI-672, SI-671).

Separate ESFAS actuation devices are used for the CSP and Spray Header Isolation valve. The design is such that the pump actuation device may be tested separately from the valve actuation device.

The CSAS may be overridden on the component level.

Manual initiation of the CSAS is achieved by the actuation of two separate control switches. Similarly the RAS may be initiated manually by the actuation of two separate control switches. Manual initiation of containment spray actuation and recirculation actuation signals can be accomplished on a component level also.

Control room indications of pump operation and flow delivery are provided by pressure indicators and flow meter in the CSP discharge piping. Alignment of automatic valves is shown in the control room by open-closed indicator lights. Throttling valves are provided with continuous position indication.

6.2.2.5.2 INSTRUMENTATION

Display instrumentation which is available to the operator to allow him to adequately monitor conditions in the Containment Spray System and to perform any required manual safety functions. The information provided is sufficient to allow the operator to accurately assess the conditions within the Containment Spray System and in a timely manner perform those actions to maintain the system within the conditions assumed. In addition, the information allows cross-checking of the instrument channels to assure operational availability and positive indications that pumps and valves have actuated and that flows have been established.

6.2.2.6 System Operation

6.2.2.6.1 OPERATING MODE

6.2.2.6.1.1 Normal Operation

During normal plant operation the CSS is aligned for the injection mode, but does not operate.

6.2.2.6.1.2 Operation During Plant Accident Conditions

6.2.2.6.1.2.1 Injection Mode of Operation

The Containment Spray System is initiated by a containment spray actuation signal (CSAS) which occurs on a two out of four high-high containment pressure signal. The CSAS may also be initiated manually in the control room. The signal starts the containment spray pumps and opens the spray header isolation valves SI-671 and 672 to the containment.

The Safety Injection Actuation Signal (SIAS) automatically starts the containment spray pumps but does not open the spray header isolation valves SI-671 and SI-672.

The specific sequence of pump and valve actuation depends on which power source is available. If offsite power is available, then all equipment may receive power simultaneously. If offsite power is not available, the safeguards loads are divided between the two plant emergency diesel generators and are sequentially started after the diesel generators are running. During the injection mode, the minimum flow lines just downstream of each spray pump are kept open to prevent deadheaded operation. Water which passes through the minimum flow lines is returned to the refueling water tank (RWT).

Once the spray pumps are started and the valves are opened, the spray water flows into the containment spray headers. These headers contain spray nozzles which break the flow into small droplets, thus enhancing the water's cooling effect on the containment atmosphere. As these droplets fall to the containment floor they absorb heat until they reach thermal equilibrium with the containment. When the water reaches the

containment floor it drains to the containment ESF sump where it remains until the recirculation mode begins.

The Containment Spray System utilizes the RWT of the Chemical and Volume Control System. Whenever the CSS availability is required for containment heat removal the RWT contains sufficient borated water to supply both trains of the ESF pumps at their respective maximum flow rates until such time that the pump suction may be realigned to the containment ESF sumps and provide adequate cooling flow to maintain the core covered.

6.2.2.6.1.2.2 Recirculation Mode of Operation

When RWT inventory is reduced to approximately 10% level, a two out of four low RWT level signal will initiate a recirculation actuation signal (RAS). The RAS stops the LPSI pumps, closes e minimum flow line isolation valves (SI-664 and 665, SI-666 and 667, SI-668 and 669, SI-659 and 660), and opens the containment ESF sump isolation valves (SI-673, 674, 675, & 676). Upon indication that transfer to recirculation has occurred, the operator will verify that the LPSI pumps are stopped, and that the flow path from the sump to the suction of the injection pumps is open. Timely operator action is then required to isolate the RWT using valves CH-530 and CH-531 to prevent ingress of air in the ESF pump suction piping during switchover to recirculation. The operator will also check to see that the miniflow isolation valves are closed to prevent depletion of containment ESF sump inventory. The RAS may also be manually initiated at the component level.

6.2.2.6.1.3 Plant Shutdown

The CSS is aligned for injection until shutdown cooling is initiated.

Shutdown cooling is initiated when the Reactor Coolant System temperature and pressure drop below approximately 350°F and 400 psia. An interlock prevents opening of shutdown cooling suction isolation valves if RCS pressure is above 410 psia. The following steps are taken to align the system for shutdown cooling:

a. Unlocking and opening the valves bypassing containment spray flow around the shutdown cooling heat exchangers (SI-688, SI-693).

b. Unlocking and closing the valves isolating the Containment Spray System from the shutdown cooling heat exchangers (SI-684, SI-689, and SI-687, SI-695).

For a normal plant shutdown when Reactor Coolant System temperature is below 200°F (typically 170°F), and RCS pressure less than 250 psia the containment spray pumps can be realigned to provide additional flow through the shutdown cooling heat exchangers. This is done by opening the isolation valves (SI-689, 684) between the containment spray pumps and the shutdown cooling heat exchangers, closing the containment spray bypass valves (SI-688, 693) around the shutdown cooling heat exchangers, isolating the containment spray pumps from the refueling water tank (SI-104, 105) and unlocking and opening the valves (SI-184, 185) connecting the shutdown cooling suction lines to the containment spray pump suction lines.

Shutdown cooling is then continued using the low pressure and containment spray pumps until the refueling temperature of 135°F is attained.

6.2.2.6.1.4 Plant Startup

During cold shutdown, the CS pumps are used for their shutdown cooling function. Prior to commencing plant heatup, the CSS is lined up for emergency operation by closing the CS pump discharge valves (SI-684, 689) to the SDC heat exchangers and opening the CS/SDC heat exchangers bypass valves (SI-688. 693). The RCS is then warmed up to the maximum SDC temperature (approx. 350°F) at which time SDC is secured and the CS to SDC heat exchanger valves are opened and the SDC heat exchanger bypass valves are closed. The CSS is now aligned for the injection mode.

6.2.2.6.1.5 Maintenance

The system is designed to allow maintenance during both normal and post-accident conditions. CSS components are located to allow access for maintenance or manual system realignment of an intact train during recirculation.

TABLE 6.2.2-4

(Sheet 1 of 5)

CONTAINMENT SPRAY SYSTEM FMEA

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
1	Containment Spray Pump Suction Isolation Valve SI 104, SI 105	a) Fails closed	Corrosion, mechanical binding	Effective loss of one containment spray pump	Low flow indication F338, F348; Periodic testing	Parallel redundant containment spray path	Valves are normally locked open
		b) Fails open	Corrosion	No effect on safety operation	Periodic testing	None required	
2	Containment Spray Pump 1, 2	Fails to pump on CSAS	Mechanical failure, Electrical failure	Effective loss of one containment spray path	Low flow indication F 338, F 348; Periodic testing	Parallel redundant containment spray path	
3	Containment Spray Pump Flow Control Valve SI 678 SI 679	a) Fails closed	Corrosion, mechanical binding Electrical failure	Effective loss of one containment spray path	Low flow indication F 338, F 348; Valve position indicator; Periodic testing	Parallel redundant containment spray path	Valves are normally locked open; and design to fail as is; min. flow line will provide the min. flow required to protect the pump during injection phase.
		b) Fails open	Same as 3 a)	No effect on emergency operation	Valve position indicator; Periodic testing	Parallel redundant containment spray and shutdown cooling subsystem	

TABLE 6.2.2-4

(Sheet 2 of 5)

CONTAINMENT SPRAY SYSTEM FMEA

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
4	Shutdown Cooling Heat Exchanger 1, 2	Loss of cooling	Insufficient component cooling water flow, excessive fouling	Diminished ability of susystem to provide temperature, & pressure suppression within the containment during recirculation mode of operation	High temperature indication from T 303X, T 303Y	Parallel redundant containment spray path	
5	Shutdown Cooling/Cont. Spray Isolation Valve SI 687, Si 695 SI 684 SI 689	a) Fails closed	Corrosion, mechanical binding, electrical failure	Effective loss of one containment spray path	Valve position indicator, periodic testing	Parallel redundant containment spray path	Same as 3 a)
		b) Fails open	Mechanical failure, electrical failure	Cannot isolate one containment spray bypass line from one shutdown cooling path when manually switching into post accident shutdown cooling	Valve position indicator; periodic testing	Parallel redundant containment spray and shutdown cooling paths	
6	Containment Spray Header Isolation Valve SI 671 SI 672	a) Fails closed	Corrosion, mechanical binding Electrical failure	Effective loss of one containment spray path	Valve position indicator; periodic testing;	Parallel redundant containment spray path	Valve is normally closed with manual handwheel locked
		b) Fails open	Mechanical failure, Electrical failure	No effect during emergency operation	Valve position indicator; periodic testing	None required	CSAS opens valve-manual handwheel is locked

TABLE 6.2.2-4

(Sheet 3 of 5)

CONTAINMENT SPRAY SYSTEM FMEA

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
7	Containment Spray Nozzles	Nozzle blockage	Foreign objects in containment spray lines, corrosion	No containment spray flow to affected nozzle	Low flow indication F 338, F 348; Periodic testing	Parallel redundant nozzles	The nozzles have an approximately 3/8" spray orifice and will not be subject to clogging by particles less than 1/4" in maximum dimension. The spray solution is completely stable and soluable at all temperatures of interest in the containment and therefore will not precipitate or otherwise interfere with nozzle performance
8	SDCHX Discharge valve SI686 SI696	a) Fails closed	Corrosion, mechanical binding Electrical failure	None	Valve position indicator Periodic testing	None required	Valves are normally locked closed
		b) Fails open	Mechanical failure, Electrical failure	No effect during emergency operation	Valve position operation Periodic testing	Series isolation valve	Valve is normally locked closed

TABLE 6.2.2-4

(Sheet 4 of 5)

CONTAINMENT SPRAY SYSTEM FMEA

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
9	Containment Spray Min. Flow Isolation Valve SI 664, SI 665	a) Fails closed	Electrical failure, mechanical binding, corrosion	Might damage containment spray pump if run dead headed	Periodic testing Valve position indicator	Parallel redundant containment spray subsystem would not be affected.	Valve is normally locked open
		b) Fails open on on RAS	Electrical failure mechanical failure	None	Periodic testing; valve position indicator. The operator is required by the operator procedures to check that the valve is closed at the start of recirculation	Series redundant valve, SI 659 or SI 660 closes on Ras	
10	Containment Spray Pump to Shutdown Heat Exchanger Bypass Line Isolation Valve SI 688, SI 693	a) Fails closed	Electrical failure, mechanical binding, corrosion	Loss of flow to one spray header during Post LOCA shutdown cooling	Valve position indicator periodic testing	Parallel redundant containment spray line	
		b) Fails open	Electrrcal failure mechanical failure	Effectively reduce the cooling capacity of the shutdown heat exchanger	High flow indication F 338, F348; valve position indicator; periodic testing	Same as 9 a)	Valve is normally locked closed

After Containment Spray Actuation Signal (CSAS) is generated the following equipment is actuated

TABLE 6.2.2-4

(Sheet 5 of 5)

CONTAINMENT SPRAY SYSTEM FMEA

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
11	Containment Spray Pump 1, 2	Fails to pump on CSAS	Mechanical failure, electrical failure	Effective loss of one containment spray pump	Low flow indication F 338, F 348; periodic testing	Parallel redundant containment spray path	
12	Containment Spray Header Isolation Valve SI 671, SI 672	a) Fails to open on CSAS	Corrosion, mechanical binding, electrical failure	Effective loss of one containment spray path	Valve position indicator; periodic testing	Parallel redundant containment spray path	
	After Recirculation Actuation Signal (RAS) is generated the following equipment is actuated / operated						
13	Containment Spray Min. Flow Isolation Valve SI 664, SI 665	Fails to close on RAS	Electrical malfunction, mechanical failure	None	Position indicator in the control room The operator is required by the the operating procedures to check that the valve is closed recirculation	Series redundant valve, SI 659 or SI 660 closes on RAS	
14	Min. Flow Line to RWT Isolation Valve SI660, SI659	Fails to close on RAS	Electrical malfunction, mechanical binding	None	Valve position indicator; periodic testing	Series isolation valves	
15	RWT Isolation Valve CH-530, CH-531	Fails to close (manual action)	Electrical malfunction, mechanical failure	Degraded performance of one train of containment spray (if air is entrained)	Valve position indicator; periodic testing	Parallel redundant containment spray path	Timely operator action required to close

6.2.3 SECONDARY CONTAINMENT FUNCTIONAL DESIGN

PVNGS does not utilize a secondary containment design.

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6.2.4 CONTAINMENT ISOLATION SYSTEM

There is no particular system for complete containment isolation; isolation design is achieved by applying acceptable common criteria to the penetrations of fluid systems and by using the Containment Isolation Actuation Signal (CIAS) to automatically actuate the appropriate containment isolation valves. Also see subsection 18.II.E.4.2.

6.2.4.1 Design Basis

6.2.4.1.1 Criteria

Containment isolation is mandatory in the event of certain design basis accidents. A containment isolation actuation signal (CIAS) automatically initiates closure of containment isolation valves. Refer to paragraph 7.3.1.1.10.1 for a discussion of the generation of the CIAS.

Containment Isolation System design is based on the following criteria:

a) Two isolation valves are provided at each containment penetration: one inside the containment, and one outside the containment.

b) Systems which are not required to operate, or which only operate intermittently during normal plant power operation, are isolated at the containment penetration in accordance with General Design Criteria 55 and 56.

c) All containment penetration lines and their associated isolation valves are constructed to Safety Class 2, Seismic Category I standards.

d) The design temperature and pressure of the containment penetration lines and their associated isolation valves meet or exceed containment design conditions.

e) Containment isolation is required to minimize the release of fission products (which is postulated to occur within the Reactor Coolant System (RCS) and the containment) to the environment following a loss of Coolant Accident (LOCA). A CIAS is generated upon an indication that a LOCA has occurred to allow for automatic isolation of lines which are normally open during normal plant operation, and do not function in mitigating the effects of the accident. In particular, this includes lines which are part of the RCS pressure boundary, and through which flow normally leaves the containment. A detailed description of sensed parameters, setpoints, and signal generation, as applied to the CIAS is provided in Section 7.3.

f) The Safety Injection System (SIS) and the Shutdown Cooling System (SCS) are considered to be extensions of the containment pressure boundary following an accident. The portions of the SIS and SCS which are opened to the RCS or containment following an accident are constructed to Safety Class 2, Seismic Category I requirements. In addition, the design temperature and pressure of the subject portions of the SIS and SCS exceed containment design conditions. Details of SIS and SCS design and operation are provided in Sections 6.3 and 5.4.7 respectively.

   Containment isolation valves for these systems are identified in Table 6.2.4-1. Outside the containment isolation boundary, isolation valves are provided between

the portions of these systems handling RCS or containment sump fluid, and the environment. Double isolation is provided where active valves are used. Single isolation is allowable where passive valves (e.g., manual vent valves, manual drain valves, etc.) are used, since they are not subject to single failure criteria.

6.2.4.1.2 System Design Requirements

The containment isolation valves are located to minimize the length of piping between the containment and the valve. The actual piping and valve arrangements are indicated in tables 6.2.4-1 and 6.2.4-2. The test methods, including inservice valve testing, are discussed in paragraph 6.2.4.4.

The following is a summary of Containment Isolation System design features. Incorporation of these features into the Containment Isolation System results in a design where the design requirements for containment isolation barriers given above are met:

a) Containment isolation valves and interconnecting piping are designed and constructed to Safety Class 2 and Seismic Category I standards as defined in ANSI N18.2-1973 and Regulatory Guide 1.29 respectively.

b) Containment isolation valves and interconnecting piping are designed to withstand the effects of earthquakes.

c) Containment isolation valves and interconnecting piping are protected against missiles.

d) Containment isolation valves and interconnecting piping are protected against the effects of pipe whip and jet impingements.

e) The maximum allowable particle size entrained in water taken from the containment sump is limited. This ensures that the proper operation of ESF systems and CIS valves will not be inhibited by debris introduced into the containment following a LOCA.

f) Containment isolation valves are designed to operate under normal environmental conditions and to fulfill their safety related function under post-accident environmental conditions, consistent with the requirements of Section 3.11.

g) Containment isolation valves and associated penetration piping are qualified to Section III of the ASME Code, as Class 2 components, as described in Section 3.9.3.

h) Maximum allowable actuation times are imposed on containment isolation valves (see Table 6.2.4-1) consistent with their required safety function, as described in Table 6.2.4-1.

i) Valve operators and power sources are selected for containment isolation valves (see Table 6.2.4-2) consistent with their required safety function.

j) Valve controls for containment isolation valves are designed to allow valve actuation in accordance with the actuation modes given in Table 6.2.4-2.

k) Means of detecting leakage from the systems associated with containment isolation valves are provided as discussed in Section 5.4.7 for the Shutdown Cooling System, Section 6.3 for the Safety Injection System, and Section 9.3.4 for the Chemical and Volume Control System. Provisions for the detection of leakage in these systems allows the operator to determine when to isolate the affected system or train.

l) Provisions are made to allow the testing of containment isolation valves as described in Section 6.2.4.4.

6.2.4.2 System Design

6.2.4.2.1 General Description

Tables 18.II.E-2 and 18.II.E-3 list all essential and nonessential systems, respectively, penetrating the containment.

Table 6.2.4-1
CONTAINMENT ISOLATION SYSTEM[i] (Sheet 1 of 9)

Penetration Number[g]	Applicable GDC	System/Fluid	Essential System	Valve[a] Arrangement	Line[b] Size (in.)	Valve Number	Valve Location/[c] Distance from Containment (ft)	Type C[d] Leakage Test	Valve [e] Type
1,2,3,4	57	Main steam / steam	No	14	28	SGE-UV170 SGE-UV171 SGE-UV180 SGE-UV181	Outside/34	No	Gate
					6	SGE-PSV691 SGE-PSV692 SGE-PSV694 SGE-PSV695	Outside/8	No	Safety
					6	SGE-PSV575 SGE-PSV576 SGE-PSV557 SGE-PSV558	Outside/11	No	Safety

a. Valve arrangements are shown on figure 6.2.4-1.

b. Line size, inches, represent maximum ID of associated valves (except pressure sensing valves where it represents inlet size).

c. Distance from containment denotes maximum length of pipe from outside containment wall to associated valve.

d. Type C leakage tests are described in subsection 6.2.6.

e. A check valve inside the containment is considered to be an automatic valve for purposes of containment isolation.

f. These penetrations meet the exception clause of GDC 56 which allows for containment isolation acceptability on "some other defined basis" for a specific class of lines. Refer to paragraph 6.2.4.2.1 for a discussion of this basis.

g. Manual vent, drain, and test valves between the Containment Isolation Valves will be maintained locked closed under administrative controls or surveilled closed per Technical Specifications.

h. These penetrations were designed to the requirements of GDC 56 but may be isolated using a blind flange in plant operating modes 1-4. When blind flange is installed, only Type B testing of blind flange is required.

i. For application of the single failure rule to check valves, refer to Section 3.1.30.

j. In Units where DMWO 2529758 has been implemented, valve CHA-UV-715 is removed and valves HPA-UV-023 & HPA-UV-024 are de-terminated with upstream piping cut and capped as the new containment boundary.

k. Deleted

l. In units where DMWO 2778159 has been implemented, applicable valve(s) have been removed.

m. Applicable in those Units where DMWO 4345882 has been implemented.

n. Applicable in those Units where DMWO 4304156 has been implemented.

Symbols:

N.A.	- not applicable	LC	- locked closed
EA	- Class 1E bus A	FO	- fail open
EB	- Class 1E bus B	FC	- fail closed
EC	- Class 1E bus C	FAI	- fail-as-is
ED	- Class 1E bus D	MSIS	- main steam isolation signal
N	- normal power source	CSAS	- containment spray actuation signal
O	- open	CPIAS	- containment purge isolation actuation signal
C	- closed	AFAS	- auxiliary feedwater actuation signal
A	- automatic	SIAS	- safety injection actuation signal
R	- remote operation	RAS	- recirculation actuation signal
M	- manual local operation	CIAS	- containment isolation actuation signal

Table 6.2.4-1

CONTAINMENT ISOLATION SYSTEM[i] (Sheet 2 of 9)

Penetration Number[g]	Applicable GDC	System/Fluid	Essential System	Valve[a] Arrangement	Line[b] Size (in.)	Valve Number	Valve Location/[c] Distance from Containment (ft)	Type C[d] Leakage Test	Valve [e] Type
1,2,3,4	57	Main steam / steam	No	14	6	SGE-PSV574 SGE-PSV577 SGE-PSV556 SGE-PSV559	Outside/15	No	Safety
			No		6	SGE-PSV573 SGE-PSV578 SGE-PSV555 SGE-PSV560	Outside/18	No	Safety
			No		6	SGE-PSV572 SGE-PSV579 SGE-PSV554 SGE-PSV561	Outside/21	No	Safety
			Yes		6	SGA-UV134 SGA-UV138	Outside/54	No	Gate
			Yes		1.5	SGA-UV134A SGA-UV138A	Outside/54	No	Globe
			Yes		12	SGA-HV184 SGB-HV178 SGB-HV185 SGA-HV179	Outside/46	No	Globe
			No		4	SGE-UV169 SGE-UV183	Outside/60	No	Globe
			No		1	SGA-UV1133 SGA-UV1134	Outside/61	No	Globe
			No		1	SGB-UV1135A SGB-UV1135B SGB-UV1136A SGB-UV1136B	Outside/68 Outside/69 Outside/65 Outside/65	No	Globe
			No		1	SGE-V603 SGE-V611	Inside	No	Globe
5		Spare							
6	56	Demineralized water/water	No	35	2	DWE-V061 DWE-V062	Outside/8 Inside	Yes Yes	Globe Globe
7	56	Fire Protection/ water	No	43	6	FPE-V089 FPE-V090	Outside/8 Inside	Yes Yes	Gate Check

Table 6.2.4-1

CONTAINMENT ISOLATION SYSTEM[i] (Sheet 3 of 9)

Penetration Number[g]	Applicable GDC	System/Fluid	Essential System	Valve Arrangement[a]	Line[b] Size (in.)	Valve Number	Valve Location/[c] Distance from Containment (ft)	Type C[d] Leakage Test	Valve[a] Type
8,10	57	Feedwater/ water	No	15	24	SGB-UV132 SGB-UV137	Outside/19	No	Gate
						SGA-UV174 SGA-UV177	Outside/24	No	Gate
						SGE-V003 SGE-V006	Inside	No	Check
						SGE-V007 SGE-V005	Inside	No	Check
9	56	Radwaste/ water	No	34	3	RDA-UV023 RDB-UV024	Inside Outside/4	Yes Yes	Gate Gate
11,12	57	Feedwater/ water	No	15	8	SGE-V652 SGE-V653	Inside	No	Check
			Yes		3/8	SGB-HV200	Outside/14	No	Globe
			No		8	SGE-V642 SGE-V693	Outside/3	No	Check
			Yes		3/8	SGB-HV201	Outside/12	No	Globe
			No		8	SGB-UV130 SGB-UV135	Outside/7	No	Gate
			No		8	SGA-UV172 SGA-UV175	Outside/11	No	Gate
13	55	HPSI/water	Yes	7	3 2 2	SIE-V113 SIB-UV616 SIA-UV617	Inside Outside/59 Outside/66	No No No	Check Globe Globe
14	55	HPSI/water	Yes	7	3 2 2 3	SIE-V123 SIB-UV626 SIA-UV627 SIE-V1024[n]	Inside Outside/40 Outside/39 Outside/22	No No No No	Check Globe Globe Gate
15	55	HPSI/water	Yes	7	3 2 2	SIE-V133 SIB-UV636 SIA-UV637	Inside Outside/34 Outside/45	No No No	Check Globe Globe

Table 6.2.4-1

CONTAINMENT ISOLATION SYSTEM[i] (Sheet 4 of 9)

Penetration Number[g]	Applicable GDC	System/Fluid	Essential System	Valve [a] Arrangement	Line[b] Size (in.)	Valve Number	Valve Location/[c] Distance from Containment (ft)	Type C[d] Leakage Test	Valve[e] Type
16	55	HPSI/water	Yes	7	3	SIE-V143	Inside	No	Check
					2	SIB-UV646	Outside/31	No	Globe
					2	SIA-UV647	Outside/30	No	Globe
					3	SIE-V1027[n]	Outisde/28	No	Gate
17	55	LPSI/water	Yes	1	12	SIE-V114	Inside	No	Check
					12	SIB-UV615	Outside/10	No	Globe
18	55	LPSI/water	Yes	1	12	SIE-V124	Inside	No	Check
					12	SIB-UV625	Outside/12	No	Globe
19	55	LPSI/water	Yes	1	12	SIE-V134	Inside	No	Check
					12	SIA-UV635	Outside/12	No	Globe
20	55	LPSI/water	Yes	1	12	SIE-V144	Inside	No	Check
					12	SIA-UV645	Outside/12	No	Globe
21	56	Containment spray/water	Yes	23	10	SIA-V164	Inside	Yes	Check
					8	SIA-UV672	Outside/3	No	Gate
22	56	Containment spray/water	Yes	23	10	SIB-V165	Inside	Yes	Check
					8	SIB-UV671	Outside/14	No	Gate
23	56	Recirculation / water	Yes	40	24	SIA-UV673	Inside	No	B'fly
					24	SIA-UV674	Outside/4	No	B'fly
					¾	SIA-PSV151	Outside/5	No	Safety
					½	SIA-UV708[l]	Outside/6	No	Globe
24	56	Recirculation / water	Yes	16	24	SIB-UV675	Inside	No	B'fly
					24	SIB-UV676	Outside/5	No	B'fly
					¾	SIB-PSV140	Outside/5	No	Safety
25A	56	Radiation monitor/air	No	33	1	HCB-UV044	Inside	Yes	Globe
					1	HCA-UV045	Outside/4	Yes	Globe
25B	56	Radiation monitor/air	No	33	1	HCB-UV047	Inside	Yes	Globe
					1	HCA-UV046	Outside/5	Yes	Globe
26	55	Shutdown cooling/water	yes	10	16	SID-UV654	Inside	No	Gate
					16	SIB-UV656	Outside/9	No	Gate
					10	SIB-HV690	Outside/33	No	Globe
					6	SIB-PSV189	Inside	No	Safety
27	55	Shutdown cooling /water	Yes	10	16	SIC-UV653	Inside	No	Gate
					16	SIA-UV655	Outside/23	No	Gate
					10	SIA-HV691	Outside/41	No	Globe
					6	SIA-PSV179	Inside	No	Safety

Table 6.2.4-1

CONTAINMENT ISOLATION SYSTEM[i] (Sheet 5 of 9)

Penetration Number[g]	Applicable GDC	System/Fluid	Essential System	Valve Arrangement[a]	Line Size (in.)[b]	Valve Number	Valve Location[c] Distance from Containment (ft)	Type C[d] Leakage Test	Valve[e] Type
28 / (CESSAR 29)	55	Safety injection drain / water	No	12	2 2 ¾	SIA-V682 SIE-V463 SIE-PSV474	Inside Outside/2 Inside	Yes Yes Yes	Globe Globe Safety
29	56	LP nitrogen/ nitrogen	No	19a	1 1	GAE-V015 GAA-UV002	Inside Outside/1	Yes Yes	Check Globe
30	56	HP nitrogen/ nitrogen	No	19b	1 1	GAE-V011 GAA-UV001	Inside Outside/2	Yes Yes	Check Globe
31	56	Instrument air/air	No	29	2 2	IAE-V021 IAA-UV002	Inside Outside/2	Yes Yes	Check Globe
32A	56[f]	CB pressure monitor/air	Yes	37	¾	HCC-HV076	Outside/3	No	Globe
32B	Spare								
32C	Spare								
33	56	Nuclear cooling water/water	No	4	10 10	NCE-V118 NCB-UV401	Inside Outside/2	Yes Yes	Check B'fly
34	56	Nuclear cooling water/water	No	11	10 10 ¾	NCB-UV403 NCB-UV402 NCE-PSV0617	Inside Outside/2 Inside	Yes Yes Yes	B'fly B'fly Relief
35	56	Hydrogen control/air	Yes	2	2 2 1 *	HPA-UV001 HPA-UV003 HPA-HV007A HPA-UV0024[j]	Inside Outside/6 Outside/8 Outside/17	Yes Yes Yes Yes	Globe Globe Globe Globe
36	56	Hydrogen control/air	Yes	2	2 2 1	HPB-UV002 HPB-UV004 HPB-UV008A	Inside Outside/4 Outside/10	Yes Yes Yes	Globe Globe Globe
37A	57	SG blowdown sample/water	No	39	½ ½	SGA-UV211 SGB-UV228	Inside Outside/8	No No	Globe Globe
37B	57	SG blowdown sample/water	No	39	½ ½	SGA-UV204 SGB-UV219	Inside Outside/8	No No	Globe Globe
38	56	Hydrogen control/air	Yes	32	2 2 1 *	HPA-V002 HPA-UV005 HPA-HV007B HPA-UV23[j]	Inside Outside/4 Outside/4 Outside/8	Yes Yes Yes Yes	Check Globe Globe Globe

* Unit #1 is ½"
Units #2 & 3 are 1"

Table 6.2.4-1

CONTAINMENT ISOLATION SYSTEM[i] (Sheet 6 of 9)

Penetration Number[g]	Applicable GDC	System/Fluid	Essential System	Valve Arrangement[a]	Line Size (in.)[b]	Valve Number	Valve Location/ Distance from Containment[c]	Type C Leakage Test[d]	Valve Type[e]
39	56	Hydrogen control/air	Yes	31	2 2 1	HPB-V004 HPB-UV006 HPB-HV008B	Inside Outside/4 Outside/8	Yes Yes Yes	Check Globe Globe
40	55	CVCS letdown/water	No	17	2 2 ½	CHA-UV516 CHB-UV523 CHB-UV924[l]	Inside Outside/42 Outside/46	Yes Yes Yes	Globe Globe Globe
41	55/56	CVCS charging/water	No	8	3 2 3/4	CHE-VM70 CHA-HV524 CHE-V854	Inside Outside/47 Outside/41	Yes Yes Yes	Check Globe Globe
42A	55	Pressurizer sample/water	No	21	3/8 3/8	SSA-UV204 SSB-UV201	Inside Outside/20	Yes Yes	Needle Needle
42B	55	Pressurizer sample/steam	No	21	3/8 3/8	SSA-UV205 SSB-UV202	Inside Outside/22	Yes Yes	Needle Needle
42C	55	Hot leg sample/water	No	21	3/8 3/8	SSA-UV203 SSB-UV200	Inside Outside/17	Yes Yes	Needle Needle
43	55	CVCS/water	No	21	1 1	CHA-UV506 CHB-UV505	Inside Outside/12	Yes Yes	Globe Globe
44	55	CVCS/water	No	6	3 3	CHA-UV560 CHB-UV561	Inside Outside/13	Yes Yes	Globe Globe
45	55	CVCS/water	No	13	1-½ 1-½ 1/2	CHE-V494 CHA-UV580 CHA-UV715[j]	Inside Outside/11 Outside/8	Yes Yes Yes	Check Gate Globe
46	57	SG blowdown/water	No	39	6 6	SGA-UV500P SGB-UV500Q SGE-V293	Inside Outside/6 Outside/6	No No No	Gate Gate Globe
47	57	SG blowdown/water	No	39	6 6	SGB-UV500R SGA-UV500S SGE-V294	Inside Outside/5 Outside/6	No No No	Gate Gate Globe
48	57	SG downcomer sample/ water	No	39	½ ½	SGB-UV226 SGA-UV227	Inside Outside/4	No No	Globe Globe
49	57	SG downcomer sample / water	No	39	½ ½	SGA-UV220 SGB-UV221	Inside Outside/4	No No	Globe Globe

Table 6.2.4-1

CONTAINMENT ISOLATION SYSTEM[i] (Sheet 7 of 9)

Penetration Number[g]	Applicable GDC	System/Fluid	Essential System	(a) Valve Arrangement	(b) Line Size (in).	Valve Number	(c) Valve Location/ Distance from Containment	(d) Type C Leakage Test	(e) Valve Type
50	56	Pool cooling/water	No	3	4	PCE-V071 PCE-V070	Inside Outside/2	Yes Yes	Gate Gate
51	56	Pool cooling/water	No	5	4	PCE-V075 PCE-V076	Inside Outside/6	Yes Yes	Gate Gate
52	56	RDT vent	No	18	1 1	GRA-UV001 GRB-UV002	Inside Outside/34	Yes Yes	Globe Globe
53	None	Fuel transfer/water	No	9	36	Flange	Inside	Type B	Flange
54A	56[f]	CB pressure monitor/air	Yes	37	¾	HCA-HV074	Outside/3	No	Globe
54B	Spare								
54C	Spare								
55A	56[f]	CB pressure monitor/air	Yes	37	¾	HCB-HV075	Outside/3	No	Globe
55B	Spare								
55C	Spare								
56	56[i]	CB purge/air	No	22	42 42	CPB-UV003A CPA-UV002A	Inside Outside/2	Yes[h] Yes[h]	B'fly B'fly/Flange
57	56[i]	CB purge/air	No	30	42 42	CPA-UV002B CPB-UV003B	Inside Outside/2	Yes[h] Yes[h]	B'fly B'fly/Flange
58	None	CB test/air	No	27	8 8	Flange Flange	Inside Outside/2	Type B No	Flange Flange
59	56	Service air/air	No	28	3	IAE-V073 IAE-V072	Inside Outside/1	Yes Yes	Check Globe
60	56	Chilled water/water	No	24	10 10	WCE-V039 WCB-UV063	Inside Outside/4	Yes Yes	Check Gate
61	56	Chilled water/water	No	25	10 10	WCB-UV061 WCA-UV062	Inside Outside/4	Yes Yes	Gate Gate
62A	56[f]	CB pressure monitor/air	Yes	37	¾	HCD-HV077	Outside/3	No	Globe

Table 6.2.4-1

CONTAINMENT ISOLATION SYSTEM[i] (Sheet 8 of 9)

Penetration Number[g]	Applicable GDC	System/Fluid	Essential System	Valve [a] Arrangement	Line [b] Size (in).	Valve Number	Valve Location/(c) Distance from Containment (ft)	Type C[d] Leakage Test	Valve [e] Type
62B	None	ILRT verification leak	No	27	3/4 3/4	Flange Flange	Inside Outside/5	Type B No	Flange Flange
62C	None	ILRT pressure measurement	No	27	3/4 3/4	Flange Flange	Inside Outside/5	Type B No	Flange Flange
63A	57	SG blowdown sample	No	39	½	SGB-UV224 SGA-UV225	Inside Outside/12	No No	Globe Globe
63B	57	SG blowdown sample	No	39	½	SGB-UV222 SGA-UV223	Inside Outside/9	No No	Globe Globe
64	Spare								
65	Spare								
66	Spare								
67	55	Long term recirculation / water	Yes	36	3	SIB-V533 SID-HV331	Inside Outside/11	No No	Check Globe
68	Spare								
69	Spare								
70	Spare								
71	Spare								
72	55	RCP seal injection/ water	No	38	1-1/2	CHN-V835 CHB-HV255	Inside Outside/18	Yes Yes	Check Globe
73	Spare								
74	Spare								
75	57	Aux Fw/water	Yes	15	6 3	AFA-V079 AFC-UV036 AFB-UV034 AFA-PSV108 AFB-V524[m]	Inside Outside/19 Outside/45 Outside/22 Outside/53	No No No No No	Check Gate Gate Relief Gate
76	57	Aux Fw/water	Yes	15	6 3	AFB-V080 AFB-UV035 AFA-UV037 AFA-PSV109 AFB-V529[m]	Inside Outside/31 Outside/48 Outside/51 Outside/53	No No No No No	Check Gate Gate Relief Gate

Table 6.2.4-1

CONTAINMENT ISOLATION SYSTEM[i] (Sheet 9 of 9)

Penetration Number[g]	Applicable GDC	System/Fluid	Essential System	Valve[a] Arrangement	Line[b] Size (in.)	Valve Number	Valve Location/[c] Distance from Containment (ft)	Type C[d] Leakage Test	Valve[e] Type
77	55	Long term recircula-tion/water	Yes	36	3	SIA-V523 SIC-HV321	Inside Outside/6	No No	Check Globe
78	56	CB purge/air	No	41	8 8	CPB-UV005A CPA-UV004A	Inside Outside/2	Yes Yes	B'fly B'fly
79	56	CB purge/air	No	42	8 8	CPA-UV004B CPB-UV005B	Inside Outside/2	Yes Yes	B'fly B'fly
80	Spare								
81	Spare								
L-1 L-3	None None	Personnel lock Emergency lock	No No	26 26	Doors 6' 8” x 3' 6”	NA NA	NA NA	Type B Type B	NA NA
L-2	None	Equipment hatch	No	20	23' dia hatch	NA	NA	Type B	NA

Table 6.2.4-2
CONTAINMENT ISOLATION SYSTEM(h) (Sheet 1 of 9)

Pene-tration(g) Number	System	Valve Numbers	Valve Operator	Primary (a) Actuation Mode	Secon-dary (a) Actuation Mode	Valve Position				ESF(b) Actuation Signal	Stroke Time (c) (Sec)	Power Source
						Normal	Shut-down	Post-Accident	Failure			
1,2,3,4	Main Steam	SGE-UV170 SGE-UV171 SGE-UV180 SGE-UV181	Hydraulic	A	R	O	C	C	FC	MSIS	4.6	Accumulator
		SGE-PSV691 SGE-PSV692 SGE-PSV694 SGE-PSV695	Safety	A	NA	C	C	C	FC	None	NA	NA
		SGE-PSV575 SGE-PSV576 SGE-PSV557 SGE-PSV558	Safety	A	NA	C	C	C	FC	None	NA	NA
		SGE-PSV574 SGE-PSV577 SGE-PSV556 SGE-PSV559	Safety	A	NA	C	C	C	FC	None	NA	NA
		SGE-PSV573 SGE-PSV578 SGE-PSV555 SGE-PSV560	Safety	A	NA	C	C	C	FC	None	NA	NA

a. Position indications for remotely actuated valves are shown in the control room.
b. The parameters sensed and the values which generate actuation signals are given in Section 7.3.
c. Stroke Time is the time it takes for a valve to change positions, normally Open to Close. A time is given except in cases where the valve is only requried to change position (time independent). In these cases only the required stroke to position is given. See Table 7.3-1B for ESF Response Times.
d. Valves are essential. Operator actuation required to open valve.
e. The power supply to valve CHA-HV-524 is removed by locking open its breaker at MCC PHA-M3520. Restoration of power requires local operator action at the MCC. This has been done to prevent inadvertent closure of the valve when auxiliary spray or charging flow is required. This is an exception from CESSAR Section 6.2.4.
f. Failure mode for valves is open on loss of power and closed on loss of air.
g. Manual vent, drain, and test valves between the Containment Isolation Valves will be maintained locked closed under administrative controls or surveilled closed per Technical Specifications.
h. For application of the single failure rule to check valves, refer to Section 3.1.30.
i. In Units where DMWO 2529758 has been implemented, valve CHA-UV-715 is removed and valves HPA-UV-023 & HPA-UV-024 are de-terminated with upstream piping cut and capped as the new containment boundary.
j. Deleted
k. In units where DMWO 2778159 has been implemented, applicable valve(s) have been removed.
l. Applicable in those Units where DMWO 4345882 has been implemented.
m. Applicable in those Units where DMWO 4304156 has been implemented.

Symbols:

N.A	- not applicable	LO	- locked open
EA	- Class 1E bus A	LC	- locked closed
EB	- Class 1E bus B	FO	- fail open
EC	- Class 1E bus C	FC	- fail closed
ED	- Class 1E bus D	FAI	- fail-as-is
N	- normal power source	MSIS	- main steam isolation signal
O	- open	CSAS	- containment spray actuation signal
C	- closed	CPIAS	- containment purge isolation actuation signal
A	- automatic	AFAS	- auxiliary feedwater actuation signal
R	- remote operation	SIAS	- safety injection actuation signal
M	- manual local operation	RAS	- reciculation actuation signal
DU	-Data currently unavailable	CIAS	- containment isolation actuation signal
			- bracket indicates any one signal actuates each valve

Table 6.2.4-2

CONTAINMENT ISOLATION SYSTEM[h] (Sheet 2 of 9)

Pene-tration[g] Number	System	Valve Numbers	Valve Operator	Primary[a] Actuation Mode	Secon-dary[a] Actuation Mode	Valve Position: Normal	Valve Position: Shut-down	Valve Position: Post-Accident	Valve Position: Failure	ESF[b] Actuation Signal	Stroke Time[c] (Sec)	Power Source
1,2,3,4	Main steam	SGE-PSV572 SGE-PSV579 SGE-PSV554 SGE-PSV561	Safety	A	NA	C	C	C	FC	None	NA	NA EA
1,2,3,4	Main steam	SGA-UV134 SGA-UV138	Motor	A	R	C	C	O/C	FAI	AFAS	Opens	EA
		SGA-UV134A SGA-UV138A	Motor	A	R	C	C	O/C	FAI	AFAS	Opens	EA
		SGA-HV184 SGB-HV178 SGB-HV185 SGA-HV179	Piston	R	M	C	C	O/C	FC	None [d]	Opens	Accumul-ator & EA EB EB EA
		SGE-UV169 SGE-UV183	Diaphragm	A	R	C	C	C	FC	MSIS	4.6 4.6	EA & EB EA & EB
A & EB 1,2,3,4	Main Steam	SGA-UV1133 SGA-UV1134	Piston	A	R	O	C	C	FC	MSIS	4.6 4.6	EA EA
		SGB-UV1135A SGB-UV1135B SGB-UV1136A SGB-UV1136B	Piston	A	R	O	C	C	FC	MSIS	4.6 4.6 4.6 4.6	EB EB EB EB
		SGE-V603 SGE-V611	Hand	M	M	LC	C	C	NA	None	NA	NA
5	Spare											
6	Demin-eralized water	DWE-V061 DWE-V062	Hand Hand	M M	M M	LC LC	O O	C C	NA NA	None None	NA NA	NA NA
7	Fire Protection	FPE-V089 FPE-V090	Hand None	M A	M A	LC C	C C	C C	NA NA	None None	NA NA	NA NA
8, 10	Feed-water	SGB-UV132 SGB-UV137	Hydraulic	A	R	O	C	C	FC	MSIS	9.6	Accumulator
		SGA-UV174 SGA-UV177	Hydraulic	A	R	O	C	C	FC	MSIS	9.6	Accumulator

Table 6.2.4-2
CONTAINMENT ISOLATION SYSTEM(h) (Sheet 3 of 9)

Pene-tration(g) Number	System	Valve Numbers	Valve Operator	Primary (a) Actuation Mode	Secon-dary(a) Actuation Mode	Valve Position				ESF(b) Actuation Signal	Stroke Time(c) (Sec)	Power Source
						Normal	Shut-down	Post-Accident	Failure			
8, 10	Feedwater	SGE-V003 SGE-V006	None	A	A	O	C	C	NA	None	NA	NA
		SGE-V007 SGE-V005	None	A	A	O	C	C	NA	None	NA	NA
9	Radwaste drain	RDA-UV023 RDB-UV024	Motor Piston	A A	R R	O O	O C	C C	FAI FC	CIAS CIAS	47.5 5	EA EB
11, 12	Feedwater	SGE-V652 SGE-V653	None	A	A	O	C	C	NA	None	NA	NA
		SGE-V642 SGE-V-693	None	A	A	O	C	C	NA	None	NA	NA
11.12	Feedwater	SGB-UV130 SGB-UV135	Piston	A	R	O	C	C	(f)	MSIS	9.6	EA and EB
		SGB-HV200	Solenoid	A	R	C	C	C	FC	CIAS MSIS	1	EB
		SGA-UV172 SGA-UV175	Piston	A	R	O	C	C	(f)	MSIS	9.6	EA and EB
		SGB-HV201	Solenoid	A	R	C	C	C	FC	CIAS MSIS	1	EB
13	HPSI	SIE-V113 SIB-UV616 SIA-UV617	None Motor Motor	A A A	A R,M R,M	C C C	C C C	O O O	NA FAI FAI	None SIAS SIAS	NA 10 10	NA EA EB
14	HPSI	SIE-V123 SIB-UV626 SIA-UV627 SIE-1024(m)	None Motor Motor Hand	A A A M	A R,M R,M M	C C C LC	C C C C	O O O C	NA FAI FAI NA	None SIAS SIAS None	NA 10 10 NA	NA EA EB NA
15	HPSI	SIE-V133 SIB-UV636 SIA-UV637	None Motor Motor	A A A	A R, M R, M	C C C	C C C	O O O	NA FAI FAI	None SIAS SIAS	NA 10 10	NA EA EB
16	HPSI	SIE-V143 SIB-UV646 SIA-UV647 SIE-1027(m)	None Motor Motor Hand	A A A M	A R, M R, M M	C C C LC	C C C C	O O O C	NA FAI FAI NA	None SIAS SIAS None	NA 10 10 NA	NA EA EB NA

Table 6.2.4-2
CONTAINMENT ISOLATION SYSTEM[h] (Sheet 4 of 9)

Penetration[g] Number	System	Valve Numbers	Valve Operator	Primary[a] Actuation Mode	Secondary[a] Actuation Mode	Valve Position: Normal	Valve Position: Shut-down	Valve Position: Post-Accident	Valve Position: Failure	ESF[b] Actuation Signal	Stroke Time[c] (Sec)	Power Source
17	LPSI	SIE-V114	None	A	A	C	O	O	NA	None	NA	NA
		SIB-UV615	Motor	A	R, M	C	O	O	FAI	SIAS	10	EB
18	LPSI	SIE-V124	None	A	A	C	O	O	NA	None	NA	NA
		SIB-UV625	Motor	A	R, M	C	O	O	FAI	SIAS	10	EB
19	LPSI	SIE-V134	None	A	A	C	O	O	NA	None	NA	NA
		SIA-UV635	Motor	A	R, M	C	O	O	FAI	SIAS	10	EA
20	LPSI	SIE-V144	None	A	A	C	O	O	NA	None	NA	NA
		SIA-UV645	Motor	A	R, M	C	O	O	FAI	SIAS	10	EA
21	CS	SIE-V164	None	A	A	C	C	O	NA	None	NA	NA
		SIA-UV672	Motor	A	R	LC	C	O	FAI	CSAS	10	EA
22	CS	SIB-V165	None	A	A	C	C	O	NA	None	NA	NA
		SIB-UV671	Motor	A	R	LC	C	O	FAI	CSAS	10	EB
23	SI	SIA-UV673	Motor	A	R,M	C	C	O	FAI	RAS	Opens	EA
		SIA-UV674	Motor	A	R,M	C	C	O	FAI	RAS	Opens	EA
		SIA-PSV151	Safety	A	NA	C	C	C	FC	None	NA	NA
		SIA-UV708[k]	Solenoid	A	R	C	C	C	FC	CIAS	5	EA
24	SI	SIB-UV675	Motor	A	R,M	C	C	O	FAI	RAS	Opens	EB
		SIB-UV676	Motor	A	R,M	C	C	O	FAI	RAS	Opens	EB
		SIB-PSV140	Safety	A	NA	C	C	C	FC	None	NA	NA
25A	CN rad mon	HCB-UV044	Solenoid	A	R	O	O	O or C	FC	CIAS	1	EB
		HCA-UV045	Solenoid	A	R	O	O	O or C	FC	CIAS	1	EA
25B	CN rad mon	HCB-UV047	Solenoid	A	R	O	O	O or C	FC	CIAS	1	EB
		HCA-UV046	Solenoid	A	R	O	O	O or C	FC	CIAS	1	EA
26 (CESSAR 27)	SDC	SID-UV654	Motor	R	R	LC	O	O or C	FAI	None	80	ED
		SIB-UV656	Motor	R	M	LC	O	O or C	FAI	None	80	EB
		SIB-HV690	Motor	R	M	LC	O or C	O or C	FAI	None	30	EB
		SIB-PSV189	Safety	A	NA	C	C	C	FC	None	NA	NA
27 (CESSAR 28)	SDC	SIC-UV653	Motor	R	R	LC	O	O or C	FAI	None	80	EC
		SIA-UV655	Motor	R	M	LC	O	O or C	FAI	None	80	EA
		SIA-HV691	Motor	R	M	LC	O or C	O or C	FAI	None	30	EA
		SIA-PSV179	Safety	A	NA	C	C	C	FC	None	NA	NA

Table 6.2.4-2

CONTAINMENT ISOLATION SYSTEM[h] (Sheet 5 of 9)

Penetration[g] Number	System	Valve Numbers	Valve Operator	Primary[a] Actuation Mode	Secondary[a] Actuation Mode	Valve Position: Normal	Valve Position: Shutdown	Valve Position: Post-Accident	Valve Position: Failure	ESF[b] Actuation Signal	Stroke Time[c] (sec)	Power Source
28 (CESSAR 29)	SI	SIA-UV682	Air	A	R	C	O or C	C	FC	SIAS	5	EA
		SIE-V463	None	M	M	LC	O or C	C	NA	None	NA	NA
		SIE-PSV474	Safety	A	NA	C	C	C	FC	None	NA	NA
29	N_2	GAE-V015	None	A	A	O	O or C	C	NA	None	NA	NA
		GAA-UV002	Solenoid	A	R	O	O or C	C	FC	CIAS	10	EA
30	N_2	GAE-V011	None	A	A	C	O or C	C	NA	None	NA	NA
		GAA-UV001	Solenoid	A	R	C	O or C	C	FC	CIAS	10	EA
31	Inst air	IAE-V021	None	A	A	O	O or C	C	NA	None	NA	NA
		IAA-UV0002	Solenoid	A	R	O	O or C	C	FC	CSAS	10	EA
32A	CB pres mon	HCC-HV076	Solenoid	R	R	O	O	O	FO	None	Opens	EC
32B	Spare	-	-	-	-	-	-	-	-	-	-	-
32C	Spare	-	-	-	-	-	-	-	-	-	-	-
33	Nuc CW	NCE-V118	None	A	A	O	O	C	NA	None	NA	NA
		NCB-UV401	Motor	A	R	O	O	C	FAI	CSAS	10	EB
34	Nuc CW	NCB-UV403	Motor	A	R	O	O	C	FAI	CSAS	10	EB
		NCA-UV402	Motor	A	R	O	O	C	FAI	CSAS	10	EA
		NCE-PSV0617	Relief	A	NA	C	C	C	FC	None	NA	NA
35	CB hyd control	HPA-UV001	Motor	A	R	C	C	O or C	FAI	CIAS	12	EA
		HPA-UV003	Motor	A	R	C	C	O or C	FAI	CIAS	12	EA
		HPA-HV007A	Solenoid	R	R	C	C	O or C	FC	None	1	EA
		HPA-UV0024[i]	Solenoid	A	R	C	C	C	FC	CIAS	5	EA
36	CB hyd control	HPB-UV002	Motor	A	R	C	C	O or C	FAI	CIAS	12	EB
		HPB-UV004	Motor	A	R	C	C	O or C	FAI	CIAS	12	EB
		HPB-HV008A	Solenoid	R	R	C	C	O or C	FC	None	1	EB
37A	SG blow-down sample	SGA-UV211	Solenoid	A	R	O	C	C	FC	MSIS	9.6	EA
		SGB-UV228	Solenoid	A	R	O	C	C	FC	AFAS SIAS	9.6	EB

Table 6.2.4-2
CONTAINMENT ISOLATION SYSTEM[h] (Sheet 6 of 9)

Penetration[g] Number	System	Valve Numbers	Valve Operator	Primary[a] Actuation Mode	Secondary[a] Actuation Mode	Valve Position: Normal	Valve Position: Shutdown	Valve Position: Post-Accident	Valve Position: Failure	ESF[b] Actuation Signal	Stroke Time[c] (sec)	Power Source
37B	SG blow down sample	SGA-UV204	Solenoid	A	R	O	C	C	FC	MSIS	9.6	EA
		SGB-UV219	Solenoid	A	R	O	C	C	FC	AFAS	9.6	EB
										SIAS		
38	CB hyd control	HPA-V002	None	A	A	C	C	O or C	NA	None	NA	NA
		HPA-UV005	Motor	A	R	C	C	O or C	FAI	CIAS	12	EA
		HPA-HV007B	Solenoid	R	R	C	C	O or C	FC	None	1	EA
		HPA-UV23[i]	Solenoid	A	R	C	C	C	FC	CIAS	5	GA
39	CB hyd control	HPB-V004	None	A	A	C	C	O or C	NA	None	NA	NA
		HPB-UV006	Motor	A	R	C	C	O or C	FAI	CIAS	12	EB
		HPB-HV008B	Solenoid	R	R	C	C	O or C	FC	None	1	EB
40	CVCS	CHA-UV516	Air	A	R	O	C	C	FC	CIAS / SIAS	5	EA
		CHB-UV523	Air	A	R	O	C	C	FC	CIAS	5	EB
		CHB-UV924[k]	Solenoid	A	R	C	C	C	FC	CIAS	5	EB
41	CVCS	CHE-VM70	None	A	A	O	O or C	O or C	NA	None	NA	NA
		CHA-HV524	Motor	R	M	LO	LO	LO	FAI	None	NA	EA
		CHE-V854	Hand	M[e]	M	LC	LC	LC	NA	None	NA	NA
42A	Sample	SSA-UV204	Solenoid	A	R	C	C	C	FC	CIAS	5	EA
		SSB-UV201	Solenoid	A	R	C	C	C	FC	CIAS	5	EB
42B	Sample	SSA-UV205	Solenoid	A	R	C	C	C	FC	CIAS	5	EA
		SSB-UV202	Solenoid	A	R	C	C	C	FC	CIAS	5	EB
42C	Sample	SSA-UV203	Solenoid	A	R	C	C	C	FC	CIAS	5	EA
		SSB-UV200	Solenoid	A	R	C	C	C	FC	CIAS	5	EB
43	CVCS	CHA-UV506	Air	A	R, M	O	O or C	C	FC	CSAS	5	EA
		CHB-UV505	Air	A	R, M	O	O or C	C	FC	CSAS	5	EB
44	CVCS	CHA-UV560	Air	A	R	O or C	C	C	FC	CIAS	5	EA
		CHB-UV561	Air	A	R, M	O or C	C	C	FC	CIAS	5	EB
45	CVCS	CHE-V494	None	A	A	O or C	C	C	NA	None	NA	NA
		CHA-UV580	Air	A	R, M	O or C	C	C	FC	CIAS	5	EA
		CHA-UV715[i]	Solenoid	A	R	C	C	C	FC	CIAS	5	EA
										MSIA		
46	SG blow-down	SGA-UV500P	Piston	A	R	O	C	C	FC	AFAS	9.6	EA
		SGB-UV500Q	Piston	A	R	O	C	C	FC	SIAS	9.6	EB
		SGE-V293	Hand	M	M	C	C	C	NA	None	NA	NA

Table 6.2.4-2
CONTAINMENT ISOLATION SYSTEM[h] (Sheet 7 of 9)

Penetration[g] Number	System	Valve Numbers	Valve Operator	Primary[a] Actuation Mode	Secondary[a] Actuation Mode	Valve Position: Normal	Valve Position: Shutdown	Valve Position: Post-Accident	Valve Position: Failure	ESF[b] Actuation Signal	Stroke Time[c] (sec)	Power Source
47	SG blow-down	SGB-UV500R SGA-UV500S SGE-V294	Piston Piston Hand	A A M	R R M	O O C	C C C	C C C	FC FC NA	MSIS AFAS SIAS None	9.6 9.6 NA	EB EA NA
48	SG downcomer sample/ water	SGB-UV226 SGA-UV227	Solenoid Solenoid	A A	R R	O O	C C	C C	FC FC	MSIS AFAS SIAS	9.6 9.6	EB EA
49	SG downcomer sample/ water	SGA-UV220 SGB-UV221	Solenoid Solenoid	A A	R R	O O	C C	C C	FC FC	MSIS AFAS SIAS	9.6 9.6	EB EA
50	Pool Cooling	PCE-V071 PCE-V070	Hand Hand	M M	M M	LC LC	O or C O or C	C C	NA NA	None None	NA NA	NA NA
51	Pool Cooling	PCE-V075 PCE-V076	Hand Hand	M M	M M	LC LC	O or C O or C	C C	NA NA	None None	NA NA	NA NA
52	CVCS	GRA-UV001 GRB-UV002	Motor Solenoid	A A	R R	O O	O O	C C	FAI FC	CIAS CIAS	12 10	EA EB
53	Fuel tran	Flange	NA	NA	NA	C	O or C	C	NA	None	NA	NA
54A	CB press monitor	HCA-HV074	Solenoid	R	R	O	O	O	O	None	Opens	EA
54B	Spare											
54C	Spare											
55A	CB press monitor	HCB-HV075	Solenoid	R	R	O	O	O	O	None	Opens	EB
55B	Spare											
55C	Spare											
56	CB purge	CPB-UV003A CPA-UV002A	Motor Motor	A A	R R	LC LC	O O	C C	FAI FAI	CIAS CPIAS	12 12	EB EA
57	CB purge	CPA-UV002B CPB-UV003B	Motor Motor	A A	R R	LC LC	O O	C C	FAI FAI	CIAS CPIAS	12 12	EA EB
58	CB test	Flange	NA	NA	NA	C	C	C	NA	None	NA	NA
59	Air	IAE-V073 IAE-V072	None Hand	A M	A M	C LC	O or C O or C	C C	NA NA	None None	NA NA	NA NA

Table 6.2.4-2
CONTAINMENT ISOLATION SYSTEM[h] (Sheet 8 of 9)

Pene-tration[g] Number	System	Valve Numbers	Valve Operator	Primary[a] Actuation Mode	Secondary[a] Actuation Mode	Valve Position Normal	Shut-down	Post-Accident	Failure	ESF[b] Actuation Signal	Stroke Time[c] (Sec)	Power Source
60	Chilled water	WCE-V039 WCB-UV063	None Motor	A A	A R	O O	C C	C C	NA FAI	None CIAS	NA 10	NA EB
61	Chilled water	WCB-UV061 WCA-UV062	Motor Motor	A A	R R	O O	C C	C C	FAI FAI	CIAS CIAS	10 10	EB EA
62A	CB press monitor	HCD-HV077	Solenoid	R	R	O	O	O	FO	None	Opens	ED
62B	CB test	Flange	NA	NA	NA	C	C	C	NA	None	NA	NA
62C	CB test	Flange	NA	NA	NA	C	C	C	NA	None	NA	NA
63A	SG blow-down sample	SGB-UV224 SGA-UV225	Solenoid Solenoid	A A	R R	O O	C C	C C	FC FC	MSIS AFAS SIAS	9.6 9.6	EB EA
63B	SG blow-down sample	SGB-UV222 SGA-UV223	Solenoid Solenoid	A A	R R	O O	O O	C C	FC FC	MSIS AFAS SIAS	9.6 9.6	EB EA
64	Spare											
65	Spare											
66	Spare											
67 (CESSAR 11)	SIS	SIB-V533 SID-HV331	None Motor	A R	A M	C LC	C C	O O	NA FAI	None None	NA 10	NA ED
68	Spare											
69	Spare											
70	Spare											
71	Spare											
72 (CESSAR 57)	CVCS	CHN-V835 CHB-HV255	None Motor	A R	A M	O O	O O	O or C O or C	NA FAI	None None	NA 10	NA EB
73	Spare											
74	Spare											

Table 6.2.4-2
CONTAINMENT ISOLATION SYSTEM[h] (Sheet 9 of 9)

Penetration[g] Number	System	Valve Numbers	Valve Operator	Primary[a] Actuation Mode	Secondary[a] Actuation Mode	Valve Position: Normal	Valve Position: Shutdown	Valve Position: Post-Accident	Valve Position: Failure	ESF[b] Actuation Signal	Stroke Time[c] (Sec)	Power Source
75	Aux Fw	AFA-V079	None	A	A	C	C	O	NA	None	NA	NA
		AFC-UV036	Motor	R	R	C	C	O	FAI	AFAS	15	EC
		AFB-UV034	Motor	R	R	C	C	O	FAI	AFAS	15	EB
		AFA-PSV108	Relief	A	NA	C	C	C	FC	None	NA	NA
		AFB-524[l]	Hand	M	M	LC	C	C	NA	None	NA	NA
76	Aux Fw	AFB-V080	None	A	A	C	C	O	NA	None	NA	NA
		AFB-UV035	Motor	R	R	C	C	O	FAI	AFAS	15	EB
		AFA-UV037	Motor	R	R	C	C	O	FAI	AFAS	15	EA
		AFA-PSV109	Relief	A	NA	C	C	C	FC	None	NA	NA
		AFB-529[l]	Hand	M	M	LC	C	C	NA	None	NA	NA
77 (CESSAR 12)	SI	SIA-V523	None	A	A	C	C	O	NA	None	NA	NA
		SIC-HV321	Motor	R	M	LC	C	O	FAI	None	10	EC
78	CB purge	CPB-UV005A	Air	A	R	C	C	C	FC	CIAS	2	EB
		CPA-UV004A	Air	A	R	C	C	C	FC	CPIAS	2	EA
79	CB purge	CPA-UV004B	Air	A	R	C	C	C	FC	CIAS	2	EA
		CPB-UV005B	Air	A	R	C	C	C	FC	CPIAS	2	EB
80	Spare											
81	Spare											
L-1 L-3	Air locks	NA	None	M	M	C	C	C	NA	None	NA	NA
L-2	Equipment hatch	NA	None	M	M	C	O or C	C	NA	None	NA	NA

In addition, figure 6.2.4-1 shows containment isolation valve arrangements. Containment isolation schemes comply with the requirements of GDC 54, 55, 56, and 57. Valves which receive an Engineered Safety Features Actuation Signal (ESFAS), or are actuated remotely by the operator, have actuation times consistent with the functional requirements of the systems they are associated with.

1) The CVCS charging line containment isolation valve (CHA-HV-524) has been locked in the open position by removing the power supply for the valve and the local handwheel has been chained and locked. This was done to prevent inadvertent closure of valve CHA-HV-524 during periods when charging or auxiliary spray flow is required.

2) The outside isolation valve associated with the CVCS reactor coolant pump seal injection line penetration is normally open, and does not receive a CIAS.

It is desirable to leave these two paths open to provide additional core protection after an accident in which offsite power is available by maintaining charging capability and reactor coolant pump seal injection capability. In addition, the charging pumps can be transferred to emergency power at the discretion of the operator in the event that offsite power is lost. Conversely, it is undesirable to lose charging or seal injection capability during normal operation due to an inadvertent CIAS.

The potential release of fission products through the two penetrations under discussion does not present a problem for the following reasons:

a) Flow through these penetrations is into the containment and the RCS.

b) Check valves inside the containment prevent backflow out of the containment if the charging pumps stop.

c) The connecting portions of the CVCS outside of containment are designed to Safety Class 2, Seismic Category I standards and have design pressures well in excess of containment design pressure.

d) The operator has the capability of isolating these lines if continued charging or seal injection proves to be unnecessary.

Table 6.2.4-2 lists all fluid penetrations and indicate ESF actuation signals that initiate closure of containment isolation valves. Refer to section 7.3 for a discussion of the generation of the signals.

The containment pressure instrumentation is located outside the containment. The containment pressure instrumentation lines are extensions of the containment boundary. These lines are critical to the functioning of the ESF systems. The design criteria for these lines are as follows:

A. Containment pressure instruments are located as close as practical to the containment and are installed using 3/8-inch stainless steel tubing.

B. All instrumentation provided is designed as a pressure-containing system.

C. One remote manually operated shutoff valve, meeting the requirements of Regulatory Guide 1.11, is provided outside the containment.

The instrument line, up to the instrument process connection, is Seismic Category I and ASME Section III, Class 2, and the instrument is Seismic Category I. The equipment is located in an area protected against physical damage due to pipe whip or missiles.

The parameters associated with containment isolation are high containment pressure or low pressurizer pressure. The parameters which actuate main steam and feedwater isolation are low steam generator pressure or high containment pressure or high steam generator water level. Channel separation is provided for automatic isolation valves. Automatic isolation valves are provided with position switches and position indicating lights in the control room to indicate valve positions.

The integrity of the isolation valve system and connecting lines under the dynamic forces resulting from inadvertent closure under operating conditions and seismic conditions is assured by performance of static and dynamic analyses on the piping, valves, and restraints. The static and dynamic analyses are discussed in subsection 3.9.2.

Piping isolation valves and actuators located outside containment are located as close as practical to the containment wall in accordance with General Design Criteria 55, 56, and 57.

Isolation valves inside the containment are located between the secondary shield and the inside containment wall. The secondary shield serves as the missile barrier. Isolation valves for the ECCS recirculation lines are located inside the recirculation sumps. Any necessary missile barriers for isolation valves and piping that provide one of the isolation barriers outside the containment consist of structural steel and concrete which forms walls and floors of adjacent buildings.

The effect of pipe whip and jet impingement forces on containment isolation valves and piping are considered in section 3.6.

The operability assurance of valve and valve operators under normal and accident conditions is discussed in section 3.9. Containment environmental conditions under normal and accident circumstances and qualification test conditions are described in section 3.11.

Containment isolation valves and piping are classified as Quality Group B, Seismic Category I.

Detection of leakage from systems that are required to function in the event of an accident is discussed in Section 6.2.4.1.

Valve stroke times are listed in table 6.2.4-2. Stroke times and valve leak tightness are specified to limit radiological effects from exceeding the guidelines established by 10CFR100.

Piping penetrations, except the containment pressure monitoring instrument lines and main steam lines, are furnished with two isolation valves to provide redundancy in the event that one valve fails to close.

The type of valve operators are indicated in table 6.2.4-2. Valve operators are supplied from the emergency, Class 1E power supplies as described in section 8.3.

6.2.4.2.2 Applicable Codes, Standards, and Regulatory Guides

The following list identifies the industry standards, NRC regulatory guides, and the general design criteria applicable to the design of the containment isolation system which were considered in system design:

A. General Design Criteria 54, 55, 56, and 57 of 10CFR50, Appendix A, and Appendix J of 10CFR50.

B. NRC Regulatory Guides 1.11, 1.26, 1.29, 1.73, and 1.141 (see section 1.8).

C. IEEE 382-1972, ANSI N18.2-1973, and Section III of the ASME Code.

Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions," was issued by the NRC on September 30, 1996. This letter required that addressees determine:

1. if containment air cooler cooling water systems are susceptible to either waterhammer or two-phase flow conditions during postulated accident conditions;

2. if piping systems that penetrate the containment are susceptible to thermal expansion of fluid so that overpressurization of piping could occur.

The PVNGS 120 day response to Generic Letter 96-06, was transmitted to the NRC under APS Letter 102-03855-JML/AKK/JRP

dated January 28, 1997. This response documented that the PVNGS containment cooling water systems are not susceptible to the development of waterhammer or two phase flow conditions as discussed in Generic Letter 96-06. No corrective actions were required, however, limited, defense in depth actions were taken to further enhance the system design with respect to these conditions. The response further stated that the as-built containment penetration configurations which do not have installed relief valves were evaluated and accepted by the NRC during initial PVNGS licensing and documented by reference in the PVNGS Safety Evaluation Report. This acceptance was based on a qualitative assessment which credits pipe deformation, valve leakage, and limiting heat transfer effects to preclude penetration failure due to overpressurization. PVNGS subsequently transmitted a supplemental response to the NRC under APS Letter 102-03943-JML/AKK/JRP dated May 30, 1997, wherein plant modifications were described which would accommodate a quantitative as well as a qualitative licensing basis.

These plant changes consisted of reducing fastener torque in the body to bonnet joint for containment isolation valves 13JRDBUV0024, 13JWCBUV0061, 13JWCAUV0062, 13PPCEV070, 13PPCEV076, 13PDWEV061 and 13DWEV062. The change in valve body to bonnet joint fastener torque for some of the containment isolation valves is to allow the body to bonnet gasket joint in the valves to leak at lower pressures and then reset. The use of ASME B&PV Code, Section III, Division I-1974 Edition with Winter 1975 Addenda, Appendix F-1000 in the evaluation of the containment penetration piping and valve components provides a

conservative limit in the amount of plastic strain allowed in the piping to be used to self relieve the pressure build-up inside the penetration. These inherent relief mechanisms in the valves and piping are in agreement with PVNGS' qualitative licensing basis. The referenced adjustment of bonnet joint fastener torque in conjunction with the use of ASME Code Appendix F-1000 stress criteria enables PVNGS to expand the current design criteria to encompass quantitative limits regarding thermally induced overpressurization of containment penetration isolation piping and valves due to a LOCA. PVNGS' response to a request for additional information from the NRC provided, under APS letter 102-04130-JML/SAB/RNW, dated June 4, 1998, detailed information on the methodology utilized to predict the response of the containment penetrations to thermally induced over-pressurization due to a LOCA. This response identified the use of ASME B&PV Code, Section II, Division I-1974 Edition with the Winter 1975 Addenda, Appendix F-1000 in the evaluation of the containment penetration piping and valve components as well as the reduction of fastener torque in the body to bonnet joint for some of the containment isolation valves.

6.2.4.2.3 Containment Purge Isolation Valves

A containment purge system consisting of a power access purge (2000 cubic feet per minute) and a refueling purge (30,000 cubic feet per minute) is provided as described in section 9.4. During preoperational flow balancing testing the 8-inch power access purge was unable to meet the design flow rates due to leaking seals, dampers, and higher than assumed pressure drops. An overall assessment confirmed that the as-built condition

(1100 cfm exhaust and 1200 cfm supply) is adequate to meet the design requirements as identified in NRC Inspection Report 87-15, Followup Item 50-529/85-43-01 Closure. The power access purge used during operation at power has 8-inch containment penetrations sized in accordance with the guidelines of Branch Technical Position CSB 6-4.

The 8-inch diameter valves (CPA-UV004A, 4B, CPB-UV005A, 5B) are capable of closing in less than 2 seconds after receipt of a CIAS or a CPIAS. This minimizes the amount of containment atmosphere mass released to the environment in the unlikely event that a LOCA should occur with the power access purge valves open.

The normally closed 42-inch diameter refueling purge valves (CPA-UV002A, 2B, CPB-UV003A, 3B) are designed to close in less than 12 seconds after the receipt of a CIAS or a CPIAS with offsite power available. The 42-inch diameter refueling purge valves are sealed closed during power operation. The 42-inch diameter refueling purge penetrations may be isolated using a blind flange in plant operating modes 1-4.

The setpoint for containment isolation is approximately 3 psig and purge isolation valve closure is initiated 0.9 second after the setpoint is reached.

In addition, the following valve characteristics are specified:

- Power access valves (8 inches) are ANSI rated 150 pounds. Refueling purge valves (42 inches) are ANSI rated 75 pounds.

- Power access valve bodies were hydrotested at 225 psi. Refueling purge valves were hydrotested at 112 psi.

- Power access valves seat leak test was at 150 psi differential. Refueling purge valves seat leak test was at 75 psi differential.
- Operability tests will be in conformance with the requirements of section 3.9.

6.2.4.2.4 Main Steam Line Penetrations

Valve arrangement 14, the main steam line penetration, contains relief valves which are connected to a closed system penetrating the containment. This arrangement complies with General Design Criterion 57 in that at least one remotely-operated, automatically-actuated isolation valve is provided in the piping outside of the containment. The relief valves shown in this arrangement are the main steam safety valves which are provided for protection of portions of the main steam system as described in subsections 5.2.2 and 5.4.13 and section 10.3. These safety valves, which are located outside containment, discharge directly to the atmosphere and are thus a potential release path. Their setpoints are such that they will normally only lift in the event a condition occurs that requires them to function to protect the integrity of the reactor coolant pressure boundary (RCPB) (see subsection 5.2.2) and that portion of the main steam supply system discussed in section 10.3 Sections 15.1, 15.2, and 15.6 discuss postulated accident transients in which these valves function to protect the system integrity. Section 15.2 discusses a potential incident that could be caused by the inadvertent operation of one of these valves.

6.2.4.2.5 Access Penetrations

The isolation arrangement of each equipment hatch, emergency personnel hatch, personnel lock, containment test connection, integrated leakage rate test (ILRT) verification, ILRT pressure measurement, and fuel transfer penetration shown in valve arrangements 20, 26, 27, and 9 consists of an access connection attached to and located inside the containment building. A blind flange or hatch encloses the inside end of the access connection. The 42-inch diameter refueling purge penetrations may be isolated with blind flanges located outside containment in plant operating modes 1 – 4 (shown in valve arrangements 22 and 30). The blind flange or hatch contains two 0-rings or gasket grooves and a pressure tap. The pressure tap is routed through the blind flange or hatch to the annulus between the two 0-rings or gaskets. When assembled preparatory to reactor operation, the blind flanges and hatches are secured to the access connection and the annulus between the 0-rings or gaskets is pressurized to ensure that both seals are functioning. The seal is further tested when test pressure is introduced into the containment.

The emergency personnel hatch, personnel lock, equipment hatch, ILRT verification, ILRT pressure measurement, containment test connection, refueling purge penetrations (when isolated with blind flanges in plant operating modes 1 – 4), and fuel transfer connection are considered to be part of the containment boundary and therefore General Design Criterion 56 does not apply to these penetrations and an isolation valve is not required.

6.2.4.3 Design Evaluation

A failure mode and effects analysis for components used for containment isolation is presented as part of the Chemical and Volume Control System failure mode and effects analysis (section 9.3.4), the Safety Injection System failure mode and effects analysis (section 6.3), and BOP ESFAS and NSSS ESFAS (section 7.3 and section 7.2). Single valve failure does not affect the integrity of the containment building due to redundancy of double isolation valve protection. There are two classes of exceptions to double isolation valve redundancy. Single isolation is provided for the main steam lines in accordance with the provisions of General Design Criterion 57. Containment pressure instrumentation has single isolation in accordance with Regulatory Guide 1.11. Operator action will be required to isolate a pressure instrument line rupture downstream of the isolation valve.

Proper functioning of the Containment Isolation System results from the following:

A) Environmental qualification of containment isolation valves to ensure that they fulfill their safety functions under post-accident conditions as described in section 6.2.4.2.1.

B) Protection of containment isolation components from the failures of other fluid systems following an accident, as described in section 6.2.4.2.1.

C) Preoperational and inservice testing of containment isolation components, as described in section 6.2.4.4.

D) The use of double isolation at the containment boundary as described in section 6.2.4.1.

E) Administrative control of the proper position of manual containment isolation valves, and automatic isolation valves whose use is not required subsequent to the design basis post accident conditions. All manual vent, drain, and test valves within a Containment Penetration (i.e., between the Containment Isolation valves) will be maintained locked closed per the locked valve administrative program or surveilled closed per Technical Specifications.

F) The use of ESFAS to actuate automatic containment isolation valves whose function is required in the short term to mitigate the effects of an accident.

G) Selection of isolation valve failure position consistent with the safety related function of the valve as shown in Table 6.2.4-2.

H) The use of redundant paths for systems required to be open to the containment following an accident.

I) The use of diverse means of powering the containment isolation valves required to be closed following an accident such that the required degree of containment isolation is assured despite a single active failure (see Table 6.2.4-2).

J) The design of normally open path to the containment after an accident to withstand containment design conditions and with double isolation between the system and the environment, as discussed in section 6.2.4.1.

K) Providing provisions for the detection and isolation of leakage in systems required to be open to the containment following an accident, as discussed in section 6.2.4.2.1.

As noted in paragraph 6.2.4.2, the equipment hatch, the emergency personnel hatch, the personnel lock, the containment test connection, ILRT verification, ILRT pressure measurement, refueling purge penetrations (when isolated with blind flanges in plant operating modes 1-4), and the fuel transfer penetration all have closures surrounding the access pipe with a blind flange fitted with double 0-rings or gaskets which serve as the primary containment seal. The respective access pipe closures and double 0-ringed blind flanges are designed to withstand the forces resulting from the safe shutdown earthquake. Prior to returning to operation after each refueling, the leaktightness of each foregoing mentioned closure is tested by the application of pressure between the O-rings. Therefore, the requirements of General Design Criterion 56 do not apply.

Also the containment pressure monitoring instrumentation is designed as an extension of the containment building and General Design Criterion 56 does not apply.

Piping penetrations which are connected to the RCS are provided with containment isolation valves in accordance with General Design Criterion 55.

Containment isolation of systems connected to the secondary side of the steam generators (SGs) are designed as extensions of the containment boundary. Such systems include main steam, feedwater, auxiliary feedwater, SG blowdown, and SG blowdown

samples and are shown in valve arrangements 14, 15, and 39. The systems are not connected to the RCS nor to the containment atmosphere. Piping inside the containment from the penetration to the steam generator is Seismic Category I, and thus a piping failure which would connect the penetration to the containment atmosphere is not postulated.

Valves HP-HV-007B (penetration 38) and HP-HV-008B (penetration 39) are the outlet valves to the hydrogen analyzers and valves HP-HV007A (penetration 35) and HP-HV008A (penetration 36) are the inlet valves to the hydrogen analyzers. These valves are used only for post-LOCA hydrogen analysis that may be required at elevated pressures, e.g., above the containment isolation signal setpoint. The valves are normally closed and fail closed. The hydrogen monitoring system is a closed system outside the containment and the piping and monitors are Seismic Category I and Safety Class 2. Therefore, a containment isolation actuation signal to close the valves is not required.

The containment purge penetrations, valve arrangements 22 and 30, are connected directly to the containment atmosphere. When the plant is in operating modes 1-4, the containment purge penetrations may be isolated using blind flanges and General Design Criteria 56 does not apply. When not isolated using the blind flanges in plant operating modes 1-6, containment isolation is provided by automatic containment isolation valves installed inside and outside the containment and General Design Criteria 56 does apply.

The remaining piping penetrations, other than described above, are not connected to the RCS nor to the containment atmosphere.

General Design Criterion 57, therefore, applies. However, as indicated in table 6.2.4-1, the more severe requirements of General Design Criterion 56 are used as the design basis. Each of these remaining penetrations is provided with an automatic isolation valve inside the containment, a check valve being used for this purpose when direction of fluid flow is into the containment.

An operating procedure will require that manual valves, such as those shown on valve arrangements 3, 5, 12, 28, and 35, be verified as closed prior to any operation requiring containment integrity.

An operating procedure will ensure that the charging flow valves are properly positioned following a CIAS and reactor coolant pump seal bleedoff valves are properly positioned following a CSAS.

6.2.4.4 Testing and Inspection

Leak testing of individual valves and penetrations may be accomplished by use of one of the following methods (refer to subsection 6.2.6):

A. Method 1, Pressure Decay

The test volume is established by closing the appropriate isolation valves. The volume to be tested is determined by either direct measurement of liquid drained from the system or by computation. The test volume is pressurized. The test volume pressure is recorded at 5-minute intervals for a minimum of

15 minutes. The leakage rate is computed using the rate of decay of pressure.

B. Method 2, Air Flow

The test volume is established by closing the appropriate isolation valves. This method does not require the determination of the volume to be tested. The test volume is maintained pressurized by a measurable air flow. No minimum test duration shall be required for an air flow test; however, test data shall be obtained during stable conditions.

C. Method 3, Water Flow

The test volume is established by closing the appropriate isolation valves. The test volume is filled with water and is vented by using the test vents and test connections provided on the containment penetrations. The test volume is pressurized and the leakage flow is measured from each valve.

Inservice testing of isolation valves in accordance with ASME OM Code is outlined in paragraph 3.9.6.2.

The initial test program is described in section 14.2.

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6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

The containment hydrogen control system is classified as an engineered safety feature that serves as the combustible gas control system in the containment. Portions of the system, however, are nonsafety-related and non-Seismic Category I as described in this section and in table 3.2-1.

General Design Criterion 41 of Appendix A to 10CFR50 requires that systems be provided as necessary to control the concentrations of hydrogen, oxygen, and other substances, which may be released into the reactor containment following postulated accidents, to ensure containment integrity is maintained.

Following a LOCA, hydrogen gas is generated inside the containment as a result of the following:

A. Metal-water reaction involving the zirconium fuel cladding and the reactor coolant.

B. Radiolytic decomposition of the post-LOCA emergency cooling solutions (oxygen also evolves in this process).

C. Corrosion of metals and paints by solutions used for emergency cooling or containment spray.

The containment hydrogen control system is provided to ensure that the hydrogen concentration is maintained below the lower combustible limit (4 volume %) established by Regulatory Guide 1.7.

The hydrogen control system is composed of a hydrogen recombiner system, a hydrogen monitoring system, and a hydrogen purge system as described in the following sections.

6.2.5.1 Design Bases

Protection of the hydrogen control system from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11. Testing and inspection is discussed in paragraph 6.2.5.4. Additional design bases follow:

A. The hydrogen recombiner system is designed to maintain the containment hydrogen concentration below 4.0 volume %, the lower combustible limit of hydrogen in air as specified in Regulatory Guide 1.7. The design includes provisions to install the system, with all required services connected, within 72 hours of a LOCA, and to have the system functional within 100 hours of the same LOCA. Per the requirements of the Standard Review Plan, the manually installed system at PVNGS can be installed and functional before the hydrogen concentration in Containment reaches 3.5 volume percent.

B. Hydrogen mixing is provided by the containment spray system (described in paragraph 6.2.2.1), and the containment internal structure design, which permits convective mixing and prevents local entrapment of the hydrogen for as long as accident conditions require.

C. The redundant hydrogen monitoring system is designed to measure the hydrogen concentration inside the containment at two independent locations and to alert

the operator in the control room of the need to activate the hydrogen recombiners or hydrogen purge system. The monitors comply with Regulatory Guides 1.7 and 1.97.

D. The redundant hydrogen recombiner and hydrogen monitoring systems are designed so that a single failure of any component, assuming loss of offsite power, cannot impair the ability of the system to perform its designated function.

E. The Seismic Category I hydrogen recombiner system is designed to be functional after an SSE. The recombiner is designed to remain functional during and after an OBE.

System equipment located in the auxiliary building is arranged to preclude loss of hydrogen control capability due to failure of non-Seismic Category I systems or components.

F. Recombiner components are designed in accordance with the applicable safety classification of the ASME Boiler and Pressure Vessel Code, Section III.

G. In the event of offsite power loss, power to the hydrogen control system is supplied by the diesel generators.

H. The hydrogen control system is designed and qualified to remain functional in a non-HELB, harsh radiation environment, as described in the Equipment Qualification Program and UFSAR section 3.11.

I. Periodic tests and inspections are performed to ensure operability and are covered in paragraph 6.2.5.4.

J. Two hydrogen recombiners and their associated control cabinets are shared by all units on the site.

K. One hydrogen purge exhaust air filtration unit is shared by all units on the site.

L. Radiation protection for personnel during recombiner hookup is provided by a shield wall between the containment penetrations and the recombiner. Radiation protection for personnel during recombiner operation is provided by a shield wall between the recombiners and the control cabinets.

M. The hydrogen purge system provides the capability for a controlled purge of the containment atmosphere in order to maintain the hydrogen concentration below 4 volume % following a LOCA. The hydrogen purge system would be utilized in the unlikely event of the combined failure of the redundant hydrogen recombiners. With exception of the containment penetrations (which are common to the recombiner subsystem) the hydrogen purge system is non-Seismic Category I.

6.2.5.2 System Design

6.2.5.2.1 General Description

The total system for control of combustible hydrogen concentrations in the containment following a LOCA consists of a hydrogen monitoring system that measures the containment atmosphere hydrogen concentration, a hydrogen recombiner system

that provides the primary means of reducing containment hydrogen concentrations, and a hydrogen purge system that provides a backup capability for a controlled purge of the containment atmosphere.

These systems are shown schematically in engineering drawings 01, 02, 03-M-HPP-001. Design parameters for major components of each of these systems are given in table 6.2.5-1. Codes and standards applicable to the combustible gas control systems are listed in table 3.2-1. Design provisions for periodic tests and inspections are discussed in paragraph 6.2.5.4.

Following a LOCA, the containment spray system is automatically started. This system serves to minimize localized hydrogen buildup within the containment as well as remove fission products from the containment atmosphere and reduce containment pressure. Within 30 minutes after a LOCA, both redundant hydrogen analyzers are manually activated to monitor hydrogen levels, in accordance with UFSAR 18.II.F.1.6, and to alert the operator in the control room when operation of the hydrogen recombiners or hydrogen purge system is required.

The recombiners are manually started within 100 hours following a LOCA. A plot of post-LOCA containment hydrogen concentration vs. time with one recombiner train functioning for an analyzed core power of 4070 MWt is provided in Figure 6.2.5-2. The Hydrogen Recombiner System design includes two independent redundant trains. Accordingly, system function will not be lost as a result of a single failure (See Table 6.2.5-2). In the improbable event that both recombiner trains are unavailable, operation of the Hydrogen Purge System may be

Table 6.2.5-1
COMBUSTIBLE GAS CONTROL SYSTEM DESIGN PARAMETERS (Sheet 1 of 3)

Parameter	Value
Hydrogen recombiner system	
Hydrogen recombiner units	
Number (total plants)	2
Number required for operation	1
Power (maximum), kW	75[a]
Capacity (minimum), standard ft^3/min	50
Cooling air design flow, standard ft^3/min	3000
Maximum cooling air temperature, °F	120
Heaters	
Number	15 elements
Maximum heat flux, W/in^2	15
Maximum sheath temperature, °F	1600
Gas temperature	
Inlet, °F	see design temperature
In heater section, °F	1300 to 1325
Materials	
Pressure boundary	304 S.S.
Skid and heater enclosure	Structural steel
Heater element sheath	Incoloy-Clad
Dimension (approximate)	
Length, ft/in.	9/8
Width, ft/in.	5/5
Height, ft/in.	8/0
Weight (approximate), lbs	8000
Design pressure, psig	Non-HELB, harsh radiation environment. See UFSAR Section 3.11
Design temperature, °F	
Design integrated radiation exposure, rads	

a. Steady-state operating power is approximately 20 kW.

Table 6.2.5-1
COMBUSTIBLE GAS CONTROL SYSTEM DESIGN PARAMETERS (Sheet 2 of 3)

Parameter	Value
Hydrogen monitoring system	
Hydrogen analyzer	
Number (per unit)	2
Number required for operation	1
Measurement range, volume %	0-10
Accuracy, %	±6.0 (full scale)[(b)]
Design pressure, psig	60
Design temperature, °F	300
Valves	
Design pressure, psig	60
Design temperature °F	300
Piping	
Design pressure, psig	60
Design temperature, °F	300
Hydrogen purge system	
Hydrogen purge exhaust air filtration unit	
Number (total plant)	1
Flowrate, standard ft^3/min	50
Mist eliminator	
Quantity	1
Airflow, standard ft^3/min	50
HEPA filter (upstream)	
Quantity and size	1 - 24x24x12
Pressure drop, Max. in. WG	0.15
Efficiency	99.97% minimum for 0.3 micron particles of DOP per MIL-STD-282

b. Accuracy applies to the components needed to meet Regulatory Guide 1.7. Refer to Table 7.5-1 for accuracy of control room indication needed to meet Regulatory Guide 1.97.

Table 6.2.5-1
COMBUSTIBLE GAS CONTROL SYSTEM DESIGN PARAMETERS (Sheet 3 of 3)

Parameter	Value
Charcoal filter	
Type	Type III Adsorber
Quantity and size approximate	1 cell - 24x24x2
Pressure drop, in. WG	0.45
Efficiency	
Removing elemental iodine (specified)	99.9% minimum (per R.G. 1.52, Rev .2)
Removing methyl iodide (test)	99% minimum Per R.G. 1.52, Rev 2. Corresponds to a 95% decontamination factor for both elemental iodine and organic iodide.
Heating coil capacity, kW	0.66
HEPA filter (downstream)	
Quantity and size	1 - 24x24x12
Pressure drop, clean, in. WG	0.15
Efficiency	99.97% minimum for 0.3 micron particles of Dop per MIL-STD-282

manually initiated under the applicable Emergency Plan Implementing Procedures.

6.2.5.2.2 Hydrogen Mixing

Hydrogen mixing within the containment is accomplished by the containment spray system and the containment internal structure design, which permits convective mixing and prevents entrapment (Design Basis B).

Procedures to terminate system operation contain prerequisites to ensure that either adequate hydrogen mixing has been accomplished and further forced circulation by sprays is not required, or that forced air cooling is established in containment. This ensures that operation will not be terminated just because the system's heat removal function is completed.

The internal structures of the containment building were designed to provide vertical compartments, around each of the steam generators and the reactor vessel, which project upward from the containment basemat. (See engineering drawings 13-P-OOB-007 and -008.) Following a LOCA, the lower portions of the containment will be flooded (See section 6.2.1.1.2.4). This volume of water (long-term) and the steam generators, reactor vessel, and reactor coolant piping (short-term) represent heat sources that establish and maintain natural convective flows upward out of the lower containment volume through the steam generator compartments and reactor cavity.

Intermediate floors and other internal structures of the containment are designed to avoid stagnant accumulations of

containment atmosphere. The use of grating in appropriate areas also promotes the circulation of air.

The reactor drain tank (RDT) room is a closed-ended subcompartment within the containment. A review of possible hydrogen sources within the subcompartment indicated that the only credible mechanism for hydrogen evolution is radiolysis of the water entering the subcompartment as a result of the LOCA and subsequent ESF initiation. In order to eliminate potential ignition sources within the RDT room, permanent lighting have been removed from the room, thereby assuring that there are no ignition sources within the RDT room.

Analysis of hydrogen transport from the RDT room through the annular pipe opening for 30 days post-LOCA was conducted with the following results:

A. Convective transfer is sufficient to maintain the RDT room hydrogen concentration below the combustible limit. Convective transfer is brought about by a density differential between the gas mixture in the RDT room and the remainder of the containment. The density differential results from differences in the average molecular weights of the gas mixtures in the two regions (i.e., the RDT room versus the containment), or the temperature difference between the two regions, or both.

B. The temperature differential between the RDT room and the containment ambient atmospheres is expected to be positive (i.e., the RDT temperature being greater than the containment ambient) and, therefore, aids the establishment of convective flow. However, even under

assumptions which cause the temperature differential to be reduced to zero, the peak hydrogen concentration within the RDT room is 3.7% by volume. A sensitivity study using an extremely conservative -3F differential resulted in a nominal increase in hydrogen concentration over Regulatory Guide 1.7 limit, within the RDT room.

The hydrogen purge system (portion inside containment) is designed to remain intact following a LOCA.

Single failure analyses for the systems that provide containment atmosphere mixing are provided in subsection 6.2.2.

6.2.5.2.2.1 Hydrogen Recombiner System. The hydrogen recombiner system consists of the following components: Within the containment, each loop is comprised of a suction header (influent piping) with motor-operated valves and a discharge header (effluent piping) with check valves. Outside the containment, in the auxiliary building, each loop consists of influent piping, manual and motor-operated isolation valves, sample piping, a portable hydrogen recombiner skid, and effluent piping.

The hydrogen recombiner skid packages are thermal-type units and will be shared by all units. A single failure analysis is given in table 6.2.5-2.

The piping and instrumentation diagram for the system is given in engineering drawings 01, 02, 03-M-HPP-001. The hydrogen recombiner system is started manually. To put the hydrogen control system into operation, two recombiner skids are moved into the auxiliary building from onsite storage, aligned, and

Table 6.2.5-2

COMBUSTIBLE GAS CONTROL SYSTEM SINGLE FAILURE ANALYSIS

No.	Component	Failure Mode	Failure Mechanism	Effect on System	Method of Detection
1	Hydrogen recombine	Fails to start	Diesel generator failure: mechanical and/or electrical failure	None due to redundant recombiner train	Indication of lack of power at manual control station
2	Hydrogen analyzer	Signal failure	Sensing cell depletion	None due to redundant analyzer	Periodic testing and control room annunciation
		Electronic failure	Electrical component fails	None due to redundant analyzer	Periodic testing and control room annunciation
		Mechanical failure	Mechanical component fails	None due to redundant analyzer	Periodic testing and control room annunciation

connected to the influent and effluent piping in the auxiliary building. The recombiner control units are also moved into the auxiliary building, aligned, and connected to Class 1E power. All system services and isolation valves are opened and the recombiner units are manually started.

The containment atmosphere is drawn into the recombiner package through the suction header by means of a blower. Before entering the reaction chamber, the feed gas is electrically heated above 1150F, the hydrogen-oxygen reaction temperature. After recombination, the hot gas and water vapor leaving the reaction chamber enter a heat exchanger where they are cooled to approximately 150F. Air from outside the auxiliary building is used as cooling air and is returned to outside after cooling. The cooled air is at a low enough relative humidity and high enough temperature to prevent condensation of water vapor. The cooled gas and water vapor are then piped back to the containment.

Containment hydrogen concentration is measured by drawing recombiner influent through the gas analyzer. Provisions are also made for periodic checks of the hydrogen analyzer performance. A backup analyzer is available should a malfunction occur in the first analyzer.

Tests have verified that the hydrogen-oxygen recombination is not a catalytic surface effect associated with the heaters, but occurs due to the increased temperature of the process gases. As the phenomenon is not a catalytic effect, saturation of the unit is not predicted to occur. Results of testing a prototype electric hydrogen recombiner and production unit test results

are given in reference 1. There is no difference between the hydrogen recombiner units to be installed in PVNGS and the unit for which the tests were conducted.

6.2.5.2.2.2 Hydrogen Monitoring System. The hydrogen monitoring system for each unit consists of two completely redundant trains. Each train consists of a hydrogen sensor, an electronic subassembly, and local and remote readout/alarms. The electronic subassemblies for trains A and B are housed separately in cabinets located in the auxiliary building. A remote control panel mounted on the main control board provides control of each analyzer. Local indication and a control room high hydrogen alarm are provided to meet the guidance of Regulatory Guide 1.7. Redundant indication and recording for one channel are also provided in the control room per Regulatory Guide 1.97 (refer to Table 1.8-1). The heat trace used on the hydrogen monitoring sample piping is quality class QAG seismic Category IX.

A bottled nitrogen and hydrogen supply is used to calibrate the sensors at those intervals specified in the Technical Specifications.

Hydrogen measurement is accomplished by using a thermal conductivity cell and a catalytic reactor. The sample gas first flows through the sample section of the cell, then passes through the catalytic converter where hydrogen in the sample is catalytically combined with free oxygen to form water vapor, then passes through the reference section of the cell. The hydrogen content is indicated by the difference in thermal conductivity between the sample and reference sides of the

cell. Oxygen, in an amount sufficient to combine hydrogen at the highest range of the analyzer, is added to the sample gas, prior to passing through the sample section of the cell. The accuracy of the hydrogen analyzer components (e.g., the high level alarm) supporting compliance with Regulatory Guide 1.7 is given in Table 6.2.5-1.

The accuracy of the hydrogen analyzer components (e.g., control board recorder and indicator) supporting compliance with Regulatory Guide 1.97 is given in Table 7.5-1. These Table 7.5-1 values are descriptive of installed equipment, not prescriptive; the adequacy of the subject instruments is evaluated in applicable plant calculations and/or other design output documents.

A single failure analysis is given in table 6.2.5-2.

Refer to subsection 18.II.F.1.6 for TMI-related information pertaining to the containment hydrogen monitor.

6.2.5.2.2.3 Hydrogen Purge System. The hydrogen purge exhaust air filtration unit consists of a mist eliminator, an upstream and downstream high efficiency particulate air (HEPA) filter, charcoal adsorption filter, electric duct heater, and associated piping, valves, ductwork, dampers, instruments, and controls. The isolation valves are the only moving parts located inside the containment. The hydrogen purge system is designed to exhaust containment atmosphere at a rate of 50 standard cubic feet per minute and feed service air back to containment at the same rate. The driving head for the purge unit is developed from the differential pressure between the containment building and the plant stack. If the pressure

inside containment is insufficient to establish flow through the purge unit, the continual air flow into the containment from the service air system will serve to reduce the hydrogen concentration until the necessary differential pressure is achieved. The purge unit, like the recombiners, is mounted on a mobile skid package shared by all units.

The hydrogen purge supply and exhaust lines are located in missile-protected areas, and are designed to circulate air in a manner that prevents either containment spray or sump water from entering the ducts.

Should it be necessary to use the hydrogen purge system, operational considerations and site meteorology would determine the timing and duration of purges. In any case, sufficient purging would be performed to maintain the hydrogen concentration in the containment atmosphere below 4 volume %.

The hydrogen purge system was designed and constructed as a nonsafety system except for containment penetrations which are the same Seismic Category I penetrations used by the recombiners. A single failure analysis is not applicable to this system.

6.2.5.2.3 Plant Protection System Signals

The post-LOCA hydrogen monitoring and hydrogen recombiner systems are manually initiated. No plant protection signals are incorporated.

6.2.5.2.4 Environmental Qualification Tests

Environmental qualification tests are described in section 3.11.

6.2.5.3 Design Evaluation

A. Two completely separate and redundant recombiner systems are shared by all units at the site, each powered from a separate Class 1E electrical bus. Thus, a single failure will not prevent the recombiners from performing their safety function as shown in table 6.2.5-2.

Tests have verified that recombination is not a catalytic surface effect, but that it occurs due to the increased temperature of the process gases. Poisoning of the unit by fission products or containment spray solution will not occur. The heater-recombiner section consists of 15 electric heater elements each with a rating of 2.4 kW. Failure of up to one-third of the heaters will not significantly affect the efficiency of the recombiner.

During their operation, the recombiners and auxiliary equipment are located in the auxiliary building and are not exposed to the temperature and pressure transients, chemical, and radiation environment of the containment post-LOCA. Table 6.2.5-3 gives the plant parameters used to determine the amount of hydrogen evolved from the sources discussed below. For an analyzed core power of 4070 MWt, the hydrogen production from each of these sources is shown in figure 6.2.5-1.

The following paragraphs discuss the method used to evaluate the contribution of various sources.

1. Radiolytic Hydrogen Generation

   Water is decomposed into free hydrogen and oxygen by the absorption of energy emitted by fission products

contained in the fuel and fission products intimately mixed with the LOCA water. The quantity of hydrogen that is produced by radiolysis is a function of both the energy of ionizing radiation absorbed by the LOCA

Table 6.2.5-3

PARAMETERS USED TO DETERMINE HYDROGEN GENERATION

(Sheet 1 of 1)

Reactor power level, MWt (3990 +2% uncertainty)	4070
Containment net free volume (minimum), ft^3	2.6×10^6
Containment temperature before accident, °F	120
Weight zirconium, lb	83,000[(a)]
Corrodible metals	Aluminum, Zinc (galvanized steel), zinc-based paints

(a) The value listed for quantity of Zirconium is conservative following implementation of new top grid design for fuel assemblies. See Chapter 4 for details.

water and the net hydrogen radiolysis yield, $G(H_2)$, pertaining to the particular physical-chemical state of the irradiated water.

Evidence indicates that the net hydrogen yield from the radiolysis of pure water is 0.44-0.45 molecules per 100 eV of absorbed energy when the gaseous radiolysis products are continuously purged from the water. In the presence of reactive solutes in water, assuming the absence of gas purging of the solution, significant recombination of the products of radiolysis can occur, thereby reducing the net hydrogen yield. According to published data from ORNL, the net yield of hydrogen under conditions approximating those of the containment sump is 0.3 molecule/100 eV. In accordance with Standard Review Plan 6.2.5, a value of 0.5 molecule/100 eV was conservatively assumed for the net yield of hydrogen from radiolysis of all LOCA water.

The assumptions given in Regulatory Guide 1.7 were used to determine the fission product distribution after the accident. This distribution is assumed to occur instantaneously after the accident, and hydrogen production is assumed to begin immediately. Fifty percent of the halogens and 1% of the solids in the core are assumed to be released from the fuel and intimately mixed with the water in the sump. All noble gas activity is released from the fuel and is present in the containment atmosphere. Table 6.2.5-4 gives a summary of the assumptions made in the

analysis. The analysis was based on the equations given in Appendix A to NRC Standard Review Plan 6.2.5.

2. Zirconium-Water Reaction

As a result of a LOCA, fuel cladding temperatures begin to rise beginning after blowdown and continue until core refill. Zirconium reacts with steam according to the following reaction:

$$Zr + 2H_2O \rightarrow ZrO_2 + 2H_2$$

Thus, for each mole of zirconium that reacts, two moles of free hydrogen are produced. The extent of the metal-water reaction and associated hydrogen generated depends strongly on the course of events assumed for the accident and on the effectiveness of emergency cooling systems. Paragraph 6.3.3.1 indicates the peak core-wide oxidation of less than 0.86% for the design basis LOCA. The amount of hydrogen assumed to be generated by metal-water reaction in determining the performance requirements for combustible gas control systems is five times the maximum amount calculated.

The analysis conservatively assumes that hydrogen generation from the metal-water reaction goes to completion instantaneously. The hydrogen evolved is assumed to mix homogeneously with the containment atmosphere.

Table 6.2.5-4

SUMMARY OF ASSUMPTIONS USED FOR HYDROGEN GENERATION FROM RADIOLYSIS

1. Reactor power level is 4070 MWt (3990 + 2% uncertainty).
2. An insignificant quantity of hydrogen is generated due to the radiolysis from the noble gas isotopes.
3. The guidelines as set forth in Regulatory Guide 1.7 were followed:
   a. 100% of the noble gases are released to the atmosphere
   b. 50% of the halogens and 1% of the solids present in the core are intimately mixed with the coolant water
   c. $G(H_2)$ is 0.5 molecule/100 eV
   d. The following percentage of fission product radiation energy is absorbed by the coolant:

Percentage	Radiation Type	Location of Source
0	Beta	Fuel rods
100	Beta	Coolant
10	Gamma	Fuel rods
100	Gamma	Coolant

3. Corrosion of Metals and Paints in Containment

Hydrogen is formed by corrosion of metals in the containment. The significant portion of this source of hydrogen is from the corrosion of zinc (and, to a lesser extent, aluminum).

Zinc in the containment is in two forms: zinc-based paint and galvanized steel. Use of galvanized steel and zinc-rich primers in containment is limited as much as practical. The mass of zinc in containment is conservatively analyzed at 21,000 lb_m over a surface area of 230,000 ft^2. The mass of zinc-rich primer is conservatively analyzed at 32,000 lb_m over a surface area of 287,000 ft^2. During a LOCA, the containment is sprayed with a borated solution. During the long-term recirculation phase, the pH of the spray will be maintained in the range of 7 to 8.5 by the addition of trisodium phosphate (from baskets located near the containment sump). The hydrogen generation rates from zinc-based paint and galvanized steel in this environment are given in table 6.2.5-5. The hydrogen generation rate from corrosion of zinc is shown in figure 6.2.5-2. Use of aluminum inside the containment has been kept to a practical minimum. The mass of aluminum in containment is conservatively analyzed at 3,000 lb_m over a surface area of 1,096.9 ft^2. The hydrogen generation rate from corrosion of aluminum for an analyzed core power of 4070 MWt is shown in figure 6.2.5-2.

Table 6.2.5-5

HYDROGEN GENERATION RATES USED IN THE POST-ACCIDENT CONTAINMENT HYDROGEN GENERATION ANALYSIS(2) - ALL ANALYZED CORE POWER / STEAM GENERATOR CONFIGURATIONS

Temperature (°F)	Hydrogen Generation Rate (SCF/ft^2-h)	
	Galvanized Steel	Zinc-Based Paint
120	3.76E-05	6.65E-05
160	0.000162	2.87E-04
200	5.86E-04	0.00104
240	0.00183	3.24E-03
280	5.05E-03	8.94E-03

4. Miscellaneous Sources of Hydrogen

During normal operation of the plant, hydrogen is dissolved in the primary system water. The concentration of hydrogen in primary coolant ranges from 25 to 50 cubic centimeters per kilogram of coolant. The total amount of hydrogen in the primary system is considered to be insignificant (less than 10 pounds of H_2 total if the concentration is 50 cubic centimeters per kilogram of coolant).

B. In the extremely unlikely event that a LOCA occurs and the redundant recombiners fail to function properly, the hydrogen purge system may be utilized to control the hydrogen concentration inside the containment. Operation of the hydrogen purge system would be as directed from the TSC under applicable Emergency Plan Implementing Procedures.

The credible failures to the hydrogen recombiners and monitors involve mechanical failure, loss of power, missile impact, and flooding. Since both recombiners and monitors are completely redundant, no single mechanical failure could cause loss of function. The power supply to each redundant unit is from a separate Class 1E power source so that no single electrical failure could impair the operation of both safety trains. The components contained in each of the redundant systems are physically separated to ensure that missile impact due to a single failure would not impair the ability of the system to perform its designated safety function. The recombiners

and the hydrogen analyzers are located in the auxiliary building.

The suction points are above the post-LOCA water level (as specified in paragraph 6.2.1.1.2.4). The hydrogen recombiner system and hydrogen monitoring system are designed in accordance with Seismic Category I requirements as specified in section 3.2. (The hydrogen purge system and recombiners use the same Seismic Category I containment penetrations.) The components (and supporting structures) of any system, equipment, or structure, which are not Seismic Category I, and whose collapse could result in loss of a required function through either impact or flooding, are analytically checked to determine that they will not collapse when subjected to seismic loading.

C. The internal structures of the containment building are designed to provide vertical, open-ended compartments around each steam generator and pair of reactor coolant pumps and to rise from the lowest level of the containment to above the operating floor. Outside the secondary shield, the levels beneath the concrete operating floor are designed as open grating to preclude stagnant air pocketing. Auxiliary spray headers are located at elevation 120 and 140 feet to ensure adequate spray coverage of this sheltered volume. The interior of the containment above the operating floor is designed as one large, open compartment. With one of two redundant trains of four spray headers operating in conjunction with the auxiliary spray headers described above, the containment

spray system is designed to provide 94% coverage of the containment volume at a flowrate of 3890 gallons per minute with a maximum water temperature of 120F. These flows provide the mechanism for establishing convection air flows downward. Following a LOCA, the steam generators and reactor coolant system (short-term), and containment sump water (long-term) would provide the heat sources which establish and maintain upward natural convection flows within the containment. The water level in the containment post-LOCA has been calculated to be approximately 10 feet 6 inches above the floor and has a nominal temperature of 300F.

6.2.5.4 Test and Inspections

The analytical and test program for the hydrogen recombiners includes proof of principle tests and full-scale prototype tests on a production recombiner. The tests were completed and the results of these tests were submitted to the NRC in reference 1.

In the design of the equipment actually installed at PVNGS, all recombiner components can be inspected and are accessible for maintenance during normal plant operation.

Periodic testing of the containment hydrogen control system is described in the Technical Specifications.

Initial testing is described in section 14.2

6.2.5.5 Instrumentation Requirements

6.2.5.5.1 Hydrogen Recombiner System

A manual control station is provided for each train for starting and stopping the unit. The controller maintains the correct power input to bring the recombiner above the threshold temperature for the recombination process. The controller setting can be adjusted to accommodate variations in containment temperature and pressure in the post-LOCA environment. The system is designed to conform to the applicable portions of IEEE-279 and is powered from a Class 1E source. No automatic initiating signals or alarms are provided. The hydrogen recombiners are manually actuated based on containment atmospheric samples discussed in paragraph 6.2.5.2.2.2. The unit gas flow is monitored at various points on the unit control panel. Monitoring the recombiner system is provided in accordance with subsection 7.5.1 and table 7.5-1.

6.2.5.5.2 Hydrogen Purge System

Operation of the hydrogen purge system is manually initiated from the control room. No automatic initiating signals or alarms are provided. In the improbable event of loss of both recombiner trains, the hydrogen purge system may be manually actuated based on containment atmospheric samples discussed in paragraph 6.2.5.2.2.2.

6.2.5.6 References

1. Henrie, J. O. and Stone, L. R., "Thermal Hydrogen Recombiner System for Water-Cooled Reactors," Rockwell International, AI-75-2, Rev 3(P), Canoga Park, California, July 1977. APS Number N993-90-3.

2. Van Rooyen, D., Hydrogen Release From Zn Corrosion, Brookhaven National Laboratory Memorandum to H. F. Conrad, August 2, 1978.

6.2.6 CONTAINMENT LEAKAGE TESTING

This subsection presents the testing program for the reactor containment integrated leakage rate tests (Type A tests), containment penetration leakage rate tests (Type B tests), and containment isolation valve leakage rate tests (Type C tests) and complies with 10CFR50, Appendix A, General Design Criteria, and Appendix J, Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors, Option B – Performance-Based Requirements. Option B identifies the performance-based requirements and criteria for periodic leakage-rate testing. Specific guidance concerning a performance-based leakage-test program, acceptable leakage-rate test methods, procedures and analyses that may be used to implement these requirements and criteria that are provided in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program." Regulatory Guide 1.163 endorses, with exceptions, NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10CFR Part 50, Appendix J. The NEI 94-01 guideline in turn, endorses ANSI/ANS 56.8-1994, "Containment System Leakage Testing Requirements."

6.2.6.1 Reactor Containment Integrated Leakage Rate Test

After completion of construction of the reactor containment, including installation of all portions of mechanical, fluid, electrical, and instrumentation systems penetrating containment associated with containment integrity, and after satisfactory completion of the structural integrity tests as described in subsection 3.8.1, the preoperational containment integrated

leakage rate test is performed to verify that the actual containment leakage rate does not exceed the design limits.

After completion of the preoperational containment integrated leakage rate test, periodic Type A tests are conducted at intervals described in facility Technical Specifications.

In order to ensure a successful integrated leakage rate test, local leakage rate tests (Types B and C) are performed on penetration boundaries and on containment isolation valves. During the period between the completion of one Type A test and the initiation of the containment inspection for the subsequent Type A test, repairs are made, if necessary, to ensure that leakage through the containment isolation barriers does not exceed design limits. Repairs or adjustments are permitted prior to or during the Type A test provided that the change in leakage rate determined by local leakage rate testing is added to the Type A test result.

An integrated leakage rate test (Type A) is performed to determine that the total leakage from the containment does not exceed the maximum allowable leakage rate (La) at a calculated peak containment internal pressure of Pa, as defined in 10CFR50, Appendix J. Pertinent test data, including test pressures, test duration, and definitions of terms are presented in table 6.2.6-1. Acceptance criteria is given in facility Technical Specifications.

The Type A test may be conducted per ANSI/ANS 56.8-1994 or per BN-TOP-1, using the absolute method. Measurements of containment atmosphere drybulb temperature, dewpoint temperature (water vapor pressure), and pressure are taken to

calculate the leakage rate. A standard statistical analysis of the data is conducted using a linear least squares fit regression analysis to calculate the leakage rate and associated 95% confidence level (or maximum expected measurement system error). The calculated leakage rate and upper 95% confidence level are documented. Type B and C leakage rates not accounted for in the integrated leak rate test shall be added to the Type A test leakage rate UCL to determine an upper bound on the overall integrated leakage rate. The additions shall be based on minimum pathway leakage rates. Instrumentation meeting the requirements of ANSI/ANS 56.8-1994 may be used in lieu of the data acquisition system described in table 6.2.6-2.

Prior to commencement of any Type A test, the pretest requirements described in 10CFR50, Appendix J, are met.

Upon completion of the Type A test, a verification test is conducted to confirm the capability of the Type A data acquisition and reduction system to satisfactorily determine the calculated containment integrated leakage rate. The verification test is accomplished by imposing a known leak on the containment or by pumping back a known quantity of air into containment through a calibrated flow measurement device. Verification test acceptance criteria are in accordance with ANSI/ANS 56.8-1994 or BN-TOP-1, as applicable.

If, during a Type A test, including the verification test, excessive leakage paths are identified which interfere with satisfactory completion of the test, or which result in the Type A test not meeting the acceptance criteria of facility

Table 6.2.6-1

TYPE A TEST DATA (Sheet 1 of 2)

<u>4070 MWt</u>:	
Peak test pressure The calculated peak internal pressure related to the design basis loss-of-coolant accident.	Pa = 58 psig (see table 6.2.1-9)
Maximum allowable leakage rate The maximum allowable leakage from the containment building.	La = 0.1%/day (mass percent)
Measured leakage rate Overall measured leakage rate during Type A test.	Lam (%/day) (mass percent)
Imposed leakage rate The leakage rate imposed on the containment during the verification test. Li is 75% to 125% of La.	Lo
Verification test leakage The total containment leakage, including Lo, measured during the verification test.	Lc
Test duration A. After the containment atmosphere has stabilized, the integrated leakage rate test period begins. The duration of the test period must be sufficient to enable adequate data to be accumulated and statistically analyzed so that leakage rate and upper confidence limit can be accurately determined.	

Table 6.2.6-1

TYPE A TEST DATA (Sheet 2 of 2)

B. A Type A test shall last a minimum of 8 hours after a minimum 4-hour stabilization period and shall have a total of not less than 20 sets of data points at approximately equal time intervals.	
C. The Type A test cannot be successfully terminated until the acceptance criteria of facility Technical Specifications are met.	
Temperature limits during Type A test	40 to 120F
Free air volume	2.6×10^6 ft^3

Table 6.2.6-2

TYPICAL DATA ACQUISITION SYSTEM FOR PRIMARY CONTAINMENT INTEGRATED LEAKAGE RATE TEST (Sheet 1 of 2)

Item	No. Req'd	Description
UJN-1	1	Data acquisition system consisting basically of: multiplexer/ scanner/programmer/coupler capable of automatic, periodic scan mode
UI-1	1	Numeric display to read drybulb and dewpoint temperature in °F
KIT-1	1	Digital clock with binary coded decimal (BCD) output
UR-1	1	Digital printer with BCD 8421 code or pure binary 8421 code
PIT-1	1	Precision pressure gauge with BCD 8421 shaft encoder kit Range: 0 to 100 psia Accuracy: 0.010% of reading ±0.002% of full scale or better Repeatability: 0.005% of full scale
PE-1	1	Fused quartz bourdon capsules - for PI-1 Range: 0 to 100 psia
TE-1	10	Resistance temperature detectors Range: (system) 32 to 150F Accuracy: ±0.5F or better Repeatability: ±0.1F
ME-1	3	Dewpoint temperature detectors Range: (dewpoint temperature) 0 to 120F Accuracy: ±1.0F or better Repeatability: ±0.5F over the range of 40 to 120F

Table 6.2.6-2

TYPICAL DATA ACQUISITION SYSTEM FOR PRIMARY CONTAINMENT INTEGRATED LEAKAGE RATE TEST (Sheet 2 of 2)

Item	No. Req'd	Description
FT-1[(a)]	1	Flow transmitter Range: 0 to 10 standard ft^3/min Accuracy: ±1% full scale including linearity Repeatability: ±0.2% full scale
PT-1[(a)]	1	Pressure transducer Range: 0 to 75 psig Accuracy: Combined linearity and hysteresis within ±0.5% full scale
FI-1/PI-1[(a)]	2	Digital display FI-1: 0 to 10 standard ft^3/min PI-1: 0 to 75 psig

a. Used for imposed leakage verification test only.

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 1 of 12)

Penetration[j] Number	1,2,3,4	5	6		7		8,10	9	
Valve arrangement (see figure 6.2.4-1)	14	-	35		43		15	34	
Function	Main steam	Spare	Demineralized water		Fire protection		Feedwater	Radwaste drain	
Vented and drained for Type A test[g]	No[a]		Yes		Yes		No[a]	Yes	
Containment isolation valve tag nos.	None[a]		DWE-V061	DWE-V062	FPE-V089	FPE-V090	None[a]	RDA-UV023	RDB-UV024
Valve sizes, in.	-		2	2	6	6		3	3
Valve type	-		Globe	Globe	Gate Outside	Check		Gate	Gate
Location	-		AB	CB	AB	CB		CB	AB
Type C tested	-		Yes	Yes	Yes	Yes		Yes	Yes
Test pressure on CB side[h]	-		Yes	Yes	Yes	Yes		Yes	Yes
Status during Type A test	-		C	C	C	-		C	C

a. Valves are in the secondary side of the steam generator (SG). These valves are not subject to Type C tests because they are not depended on in the LOCA dose calculations to keep the radiological consequences of a LOCA to within the 10 CFR 50, Appendix A General Design Criteria 19 and 10 CFR 100 limits. The LOCA dose calculations assume a single failure of a 10 CFR 50, Appendix A General Design Criteria 57 valve or a stuck open ADV.
b. Valves are opened in event of LOCA.
c. Instrumentation lines are considered an extension of CB boundary.
d. Inboard butterfly valves will be leakage tested in reverse direction.
e. Relief valves exhausting to containment sump or RDT are tested hydrostatically when piping is pressurized for Type C test of isolation valves. Pressure is under seat which provides a conservative test.
f. This system is used for decay heat removal after plant initial operation. Isolation valves are closed and system vented only for initial Type A test (prior to operation).
g. Pathways that are Type B or C tested within the previous 24 calendar months prior to the Type A test need not be vented or drained.
h. If test pressure is not applied during the Type A test, the Type A test results will be adjusted.
i. Position of valve is determined by Operations to maintain the plant in a safe shutdown condition.
j. Manual vent, drain, and test valves between the Containment Isolation Valves will be maintained locked closed under administrative controls or surveilled closed per Technical Specifications.
k. Penetrations may be isolated using blind flanges located outside containment in plant operating modes 1-4. Double o-ring blind flanges are Type B tested by pressurizing the interspace between o-rings.
l When blind flanges are installed, only Type B testing of the blind flanges is required.
m. For application of the single failure rule to check valves, refer to Section 3.1.30.
n. In Units where DMWO 2529758 has been implemented, valve CHA-UV-715 is removed and valves HPA-UV-023 & HPA-UV-024 are de-terminated with upstream piping cut and capped as the new containment boundary.
o. In units where DMWO 2778159 has been implemented, applicable valve(s) have been removed.
p. Applicable in those Units where DMWO 4304156 has been implemented.

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 2 of 12)

Penetration[j] Number	11,12	13		14			15		16			17	
Valve arrangement (see figure 6.2.4-1)	15	7		7			7		7			1	
Function	Feedwater	HPSI		HPSI			HPSI		HPSI			LPSI	
Vented and drained for Type A test[g]	No[a]	No		No			No		No			No	
Containment isolation valve tag nos.	None[a]	SIE-V113	SIB-UV616 SIA-UV617	SIE-V123	SIB-UV626 SIA-UV627	SIE-[p] V1024	SIE-V133	SIB-UV636 SIA-UV637	SIE-V143	SIE-UV646 SIA-UV647	SIE-[p] V1027	SIE-V114	SIB-UV615
Valve sizes		3	2	3	2	3	3	2	3	2	3	12	12
Valve type		Check	Globe	Check	Globe	Gate	Check	Globe	Check	Globe	Gate	Check	Globe
Location		CB	AB	CB	AB	AB	CB	AB	CB	AB	AB	CB	AB
Type C tested		No[b]	No[b]	No[b]	No[b]	No	No[b]	No[b]	No[b]	No[b]	No	No[b]	No[b]
Test pressure on CB side[h]		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Status during Type A test		NA	C	NA	C	C	NA	C	NA	C	C	NA	O/C[i]

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 3 of 12)

Penetration[j] Number	18		19		20		21		22		23			
Valve arrangement (see figure 6.2.4-1)	1		1		1		23		23		40			
Function	LPSI		LPSI		LPSI		CB spray		CB Spray		Recirc. sump			
Vented and drained for Type A test[g]	No		No		No		Yes		Yes		Yes			
Containment isolation valve tag nos.	SIE-V124	SIB-UV625	SIE-V134	SIA-UV635	SIE-V144	SIA-UV645	SIA-V164	SIA-UV672	SIB-V165	SIB-UV671	SIA-UV673	SIA-UV674	SIA-PSV151	SIA-UV708[o]
Valve sizes	12	12	12	12	12	12	10	8	10	8	24	24	3/4	1/2
Valve type	Check	Globe	Check	Globe	Check	Globe	Check	Gate	Check	Gate	B'fly	B'fly	RV	Globe
Location	CB	AB	CB	AB	CB	AB	CB	AB	CB	AB	CB	AB	AB	AB
Type C tested	No[b]	No[b]	No[b]	No[b]	No[b]	No[b]	Yes	No	Yes	No	No[b]	No[b]	No	No
Test pressure on CB side[h]	NA	NA	NA	NA	NA	NA	NA	Yes	NA	Yes	NA	NA	NA	NA
Status during Type A test	NA	O/C[i]	NA	O/C[i]	NA	O/C[i]	NA	C	NA	C	C	C	C	C

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 4 of 12)

Penetration[j] Number	24			25A		25B		26			
Valve arrangement (see figure 6.2.4-1)	16			33		33		10			
Function	Recirc. sump			Radiation monitor		Radiation monitor		Shutdown cooling			
Vented and drained for Type A test[g]	Yes			Yes		Yes		No[g]			
Containment isolation valve tag nos.	SIB-UV675	SIB-UV676	SIB-PSV140	HCB-UV044	HCA-UV045	HCB-UV047	HCA-UV046	SID-UV654	SIB-UV656	SIB-HV690	SIB-PSV189
Valve sizes	24	24	3/4	1	1	1	1	16	16	10	6 x 10
Valve type	B’fly	B’fly	RF	Globe	Globe	Globe	Globe	Gate	Gate	Globe	RV
Location	CB	AB	AB	CB	AB	CB	AB	CB	AB	AB	CB
Type C tested	No[b]	No[b]	No	Yes	Yes	Yes	Yes	No	No	No	No
Test pressure on CB side[h]	NA	NA	NA	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No[e]
Status during Type A test	C	C	C	C	C	C	C	O/C[f],[i]	O/C[f],[i]	C	C

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 5 of 12)

Penetration[j] Number	27				28			29		30		31	
Valve arrangement (see figure 6.2.4-1)	10				12			19		19		29	
Function	Shutdown cooling				SI tank drain			LP nitrogen		HP nitrogen		Instrument air	
Vented and drained for Type A test[g]	No[f]				Yes			Yes		Yes		Yes	
Containment isolation valve tag nos.	SIC-UV653	SIA-UV655	SIA-HV691	SIA-PSV179	SIA-UV682	SIE-V463	SIE-PSV474	GAE-V015	GAA-UV002	GAE-V011	GAA-UV001	IAE-V021	IAA-UV002
Valve sizes	16	16	10	6 x 10	2	2	3/4	1	1	1	1	2	2
Valve type	Gate	Gate	Globe	RV	Globe	Globe	RV	Check	Globe	Check	Globe	Check	Globe
Location	CB	AB	AB	CB	CB	AB	CB	CB	AB	CB	AB	CB	AB
Type C tested	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Test pressure on CB side[h]	Yes	Yes	Yes	No[e]	Yes	Yes	No[e]	Yes	Yes	Yes	Yes	Yes	Yes
Status during Type A test	O/C[f],[i]	O/C[f],[i]	C	C	C	C	C	NA	C	NA	C	C	C

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 6 of 12)

Penetration[j] Number	32A	32B	32C	33		34		35			
Valve arrangement (see figure 6.2.4-1)	37	-	-	4		11		2			
Function	CB pressure monitor	Spare	Spare	Nuclear cool-ing water		Nuclear cool-ing water		Hydrogen control			
Vented and drained for Type A test[g]	Yes			Yes		Yes		Yes			
Containment isola-tion valve tag nos.	HCC-HV076			NCE-V118	NCB-UV401	NCB-UV403	NCA-UV402	HPA-UV001	HPA-UV003	HVA-HV007A	HPA-UV0024[n]
Valve sizes	3/4			10	10	10	10	2	2	1	*
Valve type	Globe			Check	B'fly	B'fly	B'fly	Globe	Globe	Globe	Globe
Location	AB			CB	AB	CB	AB	CB	AB	AB	AB
Type C tested	No[c]			Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Test pressure on CB side[h]	NA			Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Status during Type A test	O			NA	C	C	C	C	C	C	C

* Unit #1 is ½"

Units #2 & 3 are 1"

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 7 of 12)

Penetration[j] Number	36			37A	37B	38				39		
Valve arrangement (see figure 6.2.4-1)	2			39	39	32				31		
Function	Hydrogen control			SG BD sample	SG BD sample	Hydrogen control				Hydrogen control		
Vented and drained for Type A test[g]	Yes			No[a]	No[a]	Yes				Yes		
Containment isolation valve tag nos.	HPB-UV002	HPB-UV004	HPB-HV008A	None[a]	None[a]	HPA-V002	HPA-UV005	HPA-HV007B	HPA-UV23[n]	HPB-V004	HPB-UV006	HPB-HV008B
Valve sizes	2	2	1			2	2	1	*	2	2	1
Valve type	Globe	Globe	Globe			Check	Globe	Globe	Globe	Check	Globe	Globe
Location	CB	AB	AB			CB	AB	AB	AB	CB	AB	AB
Type C tested	Yes	Yes	Yes	No[a]	No[a]	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Test pressure on CB side[h]	Yes	Yes	Yes			Yes	Yes	Yes	Yes	Yes	Yes	Yes
Status during Type A test	C	C	C			NA	C	C	C	NA	C	C

* Unit #1 is ½"

Units #2 & 3 are 1"

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 8 of 12)

Penetration[j] Number	40			41			42A		42B	
Valve arrangement (see figure 6.2.4-1)	17			8			21		21	
Function	Letdown line			Charging line			Pressurizer sample		Pressurizer sample	
Vented and drained for Type A test[g]	Yes			Yes			Yes		Yes	
Containment isolation valve tag nos.	CHA-UV516	CHB-UV523	CHB-UV924[o]	CHE-VM70	CHA-HV524	CHE-V854	SSA-UV204	SSB-UV201	SSA-UV205	SSB-UV202
Valve sizes	2	2	1/2	3	2	3/4	3/8	3/8	3/8	3/8
Valve type	Globe	Globe	Gate	Check	Globe	Globe	Needle	Needle	Needle	Needle
Location	CB	AB	AB	CB	AB	AB	CB	AB	CB	AB
Type C tested	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Test pressure on CB side[h]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Status during Type A test	C	C	C	NA	C	C	C	C	C	C

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 9 of 12)

Penetration[j] Number	42C		43		44		45			46,47,48,49	50	
Valve arrangement (see figure 6.2.4-1)	21		21		6		13			39	3	
Function	Hot leg sample		RCP bleedoff		Reactor drain tank drain		Reactor drain tank makeup			SG blowdown	Pool cooling	
Vented and drained for Type A test[g]	Yes		Yes	Yes	Yes		Yes			No[a]	Yes	
Containment isolation valve tag nos.	SSA-UV203	SSB-UV200	CHA-UV506	CHB-UV505	CHA-UV560	CHB-UV561	CHE-V494	CHA-UV580	CHA-UV715[n]	None[a]	PCE-V071	PCE-V070
Valve sizes	3/8	3/8	1	1	3	3	1-1/2	1-1/2	1/2		4	4
Valve type	Needle	Needle	Globe	Globe	Globe	Globe	Check	Gate	Globe		Gate	Gate
Location	CB	AB	CB	AB	CB	AB	CB	AB	AB		CB	AB
Type C tested	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		Yes	Yes
Test pressure on CB side[h]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		Yes	Yes
Status during Type A test	C	C	C	C	C	C	NA	C	C		C	C

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 10 of 12)

Penetration[j] Number	51		52		53	54A	55A	56		57	
Valve arrangement (see figure 6.2.4-1)	5		18		9	37	37	22		30	
Function	Pool cooling		RDT vent		Fuel transfer	CB pressure monitor	CB pressure monitor	CB purge		CB purge	
Vented and drained for Type A test[g]	Yes		Yes		Yes	Yes	Yes	Yes		Yes	
Containment isolation valve tag nos.	PCE-V075	PCE-V076	GRA-UV001	GRB-UV002	NA	HCA-HV074	HCB-HV075	CPB-UV003A	CPA-UV002A	CPA-UV002B	CPB-UV003B
Valve sizes	4	4	1	1	NA	3/4	3/4	42	42	42	42
Valve type	Gate	Gate	Globe	Globe	NA	Globe	Globe	B’fly	B’fly	B’fly	B’fly
Location	CB	AB	CB	AB	CB	AB	AB	CB	AB	CB	AB
Type C tested	Yes	Yes	Yes	Yes	Type B	No[c]	No[c]	Yes[l]	Yes[k][l]	Yes[l]	Yes[k][l]
Test pressure on CB side[h]	Yes	Yes	Yes	Yes	NA	NA	NA	No[d]	Yes	No[d]	Yes
Status during Type A test	C	C	C	C	C	O	O	C	C	C	C

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 11 of 12)

Penetration[j] Number	58		59		60		61		62A	63A,63B	67		62B,62C
Valve arrangement (see figure 6.2.4-1)	27		28		24		25		37	39	36		27
Function	CB ILRT		Service air		Chilled water		Chilled water		CB pressure monitor	SGBD sample	Long Term recirc		CB ILRT
Vented and drained for Type A test[g]	NA		Yes		No		No		Yes	No[a]	Yes[b]		NA
Containment isolation valve tag nos.	NA	NA	IAE-V073	IAE-V072	WCE-V039	WCB-UV063	WCB-UV061	WCA-UV062	HCD-HV077	None[a]	SIB-V533	SID-HV331	NA
Valve sizes	NA		3	3	10	10	10	10	3/4		3	3	NA
Valve type	NA	NA	Check	Globe	Check	Gate	Gate	Gate	Globe		Check	Globe	NA
Location	CB	Outside	CB	AB	CB	AB	CB	AB	AB		CB	BA	CB AB
Type C tested	Type B	No	Yes	Yes	Yes	Yes	Yes	Yes	No[c]		No	No	Type B
Test pressure on CB side[h]	NA	NA	Yes	Yes	Yes	Yes	Yes	Yes	NA		NA	Yes	NA
Status during Type A test	NA	NA	NA	C	NA	C	C	C	O		NA	C	NA

Table 6.2.6-3

CONTAINMENT ISOLATION VALVE TESTING[m] (Sheet 12 of 12)

Penetration[j] Number	72		75,76	77		78		79		L1,L3	L2
Valve arrangement (see figure 6.2.4-1)	38		15	36		22		30		26	20
Function	RCP seal injection		Aux FW	Long term recirc		CB purge		CB purge		Air Locks	Eqpt Hatch
Vented and drained for Type A test[g]	Yes		No[a]	Yes		Yes		Yes		NA	NA
Containment isolation valve tag nos.	CHN-V835	CHB-HV255	None[a]	SIA-V523	SIC-HV321	CPB-UV005A	CPA-UV004A	CPA-UV004B	CPB-UV005B	NA	NA
Valve sizes	1-1/2	1-1/2		3	3	8	8	8	8	NA	NA
Valve type	Check	Globe		Check	Globe	B'fly	B'fly	B'fly	B'fly	NA	NA
Location	CB	AB		CB	AB	CB	AB	CB	AB	NA	NA
Type C tested	Yes	Yes		No	No	Yes	Yes	Yes	Yes	Type B	Type B
Test pressure on CB side[h]	Yes	No		NA	Yes	No[d]	Yes	No[d]	Yes	NA	NA
Status during Type A test	NA	C		NA	C	C	C	C	C	C	C

Technical Specifications, the leakage path may be isolated and the Type A test completed. Subsequent to the Type A test, the leakage path is locally leak rate tested and the post repair minimum pathway leakage is added to the Type A test result.

If any Type A test fails to meet the acceptance criteria, the test schedule applicable to subsequent Type A tests is as described in facility Technical Specifications.

6.2.6.2 Primary Containment Penetration Leakage Rate Test

Containment penetrations whose design incorporates resilient seals, gaskets, or sealant compounds; air locks and lock door seals; equipment and access hatch seals; and electrical penetrations receive preoperational and periodic Type B leakage rate tests in accordance with 10CFR50, Appendix J. A list of all containment penetrations subject to Type B tests is provided in table 6.2.6-4.

Electrical penetrations are of a modular design and are provided with leak testing provisions meeting the requirements of IEEE 317.

Electrical penetrations are described in paragraph 3.8.1.1.3.4.

Expansion bellows are not utilized in the design of the mechanical penetrations. The bellows used on the fuel transfer tube penetration is to accommodate relative movement between the refueling canal liner and the containment building penetration and does not form part of the containment building pressure boundary.

Table 6.2.6-4

PENETRATIONS SUBJECT TO TYPE B TESTS

Penetration	Quantity	Test
Personnel lock L-1	1	Door seals interspace Electrical and mechanical penetrations interspace Air lock volume
Emergency lock L-3	1	
Equipment hatch L-2	1	Hatch seals
Fuel transfer tube 53	1	Flange seal interspace
Refueling purge (56, 57) (when blind flanges are installed)	2	
CB pressurization 58, 62B, 62C	1	
Electrical 24 in. nozzle	5	Interspace and seals
Electrical 18 in. nozzle	46	
Electrical 12 in nozzle	40	

The equipment hatch and air lock doors are fitted with double seals with an interspace test connection. Clamps are provided for restraining the air lock inner doors when the air lock chamber is pressurized. When multiple openings of the containment air locks occur, the air locks will be tested at least once every 7 days.

Electrical and mechanical penetrations on the air lock are provided with double seals and test connections.

Type B tests are conducted at containment peak accident pressure (Pa) as defined in table 6.2.6-1. The acceptance

criteria and leakage rate limits are given in the facility test specifications. Test methods are described in paragraph 6.2.6.3 below.

6.2.6.3 Containment Isolation Valve Leakage Rate Tests

Containment isolation valves are Type C tested in accordance with 10CFR50, Appendix J, as listed in table 6.2.6-3.

The process piping, instrumentation tubing, and personnel access penetrations are listed in table 6.2.4-1. Figure 6.2.4-1 shows the location of all test vent and drain connections and the direction in which the isolation valves will be tested.

The containment isolation valves for each piping penetration are tabulated in table 6.2.6-3, together with test method and test direction. The table also indicates the status of the valves during containment building, Type A test, and whether the system will be vented to the containment and drained during the Type A test.

Type C (and B) tests are performed by local pressurization utilizing either the pressure decay or flowmeter method. For the pressure decay method, the test volume is pressurized with air or nitrogen to at least Pa. The rate of decay of pressure of the known free air test volume is monitored to calculate leakage rate. For the flowmeter method, pressure is maintained in the test volume by makeup air, or nitrogen, through a calibrated flowmeter. The flowmeter fluid flowrate is the isolation valve leakage rate. Refer to paragraph 6.2.4.4.

Unless otherwise justified, the containment isolation valves are tested by measuring leakage across the valve seat in the direction out of the containment, in accordance with the requirements of 10CFR50, Appendix J, for Type C testing.

Systems connected to the secondary side of the steam generator, cooling water systems, and other closed systems are not vented to the containment building during Type A tests as indicated in table 6.2.6-3.

Where Type C tests can be performed on isolation valves in closed systems, the results of the Type C test will be added to the Type A test if the system is not vented during the Type A test.

Type C testing of the safety injection lines is not performed. Justification for this is on the basis that these valves will be opened in the event of a LOCA and, therefore, leakage across the isolation valves is not pertinent. If the valves are subsequently closed, the containment pressure will have dropped and reactor coolant will provide a water seal, thus eliminating any leakage across these valves. Reactor coolant will be replenished by the safety injection system, which meets the single failure criteria. A further consideration is that the addition of extra isolation valves in the injection lines for the sole purpose of performing Type C tests would impair the operability of these engineered safety features.

Inservice testing and inspection of these isolation valves, and also the associated piping system outside the containment, will be performed periodically under the ISI requirements of

ASME XI. During normal operation, the systems are water filled and degradation of valves or piping would be readily detected.

The 24-inch butterfly isolation valves on the safety injection system suction piping from the containment recirculation sumps are not Type C tested. These valves are normally closed, do not receive a CIAS and are opened post-accident on a recirculation actuation signal (RAS) to provide cooling and recirculation of safety injection and containment spray water. In addition, the recirculation sump piping penetrating containment connects to a Seismic Category I, Q Class, closed system outside containment that will effectively prevent direct communication between the atmosphere inside and outside containment through these valves. Post-accident, the sump suction lines and in-containment isolation valves will be water-flooded and submerged with a water seal providing additional protection against containment atmosphere leakage.

Isolation valves connected to the secondary side of the steam generator, such as main steam isolation valves, main steam relief valves, feedwater valves, vent valves, blowdown lines, and blowdown sample lines are considered containment isolation valves. These valves are not subjected to Type C tests because they are not depended on in the LOCA dose calculations to keep the radiological consequences of a LOCA to within GDC 19 and 10 CFR 100 limits. The LOCA dose calculations assume a single failure of a GDC 57 valve or a stuck open ADV.

Valves which are Type C tested are tested with the applied test pressure in the same direction as the pressure existing following an accident, except the butterfly and relief valves

listed in table 6.2.6-3. Due to the design of these valves, the test leakage will inherently be equal to or greater than the leakage following an accident.

Containment pressure monitoring lines are considered an extension of the containment boundary and, therefore, the isolation valves are not Type C tested.

Outboard motor operated containment isolation valves on the Containment Spray lines penetrating containment are not required to close on a containment isolation signal, are not required to operate intermittently during an accident, open on a containment spray actuation signal and are designed to fail as is. Therefore, these valves are not Type C tested.

The acceptance criteria for all penetrations and isolation valves subject to Types B and C tests will be given in the PVNGS Technical Specifications.

6.2.6.4 Scheduling and Reporting of Periodic Tests

The periodic leakage rate test schedules for Types A, B, and C tests will be given in the PVNGS Technical Specifications.

Type B and C tests may be conducted at any time during normal plant operations or during shutdown periods so long as the time interval between tests for any individual Type B or C test does not exceed the maximum allowable interval specified in the PVNGS Technical Specifications. Each time a Type B or C test is completed, the overall total leakage rate for all required Type B and C tests is corrected for any differences noted.

Provisions for reporting test results will be given in the PVNGS Technical Specifications.

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6.3 EMERGENCY CORE COOLING SYSTEM

6.3.1 DESIGN BASES

6.3.1.1 Summary Description

The Emergency Core Cooling System (ECCS) or Safety Injection System (SIS) is designed to provide core cooling in the unlikely event of a Loss-of-Coolant Accident (LOCA). The ECCS prevents significant alteration of core geometry, Precludes fuel melting, limits the cladding metal-water reaction, removes the energy generated in the core and maintains the core subcritical during the extended period of time following a LOCA.

The SIS accomplishes these functional requirements by use of redundant active and passive injection subsystems. The active portion of the SIS consists of high and low pressure Safety Injection pumps and associated valves. The passive portion consists of pressurized Safety Injection Tanks (SIT).

Events associated with ECCS and Safety Injection are described in Chapter 15 of the UFSAR.

6.3.1.2 Criteria

6.3.1.2.1 Functional Design Bases

a. The shutoff head and flowrates of the High Pressure Safety Injection Pump (HPSIP) and Low Pressure Safety Injection Pump (LPSIP) were selected to insure that adequate flow is delivered to the RCS to accomplish the functional requirements of Section 6.3.1.1.

b. Storage of fluid for the SIS is accomplished by the Refueling Water Tank (RWT) which contains a sufficient amount of borated fluid to accomplish the functional requirements of Section 6.3.1.1.

c. The SIS is designed such that equal flows are delivered to each injection point, regardless of break location.

6.3.1.2.2 Reliability Design Bases

a. The safety function defined in Section 6.3.1.1 can be accomplished assuming the failure of a single active component during the injection mode of operation or a single active or limited leakage passive failure of a component during the recirculation mode of operation (see 3.1.30 note "a"). For failure analysis, all necessary supporting systems including the onsite electrical power system are considered a part of the Safety Injection System. A Failure Modes and Effects Analysis is presented in Table 6.3.2-3.

b. Components of the Safety Injection System and instrumentation which must operate following a LOCA are designed to operate in the environment of Section 3.11.

c. The Safety Injection System is designed to perform the functions of Section 6.3.1.1 for the entire duration of a LOCA.

d. The Safety Injection System is designed to Seismic Category I requirements.

6.3.1.3 CESSAR Interface Requirements

Provided below are interface requirements repeated from CESSAR Section 6.3.1.3.

Below are detailed the interface requirements that the SIS places on certain aspects of the BOP, listed by categories. In addition, applicable GDC and Regulatory Guides, which C-E utilizes in its design of the SIS, are presented. These GDC and Regulatory Guides are listed only to show what C-E considers to be relevant, and are not imposed as interface requirements, unless specifically called out as such in a particular interface requirement.

Relevant GDC - 1, 2, 3, 4, 13, 18, 20, 21, 22, 23, 35, 36, 37, 54, 57

Relevant Reg. Guides - 1.1, 1.26, 1.28, 1.29, 1.31, 1.36, 1.38, 1.44, 1.46, 1.48, 1.53, 1.64, 1.68, 1.75, 1.79, 1.82

A. Power

1. The Safety Injection System pumps and valves shall be capable of being powered from the plant turbine generator (onsite power source), and/or plant startup power source (offsite power), and the emergency generators (emergency power).

2. Power connections shall be through a minimum of two independent buses so that in the event of a LOCA in conjunction with a single failure in the electrical supply, the flow from one high-pressure and one low-pressure safety injection train shall be available for core protection.

3. Each electrical bus of the above shall be connected to one high-pressure safety injection pump and associated valves and one low-pressure safety injection pump and associated valves.

4. Each emergency generator and the automatic sequencers necessary for generator loading shall be designed such that flow to the core is delivered to the RCS within a maximum of 29 seconds after SIAS is generated. The emergency generator interface requirements are described in Section 8.3.1 and shall be complied with.

5. Instrument power supplies shall be provided as stated in Chapter 8.

6. The SIS hot leg injection valves shall be powered such that a single electrical failure cannot cause spurious initiation of hot leg injection flow through either hot leg injection line, nor shall a single electrical failure prevent deliberate hot leg injection flow through at least one of the hot leg injection lines.

7. Air for all SIS pneumatic valve operators shall be clean, dry, and oil-free.

8. Provisions shall be made to remove power to the safety injection tank vent valves (SI-605, -606, -607, -608, -613, -623, -633 and -643) during plant operation. Provisions shall be made to allow restoration of power to these valves from

the control room and a remote shutdown location. The two safety injection tank vent valves on each SIT shall be powered from separate and independent emergency power sources.

B. Protection from Natural Phenomena

1. Design provisions shall be incorporated such that SIS components are capable of functioning in the event of the maximum probable flood or other natural phenomenon defined in General Design Criteria (GDC) 2 of 10CFR50.

C. Protection from Pipe Failure

1. Pipe Break Considerations - The maximum expected leakage from a moderate energy pipe rupture postulated during normal plant conditions in the Safety Injection System shall be as defined by the methods of Section 3.6. Isolation valves used to contain leakage shall be protected from the adverse effects of a high or moderate energy pipe rupture which might preclude their operation when required.

2. Pipe Leakage Considerations - No limited leakage passive failure or the effects thereof (such as flooding, spray impingement, steam, temperature, pressure, radiation, loss of NPSH, or loss of recirculation water inventory), in the SIS during the recirculation mode shall preclude the availability of minimum acceptable recirculation capability (minimum acceptable capability is

defined as that which is provided by the operation of one subsystem).

3. Design Requirements for Protection from Pipe Break - The Safety Injection System shall be protected from the effects of pipe rupture.

4. The Safety Injection System shall be protected from the effects of pipe whip.

D. Missiles

1. The Safety Injection System shall be protected from missiles in accordance with the Missile Barrier Design Interface Requirements.

E. Separation

1. Adequate physical separation shall be maintained between the redundant piping paths and containment penetrations of the SIS such that the SIS will meet its functional requirements even with the failure of a single active component during the injection mode, or with a single active failure or a limited leakage passive failure during the recirculation mode.

2. The cabling which is associated with redundant channels of vital Class 1E circuits for the SIS shall be physically separated to preserve redundancy and prevent a single event from causing multiple channel malfunctions or interactions between channels.

Associated circuit cabling from redundant channels shall either be separated, provided with isolation devices, or analyzed and/or tested to demonstrate that no credible single failure could adversely affect redundant channels of Class 1E circuits.

3. In the routing of SIS Class 1E circuits and location of equipment served by these Class 1E circuits, consideration shall be given to their exposure to potential hazards such as postulated ruptures of piping, flammable material, flooding, and non-flame retardant wiring. Adequate separation or protective measures shall be provided.

4. Failures of non-safety grade systems shall not compromise redundancy of the SIS.

F. Independence

1. Each SIS safeguards train shall be provided with an independent environmental control system.

2. Power connections for SIS components shall be from a minimum of two independent electrical buses. See A.2 above.

3. Two independent vital instrument power sources shall be provided for the SIS instrumentation. See A.5 above.

G. Thermal Limitations

Not Applicable

H. Monitoring

1. Provisions shall be made for the detection, containment, and isolation of the maximum expected leakage from a moderate energy pipe rupture, as discussed in C.1 above.

2. Process instrumentation shall be available to the operator in the control room to assist in assessing post-LOCA conditions. The type of instrument, parameter measured, and instrument range and accuracy are listed in Table 6.3.1.3-1.

I. Operational Controls

Not Applicable

J. Inspection and Testing

1. Inspection and testing requirements for the SIS are contained in Section 3/4.5 of the CESSAR Technical Specifications and shall be complied with.

2. Prior to initial plant startup, SIS flow tests shall be performed. An adequate supply of water and the necessary test connections at the containment sump shall be provided.

TABLE 6.3.1.3-1
(Sheet 1 of 2)

SAFETY RELATED PROCESS INSTRUMENTATION CESSAR TABLE 6.3.2-3
(Interface Requirements)

Instrument	Number of Channels	Range	Accuracy	Post-Accident Function
Primary System				
Pressurizer Pressure	4	0-3000 psia	± 1%	Initiate SIAS, monitor primary system pressure
Pressurizer Pressure	4	0-750 psia	± 1%	Monitor primary system pressure, provides interlocks on SCS suction valves and SIT isolation valves
Reactor Coolant Hot Leg Temperature Indicator/Recorder	1 per hot leg	375-675°F	± 1%	Monitor and record hot leg temperatures, used to determine when shutdown cooling can be initiated.
Safety Injection System				
HPSI Cold Leg Flow Rate	4	0-750 gpm	± 2.5%	Monitor HPSI cold leg injection flow
HPSI Hot Leg Flow Rate	2	0-750 gpm	± 2.5%	Monitor HPSI hot leg injection flow
Shutdown Cooling/LPSI Flow Rate	2	0-10000 gpm	±2.5%	Monitor Shutdown Cooling/LPSI flow rate. Used to set shutdown cooling flow
Shutdown Cooling Heat Exchanger Inlet and Outlet Temperature Indicator/Recorder	2	40-400°F	± 2.5%	Monitor and record shutdown cooling performance. Used to control RCS cooldown rate.
Shutdown Cooling Heat Exchanger Outlet Temperature	2	40-400°F	± 2.5%	Monitor Shutdown Cooling Heat Exchanger performance.

TABLE 6.3.1.3-1 (Cont'd) (Sheet 2 of 2)

SAFETY RELATED PROCESS INSTRUMENTATION CESSAR TABLE 6.3.2-3
(Interface Requirements)

Instrument	Number of Channels	Range	Accuracy	Post-Accident Function
Safety Injection System				
Wide Range SIT Pressure	1 per tank	0-750 psig	± 2.5%	Monitor SIT pressure
RWT Level	4	0-100%	± 2%	Initiate RAS, monitor RWT level.
Wide Range SIT Level	1 per tank	0-100%	± 2.5%	Monitor SIT Level.
Containment				
Containment Pressure	4	-4-20 psig	± 1 psig	Initiate SIAS, monitor containment pressure

K. Chemistry/Sampling

1. The Sampling System shall provide a means of obtaining remote liquid samples from the SIS for chemical and radiochemical laboratory analysis.

2. The sample lines in contact with the reactor coolant shall be austenitic stainless steel or equivalent material compatible with the fluid chemistry.

L. Materials

1. Safety injection piping and fittings shall be Seismic Category 1.

2. Design and fabrication of the safety injection piping and fittings shall conform to ASME Boiler and Pressure Vessel Code (B&PV) Section III, Class 1 and 2.

3. Pipes and all parts in contact with the system fluid must be of austenitic stainless steel.

   Valve packings, gaskets, and valve diaphragm materials shall also be compatible with the chemistry of the water and the radioactive dose at that location.

4. Care shall be taken to prevent sensitization and to control the delta ferrite content of (1) the welds which join any system fabricated of austenitic stainless steel to the SIS, and (2) the field welds on the SIS.

5. Controls shall be exercised to assure that contaminants do not significantly contribute to stress corrosion of stainless steel.

6. Materials used for the containment and its internal structures shall withstand exposure to all post-accident conditions without causing deleterious or undesirable reactions, or significantly altering the existing recirculating water chemistry.

7. If the Containment Spray System utilizes a common suction with the SIS from the RWT or containment sump, then the materials used in this system shall be austenitic stainless steel or other compatible material and shall conform to the standards of Section III Class 2, ASME B&PV Code and applicable Code cases.

M. System/Component Arrangement

1. To assure that the Engineered Safety Features Systems flow requirements are met, the maximum and minimum acceptable head losses for the piping and fittings are as presented in Table 6.3.1.3-2. The NPSH requirements are shown in table 6.3.2-1.

2. For each safeguards train, the top of the piping junction between the RWT discharge and the containment sump must be located at a minimum of 16 feet below the minimum containment sump water level during recirculation. If containment pressure could go subatmospheric by values

greater than 3 psid, this must be accommodated for by increasing the distance of the piping junction top below the minimum containment sump water level during recirculation by 2.31 feet for each additional psid. The purpose of this requirement is to preclude the possibility of drawing air from the RWT to the safeguard pumps suction during recirculation should the RWT isolation valves remain open during recirculation.

Frictional losses in the safeguard pump suction piping between the containment sump and the junction with the RWT shall not exceed 7 feet, unless the elevation of the top of this junction is lowered an additional foot for each additional foot of head loss.

3. The high pressure safety injection pumps shall be located in the auxiliary building as close as practical to the containment structure.

   a. The elevation of these pumps shall be low enough such that adequate NPSH is available during the recirculation mode when the pumps take suction from the containment sump.

   b. The available NPSH shall be calculated at the pump suction, which may be assumed to be 2.5 ft. above its foundation elevation.

   c. The calculation shall consider concurrent low-pressure safety injection and containment

spray pump operation. Table 6.3.1.3-2 provides CESSAR, HPSI and LPSI pump head loss requirements. NPSH requirements are shown in table 6.3.2-1.

d. Credit shall not be taken for water that could be trapped above the containment floor.

4. The above requirements on location and elevation shall also be applied to the low-pressure safety injection pumps except the pump's suction is 14 inches below its supports. The NPSH required by these pumps is 18 feet at a runout flow rate of 5100 gpm per pump. This design calculation shall assume:

   a. Concurrent high-pressure safety injection and containment spray pump operation and flow.

   b. A refueling water tank temperature of 100F.

5. SIS components shall be properly supported such that pipe stresses and support reactions are within allowable limits. C-E will provide to each Applicant the design loads at the support/ structure interface locations for components that C-E supplies.

TABLE 6.3.1.3-2

SAFETY INJECTION SYSTEM HEAD LOSS REQUIREMENTS FROM CESSAR TABLE 6.3.2-5.b (Interface Requirements)

	Flow/Pump (gpm)	Required System Resistance (ft)
High Pressure Pumps		
a) Injection Mode	1130	1580(1)
b) Recirculation Mode	1130	1580(2)
c) Long Term Cooling Mode	1130	1580(3)
Low Pressure Pumps		
a) Injection Mode	5000	290(4)
b) Recirculation Mode	3500	370(5)
c) Ambient Temperature Recirculation Test	3500	370(6)

NOTES:

(1) Friction and elevation losses between the water level in the RWT at the start of recirculation and the outlet of the cold leg injection nozzle. One high pressure pump operating.

(2) Friction and elevation losses between the minimum water level in the containment sump and the outlet of the cold leg injection nozzle. One high pressure pump operating.

(3) Friction and elevation losses between the minimum water level in the containment sump and the outlet of the cold leg injection nozzles and the shutdown cooling nozzle on the hot leg. Required head losses include the flow balancing orifice. One high pressure pump operating.

(4) Friction and elevation losses between the water level in the RWT (at the start of recirculation) and the outlet of the cold leg injection nozzle. One low pressure pump operating.

(5) Friction and elevation losses between the minimum water level in the containment sump and the outlet of the cold leg injection nozzle. One low pressure pump operating.

(6) Friction and elevation losses through the entire flow path. One LPSI pump in operation taking suction from the containment sump and discharging to the RWT via the cross-connect lines normally used for inservice testing of the LPSI and CS pumps. Valves SI-306/307 and SI-657/658 must be set to the appropriate test position prior to starting this test in order to provide sufficient system resistance.

6. The loadings imposed by the SIS piping on the SIS/ RCS nozzles, or by the connecting system piping on SIS nozzles, shall be less than the design loads for these nozzles. C-E will provide to each Applicant the design loads for all nozzles on those SIS components that C-E supplies.

7. In the event of a limited leakage passive failure in one SIS train during recirculation, personnel access to the intact train shall be possible.

8. The two safety injection check valves in each of the six safety injection lines shall be located as follows: one as close as practicable to the Reactor Coolant System piping, the other as close as practicable to the containment penetration.

    a. Allowance shall be made for valve accessibility and maintenance.

    b. The total water volume in the piping from the Reactor Coolant System up to these valves shall be less than 30 cubic feet per line. This volume shall be kept to a minimum so that the delay time for injection of borated water will be a minimum.

    c. The check valve leakage lines shall be connected to the safety injection line immediately upstream of the safety injection check valve closest to the Reactor Coolant System piping. This is necessary to ensure

that all of the safety injection piping is borated to the refueling concentration at all times.

9. Each safety injection tank shall be located inside the containment, outside the biological shield, and as close as possible to the reactor coolant cold leg into which it injects.

   a. The piping run from each tank to the reactor coolant cold leg shall be as direct as possible with a minimum of bends and elbows.

   b. Long radius elbows or pipe bends shall be used.

   c. The piping run "K" factor shall not be less than 4.5 or greater than 7.0 including entrance and exit losses and valve resistance referenced to an area of 0.6827 ft^2.

   d. The bottom of the Safety Injection Tank shall be located above the centerline of the reactor coolant cold leg piping.

10. Manually-operated valves shall be provided with locking provisions as shown on P&ID, 01, 02, 03-M-SIP-001, -002 and -003.

11. Physical identification of safety related SIS equipment and cabling shall be provided to allow recognition of safety status by plant personnel.

12. In the routing of SIS Class 1E circuits and location of equipment served by these Class 1E

circuits, consideration shall be given to their exposure to potential hazards. See E.3 above.

13. All SIS ASME Boiler and Pressure Vessel Code Section III components shall be arranged to provide adequate clearances to permit inservice inspection.

14. Protection shall be provided from internally generated flooding that could prevent performance of safety-related functions.

N. Radiological Waste

1. Safety Injection System leakage to the safeguards room will normally drain to the room sump. Provisions shall be provided to accept the maximum leakage rates listed below:

   a. HPSI and LPSI pump seals: 100 cc/hr

   b. Valves

      backseat leakage: 10 cc/hr/inch seat diameter

      across the valve seat: 10 cc/hr/inch of nominal valve size

   All leakages shall be treated as radioactive waste with a low dissolved solids and organic content.

O. Overpressure Protection

Not Applicable

P. Related Services

1. Nitrogen gas shall be supplied to the safety injection tanks. This supply shall satisfy the following requirements:

Minimum Required Flow Rate	300 SCFM (at supply pressure)
Maximum Allowable Flow Rate	2490 SCFM (at supply pressure)
Minimum Supply Pressure	630 psig (for normal plant operations)
Maximum Supply Pressure	700 psig (all conditions)
Gas Volume Required for 4 Tank Blowdown	105,000 SCF
Design Criteria	ANSI B31.1
Nitrogen Supply	$\geq$ 99.99% N_2 $\leq$ 5 ppm O_2
Maximum Supply Free Stream Temperature	115F

No single failure shall allow the compressed nitrogen system delivery pressure to exceed 700 psig.

2. A containment sump shall be provided. Baffles and intake screens shall be installed to limit

the maximum particle size entering the recirculation piping to 0.09 in diameter in order to prevent flow blockage in the Engineered Safety Features components and piping and in the reactor.

3. The maximum particle size in the water exiting from the refueling water tank shall be 0.09 in diameter in order to preclude flow blockage in Engineered Safety Features components and piping and in the reactor.

4. A fire protection system shall be provided to protect the Safety Injection System consistent with the requirements of GDC 3, and shall include, as a minimum, the following features:

   a. Facilities for fire detection and alarming.

   b. Facilities or methods to minimize the probability of fire and its associated effects.

   c. Facilities for fire extinguishment.

   d. Methods of fire prevention such as use of fire resistant and non-combustible materials whenever practical, and minimizing exposure of combustible materials to fire hazards.

   e. Assurance that fire protection systems do not adversely affect the functional and structural integrity of safety related structures, systems, and components.

f. Care should be exercised to ensure fire protection systems are designed to assure that their rupture or inadvertent operation does not significantly impair the capability of safety related structures, systems, and components.

5. The SIS containment penetrations shall not be subject to loss of function from dynamic effects (e.g., missiles, pipe reactions, fluid reaction forces) resulting from failure of equipment or piping inside or outside the containment.

6. Where required, bellows shall be provided between piping and the containment wall to prevent excessive forces on the piping.

Q. Environmental

1. Each SIS safeguards train shall be provided with an independent environmental control system such that the safety-related equipment in each train operates within the environmental design limits specified in Section 3.11.

6.3.1.4 CESSAR Interface Evaluations

The CESSAR interface requirements are met by the PVNGS design as follows:

A. Power

1. The SIS pumps and valves can be connected to the offsite (preferred) power supply, and the diesel generator (standby) power supply.

2. The connections are through two independent buses so that in the event of a LOCA in conjunction with a single failure in the electrical supply, the flow from one high-pressure safety injection (HPSI) train and one low-pressure safety injection (LPSI) train is available for core protection.

3. One HPSI pump and associated valves and one LPSI pump and associated valves are connected to each Class 1E load group.

4. The diesel generator and the automatic sequencers necessary for diesel loading are designed such that flow to the core is attained within a maximum of 30 seconds of reaching SIAS setpoint. Upon receipt of start signal, the diesel generator starts, achieves or exceeds minimum acceptable speed and voltage and the diesel generator output breaker closes, all within 10 seconds. Refer to section 8.3 for a detailed description of the electrical supply system.

CESSAR interface requirements in CESSAR Section 8.3.1, items 1 and 2, and the safety injection system (SIS) equipment electrical power requirements in CESSAR Table 8.3.1-1 are addressed in subsections 8.3.4 and 8.3.5.

5. Refer to subsection 8.3.1 for a discussion covering the instrument power sources.

6. The SIS hot leg injection valves are powered such that a single electrical failure will not cause a spurious initiation of hot leg injection flow, nor prevent deliberate hot leg injection flow through at least one of the hot leg injection lines. Each valve is powered from a separate power supply and is controlled by a keylocked switch in the control room. The design meets the single failure criterion to prevent premature hot leg injection.

7. Instrument air supplied to all SIS pneumatic valve operators is clean, dry, and oil-free as described in subsection 9.3.1.

8. Provisions are made to remove power to the safety injection tank vent valves (SI-605, -606, -607, -608, -613, -623, -633, and -643) during plant operation. Provisions are made to allow restoration of power to these valves from the control room and a remote shutdown location. The two safety injection tank vent valves on each SIT are powered from separate and independent

emergency power sources. Engineering drawings 01, 02, 03-M-SIP-001, -002 and -003 reflects these design provisions.

In addition the following valves require power lockout:

Safety Injection Tank (SIT) Isolation Valves

Valve No.

J-SIA-UV-634
J-SIA-UV-644
J-SIB-UV-614
J-SIB-UV-624

The SIT isolation valve motor power feeder breakers are locked open before RCS pressure exceeds 430 psia.

Electrical power cannot be restored to the valves from the control room. The safety injection tanks can be depressurized for cold shutdown by venting rather than performing tank isolation in the event the motor centers are not accessible during an emergency shutdown.

Testing is performed by manually opening the breaker and verifying breaker position, with indication provided in the control room.

Valve position indication is provided by indicating lights driven from valve limit switches and by a redundant and independent position indicator.

For the safety injection tank vent valves, power is disconnected from the solenoid valves by a switch in the control room. One switch disconnects power for the train A valves, and one switch disconnects power for the train B valves.

Electrical power can be restored to the valves by the control room switches.

Testing is performed by disconnecting power and verifying proper operation by indication provided in the control room.

One set of valve position indicating lights driven from proximity type limit switches on each solenoid valve is provided in the control room. Due to the small size of the solenoid valve, a second means of direct valve position indication cannot be provided. Indication of valve position can, however, be derived from safety injection tank pressure.

B. Protection from Natural Phenomena

1. Design provisions for maintaining functional capability of safety-related systems during the maximum probable flood or other natural phenomena defined in GDC 2 are discussed in subsection 3.1.2. All safety-related pumps and components are located in Seismic Category I structures. The protection of Seismic Category I structures against natural phenomena is presented in sections 3.3 and 3.4.

C. Protection from Pipe Failure

1. Pipe Break Considerations

Maximum expected leakage from a moderate energy pipe rupture is defined by the methods of subsection 3.6.2 and CESSAR Sections 3.6.1 and 3.6.2. The piping rupture is postulated (as defined in CESSAR Section 3.6.2.1) in the LPSI system dual-purpose piping outside containment which operates during normal as well as emergency plant conditions.

The above-mentioned leakage could be from RWT inventory and will occur when the LPSI system is idle or from the RCS when the LPSI system is operating. Provisions are made for detection, containment, and isolation of such leakage. Reactor coolant leakage from the HPSI, LPSI or CS pumps pipe breaks, considered as moderate energy line breaks, are bounded by the SCS line break postulated in UFSAR Section 5.4.7.3.C.1, dealing with the shutdown cooling system.

2. Provisions are incorporated to assure the required minimum acceptable capability of the emergency core cooling system (ECCS) and containment spray system (CSS) due to a limited leakage passive failure. Each HPSI, LPSI, and containment spray pump and shutdown cooling heat exchanger is located in a separate room (refer to engineering drawing 13-P-OOB-002). The

Containment Spray System components and supportive systems are powered through two independent engineered safety features (ESF) electrical power trains so that in the event of postulated accident conditions, in conjunction with loss of the preferred plant electrical power source and a single failure in the emergency electrical power sources, one containment spray train will be available to perform the system safety functions. Each electrical power train is connected to one containment spray pump and its associated valves and instrumentation. Emergency electrical power source loads are given in Table 8.3-1.

3. Design Requirements for Protection from Pipe Break

The ECCS, both inside and outside containment, is protected from the effects of postulated high and moderate energy pipe ruptures. Appropriate design procedures are employed to ensure that postulated failures do not result in loss of ECCS function. The ECCS design includes the following features:

a. Protection from the consequences of a postulated pipe failure by: (1) separation via physical plant layout, (2) pipe restraints, (3) protective structures, (4) isolation capability, (5) drain check valves or (6) other suitable means (see UFSAR Table 3.6-3).

b. Isolation valves (system and/or containment) used to contain leakage are protected from the adverse effects of a pipe failure which might preclude their operation when required.

These design features protect the redundant ECCS train and other plant equipment from the effects of a pipe break (pressurization, pipe whip, impingement, and flooding). The design basis flood for specific rooms and compartments is based on the line break with the largest spillage per Section 3.6.2.1.

Flood protection for the ECCS pumps is provided by train separation and drainage system design. Each HPSI, LPSI, and CS pump is located in a separate compartment. The compartment walls serve as flood barriers so that flooding within or outside of the ESF pump room of one train will not jeopardize the operation of the pump of the redundant train. Water in the ECCS compartments is routed to the Radioactive Waste Drain System, which includes two ESF drain subsystems, one serving Train A equipment and the other serving Train B equipment. A drain header from each ECCS pump room is routed directly to the appropriate ESF sump and is equipped with a check valve to prevent backflow. These check valves are included in the ISI and IST Programs. The two ESF drain Subsystems are included in the Maintenance Rule, and the two ESF drain subsystems are physically separate from drains serving the non-ESF equipment rooms (reference engineering

drawings 01, 02, 03-M-RDP-002). Thus, the worst case (design basis) flooding of one ESF pump room, will not affect the operation of redundant safety-related equipment that is required to perform protective actions to mitigate the consequences of the postulated break or place the plant in a safe shutdown condition.

The level instrumentation is mounted in each safety injection pump room sump. This provides a high water level alarm in the control room after an accumulation of 3.5 gallons of water in the sump. Each safety injection pump room sump high water level alarm is a 1E annunciation in the control room. This level is sufficient to provide isolation of the leak by appropriate operator action within 30 minutes. This action will consist in part of shutting suitable isolation valves to stop the leak. This action will also include steps to isolate the leaking train. The safety injection leak detection system consists of individual level switches in each train pump room. Individual control room 1E annunciation windows enable identification of the leaking train.

Fuel building exhaust radiation monitors 13-J-SQB-RU-145 and -146 will monitor noble gas releases from the essential filtration units that serve areas subject to leakage from ESF recirculation components and piping. Monitor sensitivities are described in section 11.5 and are adequate to provide early detection of recirculation loop leakage.

The safety injection leak detection system consists of a 1E (safety grade) switch in each pump room for each train of the high-pressure safety injection pump, low-pressure safety injection pump, and containment spray pump.

Each level switch actuates a 1E annunciation in the control room. The train A pump rooms are monitored by channel A instrumentation powered by train A, Class 1E power. The train B pump rooms are monitored by channel B instrumentation powered by train B, Class 1E power. The system complies with IEEE Standard 279-1971 except for single failure requirements. These level switches are not required to be environmentally qualified since flooding of these pump rooms will not occur as a result of an initiating event considered by the PVNGS EQ program.

4. The safety injection system components are located such that any missiles from pipe breaks, pipe whip, and/or any of the associated dynamic effects originating in one train would not affect performance of the other safety-related train, as discussed in sections 3.5 and 3.6.

D. Missiles

The SIS is protected from missiles as discussed in subsection 3.5.2

E. Separation

1. Physical separation is provided and maintained between redundant piping paths and containment

penetrations of the SIS and containment spray system such that the SIS and containment spray system will meet their functional requirement even with the failure of a single active component during the injection mode, or with a single active failure, or a limited leakage passive failure during the recirculation mode.

2. Separation of cabling associated with redundant channels is provided as discussed in subsection 8.3.1.

3. In the routing of Class 1E circuits and in locating equipment served by these Class 1E circuits, consideration is given to their exposure to potential hazards such as postulated ruptures of piping, flammable material, flooding, and nonflame-retardant wiring. Adequate separation or protective measures commensurate with the damage potential of the hazard is provided. In addition, discussion of separation or protective measures against the effects of possible missile generation and pipe whip is provided in sections 3.5 and 3.6, respectively.

4. Single active failures of nonsafety grade systems will not compromise redundancy of the SIS.

F. Independence

1. Each subsystem of the ECCS and CSS is provided with a separate environmental control system such that the system operates within the environmental

design limits (refer to subsection 9.4.2). Each pump room is provided with a separate self-contained essential cooling system (refer to subsection 9.4.2.).

2. Refer to sublisting A.2.

3. Refer to sublisting A.5.

G. Thermal Limitation

Not applicable

H. Monitoring

1. Refer to sublisting C.1.

2. Process instrumentation as described in Table 1.8-1 is available to operators in the control room to assist in assessing post-LOCA conditions.

I. Operational Controls

Following a LOCA in which the CSS is actuated, the operator will be able to secure the CSS when the containment vapor temperature falls within the qualification envelope described in Appendix A of the Equipment Qualification Program Manual. An indirect method of determining containment mixing will be by comparing the temperature displays of the ten sensing elements (TE-37 through TE-42E, as shown in engineering drawings 01, 02, 03-M-HCP-001) distributed about the containment shell. Temperature stratification would be indicated by significant local temperature differentials. Additionally, temperatures

approaching the qualification temperatures of Appendix A of the Equipment Qualification Program Manual will independently direct the operator to manually reinitiate CSS for a short period.

For MSLB only the temperature concerns of containment mixing are applicable. (Since MSLB will not generate hydrogen, hydrogen pocketing is not a concern.)

The PVNGS procedures will provide sufficient information so that the operator can take the proper action to restore the plant to a safe condition. An SIAS will not be reset unless the operator has determined that conditions warrant this action.

Additionally, procedures will be provided to cover operation of the diesel generators. These procedures will ensure that the diesels are correctly loaded, including the event of loss of offsite power following an SIAS reset.

Plant procedures will ensure timely operator action to isolate the RWT after a RAS to prevent ingress of air in the ESF pump suction piping during switchover to recirculation.

Plant procedures will also require an operator to check at least once per shift ECCS performance during long-term recirculation cooling using the ECCS. These procedures will provide specific guidance on recognition and mitigation of ECCS performance degradation during recirculation operation. They will

also include guidance to alert the operator to the symptoms of inadequate core cooling.

J. Inspection and Testing

1. The inspection and testing are described in the Technical Specifications.

2. Prior to initial plant startup, SIS flow tests will be performed in accordance with the C-E position on Regulatory Guide 1.79. In addition, full scale hydraulic model testing will be performed as described in subsection 6.2.2.

   A preoperational test was performed at PVNGS to demonstrate that the ECCS pump runout flows are lower than those assumed in the NPSH calculations.

K. Chemistry/Sampling

1. Sample points are provided at the following locations:

   - Shutdown cooling suction lines
   - Minimum flow bypass lines
   - Recirculation line back to refueling water tank
   - Each shutdown cooling heat exchanger outlet
   - Safety injection tanks
   - Refueling water tank

   Refer to subsection 9.3.2.

2. The sample lines in contact with the reactor coolant are austenitic stainless steel or

equivalent material compatible with the fluid chemistry.

L. Materials

1. Safety injection piping and fittings are Seismic Category I (refer to section 3.2).

2. Design and fabrication of the safety injection piping and fittings conform to ASME Boiler and Pressure Vessel Code, Section III, Class 1 and 2 (refer to section 3.2).

3. Piping and components in contact with the system fluid are of austenitic stainless steel (type 316, type 304, or C-E-approved alternate) compatible with the chemistry of the injection and recirculation fluid. Valve packings, gaskets, and valve diaphragm materials are also compatible with the chemistry of the water and the radioactive dose at that location.

4. Using the guidance of Regulatory Guides 1.44 and 1.31, as discussed in section 1.8, care is taken in preventing sensitization and in controlling the delta ferrite content of:

   a. Welds that join any system fabricated of austenitic stainless steel in the ECCS

   b. Field welds on the ECCS (refer to subsection 5.2.3)

5. Cleaning and contamination protection procedures are discussed in subsection 6.1.1. The

insulation used on the austenitic stainless steel is discussed in subsection 5.2.3. Conformance to Regulatory Guides 1.36 and 1.37 is discussed in section 1.8.

6. The materials used for the containment and its internal structures are compatible with both the normal operating environment and the most severe thermal, chemical, and radiation environment expected during post-accident conditions. Appendix A of the Equipment Qualification Program Manual lists the environmental conditions. Containment materials were selected to be compatible with the spray water chemistry and existing recirculating water chemistry to ensure that containment materials will withstand this exposure without causing deleterious or undesirable reactions, or significantly altering the water chemistry.

7. The containment spray system is designed and constructed in conformance with ASME III, Class 2, requirements. The material used in this system is austenitic stainless steel type 316 or 304 or other C-E-approved compatible material.

M. System/Component Arrangement

It is noted that some of the Interface Requirements described in this section were provided for original piping and component design/selection to ensure that the as-built system would support required design

functions. For the operating plant, the adequacy of the design to support required design functions is maintained and demonstrated by current design basis calculations and surveillance tests that evaluate the as-built systems, and the values specified by the original interface requirements are no longer relevant. The specific interface requirement in this section for which this applies and that provides historical information is: M.1.

1. The piping arrangement is such that the head loss requirements presented in Table 6.3.1.3-2 were met for the initial design. For the as-built systems, the total system losses provide the required ECCS flow to support design functions.

2. The piping for each safeguards train is designed such that the top of the piping junction of the pipe runs to the refueling water tank and the containment recirculation sump is located at least 16 feet below the top of the recirculation containment sump, which is 4 feet below the minimum water level in the containment during recirculation. This provides adequate margin for the containment minimum pressure of –3.5 psig, as described in subsection 6.2.1, to preclude the water level in the RWT suction line from dropping below the piping junction. To preclude the possibility of drawing air from the RWT into the safeguards pump suction during recirculation,

timely operator action is required to isolate the RWT after the RAS has occurred.

Frictional losses in the safeguard pump suction piping between the containment sump and the junction with the RWT are less than 5 feet.

3. The location and elevation of the HPSI pumps are indicated in engineering drawing 13-P-OOB-002. The HPSI pumps are located in the auxiliary building as close as practical to the containment.

   a. The elevation of the HPSI pumps is such that the available NPSH is at least 25 feet during the recirculation mode when the pumps take suction from the containment sump. In determining this elevation, no credit was taken for subcooled water in the containment sump following a LOCA.

   b. The available NPSH was calculated at the pump suction inlet that is 4.5 feet above its foundation elevation.

   c. The available NPSH was calculated taking into consideration the concurrent operation of the low-pressure safety injection and containment spray pumps. The available NPSH of each pump is summarized below to demonstrate that an adequate margin exists:

Pump	Required NPSH	Available NPSH	Margin
HPSI	25 feet	28.8 feet	3.8 feet
LPSI	20 feet	26.1 feet	6.1 feet
CS	22 feet	24.8 feet	2.8 feet

These margins are calculated for concurrent operation of HPSI and LPSI pumps at their respective recirculation mode flow rates (Table 6.3.2-1) and the CS pump at maximum flow (Section 6.2.2.2), which is conservative for the NPSH calculation. The required NPSH values are revised from original CESSAR Interface requirements to reflect the required NPSH at these flow rates.

d. Credit was not taken for water trapped above the containment floor.

4. The requirements on location and elevation applied to the HPSI are applied to the location and elevation of the LPSI pumps except that the pump's suction is located at the impeller eye, which is at the lower surface of the pump support mounting feet. This reference point was changed by CE from the originally specified reference point of 14 inches below the pump supports. Each LPSI pump is located so that the NPSH requirements listed in table 6.3.2-1 are satisfied. For the injection mode, the design calculation assumes:

a. Concurrent HPSI, LPSI, and containment spray pump operation.

b. A refueling water tank temperature of 120F.

5. Safety injection system components are properly supported such that pipe stresses and support reactions are within the allowable limits as defined in subsection 3.9.3.

6. The PVNGS design of the SIS piping and any connecting system piping is such that the loadings imposed on the SIS/RCS nozzles or SIS nozzles are less than the C-E-furnished nozzle design loadings for the C-E-supplied SIS components.

7. In the event of a limited leakage passive failure in one SIS train during recirculation, personnel access to the intact train will not be precluded due to flooding.

8. Two safety injection check valves in each of the six safety injection lines are located as follows: one as close as practical to the RCS cold leg piping and the other as close as practical to the containment penetration. Additionally, a third check valve is located in each of the four cold leg injection lines upstream of the safety injection tank branch connection in order to minimize high energy piping runs.

a. Space is provided to permit valve accessibility and maintenance.

b. The total unborated water volume for all four cold leg injection SI lines from the RCS to the first SI valve is less than 120 cubic feet. Specifically, the total (four leg) calculated volume is less than 33 cubic feet and the safety analysis described in Section 15.1.5.3.2.2 uses a total sweepout volume of 60.6 cubic feet. The total unborated water volume in each of the two long term recirculation lines between the RCS and the first SI valve is less than 16 cubic feet for A train for all three units and less than 44 cubic feet for B train for all three units. Refer to UFSAR Section 1.9.2.4.7. The total volume of safety injection water that must be swept out of the piping before borated water reaches the core is 67 cubic feet.

c. Each check valve leakage line is connected to the safety injection line immediately upstream of the safety injection check valve.

9. The safety injection tanks are located inside the containment and outside the biological shield. Each safety injection tank is located as close as practical to the reactor coolant cold leg to which it injects.

a. The piping run from each tank to the reactor coolant cold leg is as direct as possible with a minimum of bends and elbows.

b. Long-radius elbows or pipe bends are used.

c. The piping run "K" factor or resistance is between 2.0 and 7.0, including entrance and exit losses and valve resistance, referenced to an area of 0.6827 square foot. The ECCS small and large break LOCAs were evaluated to expand the K-factor range from the original range of 4.5 to 5. It was determined that the original analysis remains valid and compliance with the ECCS performance criteria of 10CFR50.46 is assured with a range of K-factors from 2.0 to 7.0 with a reference area of 0.6827 square feet.[1]

d. The bottom of the safety injection tank is located above the centerline of the reactor coolant cold leg piping.

10. See Response to Question 6A.35 (NRC Question 440.14) The six manual valves identified during inspection of the CESSAR-F design, which if improperly aligned, could prevent flow from the associated train are: SI-435 and SI-447 located downstream of the LPSI pumps; SI-402 and SI-470, located upstream of the HPSI pumps; and valves SI-476 and SI-478, located downstream of the HPSI pumps. These valves are

locked open and administrative procedures are used to assure their proper position (the locked position designation has been removed from plant drawings.)

11. Physical identification of safety-related equipment is provided as discussed in subsection 7.1.1 and section 8.3.

12. Refer to sublisting E.3 above.

13. All SIS ASME Boiler and Pressure Vessel Code, Section III, components are arranged to provide adequate clearances to permit inservice inspection.

14. Protection is provided from internally generated flooding that could prevent performance of safety-related functions. Refer also to section 3.6 and subsection 9.3.3.

N. Radiological Waste

1. Safety injection system leakage to the safeguards room will normally drain to the room sump, from where it drains into the safety-related ESF pump rooms drain sump. Provisions are provided to accept the maximum leakage rates listed below:

    a. HPSI and LPSI pump seals: 100 cc/h

       The pump seal leakage is piped to the radioactive drain system.

b. Valves

Backseat leakage:	10 cc/h/inch seat diameter
Across the valve seat:	10 cc/h/inch of nominal valve size

All leakages are treated as radioactive waste with a low dissolved solids and organic content.

O. Overpressure Protection

Not applicable

P. Related Services

1. A supply of nitrogen meets the requirements of subsection 6.3.1.3.P.1.

2. The containment sump design meets the guidance of Regulatory Guide 1.82 requirements as discussed in Section 1.8 and paragraph 6.2.2.2.1.

   Baffles and intake screens are installed as required to prevent the introduction into the recirculation piping of particles which are over 0.09 inch in diameter.

3. The maximum particle size in water exiting from the refueling water tank will be 0.09 inch in diameter.

4. The fire protection system meets the interface requirements listed in subsection 6.3.1.3.P.4. The detailed description of the fire protection

system provided to protect the SIS components is discussed in subsection 9.5.1.

5. The SIS containment penetrations will not be subject to loss of function from dynamic effects (e.g., missiles, pipe reactions, fluid reaction forces) resulting from failure of equipment or piping inside or outside the containment. This is accomplished by physical separation and the use of shielding barriers.

6. Not applicable

Q. Environmental

1. The SIS is provided with an environmental control system such that the safety-related equipment operates within the environmental design limits specified in Appendix A of the Equipment Qualification Program Manual.

6.3.2 SYSTEM DESIGN

6.3.2.1 System Schematic

The Safety Injection System Piping and Instrumentation Diagram is shown in engineering drawings 01, 02, 03-M-SIP-001, -002 and -003. The major components of this system are high pressure safety injection pumps, low-pressure safety injection pumps, safety injection tanks, high-pressure injection valves, and low-pressure injection valves. The major components are described in the following section. In addition, the system uses the refueling water tank of the Chemical and Volume Control System, Section 9.3.4. PVNGS has an additional

pressure boundary isolation check valve (SI-540, -541, -542, -543) in each of the HPSI/LPSI combined headers to the RCS cold legs.

Connections for the refueling water level indication system are shown in engineering drawings 01, 02, 03-M-SIP-001, -002 and -003.

Engineering drawings 01, 02, 03-M-SIP-001, -002 and –003 shows PVNGS tag numbers and vent/drain valves.

6.3.2.2 Component Description

A summary of design parameters and codes for major components are given in Table 6.3.2-2.

6.3.2.2.1 Safety Injection Tanks

The four safety injection tanks discharge their contents to the Reactor Coolant System following depressurization as a result of a Loss-of-Coolant Accident. Each tank is piped into a cold leg of the Reactor Coolant System (RCS) via a safety injection nozzle located on the RCS piping near the reactor vessel inlet. During normal plant operation each safety injection tank is isolated from the Reactor Coolant System by two check valves in series. The safety injection tanks automatically discharge into the RCS if RCS pressure decreases below safety injection tank pressure during reactor operation.

The motor-operated isolation valves on the safety injection tank discharge are interlocked with the pressurizer pressure measurements channels, to automatically open these valves, when RCS pressure is above the setpoint value shown in Table 7.6-1,

and to prevent inadvertent closure prior to or during an accident. After the valve is opened, it will be locked open in the Control Room, and power to the motor will be removed (See Section 7.6).

During normal power operation, the valve, although locked open, receives a confirmatory SIAS "Open" signal, if the Reactor Coolant System pressure should inadvertently drop below 1837 psia. During startup and shutdown operations, a variable setpoint is used as described in Section 7.2.1.1.1.6. During plant cooldowns, safety injection tank pressure will be lowered to 300 psig by the operator when Reactor Coolant System pressure (nominal) reaches 750 psia. An interlock with pressurizer pressure will prevent the safety injection tank valves from being closed until RCS pressure drops below the setpoint value shown in Table 7.6-1; and if the valves are closed, a SIAS will cause them to open. Inadvertent repressurization of the safety injection tanks during this mode of operation due to a leaky nitrogen supply valve or by accidental tripping of a nitrogen supply valve switch is prevented by having two fail-closed valves in series with separate hand switches on each safety injection tank nitrogen supply line. The air supply actuating the nitrogen supply valves is controlled by solenoid valves. The two nitrogen supply valve solenoids on each safety injection tank are connected to separate electrical buses via redundant and physically separated electrical trains. This is to ensure that a fault in one of the trains will not cause a spurious opening of both nitrogen supply valves.

If Reactor Coolant pressure is above the setpoint value shown in Table 7.6-1, an interlock with pressurizer pressure will automatically open the safety injection tank isolation valves. The operator will repressurize the safety injection tanks when pressurizer pressure exceeds SIT operating pressure, but before pressurizer pressure reaches the SIT-RCS 1E differential pressure alarm condition described in Table 7.6-1.

The tank gas/water fractions, gas pressure, and outlet pipe size are selected to allow three of the four tanks to recover the core before significant clad melting or zirconium-water reaction can occur following a LOCA. The volume of water in the tanks is conservatively calculated assuming that all water injection prior to the end of the RCS blowdown is lost.

The tanks contain borated water and are pressurized with nitrogen as specified in the Technical Specifications.

Redundant level and pressure instrumentation (described in more detail in Section 6.3.5.3 and Table 7.5-2) is provided to monitor the condition of the tanks. Sufficient visual and audible indication has been made available to the operator such that maintaining the safety injection tanks within the required technical specifications during various modes of plant operation is readily accomplished from the control room. Provisions have been made for sampling, filling, draining, and correcting boron concentration. Atmospheric vent valves are provided for tank venting. They are locked closed and the power to each valve is removed during normal operation. This prevents inadvertent tank venting during normal plant operation. Safety Injection Tank Data is summarized in Table 6.3.2-2.

6.3.2.2.2 Low-Pressure Safety Injection Pumps

The Low-Pressure Safety Injection (LPSI) pumps serve two functions. One of these is to inject large quantities of borated water into the Reactor Coolant System in the event of a large pipe rupture. Sufficient flow is delivered under these conditions to satisfy functional requirements described in Section 6.3.1.1. The other function of the low-pressure safety injection pumps is to provide shutdown cooling flow through the reactor core and shutdown cooling heat exchangers for normal plant shutdown cooling operation or as required for long term core cooling. A typical pump characteristic curve is presented in Figure 6.3.2-2.

During normal operation the low-pressure safety injection pumps are isolated from the RCS by motor-operated valves. During safety injection the LPSI pumps deliver water from the refueling water tank to the RCS via the RCS safety injection nozzles whenever system pressure is below pump shutoff head.

Sizing of the low-pressure safety injection pump is governed by the shutdown cooling function. The flow available with a single low pressure safety injection pump is sufficient to maintain a core ΔT at an acceptable level at the initiation of shutdown cooling (3.5 hours after shutdown).

The design temperature for the low-pressure safety injection pumps is based upon the temperature of the reactor coolant at the initiation of shutdown cooling, about 350°F nominal, plus a design tolerance, resulting in a temperature of 400°F. The design pressure for the low pressure pumps is based upon the sum of the maximum pump suction pressure, which occurs at the

initiation of shutdown cooling, and the pump shutoff head. (See Section 5.4.7 also).

The low-pressure safety injection pumps are vertical, single stage centrifugal units equipped with mechanical face seals backed up by a bushing, with a leakoff to collect the leakage past the seals. The seals are designed for operation with a pumped fluid temperature of 400°F. The pump motors are specified to have the capability of starting and accelerating the driven equipment, under load, to design point running speed within 5 seconds, based upon an initial voltage of 75% of rated voltage at the motor terminals, and increasing linearly with time to 90% voltage in the first 2 seconds, and increasing to 100% voltage in the next 2 seconds.

The pumps are provided with drain and flushing connections to permit reduction of radiation levels before maintenance. The pressure containing parts are fabricated from stainless steel; the internals are selected for compatibility with boric acid solutions. The pumps are provided with minimum flow protection to prevent damage when starting against a closed system. The low-pressure pump data is summarized in Table 6.3.2-2. The shutdown cooling function of the pump is described in Section 5.4.7.

6.3.2.2.3 High-Pressure Safety Injection Pumps

The primary function of a High-Pressure Safety Injection (HPSI) pump is to inject borated water into the RCS if a break occurs in the RCS boundary. For small breaks, the RCS pressure remains high for a long period of time following the accident,

and the high-pressure safety injection pumps ensure that the injected flow is sufficient to meet the criteria given in Section 6.3.1. The high-pressure safety injection pumps are also used during the recirculation mode to maintain a borated water cover over the core for extended periods of time following a Loss Of Coolant Accident. For long term core cooling, the HPSI pumps are manually realigned for simultaneous hot and cold leg injection. This insures flushing and ultimate subcooling of the core independent of break location. For small breaks, the HPSI pumps continue injecting into the RCS to provide makeup for spillage out the break while a normal cooldown is implemented.

During normal operation the high pressure safety injection pumps are isolated from the RCS by motor operated valves. During safety injection the HPSI pumps deliver water from the refueling water storage tank to the RCS via the cold leg safety injection nozzles whenever RCS pressure falls below pump shutoff head. During the recirculation mode of operation, the pumps take suction from the containment sump.

The high-pressure safety injection pumps are sized such that one HPSI pump (after consideration of spillage directly out the break) will supply adequate water to the core to match decay heat boiloff rates soon enough to minimize core uncovery and allow small break LOCA’s to meet the performance criteria of 10CFR50.46. A typical pump characteristic curve is shown in Figure 6.3.2-3. The effectiveness of the pump during a steam line break is also analyzed to assure that the pumps are adequately sized. Mechanical shaft seals are used and are provided with leakoffs which collect any leakage past the

seals. The seals are designed for operation with a pumped fluid temperature of 350°F.

The pump motors are specified to have the capability of starting and accelerating the driven equipment, under load, to design point running speed within 5 seconds based on an initial voltage of 75% of the rated voltage at the motor terminals, increasing linearly with time to 90% voltage in the first 2 seconds, and increasing to 100% voltage in the next 2 seconds.

The pumps are provided with drain and flushing connections to permit reduction of radiation before maintenance. The pressure containing parts of the pump are stainless steel with internals selected for compatibility with boric acid solutions. The materials selected are analyzed to ensure that differential expansion during design transients can be accommodated.

The pumps are provided with minimum flow protection to prevent damage resulting from operation against a close discharge. Also, individual HPSI pump ultrasonic flow meters provide low flow alarming.

The design temperature is based on the saturation temperature of the reactor coolant at the containment design pressure plus a design tolerance. The design pressure for the high pressure pumps is based on the shutoff head plus maximum containment pressure plus a design tolerance. The High-Pressure Pump Data is summarized in Table 6.3.2-2.

6.3.2.2.4 Piping

Piping is specified to deliver borated safety injection water from the safety injection tanks and from the refueling water tank via the safety injection pumps, to the safety injection nozzles in the RCS. The major piping sections are (refer to engineering drawings 01, 02, 03-M-SIP-001, -002 and -003):

a. From each safety injection tank to its respective RCS cold leg safety injection nozzle;

b. Redundant piping from the refueling water tank and containment sump to the suction of the high- and low-pressure safety injection pumps;

c. Redundant piping from the high-pressure safety injection pumps discharge to redundant high-pressure injection headers each of which serves the four safety injection nozzles on the cold legs and one nozzle on each shutdown cooling suction line;

d. Redundant piping from the low-pressure safety injection pump discharge to each low-pressure injection header which serves two of the four safety injection nozzles.

The Safety Injection System piping is fabricated of austenitic stainless steel and is designed to ASME Code Section III. Flexibility and seismic loading analyses are performed by each Applicant to confirm the structural adequacy of the system piping. In addition, the flexibility and seismic loading analyses of piping are presented in section 3.9.

6.3.2.2.5 Valves

The location, type and size, type of operator, position (during the normal operating mode of the plant) and failure position of the SIS valves, is shown in engineering drawings 01, 02, 03-M-SIP-001, -002 and -003. Pressure design rating and code design classification are also shown.

a. Relief Valves

Protection against overpressure of components within the Safety Injection System is provided by conservative design of the system piping, appropriate valving between high-pressure sources and low-pressure piping, and by relief valves. All lines within the high- and low-pressure systems from the RCS up to and including the safety injection valves are designed for full Reactor Coolant System pressure. In addition, the high-pressure header to which the charging pumps discharge is designed for full Reactor Coolant System pressure up to and including the header check valve. Relief valves are provided as required by applicable codes. All relief valves are of the totally enclosed, pressure tight-type with suitable provisions for gagging.

A tabulation of Safety Injection System relief valves is provided below.

1. SI-211, 221, 231, and 241, Safety Injection Tank relief valves.

The relief valves on the safety injection tanks are sized to protect the tanks against the maximum fill rate of liquid or gas into the safety injection tanks. They discharge into the

containment. The set pressure is 700 psig with a capacity of 6000 SCFM of gas or 230 gpm of liquid.

2. SI-473, Check Valve Leakage Relief Valve.

A relief valve is provided on the safety injection test and leakage return line.

This relief valve is sized to protect against overpressure of the line when relieving injection line pressure following check valve testing or during normal operation. It discharges into the reactor drain tank. The set pressure is 2050 psig with a capacity of 35 gpm.

3. SI-474 and SI-407, Safety Injection Tank Fill Line Relief Valves.

Relief valves are located on the Safety Injection Tank fill line to protect against overpressure due to a temperature increase. SI-474 discharges to the Reactor Drain Tank and SI-407 discharges to the Equipment Drain Tank. They are set at 2050 psig with a capacity of 10 gpm.

4. SI-439 and SI-449 Low Pressure Safety Injection Relief Valves.

These valves protect each isolated low-pressure safety injection line against the pressure developed due to a temperature increase. They discharge into the equipment drain tank. The set pressure is 650 psig with a capacity of 10 gpm per valve.

5. SI-409 and SI-468 High Pressure Safety Injection Relief Valves.

These valves are sized to protect the isolated high pressure headers against the pressure due to a temperature increase. They discharge into the equipment drain tank. SI-409 is set at 2050 psig and SI-468 is set at 2485 psig. Each has a capacity of 10 gpm.

6. SI-166 and SI-417, High Pressure Safety Injection Relief Valves.

The high pressure safety injection headers to which the charging pumps discharge are protected from the charging pumps discharge pressure by these valves. They discharge into the equipment drain tank. The set pressure is 2485 psig with a capacity of 145 gpm each.

7. SI-288, Low Pressure Safety Injection Relief Valve.

This valve is sized to protect the isolated low pressure safety injection test line from pressure due to a temperature increase. It discharges into the equipment drain tank. The set pressure is 650 psig with a capacity of 10 gpm.

8. SI-140 and SI-151, Containment Sump Suction Relief Valves.

These valves are sized to protect a normally isolated section of piping from pressure due to a temperature increase. They discharge to the non-ESF sump. The set pressure is 100 psig with a capacity of 10 gpm.

9. SI-141 and SI-150, Pool Cooling and Purification to Shutdown Cooling System Cross Connect Relief Valves.

These valves are sized to protect a normally isolated section of pipe in the cross-connect line against pressure due to temperature increase. They discharge to the Equipment Drain Tank. The set pressure is 485 psig with a capacity of 10 gpm.

10. SI-192 and SI-162, Pool Cooling and Purification to Shutdown Cooling System Cross Connect Relief Valves.

These valves are sized to protect a normally isolated section of pipe in the cross-connect line against pressure due to temperature increase. They discharge to the Equipment Drain Tank. The set pressure is 650 psig with a capacity of 10 gpm.

11. SI-285 and SI-286, Safety Injection Relief Valves.

These valves are sized to protect the Safety Injection pump bypass flow lines against pressure due to a temperature increase. They discharge to the Equipment Drain Tank. The set pressure is 2050 psig with a capacity of 10 gpm.

12. SI-475 and SI-476, Alternate RC Makeup Connection Relief Valves

For Units where DMWO 4304156 has been implemented, these valves are sized to protect a normally isolated section of pipe in the alternate RC makeup connection piping against pressure due to temperature increase. They discharge to a local floor drain in the mechanical penetration rooms. The set pressure is 2050 psig with capacity of 10 gpm.

b. Actuator-Operated Throttling and Stop Valves

The position of each valve on loss of actuating signal or power supply (failure position) is selected to ensure safe operation. System redundancy is considered when defining the failure position of any given valve. Valve position indication is provided at the main control panel as indicated in engineering drawings 01, 02, 03-M-SIP-001, -002 and -003. A locking-type control switch on the main control panel and/or manual override handwheel is provided where necessary for efficient and safe plant operation. All actuator-operated valves were supplied with a double packing with a lantern ring leakoff connection. During original plant design, an evaluation determined that leakoffs piped to the equipment drain tank present a greater ALARA concern than capping the valve leakoff. The cap has been designed as part of the SIS pressure boundary.

The high pressure and low pressure safety injection valves are trimmed during pre-operational flow tests to prevent the safety injection pumps from exceeding runout flow and for flow balancing during emergency operation. Following the determination of the required valve stem position for proper functioning of the system, each of the safety injection valves will be fitted with stops or limit switches to ensure that is will open to the position necessary to fulfill its safety function.

HPSI hotleg injection valves SI-321,-331 are manually throttled for proper flow balance during long term coding initiation.

Following the determination of the required valve stem position for proper functioning of the system, each of the safety

injection valves will be fitted with stops or limit switches to ensure that it will open to the position necessary to fulfill its safety function. For PVNGS, HPSI hotleg injection valves SI-321 and SI-331 are manually positioned for proper flow balance. The limit switches are positioned such that they will allow the valves to achieve their required position but do not determine that final position.

c. Check Valves

All check valves are the totally enclosed type. Check valves in pump suction lines are of a low pressure drop type with flow resistance characteristics equal to or less than a swing check valve of the same size as the connecting pipe.

6.3.2.2.6 Containment Sump

For interfaces see UFSAR Section 6.3.1.3. The design of the containment recirculation sump is described in subsection 6.2.2.

6.3.2.3 <u>Applicable Codes and Classification</u>

Refer to Section 6.3.2.2 and Table 6.3.2-2

6.3.2.4 <u>Material Specification and Compatibility</u>

The materials used in the construction of the Safety Injection System components are presented along with the components parameters in Table 6.3.2-2. Basically, all materials in contact with reactor coolant are austenitic stainless steel with stellite or equivalent material being used for valve seats. The materials of construction used in both the active

Table 6.3.2-1

ECCS PUMP NPSH REQUIREMENT

HIGH PRESSURE PUMPS	FLOW/PUMP (gpm)	REQUIRED NPSH (feet)
a) Pump runout	1400	25
b) Injection mode	1400	25
c) Recirculation mode	1400	25
D) Long term cor cooling mode	1400	25
LOW PRESSURE PUMPS		
a) Pump runout	5500	26
b) Injection mode	5500	26
c) Recirculation mode	5000	20

Table 6.3.2-2 (Sheet 1 of 2)
SAFETY INJECTION SYSTEM
COMPONENTS PARAMETERS

Low-pressure Safety Injection Pumps

Quantity	2
Type	Single Stage, Vertical, Centrifugal
Safety Classification	2
Code	ASME III, Class 2
Design Pressure	710 psig
Maximum Operating Suction Pressure	485 psig
Design Temperature	400°F
Design Flow Rate	4200 gpm*
Design Head	335 ft
Maximum Flow Rate	5000 gpm*
Head at Maximum Flow Rate	290 ft
Materials	Stainless Steel Type 304 316 or approved alternate
Seals	Mechanical
Brake Horsepower	515[(a)]

*Does not include 100 gpm by-pass flow

High-pressure Safety Injection Pumps

Quantity	2
Type	Multistage, Horizontal Centrifugal
Safety Classification	2
Code	ASME III, Class 2
Design Pressure	2050 psig
Maximum Operating Suction Pressure	100 psig
Design Temperature	350°F
Design Flow Rate	815 gpm*
Design Head	2850 ft
Maximum Flow Rate	1130 gpm*
Head at Maximum Flow Rate	1580 ft
Materials	Stainless Steel, type 304, 316 or approved alternate
Shaft Seal	Mechanical
Brake Horsepower	1000[(a)]

*Does not include 85 gpm by-pass flow

a. The horsepower ratings listed in this table are for reference only. The actual ratings may be found in the Electrical Equipment Database. This database is controlled and lists the actual rating.

TABLE 6.3.2-2 (Sheet 2 of 2)

SAFETY INJECTION SYSTEM

COMPONENTS PARAMETERS

Safety Injection Tanks	
Quantity	4
Safety Classification	2
Code	ASME III, Class 2
Design Pressure, Internal/External	700 psig/100 psig
Design Temperature	200°F
Operating Temperature	140°F
Normal Operating Pressure	610 psig
Minimum Operating Pressure	600 psig
Volume, Total	2400 ft
Liquid	
Minimum	1790
Nominal	1858
Maximum	1957
Fluid	Borated Water, 4200 ppm Boron Nominal, 6200 ppm max.
Material	Clad - Stainless Steel, type 304, 316, or approved alternate Body - Carbon Steel, type SA-516 Gr.7 or approved alternate

and passive components have been evaluated and in each case it has been concluded that the materials selected are both compatible with the most severe environmental condition they will be exposed to and in accordance with all code requirements.

6.3.2.5 System Reliability

Refer to section 8.3 for a discussion of power sources.

6.3.2.5.1 Safety Injection Tanks

The safety injection tanks containing borated water pressurized by a nitrogen cover constitute a passive injection system because no operator action or electrical signal is required for operation. Each tank is connected to its associated reactor coolant cold leg by a separate line containing two check valves which isolate the tank from the Reactor Coolant System during normal operation. When the reactor coolant pressure falls below the tank pressure, the check valves open discharging the contents of the tank into the Reactor Coolant System.

The evaluation in Section 6.3.3 demonstrates the adequacy of the quantity of coolant supplied. In order to prevent accidental overpressurization of the Shutdown Cooling System, safety injection tank pressure is controlled by facility procedures when reactor coolant pressure is being reduced as discussed in section 6.3.2.2.1. An interlock with pressurizer pressure prevents these valves from being closed if pressurizer pressure is above the setpoint value shown in Table 7.6-1. In the unlikely event of a LOCA during shutdown cooling, an SIAS will automatically open the SI tank isolation valves.

Inadvertent repressurization of the safety injection tanks during shutdown cooling due to a leaky nitrogen supply valve or the accidental tripping of a valve switch is prevented by having two such fail-closed supply valves in a series with separate hand switches. The air supply actuating the nitrogen supply valves is controlled by solenoid valves. The two nitrogen supply valve solenoids on each safety injection tank are connected to separate electrical buses via redundant and physically separated electrical trains. This is to ensure that a fault in one of the trains will not cause a spurious opening of both nitrogen supply valves.

The motor-operated isolation valves on the safety injection tank discharge are interlocked with the pressurizer pressure, to automatically open the valves when RCS pressure is above the setpoint value shown in Table 7.6-1. The operator will repressurize the safety injection tanks when pressurizer pressure exceeds SIT operating pressure, but before pressurizer pressure reaches the SIT-RCS 1E differential pressure alarm condition described in Table 7.6-1. Further details of valve control are provided in Section 7.6.

The atmospheric vents on the safety injection tank are locked closed, fail closed and power to their solenoid valve is interrupted during operation with the RCS pressure greater than 700 psig. This ensures that the tank will not be vented during RCS power operation.

6.3.2.5.2 High Pressure and Low Pressure Safety Injection Subsystems

Two redundant high pressure safety injection subsystem trains are provided. One pump and the associated injection valves operate from one emergency power supply, the other pump and injection valves from a second independent source of emergency power. This provides the automatic operation of one complete, full capacity subsystem in the unlikely event of concurrent loss of offsite power and the failure of an active component, including a standby generator.

Two redundant low pressure safety injection subsystems trains are provided. One pump and the associated valves operate from one load group, the other pump and injection valves from the other load group. This provides automatic operation of one complete, full capacity subsystem in the unlikely event of a simultaneous loss of both offsite (preferred) power supplies and the failure of an active component, including an emergency diesel generator.

All valves in the injection paths not receiving a SIAS signal are maintained locked in position by administrative controls.

Prevention of flow blockage in small diameter pipes, including the above piping, is accomplished by control of particle size and specific weight in the injection water through containment sump and RWT exit design.

6.3.2.5.3 Power Source

Independent electrical buses supply power to the Safety Injection System equipment. Each bus may receive power from:

a. Offsite (preferred) power supply

b. Diesel generator (standby) power supply

The safeguards initiation sensors, electrical controls, and electrical indication equipment normally receive power from four 120-volt ac buses. Four 125-volt station batteries with inverters are provided as a backup upon loss of all other sources of power.

System reliability is achieved with the following:

a. Two electrical buses, with each bus supplying power to a 100% capacity low-pressure pump, a 100% capacity high-pressure pump, associated valves and associated support systems. (Each support system contains two full capacity subsystems, one connected to each bus and one subsystem servicing each independent injection train).

b. Two sources of power, normal and standby to both buses, with automatic backup from the emergency generators.

c. Two emergency generators, each capable of supplying power for the minimum safeguards loads.

d. The system is designed such that a single electrical failure can neither spuriously initiate unnecessary injection flow, not prevent initiation of required injection flow.

A detailed description of the power sources is given in Section 8.3.

6.3.2.5.4 Capacity to Maintain Cooling Following a Single Failure.

The Safety Injection System is designed to meet its functional requirements even with the failure of a single active component during the injection mode of operation or with the single active or limited leakage passive failure of a component during the recirculation mode of operation. By providing proper redundancy of equipment, even with the single failure noted above, the minimum required safety injection equipment is always available.

A failure modes and effects analysis demonstrating this is given in table 6.3.2-3. The analysis is based on the following assumptions:

A. One Active Failure is assumed to occur in the system.

B. Relief and check valve failures are not considered credible failures.

C. Failure to respond to an external signal is considered an active failure.

Minimum operability requirements for components of the ECCS are as delineated in PVNGS Technical Specifications, Section 3.5. Consistent with these operability requirements and system failure modes, the minimum ECCS equipment that will operate during postulated accidents is as discussed in Section 6.3.3. This complement of equipment is required to mitigate the consequences of a LOCA initiated when the reactor is anywhere from hot shutdown to full power operation, and this complement will result in conservative results for other incidents where ECCS is required.

The following design features are provided in the system in order to meet the single failure criterion.

a. Redundant high and low pressure safety injection pumps.

b. Redundant piping and valving between refueling water tank and safety injection pump suction.

c. Redundant piping between containment sump and safety injection pump suction.

d. Redundant high-pressure and low-pressure safety injection headers.

e. Four injection discharge points into the Reactor Coolant System cold legs and redundant injection discharge points into the RCS hot legs.

f. Separation of the redundant subsystems of the ECCS. No limited leakage passive failure, as defined in Section 3.1.31, or the effects thereof (such as flooding, spray impingement, steam, temperature, pressure, radiation, loss of NPSH, or loss of recirculation water inventory) during them recirculation mode precludes the availability of minimum acceptable recirculation capability (minimum acceptable capability is defined as that which is provided by the operation of one subsystem).

g. Those portions of the Safety Injection System required for safe plant shutdown and cooldown are required to be protected from the effects of high and moderate energy pipe ruptures as described in Section 3.6.5.1.

TABLE 6.3.2-3 (Sheet 1 of 10)

SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
	When pressurizer pressure drops below 1750 psia or containment pressure rise above 5 psig during plant operation a Safety Injection Actuation Signal (SIAS) will be generated and this SIS automatically goes into operation. The following equipment are actuated: (Item 1 to 16).						
1	LPSI Pump to Shutdown Cooling Valve Isolation Valve SI656, SI690, SI654, SI655, SI691, SI653, SI652, SI651	a) Fails closed	Mech. binding, corrosion,	None	Periodic testing; Valve position indicator	None required	
		b) Fails open	Mech. binding, elect. malf.	None	Same as 1 (a)	Series redundant valve	Valve is normally closed
2	Safeguard Pump Test Line Isolation Valve SI460, SI464	a) Fails closed	Mech. binding, corrosion	None	Periodic testing	None required	
		b) Fails open	Mech. binding,	None	Periodic testing	Series redundant valve	Valve is normally closed
3	HPSI Pump 1, 2	a) Fails to start on SIAS	Elect. malf., bearing failure	Reduce flow to high pressure header	Low pressure indication P308 or P309; Periodic testing	Redundant HPSI pump	
4	LPSI Pump 1, 2	a) Fails to start on SIAS	Elect. malf., bearing failure	Reduce flow to low pressure header	Low pressure indication P306 or P307; Periodic testing	Redundant LPSI pump	
5	HP Header Isolation Valve SI616, SI617, SI626, SI627, SI636, SI637, SI646, SI647	a) Fails to open on SIAS	Elect. malf., mech. binding	Decrease in ability to inject high pressure water in RCS	Period testing	Parallel redundant cold leg injection lines	

TABLE 6.3.2-3 (Sheet 2 of 10)

SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
5	HP Header Isolation Valve (Continued)	b) Fails closed	Mech. binding, elect. malf.	Decrease in ability to inject high pressured water to RCS.	Periodic testing; valve position indicator	parallel redundant cold leg injection lines	
		c) Fails open	Mech. binding, contamination, seat failure, elect. malf.	None	Valve position indicator; periodic testing	None required	
6	LP Header Isolation Valve SI615, SI625, SI635, SI645	a) Fails to open on SIAS	Elect. malf., mech. binding	Loss of flow from LPSI pump to one of the RCS cold legs	Valve position indicator; periodic testing	Redundant LPSI train	
		b) Fails closed	Mech. binding, elect. malf.	Loss of flow from LPSI pump to one of the RCS cold legs	Valve Position Indicator; periodic testing	Sufficient LPSI flow is provided with redundant train	HPSI pumps and safety injection tanks will con-tinue to charge cold legs
		c) Fails open	Elect. malf., mech. binding, contamination	None	Period testing; valve position indicator	In line check valves prevent reverse flow during recirculation phase	
7	SI Tank Dis-charge Isola-tion Valve SI614, SI624 SI634, SI644	a) Fails open	Elect. malf., mech. binding, contamination	Cannot isolate affected tank for maintenance	Valve position indicator; periodic testing	None	
8	SI Tank Drain & Fill Line Air Oper. Isolation Valve SI611,	a) Fails to close on SIAS	Elect. malf. seat failure, contamination	None	Periodic testing; valve position indicator	Redundant stop valve in series SI682 prevent SI Tanks being drained	Valve is designed to fail closed and is normally closed
	SI621, SI631, SI641	b) Fails closed	Air line separated from operator; mech. binding	Cannot adjust the SI tank water level when required for maintenance	Same as 8(a); SI tank level		Valve is normally closed
		c) Fails open	Elect. malf., seat failure, contamination	None	Periodic testing; valve position indicator	Redundant stop valve in series SI682 prevent SI tanks being drained	Valve is designed to fail closed

Table 6.3.2-3 (Sheet 3 of 10)

SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
9	SI Cold Leg Check Valve Test Isolation Valve SI618, SI628, SI638	a) Fails to close on SIAS	Elect. malf., seat failure, contamination	None	Periodic testing; valve position indicator	Redundant stop valve in series SI682 prevent SI cold leg being drained	Valve is designed to fail closed and is normally closed
	SI648	b) Fails closed	Mech. binding, air line separates from operator	Cannot perform test on the cold leg check valve	Same as 9(a)	None required	Plant must be shut down and valve repaired
		c) Fails open	Seat failure, contamination	None series stop valves prevent cold leg being drained	Same as 9(a)	Same as 9(a)	Valve is normally closed and failed closed
10	Hot Leg Check Valve Test Isolation Valve SI322, SI332	a) Fails to close on SIAS	Elect. malf., seat failure, contamination	None	Periodic testing valve position indicator	Redundant stop valve in series SI682 prevent SI Hot leg being drained	Valve is designed to fail closed
		b) Fails closed	Mech. binding, air line separates from operator	Cannot perform test on the hot leg injection line check valve	Same as 10(a)	Repair	
		c) Fails open	Seat failure, contamination	None	Same as 10(a)	Redundant stop valve in series SI6852 prevent SI Hot leg being drained	Valve is normally closed and failed closed
11	SI Tank Drain & Fill Line to FWT Isolation Valve SI682, SI463	a) Fails to close on SIAS	Elect. malf seat failure, contamination	None	Periodic testing Valve Position indicator	Redundant stop valve in series	Valve is normally to fail closed
		b) Fails closed	Mech. binding, or air line separate from operator	Cannot adjust the SI tank water level when required	Same as 11(a) SI tank level indicator	None required	
		c) Fails open	Seat failure, contamination	None	Periodic testing; valve position indicator; low SI tank level alarm & indicator	Series isolation valves	Valve designed to fail closed

Table 6.3.2-3 (Sheet 4 of 10)

SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
12	LP Pump Min. Flow Line Isolation Valve SI669, Si668	a) Fails closed	Elec. malf., mech. binding	Possible damage to one LPSI pump	None, unless pump overheats and fails; valve position indicator; periodic testing	Redundant pump	Valve is normally locked open
13	Min. Flow Line to RWT Isolation Valve SI660, SI659	a) Fails closed	Elect. malf., mech. binding	Possible damage to associated pump	Same as 12(a)	Redundant train	Valve is normally locked open
14	HP Pump Min. Flow Line Isolation Valve SI666, SI667	a) Fails closed	Elect. malf., mech binding	Possible damage to one HPSI pump	Same as 12(a)	Redundant pump	Valve is normally locked open
15	LPSI Line to Shutdown Cooling Heat Exchanger (SDCHX) Discharge and Isolation Valves SI685, SI657, SI686, SI694, SI658, SI696	a) Fails open	Mech. binding, elect. malf.	Potential diversion of LPSI flow to Containment Spray System	Same as 1(a)	Series isolation valves for SI657, SI686, SI658, SI696	Valve is normally locked closed
	When RWT inventory is down to approximately 10% of the inventory required to be available for safety injection mode operation, a Recirculation Actuation Signal (RAS) is generated. The following equipment are actuated/operated. (Item 16 to 21)						
16	LPSI Pump 1, 2	a) Fails to stop on RAS	Elect. malf.	LPSI pump dead headed, or possible damage due to insufficient NPSH or air entrainment from RWT.	Pump run light; Periodic testing	Timely operator action to isolate RWT after RAS. Ensures vortex breaker is not uncovered.	RWT transfer volume is sized assuming this failure, crediting timely operator action.**
17	Sump Line Isolation Valve SI673, SI674 SI675, SI676	a) Fails to open on RAS	Elec. malf., mech. binding	Effective loss of one safety injection train (HPSI and CS) during recirculation.	SESS alarms. Valve position indicators.	Redundant sump line and pumps. LPSI not required after RAS.	For some break sizes, this could mean a faster drain down of the RWT, which would ultimately be terminated by operator action to isolate the RWT.

**In initially establishing reliance on timely operator action as the licensing basis for this failure, APS performed analyses to quantify the likelihood of the single failure and obtained a license amendment based upon that analysis. Subsequent to NRC approval and implementation of the license amendment, the NRC staff concluded that exclusion of the LPSI pump single failure on probabilistic grounds was inappropriate. Rather, the NRC staff concluded that the LOCA-related design requirement related to RWT transfer volume sizing should be established using solely deterministic methods. In response to this, the design and licensing bases were revised to deterministically evaluate the LPSI pump single failure (Ref. 16-21).

Table 6.3.2-3 (Sheet 5 of 10)
SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
17	Sump Line Isolation Valve (Continued)						
		b) Fails open	Elect. malf., mech. binding, contamination	None, redundant isolation valve, and check valve	Same as 17(a)	Redundant Isolation valve and check valve	
18	LP Pump to Min. Flow Line Isolation Valve SI669, SI668	a) Fails to close on RAS	Elect. malf., mech. binding, contamination	None	Valve position indicator; Periodic testing	Series isolation valve SI660, SI659	
19	Min. Flow Line to RWT Isolation Valve SI660, SI659	a) Fails to close on RAS	Elect. malf., mech. binding contamination	None	Valve position indicator; periodic testing	Series isolation valves	
20	HP Pump to Min. Flow line Isolation Valve SI666, SI667	a) Fails to close on RAS	Elect. malf., mech. binding contamination	None	Valve position indicator; Periodic testing	Series isolation valve SI660, SI659	
21	RWT Isolation Valve CH-530, CH-531	a) Fails to close (manual action)	Electrical malfunction, mechanical failure	Degraded performance of one train of HPSI (if air is entrained)	Valve position indicator; periodic testing	Parallel redundant HPSI path from sump. LPSI not required after RAS.	Timely operator action required to close

At one hour after the Loss of Coolant Accident (LOCA), the operator initiates cooldown with the Steam Generators (S.G.). Steam is relieved through the turbine bypass system if AC power is available or through the atmospheric dump system if power is unavailable. Then at two hours after the LOCA, the High Pressure Safety Injection (HPSI) pump discharge lines are realigned so that the total injection flow is divided equally between the hot and the cold legs. The following equipment are actuated: (Item 22 to 23)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
22	HPSI Pump Discharge Isolation Valve SI698, SI699, SI476, SI478	a) Fails open during hot and cold legs injection	Elect. malf., mech. failure	Flow to the affected hot leg will be less than 50% of total flow. HPSI pump may exceed run out flow	Periodic testing; valve position indicator	Redundant HPSI train	
		b) Fails closed	Mech. binding	Effective loss of one HPSI pump if SI476 or SI478 fails closed. None for SI698, SI699	Low pressure indication P308, P309; same as 22(a)	Redundant HPSI train	Valve is normally locked open

Table 6.3.2-3 (Sheet 6 of 10)

SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
23	Hot Leg Injection Line Isolation Valve SI604, SI321, SI609, SI331	a) Fails closed during hot and cold legs injection	Elect. malf., mech. failure	Loss of one Hot leg Safety injection flow path	Periodic testing; valve position indicator	Redundant HPSI train	
		b) Fails open	Mech. binding, elect. malf.	None	Valve position indicator; periodic testing	Series Isolation Valve	Valve is normally locked closed

At eight hours after the LOCA, if RCS pressure has fallen (or remained) below 300 psia, the break may be too large for absolute assurance that proper suction is available for the shutdown cooling mode; however, in this event there is assurance that simultaneous hot leg/cold leg injection alone will both cool the core and flush the reactor vessel indefinitely.

At eight hours after the LOCA, if RCS pressure has remained above 300 psia, this indicates that there is sufficient fluid in the RCS to allow the LPSI pumps to operate in their shutdown cooling mode. The Operator will realign the LPSI pumps for this service, thus inducing a subcooled flushing flow through the core. In the shutdown cooling mode, the LPSI pumps take suction from the hot legs of the RCS through the shutdown cooling lines, discharge through the shutdown cooling heat exchangers, and return flow to the RCS through the injection lines. Prior to the initiation of this mode of operation, RCS pressure must be reduced to 400 psia to allow opening of the shutdown cooling suction line isolation valves. This is done by dumping steam and throttling HPSI flow with the HPSI valves. To accomplish depressurization of RCS to below 400 psia in a reasonable time period, it may also be necessary to reduce the pressure in the SIT’s. This is done by opening at least one of the two solenoid operated vent valves on each SIT from the control room. The HPSI pumps continue to make up for spillage. The following equipments are actuated: (Item 24 to 31)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
24	LPSI Pump Suction Isolation Valve SI683, SI692	a) Fails to close during shutdown cooling phase	Elect. malf., mech. failure	None	Valve position indicator; periodic testing	Cooldown can be achieved by using one shutdown path; Series check valves provide required isolation	
		b) Fails closed	Mech. binding, elect. malf.	None	Same as 24(a)	None required	Valve is required to be closed during this mode

Table 6.3.2-3 (Sheet 7 of 10)
SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
25	LPSI Pump #1, #2	a) Fails to start during shutdown cooling phase	Elect. malf., mech. failure	Effective loss of one shutdown cooling path	Valve position indicator; Low flow indication F306 or F307 periodic testing	Cooldown can be achieved by using one pump	
26	LPSI Line to Shutdown Cooling Heat Exchanger Isolation (SDCHX) Discharge and Valves SI685, SI657, SI686, SI694, SI658, SI696	a) Fails to open during shutdown cooling phase	Mech. malf., Elect. malf.	Effective loss of one shutdown heat exchanger. Reduced cooldown rate	Periodic testing; valve position indicator	Cooldown can be achieved by using one train	
27	LPSI Pump Discharge Isolation to Valve SI306, SI307, SI435, SI447	a) Operator unable to close valve during shutdown cooling	Mech. binding, elect. malf.	Reduce flow through shutdown heat exchanger thus reduce cooldown rate	Valve position indicator; periodic testing	Redundant shutdown cooling path	
		b) Fails closed	Mech. binding	None	Valve position indicator; low flow indication F306 or F307; same as 27(a)	Throttling can be accomplished by using SI657/658	Valve is normally locked open
28	LPSI Pump to Shutdown Cooling Line Isolation Valve SI653, SI655, SI652, SI654, SI655, SI651	a) Fails to open during shutdown cooling phase	Mech. binding, elect. malf.	Effective loss of one LPSI pump suction. Reduce cooldown rate	Low pressure indication P306, P307. Low flow indication F306 or F307; periodic testing; valve position indicator	Can be achieved by using one pump	
29	Hot Leg Injection Line Isolation Valve SI604, SI321, SI609, SI331	a) Operator unable to close the valve during shutdown	Mech. binding, elect. malf.	None	Periodic testing; valve position indicator	Redundant Series Isolation Valve	

Table 6.3.2-3 (Sheet 8 of 10)

SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
29	Hot Leg Injection Line Isolation Valve (Continued)	b) Fails closed	Mech. binding, corrosion, elect. malf.	Loss of one hot leg safety injection flow path	Same as 29(a)	Redundant hot leg injection flow path	
		c) Fails open	Mech. binding, elect. malf.	None	Valve position indicator; periodic testing	Series Isolation Valve	Valve is normally locked closed
30	LPSI Pumps Min. Flow Line Isolation Valve SI669, SI668	a) Fails to closed during shutdown cooling phase	Mech. binding, elect. malf.	None	Periodic testing; valve position indicator	Series Isolation Valve SI660, SI659	
31	SI Tank Discharge Isolation Valve SI614, SI624, SI634, SI644	a) Fails to close when RCS pressure is at 415 psig	Mech. binding, elect. malf.	None	SI Tank level and pressure indicator; periodic testing; valve position indicator	Ability to bleed off SI tank pressure	
	The following equipment are part of SIS which are not actuated by SIAS or RAS						
32	Sump Lines	a) One line clogs	Sump screen plugs	Effective loss of one HPSI and one LPSI pump during recirculation mode of post LOCA operation	Periodic testing	Redundant sump lines and pumps	
33	Low Pressure Pressure Boundary	a) External leakage	Seal failure (limited)	Spillage of containment sump fluid. Effective loss of one LPSI pump	Local leak detector is discussed in Applicant's SAR	One S.I. Train can be isolated at any time since there is a parallel redundant S.I. Train	Leakage is a design basis only during recirculation Mode
34	HP Pump to Min. Flow Line Orifice Bypass Valve SI218, SI219	a) Fails closed	Mech. binding	Cannot provide a path for SI Tank refilling or HPSI pump testing.	Operator	Orifice is available to provide an alternate !atj	Valve is normally closed

Table 6.3.2-3 (Sheet 9 of 10)

SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
35	Valve Leak Test Isolation Valve SI210, SI220, SI230, SI240	a) Fails closed	Mech. binding	Same as 11(b)	Same as 11(b)		Valve is normally locked open
		b) Fails open	Seat failure, contamination	Unable to perform leak test on valve SI611, SI621, SI631, SI641	Periodic testing	None required	
36	SI Tank Level Indicator L311 L312, L313, L321, L322, L323, L331, L332, L333, L341, L342, L343	a) Fails to indicate correct	Elect. malf., mech. failure	Inconsistent level indication between level indicators	Level indicators in control room; periodic testing	Three parallel redundant level indicators for each SI tank	
37	SI Tank Nitrogen Supply Isolation Valve SI619, SI612, SI629, SI622, SI639, SI632, SI649, SI642	a) Fails closed	Mech. binding, air line separate from operator	Cannot repressurize SI tank when required	Periodic testing; valve position indicator	Repair	
		b) Fails open	Mech. binding, seat erosion elect. malf.	None	Same as 37(a)	Series Isolation Valve	Valve is designed fail closed
38	SI Tank Level Indicator line Isolation Valve SI212, SI213, SI228, SI229, SI222, SI223, SI238, SI239, SI232, SI233, SI242, SI243, SI258, SI259	a) Fails closed	Mech. binding	Cannot measure SI tank water level	Inconsistent SI tank level indication	Parallel indicator lines	
		b) Fails open	Mech. binding, contamination	None, cannot isolate line for repair	Periodic testing	None required	
39	SI Tank Pres-ure Indicator Line Isolation Valve, SI119, SI117, SI127, SI129, SI137, SI139, SI147, SI149	a) Fails closed	Mech. binding	Cannot measure SI tank pressure	Inconsistent SI tank pressure	Parallel indicator line	
		b) Fails open	Mech. binding,	Cannot isolate line	Periodic testing	Not required	

Table 6.3.2-3 (Sheet 10 of 10)

SAFETY INJECTION SYSTEM FMEA CESSAR Table 6.3.2-2

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
40	SI Tank Vent Valve, SI605, SI613, SI606, SI623, SI607, SI633, SI608, SI643	a) Fails closed	Mech. binding, elect. malf.	Degradation of redundancy to vent the tank for refill or to relieve pressure	No change in tank pressure when valve is opened; periodic testing; valve position indicator	Redundant parallel valve	
		b) Fails open	Elect. malf., mech. binding, contamination	None, power removed when operation not required	Low SI tank pressure alarm		Power removed from valve until tanks are required to be vented
41	LPSI Line to Pool Cooling & Purif. System Isolation Valve SI453, SI450, SI455, SI454	a) Fails closed	Mech. binding, corrosion	No impact on safety injection	Operator	None required	Redundant train available
		b) Fails open	Mech. binding	None	Operator, or SFP level	Series Isolation Valve	Valve is normally locked closed
42	Pool Cooling & Purif. System (PCPS) to LP Pump Suction Isolation Valve SI443, SI256, SI442, SI204	a) Fails closed	Mech. binding, corrosion	No impact on safety injection	Operator	None required	
		b) Fails open	Mech. binding	Potential diversion of PCPS inventory to LPSI system	Spent Fuel Pool level indicator	Series redundant valve	Valve is normally closed
43	Shutdown Purif. To LP Pump Suction Isola-tion Valve CH397, SI418, CH419	a) Fails closed	Mech. binding, corrosion	No impact on safety injection	Operator	Not required	
		b) Fails open	Mech. binding	None	Operator	Series redundant valve	Valve is normally closed
44	RC Makeup Isolation Valves SI1024 and SI1027 (Effective for Units where DMWO 4304156 has been implemented.)	a) Fails closed	Mech. Binding, corrosion	No impact on safety injection	Operator	Not required	
		b) Fails open	Mech. Binding	None	Operator	Series redundant valve	Valve is normally closed

* The Method of Detection column is used to show that it is possible to detect the failure, during or before the accident.

6.3.2.6 Protection Provisions

The Safety Injection System is provided with protection from damage that could result from a LOCA by: (a) designing components to withstand the Design Bases Event environment including coolant chemistry, radiation, temperature and pressure resulting from the accident, (b) a seismic design that will withstand the stress imposed by a Safe Shutdown Earthquake occurring simultaneously with a LOCA, and (c) protection from missiles in accordance with Section 3.5.4.1.

To minimize the potential for water hammer and degraded pump performance, the safety injection suction and discharge piping will be maintained filled with water in accordance with Technical Specification and Technical Requirements Manual surveillance requirements. All piping is provided with high point vents and low point drains. The centrifugal pumps are vented through their discharge pipes. All SI pumps use a casing drain for draining and are tested quarterly to satisfy the requirements of ASME XI.

6.3.2.6.1 Capability to Withstand Design Bases Environment

Components located in the containment, such as remote-operated valves and instrumentation and control equipment, required for initiation of Safety Injection System are designed to withstand the LOCA conditions of temperature, pressure, humidity, chemistry and radiation for the extended period of time required as detailed in Section 3.11. These valves include the two sump isolation valves, and the valves associated with fill, drain, and pressure control of the safety injection tanks which receive SIAS or are required to operate following an accident.

The instrumentation includes the wide range level and pressure instrumentation associated with the safety injection tanks.

Insofar as practical, safety injection components required to maintain a functional status have been located outside containment to eliminate exposure of this equipment to the post-LOCA conditions. The equipment outside containment is designed in consideration of the chemical and radiation effects associated with operation following a LOCA. (Engineering drawings 01, 02, 03-M-SIP-001, -002 and -003 indicates location of equipment inside or outside of containment).

The design life of the safety injection pumps is 40 years, corresponding to the life of the plant. Design pressures and temperatures are in excess of the maximum pressures and temperatures seen by the respective component during the worst or normal operating and design bases conditions. Materials of construction for the pumps are compatible with the expected water-chemistry under normal and LOCA conditions. A radiation resistance requirement has been placed on the pumps consistent with Section 3.11.

6.3.2.6.2 Missile Protection

Protection from possible Reactor Coolant System generated missiles is afforded by locating all components outside the containment except for the safety injection tanks. These tanks are located outside the biological shield such that protection from possible Reactor Coolant System generated missiles is provided.

6.3.2.6.3 Seismic Design

Since operation of the Safety Injection System is essential following a Loss-of-Coolant Accident, it is considered Category 1 for seismic design. The general design basis for Category I equipment is that it must be able to withstand the appropriate seismic loads plus other applicable loads without loss of design functions which are required to protect the public.

For the safety injection system this means that the components must be able to withstand the stresses resulting from emergency operation following a LOCA, simultaneous with the stresses resulting from the Safe Shutdown Earthquake (SSE) without loss of function.

Refer to Section 3.7 for details on seismic design and analysis methods.

6.3.2.7 Required Manual Actions

The two modes of operation, injection and recirculation, are automatically initiated by a Safety Injection Actuation Signal (SIAS) and a Recirculation Actuation Signal (RAS) respectively. Timely Operator action is required to close the RWT discharge valves after verifying the sump discharge valves have opened after receiving a RAS to prevent ingress of air in the ESF pump suction piping during switchover to recirculation.

Long term core cooling is manually initiated at approximately 2 hours post-LOCA at which time the hot leg injection valves are opened to provide simultaneous hot and cold leg high pressure safety injection, which results in a circulation flow

through the core. For small pipe breaks, the HPSI pumps provide makeup for spillage, while the Reactor Coolant System is cooled down and depressurized to shutdown cooling initiation conditions utilizing the steam generator atmospheric dump valves and Auxiliary Feedwater System. For small LOCA's the SIT's must be vented to allow RCS depressurization. This is followed by manual SDC operation.

6.3.3 PERFORMANCE EVALUATION

6.3.3.1 Introduction and Summary

10 CFR 50.46 provides acceptance criteria for Emergency Core Cooling Systems (ECCS) for light-water nuclear power reactors [Reference 1]. The ECCS performance analyses described in this section demonstrate that the PVNGS ECCS design satisfies these criteria.

The PVNGS ECCS performance analyses encompass a wide range of Reactor Coolant System (RCS) break locations and sizes, including both large and small break Loss-of-Coolant Accident (LOCAs). The limiting break, which results in the closest approach to 10 CFR 50.46 acceptance criteria for peak clad temperature, is a 0.6 DEG/PD (Double-Ended Guillotine in the Reactor Coolant Pump Discharge leg) as noted in UFSAR Section 6.3.3.2. The limiting break, which results in the closest approach to 10 CFR 50.46 acceptance criterion maximum clad oxidation (or local clad oxidation), and maximum core-wide cladding oxidation is a 0.8 DEG/PD as noted in UFSAR Section 6.3.3.2. For these limiting breaks, the PVNGS ECCS design meets the acceptance criteria of 10 CFR 50.46 as follows:

Criterion 1: Peak Cladding Temperature. ". . .The calculated maximum fuel element cladding temperature shall not exceed 2200°F. . . ."

For the limiting break, the PVNGS ECCS performance analysis yielded a peak cladding temperature of 2106°F.

Criterion 2: Maximum Cladding Oxidation.". . . The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation. . . ."

For the limiting break, the PVNGS ECCS performance analysis yielded a maximum cladding oxidation of 0.119 times the total cladding thickness before oxidation.

Criterion 3: Maximum Hydrogen Generation. ". . . The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react. . ."

For the limiting break, the PVNGS ECCS performance analysis yielded a maximum core-wide oxidation of less than 0.0099 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders

surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

Criterion 4: Coolable Geometry. ". . . Calculated changes in core geometry shall be such that the core remains amenable to cooling. . . ."

For the limiting breaks, the PVNGS ECCS performance analysis utilized the NRC-approved 1999 EM version of the Westinghouse Electric Company LLC large break LOCA evaluation model for Combustion Engineering designed PWRs, which is described in UFSAR Section 6.3.3.2.2. This evaluation model includes a cladding swelling and rupture model that accounts for the effects of changes in core geometry, if such changes are predicted to occur [Reference 2]. The ECCS performance analysis demonstrated adequate core cooling even with core geometry changes. The ECCS performance analysis was performed to a point in time where cladding temperatures were decreasing and the RCS was depressurized, thereby precluding any further cladding deformation. Therefore, a coolable core geometry has been demonstrated.

Criterion 5: Long-Term Cooling. ". . . After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low

value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core. . . ."

For the limiting breaks, the ECCS performance analysis showed that the rapid insertion of borated water from the Safety Injection Tanks (SITs) and the safety injection pumps limits the peak cladding temperature and cools the core within a short period of time. Subsequently, the safety injection pumps will continue to supply cooling water from the Refueling Water Tank (RWT) or the containment sump. See UFSAR Section 6.3.3.4 for additional information on post-LOCA long-term cooling.

6.3.3.2 Large Break LOCA Analysis

6.3.3.2.1 Historical Background and Analyses of Record

Early large break LOCA analyses were performed to support NRC approval of the CE Nuclear Power LLC large break LOCA evaluation model [Reference 3]; to obtain a Final Design Approval (FDA) from the NRC for the standard System 80 plant design described in the Combustion Engineering Standard Safety Analysis Report (CESSAR) [Reference 4]; and to support NRC issuance of operating licenses for PVNGS Units 1, 2, and 3. These early large break LOCA analyses considered a wide spectrum of breaks including slot breaks and guillotine breaks, ranging in size from 0.5 ft^2 up to the full double-ended break

area. Postulated break locations included the Reactor Coolant Pump (RCP) suction and discharge legs, as well as the hot leg. These analyses demonstrated that large breaks in the RCP discharge leg were the most limiting, because both the core flow rate during blowdown and the core reflood rate were minimized for this location.

Additional large break LOCA analyses were subsequently performed to support NRC approval of PVNGS operating license amendments; to support core reload design efforts; and to correct miscellaneous errors that were discovered either in the evaluation model itself, or in the plant design data that was used as input to the evaluation model.

PVNGS conformance to the acceptance criteria of 10 CFR 50.46 is established by the following large break LOCA analysis of record:

A. A "break spectrum analysis" was performed to support implementation of replacement steam generators with 10% tube plugging and simplified head assembly for ZIRLO™ clad fuel rods. The results of this analysis are applicable to the PVNGS units with or without Simplified Head Assembly (SHA) implementation. The impact of SHA or ECCS performance has been determined to be insignificant and any differences in the containment configuration due to SHA would be covered by using contingency in the passive heat sink accounting. This analysis bounds PVNGS units utilizing Zircaloy-4 clad material.

This analysis of record serves to establish the limiting break size in the RCP discharge leg (i.e., a 0.6 DEG/PD), which produces the closest approach to the 10 CFR 50.46 acceptance criterion for peak clad temperature. This analysis also identifies a separate limiting break size of 0.8 DEG/PD for the maximum clad oxidation and core-wide cladding oxidation criteria.

Table 6.3.3.2-1 identifies the break sizes that were examined in this analysis of record. This analysis was conducted with the 1999 EM version of the Westinghouse Electric Company LLC large break LOCA evaluation model for Combustion Engineering designed PWRs, which is described in UFSAR Section 6.3.3.2.2.

6.3.3.2.2 1999 EM Large Break LOCA Evaluation Model

The current PVNGS large break LOCA break spectrum analysis of record, was performed using the NRC-approved 1999 EM version of the Westinghouse Electric Company LLC large break LOCA evaluation model for Combustion Engineering designed PWRs [Reference 5]. This evaluation model utilizes the CEFLASH-4A computer code [Reference 6] to determine the behavior of the RCS during the blowdown phase of a LOCA, and the COMPERC-II computer code [Reference 7] to determine the behavior of the RCS during the refill and reflood phases of a LOCA. Core flow and thermodynamic parameters from these two computer codes are input to the STRIKIN-II computer code [Reference 8] to calculate the hot rod cladding temperature transient. STRIKIN-II also utilizes steam cooling heat transfer

Table 6.3.3.2-1

TIMES OF INTEREST

FOR THE LARGE BREAK LOCA ECCS PERFORMANCE ANALYSES

(Seconds after Break Occurs)

Break Spectrum Analysis

Break Size (DEG/PD)	SI Tanks On	End of Blowdown	Start of Reflood(5)	SI Tanks Empty	SI Pumps On	Hot Rod Rupture
Spectrum Results for Peak Cladding Temperature(2)						
1.0	14.12	18.42	23.17	40.77	38.38	27.48
0.8	15.25	19.64	24.38	41.99	38.47	29.07
0.6	17.30	21.76	26.48	44.18	38.65	41.83
0.4	22.55	27.08	31.76	49.67	38.98	57.81
Case Results for Peak Local Oxidation(3)						
0.8	15.25	19.64	24.38	41.99	38.47	54.42
Case Results for Maximum Core-Wide Oxidation(4)						
0.8	15.83	24.11	32.37	84.3	38.48	55.06

(1) Break type is Double-Ended Guillotine (DEG), located in the Reactor Coolant Pump Discharge (PD) leg (i.e., RCS cold leg). The effective break area for the 1.0 DEG/PD is 9.8174 ft^2, corresponding to twice the pump discharge leg cross-sectional flow area. The limiting break for PCT (i.e., a 0.6 DEG/PD) has a break area that is 60% of this value.

(2) Results are for Erbia fuel type at a burnup of 34 GWD/MTU (corresponding to FATES3B Cycle 28)

(3) Results are for Erbia fuel type at a burnup of 0.5 GWD/MTU (corresponding to FATES3B Cycle 4)

(4) Results are for Erbia fuel type at a burnup of 0.5 GWD/MTU (corresponding to FATES3B Cycle 4)

(5) Start of reflood is defined by the Contact Time.

coefficients that are calculated with the HCROSS [Reference 2] and PARCH [References 2 and 9] computer codes.

Peak cladding temperature and maximum cladding oxidation are obtained from the STRIKIN-II computer code. The maximum core-wide cladding oxidation is obtained from the results of both the STRIKIN-II and COMZIRC [Reference 7] computer codes. Initial steady-state fuel rod conditions used in STRIKIN-II are determined with the FATES computer code [Reference 10].

6.3.3.2.3 Large Break LOCA "Break Spectrum Analysis"

The PVNGS large break LOCA break spectrum analysis of record evaluated four double-ended guillotine (DEG) breaks located on the RCP discharge. Slot breaks were not included in the analysis because they are known to be less limiting than guillotine breaks on a pump discharge line. Table 6.3.3.2-2 summarizes important results of the analysis.

The analysis of record demonstrated that the limiting break size for peak cladding temperature was 0.6 DEG/PD and for both maximum cladding oxidation and maximum core-wide cladding oxidation was 0.8 DEG/PD. It should be noted that the RCP discharge leg has an inside diameter of 30 inches and consequently a cross-sectional flow area of 4.9087 ft^2. Therefore, the effective break area for the 1.0 DEG/PD is approximately 9.8174 ft^2, and the limiting breaks have break areas of 60% and 80% of this value, or approximately 5.89 ft^2 and 7.857 ft^2 respectively.

Table 6.3.3.2-2

PEAK CLADDING TEMPERATURES AND OXIDATION PERCENTAGES
FOR THE LARGE BREAK LOCA ECCS PERFORMANCE ANALYSES

Break Spectrum Analysis

Break Size (DEG/PD)	Peak Cladding Temperature(°F)	Maximum Cladding Oxidation (%)	Maximum Core-Wide Oxidation (%)
Spectrum Results for Peak Cladding Temperature(1)			
1.0	2086	11.1	0.670
0.8	2093	10.6	0.679
0.6	2106	7.3	0.504
0.4	2069	6.4	0.389
Case Results for Peak Local Oxidation(2)			
0.8	2063	11.9	0.749
Case Results for Maximum Core-Wide Oxidation(3)			
0.8	2045	11.8	0.781

(1)Results are for Erbia fuel type at a burnup of 34 GWD/MTU (corresponding to FATES3B Cycle 28)

(2)Results are for Erbia fuel type at a burnup of 0.5 GWD/MTU (corresponding to FATES3B Cycle 4)

(3)Results are for Erbia fuel type at a burnup of 0.5 GWD/MTU (corresponding to FATES3B Cycle 4)

6.3.3.2.4 Safety Injection System Parameters

The Safety Injection (SI) system consists of four SITs, two High Pressure Safety Injection (HPSI) pumps, and two Low Pressure Safety Injection (LPSI) pumps. The SITs automatically discharge when RCS pressure decreases below the SIT pressure. Each SIT injects to a single cold leg. The HPSI and LPSI pumps are automatically actuated by a Safety Injection Actuation Signal (SIAS) that is generated by either low pressurizer pressure or high containment pressure. Each HPSI pump injects to one of two high pressure injection headers, each of which feeds four cold legs. Each LPSI pump injects to one of two low pressure injection headers, each of which feeds two cold legs.

The large break LOCA analyses of record conservatively represent the spillage of safety injection flow. All of the safety injection flow to the broken RCP discharge leg (i.e., cold leg) is assumed to spill out through the break and into the containment building.

The large break LOCA analyses of record considered several single failures i.e., failure of one LPSI pump, failure of one HPSI pump, failure of one diesel generator and no failure. No failure was determined to be the most limiting condition for the following two reasons. First, any equipment failure results in essentially the same liquid level in the downcomer during reflood as the case of no failure. Therefore, both cases are equivalent in terms of maintaining the downcomer head which drives core reflooding. Secondly, the no failure case results in more spillage of ECCS flow to the containment. This results in a lower containment pressure, which impedes the

reflood process. Specifically, as pressure is reduced, steam density decreases, thereby making it more difficult for steam to flow from the core to the break, and for water to reflood the core. Consequently, no failure is more limiting because it has an adverse impact on the core reflood rate, and because it does not have a beneficial impact on the downcomer level relative to any equipment failure.

Based on the PVNGS ECCS design, spillage considerations, and no failure of the ECCS, the following SI flows into the RCS were used for the large break LOCA analyses of record for RCP discharge leg breaks:

A. 100% of the flow from three SITs;

B. 75% of the flow from two HPSI pumps; and

C. 100% of the flow from one LPSI pump and 50% of the flow from the other LPSI pump.

Consistent with the fact that no ECCS failure is the worst condition, maximum HPSI and LPSI pump flow rates were used in the large break LOCA analyses of record. The pumps were modeled to start injection after the downcomer was refilled by the SITs, as noted in UFSAR Section 6.2.1.5.3.5.

6.3.3.2.5 Core and System Parameters

Pertinent input parameters and initial conditions used in the large break LOCA break spectrum analysis are listed in Table 6.3.3.2-3. In this analysis the initial reactor power level is 4070 MW_t, or 102% of a rated thermal power of 3990 MW_t.

Table 6.3.3.2-3

SYSTEM PARAMETERS AND INITIAL CONDITIONS FOR THE LARGE BREAK LOCA ECCS PERFORMANCE BREAK SPECTRUM ANALYSIS

Parameter	Units	Value
Reactor Power Level (102% of 3990)	Mwt	4070
Peak Linear Heat Generation Rate (PLHGR) of the Hot Rod	kW/ft	13.1
PLHGR of the Average Rod in the Assembly with the Hot Rod	kW/ft	12.35
Gap Conductance at the PLHGR	Btu/hr-ft^2-°F	2143[a]
Fuel Centerline Temperature at the PLHGR	°F	3260[a]
Fuel Average Temperature at the PLHGR	°F	2020[a]
Hot Rod Gas Pressure	psia	2408[a]
Moderator Temperature Coefficient at Initial Density	$\Delta\rho$/°F	0.5×10^{-4}
RCS Flow Rate	lbm/hr	147.6×10^6
Core Flow Rate	lbm/hr	143.2×10^6
RCS Pressure	psia	2250
Cold Leg Temperature	°F	541
Hot Leg Temperature	°F	611
Safety Injection Tank Pressure (Minimum/Maximum)	psia	602/652
Safety Injection Tank Water Volume (Minimum/Maximum)	ft^3	1750/1950
Containment Temperature (Minimum)	°F	50

NOTE:

(a) These values correspond to the rod average burnup of the hot rod that yielded the highest peak cladding temperature.

The limiting break reanalysis accounts for up to 2516 plugged steam generator tubes (total for both replacement steam generators). Because the overall steam venting loss coefficient in COMPERC-II is not significantly impacted by asymmetric tube plugging, the limiting break reanalysis does not impose any asymmetric steam generator tube plugging limits.

6.3.3.2.6 Containment Parameters

Section 6.2.1.5 describes the minimum containment pressure analyses that were performed as part of the large break LOCA analyses of record, including pertinent input parameters and initial conditions. For the "break spectrum analysis," passive heat sink inputs to the COMPERC-II code were based on data contained in UFSAR Table 6.2.1-27,B Detailed Listing.

The containment pressure response predicted by the "break spectrum analysis" for the limiting break size is shown in Figure 6.3.3.2-3F.

6.3.3.2.7 Results and Conclusions

Table 6.3.3.2-1 lists times of interest for the large break LOCAs that were analyzed for the "break spectrum analysis”. Likewise, Table 6.3.3.2-2 summarizes the peak cladding temperatures, maximum cladding oxidation percentages, and maximum core-wide oxidation percentages for each of the breaks that were analyzed.

As noted in Table 6.3.3.2-4, the results for each break are presented in Figures 6.3.3.2-1 through 6.3.3.2-4. For each break size, the results of eight parameters (e.g., cladding

temperature) are plotted as a function of time as indicated by Table 6.3.3.2-5. For the limiting break size, thirteen additional parameters are plotted as a function of time as indicated by Table 6.3.3.2-6.

As shown in Table 6.3.3.2-2, analysis of the limiting large break LOCA for peak clad temperature (i.e., the 0.6 DEG/PD break resulted in a peak clad temperature of 2106°F, a maximum clad oxidation percentage of 11.9% for the limiting large break LOCA (i.e., the 0.8 DEG/PD), and a maximum core-wide oxidation percentage of less than 0.99% (chosen to bound all the values in Table 6.3.3.2-2). These results meet the acceptance criteria of 10 CFR 50.46.

6.3.3.3 Small Break Analysis

6.3.3.3.1 Evaluation Model

The analysis reported in this section was performed using the C-E small break LOCA evaluation model which is described in reference 11 and was approved by the NRC in reference 12. This particular version is the Supplement 2 Model (S2M) of the Westinghouse Electric Company LLC for Combustion Engineering designed PWRs. In the C-E model, the CEFLASH-4AS[Reference 13] computer program is used to determine the RCS behavior during the blowdown phase, and the COMPERC-II[Reference 7] computer program is used to determine the RCS behavior during the reflood phase. Fuel rod temperatures and cladding oxidation percentages are calculated using the STRIKIN-II[Reference 8] and PARCH[Reference 9] computer programs. The interfacing between these programs is discussed in detail in reference 11.

Table 6.3.3.2-4

RESULTS FOR THE LARGE BREAK LOCA
ECCS PERFORMANCE ANALYSES OF RECORD

Break Spectrum Analysis

Break Size, Type, and Location	Abbreviation	Figure Nos.[a]
1.0 Double-Ended Guillotine Break in Pump Discharge Leg	1.0 DEG/PD	6.3.3.2-1x
0.8 Double-Ended Guillotine Break in Pump Discharge Leg	0.8 DEG/PD	6.3.3.2-2x
0.6 Double-Ended Guillotine Break in Pump Discharge Leg	0.6 DEG/PD	6.3.3.2-3x
0.4 Double-Ended Guillotine Break in Pump Discharge Leg	0.4 DEG/PD	6.3.3.2-4x

NOTE:

(a) Figure numbers have a format ending in the character “x”, where “x” represents a variable between “A” and “U”. These variables identify the parameter that is plotted as a function of time, as delineated in Tables 6.3.3.2-5 and 6.3.3.2-6.

Table 6.3.3.2-5

VARIABLES PLOTTED AS A FUNCTION OF TIME

FOR EACH BREAK SIZE, AND LOCATION ANALYZED IN THE

"BREAK SPECTRUM ANALYSIS"

Variable	Figure Designation[a]
Core Power	A
Pressure in Center Hot Assembly Node	B
Leak Flow Rate	C
Hot Assembly Flow Rate	D
Hot Assembly Quality	E
Containment Pressure	F
Mass Added to Core During Reflood	G
Peak Cladding Temperature	H

NOTE:

a. Refer to Table 6.3.3.2-4 for the figure numbers for each break size and location.

Table 6.3.3.2-6
VARIABLES PLOTTED AS A FUNCTION OF TIME
FOR THE LIMITING BREAK SIZE IN THE
"BREAK SPECTRUM ANALYSIS"

Variable	Figure Designation[(a)]
Mid Annulus Flow Rate	I
Quality Above and Below the Core	J
Core Pressure Drop	K
Safety Injection Flow Rate into Intact Discharge Legs	L
Water Level in Downcomer During Reflood	M
Hot Spot Gap Conductance	N
Local Cladding Oxidation Percentage	O
Fuel Centerline, Fuel Average, Cladding and Coolant Temperature at the Hot Spot	P
Hot Spot Heat Transfer Coefficient	Q
Hot Pin Pressure	R
Containment Atmosphere Temperature	S
Containment Sump Temperature	T
Core Bulk Channel Flow Rate	U

NOTE:

a. Refer to Table 6.3.3.2-4 for the figure numbers associated with the limiting break size.

6.3.3.3.2 Safety Injection System Assumptions

The safety injection system (SIS) includes two high pressure pumps, two low pressure pumps, and four safety injection tanks. It is conservatively assumed that offsite power is lost upon reactor trip and, therefore, all safety injection pumps must await diesel startup and load sequencing before they can start. The total time delay assumed is 30 seconds from the time that the pressurizer pressure reaches the SIAS setpoint to the time that the SI flow is delivered to the RCS. For breaks in the reactor coolant pump discharge leg, it is also assumed that all safety injection flow delivered to the broken leg spills out the break.

An analysis of the possible single failures that can occur within the SIS has shown that the worst single failure for the small break LOCA analysis is the failure of one of the emergency diesels to start.[Reference 11] This failure causes a loss of both a high pressure pump and a low pressure pump, and results in a minimum of safety injection water being available to cool the core. Therefore, based on the above assumptions, the following safety injection flows are credited for the small break analysis.

A. Since each high pressure safety injection pump (HPSIP) is piped so that it can feed all four cold leg injection points:

   1. For a break in the pump discharge leg, the HPSIP flow credited is 75% of the flow from one HPSIP. The remaining 25% is assumed to spill out the break.

2. For breaks in other locations, the HPSIP flow credited is 100% of one HPSIP.

B. Since each low pressure safety injection pump (LPSIP) is piped so that it feeds two of the cold leg injection points:

1. For a break in the pump discharge leg, the LPSIP flow credited is 50% of the flow from one LPSIP. The remaining 50% is assumed to spill out the break.

2. For breaks in other locations, the LPSIP flow credited is 100% of one LPSIP.

C. The four safety injection tanks (SITs) are piped so that each SIT feeds a single cold leg injection point. Thus:

1. For a break in the pump discharge leg, the SIT flow credited is 100% of the flow from three SITs. The remaining SIT is assumed to spill out the break.

2. For breaks in other locations, the SIT flow credited is 100% of four SITs.

6.3.3.3.3 Core and System Parameters

The significant core and system parameters and initial conditions used in the Unit 2 Cycle 11 small break LOCA analysis, hereafter referred to as the SBLOCA reference cycle, are presented in Table 6.3.3.3-2. The peak linear heat generation rate (PLHGR) of 13.5 kw/ft was assumed to occur 15% from the top of the active core. A conservative beginning-of-

life moderator temperature coefficient of 0.0 $\Delta\rho/°F$ was used in the analysis.

The analysis accounts for up to 2,750 plugged tubes per steam generator.

The initial steady state fuel rod conditions were obtained from the FATES3B(Reference 17) computer program. The small break LOCA analysis employed a hot rod average burnup which maximized the amount of stored energy in the fuel.

Table 6.3.3.3-1 presents the high and low pressure safety injection pump flow rates used in the PVNGS small break LOCA analysis.

6.3.3.3.4 Containment Parameters

The small break LOCA analysis does not use a detailed containment model. Therefore, other than the initial containment pressure and the containment volume, which are assumed to be 14.7 psia and 3.0 x 10^6 ft^3, respectively, no containment parameters are employed for this analysis.

6.3.3.3.5 Break Spectrum

Seven breaks were analyzed to characterize the small break spectrum. Six breaks, ranging in size from 0.01 ft^2 to 0.07 ft^2, were postulated to occur in the pump discharge leg. The break size range of 0.01 ft^2 to 0.07 ft^2 encompasses the breaks sizes for which hot rod cladding heatup is terminated solely by injection from the HPSIP. It is within this range that the limiting SBLOCA, the 0.05 ft^2 break, resides. Breaks

Table 6.3.3.3-1

SAFETY INJECTION PUMPS MINIMUM DELIVERED FLOW TO RCS
(ASSUMING ONE EMERGENCY GENERATOR FAILED)

RCS Pressure (psig)	Flow Rate Per Injection Point[a] (gpm)			
	A1	A2	B1	B2
1700	0.50	0.50	0.50	0.50
1581	51.25	51.25	51.25	51.25
1483	76.75	76.75	76.75	76.75
1349	101.25	101.25	101.25	101.25
1199	123.50	123.50	123.50	123.50
993	149.25	149.25	149.25	149.25
782	172.00	172.00	172.00	172.00
605	189.00	189.00	189.00	189.00
310	214.00	214.00	214.00	214.00
200	222.75	222.75	222.75	222.75
130	561.50	561.50	228.00	228.00
100	1242.75	1242.75	230.25	230.25
50	1744.00	1744.00	234.00	234.00
0	2109.50	2109.50	237.50	237.50

(a) Injection point A1 is assumed to be attached to the broken pump discharge leg.

Table 6.3.3.3-2

SYSTEM PARAMETERS AND INITIAL CONDITIONS

FOR THE SMALL BREAK LOCA ECCS PERFORMANCE ANALYSIS

Parameter	Value	Units
Reactor power level (102% of 3990)	4070	MWt
Average linear heat generation Rate	5.9	kW/ft
Peak linear heat generation rate (PLHGR)	13.5	kW/ft
Gap conductance at PLHGR	1839	BTU-hr-ft^2-°F
Fuel centerline temperature at PLHGR	3243	°F
Fuel average temperature at PLHGR	2045	°F
Hot rod gas pressure	1,058	psia
Moderator temperature coefficient at initial density	0.0	$\Delta\rho$/°F
RCS flow rate	147.6×10^6	lbm/hr
Core flow rate	143.2×10^6	lbm/hr
RCS pressure	2,250	psia
Core inlet temperature	541[a]	°F
Core outlet temperature	612	°F
Low pressurizer pressure reactor trip setpoint	1,600	psia
Low pressurizer pressure SIAS setpoint	1,600	psia
Safety injection tank pressure	200[b]	psia

a. This is below Technical Specification minimum cold leg temperature, but is conservative for LOCA analysis.

b. This pressure arbitrarily set at the low value to prevent SIT water injection during a SBLOCA transient. This is a conservative approach by not taking any SIT credit.

outside this range are either too small to experience any core uncovery or are sufficiently large such that injection from the SITs will recover the core and the terminate cladding heatup before the cladding temperature approaches the PCT calculated for the limiting SBLOCA. The PVNGS Cycle 1 SBLOCA break spectrum analysis demonstrated that breaks larger than 0.07 ft^2 had peak cladding temperatures that were less than the limiting SBLOCA. One break, equal in area to a fully open pressurizer safety valve (0.03 ft^2), was postulated to occur in the top of the pressurizer. Each break size was evaluated for different combinations of the cladding material of Zircaloy-4 and ZIRLO™ and fuel of $U0_2$ and Erbia. Table 6.3.3.3-3 lists the various break sizes and locations.

6.3.3.3.6 Results

The analysis found the combination of ZIRLO™ clad and $U0_2$ fuel resulted in the highest PCTs, 0.05 ft^2/PD being the limiting break size. For different break sizes the results were less sensitive to the combination of clad and fuel.

The transient behavior of important NSSS parameters is shown in the figures listed in table 6.3.3.3-4. Table 6.3.3.3-5 summarizes the important results of this analysis. Times of interest for the various breaks analyzed are presented in table 6.3.3.3-6. A plot of peak cladding temperatures (PCT) versus break size is presented in figure 6.3.3.3-8. The 0.05 ft^2 break results in the highest PCT (1618F) of the small breaks analyzed. The PCT is approximately 490F lower than that reported in paragraph 6.3.3.1 for the limiting large break.

The break resulting in the next highest PCT of the small break spectrum is the 0.06 ft^2 break with a PCT of 1485F.

Table 6.3.3.3-3

BREAK SPECTRUM
FOR THE SMALL BREAK LOCA ECCS PERFORMANCE ANALYSIS

Break Size and Location	Abbreviation	Figure No.
0.07 ft^2 Break in Pump Discharge Leg	0.07 FT^2/PD	6.3.3.3-1
0.06 ft^2 Break in Pump Discharge Leg	0.06 FT^2/PD	6.3.3.3-2
0.05 ft^2 Break in Pump Discharge Leg	0.05 FT^2/PD	6.3.3.3-3
0.04 ft^2 Break in Pump Discharge Leg	0.04 FT^2/PD	6.3.3.3-4
0.03 ft^2 Break in Pump Discharge Leg	0.03 FT^2/PD	6.3.3.3-5
0.01 ft^2 Break in Pump Discharge Leg	0.01 FT^2/PD	6.3.3.3-6
0.03 ft^2 Break at Top of Pressurizer	0.03 FT^2/PRZ	6.3.3.3-7

Table 6.3.3.3-4
VARIABLES PLOTTED AS A FUNCTION OF TIME FOR EACH BREAK
OF THE SMALL BREAK LOCA ECCS PERFORMANCE ANALYSIS

Variable	Figure Designation[a]
Normalized total core power	A
Inner vessel pressure	B
Break flow rate	C
Inner vessel inlet flow rate	D
Inner vessel two-phase mixture level	E
Heat transfer coefficient at hot spot	F
Coolant temperature at hot spot	G
Hot spot clad surface temperature	H

a. Refer to figures 6.3.3.3-1 through 6.3.3.3-7.

Table 6.3.3.3-5
PEAK CLADDING TEMPERATURES AND OXIDATION PERCENTAGES
FOR THE SMALL BREAK LOCA ECCS PERFORMANCE ANALYSIS

Break Size (ft^2)	Peak Cladding Temperature (°F)[(a)]	Maximum Clad Oxidation (%)[(b)]	Hot Rod Oxidation (%)[(c)]
0.07 FT^2/PD	1409	0.4	<0.1
0.06 FT^2/PD	1485	0.61	<0.12
0.05 FT^2/PD	1618	1.28	<0.2
0.04 FT^2/PD	1474	0.67	<0.13
0.03 FT^2/PD	1416	0.52	<0.11
0.01 FT^2/PD	1434[d]	0.3	<0.08
0.03 FT^2/PRZ	1439[d]	0.3	<0.08

a. Acceptance criterion is 2200°F.
b. Acceptance criterion is 17%.
c. Acceptance criterion is 1.0% core-wide cladding oxidation. Rod-average oxidation of the hot rod is given as a conservative representation of the core-wide oxidation.
d. Blowdown peak cladding temperature

Table 6.3.3.3-6
TIMES OF INTEREST
FOR THE SMALL BREAK LOCA ECCS PERFORMANCE ANALYSIS
(Seconds after Break)

Break Size (ft^2)	HPSI Flow Delivered to RCS[c] (sec)	LPSI Flow Delivered to RCS[c] (sec)	SIT Flow Delivered to RCS (sec)	Peak Cladding Temperature Occurs (sec)
0.07 FT^2/PD	184	(a)	(b)	1304
0.06 FT^2/PD	210	(a)	(b)	1514
0.05 FT^2/PD	245	(a)	(b)	1592
0.04 FT^2/PD	300	(a)	(b)	1744
0.03 FT^2/PD	388	(a)	(b)	2360
0.01 FT^2/PD	999	(a)	(b)	784[d]
0.03 FT^2/PRZ	744	(a)	(b)	559[d]

a. Calculation completed before LPSI flow delivery to RCS begins.
b. SIT pressure was set at 200 psia to prevent SIT injection.
c. Time includes the 30 second delay from the time the pressurizer pressure reaches the low pressure SIAS setpoint to the time the pump powered and at full speed.
d. Blowdown peak clad temperature.

6.3.3.3.7 Instrument Tube Rupture

In addition to the seven small breaks discussed above, the rupture of an in-core instrument tube was considered. A break, equal in size to a completely severed instrument tube (0.003 ft^2), was postulated to occur in the reactor vessel bottom head.

Following rupture, the primary system depressurizes until a reactor scram signal and safety injection actuation signal (SIAS) are generated due to low pressurizer pressure. The assumed loss of offsite power causes the primary coolant pump and the feedwater pumps to coast down. After the delay required to start the emergency diesel and the high pressure safety injection pump following SIAS, safety injection flow is initiated to the RCS. At this time an auxiliary feedwater pump is also started, providing a source of cooling to the steam generators. Due to the assumed failure of one diesel, only one high pressure safety injection pump and one auxiliary feedwater pump are available. (Four SITs and one low pressure safety injection pump are also available but do not inject due to the high reactor coolant system (RCS) pressure.) The steam generator secondary sides also become isolated at this time.

The primary side depressurization continues accompanied by a rise in secondary side pressure until the secondary side pressure reaches the lowest setpoint of the steam generator safety relief valves. The primary system pressure continues to fall until it is just slightly greater than the secondary side pressure. At this point, the flow from the one operating HPSIP exceeds the leak flow. Therefore the RCS will fill. The decay

heat generated in the core is removed in the steam generators by steam flow through the automatic secondary side safety relief valves. Thus, the core will remain covered and cooled in this condition. The post-LOCA long term procedures described in paragraph 6.3.3.4 are initiated at 1 hour to provide long term cooling.

6.3.3.4 Post-LOCA Long-Term Cooling

6.3.3.4.1 General Plan

Long Term Cooling (LTC) is initiated when the core is quenched after a LOCA and is continued until the plant is secured. The objectives of LTC are to maintain the core at safe temperature levels and to avoid the precipitation of boric acid in the core region. To accomplish these objectives, a LTC analysis for PVNGS was performed using the computer codes and methods documented in Reference 14.

The LTC plan for PVNGS uses one of two procedures, depending on the break size. Shutdown cooling is initiated if the break is sufficiently small that successful operation of the shutdown cooling system (SCS) is assured. Otherwise, simultaneous hot and cold side injection is used to maintain core cooling and boric acid flushing. The appropriate procedure is selected on the basis of the indicated reactor coolant system (RCS) pressure.

Figure 6.3.3.4-1 shows the basic sequence of events and the time schedule for operator actions in the PVNGS LTC plan. The time schedule gives a time interval in which the action is to

be accomplished. It is assumed that the specified functional requirement is met within the specified time interval.

The operator's first action is to initiate cooldown within 1 hour post-LOCA by releasing steam from the steam generators. The steam is released either through the turbine bypass system, if it is available, or through the atmospheric dump valves. Between 1 and 3 hours post-LOCA, the Safety Injection Tanks (SITs) are isolated or vented to avoid injecting nitrogen, a non-condensable gas, into the RCS. Between 1 and 4 hours post-LOCA, pressurizer cooldown is initiated. Between 2 and 3 hours post-LOCA, the high pressure safety injection (HPSI) pump discharge is realigned so that the injection flow is divided between the hot and cold sides of the RCS.

If the indicated RCS pressure is above 440 psia between 8 and 9 hours after the LOCA, the RCS is filled which assures that proper suction is available for initiating shutdown cooling. Cooling the RCS continues until the indicated RCS temperature is lower than the maximum SCS entry temperature including instrument uncertainty. The HPSI pumps are then throttled until RCS pressure is reduced to below the SCS entry pressure including instrument uncertainty. All HPSI pump flow is then shifted back to the cold legs and shutdown cooling is initiated.

A prerequisite for throttling or terminating HPSI pump flow is that the RCS must be in a subcooled condition for the indicated RCS pressure. Therefore, while reducing RCS pressure to initiate shutdown cooling, it is essential to maintain subcooling of the RCS consistent with Emergency Operating Guidelines.

For EOP purposes, an alternative method for decay heat removal is the continued use of the steam generators. This requires the continued availability of auxiliary feedwater and the atmospheric dump valves or the turbine bypass system. If the SCS becomes operable at a later time, it is put into operation. This path is indicated by the dashed lines in Figure 6.3.3.4-1.

If the indicated RCS pressure is below 440 psia between 8 and 9 hours, the break is too large for absolute assurance that proper suction is available for initiating shutdown cooling. In this event, simultaneous hot and cold side injection of HPSI pump flow is used to both cool the core and flush the reactor vessel.

6.3.3.4.2 Assumptions Used in the Short Term LTC Analysis

The major assumptions used in performing the LTC analysis are listed below:

1. No offsite power is available.
2. The worst single failure is the failure of an emergency diesel generator. Therefore:
    a. One HPSI pump is operable. (No LPSI pumps are used during the recirculation mode.)
    b. One auxiliary feedwater pump is operable.
3. One atmospheric dump valve on each steam generator is operable.
4. RCS cooldown begins at one hour post-LOCA.
5. The SITs are vented or isolated in establishing SCS entry conditions for the small break LTC procedure.

6. The pressurizer is cooled down in establishing SCS entry conditions for the small break LTC procedure.

7. RCS cooldown is terminated when the hot leg temperature is below the maximum SCS entry temperature including instrument uncertainty.

8. Pump flow rates and initial water source inventories used in the large break LOCA boric acid precipitation analysis are selected to maximize the boric acid concentration in the core.

9. A boric acid precipitation limit of 30 wt% is used in the large break LOCA boric acid precipitation analysis. This is the precipitation limit in saturated water at 17 psia. The value of 17 psia was calculated using a conservative model for containment pressure.

6.3.3.4.3 Parameters Used in the LTC Analysis

The significant core and system parameters and initial conditions used in the Unit 2 Cycle 7 LTC analysis, hereafter referred to as the LTC reference cycle, are presented in Table 6.3.3.4-1.

6.3.3.4.4 Results of the LTC Analysis

The double-ended (9.8 ft^2) cold leg break is the limiting break for long term boric acid accumulation in the reactor vessel. For a cold leg break, the core flushing flow is the difference between the hot side HPSI pump flow rate and the core boiloff flow rate. The initiation of a simultaneous hot and cold side HPSI pump flow rate of at least 380 gpm to each side between 2

and 3 hours post-LOCA provides a substantial and time-increasing core flushing flow as shown in Figure 6.3.3.4-2. Figure 6.3.3.4-3 shows that with no core flushing flow, boric acid would begin to precipitate at approximately 3.5 hours post-LOCA. However, with a hot side injection flow rate of 380 gpm, initiated at 3 hours post-LOCA, the maximum boric acid concentration in the core is 28.5 wt% as compared to the precipitation limit of 30 wt%. The margin provided for the prevention of boric acid precipitation by a constant core flushing flow of 30 gpm is also shown in Figure 6.3.3.4-3.

The time at which all hot leg steam entrainment of injection water is terminated was calculated to be less than 2 hours post-LOCA. Therefore, the initiation of simultaneous hot and cold side injection between 2 and 3 hours is after the potential for hot leg entrainment has been terminated.

Figure 6.3.3.4-1 shows the two procedures for long term cooling. The small break procedure (left branch) applies to those break sizes for which the RCS refills before all auxiliary feedwater is exhausted. The LTC analysis determined that more than 13 hours is required to exhaust all auxiliary feedwater during the cooldown of the RCS. The analysis predicts the RCS to refill at various times depending on the break area as shown in Figure 6.3.3.4-4. To allow a substantial time margin to avoid exhausting the auxiliary feedwater, a time of 8 to 9 hours post-LOCA was selected for the operator to decide if the small break procedure is appropriate. As shown in Figure 6.3.3.4-4, a break area as large as 0.03 ft^2 refills within 8 hours. By 13 hours the RCS will refill for even larger break areas. Therefore, the

analysis demonstrates that breaks as large as 0.03 ft^2 will be able to use SCS for the long term cooling and flushing of the core.

The LTC analysis determined that the large break procedure (right branch) can flush the core for break areas as small as 0.006 ft^2. The overlap in break areas for which either the large or small break procedure can be used is illustrated in Figure 6.3.3.4-5.

The operator chooses the appropriate procedure on the basis of indicated RCS pressure between 8 and 9 hours. Figure 6.3.3.4-5 lists the RCS pressure at 8 hours for a wide range of break sizes and Figure 6.3.3.4-6 presents this information graphically. The decision pressure is selected as 440 psia, such that, for the pressurizer pressure measurement uncertainty of +77/-100 psi (Table 6.3.3.4-1), the operator is assured of selecting the proper procedure for any break size.

The emergency operating procedures (EOPs) do not require the operator to wait for 8 to 9 hours before choosing the long term cooling mode. The EOPs direct the operator to place shutdown cooling into service when the RCS pressure and temperature are within the design limits of the shutdown cooling system, and when pressure and inventory control have been established (as indicated by the RCS being subcooled and the pressurizer level being above the minimum to allow heater operation). The objective of the UFSAR assumption is to assure that the RCS is refilled. The EOP step implements this strategy by using other indications to assure the RCS is refilled.

Table 6.3.3.4-1

Core and System Parameters Used in the LTC Analysis

Parameter	Value
Reactor power level	4070 MWt (102% of 3990 MWt)
Number of plugged tubes per SG	2750
SCS entry temperature	350°F[a]
SCS entry pressure	385 psia[a]
Pressurizer pressure measurement uncertainty for determining entry into shutdown cooling	+77/-100 psi
Atmospheric dump valve capacity at 1000 psia	950,000 lbm/hr/valve (minimum)
Condensate storage tank inventory	300,000 gallons (minimum)
Initial boric acid concentration	
RCS	2100 ppm (1.20 wt%) (maximum)
RWT	4400 ppm (2.52 wt%) (maximum)
SIT	4400 ppm (2.52 wt%) (maximum)
Initial inventory used in boric acid precipitation analysis	
RCS	670,000 lbm (maximum)
RWT	760,000 gal (maximum)
SIT	1950 ft^3/tank (maximum)
Pump flow rates used in boric acid precipitation analysis	
HPSI pump	900 gpm (minimum)
LPSI pump	3000 gpm (minimum)
Containment spray pump	3000 gpm (minimum)

(a) Maximum indicated value for entry into shutdown cooling.

Table 6.3.3.5-1
SEQUENCE OF EVENTS FOR REPRESENTATIVE LARGE AND SMALL BREAK LOCAS
(Sheet 1 of 2)

Event	Large Break (0.8 DEG/PD)[a] Setpoint or Value	Large Break (0.8 DEG/PD)[a] Time (sec)	Small Break (0.02 Ft^2)[b] Setpoint or Value	Small Break (0.02 Ft^2)[b] Time (sec)	Success Path
Break occurs		0.0		0.0	
Core peak power	117%	0.15	105%	96.0	
Pressurizer pressure reaches reactor trip and SIAS analysis setpoint	1,600 psia	9.43	1,600 psia	456.0	Reactivity control
Reactor trip and safety injection actuation signals generated		10.43		457.0	Reactivity control
SIT discharge begins	607.7 psia	16.2	607.7 psia	7,500	Reactivity control
Reflood begins		37.7		NA	
Main steam safety valves begin to open		NA	1,295 psia[c]	456.0	Secondary system integrity
Maximum secondary pressure	1,239 psia		1,340 psia	184.0	
HPSI pump flow delivered to RCS		68.2		492.0	Reactivity control
SITs empty		68.2		NA	
LPSI pump flow delivered to RCS		68.2		NA	Reactivity control

a. For the large break, loss of ac power and start of the diesel generators occurs at initiation of event (t = 0.0).

b. For the small break, loss of ac power and start of the diesel generator occurs at time of P_pL trip (t = 456.0).

c. Current MSSV (1303 psia) opening pressures used in the analyses have been justified based upon the tolerance changes (+/- 1% to +/-3%) but the sequence of event does not reflect the minor change in time.

Table 6.3.3.5-1

SEQUENCE OF EVENTS FOR REPRESENTATIVE LARGE AND SMALL BREAK LOCAS

(Sheet 2 of 2)

Event	Large Break (0.8 DEG/PD)[(a)]		Small Break (0.02 Ft^2)[(b)]		Success Path
	Setpoint or Value	Time (sec)	Setpoint or Value	Time (sec)	
Main steam safety valves closed			1,295 psia[(c)]	2,600	
Recirculation actuation signal	15% range	1,200-7,200	15% range	1,200-7,200	Reactivity control
Initiate cooldown		3,600		3,600	Secondary system integrity
Enter hot and cold leg injection mode		7,200		7,200	Reactor heat removal
Decision point for entry into shutdown cooling or continuation of hot and cold leg injection mode		28,800		28,800	Reactor heat removal

c. New PSV (2575 psia for Units 1 and 3, and 2550 psia for Unit 2) and MSSV (1303 psia) opening pressures used in the analyses have been justified based on the tolerance changes (+/-1% to +3/-1% and +/-1% to +/-3%, respectively), but the sequence of event does not reflect the minor changes in time.

Table 6.3.3.5-2

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR LARGE AND SMALL BREAK LOCA ANALYSES (Sheet 1 of 2)

System	Normal Automatic Mode Throughout Transient	Manual Mode Throughout Transient	Normal Automatic Mode Inoperative On Loss of AC	Manual Mode Inoperative On Loss of AC	Single Failure Assumed Within System	Associated Notes
1. Main feedwater control system			X			
2. Main feedwater pump turbine control system[a]			X			
3. Turbine-generator control system[a]			X			
4. Steam bypass control system				X		
5. Pressurizer pressure control system						(b)
6. Pressurizer level control system						(b)
7. Control element drive mechanism control system						(b)
8. Reactor regulating system						(b)
9. Core operating limit supervisory system			X			
10. Reactor coolant pumps			X			
11. Chemical and volume control system						(c)
12. Secondary chemistry control system[a]						(b)

a. Balance of plant systems.

b. The indicated systems are not modelled in either the large or small break LOCA analyses.

c. The CVCS is not modelled in either the large or small break analyses. However, the RWT which is considered to be part of the CVCS is available as a supply of safety injection water.

Table 6.3.3.5-2

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR LARGE AND SMALL BREAK LOCA ANALYSES (Sheet 2 of 2)

System	Normal Automatic Mode Throughout Transient	Manual Mode Throughout Transient	Normal Automatic Mode Inoperative On Loss of AC	Manual Mode Inoperative On Loss of AC	Single Failure Assumed Within System	Associated Notes
13. Condenser evacuation system[a]						(b)
14. Turbine gland sealing system[a]						(b)
15. Nuclear cooling water system[a]						(b)
16. Turbine cooling water system[a]						(b)
17. Plant cooling water system[a]						(b)
18. Condensate storage facilities[a]						(b)
19. Circulating water system[a]						(b)
20. Spent fuel pool cooling and cleanup system[a]						(b)
21. Non-Class 1E (non-ESF) ac power[a]			X			
22. Class 1E (ESF) ac power[a]	X					
23. Non-Class 1E dc power[a]			X			
24. Class 1E dc power[a]	X					

6.3.3.5 Sequence of Events and Systems Operation

Table 6.3.3.5-1 presents a chronological list of events which occur during two representative LOCAs, a small break of 0.02 ft^2 and a large break, the 0.8 x double-ended guillotine break in pump discharge leg (DEG/PD). Table 6.3.3.5-1 extends from the occurrence of the break to the decision point at 8 hours about whether or not to enter the shutdown cooling mode.
Figure 15.0-1 contains a glossary of symbols and acronyms which may be used with the sequence of events diagram, figure 6.3.3.5-1, to trace the actuation and interaction of systems which mitigate the consequences of these events.
Table 6.3.3.5-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the event. An explanation of the interpretation of the sequence of events diagram may be found in paragraph 15.0.1.6.
The inadvertent opening of the primary safety valve is considered as a special case in the small break spectrum.

The success paths in the sequence of events diagram (figure 6.3.3.5-1) are as follows:

A. Reactivity Control

Following the break, the RCS pressure drops rapidly. For both breaks, this results in the generation of a low pressurizer pressure trip signal and the CEAs drop into the core. In the case of the large break, the insertion of negative reactivity via the scram will probably also occur but is not required, as the amount of voiding which occurs in the moderator introduces sufficient negative reactivity to make the reactor

subcritical. At the low pressurizer pressure trip setpoint a safety injection actuation signal (SIAS) is generated and additional negative reactivity is added to the system, in the form of borated water from the refueling water tank (RWT). In the case of the large break, the RCS pressure drops low enough to allow discharge of the SITs and LPSIs and additional borated water is added. For the small break only the SITs discharge. For all breaks, the water level in the RWT will eventually drop sufficiently to result in the generation of a recirculation actuation signal (RAS). Upon generation of the RAS, the containment sump isolation valves open to supply the HPSI pumps during the recirculation phase. For some small breaks, relatively small amounts of borated water are added during the ECC injection phase and additional boron must be added to bring the system to the cold shutdown concentration. To accomplish this the operator may use the HPSI pumps to add boron by replacing the volume shrinkage which occurs during cooldown.

B. Reactor Heat Removal

Following the loss of power to the non-engineered safety feature (ESF) loads as a result of the turbine trip and the subsequent grid collapse, the reactor coolant pumps coast down. For the small break, reactor heat removal takes place by means of natural circulation and the additional cooling capability of the relatively low enthalpy RWT water, introduced by the safety injection system. For the large break,

reactor heat removal is initially accomplished by the safety injection system, since the conditions which exist within the RCS during the early phase of the accident will prevent the establishment of natural circulation flow. Following the generation of the RAS, reactor heat removal continues through the use of the safety injection system, in the recirculation mode.

Two hours after the LOCA the operator manually aligns the HPSI pump discharge lines for simultaneous hot and cold leg injection. Eight hours after the LOCA, the operator may initiate shutdown cooling provided that the RCS pressure has remained above 440 psia. If RCS pressure is less than 440 psia, hot and cold leg injection is sufficient to cool the core and is continued.

C. Primary System Integrity

For small break LOCAs in which the RCS pressure can be maintained at or above 440 psia, the RCS pressure is controlled by throttling the HPSI discharge valves or the SIT vent valves. If the indicated RCS pressure is above 440 psia between 8 and 9 hours after the LOCA, the RCS is filled which assures that proper suction is available for initiating plant cooldown. Cooling the RCS continues until the indicated RCS temperature is lower than the maximum SCS entry temperature including instrument uncertainty. The HPSI pumps are then throttled until RCS pressure is reduced to below the SCS entry pressure including instrument uncertainty.

D. Secondary System Integrity

For all break sizes, the reactor trip will result in a turbine trip and the subsequent loss of offsite power will result in the loss of main feedwater flow. Since the steam bypass control system is not available due to loss of condenser vacuum on loss of offsite power, the secondary system pressure will increase and for some small breaks will reach the opening pressure of the main steam safety valves (MSSVs). In the cases where the MSSVs open, the lack of main feedwater will eventually result in the generation of auxiliary feedwater actuation signals and the delivery of auxiliary feedwater to both steam generators. The operator will initiate cooldown at one hour after the LOCA, using the atmospheric dump valves if non-emergency ac power has not been reestablished or using the steam bypass system if it has. Along with the dump or bypass valves, the operator will utilize one feedwater pump designated as "auxiliary" and intended for normal startup or shutdown of the plant. During the cooldown, the operator will reduce the $P_{sg}L$ setpoint to prevent the inadvertent generation of a main steam isolation signal (MSIS).

E. Containment Integrity

A containment spray actuation signal is generated on a high-high containment pressure signal. The containment spray (CS) pumps spray water from the RWT into the containment to reduce the temperature and pressure of

the containment atmosphere. On the generation of an RAS, the containment sump isolation valves open to supply water to the CS pumps.

F. Combustible Gas Control

The containment sprays act to mix the containment atmosphere and prevent the formation of hydrogen gas pockets, and the operator actuates balance of plant (BOP) systems to control the hydrogen concentration in the containment atmosphere.

G. Radioactive Effluent Control

When the pressurizer pressure reaches the low pressure setpoint, a containment isolation actuation signal (CIAS) is generated. The CIAS results in the isolation of various containment, primary, and secondary systems to limit radioactive releases. In addition, the containment spray system functions to remove radioactive iodine from the containment atmosphere.

H. Control Room Habitability

SIAS or BOP signals may actuate control room habitability systems. See section 6.4 for a description of control room habitability systems.

I. Fuel Handling Building Habitability

SIAS or BOP signals may actuate fuel handling building habitability systems. See subsection 9.4.5 for a description of fuel building HVAC systems.

J. Restoration of AC Power

The standby generators are automatically started when an undervoltage condition is sensed on the associated ESF bus. For large break LOCAs ac power is assumed to be lost at t = 0 seconds. For small break LOCAs ac power is assumed to be lost following the reactor trip and the failure of one standby generator is assumed. All required ESF loads are loaded onto the standby generators within 30 seconds after generator breaker closure and re-energization of the ESF buses. The standby generators and automatic sequencers necessary for generator loading are also designed such that flow to the core is attained within 30 seconds of reaching a SIAS setpoint, as described in UFSAR Section 6.3.1.4.A.4.

K. Spent Fuel Heat Removal

Spent fuel pool (SFP) cooling is terminated on the loss of normal power to the ESF loads. Spent fuel heat removal is continuously accomplished utilizing the heat capacity of the SFP water. Pool cooling is restored by manually loading the SFP cooling pumps onto the standby generators and by aligning the SFP heat exchangers to receive essential cooling water.

Tables 6.3.3.5-3 and 6.3.3.5-4 contain matrices which summarize the utilization of safety systems as they appear in the LOCA analyses.

6.3.3.6 Radiological Consequences

Following a postulated double-ended rupture of a reactor coolant pipe with subsequent blowdown, the ECCS limits the clad temperature to well below the melting point and ensures that the reactor core remains intact and in a coolable geometry, minimizing the release of fission products to the containment.

Table 6.3.3.5-3

UTILIZATION OF SAFETY SYSTEMS

FOR REPRESENTATIVE SMALL BREAK (0.02 FT^2)

System	Actuated and Required	Actuated But Not Required	Safety Grade Backup to Non-Safety Grade System	Single Failure Assumed Within System (see Notes)	Associated Notes
1. Reactor protective system	X				
2. DNBR/LPD calculator					
3. Engineered safety features actuation systems	X				
4. Supplementary protection system					
5. Reactor trip switchgear	X				
6. Main steam safety valves[(a)]	X				
7. Primary safety valves					
8. Main steam isolation system[(a)]			X		
9. Auxiliary (emergency) feedwater system[(a)]	X				
10. Safety injection system	X			X	(b)
11. Shutdown cooling system	X				
12. Atmospheric dump valve system[(a)]				X	
13. Containment isolation system[(a)]	X				
14. Containment spray system[(a)]	X				
15. Deleted					
16. Containment combustible gas control system[(a)]	X				
17. Diesel generators and support systems[(a)]	X			X	(b)
18. Component (essential) cooling water system[(a)]	X				
19. Station service water system[(a)]	X				

a. Balance of plant systems.

b. See assumptions in paragraph 6.3.3.3.2.

Table 6.3.3.5-4

UTILIZATION OF SAFETY SYSTEMS

FOR REPRESENTATIVE LARGE BREAK (0.8 DEG/PD)

System	Actuated and Required	Actuated But Not Required	Safety Grade Backup to Non-Safety Grade System	Single Failure Assumed Within System (See Notes)	Associated Notes
1. Reactor protective system		X			
2. DNBR/LPD calculator					
3. Engineered safety features actuation systems	X				
4. Supplementary protection system					
5. Reactor trip switchgear		X			
6. Main steam safety valves[a]	X				
7. Primary safety valves					
8. Main steam isolation system[a]		X			
9. Auxiliary (emergency) feedwater system[a]	X				
10. Safety injection system	X			X	(b)
11. Shutdown cooling system					(c)
12. Atmospheric dump valve system[a]					
13. Containment isolation system[a]	X				
14. Containment spray system[a]	X				(d)
15. Deleted	X				
16. Containment combustible gas control system[a]	X				
17. Diesel generators and support systems[a]	X				
18. Component (essential) cooling water system[a]	X				
19. Station service water system[a]	X				

a. Balance of plant systems.

b. See assumptions in paragraph 6.3.3.2.2.

c. Break is too large to use shutdown cooling.

d. Containment sprays are assumed to be actuated at 0.0 seconds.

However, a hypothetical accident involving a significant release of fission products to the containment is evaluated.

It is assumed that 100% of the noble gas and 50% of the iodine equilibrium core saturation fission product inventory are immediately released to the containment atmosphere (Source Tem is calculated using US-AEC-TID14844, Methodology(Reference 15)). Of the iodine released to the containment, 50% is assumed to plate out onto the internal surfaces of the containment or adhere to internal components per guidelines of Regulatory Guide 1.4. The remaining iodine and the noble gas activity are assumed to be immediately available for leakage from the containment.

The source terms and associated assumptions are itemized in table 6.3.3.6-1. The following specific assumptions were used in the analysis.

A. The reactor core equilibrium noble gas and iodine inventories are based on long-term operation at the ultimate core power level (102% of Licensed Power).

B. One hundred percent of the core equilibrium radioactive noble gas inventory is immediately available for leakage from the containment.

C. Fifty percent of the core equilibrium radioactive iodine inventory is immediately released to the containment atmosphere. Half is plated out onto the internal surfaces of the containment and the other half is available for leakage from the containment.

D. Of the iodine fission product inventory released to the containment, 91% is in the form of particulate iodine, and 4% is in the form of organic iodine.

The radioactive doses associated with these source terms are described in section 15.6.

Table 6.3.3.6-1

TYPICAL PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

Isotope	Containment airborne	Containment sump
	Ci	Ci
Kr-85	See Table 15.6.5-2	0.0
Kr-85M	See Table 15.6.5-2	0.0
Kr-87	See Table 15.6.5-2	0.0
Kr-88	See Table 15.6.5-2	0.0
Kr-89	See Table 15.6.5-2	0.0
Xe-131M	See Table 15.6.5-2	0.0
Xe-133M	See Table 15.6.5-2	0.0
Xe-133	See Table 15.6.5-2	0.0
Xe-135M	See Table 15.6.5-2	0.0
Xe-135	See Table 15.6.5-2	0.0
Xe-137	See Table 15.6.5-2	0.0
Xe-138	See Table 15.6.5-2	0.0
I-131	See Table 15.6.5-2	See Table 15.6.5-2
I-132	See Table 15.6.5-2	See Table 15.6.5-2
I-133	See Table 15.6.5-2	See Table 15.6.5-2
I-134	See Table 15.6.5-2	See Table 15.6.5-2
I-135	See Table 15.6.5-2	See Table 15.6.5-2

6.3.3.7 Reload Cycle Evaluations

ECCS performance analyses of the limiting break size are performed for subsequent cycles on an as needed basis and verified as acceptable prior to unit operations. For future reloads the acceptability will be based upon the successful completion of the Reload Process Improvement (RPI) LOCA checklist.

6.3.4 TESTS AND INSPECTIONS

During fabrication of the safety injection system (SIS) components, tests and inspections are performed and documented in accordance with code requirements to assure high quality construction. As necessary, performance tests of components are performed in the vendor's facility. The SIS is designed and installed to permit inservice inspections and tests in accordance with ASME Code Section XI.

6.3.4.1 ECCS Performance Tests

Prior to initial plant startup, a comprehensive series of system flow tests, as detailed in section 14.2, were performed to verify that the design performance of the system and individual components is attained.

6.3.4.2 Reliability Tests and Inspections

6.3.4.2.1 System Level Tests

After the plant is brought into operation, periodic tests and inspections of the SIS components and subsystems are performed to ensure proper operation in the event of an accident. The

scheduled tests and inspections are necessary to verify system operability, since during normal plant operation, SIS components are aligned for emergency operation and serve no other function. The tests defined permit a complete checkout at the subsystem and component level during normal plant operation. Satisfactory operability of the complete system can be verified during normal scheduled refueling shutdown. The complete schedule of tests and inspections of the SIS is detailed in the Technical Specifications.

6.3.4.2.2 Component Testing

In addition to the system level tests described in paragraph 6.3.4.1, tests to verify proper operation of the SIS components are also conducted. These tests supplement the system level tests by verifying acceptable performance of each active component in the SIS. Pumps and automatic valves will be tested in accordance with ASME OM Code.

6.3.5 INSTRUMENT REQUIREMENTS

6.3.5.1 Design Criteria

The instruments and controls for the safety injection system (SIS) are designed in accordance with the applicable portions of IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations." The controls are interlocked to automatically provide the sequence of operations required to initiate SIS operation. The instrumentation and controls which actuate and control the SIS are designed on the following bases.

A. Redundant instruments are provided for initiation of SIS actions. Four sensors are used for each of the critical parameters. A trip from any two of these four sensors initiates the appropriate SIS action. Circuits are run in separate wiring raceways to assure the availability of safety injection actuation signals.

B. Electric power required for SIS controls and instruments is supplied via two preferred ac buses. Emergency generators provide an alternate source of power.

Actuator-operated valves are provided with key-operated control switches where considered necessary to prevent unintentional misalignment of safety injection flow paths during power operation.

All valves that are not required to operate on initiation of safety injection or recirculation in the safety injection flow path are locked in the safety injection position during operation. Administrative controls ensure that the valves are locked in the correct position.

A further discussion of the instrumentation and associated analog and logic channels employed for safety injection initiation is given in section 7.3.

6.3.5.2 System Actuation Signals

Operation of the safety injection system is controlled by two actuation signals. The first of these, the safety injection action signal (SIAS), initiates operation of the SIS in the event of low pressurizer pressure or high containment pressure. Both of these parameters provide an indication of a LOCA which

requires operation of the SIS. SIAS may be manually initiated from the control room. The second control signal is the recirculation actuation signal (RAS). This signal changes the operation mode of the SIS from injection with suction from the refueling water tank to recirculation with suction from the containment sump. The RAS is initiated by low refueling water tank level. RAS occurs automatically, whether SIAS is initiated manually or automatically. Following the RAS, timely operator action is required to close the RWT isolation valves to prevent ingress of air in the ESF pump suction piping during switchover to recirculation. Changing from the injection mode of operation to recirculation permits continuous flow to the core when the RWT water supply is depleted.

6.3.5.2.1 Safety Injection Actuation Signal (SIAS)

Initiation of safety injection is derived from four independent pressurizer pressure sensors and four independent containment pressure sensors. Coincidence trip signals from two-out-of-four sensors for either parameter will automatically initiate safety injection. Automatic SIS operation is actuated at a pressurizer pressure of 1837 psia during power operation or a containment pressure of 3 psig. During startup and shutdown operations, a variable setpoint on the low pressurizer pressure is used. A further discussion of the SIAS is given in Section 7.3.

6.3.5.3 Instrumentation During Operation

The instrumentation provided for monitoring safety injection system components during SIS operation is discussed in this

section. See engineering drawings 01, 02, 03-M-SIP-001, -002 and -003 for instrumentation readout locations, and Figures 6.3-2A through 2J for component usage during the various modes.

The flows identified on Figures 6.3-2A through 6.3-2J are typical expected flows. See Section 6.3.5.3.5 for a description of the differences in HPSI hot leg injection orifices, Section 6.2.2.2 for Containment Spray pump flow and NPSH parameters, Table 6.3.2-1 for ECCS pump NPSH requirements and Section 6.3.3 for flow performance characteristics under typical accident conditions.

6.3.5.3.1 Temperature

A. Shutdown Cooling Suction and Injection Temperature

RTDs and a recorder on each low-pressure injection header are used to measure and record shutdown cooling water temperature as it enters and leaves the safety injection system. This readout is used to provide a measure of the overall system performance and provides information allowing the operator to adjust cooldown rate. The recorder is located for easy access in the control room on the operator's console. Indication is provided in the control room and the remote shutdown panel. See subsection 5.4.7.

6.3.5.3.2 Pressure

A. Safety Injection Tank Pressure

A wide range pressure transmitter mounted on each safety injection tank permits readings of each tank pressure in the control room.

6.3.5.3.3 Valve Position

A. Safety Injection Tank Isolation Valve Position

Valve position is indicated in the control room by redundant and diverse indicators. Indicator lights verify either the fully open or fully closed position, with an alarm if the valve is not fully open. In addition, continuous valve position monitoring indicates partially opened or partially closed valve position.

B. Shutdown Cooling System Valve Position

Valves that must be repositioned and valves used to control cooldown have position indication both inside the control room and at a location outside the control room.

C. Hot Leg Injection Valve Position

Hot leg injection valve position is indicated in the control room. Indicator lights verify either open or closed position. In addition, continuous valve position monitoring indicates partially opened or partially closed position.

D. LPSI Header Isolation Valve Position

Valve position is indicated both inside the control room and at a location outside the control room.

E. HPSI Header Isolation Valve Position

Valve position is indicated inside the control room.

6.3.5.3.4 Level

A. Safety Injection Tank Level

Water level for each safety injection tank is indicated in the control room throughout the complete tank volume, except for water above the upper level or below the lower level instruments taps. The instrument taps are 5 inches nominal below the upper tank tangent and 5 inches nominal above the lower tank tangent. Signal input for this indication is provided by a differential pressure transmitter.

6.3.5.3.5 Flow

A. Shutdown Cooling/LPSI Flow

A shutdown cooling/LPSI flow indicator indicates total shutdown cooling flow.

The flowmeter may also be used for backup flow rate data during safety injection and for testing the performance of the low pressure safety injection pumps. The flow rate is indicated in the control room and at the remote shutdown panel.

B. High Pressure Safety Injection Flow

These flow channels indicate the flow rate in each of the four high pressure safety injection lines to the cold legs and each of the two lines to the hot legs. The flow elements for the flowmeters are located in such a manner that they serve both high pressure manifolds. The flowmeters are used to balance the high pressure safety injection flow rates in each of the lines. Readout is provided in the control room.

Note: On October 20, 1989, an error in the original installation of the flow measuring orifices in the "A" train HPSI pump hot leg injection lines and the use of inappropriate flow calibration curves during system testing was discovered.

The orifices installed in the "A" train HPSI pump hot leg injection line for each of the three Palo Verde units were larger in diameter than specified in the instrument data sheet. This resulted in the HPSI hot leg injection flow indication reading less than the actual flow during the performance of the simultaneous hot leg and cold leg injection testing required by Technical Specifications. Since the test was performed with the hot leg flow indicators reading lower than actual flow, the actual hot leg flows after correcting for the misinstalled orifices, were approximately 30 gpm higher than the indicated flow, thus exceeding the TS limit. A TS Change was submitted and approved in

Amendment 47 to Facility Operating License No. NPF-41 Safety Evaluation Report.

These orifices only provide flow indication and do not provide a flow control function.

6.3.5.4 Post-Accident Instrumentation

The instrumentation available for evaluation of post-accident performance is identified in subsection 6.3.2 and paragraph 7.5.1.1.5.

6.3.6 REFERENCES

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3. CENPD-132P, Volumes I and II, "Calculative Methods for the C-E Large Break LOCA Evaluation Model," August 1974.

   CENPD-132P, Supplement 1, "Calculational Methods for the C-E Large Break LOCA Evaluation Model," February 1975.

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5. Stuart A. Richards (NRC) to P.W. Richardson (WEC), "Safety Evaluation of Topical Report CENPD-132, Supplement 4, Revision 1, Calculative Methods for the CE Engineering Technology Large Break LOCA Evaluation Model," December 15, 2000.

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7. CENPD-134P, "COMPERC-II, A Program for Emergency Refill-Reflood of the Core," August 1974.

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8. CENPD-135P, "STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program," August 1974.

   CENPD-135P, Supplement 2, "STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program (Modifications)," February 1975.

   CENPD-135, Supplement 4-P, "STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program," August 1976.

CENPD-135P, Supplement 5, "STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program," April 1977.

9. CENPD-138P, "PARCH, A FORTRAN-IV Digital Program to Evaluate Pool Boiling, Axial Rod and Coolant Heatup," August 1974.

   CENPD-138P, Supplement 1, "PARCH, A FORTRAN-IV Digital Program to Evaluate Pool Boiling, Axial Rod and Coolant Heatup (Modifications)," February 1975.

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10. CENPD-139-P-A, "C-E Fuel Evaluation Model Topical Report," July 1974.

    CEN-161(B)-P-A, "Improvements to Fuel Evaluation Model," August 1989.

    CEN-161(B)-P, Supplement 1-P-A, "Improvements to Fuel Evaluation Model," January 1992.

11. "Calculative Methods for the C-E Small Break LOCA Evaluation Model," <u>CENPD-137</u>, August, 1974 (Proprietary).

    "Calculative Methods for the C-E Small Break LOCA Evaluation Model," <u>CENPD-137</u>, Supplement 1, January, 1977 (Proprietary).

    “Calculative Methods for the ABB CE Small Break LOCA Evaluation Model,” <u>CENPD-137</u>, Supplement 2-P-A, April, 1998.

12. Letter from O.D. Parr (NRC) to F.M. Stern (C-E), June 13, 1975.

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14. CENPD-254-P-A, "Post-LOCA Long Term Cooling Evaluation Model," June 1980, (Proprietary).

15. Calculation of Distance Factors for Power and Test Reactor Sites, TED-14844, March 23, 1962.

16. APS Letter Number 102-06099, dated November 30, 2009; "Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 Docket Numbers STN 50-528, 50-529, and 50-530 Request for Amendment to Technical Specification Table 3.3.5-1, Engineered Safety Features Actuation System Instrument, and Figure 3.5.5-1, Minimum Required Refueling Water Tank (RWT) Volume and Supporting Changes."

17. APS Letter Number 102-06228, dated July 22, 2010; "Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 Docket Numbers STN 50-528, 50-529, and 50-530 Response to Request for Additional Information Relating to License

Amendment Request to Change the Technical Specifications to Support Crediting an Existing Manual Operator Action to Isolate the Refueling Water Tank (RWT) (Tac Nos. ME2842, ME2843, and ME2844)."

18. Letter from J. R. Hall (NRC) to R. K. Edington (APS), dated November 24, 2010; "Palo Verde Nuclear Generating Station, Units 1, 2, and 3 – Issuance of Amendments Re: Technical Specifications Changes to Minimum Refueling Water Tank Volume and Setpoints (TAC Nos. ME2842, ME2843, and ME2844)."

19. Letter from B. K. Singal (NRC) to R. K. Edington (APS), dated May 16, 2012; "Palo Verde Nuclear Generating Station, Units 1, 2, and 3 Request for Additional Information, Review of Single Failure Analysis of Low Pressure Safety Injection Pumps for Minimum Required Refueling Water Tank Transfer Volume (TAC Nos. ME8284, ME8285, and ME8286)."

20. APS Letter Number 102-06583, dated August 3, 2012; "Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 Docket Numbers STN 50-528, 50-529, and 50-530 Request for Additional Information, Review of Single Failure Analysis of Low Pressure Safety Injection Pumps for Minimum Required Refueling Water Tank (RWT) Transfer Volume."

21. NRC Memo from J. K. Rankin (NRC) to Arizona Public Service Company, dated August 26, 2013; “Summary of August 21, 2013 Conference Call Public Meeting with Arizona Public Service Company Regarding Single Failure of the Low Pressure Safety Injection Pumps to Trip on a Recirculation Actuation Signal (TAC Nos. ME8284, ME8285, and ME8286)”.

6.4 HABITABILITY SYSTEMS

The control room habitability systems include missile protection, radiation shielding, radiation monitoring, air filtration, and heating, ventilation, and air conditioning (HVAC) systems, lighting, personnel support, and fire protection equipment. (Refer also to section 3.1 for a discussion on conformance with NRC General Design Criterion 19.)

The HVAC equipment discussed in this section is also discussed in section 7.3 and subsection 9.4.1. This section addresses essential service requirements and the response and operation of control room HVAC equipment under emergency conditions. Other equipment and systems are described only as necessary to define their connection with control room habitability.

6.4.1 DESIGN BASES

Safety design bases for the habitability systems are:

A. Design Basis One

   The habitability systems shall provide coverage for the control room envelope defined in paragraph 6.4.2.1.

B. Design Basis Two

   The control room essential system shall be capable of maintaining the control room atmosphere within conditions suitable for prolonged occupancy throughout the duration of any of the postulated accidents discussed in chapter 15.

C. Design Basis Three

The control room essential ventilation and air conditioning system shall be capable of maintaining an environment suitable for sustained occupancy by six persons.

D. Design Basis Four

Food, water, medical supplies, and sanitary facilities shall be provided for sustained control room occupancy by six persons for 7 days.

E. Design Basis Five

The radiation exposure of control room personnel, through the duration of any of the postulated limiting faults discussed in chapter 15, shall not exceed the limits set by 10CFR50, Appendix A, General Design Criterion 19.

F. Design Basis Six

The habitability systems shall provide the capability to detect and protect control room personnel from smoke and airborne radioactivity.

G. Design Basis Seven

Respiratory, eye, and skin protection shall be provided for emergency use within areas of the control room envelope.

H. Design Basis Eight

The control room essential HVAC system shall be capable of automatic and manual transfer from its normal operating mode to the emergency or isolation modes.

I. Design Basis Nine

A single active failure of a component of the control room essential HVAC system, assuming a loss of offsite power, shall not impair the ability of the system to comply with the other design bases of this section.

J. Design Basis Ten

The control room essential HVAC system shall be designed to remain functional during and after a safe shutdown earthquake (SSE).

Air ducts and their supports shall be Seismic Category I.

The control room normal HVAC system is described in subsection 9.4.1.

Protection of the habitability systems in the control room from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11. The fire protection system is discussed in subsection 9.5.1.

Codes and standards applicable to the control room emergency ventilation system are listed in table 3.2-1. The system is

consistent with the recommendations of Air Moving and Conditioning Association (AMCA) standards and NRC Regulatory Guide 1.52, except as noted in section 1.8.

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of the Control Room Envelope

The areas, equipment, and materials to which the control room operator could require access during an emergency are shown in figure 7.5-1. Those spaces requiring continuous or frequent operator occupancy are also shown in figure 7.5-1. Functional areas included on the control building's elevation 140 feet are: the satellite technical support center (STSC), the control room, the kitchen, and the sanitary facilities. A layout drawing and a description of shielding required to maintain habitability of the control room during the course of postulated accidents is provided in section 12.3.

Refer to subsection 18.III.D.3.4 for TMI-related information pertaining to "Control Room Habitability Requirements".

6.4.2.2 Ventilation System Design

6.4.2.2.1 General Description

Subsection 9.4.1 contains an overall description of the control room HVAC system. The system is shown schematically in engineering drawings 01, 02, 03-M-HJP-001, -002 and -003. Figure 6.4-1 shows the plant layout, including the location of potential radiological release points with respect to the control room air intakes. The closest distance between the containment and the air intakes is approximately 150 feet.

Elevation and plan drawings with descriptions providing building dimensions and locations are located in section 1.2. Potential sources of toxic gas releases are discussed in subsection 2.2.3.

The volume of the habitability zone served by the HVAC system in the emergency mode or the isolation mode is approximately 1.6×10^5 cubic feet.

Environmental design criteria for the air purification system are based on the most limiting conditions resulting from any of the postulated design basis accidents (DBAs) and on their duration in accordance with Regulatory Guide 1.52, as discussed in section 1.8. Two identical, physically separated high efficiency filtration trains with charcoal adsorbers are provided to process intake air flow and recirculated air flow in the control room. Components are listed in table 6.4-1. Section 1.8 presents the system design conformance to each position in Regulatory Guide 1.52. The seismic classifications of components, instrumentation, and ducting are given in table 3.2-1.

Table 6.4-1

ESSENTIAL CONTROL ROOM AIR HANDLING UNIT

COMPONENT DESCRIPTION

(Two Units Per Control Building)

High Efficiency Filter	
Flowrate, standard ft^3/min	28,600
Quantity (banks)	1
HEPA filter	
Flowrate, standard ft^3/min	28,600
Efficiency, 0.3 micron, %	99.97
Quantity (banks)	2
Carbon adsorber	
Flowrate, standard ft^3/min	28,600
Bed depth, in.	2
Efficiency, organic and elemental iodine, %	95
Quantity (banks)	1
Cooling coil	
Quantity	1
Fan	
Flowrate, standard ft^3/min	28,600
Quantity	1

Refer to subsection 18.III.D.3.4 for TMI-related information pertaining to "Control Room Habitability Requirements".

6.4.2.2.2 Component Description

The essential air handling unit contains a fan, a prefilter, a HEPA prefilter, an activated charcoal filter, a HEPA after-filter, and a cooling coil. Pneumatic-operated dampers are provided for system isolation purposes. Fans are located upstream of the HEPA filters and carbon adsorbers to ensure that air leakage is out of the essential supply system.

A. Filter Unit Housings

The filter unit housings are Seismic Category I and are made of carbon steel. Each housing is provided with a service access door, explosion-proof light, filter test connections, connections for pressure gauges, and drains. The housings are of all-welded construction.

B. Prefilter

A prefilter of the fiberglass pad type at the inlet to each filter train removes larger particulates from the air stream in order to limit the loading of the downstream HEPA filters.

C. HEPA Filters

HEPA filter elements are of pleated fiberglass with aluminum separator design, measure 24 x 24 x 11.5 inches, and are capable of handling a nominal flow-rate of 1000 cubic feet per minute each. The filter medium is cased in stainless steel, has face guards on both sides, and is water- and fire-resistant. HEPA filter elements are manufactured and tested prior to installation in accordance with MIL-F-51068, as

modified by NRC Health and Safety Information Issue 306. The filter element minimum acceptance criterion is removal of 99.97% of 0.3-micron, thermally generated monodisperse dioctylphthalate (DOP) particles.

D. Carbon Adsorbers

The carbon adsorbers for the essential air handling units are of the bulk type, 2 inches deep, and have an all-welded design.

Minimum air residence time in the carbon is 0.25 second at a nominal face velocity of 40 feet per minute. Approximately 4350 pounds of an 8 x 16 mesh impregnated-activated charcoal is used in each filter. This amount of carbon exceeds the amount needed to accommodate the iodine potentially released from the containment. The acceptance criteria for the carbon adsorbers include a requirement for greater than 95% removal of all particulates and iodines, respectively, at a controlled relative humidity of 70%. Carbon adsorbers are of rechargeable type.

E. Cooling Coil

The cooling coils are of nonferrous construction with copper fins mechanically bonded to seamless copper tubing. Coils are arranged for counter-flow operation using chilled water. The tube bundle is enclosed in a steel frame. Coils are arranged for horizontal air flow and are provided with inlet and outlet piping,

vent, and drain connections. The chilled water system is discussed in subsection 9.2.9.

F. Emergency Recirculation Train Fans

The emergency recirculation train fans are Seismic Category I and are capable of delivering 28,600 cubic feet per minute flowrate with all filters at their maximum anticipated pressure drop. Fans are chosen with a steeply rising pressure-flow characteristic to maintain a reasonably constant air flow over the full filter train life. Fan and motor materials are suitable for operation under the environmental conditions associated with the postulated DBA.

Refer to subsection 18.III.D.3.4 for TMI-related information pertaining to "Control Room Habitability Requirements".

G. Ductwork

The system ductwork and dampers are Seismic Category I. Ductwork is redundant where required to provide functional support to active components in meeting the single active failure criteria. Leaktight ductwork and isolation dampers are provided where required to isolate the system from unfiltered outside air.

In general conformance with Position C.4 of Regulatory Guide 1.52, accessibility and adequate working space for maintenance and testing operations are provided in the design and layout of the air purification system equipment.

H. Control Access Doors

To minimize inleakage, the control access doors are equipped with self-closing devices that shut the doors automatically following the passage of personnel. Two sets of doors with a corridor between, acting as an air lock, are provided at each of the two entrances to the control room and associated spaces.

I. Isolation Dampers

System isolation dampers are capable of automatically closing within approximately 50 seconds after receipt of an actuation signal, as verified by testing.

The isolation dampers, with a maximum area of approximately 12.2 square feet per damper are tested as bubble-tight dampers for zero leakage, as part of the manufacturer's test program.

Refer to subsection 18.III.D.3.4 for TMI-related information pertaining to "Control Room Habitability Requirements".

J. Radiation Detectors

Redundant radiation detectors are installed in the control room normal supply air duct. Each unit is responsive to gaseous activity at concentrations as low as 10^{-6} $\mu Ci/cm^3$ of Xe-133. The monitors are described in sections 7.3, 11.5.2.1.3.11, and table 11.5-1.

K. Breathing Apparatus

Self-contained portable breathing equipment sufficient for six individuals is stored within the habitability area of the control room, and provides at least 6 hours of breathable air. At least two spare units are provided to allow for equipment failures. The equipment selected shall be capable of being donned in 2 minutes or less. Operator training and equipment testing and maintenance shall be covered in the PVNGS Respiratory Protection Program which complies with Occupational Safety and Health Administration (OSHA) Regulations 29CFR1910.134.

L. Smoke detectors are provided to alert the control room operator to manually isolate the control room.

The remainder of the system; i.e., supply/recirculation fans, exhaust fans, ducting, and dampers are components that function during normal operation and are described in section 9.4.

6.4.2.3 Leaktightness

The exfiltration and infiltration analyses were performed using the methods and assumptions given in ASHRAE Handbook of Fundamentals-1977 Edition(1), Regulatory Guide 1.78, and ANSI N509-1976.

The leakage paths considered were ducting, piping, electrical penetrations, dampers, and doors.

Table 6.4-2 provides a listing of leakage data and total leakage rates for all leak paths. For analysis of exfiltration

from the pressurized control room envelope, a 1/4-inch water gauge (WG) pressure differential was considered for all leak paths resulting in a total outleakage of 1000 cubic feet per minute. The outside air supply is designed to pressurize the control room and is sized to deliver 1000 cubic feet per minute flowrate into the control room. Based on the rate of outleakage, this flowrate is adequate to maintain a 1/4-inch positive pressure in the control room envelope.

The sealing of doors, dampers, ducting, and penetrations was designed to be more effective in inhibiting inleakage to the control room envelope than outleakage.

6.4.2.4 Interaction With Other Zones and Pressure Contained Equipment

The outside air intake ducts are located such that:

- They are protected from the effects of a main steam line break.
- They minimize the introduction of airborne radioactive material from unit release points.
- They minimize the introduction of diesel generator exhaust and other noxious gases.

Table 6.4-2

CONTROL ROOM LEAKAGE RATES

Leak Path	Outleakage Rate At 1/4-inch WG. ft^3/min
Duct-piping: filter housing, and electrical penetrations	330
Dampers[a]	0
Doors	670
Total	1000

a. Considered bubbletight dampers at zero leakage.

The possibility of radioactive material, noxious gases, or steam to be transferred directly into the control room from adjacent areas and buildings other than through the outside air duct is improbable due to the following design arrangements and considerations:

A. The control room is at the 140-foot elevation. There are no piping penetrations into the building above the 140-foot elevation. The control room is maintained at 1/8 inch WG pressure above atmospheric to prevent infiltration of air. The volume of the control room and other space protected by the habitability system is 1.6×10^5 cubic feet. The outside air supply of 1000 cubic feet per minute will ensure pressurization of the area in excess of 1/8 inch WG so that all flow

of air through the potential leakage paths, doors, ductwork and filtration units, and cable penetrations is outwards and not inwards. The outside air intake is through the plenum system shown in engineering drawing 13-P-OOB-003. The inlet to the plenum is through louvered openings at the upper part of the building under the roof. The plenum system is designed as a Seismic Category I structure, which is an integral part of the building structure. The diesel building exhaust stack is situated such that effluent gases will not enter the control building outside air intake.

The essential HVAC system is inactive during normal operation and thus is not exposed to atmospheric dust.

The outside air supplied during emergency operation may carry airborne dust. The outside air intake filters are designed for an average dust loading of 1.78 mg/m^3 with an average maximum dust concentration period of 30 days. This dust loading is based on reference 4.

The two air intakes are located at the southeast and southwest corners of the control building.

B. The adjacent buildings to the control building are the radwaste, diesel generator, and auxiliary buildings. These buildings are maintained at a pressure slightly below atmospheric to prevent exfiltration of air. All normal releases from these buildings are exhausted

through an elevated stack. This precludes any direct transfer of contaminants to the control room intake.

C. The control room consists of two air spaces separated by a false ceiling. The upper air space contains cable penetrations (sealed) from the upper cable spreading room above, Seismic Category I duct hangers, Seismic Category I ceiling hangers, recessed light fixture enclosures (with power connections), and the Seismic Category I HVAC air ducts. There is no leakage path from any of these attachments or penetrations in the 8-inch floor slab of the cable spreading room above the control room. The suspended ceiling is not sealed from the lower air space containing the computer and control room equipment.

D. The floor of the control room contains sealed cable penetrations from the cable spreading area below the control room. There is, therefore, no leakage path from the lower cable spreading room through the control room floor into the control room.

E. There are two doorway entrances into the control room: from the corridor outside the control room or from the stairway running the full height of the building. Entrance to the corridor building is through the main entrance located between the turbine building and the diesel generator building. Outside entrance to the stairway is by a door located at ground level at the southeast corner of the control building. The door from the corridor into the control room and the door

from the alternate stairs into the control room are capable of being sealed from the external environment. The two entrances to the control room are each provided with two sets of doors acting as an air lock. The doors are provided with seals to reduce out-leakage and to secure the pressurization.

The path for entrance of radioactive material, noxious gases, or steam is so devious from the sources of such contamination to the access doors of the control room that this path is not credible. Even in the event of such potential entrance by this path, the control room doors would be sealed and the leakage past the seals would be insignificant.

F. The ductwork for the essential HVAC system for the control room under accident conditions is separated from connections to other areas or to the normal operating HVAC air handling or supply units by two Seismic Category I leaktight dampers independently actuated and powered by the two ESF trains. Air filters conforming to Regulatory Guide 1.52 are used for the makeup air supply to the essential HVAC system.

G. This section intentionally left blank.

H. Halon 1301 tanks are located at elevation 120 feet in the control building. These tanks provide fire protection capability for the communications and computer areas. A discussion of the design of the Halon fire protection systems relative to maintaining

the habitability of the control room is provided in subsection 9.5.1.

6.4.2.5 Shielding Design

The design basis loss-of-coolant accident (LOCA) dictates the shielding requirements for the control room. Control room shielding design bases are discussed in paragraph 12.3.2.2.7. Descriptions of the design basis LOCA source terms and control room shielding parameters, and evaluation of design basis accident doses to control room personnel are presented in section 15.6.

Drawings of the control room and its location in the plant, identifying distances and shielding with respect to each radiation source discussed in section 15.6. are shown in the radiation zone drawings in section 12.3.

6.4.3 SYSTEM OPERATIONAL PROCEDURES

6.4.3.1 Normal Mode

Control room HVAC system operation in the normal mode is described in subsection 9.4.1.

6.4.3.2 Essential Operation

In the event of a specified emergency signal such as a control room ventilation isolation actuation signal (CRVIAS), control room essential filtration actuation signal (CREFAS), safety injection actuation signal (SIAS), loss of offsite power (LOP), there will be automatic transfer to operation of the essential air handling units (AHUs). The tabulation below

shows the system response upon receipt of the indicated signals:

Signal	System Response
SIAS, LOP:	Receipt of either one of these signals will actuate both trains of the control room essential AHUs, ESF switchgear essential AHUs, and the battery room essential exhaust fans. Simultaneously, normal AHUs and battery room normal exhaust fans will automatically stop and isolation dampers will close. Bubbletight dampers will remain open to permit routing of the outside air chase to the control room essential AHUs.
CREFAS:	Receipt of this signal will activate the control room essential AHUs. Simultaneously, the control room normal AHU will automatically stop and isolation dampers will close. Bubbletight dampers will remain open to permit routing of the outside air from the outside air chase through the control room essential AHUs to the control room for pressurization to prevent infiltration of untreated air. However, these dampers will close in the event a CRVIAS signal is received subsequent to the CREFAS signal.
CRVIAS:	Receipt of this signal will activate the control room essential AHUs. Simultaneously, the control room normal AHU will automatically

stop and isolation dampers will close. Bubbletight dampers will close to isolate the control room and habitability areas at elevation 140 feet from the outside air.

After automatic actuation of both trains to emergency operation, one train may be manually stopped from the control room, while the other train continues to operate in the emergency mode. In the event of low-flow in the operating air conditioning train, low differential switches across the fans and air handling units will alarm the condition in the control room, so the other train can be manually actuated.

6.4.3.3 Isolation Mode

Isolation operation only applies to the control room complex when a CRVIAS signal is initiated. An alarm would sound in the control room upon detection of smoke in the outside air intake plenum from an external source. The control room essential air conditioning system may be placed into recirculation operation by manual actuation from the control room.

In recirculation operation, the control room air is continuously recirculated through one of the control room essential AHUs for cooling and filtration of radioactive particulates and radioiodine if present in the airstream. In this operating mode, when a CRVIAS signal is initiated, no outside air is introduced in the control room.

This operating mode is identical to emergency operation with the exception that the control room essential AHU is supplied with the air recirculated from the control room and no outside

air is introduced. This is accomplished by closing the normally open outside air intake dampers HJA-M02, HJA-M03, HJB-M02, and HJB-M03, shown in engineering drawings 01, 02, 03-M-HJP-001, -002 and -003.

6.4.3.4 Smoke Removal Mode

The smoke removal from the control building will be performed by use of portable smoke removal equipment which will exhaust smoke to the outside. For the portable smoke removal equipment, fresh air will be obtained by opening outside doors in the stairwells, opening missile doors or opening doors of the corridor building. The existing smoke removal system in the control building can be used to remove the smoke. Only portable equipment, however, is relied upon for smoke removal capability. This smoke removal mode of the installed equipment can remove smoke from the individual floors of the control building by exhausting 21,000 cubic feet per minute of air directly to the atmosphere, while introducing outside air as makeup. This is accomplished by opening dampers between the floor and the smoke exhaust chase with a smoke-exhaust fan exhausting to the atmosphere. Purge air makeup dampers between the smoke purge outside air intake chase and the respective floor space are opened. Dampers are simultaneously closed in the supply and return ducts, isolating the floor from the rest of the air conditioning system. All dampers for smoke purging are operated from the control room.

6.4.4 DESIGN EVALUATIONS

6.4.4.1 Radiological Protection

The effects of potential radiological accidents are analyzed in chapter 15. The radiological protection afforded operators in the event of an accident is described in subsections 6.4.2, 12.3.2, 12.3.3, and 12.3.4, and in section 11.5.

6.4.4.2 Toxic Gas Protection

Chlorine is generated in electrolytic cells in the water reclamation facility. However, chlorine gas and other toxic gases are not stored or used onsite in quantities sufficient to necessitate control room protection, as required by Regulatory Guide 1.78. The analysis of potential offsite sources for toxic gases is presented in subsection 2.2.3.

6.4.4.3 Implementation of Design Bases

These evaluations are listed to correspond with the design bases of subsection 6.4.1.

A. Safety Evaluation One

   Control room habitability system components discussed in paragraph 6.4.2.2.2 are arranged in redundant safety-related ventilation trains, as shown in engineering drawings 01, 02, 03-M-HJP-001, -002 and -003. The location of components and ducting within the control room envelope ensures an adequate supply of filtered air to all areas requiring access.

B. Safety Evaluation Two

By using chilled water cooling coils and duct heaters, the control room essential air conditioning system maintains the temperature between 70F and 80F for the Control Room and other essential occupancy areas and the relative humidity below 50%. The control room pressure is maintained at least 1/8 inch WG above atmospheric pressure during emergency operation. The control room essential ventilation system maintains the same temperature and humidity conditions when operating in the isolation mode.

C. Safety Evaluation Three

The control room ventilation system is capable of removing sensible and latent heat loads of 957,528 Btu/h and 49,872 Btu/h, respectively, which includes consideration of equipment heat loads and minimum personnel occupancy requirements. Table 9.4-3 shows the installed HVAC equipment performance data and design details.

The transfer to essential or isolation operation mode does not create a hazard for CO^2 buildup. In case of emergency operation, there is a supply of outside air at a maximum of 1000 cubic feet per minute and the long-term equilibrium for CO^2 will remain below one part per thousand for up to 50-person occupancy. In case of isolation mode operation, where the control room is sealed, the critical level of 3% would be

reached at the following times for the various occupancies:

6 persons	26.2 days
12 persons	13.1 days
30 persons	5.2 days

There is no specific design capacity limit on the number of personnel permitted in the control room under normal operation.

D. Safety Evaluation Four

Food, water, medical supplies (including a potassium iodide drug supply), and sanitary facilities are provided for a minimum occupancy of six persons for 7 days. Storage locations provided ensure that the above supplies will not be contaminated as a result of postulated accidents.

The supply of food and water is sufficient for a prolonged occupancy since outside supplies can be provided within the 7-day interval.

Refer to subsection 18.III.D.3.4 for TMI-related information pertaining to "Control Room Habitability Requirements".

E. Safety Evaluation Five

The control room air purification system and shielding designs are based on the most limiting design basis assumptions contained in NRC Regulatory Guide 1.4.

Automatic transfer of the control room normal ventilation system to the essential system is accomplished upon receipt of a high radiation signal from the outside air intake duct detectors, receipt of LOP signal, receipt of a safety injection actuation signal, or receipt of a fuel building high radiation signal from the ESF actuation system. Transfer to the essential system also may be manually initiated from the control room. Refer to section 7.3 for a discussion of the actuation logic.

The airborne fission product source term in the reactor containment following the postulated LOCA is assumed to leak from the containment at a rate of 0.1% per day for the first 24 hours after the accident, and 0.05% per day thereafter. Mixing in the building wake, in which the control room and its ventilation intake are presumed to be immersed for the duration of the post-accident phase, is also assumed.

The concentration of radioactivity, which is postulated to surround the control room after the postulated accident, is evaluated as a function of the fission product decay constants, the containment spray system effectiveness, the containment leak rate, and the meteorology conditions in effect. The assessment of the amount of radioactivity within the control room takes into consideration the flowrate through the control room outside air intake, the effectiveness of the control room air purification system, the

radiological decay of fission products, and the exfiltration rate from the control room.

Air within the control room is recirculated continuously through the emergency air conditioning units, which contain high efficiency filters, HEPA prefilters, charcoal adsorbers, HEPA after filters, cooling coil, and fan, to control room temperature and airborne radioactivity. The outside air required for pressurization is mixed with the return air before it enters the filtration unit.

During the emergency mode of operation, the control room HVAC is designed to pressurize the control room to 1/4 inch WG pressure to prevent unfiltered in leakage.

The calculated doses as a result of a postulated LOCA are given in section 15.6.

Control room shielding design, based on the most limiting design basis LOCA fission product release, is discussed in section 12.3 and is evaluated in chapter 15. The evaluations in chapter 15 demonstrate that the radiation exposures to control room personnel originate from containment direct radiation, external cloud direct radiation, and containment airborne radioactivity sources. Total exposures resulting from DBAs are below the dose limits specified by General Design Criterion 19. The portion contributed by containment direct radiation and external cloud direct radiation is reduced to a small fraction of the total

by means of shielding. The potential for radiation streaming through the control room structure boundary penetrations was also considered in the above analysis.

F. Safety Evaluation Six

As discussed and evaluated in subsection 9.5.1, the use of noncombustible construction and heat and flame-resistant materials throughout the plant minimizes the likelihood of fire and consequential fouling of the control room atmosphere. Smoke detectors in the control building air intake header alarm in the control room. The air intake to the control room can then be manually isolated.

Emergency portable breathing apparatus is also provided for the control room operators, in accordance with Regulatory Guide 1.78, Position C13.

G. Safety Evaluation Seven

A supply of protective clothing, respirators, and self-contained breathing apparatus adequate for at least six persons is stored at specified locations within the control room envelope.

H. Safety Evaluation Eight

To protect against high airborne radioactivity inside the control room, the control room HVAC system is automatically transferred from the normal mode to the emergency mode of operation upon receipt of a CREFAS due to outside air intake high radiation signal.

Transfer of the system to emergency or isolation modes may also be initiated manually from the control room. Controls and instrumentation requirements are discussed in subsection 6.4.6.

I. Safety Evaluation Nine

The filtration and cooling functions of the control room HVAC system may be performed fully even if the capability of the system is reduced by a single active component failure within the system or its supporting systems. Should one recirculation air handling unit fail, the redundant train will provide the required cooling. Redundant supply and recirculation trains provide the required filtration should an excessive pressure drop develop across the other filter train. Normally open isolation dampers are arranged in series pairs so that the failure of one damper to shut upon transfer to the emergency mode will not result in a breach of isolation. There are two emergency diesel generators for each unit. If one of the emergency diesel generators fails to start and assume its load, the control room emergency ventilation system equipment powered by the other diesel will provide the required service.

A single failure analysis is provided in table 6.4-3.

J. Safety Evaluation Ten

The control room essential ventilation system and isolation dampers are designed in accordance with Seismic Category I requirements as specified in

section 3.2. The components (and supporting structures) of any system, equipment, or structure that is not Seismic Category I, and whose collapse could result in loss of a required function of the control room HVAC system through either impact or flooding, are analytically checked to determine that they will not collapse when subjected to seismic loading. The control room essential ventilation system is designed to function during and after an SSE.

Table 6.4-3

CONTROL ROOM ESSENTIAL HVAC SYSTEM SINGLE FAILURE ANALYSIS

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision
Fan	Fails to operate/ mechanical or electrical failure	Loss of one of the two redundant filter-cooling trains	Annunciated in control room	Two redundant loops provided. Either loop is capable of providing 100% of requirement.
Filter	Plugged/mechanical failure	Loss of one of the two redundant filter-cooling trains	Annunciated in control room	Two redundant loops provided. Either loop is capable of providing 100% of requirement.
Cooling Coil	Ruptured or plugged/ mechanical failure	Loss of cooling for one of the two redundant filter-cooling trains	Annunciated in control room	Two redundant loops provided. Either loop is capable of providing 100% of requirement.
Isolation damper	Fails to close/ mechanical or electrical failure	None	Indicated in control room	Redundant in series isolation dampers provided.
Radiation monitor	Fails to operate	None	Abnormal control room indication	Redundant monitor provided
Intake damper	Fails to open/ mechanical or electrical failure	Loss of one of the two redundant filter cooling trains	Indicated in control room	Two redundant loops provided. Either loop is capable of providing 100% of requirement.
One Class IE bus	Loss of power/ electrical failure	Loss of one of the two redundant filter cooling trains	Annunciated in control room	Two redundant loops provided. Either loop is capable of providing 100% of requirement.

6.4.5 TESTING AND INSPECTION

A detailed program of preoperational and postoperational testing requirements to assure continued system capability will be implemented prior to station operation as described in section 14.2. Emphasis is placed on tests and inspections essential to a determination that performance criteria and operational capability are achieved and maintained.

The control room isolation capability and the ability to process outside air through one of the two high efficiency filter trains will be tested periodically. The filtration trains will be tested periodically by standard methods in general conformance with Regulatory Guide 1.52, as noted in section 1.8.

High efficiency particulate air (HEPA) filter elements are tested individually prior to installation to verify an efficiency of 99.97% with a thermally generated monodisperse 0.3-micron DOP aerosol. HEPA filter banks are tested in-place prior to operation and periodically thereafter in conformance with ANSI N510, and complies with Position C.5.b of Regulatory Guide 1.52.

Impregnated, activated carbon is batch tested prior to loading into the adsorber section. Acceptance criteria are those described in Table 5.1 of ANSI N509-1980 version. The carbon adsorber section is filled with carbon in a manner to ensure a uniform packing density and to minimize dusting. The adsorber section is leak tested in conformance with ANSI N510 with a gaseous fluorocarbon prior to operation and periodically thereafter to verify less than 0.05% bypass. In addition, a

periodic laboratory test of a representative sample of the impregnated activated carbon is performed to verify iodine removal efficiencies in accordance with Position C.6 and Table 2 of Regulatory Guide 1.52 for the assigned decontamination efficiency and bed depth (refer to section 1.8).

Design and testing of filtration systems is consistent with the recommendations of NRC Regulatory Guide 1.52, Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light Water-Cooled Nuclear Power Plants, except as discussed in section 1.8.

Inservice testing of the control room essential HVAC system is conducted in accordance with the surveillance requirements specified in the Technical Specifications

Portable equipment such as air samplers, personnel dosimeters, and other radiation analysis equipment applicable to control room habitability is tested and inspected periodically as noted in section 12.5.

6.4.6 INSTRUMENTATION REQUIREMENT

The following indications are displayed in the control room: fan status, damper positions, room temperatures, and outside air intake radioactivity. Alarms indicate low fan differential pressure and outside air intake airborne radioactivity greater than 10^{-6} mCi/cm^3 (Xe-133). (Refer also to sections 7.3 and 7.5.)

Instrumentation required for actuation of the control room essential HVAC system is discussed in paragraph 6.4.2.2.2 and

section 7.3. System control logic diagram is shown in figure 7.3-5.

Details of the radiation monitors used to initiate CREFAS are given in sections 7.3 and 11.5. Information, including detector locations, type of radiation detected, detector type, range, and sensitivity, is given in table 11.5-1.

The instrumentation is designed as Seismic Category I. A description of initiating circuits logic interlocks and periodic testing requirements and redundancy of instrumentation relating to control room habitability appears in section 7.3.

6.4.7 BOUNDING SYSTEM UNFILTERED AIR INLEAKAGE FOR RADIOLOGICAL DESIGN

6.4.7.1 Design

The Palo Verde Nuclear Generating Station (PVNGS) Control Room (CR) is designed to meet GDC 19 of 10 CFR 50, Appendix A during all design basis events. This design basis complies with Regulatory Guide 1.4 and 10 CFR 50.34 (a)(1)(ii)(D) guidance for source term, release, and mitigation of consequences. This section of 10 CFR 50.34 supports 10 CFR 100, which regulates offsite dose.

Bounding radiological Leakage, as described here, includes all known and unknown sources of air leaking into the positively pressurized habitability boundary. This leakage includes, but is not limited to, ingress-egress, essential and normal HVAC system component leakage, habitability boundary "wall" leakage, and other system leakage into the pressurized envelope such as instrument air and nitrogen.

Key Essential System parameters used in radiological analysis: The following Essential HVAC (HJ) Parameters are critical to the determination of an integrated inleakage rate:

1. Maximum outside air supplied by essential system and filtered by a 2 inch (minimum depth) charcoal bed is 1000 SCFM.
2. Minimum air recirculation rate for the essential HVAC system is 25740 SCFM, filtered by 2 inch (minimum depth) charcoal filter beds.
3. The filtration units meet or exceed the Regulatory Guide 1.52 requirements with exceptions as stated in Section 1.8 of the PVNGS UFSAR.
4. Minimum pressure differential for the Control Room radiological boundary is 1/8 inch (gauge) of water.
5. Maximum (net) control room volume not to exceed 1.61E+5 ft^3.
6. 10 SCFM inleakage into the habitability envelope is a result of personnel ingress-egress (Standard Review Plan section 6.4).

6.4.7.2 Single Failure Applied to Control Room Habitability Analysis

For control room habitability analysis only, it has been assumed that both essential HJ trains would be actuated and one would be immediately turned off by control room operators. This is a conservative assumption since doubling the outside air supply would pressurize the control room envelope beyond

the minimum design delta P, thereby reducing inleakage into the envelope. For this reason, the single failure assumed that for this analysis is the same as is assumed for the postulated event. No credit has been taken in this analysis for the normal HVAC system. It is assumed that the normal HVAC system would perform in a manner that would not challenge the essential HVAC. If a DBE assumes a loss of power, it is assumed that components in nonessential systems would fail in "As Is" positions, with the exception of components that are designed to fail in safe positions.

6.4.7.3 Control Room Radiological Assessment

The control room dose for bounding unfiltered inleakage is evaluated for the following four limiting accidents:

1) LOCA, as described in section 15.6.5 and Appendix 15B.
2) CEA Ejection's, as discussion in section 15.4.8 and Appendix 15B.
3) RCP sheared shaft with pre-existing iodine spike in the reactor and a stuck open ADV, as discussed in section 15.3.4 and Appendix 15B.
4) A SGTR with a stuck open ADV and a pre-existing iodine spike to the secondary side, as described in section 15.6.3 and Appendix 15B. It has been determined that the Pre-accident Iodine Spike (PIS) dominates the Generated Iodine Spike (GIS).

Table 6.4.7-1[8]

Summary of Control Room Radiological Assessment

at 51[1] SCFM Inleakage

Event	Condition of fuel during the accident	Time, Event Start to Control Room Isolation (Damper Closed)[7] (Sec.)	Limiting organ (Thyroid) dose[2] in rem
LOCA[3]	100% fuel melt (Reg Guide 1.4 model)	52	18
CEA Ejection[4]	17% fuel experiences DNBR. Failed fuel peaking factor 1.77 (Reg Guide 1.77 model)	119	27
RCP Sheared Shaft with Stuck open ADV[5]	17% fuel experiences DNBR. Failed fuel peaking factor 1.72 (Reg Guide 1.77 model)	340	13
SGTR with Stuck open ADV[6]	Preaccident iodine spike; assume no failed fuel; RCS conc. 60 μCi/cc	300	18

1. 51 SCFM is the allowable inleakage and it applies to all events. This value is in addition to a 10 SCFM in leakage requirement for ingress-egress.
2. Whole body and Beta skin doses are within GDC 19 requirements and are not bounding for the inleakage calculation.
3. Bounds all Small Break LOCAs larger than 0.05 ft^2.
4. Bounds all Small Break LOCAs smaller than 0.05 ft^2 and Fuel Handling Accident.
5. This assessment bounds all events in which fuel would experience DNBR and the primary system maintains its integrity.
6. Bounds all events that would result in PIS or GIS such as Letdown line break. This event also bound GRS / LRS events as described in section 15.7.
7. Time from initiation of event to generation of either ESFAS or BOP ESFAS signal and closure of the Control Room damper.
8. Information is applicable for Control Room dose evaluations only and is not intended to reflect Chapter 15 Offsite Dose Analyses.

As can be seen in the table 6.4.7-1, the controlling accident is the CEA Ejection with stuck open ADV. This accident sets the upper bound on the unfiltered inleakage for the control room habitability system. These analyses assume 10-scfm inleakage for ingress–egress and 51-scfm inleakage from all other sources that may penetrate control room habitability boundary. In conclusion, radiological consequences to control room operators are within the limits of 10 CFR 50, Appendix A GDC 19 for all design bases events.

6.4.8 REFERENCES

1. "Handbook of Fundamentals", ASHRAE, 1977 edition.

2. "Particulate Characteristics of Dust Storms at the Palo Verde Nuclear Generating Station", Final Report, Environmental Management Department, Arizona Public Service Company, October 1978.

3. "Dust Concentration Evaluation for Palo Verde Nuclear Generating Station Units 1, 2, and 3," Study No. 13-MS-A44, Revision 0, April 23, 1990.

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6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 ENGINEERED SAFETY FEATURE FILTER SYSTEMS

The engineered safety feature (ESF) filter systems consist of the control room ventilation filters and the fuel building filters. The effectiveness of these systems under postulated accident conditions is discussed in sections 15.6 and 15.7, respectively.

Non-ESF filter systems include the containment power access purge filters, the hydrogen purge filters, the auxiliary building exhaust filters, the waste gas decay tank filter, and the radwaste building exhaust filters. These systems are discussed in sections 9.4 and 11.3.

6.5.1.1 Design Bases

Engineered safety feature air handling units and filters for the control room and the fuel building are designed to accomplish the following:

A. (Control room system only)

   Ensure that the radiation exposures to operating personnel in the control room resulting from the hypothetical accidents discussed in chapter 15 are within the guideline values of 10CFR50, Appendix A, General Design Criterion 19.

B. (Fuel building system only)

   Ensure that the offsite radiation exposures and exposures to operating personnel in the control room are within the guideline values of 10CFR100 and

10CFR50, Appendix A, General Design Criterion 19, respectively. These exposures could result from either the postulated fuel handling accident discussed in subsections 15.7.1 and 15.7.2 or from equipment leakage due to post-LOCA coolant recirculation in the auxiliary building.

C. Ensure that failure of any component of any ESF train, assuming loss of offsite power, cannot impair the ability of either system to perform its safety function.

D. Remain intact and functional in the event of a safe shutdown earthquake (SSE).

E. Are consistent with the recommendations of Regulatory Guide 1.52 as discussed in sections 1.8 and 6.4.

The design bases employed for sizing the filters, fans, and associated ductwork are discussed in sections 6.4 and 9.4.

The design, equipment, and materials conform to the applicable requirements and recommendations of the guides, codes, and standards listed in section 3.2.

6.5.1.2 System Design

6.5.1.2.1 General System Description

The control room essential HVAC system is described in section 6.4. The fuel building essential HVAC, normal HVAC, and control room normal HVAC systems are described in section 9.4. Flow diagrams for all systems are provided in section 9.4.

6.5.1.2.2 Component Description

Each ESF filter train consists of a prefilter, a high efficiency particulate air (HEPA) filter, a charcoal adsorber, and a downstream HEPA filter. The filtration trains are connected to heating coils, axial fans with direct drive motors, associated ductwork, and controls. Specific component design parameters are provided in table 6.5-1. The design meets the recommendations of Regulatory Guide 1.52 to the extent described in section 1.8.

The filter housing design provides adequate space for filter maintenance and inspection. The housing is fitted with the necessary ports for testing. Pipe, cable, and conduit penetrations are sealed to minimize leakage. Access doors are marine-type bulkhead doors with gastight seals and double-pin hinges.

The charcoal adsorber portion of each filter train is provided with a fire detection system and a water spray system to allow flooding of the charcoal bed in the event of bed ignition.

6.5.1.3 Design Evaluation

The following design evaluations are written to correspond to the design bases of paragraph 6.5.1.1.

A. The performance capability of the control room essential filtration is discussed in section 6.4. The design of individual components, which ensure the capability to perform the safety function, is also discussed in section 6.4. Control room doses

resulting from postulated radiological accidents are given in section 15.6. These doses are within the guideline values of 10CFR50, Appendix A, General Design Criterion 19.

B. Component descriptions and safety evaluation for the fuel building essential filtration units are provided in section 9.4. Dose analyses of postulated fuel handling accidents are discussed in subsection 15.7.2. Dose analyses of the exposure to recirculation leakage post-LOCA are discussed in section 15.6. Offsite radiation exposures and control room doses resulting from these accidents are shown to be within the guideline values of 10CFR100 and 10CFR50, Appendix A, General Design Criterion 19, respectively.

C. The control room ventilation system and the fuel building ventilation system each have two independent and redundant filtration trains. Should any component in one train fail, filtration can be performed by the other train which is powered from a separate Class 1E electrical bus. Failure modes and effects analyses are provided in paragraphs 6.4.4.3, 9.4.2.2, and 9.4.5.2.

D. The ESF filter systems are designed to Seismic Category I requirements, as specified in section 3.2.

E. The ESF filter systems were designed and constructed to be consistent with the recommendations of Regulatory Guide 1.52, as discussed in section 1.8.

Table 6.5-1
ESF FILTER SYSTEM DESIGN PARAMETERS

Component	Units Installed	Units Required for Operation	Unit Capacity
Control room essential ventilation system			
Essential air handling units	2	1	
Fans per unit	1	1	
Capacity, ft^3/min			28,600
Allowed pressure drop across filters, in. WG			4.8
Motor, hp			125
Prefilter banks per unit	1	1	
Capacity, ft^3/min			28,600
HEPA filter banks per unit	2	2	
Capacity, ft^3/min			28,600
Charcoal filter backs per unit	1	1	
Capacity, ft^3/min			28,600
Fuel building essential ventilation system			
Essential air handling units	2	1	
Fans per unit	1	1	
Capacity, ft^3/min			6,000
Allowed pressure drop across filters, in. WG			5.2
Motor, hp			40
Prefilter banks per unit	1	1	
Capacity, ft^3/min			6,000
HEPA filter banks per unit	2	2	
Capacity, ft^3/min			6,000
Charcoal filter banks per unit	1	1	
Capacity, ft^3/min			6,000

6.5.1.4 Tests and Inspections

6.5.1.4.1 Preoperational Testing

High efficiency particulate air filters are manufactured and tested prior to installation in accordance with MIL-F-51068C as modified by NRC Health and Safety Information Issue 306. High efficiency particulate air filter banks are tested in-place prior to operation to verify efficiency of at least 99.95% with a cold generated polydisperse 0.7 micron DOP aerosol.

Impregnated, activated carbon is batch tested prior to loading into the adsorber bed. Acceptance criteria are those described in ANSI N509-1980, "Nuclear Power Plant Air Cleaning Units and Components." Tests include particle size distribution, hardness, density, moisture content, pH of water extract, ash content, ignition temperature, and elemental iodine and methyl iodine removal efficiencies at postulated accident conditions.

The charcoal adsorber is Freon leak tested prior to operation to verify less than 0.05% bypass. In addition, a laboratory test of a representative sample of the impregnated activated charcoal is performed to verify iodine removal efficiencies. Pre-operational testing is performed on systems in accordance with the test descriptions in section 14.2.

6.5.1.4.2 Inservice Testing

Inservice testing of the ESF filtration systems is conducted in accordance with the surveillance requirements of the Technical Specifications.

6.5.1.4.3 General Testing

Design and testing of ESF filtration systems is consistent with the recommendations of NRC Regulatory Guide 1.52, Design, Testing and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light Water-Cooled Nuclear Power Plants, as discussed in section 1.8.

6.5.1.5 Instrumentation Requirements

Controls and instrumentation for the control room and for the fuel building systems are discussed in section 7.3. Each system is designed to function automatically upon receipt of an ESF actuation system signal. Fans can also be controlled from the control room.

The status of the essential ventilation equipment is displayed in the control room during both normal and accident operations.

Section 1.8 addresses the extent to which the recommendations of NRC Regulatory Guide 1.52 are followed with respect to instrumentation.

6.5.1.6 Materials

The materials of construction used in or on the filter systems are given in paragraphs 6.4.2.2 and 9.4.5.2. Each of the materials is compatible with the normal and accident environments postulated in the control room and the fuel building.

Accident environments (i.e., extreme temperature or radiation) that could potentially produce radiolytic or pyrolytic decomposition of filter materials are not applicable to the control room or fuel building. Thus, filter system decomposition products will not be present.

6.5.2 CONTAINMENT SPRAY SYSTEMS

6.5.2.1 Design Bases

Credit for the iodine removal capability is discussed in paragraph 6.5.2.3. This credit, due to system performance, is used to meet the requirements of 10CFR100 for the design basis accidents presented in chapter 15.

6.5.2.2 System Design (for Fission Product Removal)

The spray header arrangement is shown in engineering drawings 13-P-ZCG-114, -118 and -120.

Regions within the containment can be shielded from direct spray by flooring, missile shielding, and equipment. The PVNGS containment design limits these unsprayed regions to approximately 6% of the containment volume. Most of the containment volume receives direct spray coverage from the primary spray headers (located above the operating floor), although some of the containment volume receives direct spray coverage from auxiliary headers (located below the 120-foot and 140-foot levels under concrete slabs on the eastern end of the refueling pool). These volumes that are sprayed by the auxiliary headers receive at least the same spray flowrate per

unit volume of gas space (gallons per minute per cubic foot) as the volumes which are sprayed by the primary spray headers. Detailed plans and sections of the containment which illustrate the unsprayed regions are given in figures 6.5-1 through 6.5-6. Table 6.5-2 lists the unsprayed regions by volume above elevation 100 feet. Except for the steam generator compartment, areas below elevation 100 feet are not sprayed. The gross containment volume above elevation 100 feet is 2.72×10^6 cubic feet. Therefore, the sprayed containment volume above elevation 100 feet is 2.45×10^6 cubic feet. The sprayed volume below elevation 100 feet of the steam generator compartment is 2.05×10^4 cubic feet. Thus, the total containment sprayed volume is 2.47×10^6 cubic feet. As the containment net free volume is 2.62×10^6 cubic feet, only 6% of the net free volume is unsprayed.

The containment spray nozzles are attached to and become part of the spray headers. The spray nozzles serve to disperse the spray solution throughout the containment in droplets to increase the heat transfer surface. The nozzles and headers are oriented to ensure maximum effective coverage of the containment volume. The spray nozzles are of the non-clogging type. The nozzles attached to the primary headers in the upper portion of containment are designed to pass 3/8 inch diameter particles. The nozzles attached to the auxiliary headers in the lower portion of containment are designed to pass 3/16 inch diameter particles. The design of the spray nozzles is sufficient to prevent clogging from debris entering the recirculation system through the sump screens since the spray

nozzle openings are larger than the containment sump screen openings.

6.5.2.3 Design Evaluation

The effectiveness of the containment spray system in removing radio-iodine is evaluated separately for the two sprayed regions described in paragraph 6.5.2.2. The containment spray system with no chemical additive is considered to be effective in removing only elemental and particulate forms of iodine. The elemental and particulate iodine removal coefficients are listed in Table 15.6.5-2.

In addition to the iodine removal mechanism provided by the containment spray system, iodine is also removed from the containment atmosphere as a result of plateout on containment surfaces. This phenomenon is not a function of containment spray system performance and therefore occurs in the unsprayed region as well as in the sprayed region. The significant difference in the surface area/volume ratio between the upper and lower containment regions was accounted for in the plateout model. Plateout removal coefficients are listed in Table 15.6.5-2.

Although the spray removal mechanism is not effective in the unsprayed region, iodine removal from the unsprayed region is enhanced by mixing of the sprayed and unsprayed region air volumes. This occurs as a result of diffusion as well as general bulk transfer between regions due to such factors as break location, natural convection, and steam condensation by

containment spray. Of these mechanisms, only the bulk mass transfer between the sprayed and unsprayed regions due to steam concentration is used in the evaluation of the reduction of iodine concentration within the unsprayed region.

For a containment with the majority of the mass and energy releases occurring below the operating level and the majority of the steam condensation occurring in the sprayed region above the operating level, flow is induced from below to above the operating level at a rate equivalent to the steam condensation rate. The mean volumetric exchange rate of the region below the operating level is calculated as follows:

The heat removal capacity of one spray train is related to a condensed mass of steam in the sprayed volume. The volume contraction of this condensing steam mass will induce an equivalent volume of steam from available mass sources which can be identified as being below the operating level. It is seen that the minimum volume contraction occurs at the highest temperatures in spite of the maximum mass condensation which is experienced at that time. This is due to the effect of containment pressure on the specific volume of steam.

Accordingly, a very conservative containment temperature of 300F is chosen. Makeup sources are assumed to be concentrated in the lower 25% of the containment volume for the purpose of fixing the induced makeup rate.

This approach predicts approximately 3.3 unsprayed volume changes per hour. This mixing rate is then applied to the unsprayed volumes and is used in conjunction with the spray λ

to determine doses. In summary, the assumptions underlying the calculation of mixing rates are as follows:

A. Of the several mechanisms causing containment mixing, credit is taken only for a volume contraction in the sprayed region due to the condensation of steam in that region.

B. One spray train is in operation.

C. Maximum RWT temperature of 120F is used to calculate heat removal.

D. Steam condensed in the sprayed volume is replaced by an equal volume of steam from available mass/energy sources.

E. Pressure differentials between compartments are insignificant.

F. Loss-of-coolant accident mass/energy sources are identified as being below the operating floor, or approximately the lower 25% of the containment volume.

G. Sprayed and unsprayed volumes each are homogeneous in terms of concentrations and distribution of mass/energy sources.

Table 6.5-2

UNSPRAYED REGIONS INSIDE CONTAINMENT ABOVE ELEVATION 100 FEET

Region	Unsprayed Volume (cubic feet)
Pressurizer compartment	2.87×10^4
Pressurizer valve gallery	7.34×10^3
Safety injection tanks (4)	1.22×10^4
Steam generators (2)	3.06×10^4
Reactor coolant pumps (4)	9.6×10^3
HVAC ducting	2.30×10^4
Elevator and regenerative HX compartments	1.16×10^4
Miscellaneous equipment	1.81×10^4
Steam line support	5.28×10^3
Primary and secondary shield walls	7.83×10^4
Refueling pool walls	3.19×10^4
Refueling canal floor	1.23×10^4
Total	2.50×10^5

The PVNGS design utilizes 230 Spraco 17071417 (15.2 gallons per minute) spray nozzles in each train of the primary spray headers. Spraco 17071417 spray nozzle performance data are provided in appendix 6A, figures 6A-1, 6A-2, and 6A-3 (see appendix 6A, Question 6A.11). It also uses 80 Spraco 17651308 (3 gallons per minute) nozzles in each train of the auxiliary spray headers.

6.5.2.4 Tests and Inspection

Preoperational testing is performed on the system in accordance with the test description in section 14.2. Periodic testing is performed in accordance with the requirements of the Technical Specifications.

6.5.2.5 Instrumentation Requirements

The containment spray system is provided with instrumentation and controls as described in section 6.2.2.5.

6.5.2.6 Materials

Refer to section 6.2 for a description of the material of the containment spray system and their compatibility with the containment sump solution.

6.5.2.7 CESSAR Interface Requirements

A. CONTAINMENT SPRAY SYSTEM

The following interface criteria are repeated from Section 7.0 of CESSAR Appendix 6A.

(A)7.0 INTERFACE REQUIREMENTS

(A)7.1 POWER

(A)7.1.1 The containment spray system pumps, valves, and instrumentation shall be capable of being powered from the plant turbine generator (onsite power source), plant startup power source (offsite

power), and the emergency generators (emergency power).

(A)7.1.2 Power connections shall be through a minimum of two independent buses so that in the event of a LOCA in conjunction with a single failure in the electrical supply, the flow from one containment spray train shall be available for containment heat removal.

(A)7.1.3 Each electrical bus of the above shall be connected to one containment spray pump and associated valves and instrumentation.

(A)7.1.4 Each emergency generator and the automatic sequencers necessary for generator loading shall be designed such that flow to the containment atmosphere is attained within a maximum of 58 seconds after a CSAS, as described in Section 6.3.

(A)7.1.5 Instrument power supplies shall be provided as stated in CESSAR Section 8.3.1.

(A)7.2 PROTECTION FROM NATURAL PHENOMENA

Design provisions shall be incorporated such that CSS components are capable of functioning in the event of the maximum probable flood or other natural phenomenon defined in GDC 2.

(A)7.3 PROTECTION FROM PIPE FAILURE

(A)7.3.1 The maximum expected leakage from a moderate energy pipe rupture postulated during normal plant conditions in the containment spray system shall be as defined by the methods of CESSAR Section 3.6.1.

Isolation valves used to contain leakage shall be protected from the adverse effects of a high or moderate energy pipe rupture which might preclude their operation when required.

(A)7.3.2 No limited leakage passive failure or the effects thereof (such as flooding, spray impingement, steam, temperature, pressure, radiation, loss of NPSH, or loss of recirculation water inventory), in the CSS during the recirculation mode shall preclude the availability of minimum acceptable recirculation

capability (minimum acceptable capability is defined as that which is provided by the operation of one subsystem).

(A)7.3.3 The containment spray system shall be protected from the effects of pipe rupture.

(A)7.3.4 The containment spray system shall be protected from the effects of pipe whip.

(A)7.4 MISSILES

The containment spray system shall be protected from missiles.

(A)7.5 SEPARATION

(A)7.5.1 Adequate physical separation shall be maintained between the redundant piping paths and containment penetrations of the CSS such that the CSS will meet its functional requirements even with the failure of a single active component during the injection mode, or with a single active failure or a limited leakage passive failure during the recirculation mode.

(A)7.5.2 The cabling which is associated with redundant channels of vital Class 1E circuits for the CSS shall be physically

separated to preserve redundancy and prevent a single event from causing multiple channel malfunctions or interactions between channels. Associated circuit cabling from redundant channels shall either be separated, provided with isolation devices, or analyzed and/or tested to demonstrate that no credible single failure could adversely affect redundant channels of Class 1E circuits.

(A)7.5.3 In the routing of CSS Class 1E circuits and location of equipment served by these Class 1E circuits, consideration shall be given to their exposure to potential hazards such as postulated ruptures of piping, flammable material, flooding, and non-flame retardant wiring. Adequate separation or protective measures shall be provided.

(A)7.5.4 Failures of non-safety grade systems shall not compromise redundancy of the CSS.

(A)7.6 INDEPENDENCE

(A)7.6.1 Each CSS train shall be provided with an independent environmental control system.

(A)7.6.2 Power connections for CSS components shall be from a minimum of two independent electrical buses. See 7.1.2 above.

(A)7.6.3 Two independent vital instrument power sources shall be provided for the CSS instrumentation. See 7.1.5 above.

(A)7.6.4 Mechanical See 7.3, 7.4, and 7.5 above.

(A)7.7 <u>THERMAL LIMITATIONS</u>

Each CSS train shall be provided with an independent environmental control system such that the safety related equipment in each train operates within the environmental design limits specified in CESSAR Section 3.11.

(A)7.8 <u>MONITORING</u>

Provisions shall be made for the detection, containment, and isolation of the maximum expected leakage from a moderate energy pipe rupture in one train, as discussed in 7.3.1 above.

Process instrumentation shall be available to the operator in the control room to assist in assessing post-LOCA conditions. The type of instrument, parameter measured, instrument range and

accuracy are listed in Sections 6.1 and 6.2.

(A)7.9 OPERATIONAL AND CONTROLS

Refer to Section 7.1.

(A)7.10 INSPECTION AND TESTING

Inspection and testing requirements for the CSS are contained in Section 8.0 and in CESSAR Section 16. Prior to initial plant startup, CSS flow tests which comply with Section 9.0 shall be performed. An adequate supply of water and the necessary test connections at the containment sump and containment spray header piping penetrations shall be provided.

(A)7.11 CHEMISTRY AND SAMPLING

(A)7.11.1 The CSS shall be designed for the following fluid conditions:

Basic Fluid	Water
with: H_3B0_3	3.5 w/o

phosphate controlled pH of 10 max.

(A)7.11.2 SAMPLING

(A)7.11.2.1 The sampling system shall provide a means of obtaining remote liquid samples

from the CSS for chemical and radiochemical laboratory analysis.

(A)7.11.2.2 The sample lines in contact with the reactor coolant shall be austenitic stainless steel or equivalent, such that the material is compatible with the fluid chemistry.

(A)7.11.2.3 The fluid velocity in the sample lines should be selected to obtain representative samples. The purge flowrate should be high enough to remove crud from lines.

(A)7.11.2.4 Sample taps should be located on vertical runs of pipe whenever possible. Where this cannot be done, it is permissible to take samples from the top of horizontal pipe runs.

(A)7.12 MATERIALS

(A)7.12.1 CSS piping and fittings shall be Seismic Category I.

(A)7.12.2 Design and fabrication of the CSS piping and fittings shall conform to ASME Boiler and Pressure Vessel Code (B&PV) Section III, Class 2 as identified on CESSAR Section 6.3.1.

(A)7.12.3 Pipes and all parts in contact with the system fluid shall be of austenitic stainless steel. The stainless steel shall be type 316, type 304, or CE approved alternate. Selection of the type of stainless steel shall be on the basis of compatibility with design pressure and temperature considerations and with the chemistry of the fluid.

Valve packings, gaskets, and valve diaphragm materials shall also be compatible with the chemistry of the fluid and the radioactive dose at that location.

(A)7.12.4 Care shall be taken to prevent sensitization and to control the delta ferrite content of: (1) the welds which join any system fabricated of austenitic stainless steel to the CSS, and (2) the field welds on the CSS. The guidance of Regulatory Guides 1.44, "Control of the Use of Sensitized Stainless Steel" and 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal" is relevant at these weld locations.

(A)7.12.5 Controls shall be exercised to assure that contaminants do not significantly

contribute to stress corrosion of stainless steel. Regulatory Guides 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel", and 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water Cooled Nuclear Power Plants" are relevant for CSS components, and for all CSS field welds, including welds at the CSS boundaries.

(A)7.12.6 Materials used for the containment and its internal structures shall withstand exposure to all post-accident conditions without causing deleterious or undesirable reactions, or significantly altering the recirculating water chemistry.

(A)7.12.7 If the containment spray system utilizes a common suction with the SIS from the RWT or containment sump, then the materials used in this system shall be austenitic stainless steel, type 316 or 304, or other compatible material subject to approval by C-E, and shall conform to Section III Class 2, ASME B&PV Code.

(A)7.13 PHYSICAL ARRANGEMENT

(A)7.13.1 To assure that containment spray system flow requirements are met, the maximum and minimum acceptable head losses for the piping and fittings are presented in CESSAR Appendix 6A, Table 7.13. The required NPSH for the CS pumps are presented in UFSAR section 6.2.2.2.

(A)7.13.2 Flow measurement devices are provided on the containment spray pump discharge lines. The piping runs upstream and downstream of the flow measurement devices shall meet the recommendations of "ASME Fluid Meters: Their Theory and Application, Parts 1 and 2".

(A)7.13.3 For each spray train, the top of the piping junction between the RWT discharge and the containment sump must be located at a minimum of 16 feet below the minimum containment sump water level during recirculation. If containment pressure could be sub-atmospheric by values greater than 3 psig, this must be accommodated for by increasing the distance of the piping junction top below the minimum containment sump water

level during recirculation by 2.31 feet for each additional psig.

(A)7.13.4 Frictional losses in the CSS pump suction piping between the containment sump and the junction with the RWT shall not exceed 7 feet, unless the elevation of the top of this junction is lowered an additional foot for each additional foot of head loss.

(A)7.13.5 The CSS pumps shall be located in the auxiliary building as close as practicable to the containment structure.

(A)7.13.5.1 The elevation of these pumps shall be low enough such that adequate NPSH is available during the recirculation mode when the pumps take suction from the containment sump.

(A)7.13.5.2 The available NPSH shall be calculated at the pump impeller eye.

(A)7.13.5.3 The calculation of NPSH shall consider concurrent high pressure safety injection, low pressure safety injection and containment spray pump operation. Table 6.3.1.3-2 provides HPSI and LPSI pump head loss requirements. The

corresponding NPSH requirements are presented in UFSAR table 6.3.2-1. CS pump NPSH requirements are identified in UFSAR section 6.2.2.2. No credit shall be taken for sub-cooled water in the sump.

(A)7.13.5.4 Credit shall not be taken for water that could be trapped above the containment floor.

(A)7.13.6 In the event of a limited leakage passive failure in one CSS train during recirculation, personnel access to the intact train shall be possible.

(A)7.13.7 The two CSS check valves in each of the spray header lines shall be located as close as practicable to the containment penetration:

a. Allowance shall be made for valve accessibility and maintenance.

b. The total water volume in the spray header piping shall be kept to a minimum so that the delay time for spray of borated water will be a minimum.

(A)7.13.8 Manually-operated valves shall be provided with locking provisions as shown on P&ID's CESSAR Section 6.3.

(A)7.13.9 Physical identification of safety-related CSS equipment and cabling shall be provided to allow recognition of safety status by plant personnel.

(A)7.13.10 In the routing of CSS Class 1E circuits and location of equipment served by these Class 1E circuits, consideration shall be given to their exposure to potential hazards. See 7.5 above.

(A)7.13.11 The CSS containment penetrations shall not be subject to loss of function from dynamic effects (e.g., missiles, pipe reactions, fluid reaction forces) resulting from failure of equipment or piping inside or outside the containment.

(A)7.13.12 Where required, bellows shall be provided between piping and the containment wall to prevent excessive forces on the piping.

(A)7.13.13 Each CS pump bypass flow line shall be capable of passing 150 gpm with its CS

pump operating at design operating conditions.

Note: This original interface requirement was prescribed to satisfy recirculation line allowable head loss and line sizing requirements at design operating conditions. This particular interface requirement does not establish the minimum (or maximum) recirculation flow rate. Minimum recirculation flow rates have been established by the CS pump vendor to provide adequate pump cooling at or near shut-off conditions and these requirements are documented in the respective Containment Spray pump vendor technical manual.

(A)7.13.14 The design of the CSS piping and spray headers shall consider the effects of water hammer. Fill and drain connections together with associated valves and instrumentation shall be provided if filling of the riser piping inside the containment is required to preclude the effects of water hammer.

The maximum spray header elevation above the RWT outlet nozzles shall not exceed 185 feet.

(A)7.13.15 The resistance of the RWT return lines shall be established so as to permit periodic testing of each spray pump at conditions as near to design (see Table 1) as practicable. For pre-operational testing, provisions should be made to provide full flow. For this test, the RWT return line or an alternate may be used.

(A)7.13.16 All CSS ASME, Section III components shall be arranged to provide adequate clearances to permit inservice inspection. The design of the arrangement should conform to the guidelines of Section XI of the ASME Code. Manually-operated valves which contain reactor coolant or other potentially radioactive liquids during normal plant operations, shall be provided with hand wheel extensions and shielding, to allow periodic actuation as per ASME Section XI, Subsection IWV. Appropriate ALARA practices shall be followed during the periodic pressure tests and nondestructive examinations of the containment spray system.

Access to system components not designed to ASME, Section III should be provided for periodic visual inspection for leak age, structural distress and corrosion.

(A)7.13.17 Protection shall be provided from internally generated flooding that could prevent performance of safety-related functions.

(A)7.14 RADIOLOGICAL WASTE COLLECTION

Containment spray system leakage to the safeguards room will normally drain to the room sump. Provisions shall be provided to accept the maximum leakage rates listed below:

a. CSS pump seals: 100 cc/hr/pump

b. Valves

backseat leakage:	10 cc/hr/inch seat diameter/valve
across the valve seat:	10 cc/hr/inch of nominal valve size/valve

All leakages shall be treated as radioactive waste with a low dissolved solids and organic content.

(A)7.15 OVERPRESSURE PROTECTION

Relief valves shall be provided for overpressure protection.

(A)7.16 RELATED SERVICES

(A)7.16.1 REFUELING WATER TANK

The RWT will have 100% of the capacity required to operate the CSS pumps at a flow of 4,400 gpm/pump for the required minimum injection period of 20 minutes in addition to the requirements of other systems.

The maximum particle size in the water exiting from the RWT shall be 0.09 inch in diameter in order to preclude flow blockage in engineered safety features components and piping and in the reactor.

The contents of both the RWT and piping associated with the CSS must be maintained at a minimum temperature of 60F to preclude possible boron precipitation.

(A)7.16.2 CONTAINMENT SPRAY SUMP

The containment sump shall be designed to comply with Regulatory Guide 1.82, "Sumps for Emergency Core Cooling and

Containment Spray Systems" requirements. Baffles and intake screens shall be installed to limit the maximum particle size entering the recirculation piping to 0.09 in diameter in order to prevent flow blockage in the engineered safety features components and piping and in the reactor. The sump intakes shall be designed so as to preclude the entrainment of air and/or steam into the sump suction lines. The pressure drop across the baffles and intake screens shall be sufficiently low to provide the NPSH required by the containment spray pumps. The post-LOCA sump pH shall be raised to a minimum of 7.0 within 4 hours post-accident. The maximum long-term pH shall not exceed 8.5.

(A)7.16.3 SHUTDOWN COOLING HEAT EXCHANGER

Cooling water shall be provided to each shutdown cooling heat exchanger to transfer heat from the sump fluid during the recirculation mode.

The cooling water supplied to each shutdown cooling heat exchanger shall be provided at a flowrate of 11,000 gpm.

Cooling water flow shall be established to the shutdown cooling heat exchanger prior to or simultaneously with the start of recirculation.

The cooling water temperature to the inlet of the heat exchangers shall be within the limits of 65-120F during a LOCA.

(A)7.16.4 FIRE PROTECTION

A fire protection system shall be provided to protect the containment spray system consistent with the requirements of GDC 3, and shall include, as a minimum, the following features:

a. Facilities for fire detection and alarming.

b. Facilities or methods to minimize the probability of fire and its associated effects.

c. Facilities for fire extinguishment.

d. Methods of fire prevention such as use of fire resistant and noncombustible materials whenever practical, and minimizing exposure

of combustible materials to fire hazards.

e. Assurance that fire protection systems do not adversely affect the functional and structural integrity of safety-related structures, systems, and components.

f. Care should be exercised to ensure fire protection systems are designed to assure that their rupture or inadvertent operation does not significantly impair the capability of safety-related structures, systems, and components.

(A)7.17 ENVIRONMENTAL

See Section 7.7 for environmental interfaces.

(A)7.18 MECHANICAL INTERACTION

(A)7.18.1 CSS components shall be properly supported such that pipe stresses and support reactions are within allowable limits, as defined in CESSAR Section 3.9.2. C-E provides the applicant with the loads at the support/structure

interface locations for components that C-E supplies, under normal, upset, emergency, faulted, and test conditions.

(A)7.18.2 CSS piping and fittings shall be Seismic Category I.

B. IODINE REMOVAL SYSTEM (Abandoned in Place)

6.5.2.8 CESSAR Interface Evaluations

The numbering of this interface section corresponds to that used for the presentation of interface requirements in CESSAR Appendices 6A and 6B. An R prefaces the numbering to denote that these are the responses to paragraph 6.5.2.7. Refer to appendix 6A, Question 6A.42, for additional discussion.

A. INTERFACE EVALUATION FOR CONTAINMENT SPRAY SYSTEM

(RA)7.1 POWER

(RA)7.1.1 The containment spray pumps, valves, and associated instrumentation can be powered from two power sources: preferred offsite power or the emergency diesel generators. For more details, see chapter 8.

(RA)7.1.2 Two independent power trains are provided, one for each train of containment spray pump, valves, and associated instrumentation.

(RA)7.1.3 See (RA)7.1.2.

(RA)7.1.4 The full containment spray flow can be attained within 90 seconds after a CSAS. Refer to section 1.9.

(RA)7.1.5 Instrument power supplies are provided as stated in Section 8.3.1.

(RA)7.2 PROTECTION FROM NATURAL PHENOMENA

Design provisions for maintaining functional capability of the safety—related systems during a flood, earthquake, tornado, or high winds as defined in GDC 2 are discussed in subsection 3.1.2.

The containment spray system is located within Seismic Category I structures. The protection of Seismic Category I structures against natural phenomena is presented in sections 3.3 and 3.4.

(RA)7.3.1 PROTECTION FROM PIPE FAILURE

The maximum leakage from a moderate energy pipe rupture of the containment spray system postulated during normal plant conditions is as defined by the methods of subsection 3.6.2.

Isolation valves (system and/or containment) used to contain leakage will be protected from the adverse effects of a

pipe failure which might preclude their operation when required.

(RA)7.3.2 No limited leakage passive failure or the effects thereof (such as flooding, spray impingement, steam, temperature, pressure, radiation, loss of NPSH, or loss of recirculation water inventory), in the CSS during the recirculation mode will preclude the availability of minimum acceptable recirculation capability. Minimum acceptable capability is defined as that which is provided by the operation of one train.

(RA)7.3.3 The containment spray system, both inside and outside containment, will be protected from the effects of pipe rupture whenever the spray system is required to mitigate the effect of the break.

(RA)7.3.4 The containment spray system will be protected from the effects of pipe whip whenever the spray system is required to mitigate the effect of the break.

(RA)7.4 <u>MISSILES</u>

Design provisions for protecting the CSS from missiles inside the containment are discussed in section 3.5.

Design provisions for protecting the CSS from missiles outside the containment are discussed in section 3.5.

Appropriate design procedures which ensure that the impact of any potential missile does not prevent the conduct or maintenance of a safe plant shutdown are discussed in section 3.5.

(RA)7.5 SEPARATION

(RA)7.5.1 Adequate physical separation is maintained between the redundant piping paths and containment penetrations of the CSS such that the CSS will meet its functional requirements even with the failure of a single active component during the injection mode, or with a single active failure or a limited leakage passive failure during the recirculation mode.

The protection of safety systems inside and outside containment is discussed in section 3.6.

(RA)7.5.2 The cabling that is associated with redundant channels of vital Class 1E circuits for the CSS is physically separated to preserve redundancy and prevent a single event from causing

multiple channel malfunctions or interactions between channels. Associated circuit cabling from redundant channels is either separated, provided with isolation devices, or analyzed and/or tested to demonstrate that no credible single failure could adversely affect redundant channels of Class 1E circuits.

(RA)7.5.3 In the routing of CSS Class 1E circuits and location of equipment served by these Class 1E circuits, consideration is given to their exposure to potential hazards such as postulated ruptures of piping, flammable material, flooding, and non-flame retardant wiring. Adequate separation or protective measures are provided.

(RA)7.5.4 Failure of non-safety grade systems does not compromise redundancy of the CSS.

(RA)7.6 <u>INDEPENDENCE</u>

(RA)7.6.1 Each CSS train is provided with an independent environmental control system.

(RA)7.6.2 Power connections to each CSS train are from independent electrical buses.

(RA)7.6.3 Instrumentation in each train of CSS is powered by an independent power source.

(RA)7.6.4 For mechanical independence, see (RA)7.3, (RA)7.4, and (RA)7.5.

(RA)7.7 THERMAL LIMITATIONS

Each CSS train is provided with an independent environmental control system, such that the safety-related equipment in each train operates within the environmental design limits specified in Section 3.11.

(RA)7.8 MONITORING

Provisions are made for detection, containment, and isolation of the maximum expected leakage from a moderate energy pipe rupture in each train.

Redundant pressure, temperature, and flow instrumentation as described in Table 1.8-1 is available to the operator in the control room to assist in assessing post-LOCA conditions.

(RA)7.9 OPERATIONAL AND CONTROLS

See (RA)7.1.

(RA)7.10 INSPECTION AND TESTING

For inspection and testing, see the Technical Specifications.

In addition, prior to initial plant startup, the CSS system will be tested in accordance with section 14.2.

(RA)7.11 CHEMISTRY AND SAMPLING

(RA)7.11.1 The CSS is designed for the following fluid conditions:

Basic fluid:	Water
with H_3BO_3:	3.5 w/o

Trisodium phosphate controlled pH of 7 to 8.5 maximum.

(RA)7.11.2 SAMPLING

(RA)7.11.2.1 The nuclear sampling system (NSS) is designed to provide a means of obtaining remote liquid samples from the CSS for chemical and radiochemical laboratory analysis.

(RA)7.11.2.2 The sample lines in contact with the reactor coolant are fabricated of austenitic stainless steel.

(RA)7.11.2.3 The fluid velocity in the sample lines is designed to obtain representative samples. The purge flowrate is high enough to remove crud from lines.

(RA)7.11.2.4 Sample taps are located on vertical runs of pipe whenever possible. Where this cannot

be done, the samples are taken from the top of horizontal pipe runs.

(RA)7.12 MATERIALS

(RA)7.12.1 Containment spray system piping and fittings are Seismic Category I.

(RA)7.12.2 Design and fabrication of the CSS piping and fittings conform to ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Class 2, as identified in Section 6.3.1.

(RA)7.12.3 Materials in contact with the system fluid are fabricated of austenitic stainless steel of type 316, type 304, or C-E approved alternate. Selection of the type of stainless steel is based on compatibility with design pressure and temperature considerations and with the chemistry of the fluid.

Valve packings, gaskets, and valve diaphragm materials are also compatible with the chemistry of the fluid and the radiation dose at that location.

(RA)7.12.4 Care is taken to prevent sensitization and to control the delta ferrite content of (1) the welds which join any system fabricated of austenitic stainless steel to the CSS, and (2) the field welds on the CSS. The

guidance of Regulatory Guides 1.44, Control of the Use of Sensitized Stainless Steel, and 1.31, Control of Ferrite Content in Stainless Steel Weld Metal, is relevant at these weld locations (refer to section 1.8).

(RA)7.12.5 Controls are exercised to assure that contaminants do not significantly contribute to stress corrosion of stainless steel. Regulatory Guides 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel, and 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water Cooled Nuclear Power Plants, are relevant for CSS components and for all CSS field welds, including welds at the CSS boundaries (refer to section 1.8).

(RA)7.12.6 Materials used for the containment and its internal structures can withstand exposure to all post-accident conditions without causing deleterious or undesirable reactions, or significantly altering the recirculating water chemistry.

(RA)7.12.7 The material of common suction piping with the SIS from the RWT and containment recirculation sump is austenitic stainless

steel type 304 and conforms to ASME Section III, Class 2, requirements.

(RA)7.13 PHYSICAL ARRANGEMENT

It is noted that some of the Interface Requirements described in this section were provided for original piping and component design/selection to ensure that the as-built system would support required design functions. For the operating plant, the adequacy of the design to support required design functions is maintained and demonstrated by current design basis calculations and surveillance tests that evaluate the as-built systems, and the values specified by the original interface requirements are not longer relevant. The specific interface requirements in this section for which this applies and that provide historical information are: (RA)7.13.1 relative to piping head losses, (RA)7.13.14 relative to maximum spray header elevation.

(RA)7.13.1 The CSS is designed to meet the maximum and minimum piping head losses as presented in CESSAR Appendix 6A, Table 7.13. The system is also designed to meet the NPSH

requirements indicated in UFSAR section 6.2.2.2.

It is noted that the piping head losses as presented in CESSAR Appendix 6A, Table 7.13 reflect the original CE System 80 values. These requirements were subsequently changed by CE for PVNGS. The CSS was originally designed to meet the PVNGS-specific head loss of 505 ft. maximum at a pump flow rate of 3,890 gpm. For the as-built system, the total system losses provide the required CS flow to support design functions.

(RA)7.13.2 Flow measurement devices (SIA-FT338, SIB-FT348) are provided on the containment spray pumps discharge lines. The piping runs upstream and downstream of the flow measurement devices meet the recommendations of "ASME Fluid Meters: Their Theory and Application, Parts 1 and 2."

(RA)7.13.3 For each spray train, the top of the piping junction between the RWT discharge and the containment sump is located at a minimum of 38 feet below the minimum containment sump water level during recirculation. To preclude the possibility of drawing air

from the RWT into the safeguards pump suction during recirculation, timely operator action is required to isolate the RWT after the RAS has occurred.

(RA)7.13.4 Frictional losses in the CSS pump suction piping between the containment sump and the junction with the RWT do not exceed 10 feet, which exceeds the requirement by 3 feet. The junction point is, however, located 22 feet lower than C-E required minimum of 16 feet; the head loss is thus acceptable. To preclude the possibility of drawing air from the RWT into the safeguards pump suction during recirculation, timely operator action is required to isolate the RWT after the RAS has occurred.

It is noted that the frictional losses in the CSS pump suction between the containment sump and the junction with the RWT do not exceed 5 feet for the as-built design.

(RA)7.13.5 The CSS pumps are located in the auxiliary building as close as practicable to the containment structure.

(RA)7.13.5.1 The elevation of these pumps is low enough such that adequate NPSH is available during

the recirculation mode when the pumps take suction from the containment sump.

(R)7.13.5.2 The available NPSH is calculated at the pump impeller eye.

(RA)7.13.5.3 The calculation of NPSH considers concurrent high-pressure safety injection, low-pressure safety injection, and containment spray pump operation. No credit is taken for sub-cooled water in the sump. The calculated NPSH is greater than the required NPSH presented in section 6.2.2.2.

(RA)7.13.5.4 Credit is not taken for water that could be trapped above the containment floor.

(RA)7.13.6 In the event of a limited leakage passive failure in one CSS train during recirculation, personnel access to the intact train is not precluded by flooding.

(RA)7.13.7 The two CSS check valves in each of the spray header lines are located as close as practicable to the containment penetration:

A. Allowance is made for valve accessibility and maintenance.

B. To minimize delay time for spray initiation, total water volume in the spray header piping is kept to a

minimum and the spray headers are maintained full of water up to 13-foot indicated elevation. Fresh water may be used instead of borated water to fill portions of the spray headers inside containment. Refer to section 1.9.

(RA)7.13.8 Manually-operated valves are provided with locking provisions as shown in Section 6.3.

(RA)7.13.9 Physical identification of safety-related CSS equipment and cabling is provided to allow recognition of safety status by plant personnel.

(RA)7.13.10 In the routing of CSS Class 1E circuits and location of equipment served by these Class 1E circuits, consideration is given to their exposure to potential hazards. See (RA)7.5.

(RA)7.13.11 The CSS containment penetrations will not be subject to loss of function from dynamic effects (e.g., missiles, pipe reactions, fluid reaction forces) resulting from failure of equipment or piping inside or outside the containment.

(RA)7.13.12 Where required, bellows will be provided between piping and the containment wall to prevent excessive forces on the piping.

(RA)7.13.13 Each CS pump bypass flow line is capable of passing 150 gallons per minute with its CS pump operating at design operating conditions.

Note: This original interface requirement was prescribed to satisfy recirculation line allowable head loss and line sizing requirements at design operating conditions. This particular interface requirement does not establish the minimum (or maximum) recirculation flow rate. Minimum recirculation flow rates have been established by the CS pump vendor to provide adequate pump cooling at or near shut-off conditions and these requirements are documented in the respective Containment Spray pump vendor technical manual.

(RA)7.13.14 The design of the CSS piping and spray headers considers the effects of water hammer. Hydraulic Systems Transient Analysis (HSTA), Bechtel Standard Computer Program NE820, is used to develop time history forcing function input for water

hammer stress analysis. HSTA is a generalized finite difference code based on the characteristics method for analyzing water hammer effects in the complex piping systems of a power plant. HSTA predictions of pressure and velocity are in good agreement with other experimental and theoretical/numerical data for similar situations published in the literature.

The maximum spray header elevation above the RWT outlet nozzles does not exceed 192 feet. Refer to section 1.9.

It is noted that this maximum spray header elevation discussion is relative to the original design. For the as-built system, the total system losses provide the required CS spray flow to support design functions.

(RA)7.13.15 The resistance of the RWT return lines is established so as to permit periodic testing of each spray pump at conditions as near to design as practicable (the pumps will be flow-tested at approximately half-full flow).

(RA)7.13.16 All CSS ASME Section III components are arranged to provide adequate clearances to permit inservice inspection. The design of

the arrangement conforms to the guidelines of Section XI of the ASME Code. Manually operated valves that contain reactor coolant or other potentially radioactive liquids during normal plant operations, are provided with hand wheel extensions and shielding to allow periodic actuation as per ASME Section XI, Subsection IWV. Appropriate ALARA practices shall be followed during the periodic pressure tests and nondestructive examinations of the containment spray system.

Access to system components not designed to ASME Section III is provided for periodic visual inspection for leakage, structural distress, and corrosion.

(RA)7.13.17 Protection is provided from internally generated flooding that could prevent performance of safety-related functions. Also refer to section 3.6 and subsection 9.3.3.

(RA)7.14 RADIOLOGICAL WASTE COLLECTION

Containment spray system leakage to the engineered safety features room will normally drain to the room sump. Provisions are provided to accept the maximum leakage rates listed below:

a. CSS pump seals: 100 cc/h/pump

b. Valves

backseat leakage:	10 cc/h/in. seat diameter/valve
across the valve seat:	10 cc/h/in. of nominal valve size/valve

Leakages will be treated as radioactive waste with a low dissolved solids and organic content.

(RA)7.15 OVERPRESSURE PROTECTION

Relief valves are provided for overpressure protection.

(RA)7.16 RELATED SERVICES

(RA)7.16.1 Refueling Water Tank

The RWT has been sized to ensure that a sufficient volume of water will be available to sustain ESF pump flow, including the CSS pumps at run-out flow rates (5200 gpm), for the duration of the injection period as assumed in the safety analyses. Sufficient inventory is maintained to satisfy the requirements of other systems.

The RWT has been sized to also ensure that a sufficient volume of water will be

available to sustain ESF pump flow during the transfer from ECCS injection to the ECCS recirculation phase of operation. The transfer volume was sized assuming single failure of a LPSI pump to trip on a RAS and a conservative CS pump flow rate. To preclude air entrainment, timely operator action to isolate the RWT after a RAS ensures the tank is isolated before the vortex breaker is uncovered.

The maximum particle size in the water exiting from the RWT is 0.09 inch in diameter in order to preclude flow blockage in engineered safety features components and piping and in the reactor. In addition, vortexing tendencies within the tank are precluded by a suction cage inside the tank, similar in design to the cage installed in the containment emergency sump. The minimum required RWT level and volume are the useful level and volume above the volume that is unusable due to vortex considerations.

The contents of both the RWT and piping associated with the CSS is maintained at or above a minimum temperature of 60F to preclude possible boron precipitation.

The RWT is provided with two vent lines in parallel: One is an 8-inch vent at the peak of the RWT roof that is connected to a 10-inch header. The other is a 16-inch vent line connected to the manway hatch on the roof of the RWT. Both vent lines are routed to the Fuel Building normal exhaust duct system. The vent pipes are routed without piping pockets that could cause the accumulation of moisture.

(RA)7.16.2 Containment Spray Sump

The containment sump and screen are designed to comply with Regulatory Guide 1.82, Sumps for Emergency Core Cooling and Containment Spray Systems, as described in Section 1.8. The original sumps' hydraulic performance was tested on a one-to-one model in a hydraulic laboratory. As a result of the tests, a special vortex breaking cage was installed to the safety injection sump suction line inside each sump. The tests showed that the hydraulic performance of the sump is satisfactory with the vortex breaking cage installed. Further information on the model study is contained in the transcript to the containment systems independent design

review submitted under PVNGS transmittal letter ANPP-18147, dated June 4, 1981. The vortex breakers remain installed at the ECCS pump suction piping inside the sumps with the new strainers installed by DMWO 2822654. In addition, testing and evaluation has determined that the minimum submergence above the top of the new strainer cartridges (non-perforated) is sufficient and vortexing is not a concern. Intake screening elements are installed to limit the maximum particle size entering the recirculation piping in order to prevent flow blockage in the engineered safety features components and piping and in the reactor. The sump intakes are designed so as to preclude the entrainment of air and/or steam into the sump suction lines. The pressure drop across the intake screening elements is sufficiently low to provide the NPSH required by the containment spray pumps. The post-LOCA sump pH will be raised to a minimum of 7.0 within 4 hours post-accident. The maximum long-term pH will not exceed 8.5.

Containment level instrumentation is provided to ensure there is sufficient NPSH for the safety injection pumps and to

verify that essential equipment is not flooded. The range provided is from approximately 6 inches above the sumps (approximate elevation 80.5 feet) to approximately 18 inches above the maximum flood level (approximate elevation 92.5 feet). This range is above the minimum level for NPSH requirements (elevation 84.5 feet). A total range of 12 feet is provided in the control room. This safety grade instrumentation is redundant, physically separated, environmentally qualified to post-LOCA environment, seismically qualified to function during and following an SSE and powered from redundant Class 1E sources.

(RA)7.16.3 Shutdown Cooling Heat Exchanger Cooling water will be provided to each shutdown cooling heat exchanger to transfer heat from the sump fluid during the recirculation mode.

The minimum required flow of cooling water supplied to each shut-down cooling heat exchanger is a flowrate of 12,600 gallons per minute.

Cooling water flow will be established to the shutdown cooling heat exchanger prior

to or simultaneously with the start of recirculation.

The cooling water temperature to the inlet of the heat exchangers will not exceed 135°F.

(RA)7.16.4 Fire Protection

The fire protection system provided to protect the CSS is discussed in subsection 9.5.1.

(RA)7.17 ENVIRONMENTAL

For environmental interfaces, see (RA)7.7.

(RA)7.18 MECHANICAL INTERACTION

(RA)7.18.1 Containment spray system components are properly supported such that pipe stresses and support reactions are within allowable limits, as defined in CESSAR Section 3.9.2.

(RA)7.18.2 Containment spray system piping and fittings are Seismic Category I.

B. INTERFACE EVALUATION FOR IODINE REMOVAL SYSTEM (Abandoned in place)

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

6.5.3.1 Primary Containment

The primary containment structure consists of a reinforced concrete cylinder and hemispherical dome, lined with welded

¼ inch steel plates, forming a continuous, leaktight pressure boundary. Details of the containment structural design are discussed in section 3.8. Layout drawings of the containment structure and the hydrogen purge system are given in the general arrangement drawings of section 1.2 (hydrogen purge equipment is located in the auxiliary building at elevation 100 feet).

The containment walls, liner plate, mechanical penetrations, isolation valves, hatches, and locks function to limit release of radioactive materials, subsequent to postulated accidents, such that the resulting offsite doses are less than the guideline values of 10CFR100. Containment parameters affecting fission product release accident analyses are given in table 6.5-3.

Long-term containment pressure responses to the design basis accidents are discussed in subsection 6.2.1. Relative to this time period, the CSS is operated to reduce iodine concentrations and containment atmospheric temperature and pressure from the time commencing with system initiation, at approximately 90 seconds, until containment pressure has returned to normal.

For the purpose of post-LOCA dose calculations discussed in chapter 15, spray iodine removal, credit is taken only during the 0 to 2 hour time frame.

Table 6.5-3

PRIMARY CONTAINMENT OPERATION

FOLLOWING A DESIGN BASIS ACCIDENT

General		
Type of Structure	Steel-lined, reinforced cylinder and base with hemispherical dome	
Internal fission product removal systems	Redundant containment water spray systems	
Free volume of containment	2.62×10^6 ft^3	
Hydrogen purge system operation assumptions	See paragraph 6.2.5.3	
Time Dependent Parameters	Anticipated	Conservative
Containment leakage rate		
0 to 24 hours	<0.1 vol%/d	0.1 vol%/d
1 to 30 days	<0.05 vol%/d	0.05 vol %/d
Iodine spray removal coefficient (spray λ, elemental)	See paragraph 6.2.5.3	

The containment power access purge system may be operated for personnel access to the containment when the reactor is at power. Even though the purge frequency is a small percentage of the total annual operating period, operation of the power access purge system at the time of occurrence of a design basis accident is assumed in the analyses of radiological releases. The power access purge will terminate and the containment will isolate within 12 seconds after initiation of large break LOCA.

Redundant, safety-related hydrogen recombiners are provided for the containment atmosphere as the primary means of controlling post-accident hydrogen concentrations. A hydrogen purge system is provided for backup hydrogen control.

6.5.3.2 Secondary Containments

This paragraph is not applicable to PVNGS.

6.5.4 ICE CONDENSER AS A FISSION PRODUCT CLEANUP SYSTEM

This subsection is not applicable to PVNGS.

6.6 INSERVICE INSPECTION OF CLASS 2 AND 3 COMPONENTS

Design of and provision for access to ASME Code, Class 2 and 3, components is in accordance with the requirements of the 1974 Edition of ASME Section XI through the Summer 1975 Addenda. The preservice inspection will be conducted in accordance with 10CFR50.55a(g). The inservice inspection (ISI) program will be updated to a more recent code during each inspection interval as determined to be practical in accordance with the procedures of 10CFR50.55a(g)(4).

6.6.1 AUGMENTED INSERVICE INSPECTION TO PROTECT AGAINST POSTULATED PIPING FAILURES.

6.6.1.1 The EPRI Risk-Informed Inservice Inspection (RI-ISI) Methodology to Break Exclusion Region (BER) Program is being implemented in all three units. For those portions of systems located between the containment penetration and the main steam support structure wall that are identified in paragraph 3.6.2.1.1.2, listing C, an augmented inservice inspection will be performed. This augmented program will include the piping welds selected and examined using the methodology defined by EPRI Report 1006937 “Extension of the EPRI Risk-Informed Inservice Inspection (RI-ISI) Methodology to Break Exclusion Region (BER) Programs”. The specific areas subject to examination, the extent, the method and the frequency of examinations will be provided on a schedule consistent with the ISI program.

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APPENDIX 6A

RESPONSES TO NRC REQUESTS FOR INFORMATION

CONTENTS

APPENDIX 6A

FIGURES

APPENDIX 6A

<u>QUESTION 6A.1</u> (NRC comment on paragraph 6.2.2.2)

(6/18/80) (6.2.2.2)

Page 6.2.2-4 missing

RESPONSE: A spot check of 60 complete FSARs revealed that page 6.2.2-4 is present as the back side of page 6.2.2-3 in all cases. It is concluded that reviewer's copy was an inadvertent result of a printing error. Pages 6.2.2-3 and 6.2.2-4 have been transmitted to the PVNGS Licensing Project Manager.

<u>QUESTION 6A.2</u> (NRC comment on subsection 6.3.4) (6/18/80) (6.3.4)

Not included

RESPONSE: The response is given in amended subsection 6.3.4.

<u>QUESTION 6A.3</u> (NRC comment on subsection 6.3.5) (6/18/80) (6.3.5)

Not included

RESPONSE: The response is given in amended subsection 6.3.5.

<u>QUESTION 6A.4</u> (NRC Question 281.1) (6.5.2)

In the FSAR you indicated that, following an accident which requires operation of the containment spray system, hydrazine will be used in the spray water for short-term injection and trisodium phosphate will be added to the sump water for long-term recirculation. In view of the fact that trisodium

phosphate has a tendency to cake, it may not be readily dissolved in the sump water following the accident. Provide design basis information and a proposed surveillance program to ensure that, by commencement of the recirculation of sump water, sufficient trisodium phosphate will be dissolved in the sump water to achieve a pH value of at least 8.5.

RESPONSE: Refer to paragraph 6.1.1.2 for a discussion on trisodium phosphate dodecahydrate.

QUESTION 6A.5 (NRC Question 281.4) (6.2)

Indicate the total amount of protective coatings, paints, and organic materials (including uncovered cable insulation) used inside the containment that do not meet ANSI N101.2 (1972) and Regulatory Guide 1.54.

RESPONSE: Refer to section 1.8 for a discussion on conformance to Regulatory Guide 1.54.

QUESTION 6A.6 (NRC Question 460.3) (1.8 and 6.5)

In section 1.8 of the FSAR which deals with "Conformance to NRC Regulatory Guides", reference is made to Regulatory Guide 1.52, Revision 0 (June 1973) and Revision 1 (July 1976) versions. Since Regulatory Guide 1.52, Revision 2 (March 1978), "Design, Testing and Maintenance Criteria for Post-Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants" has replaced the earlier versions, comparison should be made of the design features and fission product removal capability of each ESF filter system to applicable positions detailed in

Regulatory Guide 1.52, Revision 2. For each item for which an exception is taken, the acceptability of the proposed design should be justified. For example, if, as stated under section 1.8, demisters are not provided for the fuel building ESF ventilation system, explain how relative humidity will be controlled so as not to exceed 70%. Likewise, if, as stated under section 1.8, 1E alarms or recorders for pressure drops or flowrates for the ESF ventilation systems are not provided, describe the form in which this information is available in the control room, e.g., digital readout of pressure drop and/or flow rate, type of alarm, such as high or low, visual or audible, etc.

RESPONSE: See section 1.8, response to Regulatory Guide 1.52.

QUESTION 6A.7 (NRC Question 450.3) (6.4)

In your description of the control room's protective features, provide the time interval between the time the chlorine concentration exceeds 5 ppm at the isolation dampers and the time the dampers are completely closed.

RESPONSE: Refer to the response to NUREG-0737, Section 18.III.D.3.4.(2).(j).

QUESTION 6A.8 (NRC Question 450.4) (6.4)

List the areas, equipment, and materials to which the control room operator has access during emergency operation; i.e., during the time the control room is serviced by the emergency ventilation system.

RESPONSE: The response is given in amended paragraph 6.4.2.1.

QUESTION 6A.9 (NRC Question 450.5) (6.4)

In your analysis of toxic gas protection for control room personnel, provide the number and type of respiratory devices, the type of operator training for respiratory use, the estimated time for donning or deploying the equipment, the length of time the equipment can be used, and the equipment testing and maintenance procedures.

RESPONSE: The response is given in amended paragraph 6.4.2.2.2, listing K.

QUESTION 6A.10 (NRC Question 450.6) (6.5.2)

On page 6.5-27 of the PVNGS FSAR, it is stated that the post-LOC sump pH shall be raised to a minimum of 7.0. It is not clear that the pH, by itself, is high enough to prevent iodine evolu-tion from the sump. Explain how evolution of iodine from the post-LOCA sump will be prevented, or kept to a very low level.

RESPONSE: See the responses to Questions 6A.4, 6A.28 and 6A.30.

QUESTION 6A.11 (NRC Question 450.7) (6.5.2)

Please provide spray nozzle performance data (spray droplet pattern, drop size distribution) for Spraco 17071417 and 17651308 nozzles.

RESPONSE: Spray nozzle performance data are given in figures 6A-1, 6A-2, and 6A-3.

<u>QUESTION 6A.12</u> (NRC Question 450.8) (6.5.2)

The discussion on pages 6.5-8 and 6.5-9 implies that 100% of the containment net free volume (above 100-foot elevation) is sprayed. State whether this implication is true and provide justification for the spray coverages assumed in your analysis.

RESPONSE: This statement is true as auxiliary sprays are located under concrete floors at the 120-foot and 140-foot elevations.

<u>QUESTION 6A.13</u> (NRC Question 480.1) (6.2.1.1)

State whether containment leakage was assumed as part of the containment peak pressure calculations. If so, provide and justify the leak rate used.

RESPONSE: The response is given in amended paragraph 6.2.1.1.1.1.

<u>QUESTION 6A.14</u> (NRC Question 480.2) (6.2.1.1)

Instrumentation capable of operating in the post-accident environment will be required to monitor containment atmosphere pressure and temperature and sump water temperature. Provide additional information on how this requirement will be met including the instrument range, accuracy, and response times and compliance with Regulatory Guide 1.97. (Note: See also NUREG-0737, Clarification of TMI Action Plan Requirements, II.F.1, Attachment 4, Containment Pressure Monitor.)

RESPONSE: The response was provided in PVNGS Balance of Plant Instrumentation and Control Systems Review Board, Section 2.C.3.B, Exhibits 2C3-8 and 2C3-15.

QUESTION 6A.15 (NRC Question 480.3) (6.2.1.2)

The following pertain to subcompartment nodalization:

a. It is stated in section 6.2.1.2 that the steam generator subcompartment nodalization is based on nodalization sensitivity studies of other plants. Justify this basis by specifically describing the steam generator compartments of these other plants and their dimensional similarities to the Palo Verde plant. Also provide a discussion of the results of the sensitivity studies showing that increasing the number of nodes chosen does not affect the analysis results.

b. The number of nodes used for the reactor cavity (RC) and steam generator (SG) subcompartment analyses is unclear. The FSAR text indicates 18 nodes were used for the RC analysis (table 6.2.1-19) and 54 nodes for the SG analysis, whereas the graphs of resultant pressures (figures 6.2.1-17 and 6.2.1-18) indicated 37 nodes for the RC analysis and 55 nodes for the SG analysis. Explain or correct this apparent discrepancy.

RESPONSE:

a. The response is provided in paragraph 6.2.1.2.3.2, listing B and table 6.2.1-20.

b. The response is provided in paragraph 6.2.1.2.3.2, listing B and table 6.2.1-19.

QUESTION 6A.16 (NRC Question 480.4) (6.2.1.2)

Peak calculated differential pressures do not appear in tables 6.2.1-14 and 6.2.1-15 as referenced on FSAR pages 6.2.1-94 and 6.2.1-95. Revise these tables or create new tables to include these results for all subcompartment analyses.

RESPONSE: The response is provided in paragraph 6.2.1.2.3.2, listings A and B, and tables 6.2.1-13, 6.2.1-15, and 6.2.1-17.

QUESTION 6A.17 (NRC Question 480.5) (6.2.1.2)

Justify the selected subcompartment analysis initial conditions of 14.4 psia pressure and 25% relative humidity. The initial atmospheric conditions within a subcompartment should be selected to maximize the resultant differential pressure (Reference SRP Section 6.2.1.2 II.1).

RESPONSE: Refer to table 6.2.1-13.

QUESTION 6A.18 (NRC Question 480.6) (6.2.1.3)

FSAR paragraph 6.2.1.3 simply states, "Refer to CESSAR Section 6.2.1.3." But CESSAR Section 6.2.1.3 states, "The long-term energy release, being containment design dependent, is detailed in each applicant's SAR." Therefore, provide long-term mass and energy release data for the design basis LOCA. Tabulate the data showing mass release rate in lbm/hr and energy release rate in Btu/hr. Extend the table through 10^6 seconds after shutdown. Ensure that the long-term energy

release rate accounts for the dominant mechanisms, which include decay heat and the cooling of all NSSS metal.

RESPONSE: The response is provided in amended paragraph 6.2.1.3.

<u>QUESTION 6A.19</u> (NRC Question 480.7) (6.2.4)

Valves SG-UV134 (penetration No. 2) and SG-UV138 (penetration No. 3) are listed in FSAR tables 6.2.4-1 and 6.2.4-2 as being <u>not</u> essential and yet they are automatically opened by an auxiliary feedwater actuation signal (AFAS). Either correct table 6.2.4-1 to show these valves are essential or provide justification why they do not meet the containment isolation requirements for nonessential systems.

RESPONSE: The response is provided in table 6.2.4-1.

<u>QUESTION 6A.20</u> (NRC Question 480.8) (6.2.4)

Table 6.2.4-2 does not differentiate between valves which are closed and "locked" closed. Since this distinction is important in evaluating the acceptability of the containment isolation design, modify table 6.2.4-2 to indicate when valves will be "locked" closed in accordance with the SRP Section 6.2.4.II.6.f definition of a sealed closed barrier. Based on the FSAR P&IDs this should include DW-V061, DW-V062 (penetration No. 6); SI-UV654, SI-UV656, SI-HV690 (penetration No. 26); SI-UV653, SI-UV655, SI-HV691 (penetration No. 27); SJ-V463 (penetration No. 28); CH-V854 (penetration No. 41); PC-V071, PC-V070 (penetration No. 50); PC-V075, PC-V076

(penetration No. 51); IA-V072 (penetration No. 59); SI-HV331 (penetration No. 67); and SI-HV321 (penetration No. 77).

RESPONSE: The response is provided in table 6.2.4-2.

QUESTION 6A.21 (NRC Question 480.9) (6.2.4)

Provide in table 6.2.4-1 the distance from containment for valves HC-UV045 (penetration No. 25A) and HC-UV046 (penetration No. 25B).

RESPONSE: The response is provided in table 6.2.4-1.

QUESTION 6A.22 (NRC Question 480.10) (6.2.4)

Confirm that penetration Nos. 5, 32B, 32C, 54B, 54C, 55B, 55C, 64, 65, 66, 68, 69, 70, 71, 73, 74, 80, and 81 are not used.

RESPONSE: The response is provided in amended tables 6.2.4-1 and 6.2.4-2.

QUESTION 6A.23 (NRC Question 480.11) (6.2.4)

Add valves SG-HV200 and SG-HV201 (penetration No. 11 and No. 12) to tables 6.2.4-1 and 6.2.4-2.

RESPONSE: The response is provided in tables 6.2.4-1 and 6.2.4-2.

QUESTION 6A.24 (NRC Question 480.12) (6.2.4)

Explain why valves HP-HV007B and HP-HV008B (penetration No. 35 and No. 36, respectively) will not be automatically closed by a containment isolation signal (see also open item No. 24 from May 21, 1981 IDR transcript).

RESPONSE: The response is given in amended paragraph 6.2.4.3.

QUESTION 6A.25 (NRC Question 480.13) (6.2.4)

Provide an analysis of the effect of the containment purge system; i.e., an open purge line, on the minimum containment pressure analysis for performance capability studies on the ECCS (reference CSB BTP 6-4 B.5.c). (Note: The CESSAR Section 6.2.1.5 analysis referenced from FSAR paragraph 6.2.1.5 assumes complete containment isolation.)

RESPONSE: The response is given in amended paragraph 6.2.1.5.

QUESTION 6A.26 (NRC Question 480.14) (6.2.5)

Provide the design justification for not including a fan or blower in the containment hydrogen purge exhaust unit to ensure a purge rate of 50 scfm (see also open item No. 28 from the May 21, 1981 IDR transcript).

RESPONSE: The response is given in amended paragraph 6.2.5.2.2.3.

QUESTION 6A.27 (NRC Question 480.15) (6.2.5)

Describe the guidelines that will be provided the operators following a LOCA or MSLB in which the CSS is actuated that will tell them when they can terminate and/or periodically shut down the CSS. The concern is that the CSS is needed to ensure adequate containment mixing to prevent stratification or pocketing of hydrogen.

RESPONSE: The response is given in amended paragraph 6.3.1.4 listing I.

QUESTION 6A.28 (NRC Question 450.12) (6.5.2)

The NRC staff evaluates the long-term effectiveness of containment spray systems by determining the long-term decontamination factor, which is based on possible iodine evolution from the containment sump after the injection phase of containment spray. To make this determination, the long-term (post-injection) pH range of the sump water is needed. The range of 7.0 to 8.5 for sump pH stated in the PVNGS FSAR is not sufficiently detailed for our evaluation. State the amount of TSP used for sump chemistry control, in kg or moles, and the location of the TSP baskets. Calculate the post-injection sump pH. Preliminary staff calculations indicate that the long-term pH should be at least 8.0 to meet 10CFR100 dose guidelines for the DBA LOCA.

RESPONSE: The response will be provided on the CESSAR docket. See CESSAR FSAR responses to NRC Questions (NRC Question 450.3). Also refer to the response to Question 6A.30 (NRC Question 281.5).

QUESTION 6A.29 (NRC Question 450.18) (6.4)

Provide the following information required for the control room habitability evaluation:

(1) control room shielding including radiation streaming from penetrations, doors, ducts, stairways, etc.

(2) self-contained breathing apparatus availability (number)

(3) bottled air supply (hours supply)

(4) control room personnel capacity (normal and emergency)

(5) potassium iodide drug supply

(6) control room emergency filtration system including the capability to maintain the control room pressurization at 1/8 inch water gauge, verification of isolation by test signals and damper closure times, and filter testing requirements.

RESPONSE:

1) The required information is provided in paragraphs 6.4.2.5 and 12.3.2.2.7.

2) The required information is provided in listing K of paragraph 6.4.2.2.2.

3) The required information is provided in listing K of paragraph 6.4.2.2.2.

4) The required information is provided in subsection 6.4.1 and paragraph 6.4.4.3, for the designed personnel capacity of the control room in emergencies. Refer to the PVNGS security plan for additional details of control room access restrictions.

5) The response is given in amended paragraph 6.4.4.3.

6) The required information is provided in paragraphs 6.4.2.2, 6.4.2.3, 6.4.2.4, 6.4.3.2, and 6.4.4.3 and in subsection 6.4.5.

QUESTION 6A.30 (NRC Question 281.5) (6.1.1,6.5.2)

In your response to our request for information 281.1, you stated that no surveillance of the trisodium phosphate (TSP) baskets will be conducted other than to assure that the baskets are full. It is our position, as stated in CE-PWR Standard Technical Specification (3/4.5.2), that this ECCS subsystem shall be demonstrated operable at least once per 18 months by (1) verifying that a minimum total volume of solid granular TSP dodecahydrate is contained within the TSP baskets, and (2) verifying that when a representative sample of TSP from a TSP basket is submerged, without agitation, in borated water from the refueling water tank, the pH of the mixed solution is raised to an acceptable level within 4 hours. Indicate that these surveillance requirements will be met.

Also, provide the minimum total volume of TSP to be stored in the TSP basket and state the basis for the stored quantity.

RESPONSE: The response is given in amended paragraph 6.1.1.2.

QUESTION 6A.31 (NRC Question 281.6) (6.1.2)

In table 6.1-4 of the FSAR, you indicate that there are 259,560 pounds of cable insulation inside the containment building. Indicate what fraction of this weight consists of organic materials. We also need the following additional information

for estimating the generation rate of combustible gases from organic materials in cable insulation under DBA conditions: (1) The quantity (weight and volume) of uncovered cable and cable is closed metal conduit or closed cable trays. We will give credit for beta radiation shielding for that portion of cable that is indicated to be in closed conduit or trays, (2) A breakdown of cable diameters and associated conductor cross-section, or an equivalent cable diameter and conductor cross-section that is representative of total cable surface area associated with the quantity of cable identified in 1) above, and (3) The major organic polymer or plastic material in the cables. If this information is not provided, we will assume the cable insulation to be polyethylene and assume a G value for combustible gas of 3.

RESPONSE: Refer to revised table 6.1-4.

(1) The quantity of covered/uncovered cable is not readily available. Therefore, all cable is assumed exposed.

(2) A breakdown of cable diameters and conductor cross-section was provided to the NRC under separate cover.

(3) Organic polymers in various insulation types are listed in table 6.1-4.

<u>QUESTION 6A.32</u> (NRC Question 440.11) (6.3)

Discuss the provisions and precautions for assuring proper system filling and venting of ECCS to minimize the potential for water hammer and air binding. Address piping and pump casing venting provisions and surveillance frequencies.

RESPONSE: Refer to paragraphs 6.3.2.6, 6.5.2.8 (listing A) [(RA) 7.13.7.B], and PVNGS Technical Specifications for discussions on fill and vent requirements.

<u>QUESTION 6A.33</u> (NRC Question 440.12) (6.3.3)

Paragraph 6.3.3.2.2 states that the worst single failure for the large break LOCA is the failure of one of the low pressure pumps to start which will result in a minimum amount of safety injection water available to the core. Explain why the single failure of a diesel generator, which results in loss of one HPSI train and one LPSI train, is not the worst single failure for the large break LOCA with respect to the amount of safety injection water available to the core in post LOCA operation.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC Questions.

<u>QUESTION 6A.34</u> (NRC Question 440.13) (6.3)

Identify all ECCS valves that are required to have power locked out and confirm they are included under the appropriate Technical Specifications, with surveillance requirements listed.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC Questions.

<u>QUESTION 6A.35</u> (NRC Question 440.14) (6.3)

Consideration should be given to the possibility that local manual valves (handwheel), could go undetected in the wrong position until a postulated accident occurs. Appropriate

administrative controls or valve position indication are examples of methods to be considered to minimize this possibility. Provide a list of all critical manual valves and address the actions that will be implemented to assure all critical valves are properly positioned.

Identify all manual valves which have locking provisions.

It is our position that limit switches which enable valve position to be indicated in the control room should be installed on all manually operated and normally locked ECCS valves.

In addition a recent event (Docket 50-320, LER 78-20/3L, 4/21/78) has brought to our attention that the automatic operation of some motor operated valves can be disabled when the manual handwheel pins are engaged. Identify all critical motor-operated valves associated with the CESSAR 80 design that have this design feature and describe the controls and procedures utilized to prevent the inadvertent disablement of the automatic operation of these valves.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC Questions.

<u>QUESTION 6A.36</u> (NRC Question 440.15) (6.3)

Identify the plant operating conditions under which certain automatic safety injection signals are blocked to preclude unwanted actuation of these systems. Describe the alarms available to alert the operator to a failure in the primary or secondary system during this phase of operation and the time available to mitigate the consequences of such an accident.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC Questions.

<u>QUESTION 6A.37</u> (NRC Question 440.16) (6.3)

The information in the CESSAR 80 FSAR regarding post-LOCA passive failures is not complete. It is the reactor systems branch position that detection and alarms be provided to alert the operator to passive ECCS failures during long-term cooling which allow sufficient time to identify and isolate the faulted ECCS line. The leak detection system should meet the following requirements:

1. Identification and justification of maximum leak rate should be provided.

2. Maximum allowable time for operator action should be provided and justified.

3. Demonstration should be provided that the leak detection system will be sensitive enough to initiate (by alarm) operator action, permit identification of the faulted line, and isolation of the line prior to the leak creating undesirable consequences such as flooding of redundant equipment or excessive radioactive fluid. The minimum time to be considered is 30 minutes.

4. It should be shown that the leak detection system can identify the faulted ECCS train and that the leak is isolatable.

5. The leak detection system must meet the following standards:

a. Control room alarm

b. IEEE 279-1971, except single failure requirements

RESPONSE: The response to items 1 and 2 is provided in the response to Question 5A.19 (NRC Question 440.8), items 1 and 2. Additional ECCS pump room flooding considerations are discussed in the response to Question 3A.30 (NRC Question 410.4). In addition, refer to section 6A.37.

<u>QUESTION 6A.38</u> (NRC Question 440.17) (6.3)

The acceptance criteria in the Standard Review Plan for Section 6.3 states the ECCS should retain its capability to cool the core in the event of a single active or passive failure during the long-term recirculation cooling phase following an accident. Demonstrate that CESSAR 80 ECCS design has this capability.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC Questions.

<u>QUESTION 6A.39</u> (NRC Question 440.18) (6.3)

A reported event has raised a question related to the conservatism of NPSH calculations with respect to whether the absolute minimum available NPSH has been considered. In the past, the required NPSH has been taken by the staff as a fixed number supplied through the applicant by either the architect engineer or the pump manufacturer. Since a number of methods exist and the method used can affect the suitability or unsuitability of a particular pump, it is requested that the

basis on which the required NPSH was determined be branded (i.e., test, Hydraulic Institute standards) for all the ECCS pumps and the estimated NPSH variability between similar pumps including the testing inaccuracies be provided.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC Questions.

QUESTION 6A.40 (NRC Question 440.19) (6.3)

Provide the basis for ECCS lag times. Are these times calculated or verified by test. If calculated, are they verified during preoperational tests, and periodically reverified?

RESPONSE: The response was provided on the CESSAR docket. In addition, PVNGS will verify ECCS lag times during the preoperational testing phase. See CESSAR responses to NRC Questions.

QUESTION 6A.41 (NRC Question 440.20) (6.3)

Provide in the Technical Specifications (1) the range of nitrogen cover gas pressure for the SIT, and (2) the ECCS pump discharge pressures.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC Questions.

QUESTION 6A.42 (NRC Question 440.21) (6.3)

Provide a time reference for each action in the sequence of action included in the changeover from injection to recirculation. Indicate the time required to complete each

action and what other duties the operator would be responsible for at this point in the accident. How much time does the operator have to assure that the system is realigned to the recirculation mode before RWST water is exhausted if the RWSP isolation valves are not closed? Consider the required pump NPSH in your response.

If the operator fails to close the RWST isolation valves, demonstrate that the HPSI will continue to adequately cool the core during the recirculation mode.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR responses to NRC Questions. Additional information is provided as follows:

The changeover from the safety injection mode to the recirculation mode occurs automatically upon recirculation actuation signal. For the opening time of the containment isolation valves for ECCS recirculation refer to subsection 6.2.4. After opening of these valves, the operator may close the RWT isolation valves manually (full closure takes 30 seconds) from the control room. It should be noted that the closure of these valves is not mandatory for proper ECCS performance due to the fact that physical arrangement of the RWT, as described in paragraph 6.5.2.8, PVNGS emergency procedures describe operator guidelines.

PVNGS has performed a walk through of the emergency procedures on its simulator and verified the operator has enough time to complete all required actions.

APPENDIX 6A

QUESTION 6A.43 (NRC Question 440.22) (6.3)

Recently, another plant has indicated that a design error existed in the sizing of their RWST. This error was discovered during a design review of the net positive suction head requirements for the containment spray and residual heat removal pumps. The review showed that there did not appear to be sufficient water in the RWST to complete the transfer of pump suctions from the tank to the containment sump, before the tank was drained and ECCS pump damage occurred.

It was reported that in addition to the water volume required for injection following a LOCA, an additional volume of water is required in the RWST to account for:

1. Instrument error in RWST level measurements.

2. Working allowance to assure that normal tank level is sufficiently above the minimum allowable level to assure satisfaction of technical specifications.

3. Transfer allowance so that sufficient water volume is available to supply safety pumps during the time needed to complete the transfer process from injection to recirculation.

4. Single failure of the ECCS system which would result in larger volumes of water being needed for the transfer process. In this situation, the worst single failure appears to be failure of a single ECCS train to realign to the containment sump upon low RWST signal. This result in the continuation of large RWST outflows and reduces the time available for the manual recirculation switchover,

before the tank is drawn dry and the operating ECCS pumps are damaged.

5. Unusable volume in the tank is present because once the tank suction pipes are reached, the pumps lose suction and any remaining water is unusable. Additionally, some amount of water above the suction pipes may also be unusable due to NPSH considerations and vortexing tendencies with the tank.

Preliminary indications are that approximately an additional 100,000 gallons of RWST capacity were needed to account for these considerations. It is our understanding that the design parameters for instrument error, transfer allowance and single failure have changed since the original sizing of the tank.

In light of the above information, discuss the adequacy of your RWST. Provide a discussion of the necessary water volumes to accommodate each of the five considerations indicated above. Justify your choice of volumes necessary to account for each consideration. Provide drawings of your RWST, showing placement and elevation of tank suction lines, and level sensors. Also, provide operator switchover procedures for aligning to the recirculation mode, with estimates of the time required for each action.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR responses to NRC Questions. The PVNGS design meets the CESSAR interface requirements identified in the CESSAR response.

Refer to paragraph 6.5.2.8 for a discussion on vortexing tendencies of the RWT.

Refer to paragraphs 7.5.1.1.6 and 7.5.2.6 for a discussion of the SESS panel alarms.

QUESTION 6A.44 (NRC Question 440.23) (6.3)

Provide a discussion on specific methods of detecting, alarming and isolating passive ECCS failures during long-term cooling to include valve leakage. Show that there is sufficient time for the operator to take corrective action and maintain an acceptable water inventory for recirculation. [1] Justify the basis for the assumed leak rates. [2] Describe how the contaminated water would be handled if one ECCS train must continue to operate with a leak.

RESPONSE:

1. The response will be provided on the CESSAR docket. Additional discussion is provided in amended paragraph 6.3.1.4. Normal valve leakage is considered insignificant when compared to the passive ECCS failure identified in the same response.

2. The leakage from the valves within the auxiliary building is collected in ESF sumps at the lowest building elevation of 40 feet. From this point, the waste can be pumped to the liquid radwaste system (LRS) for processing.

QUESTION 6A.45 (NRC Question 440.24) (6.3)

Assume a maximum passive failure flowrate of 50 gpm in each ECCS pump room and discuss the effects of the passive failure

to each ECCS pump operation, and demonstrate that adequate protection is provided for ECCS pumps from possible flooding.

RESPONSE: The response is given in amended paragraph 6.3.1.4.

QUESTION 6A.46 (NRC Question 440.25) (6.3)

In the event of early manual reset of the safety injection actuation signal (SIAS) followed by a loss of offsite power during the injection phase, operator action may be required to reposition ECCS valves and restart some pumps. The staff requires that operating procedures specify SIAS manual reset not be permitted for a minimum of 10 minutes after a LOCA. Provide the administrative procedures to ensure correct load application to the diesel generators in the event of loss of offsite power following an SIAS reset.

RESPONSE: The SIAS can only be reset when the initiating parameters have cleared. If SIAS were reset, then the conditions would have been restored to normal and the safety injection system would not be in the injection mode but the safety injection pumps would continue to operate until individually shut off by the operator. Refer to amended paragraph 6.3.1.4, listing I, for a discussion on procedure requirements.

QUESTION 6A.47 (NRC Question 440.26) (6.3)

Describe the instrumentation for level indication in the containment emergency sump. Also, provide detailed design drawings of the containment emergency sump including the design

provisions which preclude the formation of air entraining vortices during recirculation cooling. Confirm that the containment emergency sump design meets the requirements of Regulatory Guide 1.82.

RESPONSE: Refer to section 1.8 that describes PVNGS compliance with NRC Regulatory Guide 1.82, Revision 0.

Refer to paragraph 6.5.2.8 for discussion on the sumps vortexing breaking cage and level instrumentation.

QUESTION 6A.48 (NRC Question 440.27) (6.3)

Recent plant experience has identified a potential problem regarding the operability of the pumps used for long-term cooling (normal and post-LOCA) for the time period required to fulfill that function. Provide the pump design lifetime (including operational testing) and compare to the continuous pump operational time required during the short- and long-term of a LOCA. Submit information in the form of tests or operating experience to verify that these pumps will satisfy long-term requirements.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC Questions.

QUESTION 6A.49 (NRC Question 440.28) (6.3)

Describe the means provided for ECCS pump protection including instrumentation and alarms available to indicate degradation of ECCS pump performance. Our position is that suitable means should be provided to alert the operator to possible degradation of ECCS pump performance. All instrumentation

associated with monitoring the ECCS pump performance should be operable without offsite power, and should be able to detect conditions of low discharge flow.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC Questions.

QUESTION 6A.50 (NRC Question 440.29) (6.3)

Describe the instrumentation available for monitoring ECCS performance during post-LOCA operation (injection mode and recirculation mode).

RESPONSE: The response was provided on the CESSAR docket. See CESSAR responses to NRC questions.

QUESTION 6A.51 (NRC Question 440.30) (6.3)

Provide a commitment that Palo Verde will perform preoperational and startup tests to meet the requirements of Regulatory Guide 1.68 and 1.79.

RESPONSE: PVNGS will perform preoperational and startup tests to meet the requirements of Regulatory Guides 1.68 and 1.79 as outlined in CESSAR Chapter 14 for tests in CESSAR scope and PVNGS FSAR chapter 14 for tests outside of CESSAR scope. See section 1.8, responses to Regulatory Guides 1.68 and 1.79.

QUESTION 6A.52 (NRC Question 440.31) (6.3)

Provide a commitment that Palo Verde will perform tests of ECCS as installed to confirm that the actual ECCS flowrates are greater than the values assumed in the LOCA analyses.

RESPONSE: During the preoperational phase, PVNGS will perform tests of ECCS (as described in CESSAR Chapter 14) to confirm that the actual ECCS flowrates are greater than the values assumed in the LOCA analyses.

<u>QUESTION 6A.53</u> (NRC Question 440.56) (6.3)

The LOCA break spectrum analyses presented are stipulated to be applicable to any System 80 plant that conforms to the interface requirements specified within subsection 6.3.3. The submittal for the LOCA analyses does not address the effects of steam generator tube plugging. The effect of a decrease in steam generator tube flow area is an increase in the peak cladding temperature (when the peak occurs during the reflood portion of the transient). If the analyses provided are considered to support generators with plugged tubes, describe the intent of the plugging the analyses support and the method used to account for the plugging. If steam generator tube plugging was not considered, the applicant will be required to perform additional ECCS analyses prior to operation with plugged generator tubes. In either case, the applicant is required to include an interface requirement on the validity of the LOCA analysis (acceptance criteria of 10CFR50.46) and the Technical Specification limit for the number (or percentage) of allowable plugged steam generator tubes.

RESPONSE: The response will be provided on the CESSAR docket.

QUESTION 6A.54 (NRC Question 440.77) (6.3)

List all ECCS valve operators and controls that are located below the maximum flood level following a postulated LOCA or main steam line break. If any are flooded, evaluate the potential consequences of this flooding both for short and long-term ECCS functions and containment isolation. List all control room instrumentation lost following these accidents.

RESPONSE: Air-operated drain valves SIB-UV322 and 332 are used for relieving piping header pressure to the reactor drain tank after the RCS check valve test, but are not used during emergency operation.

An air-operated containment isolation valve CHA-UV560 is used to isolate the reactor drain tank discharge header. A second isolation valve is located outside containment.

Pressure instruments SIA-PT390 and SIB-PT391 are used in conjunction with RCS check valve testing and can also be used for indication of check valve leakage.

No control room instrumentation is lost. There are no harmful effects on the safety injection system from long- or short-term flooding of the above items.

QUESTION 6A.55 (NRC Question 440.78) (6.3)

Because of freezing weather conditions, blocking of the vent line on the refueling water tank (RWT) has occurred on at least one operating plant. Describe design bases and features that preclude this condition from occurring in the Palo Verde plant.

RESPONSE: The response is given in amended paragraph 6.5.2.8. As the winter ambient temperature at PVNGS has never been recorded below 32F for 24 consecutive hours, plugging of the RWT vent lines is considered very improbable.

QUESTION 6A.56 (NRC Question 440.79) (6.3)

It is our position that the SIS hotleg injection valves should be locked closed with power removed during normal plant operation in order to prevent premature hot leg injection following a LOCA.

RESPONSE: The response is given in amended paragraph 6.3.1.4.

QUESTION 6A.57 (NRC Question 440.80) (6.3)

Your sump test program described in subsection 6.2.2 is not in sufficient detail. The experimental program just demonstrate that sufficient margin in available NPSH over that required for each pump with all pumps at runout or maximum post-LOCA flow.

The test must demonstrate that the design precludes conditions adverse to safety system operation. Test parameters must include: (1) minimum to maximum containment water level, (2) minimum to maximum safety system flow range in various combinations (this includes transients associated with startup, shutdown, or throttling of a train or pump), (3) random blockage of up to 50 percent of the screens and grids, (4) approach flow for each dominant direction and combinations thereof, and (5) simulation of break flow or drain flow

impinging or originating within line of sight of the sump and its approaches.

If adverse conditions are encountered, the model configuration must be revised until an acceptable configuration is developed and demonstrated to perform over the full range of variables.

Since you choose to conduct a model test, provide details of the test program. Include information on the model size, scaling principles utilized, comparison of model parameters to expected post-LOCA conditions, and a discussion on how all possible flow conditions and screen blockages will be considered in the model tests. Whenever a reduced scale model is tested, all tendencies for vortex formation must be suppressed. Rota-tional flow patterns and surface dimples which might be acceptable in full scale tests, probably would not be accepted in a model program. Model testing must include some in-plant testing to demonstrate experimentally that NPSH margin exists for each pump.

RESPONSE: The response is given in amended paragraphs 6.2.2.2 and 6.3.1.4.

QUESTION 6A.58 (NRC Question 440.81) (6.3)

During our reviews of license applications we have identified concerns related to the containment sump design and its effect on long-term cooling following a LOCA.

These concerns are related to (1) creation of debris which could potentially block the sump screens and flow passages in the ECCS and the core, (2) inadequate NPSH of the pumps taking suction from the containment sump, (3) air entrainment from

streams of water or steam which can cause loss of adequate NPSH, (4) formation of vortices which can cause loss of adequate NPSH, air entrainment and suction of floating debris into the ECCS, and (5) inadequate emergency procedures and operator training to enable a correct response to these problems. Pre-operational recirculation tests performed by utilities have consistently identified the need for plant modifications.

The NRC has begun a generic program to resolve this issue. However, more immediate actions are required to assume greater reliability of safety system operation. We therefore require you take the following actions to provide additional assurance that long-term cooling of the reactor core can be achieved and maintained following a postulated LOCA.

1. Establish a procedure to perform an inspection of the containment, and the containment sump area in particular, to identify any materials which have the potential for becoming debris capable of blocking the containment sump when required for recirculation of coolant water. Typically, these mate-rials consist of: plastic bags, step-off pads, health physics instrumentation, welding equipment, scaffolding, metal chips and screws, portable inspection lights, unsecured wood, construction materials and tools as well as other miscellaneous loose equipment. "As licensed" cleanliness should be assured prior to each startup.

This inspection shall be performed at the end of each shut-down as soon as practical before containment isolation.

2. Institute an inspection program according to the requirements of Regulatory Guide 1.82, Item 14. This item addresses inspection of the containment sump components including screens and intake structures.

3. Develop and implement procedures for the operator which address both a possible vortexing problem (with consequent pump cavitation) and sump blockage due to debris. These procedures should address all likely scenarios and should list all instrumentation available to the operator (and its location) to aid in detecting problems which may arise, indications the operator should look for, and operator actions to mitigate these problems.

4. Pipe breaks, drain flow, and channeling of spray flow released below or impinging on the containment water surface in the area of the sump can cause a variety of problems; for example, air entrainment, cavitation, and vortex formation.

   Describe any changes you plan to make to reduce vortical flow in the neighborhood of the sump. Ideally, flow should approach uniformly from all directions.

5. Evaluate the extent to which the containment sump(s) in your plant meet the requirements for each of the items previously identified; namely debris, inadequate NPSH, air entrainment, vortex formation, and operator actions.

The following additional guidance is provided for performing this evaluation.

5.1 Refer to the recommendations in Regulatory Guide 1.82 (Section C) which may be of assistance in performing this evaluation.

5.2 Provide a drawing showing the location of the drain sump relative to containment sumps.

5.3 Provide the following information with your evaluation of debris:

a. Provide the size of openings in the fine screens and compare this with the minimum dimensions in the pumps which take suction from the sump (or torus), the minimum dimension in any spray nozzles and in the fuel assemblies in the reactor core or any other line in the recirculation flow path whose size is comparable to or smaller than the sump screen mesh size in order to show that no flow blockage will occur at any point past the screen.

b. Estimate the extent to which debris could block the trash rack or screens (50%). If a blockage problem is identified, describe the corrective actions you plan to take (replace insulation, enlarge cages, etc.).

c. For each type of thermal insulation used in the containment, provide the following information:

(1) type of material including composition and density,

(2) manufacturer and brand name,

(3) method of attachment,

(4) location and quantity in containment of each type,

(5) an estimate of the tendency of each type to form particles small enough to pass through the fine screen in the suction lines.

d. Estimate what the effect of these insulation particles would be on the operability and performance of all pumps used for recirculation cooling. Address effects on pump seals and bearings.

RESPONSE:

1. The Technical Requirements Manual (TRM) commits to inspection of the containment prior to establishing containment integrity.

2. Technical Specifications implement the inspection required by Regulatory Guide 1.82 (Revision 0), Item 14.

3. The response is given in amended paragraph 6.3.1.4 listing I. Amended paragraph 6.3.1.4, sublisting H.2 refers to CESSAR Table 6.3.2-3, which provides a list of the instrumentation available to the operator to monitor ECCS performance.

4. The response is given in amended paragraph 6.2.2.2.

5.1 Refer to section 1.8 for the PVNGS design requirements that meet NRC Regulatory Guide 1.82, Revision 0.

5.2 Figure 6A-4 shows the location of the drain sump relative to the containment sump.

5.3.a Figure 6A-5 provides the general arrangement and size of openings on the strainer assemblies. The response is given in amended paragraph 6.2.2.2.

5.3.b The response is given in amended paragraph 6.2.2.2.

5.3.c(1) The response is given in amended paragraph 6.2.2.2.

5.3.c(2) The response is given in amended paragraph 6.2.2.2.

5.3.c(3) The response is given in amended paragraph 6.2.2.2.

5.3.c(4) The response is given in amended paragraph 6.2.2.2.

5.3.c(5) The response is given in amended paragraph 6.2.2.2.

The only portion of the system that needs to be considered in this regard is that which is destroyed by the "blast" effects near the postulated breakpoint. In NUREG-0897, currently under review and revision, this area has been conservatively defined as all material within a right angle cone, extending seven diameters in line with the pipe. In this area, the material is "shredded" into fibers which will collect on the sump strainers. The volume of debris that is small enough to "pass through the fine screen in the suction lines" would, therefore, be much smaller than this volume. Although there exists no empirical data on which to base an analysis, it is thought that only a small percentage (less than 10%) would actually pass through the sump strainers.

This opinion is based on the fact that the majority of fibrous debris has been shown to transport along the floor and build up on the bottom of the strainers. Turbulent water is needed to disperse the fibers across a screen. Very fine fibers would tend to be trapped in large clumps

of fibers and would also be more susceptible to being "caught" in various gratings, crevices, and "crud traps".

5.3.d he stainless steel jacketed fiberglass insulation is not located near any postulated high energy line breaks (HELBs) that will require the use of the emergency sumps. Therefore, the fiberglass insulation will not be subject to the resulting affects of a HELB (i.e., pipe whip or jet impingement).

The fiberglass debris from the NUKON system does not pose a threat to the operability and performance of the pumps used for recirculation cooling. The glass fibers used in NUKON are typically less abrasive than the mineral fiber considered in Section 3.2.2.4 of NUREG-0897, Revision 1. The key conclusion of that section is that "...complete pump degradation or failure is not likely..." because the bearings are not subject to failure.

Since the TEMP-MAT insulation material will not disintegrate into a powder form, the insulation will not infiltrate the recirculating cooling water system to affect either the pump seals or bearings.

<u>QUESTION 6A.59</u> (NRC Question 440.84) (6.3)

Your response to Item II.K.3.17 of NUREG-0737 is not complete. Provide a commitment that you will establish a program prior to fuel loading for data collection on information regarding ECCS outages. The information will contain: (1) outage dates and duration of outages; (2) cause of the outages; (3) ECCS systems or components involved in the outage; and (4) collective action taken.

RESPONSE: The response is provided in amended Section 18.II.K.3.17.

QUESTION 6A.60 (NRC Question 440.86) (6.3)

Expand your interface requirements in paragraph 6.3.1.3 to include the requirement of power locked out on the SIS hot leg injection valves in order to prevent premature hot leg injection following a LOCA.

RESPONSE: The response is provided on the CESSAR docket. Refer to engineering drawings 01, 02, 03-M-SIP-001, -002 and -003.

See CESSAR FSAR responses to NRC Questions (NRC Question 440.77).

QUESTION 6A.61 (NRC Request for Additional Information, Containment System Branch)

Under postulated LOCA conditions, the reactor coolant drain tank (RCDT) room would become an essentially closed room, with only an annular pipe opening in the RCDT room ceiling available for the venting of any hydrogen evolved to the bulk containment volume. Furthermore, your present analysis of hydrogen production and accumulation following a LOCA indicates that the hydrogen concentration in the RCDT room would reach combustible levels relatively quickly. It is acknowledged that your hydrogen production analysis is conservatively based on staff licensing models for calculating hydrogen evolution for radiolysis of water, and assumptions of hydrogen transport from the RCDT room. Nevertheless, we have the following concerns which should be addressed:

(a) As a result of your Independent Design Review, you have identified the presence of the lights in the RCDT room as a potential ignition source if combustible levels of hydrogen are present. Therefore, describe the design features and/or administrative controls (normal and emergency operating procedures) that will assure the unavailability of electrical power to these lights under LOCA conditions.

(b) Provide an analysis of hydrogen transport from the RCDT room through the annular pipe opening into the adjacent containment region. For the postulated accident condition, the open containment volume, as opposed to the RCDT room, would contain a noncombustible hydrogen-air mixture. Therefore, the purpose of the calculation should be to determine if a combustible mixture exiting the RCDT room is adequately mixed to become nonflammable before it reaches a potential ignition source. Identify any potential ignition sources in the vicinity of the annular opening that could come in contact with a plume of a combustible hydrogen mixture.

(c) If the potential exists for a combustible plume of hydrogen emerging with the annular opening to come in contact with a potential ignition source, provide an analysis of the pressure response of the RCDT room assuming combustion under the most adverse conditions. Compare the calculated results to the structural capability of the RCDT room and discuss the response of any safety-related equipment located either inside or in the vicinity of the RCDT room.

RESPONSE:

(a) The response is given in paragraph 6.2.5.2.2.

(b) The response is given in paragraph 6.2.5.2.2.

(c) As noted in paragraph 6.2.5.2.2, there is no potential for a combustible plume of hydrogen emerging from the annular opening to come in contact with an ignition source.

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CHAPTER 7

INSTRUMENTATION AND CONTROLS

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7. INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

Instrumentation and control systems that monitor and perform safety-related functions are discussed in this chapter. Complete descriptions and analyses of these systems are provided in sections 7.2 through 7.6. Systems that are not required for safety are discussed in section 7.7.

7.1.1 IDENTIFICATION OF SAFETY-RELATED SYSTEMS

The safety-related instrumentation and controls, including supporting systems, are identified below. The responsibility for the design of each system is identified as follows:

Combustion Engineering (C-E)/Westinghouse Electric Company LLC

Bechtel (Bechtel)

Identification of supplier/builder not identified below can be found in table 1.9-1.

7.1.1.1 Protection System

The PPS includes the electrical and mechanical devices and circuitry required to perform the protective functions defined below.

A. Reactor Protective System (RPS)

   The RPS is the portion of the PPS that acts to trip the reactor when required. The RPS is described in section 7.2.

B. Engineered Safety Features Actuation System (ESFAS)

The ESFAS is the portion of the PPS which activates the Engineered Safety Features Systems listed in section 7.1.1.3 and described in section 7.3.

C Supplementary Protection System (SPS)

The Supplementary Protection System (SPS) augments reactor protection by utilizing a separate and diverse trip logic from the Reactor Protective System for initiation of reactor trip. The addition of the SPS provides a simple, reliable, yet diverse mechanism to initiate a reactor trip. The SPS will initiate a reactor trip when pressurizer pressure exceeds a predetermined value.

The SPS is provided with sensors and circuitry which are diverse from those of the RPS. A selective two-out-of-four logic to interrupt the power supplied to the CEDM's and thereby cause the CEA's to drop into the core by gravity is used. The system is independent and separate from all control systems.

7.1.1.2 Reactor Trip System

The RTS includes the RPS portion of the PPS, Reactor Trip Switchgear System (RTSS) and the arrangement of components that perform a reactor trip after receiving a signal from the RPS or SPS automatically or manually by the operator. The RTS initiates a reactor trip based on the signals from the sensors which monitor various NSSS parameters and the containment pressure.

7.1.1.3 Engineered Safety Feature Systems

The ESF Systems include the NSSS and BOP ESFAS and the arrangement of components that perform protective actions after receiving a signal from the NSSS or BOP ESFAS or the operator. The instrumentation and controls for ESF Systems are described in section 7.3.

The NSSS ESF Systems are:

A.	Containment Isolation System;	(C-E)/(Bechtel)
B.	Main Steam Isolation System;	(Bechtel)
C.	Safety Injection System;	(C-E)
D.	Auxiliary Feedwater System;	(Bechtel)
E.	Containment Spray System;	(C-E)
F.	Supporting Systems.	(Bechtel)

The BOP ESF Systems are:

A. Fuel building essential ventilation system

B. Containment purge isolation system

C. Control room essential filtration system

D. Control room essential ventilation system

E. Containment combustible gas control system (manual)

7.1.1.4 Systems Required for Safe Shutdown

Systems required for safe shutdown are defined as those essential for pressure and reactivity control, coolant inventory makeup, and removal of residual heat once the reactor

has been brought to a subcritical condition. These systems are categorized according to the following shutdown modes:

A. Hot Shutdown

Systems required for maintenance of the primary system at, or near, operating temperature and pressure.

B. Cold Shutdown

Systems required to cool down and maintain the primary system at or near ambient conditions.

The systems required for safe shutdown are listed below and described in section 7.4.

The safe shutdown systems required to place the reactor in hot shutdown include:

1. Diesel Generator; (Bechtel)
2. Diesel Generator Fuel Storage and Transfer System; (Bechtel)
3. Class 1E AC System; (Bechtel)
4. Emergency Power Distribution System; (Bechtel)
5. Auxiliary Feedwater System; (Bechtel)
6. Atmospheric Steam Dump System; (Bechtel)
7. Chemical and Volume Control System (portions only, see section 9.3.4) (C-E)
8. Essential Spray Pond System; and (Bechtel)
9. Condensate Storage System (Bechtel)

In addition, equipment and systems are provided to allow emergency shutdown from outside the control room.

The safe shutdown systems or portions of systems required to place the reactor in cold shutdown include those in 1. through 9. above, plus the following:

10. Nuclear Cooling Water System; (Bechtel)
11. Essential Cooling Water System; (Bechtel)
12. Shutdown Cooling System. (C-E)

7.1.1.5 Safety-Related Display Instrumentation

The Safety-Related Display Instrumentation provides information to the operator to allow him to adequately monitor plant operating conditions and to perform any required manual safety functions. Safety-Related Display Instrumentation is described in section 7.5.

Safety-related displays are provided for:

A. Safety-Related Plant Process Display Instrumentation; (C-E)/(Bechtel)

B. Reactor Trip System Monitoring; (C-E)

C. Engineered Safety Features Systems Monitoring; (C-E)/(Bechtel)

D. CEA Position Indication; (C-E)/(Bechtel)

E. Post-Accident Monitoring; and (C-E)/(Bechtel)

F. Automatic Bypass Indication. (Bechtel)

7.1.1.6 All Other Systems Required for Safety

Other systems required for safety include the interlocks required to prevent overpressurization of the Shutdown Cooling System and to ensure safety injection availability. These are provided as listed below and described in section 7.6.

A. Shutdown Cooling System Suction Line Isolation Valve Interlocks; and (C-E)

B. Safety Injection Tank Isolation Valve Interlocks. (C-E)

7.1.1.7 Design Comparison

The Reactor Protective System (RPS) is designed by Combustion Engineering. The system will be functionally identical to the system provided for the Arkansas Nuclear One - Unit 2 (ANO-2) plant (NRC Docket No. 50-368) with the following exceptions:

A. High Linear Power Level Trip is replaced by a Variable Overpower Trip. The Variable Overpower Trip provides protection to the NSSS for rapid power changes from low initial power levels.

B. The Reactor Trip Switchgear (RTSG), which had consisted of nine trip circuit breakers on ANO-2, is now four circuit breakers in a Reactor Trip Switchgear System (RTSS). The change to the RTSS was performed to implement the SPS requirements.

C. The Supplementary Protection System (SPS) is new to the CESSAR licensing scope. This system is

specifically designed to increase the reliability of reactor trip initiation.

D. A low reactor coolant flow trip has been added to provide protection in the event of a reactor coolant pump sheared shaft.

The Engineered Safety Features Actuation System (ESFAS) is designed by Combustion Engineering. Each initiation system logic, including testing features, is similar to the logic for the RPS and is contained in the same physical enclosure. The actuation logic and devices are contained in the ESFAS Auxiliary Relay Cabinets. The design of this system is described in section 7.3. The following changes from ANO-2 make the ESFAS more diverse and responsive to the situation requiring its actuation:

A. CIAS initiation logic now includes low pressurizer pressure;

B. MSIS initiation logic now includes high steam generator level and high containment pressure;

C. RAS has had manual initiation added;

D. AFAS initiation logic is modified by removing a steam generator low pressure permissive and by adding interlocks between AFAS-1 and AFAS-2.

Balance of Plant engineered safety features actuation systems (BOP ESFASs) designed to actuate ESF systems presented in paragraph 7.1.1.3 F, A through E employ one-out-of-two logic, described in section 7.3, as opposed to the two-out-of-four logic for this NSSS ESFAS.

7.1.2 IDENTIFICATION OF SAFETY CRITERIA

Comparison of the design with applicable Regulatory Guide recommendations and the degree of compliance with the appropriate design bases, General Design Criteria, standards, and other documents used in the design of the systems listed in Section 7.1.1 are described in Sections 7.1.2.1 through 7.1.2.35, and in each of the sections describing the system. (Refer to sections 7.2 through 7.6.)

7.1.2.1 Design Bases

The design bases for the safety-related instrumentation and control of each safety-related system are presented in the section of this chapter that discusses the system to which the information applies.

Consideration has been given to instrument error in the selection of all safety system setpoints. Where setpoints are listed in Chapter 7, it is understood that these are nominal values. The actual setpoint may vary within prescribed accuracies which have been considered in selection of the values.

7.1.2.1.1 Systems Required for Plant Protection

The instrumentation and controls for the Reactor Protective System and Engineered Safety Features Systems conform to the following:

A. The PPS and the ESF Systems conform to IEEE Standard 279-1971. Detailed discussion of conformance for these and other safety-related system instrumentation

and controls is provided in the applicable section of this chapter. Conformance to the other IEEE Standards is discussed in sections 7.1.2.3 through 7.1.2.12.

B. Comparison with Regulatory Guide recommendations for Water-Cooled Nuclear Power Plants, Division of Reactor Standards, Nuclear Regulatory Commission, is discussed in sections 7.1.2.6, 7.1.2.9, 7.1.2.10, and 7.1.2.13 through 7.1.2.32.

C. Quality assurance procedures are described in CENPD-210A, "Description of the C-E Nuclear Steam Supply System Quality Assurance Program (Reference 1).

D. General Design Criteria for Nuclear Power Plants, Appendix A to 10CFR50, July 7, 1971, as described in section 3.1.

E. The standards the upgraded Core Protection Calculator System (CPCS) were designed to are described in CENPD-396-P, "Common Qualified Platform Topical Report"[(4)]. However, Palo Verde has not increased its commitments to these new or revised standards.

7.1.2.1.2 Systems Required for Safe Shutdown

The design bases for the systems required for safe shutdown are described in section 7.4.

7.1.2.1.3 Safety-Related Display Instrumentation

The design bases for Safety-Related Display Instrumentation are described in section 7.5.

7.1.2.1.4 All Other Systems Required for Safety

The design bases for all other systems required for safety are described in section 7.6.

7.1.2.2 Conformance to IEEE 279

Conformance to IEEE 279-1971, is discussed in paragraphs 7.1.2.1, 7.1.2.1.1, 7.2.1.2, 7.2.2.3.2, 7.3.1.2, 7.3.2.3.1, 7.3.2.3.2, 7.4.2.1, 7.5.2.5 and 7.6.2.1.

7.1.2.3 Conformance to IEEE 308

Conformance to IEEE 308-1974, is discussed in section 8.3.

7.1.2.4 Conformance to IEEE 317

Electric penetrations and their conformance to IEEE 317-1972 are discussed in section 8.3.

7.1.2.5 Conformance to IEEE 323

The CESSAR Licensing scope compliance with IEEE 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations", for instrumentation is discussed in Combustion Engineering Topical Report CENPD-255, "Qualification of Combustion Engineering Class 1E Instrumentation", (Reference 2). The basic qualification requirements of CESSAR Licensing scope equipment are discussed in section 3.11.

Qualification of Class IE electrical equipment not supplied by C-E, is discussed in sections 8.3 and 3.11.

7.1.2.6 Conformance to IEEE 336 as Augmented by Regulatory Guide 1.30

A planned quality assurance (QA) program, in compliance with IEEE 336-1971, has been implemented. This includes a comprehensive quality control and QA program.

7.1.2.7 Conformance to IEEE 338

The PPS and ESFAS Auxiliary Relay Cabinet circuits, as well as the RTSS, are designed so that they can be periodically tested in accordance with the criteria of IEEE 338-1971, "Periodic Testing of Nuclear Power Generating Station Protection Systems".

Testing criteria are specified in sections 7.2.2.3.3 and 7.3.2.3.3. Minimum testing frequency requirements are provided in the Technical Specifications.

Since operation of the ESF Systems is not expected, the systems are periodically tested to verify operability. Complete channels, in the NSSS ESFAS systems, can be individually tested without initiating protective action and without inhibiting the operation of the system.

The system can be checked from the sensor signal through the actuation devices. The functional modules in the sensors system can be tested during reactor operation. The sensors can be checked by comparison with similar channels.

Those actuated devices, which are not tested during the reactor operation will be tested during scheduled reactor shutdown to show that they are capable of performing the necessary functions.

In addition, in conformance to IEEE 338-1971, response time testing for all plant protection system (PPS) channels and equipment is performed during preoperational testing and each refueling interval. The Technical Specifications describe testing frequency.

7.1.2.8 Conformance to IEEE 344

The CESSAR Licensing scope compliance with IEEE 344-1971, "IEEE Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations" is discussed in Combustion Engineering Topical Report CENPD-182, "Seismic Qualification of Instrumentation Equipment" (Reference 3).

Conformance to IEEE 344-1975, is discussed in section 3.10.

7.1.2.9 Conformance to IEEE 379 as Augmented by Regulatory Guide 1.53

Instrumentation for the PPS and ESFAS Auxiliary Relay Cabinets, and the RTSS conform to the requirements of IEEE 379-1972, "IEEE Trial-Use Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems", as augmented by Regulatory Guide 1.53, "Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems". A discussion of the application of the single failure criterion is provided in sections 7.2.2.3.2 and 7.3.2.3.2 for these systems.

In addition, the essential safety-related supporting systems listed in paragraph 7.1.1.4 comply with the requirements of

IEEE 379-1972 as augmented by Regulatory Guide 1.53. The single failure criterion is discussed in subsection 7.3.2.

7.1.2.10 Conformance to IEEE 384 as Augmented by Regulatory Guide 1.75

The instrumentation for the safety-related electric systems conforms to the requirements of IEEE 384-1974, "IEEE Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits", as augmented by Regulatory Guide 1.75, "Physical Independence of Electric Systems". A discussion of the physical independence is provided below which describes the compliance with section 4.6 of IEEE 279-1971 and General Design Criteria 3 and 21.

The PPS cabinet is divided into four bays which are separated by mechanical and thermal barriers. Each bay contains one of the four redundant channels of the RPS and ESFAS. This provides the separation and independence necessary to meet the requirements of section 4.6 of IEEE 279-1971.

Separation of redundant Class 1E circuits within the PPS cabinet is accomplished through 6 inch separation or barriers or conduit. However, in the formation of the logic matrices (AB, AC, BC, AD, BD, CD), initiation circuits, and actuation circuits, 6 inch separation is not maintained, nor can barriers or conduit be utilized. An analysis has been performed to show that the separation achieved is acceptable. Tests and analyses have also been completed to demonstrate that no single credible event in one PPS bay can prevent the circuitry in any other bay from performing its safety function.

The ESFAS Auxiliary Relay Cabinets provide separation and independence for the selective two-out-of-four actuation logics and actuation relays of the two redundant ESF Systems’ Trains. Each train's logic and relays are contained in a separate cabinet with all of the train A actuation circuits in one cabinet and all of the train B actuation circuits in the other cabinet. There are mechanical and thermal barriers within the cabinets to protect different portions of the selective two-out-of-four logic from spurious actuation. The two cabinets are physically separated from each other.

The RTSS consists of four RTSG. Each RTSG and its associated switches, contacts, relays, etc. is contained in a separate cabinet. Each cabinet is physically separated from the other cabinets. This method of construction ensures that a single credible failure in one RTSG cannot cause malfunction or failure in another cabinet.

The separation and independence of the power supplies for each of the above systems is discussed in Chapter 8.0. The interface requirements appear in section 7.1.3 while the implementation will appear in section 7.1.4. Protection system analog signals, sent to the Plant Monitoring System (PMS), are isolated from the protection system. Digital signals are also isolated for the associated signals coming from the protection system.

All of these isolation techniques ensure that no credible failures on the output side of the isolation device will effect the PPS side and that the independence of the PPS is not jeopardized.

In addition, compliance to General Design Criterion 17, IEEE 384-1974, and Regulatory Guide 1.75 is described in section 8.3 and section 1.8. Additionally, instrumentation for the safety-related electrical instrumentation and control systems supplied by C-E was designed using Regulatory Guide 1.75, Revision 0, 2/74.

7.1.2.11 Conformance to IEEE 387

Conformance to IEEE 387-1972 is discussed in section 8.1.

7.1.2.12 Conformance to IEEE 450

Conformance to IEEE 450 is discussed in subsection 8.3.2.

7.1.2.13 Comparison of Design with Regulatory Guide 1.6

A comparison of the design with Regulatory Guide 1.6 is provided in paragraph 8.1.4.3.1.

7.1.2.14 Comparison of Design with Regulatory Guide 1.11

Containment penetrations for the eight containment pressure detectors are consistent with the recommendations of Regulatory Guide 1.11. All other containment penetrations are in accordance with NRC General Design Criteria 55, 56, or 57. Isolation of containment penetrations is discussed in detail in subsection 6.2.4.

7.1.2.15 Conformance to Regulatory Guide 1.22

The PPS, ESFAS Auxiliary Relay Cabinets, and the RTSS, as described in section 7.1.1, conform to the guidance of

Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Functions". This conformance is described below.

A. Provisions are made to permit periodic testing of the complete PPS, ESFAS Auxiliary Relay Cabinets, and RTSS with the reactor operating at power or when shutdown. These tests cover the trip action from sensor input to the PPS cabinets through the protection system or ESFAS Auxiliary Relay Cabinets to and including the RTSS and the ESFAS actuated devices. Those ESFAS actuated devices which could affect operations are not tested while the reactor is operating but during reactor shutdown.

B. The provisions of this position are incorporated in the testing of the PPS, from sensor to actuation device, including the ESFAS and ESFAS Auxiliary Relay Cabinets and the RTSS.

   1. No provisions are made in the design of the PPS, ESFAS Auxiliary Relay Cabinets, and RTSS at the systems level to intentionally bypass an actuation signal that may be required during power operation. All bypasses are on a channel level to prevent an operator from inadvertently bypassing a trip function.

   2. The manual testing circuitry for an RPS channel is interlocked to prevent testing in more than one redundant channel simultaneously. Testing requiring a channel bypass is automatically indicated in the main control room.

3. Manual testing of an ESFAS channel requiring a channel bypass is automatically indicated in the main control room.

C. Actuated devices which cannot be tested during reactor operation will be tested by the ESFAS circuitry when the reactor is shutdown.

Additional information regarding conformance with Regulatory Guide 1.22 for non-C-E portions of the safety-related systems is provided in subsection 7.3.2.

7.1.2.16 Conformance to Regulatory Guide 1.29

The PPS and ESFAS and other instrumentation and controls necessary for safety conform to the guidance of Regulatory Guide 1.29, "Seismic Design Classification". This conformance is described below.

The systems designated as Seismic Category I are items listed in Regulatory Guide 1.29, Sections C.1.k, C.1.1, and C.1.q. The seismic classification and qualification are discussed in Combustion Engineering Topical Report CENPD-182 (Reference 3) and section 3.10. The Class 1E electric systems identified in C.1.q are discussed in section 8.3.

Those portions of structures, systems, or components whose continued function is not required, are designed so that the SSE will not cause a failure which will reduce the functioning of any plant safety feature to an unacceptable level, including incapacitating injury to the occupants of the control room. This is a qualification to Regulatory Guide 1.29 position C.1.r which would classify these items as Seismic Category I.

The classifications of non-CE systems and components which are described in sections 7.2, 7.3, 7.4, 7.5, and 7.6 are listed in section 3.2. The design methods are described in section 3.7, and test/analysis methods and results are given in section 3.10. Refer to section 1.8 for a discussion of PVNGS interpretation of Regulatory Guide 1.29.

7.1.2.17 Conformance to Regulatory Guide 1.30

Refer to section 1.8 for a discussion of PVNGS conformance to Regulatory Guide 1.30.

7.1.2.18 Conformance to Regulatory Guide 1.40

There are no Class 1E continuous-duty motors installed inside the containment.

7.1.2.19 Conformance to Regulatory Guide 1.47

The design of the RPS and the ESFAS as indicated in sections 7.2 and 7.3, is consistent with the recommendations of Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plants Safety System". Conformance is described below.

Bypasses can be classified into two groups: operating bypasses and trip channel bypasses.

7.1.2.19.1 Operating Bypasses

The operating bypass is used during routine startup and shutdown. These bypasses must be manually inserted. They utilize permissive contact inputs generated from the

parameter(s) being bypassed to ensure the bypass is removed if plant conditions deviate to the point where the bypass is no longer safe. (Example: If the coolant system pressure rises above a predetermined setpoint, the RPS/ESFAS pressurizer pressure bypass is automatically removed.) Once a bypass is automatically removed, the manual switch must be turned to the normal (unbypassed) position and then returned to bypass in order to reinsert the bypass for all systems except the CPC system. This prevents cycling the bypass with the permissive contact status. Separate contacts from the manual switch and permissive relay are combined to provide a plant annunciator output. Indicator lamps are provided in the bypass circuit to monitor directly the application of the bypass. These are located on the PPS remote operator's modules and display bypass status for each channel. Operating bypasses include the RPS/ESFAS pressurizer pressure bypass, the high log power bypass and the DNBR/LPD trip bypass.

7.1.2.19.2 Trip Channel Bypasses

These bypasses are used to individually bypass channel trip inputs to the protection system logic for maintenance or testing. The trip logic is converted from a two-of-four to a two-of-three logic for the parameters being bypassed, while maintaining a coincidence two for actuation. Only one channel for any one parameter may be bypassed at any one time. This is accomplished by electrically interlocking the manual bypass switches. These bypasses must be manually initiated and removed. Individual bypass indicator lights are provided locally at the PPS and at the PPS remote operator's modules

located in the control room. The wiring for these indicators is run within their respective channels so that faults in any one module will not affect the other channel bypass indication or bypass status. A separate signal is provided to the plant annunciator when any trip channel bypass is present. In addition, the status of each bypass is provided to the Plant Monitoring System.

A. Annunciator outputs are provided to indicate, at the system level, the bypassing or deliberate inducing of inoperability of a protection system. The system level alarms are actuated when a component actuated by a protection system is bypassed or deliberately rendered inoperable.

B. Those auxiliary and support systems within the CESSAR Licensing scope provide automatic annunciator activation to indicate, on a system level, the bypassed or deliberately induced inoperability of an auxiliary or support system that effectively bypasses or renders inoperable a protection system and the systems actuated or controlled by a protection system.

C. Annunciation shall be provided in the control room, at the system level, for each bypassed or deliberately induced inoperable status in a protection system.

    1. These are supplied for those systems discussed in A. and B. above.

    2. All of these bypasses are expected to be used at least once a year.

3. All of these bypasses are expected to be usable when the annunciated system is expected to be operable.

D. The operator shall be able to activate each system level bypass indicator manually in the control room.

For a discussion of the non-CE systems listed in paragraph 7.1.1.3 regarding conformance with Regulatory Guide 1.47, see section 7.5.

7.1.2.20 Conformance to Regulatory Guide 1.53

The conformance to Regulatory Guide 1.53 is discussed in paragraph 7.1.2.9.

7.1.2.21 Conformance to Regulatory Guide 1.62

Manual initiation of the RPS is described in sections 7.2.1.1.1.11, and 7.2.2.3.2. Manual initiation of the ESFAS is described in sections 7.3.1.2 and 7.3.2.3.2. Conformance to Regulatory Guide 1.62, "Manual Initiation of Protective Actions", is as follows:

A. Each of the above systems has means for manual actuation.

B. Manual initiation of a protective action causes the same actions to be performed by the protection system as would be performed if the protection system had been initiated by automatic action.

C. Manual switches are located in the control room and at the RTSS for use by the operator. Some functions also have actuation at remote locations.

D. The amount of equipment common to the manual and automatic initiation paths is kept to a minimum, usually just the actuation devices. No single credible failure in the manual, automatic, or common portions of the protective system will prevent initiation of a protective action by manual or automatic means.

E. Manual initiation requires a minimum of equipment consistent with the needs of A., B., C., and D. above.

F. Once initiated, manual protective action will go to completion. (Refer to section 7.3.1.1.10.7.)

In addition, manual initiation of the portions of the ESFAS not supplied by C-E is discussed in section 7.3.

7.1.2.22 Conformance to Regulatory Guide 1.63

Conformance to Regulatory Guide 1.63 is discussed in section 1.8.

7.1.2.23 Conformance to Regulatory Guide 1.68

Conformance with Regulatory Guide 1.68, Preoperational and Initial Start-Up Test Program for Water-Cooled Power Reactors, is discussed in section 14.2.

7.1.2.24 Conformance to Regulatory Guide 1.73

The CESSAR Licensing scope electric valve operators intended to be installed inside the containment are qualified in compliance with Regulatory Guide 1.73, "Qualification Tests of Electric

Valve Operators Installed Inside the Containment of Nuclear Power Plants", (see section 3.11).

In addition, non-CE supplied electric valve operators installed within the containment are in compliance with Regulatory Guide 1.73 and are discussed in section 3.11.

7.1.2.25 Conformance to Regulatory Guide 1.75

The conformance to Regulatory Guide 1.75 is discussed in section 1.8. Procurement specifications for 1E systems and components required conformance to Regulatory Guide 1.75. A further description of the conformance is contained in paragraphs 8.3.1.2 and 8.3.1.4.

7.1.2.26 Conformance to Regulatory Guide 1.80

Regulatory Guide 1.80 has been withdrawn. It is replaced by Regulatory Guide 1.68.3.

7.1.2.27 Conformance to Regulatory Guide 1.89, Revision 1

The conformance to Regulatory Guide 1.89, Rev. 1 is given in section 1.8.

7.1.2.28 Conformance to Regulatory Guide 1.95

Not applicable; see section 1.8.

7.1.2.29 Conformance to Regulatory Guide 1.97

Conformance to Regulatory Guide 1.97 is presented in section 1.8. The post-accident monitoring instrumentation is described in paragraph 7.5.2.5.

7.1.2.30 Conformance to Regulatory Guide 1.100

Conformance to Regulatory Guide 1.100 is presented in section 3.10.

7.1.2.31 Conformance to Regulatory Guide 1.105

Conformance to Regulatory Guide 1.105 is presented in section 1.8.

7.1.2.32 Conformance to Regulatory Guide 1.118

Conformance to Regulatory Guide 1.118 is given in section 1.8 and implemented in the Technical Specifications. Specific test capabilities within the reactor protective system and the engineered safety features systems are described in paragraphs 7.1.2.7 and 7.3.1.1 and subsection 7.2.1.

7.1.2.33 Evaluation of IE Bulletin 79-27

Action Item 1.

IE Bulletin 79-27 addressed three review areas, as follows:

[Area] 1. Review the Class 1E and non-Class 1E buses supplying power to safety- and nonsafety-related instrumentation and control systems which could affect the ability to achieve a cold shutdown condition using existing procedures or procedures developed under [Area] 2 below. For each bus:

a. Identify and review the alarm and/or indication provided in the control room

to alert the operator to the loss of power to the bus.

b. Identify the instrument and control system loads connected to the bus and evaluate the effects of loss of power to these loads including the ability to achieve a cold shutdown condition.

c. Describe any proposed design modifications resulting from these reviews and evaluations, and your proposed schedule for implementing those modifications.

[Area] 2. Prepare emergency procedures or review existing ones that will be used by control room operators, including procedures required to achieve a cold shutdown condition, upon loss of power to each Class 1E and non-Class 1E bus supplying power to safety and nonsafety-related instrument and control systems. The emergency procedures should include:

a. The diagnostics/alarms/indicators/ symptom resulting from the review and evaluation conducted per [Area] 1 above.

b. The use of alternate indication and/or control circuits which may be powered from other non-Class 1E or Class 1E instrumentation and control buses.

c. Methods for restoring power to the bus.

Describe any proposed design modifications or administrative controls to be implemented resulting from these procedures, and your proposed schedule for implementing the changes.

[Area] 3. Re-review IE Circular No. 79-02, Failure of 120 Volt Vital AC Power Supplies, dated January 11, 1979, to include both Class 1E and non-Class 1E safety-related power supply inverters. Based on a review of operating experience and your re-review of IE Circular No. 79-02, describe any proposed design modifications or administrative controls to be implemented as a result of the re-review.

Evaluation

Our review has determined that the PVNGS design consists of two ungrounded non-Class 1E, 120 V-ac instrument distribution panels E-NNN-D11 and E-NNN-D12 and four ungrounded vital (Class 1E) 120 V-ac instrument distribution panels E-PNA-D25, E-PNB-D26, E-PNC-D27, and E-PND-D28.

Each ungrounded non-Class 1E volt ac instrument distribution panel is normally supplied from a 480 V-ac, non-Class 1E motor control center through a voltage regulator-transformer to a transfer switch. A backup source is provided from a 480 V-ac, Class 1E motor control center through a Class 1E voltage regulator-transformer as an isolation device to the transfer switch. The transfer switch automatically transfers, upon loss

of power on the normal source, to the backup source. Manual transfer is required to return to the normal source. The distribution panel is fed from the transfer switch through a panel feeder breaker. Distribution to the instrument cabinets is through branch circuit breakers.

Each undergrounded vital (Class 1E), 120Vac instrument distribution panels is normally supplied from a 125v-dc Class 1E control center through a Class 1E inverter and its manual or static transfer switches. A backup source is provided from a 480V-ac, Class 1E motor control center through a voltage regulating transformer connected to the manual or inverter static transfer switch. Transfer from the preferred normal inverter power to the voltage regulating transformer power will occur automatically on the inverter trouble or manually (when required) without loss of load. An additional source of power is provided from a swing inverter and swing line-up switch, if available, connected to the normal inverter manual transfer switch. Transfer to the swing inverter will require manual operations with no loss of load. The distribution panel is fed from the transfer switch through a panel feeder breaker.

Our specific response to [Area] 1.a is that an alarm for each non-Class 1E instrument distribution panel is provided to the operator in the control room. Annunciation will occur on the following:

- Normal source undervoltage
- Backup source undervoltage
- Ground detection

- Overload tripping of the panel feeder breaker
- Overload tripping of any branch circuit breaker

An alarm is provided for each Class 1E instrument distribution panel and an alarm for each Class 1E inverter and transfer switch. Annunciation will occur on the following:

- Inverter output breaker tripped
- Inverter DC input breaker tripped
- Inverter AC Bypass source breaker tripped, if available per implementation of DMWO 3232547
- Inverter output voltage low or high
- Inverter system output voltage high, if available per implementation of DMWO 3232547
- Inverter overcurrent (overload)
- Inverter DC input voltage low or high
- Loss of synchronization (of the inverter only)
- Transfer switch not on normal source
- Inverter fan failure
- Inverter fuse blown, if available per implementation of DMWO 3232547
- Distribution panel undervoltage
- Ground detection
- Overload tripping of the panel feeder breaker

For [Area] 1.b, the instrument and control system loads connected to each instrument distribution panel are provided as noted on table 8.3-4.

Those specific instrument parameters and controls detailed in 7.4.1.1.10.2 as being required to achieve cold shutdown are listed in table 7.1-2. Instrument loop displays and controls available to the control room operator and the instrument distribution panel supply are identified.

Motor-operated valves, pumps, pressurizer heaters, and solenoids required to achieve cold shutdown are powered from buses other than the instrument distribution panels.

Table 7.1-1

DELETED

Table 7.1-2

INSTRUMENT PARAMETERS AND CONTROLS REQUIRED TO ACHIEVE COLD SHUTDOWN

Parameter or Control	Class 1E Instrument Distribution Panels				Non-Class 1E Instrument Distribution Panels	
	E-PNA-D25	E-PNB-D26	E-PNC-D27	E-PND-D28	E-NNN-D11	E-NNN-D12
Neutron log power	J-SEA-JI-1A	J-SEB-JI-1B	J-SEC-JI-1C	J-SED-JI-1D	-	-
Hot leg temperature & TR-112HA	J-RCA-TI-112HA	J-RCB-TI-112HB	J-RCC-TI-112HC	J-RCD-TI-112HD	J-RCN-TI-111X	J-RCN TI-111X
Pressurizer pressure	J-RCA-PI-102A & PR-102A	J-RCB-PI-102B	J-RCC-PI-102C	J-RCD-PI-102D	-	J-RCN-PIK-110 & PR-100
Pressurizer level	J-RCA-LI-110X & LR-110X	J-RCB-LI-110Y	-	-	J-RCN-LIC-110 LR-110 & LI-113	-
SG pressure	J-SGA-PI-1013A PI-1023A & PR-1013A	J-SGB-PI-1013B & PI-1023B	J-SGC-PI-1013C & PI-1023C	J-SGD-PI-1013D & PI-1023D	-	-
SG level	J-SGA-LI-1113A & LR-1113A	J-SGB-LI-1113B	J-SGC-LI-1113C	J-SGD-LI-1113D	-	-
RWT level	J-CHA-LI-203A & J-CHA-LI-200-1	J-CHB-LI-203B & LI-201	J-CHC-LI-203C	J-CHD-LI-203D	J-CHN-LI-200	J-CHN-LI-200
Charging flow	J-CHA-FI-212	-	-	-	-	-
Charging pressure	-	J-CHB-PI-212	-	-	-	-
SIT pressure	J-SIA-PI-331 & PI-333	J-SIB-PI-311 & PI-313	-	-	J-SIN-PI-332	J-SIN-PI-312
LPSI pump flow	J-SIA-FI-306	J-SIB-FO-307	-	-	-	-
Shutdown cooling heat exchanger diff. temp.	J-SIA-TR-351 & TI-303X	J-SIB-TR-352 & TI-303Y	-	-	-	-
Atmospheric dump valve control	J-SGA-HIC-179A & HIC-184A	J-SGB-HIC-178A & HIC-185A	-	-	-	-

In response to [Area] 1.c, we have determined that loss of a single instrument distribution panel, Class 1E or non-Class 1E, will cause a loss of some of the indicators and recorders available to the control room operator. This failure mode is distinguishable and will not offer confusing information to the operator since the instrumentation and control systems lost will generate alarms and actuation of some equipment as the loop output contacts fail to their deenergized states. In addition, the loss of power to each analog instrument cabinet is alarmed in the control room. In the non-Class 1E instrument loops affecting safe shutdown circuits, i.e., pressurizer level control of the pressurizer backup heaters, selector switches are provided on the main control panel to enable the operator to provide control from the unaffected control loop. No control action generated by the loss of an instrument distribution panel will prevent the operator from controlling the required safe shutdown equipment or interfere with the safe shutdown functions. Upon detection of loss of an instrument distribution panel, adequate instrumentation and control functions from the list provided above will be available to the operator to enable the operator to achieve a cold shutdown condition. No design modifications are proposed.

Action Item 2.

Emergency procedures that will be used by control room operators, including procedures required to achieve a cold shutdown condition, upon loss of power to each Class 1E and non-Class 1E bus supplying power to safety- and nonsafety-related instruments and control systems will be prepared and

then reviewed at least 3 months prior to the operating license. The procedures will include the following information:

A. The diagnostics/alarms/indicators/symptom resulting from the review and evaluation conducted per Item 1 of IE Bulletin No. 79-27.

B. The use of alternate indication and/or control circuits which may be powered from other non-Class 1E or Class 1E instrumentation and control buses.

C. Methods for restoring power to the bus.

A description of any proposed design modifications or administrative controls to be implemented resulting from these procedures, and the proposed schedule for implementing the changes will also be provided.

Action Item 3.

IE Circular No. 79-02, Failure of 120 Volt Vital AC Power Supplies, has been re-reviewed in consideration of item 3 to include both Class 1E and non-Class 1E instrument distribution panel supplies. For the Class 1E inverters, the PVNGS design precludes the possibility of a transient causing a failure of a Class 1E inverter by utilizing a battery source in parallel with a dc charger. The battery source serves to eliminate any undervoltage transients that the charger may experience.

The non-Class 1E instrument distribution panels are not supplied through inverters. Both the normal and backup supplies are fed from 480 V-ac through a voltage regulator-transformer. The transfer switch will automatically transfer, upon loss of power on the normal source, to the

backup source. Manual transfer is required to return to the normal source. The switch is also equipped with a mechanical handle which bypasses electric circuitry and can switch to either source. No design modifications are proposed.

7.1.2.34 Evaluation of IE Bulletin 80-06

The ESF actuation signals incorporated in the PVNGS design include:

A. NSSS ESFAS

- Containment isolation actuation signal (CIAS)
- Containment spray actuation signal (CSAS)
- Main steam isolation signal (MSIS)
- Safety injection actuation signal (SIAS)
- Recirculation actuation signal (RAS)
- Auxiliary feedwater actuation signals (AFAS) 1 and 2

B. BOP ESFAS

- Fuel building essential ventilation actuation signal (FBEVAS)
- Containment purge isolation actuation signal (CPIAS)
- Control room ventilation isolation actuation signal (CRVIAS)

- Control room essential filtration actuation signal (CREFAS)

Manual reset of the ESF actuation signals in both the NSSS and BOP systems design can be performed only after the initiating signals, i.e., low pressurizer pressure, have cleared. Reset switches are located at the PPS, ESFAS auxiliary relay, and BOP ESFAS cabinets.

PVNGS equipment which may change position from the safety or emergency state on reset of an ESF actuation signal is identified in table 7.1-3. These actuated devices can be categorized as follows:

A. Certain actuated devices, i.e., jog type valves or the ESF load sequencer, require a maintained ESF signal through completion of their safety function. If an ESF actuation signal is reset prior to completion of the valve stroke or completion of ESF load sequencing, the valve will stop mid-travel or the sequencer will not complete sequencing on the required equipment (equipment already sequenced or does not stop). Since completion of these actions takes no more than 60 seconds, ESF actuation signal reset is not considered. Engineered safety features actuation, followed by clearing of the initiating signals with the requirement of manual reset at the appropriate cabinet, all occurring within a short period of time (<1 minute), is not credible under true accident conditions. No modification to these equipment control circuits is required.

Table 7.1-3

IDENTIFICATION OF ACTUATED DEVICES WHICH CHANGE POSITION ON RESET OF ESF ACTUATION SIGNAL (Sheet 1 of 4)

Actuated Device	Tag No.	Elementary Diagram	ESF Actuation Signal	Safety Mode	Action of ESF Actuation Signal Reset	Corrective Action
Auxiliary feedwater regulating valves to SG 1	J-AFB-HV-30 J-AFA-HV-32	13-E-AFB-003 13-E-AFB-004	AFAS-1	Open/ Close	Valves cycle on AFAS-1	None[(a)]
Auxiliary feedwater regulating valves to SG 2	J-AFB-HV-31 J-AFC-HV-33	13-E-AFB-003 13-E-AFB-006	AFAS-2	Open/ Close	Valves cycle on AFAS-2	None[(a)]
Auxiliary feedwater isolation valves to SG 1	J-AFB-UV-34 J-AFC-UV-36	13-E-AFB-005 13-E-AFB-006	AFAS-1	Open/ Close	Valves cycle on AFAS-1	None[(a)]

a. See Paragraph 7.1.2.34, listing D.

b. See Paragraph 7.1.2.34, listing C.

c. See Paragraph 7.1.2.34, listing A.

Table 7.1-3

IDENTIFICATION OF ACTUATED DEVICES WHICH CHANGE POSITION ON RESET OF ESF ACTUATION SIGNAL (Sheet 2 of 4)

Actuated Device	Tag No.	Elementary Diagram	ESF Actuation Signal	Safety Mode	Action of ESF Actuation Signal Reset	Corrective Action
Auxiliary feedwater isolation valves to SG 2	J-AFB-UV-35 J-AFA-UV-37	13-E-AFB-005 13-E-AFB-010	AFAS-2	Open/ Close	Valves cycle on AFAS-2	None[a]
Fuel building essential exhaust AFU dampers	M-HFA-M05 M-HFB-M05	13-E-HFB-005	SIAS FBEVAS	Closes Opens	SIAS is the priority mode. On reset of SIAS, dampers will reopen if FBEVAS is present.	None[b]
Auxiliary building essential exhaust AFU dampers	M-HFA-M06 M-HFB-M06	13-E-HFB-011	SIAS FBEVAS	Opens Closes	SIAS is the priority mode. On reset of SIAS, dampers will re-close regardless of FBEVAS.	None[b]
Control room essential AHU OSA intake dampers	M-HJA-M02 M-HJA-M03 M-HJB-M02 M-HJB-M03	13-E-HJB-024	SIAS CREFAS CRVIAS	Opens Closes	CRVIAS is the priority mode. On reset of CRVIAS, dampers will reopen if SIAS or CREFAS is present.	None[b]

Table 7.1-3

IDENTIFICATION OF ACTUATED DEVICES WHICH CHANGE POSITION

ON RESET OF ESF ACTUATION SIGNAL (Sheet 3 of 4)

Actuated Device	Tag No.	Elementary Diagram	ESF Actuation Signal	Safety Mode	Action of ESF Actuation Signal Reset	Corrective Action
ESF load sequencers	J-SSA-C02A J-SAB-C02B	13-E-SAB-004	CSAS SIAS AFAS-1 AFAS-2 FBEVAS CRIVAS CREFAS	Sequential starting of ESF pumps and fans	Reset of sequencer outputs depending on ESF actuation signals present. Reset of sequencer outputs does not reset any actuated equipment. Reset prior to completion of sequencing terminates sequence.	None[c]
LP safety injection pumps	M-SIA-P01 M-SIB-P01	13-E-SIB-002	SIAS (via sequencer) RAS	Starts Stops	RAS is the priority mode. On reset of RAS, pumps will restart if SIAS (via sequencer) is present.	None[b]

Table 7.1-3

IDENTIFICATION OF ACTUATED DEVICES WHICH CHANGE POSITION

ON RESET OF ESF ACTUATION SIGNAL (Sheet 4 of 4)

Actuated Device	Tag No.	Elementary Diagram	ESF Actuation Signal	Safety Mode	Action of ESF Actuation Signal Reset	Corrective Action
Safety injection tank isolation valves	J-SIA-UV-634 and -644 J-SIB-UV-614 and -624	13-E-SIB-005 13-E-SIB-006	SIAS	Opens	Jog-type valves may stop mid-travel. Breakers are locked open during power operation.	None(c)
LPSI flow control to reactor coolant valves	J-SIB-UV-615 and -625 J-SIA-UV-635 and -645	13-E-SIB-007 13-E-SIB-008	SIAS	Opens	Jog-type valves may stop mid-travel	None(c)
HPSI flow control to reactor coolant valves	J-SIA-UV- -617, -627, -637, -647 J-SIB-UV- -616, -626, -636, -646	13-E-SIB-009 13-E-SIB-010 13-E-SIB-011 13-E-SIB-012	SIAS	Opens	Jog-type valves may stop mid-travel	None(c)
Containment spray control valves	J-SIA-UV-672 J-SIB-UV-671	13-E-SIB-020	CSAS	Opens	Jog-type valves may stop mid-travel	None(c)

B. An SIAS trips non-ESF equipment (CEDM normal ACU fans, containment normal ACU fans, pressurizer backup heaters, normal chillers) off the 1E buses. On reset of SIAS, this equipment will not be automatically loaded onto the 1E buses, but will be manually loaded onto the 1E buses at the discretion of the operator.

C. Certain actuated devices have different safety modes in response to different ESF actuation signals. In the event that ESF actuation signals requiring both safety modes occur, one safety mode by design will have priority. On reset of that particular ESF actuation signal, the actuated device will change position to the safety mode required by the remaining ESF actuation signal. This means of control does not defeat required ESF system functions, and no modification is required to these equipment control circuits.

D. The AFAS 1 and AFAS 2 signals to the auxiliary feedwater valves are designed to cycle based on steam generator level. This automatic resetting of the AFAS 1 and AFAS 2 does not affect the AFAS 1 and AFAS 2 signals to other actuated equipment. The auxiliary feedwater valve cycling represents the desired ESF system function and no modification is required to the equipment control circuits.

7.1.2.35 Evaluation of IE Information Notice 79-22

The high energy line break (HELB)/control system interaction analysis process employed in the review of the PVNGS Units 1,

2, and 3 design is illustrated by the logic diagram of figure 7.1-1. The events considered are those defined in chapters 6 and 15 of the PVNGS FSAR. The process consists of the following steps:

A. Identification of all nonsafety grade systems or control systems of significance to the FSAR chapters 6 and 15 analyses.

B. Identification of potential adverse control system malfunctions induced by HELB events.

C. Detailed system design reviews of control systems with a potentially significant impact on the course of FSAR chapters 6 and 15 events to determine which, if any, failure modes can be postulated to cause the adverse malfunctions.

D. Identification of the physical locations of control systems components whose malfunctions could be postulated to cause the adverse malfunction and determination if the components can be impacted by the HELB of concern.

E. Resolution of potential HELB/control system interaction issues through the use of backup systems and/or quantitative analyses to determine if the malfunctions effects are acceptable, and through detailed evaluations of the qualification status of control system components.

The HELBs considered in this analysis are: loss-of-coolant accident (LOCA) steam line break (SLB), feedwater line break (FWLB), and reactor coolant system (RCS) breaks which occur

outside of the containment. Completion of listings A through D disclosed four potential HELB/control system interactions which could exacerbate event consequences. These are:

1. Failure of the pressurizer pressure control system (PPCS) to deenergize pressurizer heaters when the low level cutout signal is given. This malfunction is of concern during a LOCA, or SLB due to the potential for the heater failure mode to impact the RCS pressure boundary.

2. Failure of the reactor regulating system (RRS) such that CEAs are withdrawn prior to reactor trip. The resultant core power increase is of concern during LOCA, SLB, and FWLB events.

3. Failure of the steam bypass control system (SBCS) such that the steaming rate is increased. This malfunction is of concern during SLBs because of the potential for a post-trip return to power.

4. Failure of the PLCS such that the RCS inventory is increased. This malfunction is of concern during FWLB events where a potential to fill the pressurizer could exist.

The impacts of the assumed malfunctions were determined in listing E. The results of these investigations demonstrate that the HELB/control system malfunction event consequences are bounded by the event consequences presented in the FSAR. Therefore, no design modifications or operator procedure revisions are needed to mitigate the consequences of HELB/control system interactions.

7.1.3 CESSAR INTERFACES

The following NSSS general interface requirements are repeated from CESSAR Section 7.1.3.

7.1.3.1 Power

Vital instrument power requirements for the safety-related systems are discussed in Section 8.3.1.

7.1.3.2 Protection from Natural Phenomena

Refer to Section 3.1.2. CESSAR Design Scope Class 1E equipment shall be located within the plant so as to ensure the various natural phenomena specified in GDC 2 which are applicable to the Applicant's site will not result in degradation of that equipment below the level required to allow it to perform required protective action assuming a single failure.

7.1.3.3 Protection from Pipe Failure

The location of safety-related instrumentation and control components shall take into account their potential damage due to piping failures, such as pipe whip, jet impingement, etc., from high or medium energy fluid systems.

The location of these components and the routing of 1E and associated cables and sensing lines should avoid such hazards or shall be provided with adequate protection such that required protective action can be performed assuming a single piping failure, its associated effects, and a single failure.

7.1.3.4 Missiles

The safety-related equipment shall be protected from potential missile sources. The 1E and associated cabling and sensing lines shall be handled in a similar fashion.

7.1.3.5 Separation

The routing of 1E and associated cabling and sensing lines from sensors shall be arranged to minimize the possibility of common mode failure. This requires that the cabling for the four safety channels be routed separately, however, the cables of different safety functions within one channel, may be routed together. Low energy signal cables shall be routed separately from all power cables. Safety-related sensors wired to separate channels shall be physically and electrically separated. The separation of their safety-related cables requires that the cables be routed in separate cable trays. Associated circuit cabling from redundant channels shall be separated, provided with isolation, analyzed, or tested to demonstrate that no single credible failure can adversely affect more than one redundant channel.

Non-Class 1E instrumentation circuits and cables (low level) which may be in proximity to associated circuits and cables, are to be treated as associated circuits if analyses or tests demonstrate that credible failures therein could adversely affect Class 1E circuits.

7.1.3.6 Independence

Cabling associated with redundant channels of safety-related circuits shall be installed such that a single credible event

cannot cause multiple channel malfunctions or interactions between channels.

7.1.3.7 Thermal Limitations

The safety-related equipment shall be located so as not to violate the temperature and humidity limits of Section 3.11.

7.1.3.8 Monitoring

Auxiliary and supporting systems for the safety-related instrumentation and controls shall be designed to cause a systems level bypass indication, when they are bypassed or deliberately made inoperable, for the safety-related system which would be affected by the bypassing or deliberate inoperability of the auxiliary or supporting system.

The RPS and ESFAS alarms and the remote PPS and DNBR/LPD Calculator Operator's Modules shall be located in the main control room.

7.1.3.9 Operational Controls

The RPS and ESFAS manual actuation devices shall be located in the control room. The instrumentation and control components of the safe shutdown systems on the Remote Shutdown Panel or at local locations shall be manually operable.

7.1.3.10 Inspection and Testing

The PPS, including sensors, shall be capable of being periodically tested in accordance with the Technical Specifications. Those portions which could adversely affect

reactor operations shall be capable of being tested when the reactor is shut down. All other safety-related instrumentation shall be capable of being tested during normal operation.

7.1.3.11 Chemistry/Sampling

The components of the safety-related equipment shall be located so as not to exceed the chemistry limits specified in Section 3.11.

7.1.3.12 Materials

Not applicable to the safety-related instrument and controls equipment.

7.1.3.13 System Component Arrangement

Safety-related components shall be located so as to conform to the separation, independence, and other criteria specified in this section. The safety-related components shall be located to provide access for maintenance, testing and operation as required.

Analog and digital signals provided to the safety-related components shall not share the same multiconductor cable, unless specifically called for or approved by Combustion Engineering.

7.1.3.14 Radiological Waste

Radiological waste discharge lines or components shall not be routed or located next to protection system electronic

components in a manner that will result in exceeding the radiation limits specified in Section 3.11.

7.1.3.15 Overpressure Protection

The components of the safety-related equipment shall be located so as not to exceed the pressure limits specified in Section 3.11.

7.1.3.16 Related Services

A fire protection system shall be provided to protect the safety-related equipment, including sensors, consistent with GDC 3. This shall include facilities for detection, alarming, and extinguishing of fires. Facilities and methods for minimizing the probability and effects of fires, including fire barriers, fire resistant and non-combustible materials, and other such items, shall be employed whenever possible. Adequate drainage shall be provided if water is used to extinguish fires.

Inadvertent operation or rupture of fire protection systems shall not result in the reduction of the functional capability of safety-related systems or components below that required to perform their safety function.

Physical identification shall be provided to enable plant personnel to recognize that PPS, ESFAS Auxiliary Relay Cabinets, RTSS, and their cabling are safety-related. The cabinets shall be identified by nameplates. A color coding scheme shall be used to identify the physically separated channel cabling from sensor to the PPS (refer to section

7.1.3.5); the same color code shall be used for interbay or intercabinet identification.

Cabling or wiring within a bay at the cabinet which is in the channel of its circuit classification shall not be color coded.

The cabinet nameplates and cabling shall be color coded as follows:

Protective	ESF Trains	Associated
Channel A: Red	A: Red	White Stripe with Red Stripe over Black Jacket or White Stripe over Red Jacket
Channel B: Green	B: Green	White Stripe with Green Stripe over Black Jacket or White Stripe over Green Jacket
Channel C: Yellow		White Stripe with Yellow Stripe over Black Jacket or White Stripe over Yellow Jacket
Channel D: Blue		White Stripe with Blue Stripe over Black Jacket or White Stripe over Blue Jacket

All non-panel mounted protection system instrumentation and control components are identified with a name tag which provides the channel number and the suffix A, B, C, or D to specifically identify the protection channel with which the component is identified.

7.1.3.17 Environmental

Environmental support systems shall be provided to ensure that the environmental conditions of the safety-related systems do not exceed the requirements for 1E equipment as defined in Section 3.11.

7.1.3.18 Mechanical Interaction

Seismic requirements for safety-related equipment are specified in Section 3.10.

7.1.3.19 Plant Monitoring System Inputs

The inputs to the RPS and ESFAS can be sent to the PMS for trending, data logging and other historical functions but are not used for other control functions. These inputs shall have proper isolation to prevent any failure in the PMS from adversely affecting the RPS or ESFAS.

7.1.4 CESSAR INTERFACE EVALUATIONS

Interface requirements listed in CESSAR Section 7.1.3 are met by the PVNGS design as follows:

7.1.4.1 Power

A. Vital instrument power interfaces are discussed in section 8.3.

B. Emergency diesel generator interfaces are discussed in section 8.3.

C. Power source failures are discussed in appendix 7A, Question 7A.4 response.

7.1.4.2 Protection from Natural Phenomena

Refer to subsection 3.1.2 for a description of applicable natural phenomena and references to the appropriate FSAR sections for methods of compliance.

7.1.4.3 Protection from Pipe Failure

Refer to section 3.6 for a description of the design to protect against pipe failures. Also, figures 7.2-1 through 7.2-3 and engineering drawing 13-J-ZYF-009 show locations of Class 1E instruments.

7.1.4.4 Missiles

Refer to section 3.5 for a description of designs provided for protection of 1E systems and components against missile damage.

7.1.4.5 Separation

A. Separation of cabling associated with redundant channels is provided as discussed in paragraph 8.3.1.4.

B. Separation of sensing lines associated with redundant channels is as discussed in subsection 7.1.3.

7.1.4.6 Independence

The installing methods used for redundant channels of safety-related circuits are described in paragraph 8.3.1.4.

7.1.4.7 Thermal Limitations

The C-E environmental criteria are presented in CESSAR Section 3.11 and the environmental qualification parameters for PVNGS are given in Appendix A of the Equipment Qualification Program Manual.

7.1.4.8 Monitoring

A. The bypass/inoperable status system is discussed in subsection 7.5.2.

B. The reactor protective system (RPS) and ESFAS alarms and the remote PPS and DNBR/LPD calculator operator's modules are located in the main control room.

7.1.4.9 Operational Controls

The RPS and ESFAS manual actuation devices are located in the main control room. A description of the remote shutdown capabilities which include manual actuation is in subsection 7.4.1.

7.1.4.10 Inspecting and Testing

PPS and ESFAS sensors are located to permit testing either during reactor operation or during shutdown. The test features are described in subsections 7.2.2 and 7.3.2.

7.1.4.11 Chemistry/Sampling

The components of the safety-related equipment are located to conform to the criteria listed in CESSAR Section 3.11 for C-E scope of supply and Appendix A of the Equipment Qualification Program Manual for the corresponding PVNGS environmental qualification parameters.

7.1.4.12 Materials

Not applicable.

7.1.4.13 System Component Arrangement

Locations have been selected to provide separation and access for maintenance, testing, and operation as discussed in section 7.2.

7.1.4.14 Radiological Waste

Criteria for radiation exposure limits for 1E system electronic components are given in Section 3.11. The methods by which these criteria are met are discussed in sections 3.11 and 12.3.

7.1.4.15 Overpressure Protection

The locations for C-E-furnished 1E equipment shown in figures 7.2-1 through 7.2-3 and engineering drawing 13-J-ZYF-009 meet the overpressure criteria given in CESSAR Section 3.11.

7.1.4.16 Related Services

A. Fire protection design is discussed in subsection 9.5.1.

B. Physical identification of safety-related systems, components, cabinets, and interconnecting cables is described in paragraph 8.3.1.3. The one-out-of-two ESF systems will be identified as follows:

- Channel A - Red
- Channel B - Green

7.1.4.17 Environmental

Environmental support systems are provided and discussed in CESSAR Section 3.11 for C-E scope of supply and sections 6.4 and 9.4 for the PVNGS specific design.

7.1.4.18 Mechanical Interaction

Refer to CESSAR Section 3.10 for C-E scope of supply and to section 3.10 for PVNGS specific design.

7.1.4.19 Plant Monitoring System Inputs

Isolation per Regulatory Guide 1.75 is provided for alarm signals originating from safety-related circuits that terminate in the plant monitoring system.

7.1.5 REFERENCES

1. CENPD-210A, "Description of the C-E Nuclear Steam Supply System Quality Assurance Program", Combustion Engineering, Inc.

2. CENPD-255, "Qualification of Combustion Engineering Class 1E Instrumentation", Combustion Engineering, Inc.

3. CENPD-182, "Seismic Qualification of Instrumentation Equipment", Combustion Engineering, Inc.

4. CENPD-396-P, "Common Qualified Platform Topical Report," Rev. 01, May 2000

7.2 REACTOR PROTECTIVE SYSTEM

7.2.1 DESCRIPTION

7.2.1.1 System Description

The reactor protective system (RPS) consists of sensors, calculators, logic, and other equipment necessary to monitor selected nuclear steam supply system (NSSS) conditions and to effect reliable and rapid reactor shutdown (reactor trip), if any or a combination of the monitored conditions approach specified limiting safety system settings. The system's functions are to protect the core specified acceptable fuel design limits and reactor coolant system (RCS) pressure boundary for incidents of moderate frequency, and also to provide assistance in limiting conditions for certain infrequent events and limiting faults. Four measurement channels with electrical and physical separation are provided for each parameter used in the direct generation of trip signals, with the exception of control element assembly (CEA) position. A coincidence of two like trip signals is required to generate a reactor trip signal. The fourth channel is provided as a spare and allows bypassing of one channel while maintaining a two-out-of-three system.

The reactor trip signal deenergizes the control element drive mechanism (CEDM) coils, allowing all CEAs to drop into the core.

The reactor protective instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 7.2-1.

7.2.1.1.1 Trips

7.2.1.1.1.1 RPS Variable Overpower. The RPS variable overpower trip (RPS VOPT) is provided to trip the reactor when indicated neutron flux power either (1) increases at a great enough rate, or (2) reaches a preset value. The flux signal used is the average of the three linear subchannel flux signals originating in each nuclear instrument safety channel. The trip setpoints are provided in table 7.2-1.

Pre-trip alarms are initiated below the trip value to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.2 High Logarithmic Power Level. The high logarithmic power level trip is provided to trip the reactor when indicated neutron flux power reaches a preset value. The flux signal used is the logarithmic power signal originating in each nuclear instrument safety channel. The setpoint is provided in table 7.2-1. The trip may be manually bypassed by the operator. This bypass point is provided in table 7.2-2.

Pre-trip alarms are initiated below the trip value to provide audible and visible indication of approach to a trip condition. The trip bypass also bypasses the pre-trip alarms.

7.2.1.1.1.3 High Local Power Density. The high local power density trip is provided to trip the reactor when calculated core peak local power density reaches a preset value. The preset value is less than that value which would cause fuel centerline melting. The calculation of the peak local power density is performed by the core protection calculators (CPCs), which compensate the calculated peak local power density to

Table 7.2-1

REACTOR PROTECTIVE SYSTEM DESIGN INPUTS
(Sheet 1 of 3)

Type	Typical Value (full power)	Trip Setpoint	Typical Margin To Trip
High logarithmic power level	NA	≤0.010% of neutron rated thermal power	NA
RPS Variable overpower	100% power	≤110% of rated thermal power(m)	10% power
	0%/min	≤10.6%/min(m)	10.6% min
	NA	≤9.7% band(a)(m)	NA
Low DNBR	1.79(b)	≥1.34(k)	≤0.45
High local power density, kW/ft	≤13.5 (peak)(c)	≤21.0(k)	≥7.5
High pressurizer pressure, psia	2,250	≤2,383	133
Low pressurizer pressure, psia	2,250	≥1,837(d)	413
Low steam generator water level, %(f)	82	≥44.2	37.8
Low steam generator pressure, psia	1039	≥960e	79
High containment pressure, psig	0	≤3.0	3.0
High steam generator water level, %(g)	55	≤91.0	36
Low reactor coolant flow, floor	22.2 psid(h)	≥12.81 psid(j)	9.39 psid
rate	0.0 psi/sec	≤0.112 psid/sec(j)	N/A
band	NA	≤16.87 psid(j)	9.39 psid(n)
Supplementary Protection System Pressurizer Pressure - High, psia	2,250	≤2409	159

Table 7.2-1

REACTOR PROTECTIVE SYSTEM DESIGN INPUTS
(Sheet 2 of 3)

a. % band is percent above measured excore power level.

b. Calculated value of DNBR assures trip conservatively considering all sensor and processing time delays and inaccuracies. Calculated DNBR will be less than or equal to actual core DNBR.

c. Peak value is unit and cycle specific.

d. In MODES 3-4, the value may be decreased manually, to a minimum of 100 psia, as pressurizer pressure is reduced, provided:

(1) the margin between the pressurizer pressure and this value is maintained at less than or equal to 400 psi; and

(2) when the RCS cold leg temperature is greater than or equal to 485 degrees F, this value is maintained at least 140 psi greater than the saturation pressure corresponding to the RCS cold leg temperature.

The setpoint shall be increased automatically as pressurizer pressure is increased until the trip setpoint is reached. Trip may be manually bypassed below 400 psia; bypass shall be automatically removed whenever pressurizer pressure is greater than or equal to 500 psia.

e. In MODES 3-4, value may be decreased manually as steam generator pressure is reduced, provided the margin between the steam generator pressure and this value is maintained at less than or equal to 200 psi; the setpoint shall be increased automatically as steam generator pressure is increased until the trip setpoint is reached.

Table 7.2-1

REACTOR PROTECTIVE SYSTEM DESIGN INPUTS
(Sheet 3 of 3)

f. % of the distance between steam generator upper and lower level wide range instrument nozzles.

g. % of the distance between steam generator upper and lower level narrow range instrument nozzles.

h. Average full power steam generator primary differential pressure.

i. Not Used

j. RATE is the maximum rate of decrease of the trip setpoint. There are no restrictions on the rate at which the setpoint can increase.

FLOOR is the minimum value of the trip setpoint.

BAND is the amount by which the trip setpoint is below the input signal unless limited by Rate or Floor.

Setpoints are based on steam generator differential pressure.

k. As stored within the Core Protection Calculator (CPC). Calculation of the trip setpoint includes measurement, calculational and processor uncertainties. Trip may be bypassed when logarithmic power is < 1E-4% NRTP. Bypass shall be automatically removed when logarithmic power is ≥ 1E-4% NRTP.

l. not used

m. RATE is the maximum rate of increase of the trip setpoint. (The rate at which the setpoint can decrease is no slower than five percent per second.)

CEILING is the maximum value of the trip setpoint.

BAND is the amount by which the trip setpoint is above the steady state input signal unless limited by the rate or the ceiling.

n. Value reported here is the same as the value reported for the floor because the floor overrides the band.

Table 7.2-2

REACTOR PROTECTIVE SYSTEM BYPASSES

Title	Function	Initiated By	Removed By	Notes
DNBR and local power density bypass	Disable low DNBR and high local power density trips	Key-operated switch (1 per channel) (Note 1)	Automatic if power is $\geq 10^{-4}\%$	Allows low power testing
Pressurizer pressure bypass	Disables low pressurizer pressure trip, SIAS, and CIAS	Manual switch (1 per channel) if pressure is <400 psia	Automatic if pressure is ≥500 psia	Allows testing at low pressure and, heatup and cooldown with CEA's withdrawn
High log power level bypass	Disables high logarithmic power level trip	Manual switch (1 per channel) if power is $>10^{-4}\%$	Automatic if power is $\leq 10^{-4}\%$	Bypassed during reactor startup
Trip channel bypass	Disables any given trip channel	Manually by controlled access switch	Same switch	Interlocks allow only one channel for any one type trip to be bypassed at one time

NOTE 1 DNBR and LPD Bypass may be performed from the operations module and the maintenance and test panel by a "soft" switch (i.e., touch screen). A hard-wired key-operated switch is also located in each CPCS cabinet.

account for the thermal capacity of the fuel. A trip results if the compensated peak local power density reaches the preset value. The calculated trip assures that the safety limit for peak fuel centerline temperature is not exceeded. The trip setpoint is given in table 7.2-1. The effects of core burnup are considered in the determination of the local power density trip.

Pre-trip alarms are initiated below the trip value to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.4 Low Departure from Nucleate Boiling Ratio. The low departure from nucleate boiling ratio (DNBR) trip is provided to trip the reactor when the calculated DNBR approaches a preset value. The calculation of DNBR is performed by the CPCs based on core average power, reactor coolant pressure, reactor inlet temperature, reactor coolant flow, and the core power distribution. The calculation includes allowances for sensor and processing time delays and inaccuracies, such that a trip is generated within the CPCs before violation of the DNBR safety limit occurs in the limiting coolant channel in the core, during incidents of moderate frequency. The trip setpoint is given in table 7.2-1.

Pre-trip alarms are initiated above the trip value to provide audible and visible indication of approach to a trip condition.

The CPCs also have several trip functions that monitor parameters to limits other than low DNBR or High Local Power Density. These trip functions are called Auxiliiary Trips and, if a trip is generated, the DNBR and Local Power Density trip

contact outputs are set. Auxiliary Trips do not set the pre-trip contact outputs.

The low DNBR trip incorporates a low pressurizer pressure floor, with the value given in table 7.2-1A. At this pressure, a low DNBR auxiliary trip will automatically occur.

There are two additional trip functions that are based on the analyzed operating space of the limits of the DNBR correlation. The first trip function is a reactor coolant low flow trip, which is set at a low limit for pump rotational speed. If one or more reactor coolant pumps slow down sufficiently to exceed this low limit, penalties are applied to the DNBR and Local Power Density calculated values that are large enough to ensure DNBR and Local Power Density trips are generated. The low flow trip will set the DNBR and Local Power Density trip and pre-trip contact outputs. The second trip function is a quality margin trip that is based on the updated quality at the node of minimum DNBR. If the quality margin exceeds the limit, the DNBR trip and pre-trip contact outputs are set. The quality margin does not affect the Local Power Density trip and pre-trip conditions.

Table 7.2-1A summarizes these additional trip functions (including the CPC Auxliary Trips).

The CPC auxiliary trip response times are consistent with DNBR – low values listed in UFSAR table 7.2-4AA (Reactor Protective Instrumentation Response Times). The CPC program response time is based on the CPC execution periods and functions. All of the trips have a response time of

0.75 seconds with the exception of pump speed, which has a response time of 0.3 seconds.

7.2.1.1.1.5 High Pressurizer Pressure. The high pressurizer pressure trip is provided to trip the reactor when measured pressurizer pressure reaches a high preset value. The trip setpoint is provided in table 7.2-1.

Pre-trip alarms are initiated below the trip setpoint to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.6 Low Pressurizer Pressure. The low pressurizer pressure trip is provided to trip the reactor when the measured pressurizer pressure falls to a low preset value. The trip setpoint for normal operation is provided in table 7.2-1. At pressures below the normal operating range, this setpoint can be manually decreased to a fixed increment below the existing pressurizer pressure down to a minimum value. The incremental and minimum values are given in table 7.2-1. This ensures the capability of a trip when required during plant cooldown.

The trip may be manually bypassed by the operator. This bypass point is provided in table 7.2-2. The bypass is automatically removed as pressure is increased above a fixed value and the low pressure setpoint automatically increases, maintaining the fixed increment between the plant pressure and the setpoint until it reaches and limits at the value for normal operation. These values are shown in table 7.2-1.

REACTOR PROTECTIVE SYSTEM

Table 7.2-1A

CORE PROTECTION CALCULATOR SYSTEM
ADDITIONAL TRIP FUNCTIONS[a]
(Sheet 1 of 2)

Type	**Trip Setpoint**	**Typical Margin to Trip**
AUXILIARY TRIP FUNCTIONS[g]		
1. Core conditions outside analyzed operating space:		
Cold leg temperature, °F(Tc)	Tcmin ≥ 505.0, Tcmax < 590.0	50.0 35.0
Primary pressure, psia (P)	1860 ≥ P < 2388	390 (low), 138 (hi)
Hot pin axial shape index (AHP)	−0.5 ≥ AHP < +0.5	0.5
Integrated one pin radial peak (P1)	1.28 ≥ P1 < 7.0	0.2 (low), 5.5 (hi)
2. Variable Overpower Trip (VOPT)[b]		
Ceiling (% power)	< 110.0	10.0
Rate of change up (% RTP/execution)[c]	≤ 0.000835[(h)] (≤ 1% power/min)	0.000835[(h)]
Rate of change down (% RTP/execution)[c]	≤ 0.01389[(h)] (≤ 16.67% power/min)	0.01389[(h)]
Step or band (% power)	≤ 8.0	NA
Floor (% power)	= 30.0	NA
3. Asymmetric Steam Generator Transient Trip (ASGT)		
Cold leg temperature difference trip setpoint (°F)	≤ 15.0	12.5
Power dependent bias for cold leg temperature difference trip (°F)	= 0.0 At 100% power	0.0
4. Hot leg temperature saturation trip (°F)[d]	Thmax + Therr ≥ TSAT	23
a. Thmax = max hot leg temperature (°F)	NA	NA
b. Hot leg temperature measurement uncertainty bias (°F) (Therr)	= 19.0	NA
5. Number of Reactor Coolant Pumps Running[e]	< 2	NA
6. CPC not in normal operating mode (e.g., in test, in initialization, memory unprotected)[e]	NA	NA

Table 7.2-1A
CORE PROTECTION CALCULATOR SYSTEM
ADDITIONAL TRIP FUNCTIONS[a]
(Sheet 2 of 2)

Type	Trip Setpoint	Typical Margin to Trip
7. Internal processor fault detected[e]	NA	NA
OTHER TRIP FUNCTIONS		
1. Low Reactor Coolant Pump Rotational Speed (fraction of nominal rotational speed)[f]	≥ 0.95	0.05
2. Quality margin at node of minimum DNBR.	> 0.0	0.3

a. CPCS Auxiliary Trip conditions set only the DNBR and LPD trip contact outputs.

b. The VOPT conditions are defined as follows:

CEILING is the maximum value of the trip setpoint.

RATE (up or down) is the maximum rate of increase or decrease of the trip setpoint.

STEP OR BAND is the amount by which the trip setpoint is above the steady state input signal unless limited by the rate or the ceiling.

FLOOR is the minimum value of the trip setpoint.

c. Execution = 50 milliseconds (0.05 seconds) in CPC DNBR and Power Density UPDATE program.

d. The difference between the maximum hot leg temperature including uncertainties and the saturation temperature of water. The saturation temperature of water is based on the primary (pressurizer) pressure input.

e. These trip conditions are yes/no decisions. For CPC operating mode and internal processor faults, the system is either in the condition or not. Normal operation is with all 4 pumps operating. Operations with less than two pumps running is not allowed in Modes 1 and 2.

f. If one or more pumps are determined to be running at or below the trip setpoint, then penalties are applied to the DNBR and Local Power Density values to ensure a trip condition is reached and the trip contact outputs are set.

g. CPC pre-trip annunciators are provided for the following trips, strictly as operator aids; Variable Overpower Trip (VOPT), Axial Shape Index (ASI) Trip, Asymmetric Steam Generator Trip (ASGT), and Hot Leg Saturation Trip.

Pre-trip alarms are initiated above the trip setpoint to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.7 Low Steam Generator Water Level. The low steam generator water level trip is provided to trip the reactor when measured steam generator water level falls to a low preset value. Separate trips are provided from each steam generator. The trip setpoint is provided in table 7.2-1.

Pre-trip alarms are initiated above the trip setpoint to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.8 Low Steam Generator Pressure. The low steam generator pressure trip is provided to trip the reactor when the measured steam generator pressure falls to a low preset value. Separate trips are provided from each steam generator. The trip setpoint during normal operation is provided in table 7.2-1. At steam generator pressures below normal, the operator has the ability to manually decrease the setpoint to a fixed increment below existing system pressure. This is used during plant cooldown. During startup, this setpoint is automatically increased and remains at the fixed increment below generator pressure until it reaches and limits at the value for normal operation. These values are provided in Table 7.2-1.

Pre-trip alarms are initiated to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.9 High Containment Pressure. The high containment pressure trip is provided to trip the reactor when measured containment pressure reaches a high preset value. The trip setpoint is provided in table 7.2-1. The trip is provided as additional design conservatism (i.e., additional means of providing a reactor trip). The high containment pressure trip setpoint is selected in conjunction with the high-high containment pressure setpoint to prevent exceeding the containment design pressure during a design basis LOCA or main steam line break accident.

Pre-trip alarms are initiated to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.10 High Steam Generator Water Level. A high steam generator water level trip is provided to trip the reactor when measured steam generator water level rises to a high preset value. Separate trips are provided from each steam generator. The trip setpoint is provided in table 7.2-1.

Pre-trip alarms are initiated to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.11 Manual Trip. A manual reactor trip is provided to permit the operator to trip the reactor. There are four Manual Trip pushbuttons, each of the pushbuttons operates one of the reactor trip breakers. Depressing either of the pushbuttons in both trip legs will result in a reactor trip. There are also manual reactor trip switches at the reactor trip switchgear.

The remote manual initiation portion of the reactor protective system is designed as an input to the reactor trip switchgear system (RTSS). This design is consistent with the recommendations of Regulatory Guide 1.62. The amount of equipment common to both automatic and manual initiation is kept to a minimum. Once initiated, the manual trip will go to completion as required in Section 4.16 of IEEE Standard 279-971.

7.2.1.1.1.12 Low Reactor Coolant Flow. The low reactor coolant flow trip is provided to trip the reactor when the pressure differential across the primary side of either steam generator decreases below a rate limited variable setpoint, as shown in figure 7.2-0. A separate trip is provided for each steam generator. This function is used to provide a reactor trip for a reactor coolant pump sheared shaft event.

Pre-trip alarms are provided.

7.2.1.1.2 Initiating Circuits

7.2.1.1.2.1 Process Measurements. Various pressures, levels, and temperatures associated with the NSSS and the containment building are continuously monitored to provide signals to the RPS trip bistables. All protective parameters are measured with four independent process instrument channels. A detailed listing of the parameters measured is contained in table 7.2-3. The monitored ranges associated with these parameters are listed in table 7.2-4.

A typical protective channel, as shown in figure 7.2-0A, consists of a sensor/transmitter, converter/power supply,

current loop resistors, indicating meter or recorder, trip bistable/calculator inputs, and outputs for the plant monitoring system (PMS).

The piping, wiring, and components of each channel are physically separated from that of other like protective channels to provide independence. The output of each transmitter is an ungrounded current loop. Exceptions are (1) the nuclear instruments, and (2) the reactor coolant pump speed sensors which provide a pulsed voltage signal. Signal isolation is provided for computer inputs. Each redundant channel is powered from a separate vital ac bus.

7.2.1.1.2.2 CEA Position Measurements The position of each CEA is an input to the RPS. These positions are measured by means of redundant and independent reed switch position transmitters (RSPTs) on each CEA. The RSPTs transmit analog signals to eight redundant and independent control element assembly calculators (CEACs), two for each CPC channel. CEAC 1 in each CPC channel monitors RSPT1 on all CEAs. CEAC 2 in each CPC channel monitors RSPT2 on all CEAs.

Each RSPT consists of a series of magnetically actuated reed switches spaced at intervals along the CEA housing and wired with precision resistors in a voltage divider network (see figure 7.2-0B). A magnet attached to the CEA extension shaft actuates the adjacent reed switches, causing voltages proportional to position to be transmitted for each RSPT. The RSPT assemblies and wiring are physically and electrically separated from each other (see figure 7.2-0C).

Table 7.2-3

REACTOR PROTECTIVE SYSTEM SENSORS

Monitored Variable	Type	Number of Sensors	Location
Neutron flux power	Fission chamber	12	Biological shield
Cold leg temperature	Precision RTD	8	Cold leg piping
Hot leg temperature	Precision RTD	8	Hot leg piping
Pressurizer pressure (wide range)	Pressure transducer	4[a]	Pressurizer
Pressurizer pressure (narrow range)	Pressure transducer	4	Pressurizer
CEA positions	Reed switch assemblies	2/CEA	Control element drive mechanism
Reactor coolant pump speed	Proximity device	4/pump	Reactor coolant pump
Steam generator level (wide range)	Differential pressure transducer	4/steam generator[a]	Steam generators
Steam generator level (narrow range)	Differential pressure transducer	4/steam generator[a]	Steam generators
Steam generator pressure	Pressure transducer	4/steam generator[a]	Steam generators
Containment pressure	Pressure transducer	4[a]	Containment structure
Low steam generator primary differential pressure	Differential pressure transducer	4/steam generator	Steam generators

a. Common with engineered safety feature actuation system.

Table 7.2-4

REACTOR PROTECTIVE SYSTEM MONITORED PLANT VARIABLE RANGES

Monitored Variable	Minimum	Typical (full power)	Maximum
Neutron flux power, %	2×10^{-7} of full power	100 power	200 of full power
Cold leg temperature, °F	465	557	615
Hot leg temperature, °F	375	614	675
Pressurizer pressure (narrow range), psia	1.500	2,250	2,500
Pressurizer pressure (wide range), psia	0	2,250	3,000
CEA positions	full in	NA	full out
Reactor coolant pump speed, rpm	700	1,188	1,200
Steam generator water level, % [(a)]	0	82	100
Steam generator water level, % [(b)]	0	55	100
Steam generator pressure, psia	0	1039	1,524
Containment pressure, psig	-4	0	0
Steam generator primary pressure differential, psid	0	22.2	70

a. % of the distance between the wide range level instrument nozzles (above the lower nozzle).

b. % of the distance between the narrow range level instrument nozzles (above the lower nozzle).

The CEAs are arranged into subgroups that are controlled as control groups of CEAs. The subgroups are symmetric about the core center. The subgroups of a control group are required to move together and to follow a set insertion sequence.

Each CEAC monitors the position of all CEAs within each subgroup. Should a CEA deviate by more than a specific deadband limit, the CEACs will detect the event, sound an annunciator alarm, and transmit appropriate “penalty” factors to the CPCs.

The CPCS displays the position of each regulating, shutdown, and part-strength CEA to the operator in a bar chart format on a visual display. Optical isolation is utilized at each CPC channel to the CEA position display. The operator has the capability to select any channel for display. Selecting CPC channel A or B will display RSPT1. Selecting channels C or D will display RSPT2.

The CPCs utilize 22 selected “target” CEA position reed switch signals as a measure of CEA subgroup and group position. When the CPCs determine that the subgroups of a control group are not moving together, or that the control groups are not moving in the required sequence, they generate penalty factors. The CPCs utilize single CEA deviation penalty factors from the CEACs to modify calculational results in a conservative manner. These factors may result in a reduction in margins-to-trip for low DNBR and high LPD. This assures conservative operation of the RPS during CEA deviations which require a RPS trip. The detailed signal paths of CEA position information within the RPS are shown in figure 7.2-0D. Raw analog RSPT inputs undergo

analog to digital conversion in each of two redundant CEA position processors (CPPs) in each CPC channel. Each CPP transmits CEA position to the appropriate CEAC in all four CPC channels over isolated data links. The CPP also transmits target CEA position to the CPC processor in the same channel over the CEAC to CPC data link.

7.2.1.1.2.3 Excore Neutron Flux Measurements. The excore nuclear instrumentation includes neutron detectors located around the reactor core, and signal conditioning equipment located within the containment and the auxiliary building. Neutron flux is monitored from source levels through full power operation, and signal outputs are provided for reactor protection and information display. There are four channels of safety instrumentation (see figure 7.2-0E).

The four safety channels provide neutron flux information from startup neutron flux levels to 200% of rated power covering a single range of approximately 2 x 10^{-7} to 200% power (9 decades). Each safety channel consists of three fission chambers, a preamplifier and a signal conditioning drawer containing power supplies, a logarithmic amplifier (including combination counting and mean square variation techniques), linear amplifiers, test circuitry, and a rate-of-change of power circuit. These channels provide signals for the rate-of-change power display, RPS for logarithmic power level high and variable over power trips, and CPCs for use in calculations for low DNBR and high LPD trips.

The detector assembly provided for each safety channel consists of three identical fission chambers stacked vertically along

the length of the reactor core. The use of multiple subchannel detectors in this arrangement permits the determination of axial power shape during power operation.

The fission chambers are mounted in holder assemblies which in turn are located in four dry instrument wells (thimbles) at the primary shield. The wells are spaced around the reactor vessel to provide optimum neutron flux information.

Preamplifiers for the fission chambers are mounted outside the primary shield, with two inside containment, and two outside containment in the auxiliary building. Physical and electrical separation of the preamplifiers and cabling between redundant channels are provided.

7.2.1.1.2.4 Reactor Coolant Flow Measurements. The speed of each reactor coolant pump motor is measured to provide a basis for calculation of reactor coolant flow through each pump. The measurement of reactor coolant pump speed is accurate to within 0.43% of the actual pump speed. This requirement is only applicable to pump speeds greater than 700 rpm. Two metal discs, each with 44 uniformly spaced slots about its periphery, are scanned by proximity devices. The metal discs are attached to the pump motor shaft, one to the upper portion and one to the lower portion (see Figure 7.2-0F). Each scanning device produces a voltage pulse signal. The pulse train that is input to the CPCs to calculate flow rate is based upon every n^{th} pulse from the scanning device. The frequency of this pulse train is proportional to pump speed. Adequate separation between proximity devices is provided.

The mass flow rate is obtained using the pump speed inputs from the four reactor coolant pumps, the cold leg temperatures, and the hot leg temperatures. The volumetric flow rate through each reactor coolant pump is dependent upon the rotational speed of the pump and the pump head. This relationship is typically shown in pump characteristic curves. Flow changes resulting from changes in the loop flow resistances occur slowly (i.e., core crud buildup, increase in steam generator resistance, etc.). Calibration of the calculated mass flow rate will be performed periodically using instrumentation which is not part of the reactor coolant pump speed sensing system.

Flow reductions associated with pump speed reductions are more rapid than those produced from loop flow resistance changes. Mass flow rate is calculated for each pump from the pump speed, the density of the cold leg coolant, and a correction term based on hot leg temperature.

The mass flow rates calculated for each pump are summed to give a core mass flow rate. This flow rate is then used in the CPC DNBR and ΔT power algorithms.

7.2.1.1.2.5 Core Protection Calculators. The core protection calculator (CPC) system and CEA calculators provide their outputs and a number of their inputs as inputs to the plant monitoring system (PMS) by means of fiber-optic communication.

The CPC/CEAC data processing programs within the PMS perform cross-channel comparisons for each input signal and generate an alarm whenever the difference between any single channel's value and the average value of all four channels is greater

than a constant. On operator demand, a report is printed to show the results of the latest cross-channel comparison. Some CPC and CEAC parameters are also used to calculate and alarm CPC Aux trip pretrips on the CMC. The CPC and CEAC parameters are not supplied to or used by any program in the plant computer. Some CPC and CEAC parameters are supplied to the plant computer.

Four independent CPCs are provided, one in each protection channel. Calculations of DNBR and LPD are performed in each CPC, utilizing the input signals described below. The DNBR and LPD calculated are compared with trip setpoints for initiation of a low DNBR trip (paragraph 7.2.1.1.1.4) and high LPD trip (paragraph 7.2.1.1.1.3).

Two independent CEA calculators (CEACs) in each channel are provided as part of the CPC system to calculate individual CEA deviations from the position of the other CEAs in their subgroup.

Redundant CEA position processors (CPPs) mounted within each CPCs channel process all channel RSPT inputs. CPPs process target CEA position for use by the CPC in the channel of origin. CPPs also process CEA position for use in the CEACs in all four channels. CPPs in channels A and B provide RSPT 1 CEA positional data on all CEAs to CEAC 1 in all four CPC channels. CPPs in channels C and D provide RSPT 2 CEA positional data on all CEAs to CEAC 2 in all four CPC channels. Cross channel communication of CEA positional information from the CPPs to CEACs utilizes one-way isolated data links.

As shown in figure 7.2-0G, each CPC receives the following inputs: core inlet and outlet temperature, pressurizer pressure, reactor coolant pump speed, excore nuclear instrumentation flux power (each subchannel from the safety channel), selected CEA positions, and penalty factors for CEA deviations within a subgroup from the CEACs. Input signals are conditioned and processed. The following calculations are performed in the CPC or the CEACs:

A. CEA deviations;

B. Correction factor for excore flux power for shape annealing and CEA shadowing;

C. Reactor coolant flowrate from reactor coolant pump speeds and temperatures;

D. ΔT power from reactor coolant temperatures, pressure, and flow information;

E. Excore flux power: excore flux power signals are summed and corrected for CEA shadowing, shape annealing, and cold leg temperature shadowing. This corrected flux power is periodically calibrated to the actual core power measured independently of the reactor protective system. This calibration does not modify the inherent fast time response of the excore signals to power transients;

F. Axial power distribution from the corrected excore flux power signals;

G. Fuel rod and coolant channel planar radial peaking factors, selection of predetermined coefficients based on CEA positions;

H. DNBR;

I. Comparison of DNBR with a fixed trip setpoint;

J. Local power density;

K. Comparison of local power density with a fixed trip setpoint;

L. CEA deviation alarm;

M. Variable overpower trip (VOPT) and comparison of maximum power with VOPT setpoint;

N. Reactor coolant pump (RCP) speed and comparison of RCP speed with a minimum RCP speed trip setpoint; and

O. Compensated cold leg temperature difference and comparison of the compensated cold leg temperature difference to a cold leg temperature difference trip setpoint.

The Primary Outputs of each CPC are:

- Low DNBR trip and pretrip;
- DNBR margin (to control board indication);
- High local power density trip and pretrip;
- Local power density margin (to control board indication);
- Calibrated neutron flux power (to control board indication); and

- Control element assembly withdrawal prohibit (CWP).

Each calculator is mounted in the auxiliary protective cabinet with an operator's display and control module located on the main control board. From the four modules an operator can monitor all calculators, including specific inputs or calculated functions.

7.2.1.1.2.6 Trip Generation. Signals from the trip parameter process measurement loops are sent to voltage comparator circuits (bistables) where the input signals are compared to predetermined trip values (Figure 7.2-6). Whenever a channel trip parameter reaches the trip value, the channel bistable deenergizes the bistable output relay. The bistable output relay or, in the case of trips generated by the Core Protection Calculators, an external trip contact deenergizes trip relays. Outputs of the trip relays are in the trip logic (refer to Section 7.2.1.1.3).

The trip bistable setpoints are adjustable from the PPS cabinet. Access is limited, however, by means of a key-operated cover with an annunciator indicating cabinet door access. All bistable setpoints are capable of being read out on a meter located on the PPS cabinet.

Pretrip bistables and relays are also provided to generate audible and visible alarms.

7.2.1.1.2.7 CPC Software Design. The CPC software requirements specification descriptions of the CEAC and CPC algorithms in Reference 23 includes symbolic algebra. It

includes system requirements affecting the software, hardware, and man-machine interface design.

Typical software test results of Phase I and Phase II software testing are provided in Reference 17 and Reference 18. Typical CPC database material is provided in Reference 19.

The generation of detailed software design documentation and test documentation is included as part of the structured quality assurance design documentation. These types of design documents have been used in the design process on PVNGS 1, 2, and 3 and include the CPC system requirements specifications[23] and a data base document.

Subsequent to the completion of the PVNGS CPC software base design, any revisions to the PVNGS software base design and test documentation will be prepared in accordance with the protection algorithm software change procedure in Reference 20.

The algorithms associated with the CPC Improvement Program as described in CEN-304-P[6], CEN-305-P[1], CEN-308-P-A[15], CEN-310-P-A[16], and CEN-330-P-A[11], were implemented in Cycle 2 and apply to all subsequent cycles. Values for the Reload Data Block (RDB) constants will be evaluated for applicability and consistent with the cycle design, performance, and safety analyses. Any necessary changes to the RDB constants will be accomplished by a vendor in accordance with Reference 21 or by the Nuclear Fuel Management (NFM) Department in accordance with the NFM Design Control.[14]

Trip setpoints, uncertainty factors, and other addressable constants are determined consistent with the methodology and

software established in the CPC Improvement Program. Uncertainty factors are determined using the methods contained in CEN-356(V)-P-A.[13]

7.2.1.1.3 Logic

Tripping of a bistable (or trip contact opening in the case of a calculated trip) results in a channel trip which is characterized by the deenergization of three bistable trip relays (see Figure 7.2-8).

Contacts from the bistable relays of the same parameter in the four protective channels are arranged into six logic AND's, designated AB, AC, AD, BC, BD, and CD, which represent all possible coincidence of two combinations. To form an AND circuit, the bistable trip relay contacts of two like protective measurement channels are connected in parallel (e.g., one from A and one from B). This process is continued until all combinations have been formed.

Since there is more than one parameter that can initiate a reactor trip, the parallel pairs of bistable trip relay contacts for each monitored parameter are connected in series (Logic OR) to form six logic matrices. The six matrices are designated AB, AC, AD, BC, BD and CD.

Each logic matrix is connected in series with a set of four matrix output relays (matrix relays). Each logic matrix is powered from two separate 120V vital ac distribution buses through dual dc power supplies, as shown on Figure 7.2-8. The power supplies are protected from overload by means of input and/or output fuses or circuit breakers.

The contacts of the matrix relays are combined into four initiation circuits, one initiation circuit per channel.

Each reactor initiation circuit is formed by connecting six contacts (one matrix relay contact from each of the six logic matrices) in series. The six series contacts are in series with the initiation output relay. The initiation output relays serve to deenergize the Reactor Trip Switchgear System (RTSS) breakers as discussed in section 7.2.1.1.4.

7.2.1.1.4 Actuated Devices

The above logic causes the deenergizing of the four initiation relays whenever any one of the logic matrices is deenergized as described. Each initiation circuit output relay in turn will cause one trip circuit breaker in the RTSS to open. See Figure 7.2-8.

Power input to the RTSS comes from two full-capacity motor-generator sets, so that the loss of either set does not cause a release of the CEAs. Each line passes through two trip circuit breakers (each actuated by a separate initiation circuit) in series so that, although both sides of the branch lines must be deenergized to release the CEAs, there are two separate means of interrupting each side of the line. Upon removal of power to the CEDM power supplies, the CEAs fall into the reactor core by gravity.

Two sets of manual trip pushbuttons are provided to open the trip circuit breakers, if desired. The manual trip completely bypasses the trip logic. As can be seen in Figure 7.2-8, both

manual trip pushbuttons in a set must be depressed to initiate a reactor trip.

The trip switchgear is housed in separate cabinets from the RPS. In addition to the trip circuit breakers, the cabinet also contains current monitoring devices for testing purposes and pushbuttons on each RTSG which allow for reactor trip from a location other than the control room.

7.2.1.1.5 Bypasses

The bypasses listed in table 7.2-2 are provided to permit testing, startup, and maintenance. The bypass setpoints are provided in table 7.2-2.

The DNBR and local power density bypass, which bypasses the low DNBR and high local power density trips from the CPC, is provided to allow system tests at low power when pressurizer pressure may be low or reactor coolant pumps may be off. The bypass may be manually initiated if power is below the bypass setpoint and is automatically removed when the power level increases above the bypass setpoint.

The RPS/ESFAS pressurizer pressure bypass is provided for two conditions: (1) system tests at low pressure, and (2) heatup and cooldown with shutdown CEA's withdrawn. The bypass may be manually initiated if pressurizer pressure is below the bypass setpoint. The bypass is automatically removed as pressure is increased above the bypass setpoint.

The high logarithmic power level bypass is provided to allow the reactor to be brought to the power range during a reactor startup. The bypass may be manually initiated above the bypass

setpoint and is automatically removed when power decreases below the bypass setpoint.

The trip channel bypass is provided to remove a trip channel from service for maintenance or testing. The trip logic is thus converted to a two-out-of-three basis for the trip type bypassed; other type trips that do not have a bypass in any of their four channels remain in a two-out-of-four logic. The bypass is manually initiated and manually removed. The circuit utilized to accomplish the trip channel bypass is shown in Figure 7.2-10. This circuit, which is repeated for each type trip, contains an electrical interlock which allows only one channel for any one type trip to be bypassed at one time.

All bypasses are annunciated visibly to the operator.

7.2.1.1.6 Interlocks

The following interlocks are provided:

A. Trip Channel Bypasses

   An interlock prevents the operator from bypassing more than one trip channel at a time for any one type of trip. Different type trips may be simultaneously bypassed, either in one channel or in different channels.

B. Matrix Tests

   During system testing an electrical interlock will allow only the matrix relays in one of the six matrix test modules to be held at a time. The same circuit will allow only one bistable input signal to be perturbed at a time (see Figure 7.2-9).

C. Nuclear Instrumentation Test

Placement of the linear calibration switch on the NI drawer to other than "operate" will cause a channel variable overpower trip. Placement of the logarithmic calibration switch to other than "operate" will cause a channel high logarithmic power trip. In addition to these two trips, placing either of these calibration switches, or any other calibration switch on the NI drawer to other than "operate" will cause a Power Trip Test interlock to generate a low DNBR and high LPD trip in that channel.

D. Core Protection Calculation Test

The low DNBR and high local power density channel trips are interlocked such that they both must be bypassed to test a CPC channel.

7.2.1.1.7 Redundancy

Redundant features of the RPS include:

A. Four independent channels, from process sensors through and including channel trip relays. The CEA position input is from two independent channels.

B. Six logic matrices which provide the coincidence of two logic. Dual power supplies are provided for the matrix relays.

C. Four initiation circuits, including four control logic paths and four initiation relays.

D. Four manual trip pushbuttons with either of the pushbuttons in both trip legs being sufficient to cause a reactor trip.

E. AC power for the system from four separate vital instrument buses. DC power for the trip switchgear circuit breakers control logic is provided from four separate battery buses.

The result of the redundant features is a system that meets the single failure criterion, can be tested during reactor operation, and can be indefinitely shifted to two-out-of-three logic and retain a coincidence of two for trip.

The benefit of a system that includes four independent and redundant channels is that the system can be operated, if need be, with up to two channels out of service (one bypassed and another tripped) and still meet the single failure criterion. The only operating restriction while in this condition (effectively one-out-of-two logic) is that no provision is made to bypass another channel for periodic testing or maintenance. The system logic must be restored to at least a three operating channel condition prior to removing another channel for maintenance.

7.2.1.1.8 Diversity

The system is designed to eliminate credible multiple channel failures originating from a common cause. The failure modes of redundant channels and the conditions of operation that are common to them are analyzed to assure that a predictable common

failure mode does not exist (Reference 2). The design provides reasonable assurance that:

a. The monitored variables provide adequate information during design basis events (design basis events are listed in Sections 7.2.2.1.1 and 7.2.2.1.2).

b. The equipment can perform as required.

c. The interactions of protective actions, control actions and the environmental changes that cause, or are caused by, the design basis events do not prevent the mitigation of the consequences of the event.

d. The system will not be made inoperable by the inadvertent actions of the operating and maintenance personnel.

In addition, the design is not encumbered with additional components or channels without reasonable assurance that such additions are beneficial.

7.2.1.1.9 Testing

Provisions are made to permit periodic testing of the complete RPS with the reactor operating at power or when shutdown. These tests cover the trip actions from sensor input through the protective system and the trip switchgear. The system test does not interface with the protective function of the system. The testing system meets the criteria of IEEE 338-1971, "IEEE Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection System", and is consistent with the recommendations of NRC Regulatory Guide 1.22, "Periodic Testing of Protection System Actuator Functions."

The individual tests are described briefly below. Overlap between individual tests exists so that the entire RPS can be tested. Frequency of accomplishing these tests are listed in the Technical Specifications.

7.2.1.1.9.1 Sensor Check

During reactor operation, the measurement channels providing an input to the RPS are checked by comparing the outputs of similar channels and cross-checking with related measurements.

During extended shutdown periods or refueling, these measurement channels (where possible) are checked and calibrated against known standards.

7.2.1.1.9.2 Trip Bistable Tests

Testing of the trip bistables is accomplished by manually varying the input signal up to or down to the trip setpoint level on one bistable at a time and observing the trip action (Figure 7.2-6).

Varying the input signal is accomplished by means of a trip test circuit consisting of a digital voltmeter and a test circuit used to vary the magnitude of the trip signal supplied by the measurement channel to the trip input. The trip test circuit is interlocked electrically so that it can be used in only one channel at a time. A switch is provided to select the measurement channel, and a pushutton is provided to apply the test signal. The digital voltmeter indicates the value of the test signal. Trip action (deenergizing) of each of the bistable trip relays is indicated by individual lights on the

front of the cabinet, indicating that these relays operate as required for a bistable trip condition.

The variable setpoint bistable can be tested by manually varying a simulated process input signal. Upon decreasing this input the setpoint is verified to remain constant and the trip setpoint is within specified tolerances. By manually decreasing this input and then depressing the setpoint reset, the setpoint incremental change can be tested and verified. The tracking ability of the circuit can be tested by manually increasing the test input and observing that the setpoint tracks.

The rate limited variable setpoint bistable is tested in three different ways. Using a test ramp generator, the rate of change limit on the setpoint is verified to be within specified limits. The circuit is tested to verify that the setpoint will track the signal when it increases or decreases and maintains the proper separation (it should be noted that the setpoint is still rate limited so that a rapid change in the test signal may cause it to catch the setpoint as it increases and cause a trip). The third test verifies the trip setpoint limit accuracy by use of a manual test system. When one of the bistables of a protective channel is in the tripped condition, a channel trip exists and is annunciated on the control room annunciator panel. In this condition, a reactor trip would take place upon receipt of a trip signal in one of the other three like trip channels. The trip channel under test is therefore bypassed for this test, converting the RPS to a two-out-of-three logic for the particular trip parameter. In either case, full protection is maintained.

7.2.1.1.9.3 Core Protection Calculator Tests

The sensor inputs to each calculator are compared between units. Predetermined test inputs are then inserted into one calculator at a time. The calculator outputs are then checked for specific values. Multiple tests can be performed to check each phase of the calculator program.

The checking of the trip relays for the calculator-generated trips is conducted as described in Paragraph 7.2.1.1.9.2 by initiating a calculator trip and observing the individual bistable relay trip lights.

7.2.1.1.9.4 Logic Matrix Test

This test is carried out to verify proper operation of the six two-out-of-four logic matrices, any of which will initiate a bonafide system trip for any possible coincidence of two trip conditions from the signal inputs from each measurement channel.

Only the matrix relays in one of the six logic matrix test modules can be held in the energized position during tests. If, for example, the AB logic matrix hold switch is rotated to the "HOLD" or "TRIP" positions, actuation of the other matrix hold switches will have no effect upon their respective logic matrices.

Rotating the switch to the hold position will apply a test voltage to the test system hold coils of the selected double coil matrix relays. This voltage will provide the power necessary to hold the relays in their energized position when deactuation of the bistable trip relay contacts in the matrix

ladder being tested causes deenergization of the primary matrix relay coils. The bistable trip relay contacts are deactuated when the matrix hold switch is rotated to the "TRIP" position.

The logic matrix to be tested is selected using the system channel trip select switch. Then while holding the matrix hold switch in the "TRIP" position, rotation of the channel trip select switch will release only those bistable trip relays that have operating contacts in the logic matrix under test. The channel trip select switch applies a test voltage of opposite polarity to the bistable trip relay test coils, so that the magnetic flux generated by the coils opposes that of the primary coil of the relay. The resulting flux will be zero, and the relays will release. A simplified diagram of this testing system is shown in Figure 7.2-7 using the AB matrix.

Trip action can be observed by illumination of the trip relay indicators located on the front panel and by loss of voltage to the four matrix relays, which is indicated by extinguishing indicator lights connected across each matrix relay coil.

During this test, the matrix relay "hold" lights will remain on, indicating that a test voltage has been applied to the holding coils of the matrix relays of the logic matrix module under test.

The test is repeated for all six matrices and for each actuation signal. This test will verify that the bistable relay contacts operate correctly and that the logic matrix relays will deenergize if the matrix continuity is violated. The opening of the matrix relay contacts is tested in the trip path tests (see Section 7.2.1.1.9.5).

Each logic matrix test module provides the associated test circuitry for both the RPS and ESFAS logic matrices. The system channel trip select switch permits the selection of the desired actuation logic matrix to be tested as can be seen in Figure 7.2-8.

7.2.1.1.9.5 Trip Path/Circuit Breaker Tests

Each trip path is tested individually by rotating a matrix hold switch to the "TRIP" position (holding matrix relays), selecting any trip position on the channel trip select switch (opening the matrix), and selecting a matrix relay on the matrix relay trip select switch (deenergizing one of the matrix relays). This will cause one, and only one, of the trip paths to deenergize, causing one trip circuit breaker to open. CEDMs remain energized via the other trip circuit breakers.

The dropout lamps shown on Figures 7.2-7 and 7.2-8 are used to provide additional verification that the matrix relay has been deenergized, (e.g., the 6AB-1 matrix relay contact energizes the dropout lamp). Since the matrix test modules are also utilized for the ESFAS logic matrix testing, this dropout lamp is also shared via contacts 1AB-1 through 5AB-1 as shown on Figure 7.2-8. Proper operation of the actual trip path matrix relay contacts is verified by the trip path lamp located on the trip status panel.

Proper operation of all coils and contacts is verified by lights on a trip status panel; final proof of opening of the trip circuit breakers is the lack of indicated current through the trip breakers.

The matrix relay trip select switch is turned to the next position, reenergizing the tested matrix relay and allowing the trip breakers to be manually reset.

This sequence is repeated for the other three trip paths from the selected matrix. Following this the entire sequence is repeated for the remaining five matrices. Upon completion, all 24 matrix relay contacts and all 4 trip paths and breakers will have been tested.

7.2.1.1.9.6 Manual Trip Test

The manual trip feature is tested by depressing one of the four manual trip pushbuttons, observing a trip of a trip breaker, and resetting the breaker prior to depressing the next manual trip pushbutton.

7.2.1.1.9.7 Bypass

The system bypasses, as itemized in Table 7.2-2, are tested by appropriate test circuitry. Testing includes both initiation and removal features.

7.2.1.1.9.8 Response Time Tests

Time testing is addressed in the Technical Specifications. The methods, equipment, and test frequency are also provided in the Technical Specifications. The reactor protective instrumentation response time limits are identified in table 7.2-4AA.

7.2.1.1.10 Vital Instrument Power Supply

The vital instrument power supply requirements are discussed in section 7.2.3 and Chapter 8.0.

7.2.1.2 Design Bases

The RPS is designed to assure adequate protection of the fuel, fuel cladding, and RCS boundary during Incidents of Moderate Frequency. In addition, the system is designed to assist the ESF Systems in limiting the consequences of certain Infrequent Events and Limiting Faults. To ensure that these design bases are achieved, the reactor must be maintained within the limiting conditions of operation, as defined in Technical Specifications and the limiting safety system settings.

The system is designed on the following bases to assure adequate performance of its protective function:

A. The system is designed in compliance with the applicable criteria of the "General Design Criteria for Nuclear Power Plants", Appendix A of 10CFR50, July 15, 1971.

B. Instrumentation, function, and operation of the system conforms to the requirements of IEEE Standard 279-1971, "Criteria for Protective Systems for Nuclear Power Generating Stations".

C. System testing conforms to the requirements of IEEE Standard 338-1971, "Trial Use Criteria for Periodic Testing of Nuclear Power Generating Station Protection Systems".

D. The system is designed in consistence with the recommendations of Regulatory Guide 1.53, "Application of the Single-Failure Criterion to Nuclear Power Plant Protective Systems", and Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Functions".

E. The system is designed to determine the following generating station conditions in order to provide adequate protection during Incidents of Moderate Frequency:

   1. Core power (neutron flux);

   2. Reactor coolant system pressure;

   3. DNBR in the limiting coolant channel in the core;

   4. Peak local power density in the limiting fuel pin in the core; and

   5. Steam generator water level.

F. The system is designed to determine the following generating station conditions in order to provide protective action assistance to the ESF during certain Infrequent Events and Limiting Faults:

   1. Core power;

   2. RCS pressure;

   3. Steam generator pressure; and

   4. Containment pressure.

G. The system is designed to monitor all generating station variables that are needed to assure adequate determination of the conditions given in listings E. and F. above, over the entire range of normal operation and transient

conditions. The full power nominal values and the maximum and minimum values that can be sensed for each monitored plant variable are given in Table 7.2-4. The type, number, and location of the sensors provided to monitor these variables are given in Table 7.2-3.

H. The system is designed to alert the operator when any monitored plant condition is approaching a condition that would initiate protective action.

I. The system is designed so that protective action will not be initiated due to normal operation of the generating station.

Nominal full power values of monitored conditions and their corresponding protective action (trip) setpoints are given in Table 7.2-1.

The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays and inaccuracies are taken into account. Response times and analysis setpoints used in the safety analyses are given in Chapter 15.0.

The trip delay times and analysis setpoints provided in Chapter 15.0 are representative of the manner in which the RPS and associated instrumentation will operate. These quantities are used in the transient analysis done in Chapter 15.0. Actual RPS uncertainties and delay times will be obtained from calculations and tests performed on the RPS and associated instrumentation. The verified system uncertainties are factored into all RPS settings and/or setpoints to assure that the system adequately

performs its intended function when the errors and uncertainties combine in an adverse manner.

J. All system components are qualified for environmental and seismic conditions in accordance with IEEE Standard 323-1974, and IEEE Standard 344-1971. Compliance is addressed in section 3.11 and in CENPD-255, "Qualification of Combustion Engineering Class 1E Instrumentation", (Reference 3); and in section 3.10 and CENPD-182, "Seismic Qualification of Instrumentation and Electrical Equipment", (Reference 4). In addition, the system is capable of performing its intended function under the most degraded conditions of the energy supply, as addressed in section 8.3.

K. The Regulatory Guides and IEEE standards the upgraded Core Protection Calculator System (CPCS) were designed to are listed in reference 22. However, Palo Verde has not increased its commitments to these new or revised regulatory guides and standards.

Instrument location layout drawings are presented in figures 7.2-1, 7.2-2, 7.2-3, and engineering drawing 13-J-ZYF-009.

7.2.1.3 Final System Drawings

The signal logics, block diagrams, layout drawings, and test circuit block diagrams are shown in Figures 7.2-0A through 7.2-0G and 7.2-5 through 7.2-14.

The following discussion compares the logics to be found in the preliminary CESSAR with those contained herein. The figure

numbers refer to the numbers used here and are not necessarily those of the preliminary CESSAR.

Figure 7.2-5 shows a simplified block diagram for the SPS.

The simplified functional diagram of Figure 7.2-8 has several changes incorporated. On the table of trip inputs the High Linear Power Level has been replaced with the Variable Overpower Trip. The undervoltage and shunt trip circuits have had contacts from the SPS circuit added. The Reactor Trip Switchgear consisting of nine breakers has been replaced with a four breaker Reactor Trip Switchgear System. These changes create a more reliable means of providing a reactor trip when it is required.

Figure 7.2-11 shows some changes in the interface logic from the PSAR. The first change is that the high-high containment pressure is now provided with a separate transmitter. Secondly, MSIS has added steam generator level signals and containment pressure. Third, the AFAS logic has been added. Finally, the turbine trip has been removed from the RPS.

In addition, for a list of applicable drawings and diagrams, see section 1.7.

Table 7.2-4AA

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES
(Sheet 1 of 2)

FUNCTIONAL UNIT	RESPONSE TIME
I. TRIP GENERATION	
A. Process	
1. Pressurizer Pressure - High	≤ 0.50 seconds
2. Pressurizer Pressure – Low	≤ 1.15 seconds
3. Steam Generator Level – Low	≤ 1.15 seconds
4. Steam Generator Level – High	≤ 1.15 seconds
5. Steam Generator Pressure – Low	≤ 1.15 seconds
6. Containment Presssure – High	≤ 1.15 seconds
7. Reactor Coolant Flow – Low	≤ 1.00 seconds
8. Local Power Density - High	
a. Neutron Flux Power from Excore Neutron Detectors	≤ 0.75 second[a]
b. CEA Positions	≤ 1.35 second[b]
c. CEA Positions: CEAC Penalty Factor	≤ 0.75 second[b]
9. DNBR - Low	
a. Neutron Flux Power from Excore Neutron Detectors	≤ 0.75 second[a]
b. CEA Positions	≤ 1.35 second[b]
c. Cold leg Temperature	≤ 0.75 second[d]
d. Hot leg Temperature	≤ 0.75 second[d]
e. Primary Coolant Pump Shaft Speed	≤ 0.30 second[c] [f]
f. Reactor Coolant Pressure from Pressurizer	≤ 0.75 second[e]
g. CEA Positions: CEAC Penalty Factor	≤ 0.75 second[b]
B. Excore Neutron Flux	
1. Variable Overpower Trip	≤ 0.45 second[a]
2. Logarithmic Power Level – High	
a. Startup and Operating	≤ 0.50 second[a]
b. Shutdown	≤ 0.50 second[a]

Table 7.2-4AA

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES
(Sheet 2 of 2)

FUNCTIONAL UNIT	RESPONSE TIME
C. Core Protection Calculator System	
1. CEA Calculators	Not Applicable
2. CEA Protection Calculators	Not Applicable
D. Supplementary Protection System Pressurizer Pressure - High	$\leq$ 1.15 second
II. RPS LOGIC	
A. Matrix Logic	Not Applicable
B. Initiation Logic	Not Applicable
III. RPS ACTUATION DEVICES	
A. Reactor Trip Breakers	Not Applicable
B. Manual Trip	Not Applicable

a. Neutron detectors are exempt from response time testing. The response time of the neutron flux signal portion of the channel shall be measured from the detector output or from the input of first electronic component in channel.

b. Response time shall be measured from the output of the sensor.

c. The pulse transmitters measuring pump speed are exempt from response time testing. The response time shall be measured from the pulse shaper input.

d. Response time shall be measured from the output of the resistance temperature detector (sensor). RTD response time shall be measured in accordance with the Technical Specifications. The measured response time of the slowest RTD shall be less than or equal to 8 seconds.

e. Response time shall be measured from the output of the pressure transmitter. The transmitter response time shall be less than or equal to 0.7 second.

f. The response time for the Seized Rotor Event, 0.865 second, is a theoretical maximum value based on an instantaneous RCP seizure and is not tested.

7.2.2 ANALYSIS

7.2.2.1 Introduction

The RPS is designed to provide the following protective functions:

- Initiate automatic protective action to assure that acceptable RCS and fuel design limits are not exceeded during specified incidents of moderate frequency.
- Initiate automatic protective action during limiting faults to aid the ESF systems in limiting the consequences of certain infrequent events and limiting faults.

A description of the reactor trips provided in the RPS is given in paragraph 7.2.1.1.1. Paragraph 7.2.2.2 provides the bases for all the RPS trips and table 7.2-1 gives the applicable trip setpoints.

Most of the trips in the RPS are single parameter trips (i.e., a trip signal is generated by comparing a single measured variable with a fixed setpoint). The RPS trips that do not fall into this category are as follows:

A. Low pressurizer pressure trip

This trip employs a setpoint that is determined as a function of the measured pressurizer pressure or that is varied by the operator.

B. Low steam generator pressure trip

This trip employs a setpoint that is determined as a function of the measured steam generator pressure or that is varied by the operator.

C. High local power density trip

This trip is calculated as a function of several measured variables.

D. Low DNBR trip

This trip is calculated as a function of several measured variables.

E. Variable overpower trip

This trip employs a setpoint that will track the reactor power as indicated by neutron flux measurements as long as the rate of change is low enough. A fixed ceiling on the setpoint is also incorporated.

F. Low reactor coolant flow trip

This trip employs a setpoint that is determined as a function of the rate of change of the differential pressure across the primary side of the steam generator, a fixed setpoint rate, a predetermined offset from the measured variable, and a minimum limit.

The low DNBR and high LPD trips are provided in the CPCs. All RPS trips are provided with a pre-trip alarm in addition to the trip alarm. Pre-trip alarms are provided to alert the operator to an approach to a trip condition and play no part in the safety evaluation of the plant.

Each RPS setpoint is chosen to be consistent with the function of the respective trip. The adequacy of all RPS trip setpoints, with the exception of the low DNBR and high LPD trips, is verified through an analysis of the pertinent system transients reported in chapter 15. These analyses utilize an analysis setpoint (assumed trip initiation point) and system delay times associated with the respective trip functions. The analysis setpoint along with instrument uncertainties provides the basis for the calculation of the final equipment setpoints to be reported in the Technical Specifications and UFSAR. Limiting trip delay times are given in chapter 15. The manner by which these delay times and uncertainties will be verified is discussed in paragraph 7.2.1.2.

The adequacy of the low DNBR and high LPD trips was certified by a combination of static and dynamic analyses. These analyses provide assurance that the low DNBR and high LPD trips function as required, and provide the justification for the CPC time response assumed in the chapter 15 safety analyses. This is accomplished by certifying that algorithms used in these two trips predict results that are conservative with respect to the results obtained from standard design methods, models, and computer codes used in evaluating plant performance. This verification also takes into account all errors and uncertainties associated with these two trips, in addition to trip delay times, and will assure that the consequences of any incidents of moderate frequency do not include violation of specified acceptable fuel design limits. Examples of the computer codes that will be used in this verification are given in chapter 15.

7.2.2.1.1 Incidents of Moderate Frequency and Infrequent Events

Incidents of moderate frequency and infrequent events that are accommodated by the system are those conditions that may occur one or more times during the life of the plant. In particular, the occurrences considered include single component or control system failures resulting in transients which may require protective action.

The fuel design and RCPB limits used in the RPS design for incidents of moderate frequency are:

- The DNBR, in the limiting coolant channel in the core, shall not be less than the DNBR safety limit;
- The peak LPD in the limiting fuel pin in the core shall not cause the peak fuel centerline temperature safety limit to be exceeded; and
- The RCS pressure shall not exceed established pressure boundary limits.

The incidents of moderate frequency and infrequent events that provide the basis for the system design requirements are:

A. Insertion or withdrawal of full-strength or part-strength CEA groups, including:

   - Uncontrolled sequential withdrawal of CEA groups,
   - Out-of-sequence insertion or withdrawal of CEA groups,

- Malpositioning of the part-strength CEA group, or
- Excessive sequential insertion of full-strength CEA groups;

B. Insertion or withdrawal of full-strength or part-strength CEA subgroups, including:

- Uncontrolled insertion or withdrawal of a CEA subgroup,
- Dropping of one CEA subgroup, or
- Misalignment of CEA subgroups assigned to a designated CEA group;

C. Insertion or withdrawal of a single full-strength or part-strength CEA, including:

- Uncontrolled insertion or withdrawal of a single full-strength or part-strength CEA,
- A dropped 12-finger CEA,
- A single CEA sticking, with the remainder of the CEAs in that group moving, or
- A statically misaligned CEA;

D. Uncontrolled boron dilution;

E. Excess heat removal due to secondary system malfunctions;

F. Change of forced reactor coolant flow resulting from a simultaneous loss of electrical power to all reactor coolant pumps;

G. Inadvertent pressurization or depressurization of RCS resulting from anticipated single control system malfunctions;

H. Change of normal heat transfer capability between steam and reactor coolant systems resulting from improper feedwater flow or a loss of external load and/or turbine trip;

I. Complete loss of ac power to the station auxiliaries;

J. Asymmetric steam generator transient due to instantaneous closure of one MSIV; and

K. Uncontrolled axial xenon oscillations.

7.2.2.1.2 Limiting Faults

The limiting faults for which the system will take action are those unplanned events under any conditions that may occur once during the life of several stations, and certain combinations of unplanned events and degraded systems that are never expected to occur. The consequences of most of these limiting faults will be limited by the ESF systems; the RPS will provide action to assist in limiting these conditions for these limiting faults. The limiting faults for which the RPS will provide protective action assistance are:

- RCS pipe rupture, including double-ended rupture;
- Ejection of any single CEA;
- Steam system pipe rupture, including a double-ended rupture;

- Feedwater system pipe rupture, including a double-ended rupture;
- Reactor coolant pump shaft seizure;
- Depressurization due to inadvertent actuation of primary or secondary safety valves at 100% power;
- A reactor coolant pump sheared shaft; and
- Steam generator tube rupture.

7.2.2.2 Trip Bases

The RPS consists of fifteen trips in each RPS channel that will initiate the required automatic protective action utilizing a coincidence of two like trip signals.

A brief description of the inputs and purpose of each trip is presented in paragraphs 7.2.2.2.1 through 7.2.2.2.11.

7.2.2.2.1 Variable Overpower Trip

7.2.2.2.1.1 Input. The input is neutron flux power from the excore neutron flux monitoring system.

7.2.2.2.1.2 Purpose. This trip assures the integrity of the fuel cladding and RCS boundary in the event of a very rapid power increase, resulting from an uncontrolled withdrawal of CEAs from an initial Hot Zero Power condition. This trip also provides a reactor trip to assist the ESF systems in the event of an ejected CEA limiting fault.

7.2.2.2.2 High Logarithmic Power Level Trip

7.2.2.2.2.1 Input. The input is neutron flux power from the excore neutron flux monitoring system.

7.2.2.2.2.2 Purpose. This trip assures the integrity of the fuel cladding and RCS boundary in the event of unplanned criticality from a shutdown condition, resulting from either dilution of the soluble boron concentration or uncontrolled withdrawal of CEAs. In the event that CEAs are in the withdrawn position, automatic trip action will be initiated. If all CEAs are inserted, the boron dilution alarm system provides an alarm to alert the operator to take appropriate action in the event of an unplanned criticality. The boron dilution alarm system provides high neutron flux alarms to the main control room from the startup channels. This system is separate from, and independent of, the high logarithmic power level trip. The boron dilution alarm system is described in Section 7.7.1.1.11.

7.2.2.2.3 High Local Power Density Trip

7.2.2.2.3.1 Inputs. The inputs are

- Neutron flux power and axial power distribution based on the excore neutron flux monitoring system;
- Radial peaking factors based on CEA position measurement system (RSPTs);
- ΔT power based on coolant temperatures, pressure, and RCP speed measurements;

- Penalty factors from CEACs for CEA deviation within a subgroup; and
- Penalty factors generated within the CPC for subgroup deviation and groups out-of-sequence.

7.2.2.2.3.2 Purpose. This trip prevents the linear heat rate (kW/ft) in the limiting fuel pin in the core from exceeding fuel design limits for incidents of moderate frequency, and also to provide assistance in limiting conditions for certain infrequent events and limiting faults.

7.2.2.2.4 Low DNBR Trip

7.2.2.2.4.1 Inputs. The inputs are

- Neutron flux power and axial power distribution based on the excore neutron flux monitoring system;
- RCS pressure from pressurizer pressure measurement;
- Delta T power based on coolant temperatures, pressure, and RCP speed measurements;
- Radial peaking factors based on CEA position measurement (RSPTs);
- Reactor coolant mass flow based on reactor coolant pump speeds and temperatures;
- Core inlet temperature from reactor coolant cold leg temperature measurements;
- Penalty factors from CEACs for CEA deviation within a subgroup; and

- Penalty factors generated within the CPC for subgroup deviation and groups out-of-sequence.

7.2.2.2.4.2 Purpose. This trip prevents the DNB ratio in the limiting coolant channel in the core from exceeding the fuel design limit in the event of defined incidents of moderate frequency. In addition, this trip will provide a reactor trip to assist the ESF systems in limiting the consequences of the steam line break outside containment, steam generator tube rupture, and reactor coolant pump shaft seizure limiting faults.

7.2.2.2.5 High Pressurizer Pressure Trip

7.2.2.2.5.1 Input. The input is reactor coolant pressure from narrow range (1500 to 2500 psia) pressurizer pressure measurement.

7.2.2.2.5.2 Purpose. This trip helps assure the integrity of the RCS boundary for any defined incident of moderate frequency or infrequent incident that could lead to an overpressurization of the RCS.

7.2.2.2.6 Low Pressurizer Pressure Trip

7.2.2.2.6.1 Input. The input is reactor coolant pressure from wide range (0 to 3000 psia) pressurizer pressure measurement.

7.2.2.2.6.2 Purpose. This trip provides a reactor trip in the event of reduction in system pressure, in addition to the

DNBR trip, and to provide a reactor trip to assist the ESF systems in the event of a LOCA.

7.2.2.2.7 Low Steam Generator Water Level Trips

7.2.2.2.7.1 Input. The input is the level of water in each steam generator downcomer region from wide range differential pressure measurements.

7.2.2.2.7.2 Purpose. These trips provide protective action to assure that there is sufficient time for actuating the auxiliary feedwater pumps to remove decay heat from the reactor in the event of a reduction of steam generator water inventory.

7.2.2.2.8 Low Steam Generator Pressure Trips

7.2.2.2.8.1 Input. The input is the steam pressure in each steam generator.

7.2.2.2.8.2 Purpose. These trips provide a reactor trip to assist the ESF systems in the event of a steam line break.

7.2.2.2.9 High Containment Pressure Trip

7.2.2.2.9.1 Input. The input is pressure inside reactor containment.

7.2.2.2.9.2 Purpose. This trip assists the ESF systems by tripping the reactor coincident with the initiation of safety injection caused by excess pressure in containment.

7.2.2.2.10 High Steam Generator Water Level Trips

7.2.2.2.10.1 Input. The input is the level of water in each steam generator downcomer region from narrow range differential pressure measurements.

7.2.2.2.10.2 Purpose. These trips assist the ESF systems by tripping the reactor coincident with initiation of main steam isolation caused by a high steam generator water level.

7.2.2.2.11 Low Reactor Coolant Flow

7.2.2.2.11.1 Input. The input is pressure differential measured across the steam generator primary side.

7.2.2.2.11.2 Purpose. This trip provides a reactor trip in the event of a reactor coolant pump sheared shaft.

7.2.2.3 Design

7.2.2.3.1 General Design Criteria

Appendix A of 10CFR50, "General Design Criteria for Nuclear Power Plants", establishes minimum requirements for the principle design criteria for water-cooled nuclear power plants. This section describes how the requirements that are applicable to the RPS are satisfied.

Criterion 1 - Quality Standards and Records: Refer to subsection 3.1.1 for compliance.

Criterion 2 - Design Bases for Protection Against Natural Phenomenon: Refer to subsection 3.1.2 for compliance.

Criterion 3 - Fire Protection: Refer to subsection 9.5.1 for compliance.

Criterion 4 - Environmental and Missile Design Bases: Refer to subsection 3.1.4 for compliance.

Criterion 5 - Sharing of Structures, Systems, and Components: Refer to section 3.1.5 for compliance.

Criterion 10 - Reactor Design: Refer to subsection 3.1.6 for compliance. Typical margins between the normal operating value and the trip setpoint are given in table 7.2-1.

Criterion 12 - Suppression of Reactor Power Oscillations: Refer to subsection 3.1.8 for compliance.

The axial power distribution is continuously monitored by the RPS and factored into the low DNBR and high LPD trips. This assures that acceptable fuel design limits are not exceeded in the event of axial power oscillations. Allowances are made in the trip setpoints for azimuthal power tilts.

Criterion 13 - Instrumentation and Control: Refer to subsection 3.1.9 for compliance.

Criterion 15 - Reactor Coolant System Design: Refer to subsection 3.1.11 for compliance.

Criterion 16 - Containment Design: Refer to subsection 6.2.4 and subsection 3.1.12.

Criterion 20 - Protection System Functions: Refer to subsection 3.1.16 for compliance.

Criterion 21 - Protection System Reliability and Testability: Refer to subsection 3.1.17 for compliance.

Criterion 22 - Protection System Independence: Refer to subsection 3.1.18 for compliance.

Criterion 23 - Protection System Failure Modes: Refer to subsection 3.1.19 for compliance.

Criterion 24 - Separation of Protection and Control Systems: Refer to subsection 3.1.20 for compliance.

Criterion 25 - Protection System Requirements for Reactivity Control Malfunctions: Refer to subsection 3.1.21 for compliance.

Criterion 29 - Protection Against Anticipated Operational Occurrences: Refer to subsection 3.1.25 for compliance.

7.2.2.3.2 Equipment Design Criteria

IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," establishes minimum requirements for safety-related functional performance and reliability of the RPS. This section describes how the requirements of Section 4 of IEEE 279-1971 are satisfied. As an exception, the PVNGS design provides a mono-directional data link from the core protection calculator (CPC) system to the plant monitoring system by means of fiber-optic communication. These data links are identical to the hardware utilized at each CEA calculator output (see paragraph 7.2.1.1.2.2). The non-conducting fiber-optic cable used ensures that no electrical failure at the plant monitoring system will affect the core protection

calculators or the CEA calculators. The following heading numbers correspond to the section numbers of IEEE 279-1971.

7.2.2.3.2.1 Section 4.1, General Functional Requirement. The RPS is designed to limit reactor fuel, fuel cladding, and coolant conditions to levels within plant and fuel design limits. Instrument performance characteristics, response times, and accuracy are selected for compatibility with and adequacy for the particular function. Trip setpoints are established by analysis of the system parameters. Factors such as instrument inaccuracies, bistable trip times, CEA travel times, and circuit breaker trip times are considered in the design of the system.

7.2.2.3.2.2 Section 4.2, Single Failure Criterion. The RPS is designed so that any single failure within the system shall not prevent proper protective action at the system level. No single failure will defeat more than one of the four protective channels associated with any one trip function. The wiring in the system is grouped so that no single fault or failure, including either an open or shorted circuit, will negate protective system operation. Signal conductors and power leads coming into or going out of each cabinet are protected and routed separately for each channel of each system to minimize possible interaction. Single failures considered in the design of the RPS are described in the failure modes and effects analysis (FMEA) shown on table 7.2-4A. Also see reference 24 for the FMEA of the upgraded Core Protection Calculator System (CPCS).

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 1 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
1) Excore Flux Monitor (68)	a) Low Output.	Loss of H.V. Power Supply Breakdown in insulation Resistance	Loss of data, erroneous data. Failure to detect HI flux levels.	Not annunciating. Automatic sensor. validity test. 3-channel comparison. Periodic manual test	3-channel redundancy. (4th channel in bypass)	Makes reactor Trip Logic for variable overpower HI LOG PWR, LO DNBR and HI PWR DENS 1-out-of-2 coincidence	Loss of H.V. Power Supply will fail all three subchannel detectors. To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) High Output	Detector shorts, continuous ionization	Erroneous data. Possible channel Trip for Trip for HI LINEAR PWR, LO DNBR, HI LOG PWR, or HI PWR DENSITY	Annunciating Pre-Trip and Trip HI LIN PWR alarm. Nuclear Instrument Inoperative Alarm	3-channel redundancy. (4th channel bypass)	Makes reactor Trip Logic for HI LIN PWR, LO DNBR, and HI PWR DENS 1 out-of-2 coincidence Power Reduction Signals (PRS) Logic 1-out-of-2 coincidence	To restore the sys-tem logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
2) Core Out-Let Temp. $T_{hot(80)}$	a) Low Output.	Power supply failure. RTD bridge network failure	Reduces ΔT power indication. Channel will not trip on a valid hi temp. condition.	Annunciating. Automatic sensor validity test. 3-channel comparison Plant Computer monitor and alarm Periodic test.	3-channel redundancy. (4th channel bypass)	Reactor Trip Logic for LO DNBR and HI PWR DENS is con-verted to 2-out-of-2 coincidence.	Calculated values of DNBR calibrated nuclear power and local power density (LPD) will change. To restore the system logic to 2-out-of-3 coin-cidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 2 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	b) High Output	RTD opens or Network failure.	Increases ΔT power indication. Possible channel trips (DNBR, LPD).	Annunciating	3-channel redun-dancy. (4th channel bypass)	Reactor Trip Logic for LO DNBR and HI PWR DENS is converted to 1-out-of-2 coincidence	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
3) Core Inlet Temperature $T_{hot(82)}$	a) One spurious low.	Power Supply failure. RTD bridge network failure.	Increases ΔT power indication. Possible channel trips (DNBR, LPD).	Annunciating. Automatic sensor. validity test . 3-channel comparison plant computer monitor and alarm. Periodic test	3-channel redun-dancy. (4th channel bypass)	Reactor Trip Logic for LO DNBR and HI PWR DENS is converted to 1-out-of-2 coincidence	To restor the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) One spurious high	RTD opens network failure.	Decrease in ΔT power indication. Channel not trip if T_{cold} goes low.	Annunciating.	3-channel redun-dancy. (4th channel bypass)	Reactor trip logic for LO DNBR and HI PWR DENS is converted to 2-out-of-2 coincidence	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
4) Reactor Coolant Pump speed sensor (84)	a) One spurious loss of trans-mission	Power supply or pulse amplifier failure, mech. damage to sensor.	Loss of data. Low DNBR channel trip possible.	Annunciating. Plant Computer monitor and alarm, trip status indication.	3-channel redun-dancy trip bypass.	Reactor trip logic for LO DNBR is converted to 1-out-of-2 coincidence.	Sensor transmits pulses. Pulse rate related to flow. To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 3 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	b) High signal rate.	Electronic noise.	HI RCP speed input to CPC indicating hi RCS flow, or normal flow when flow actually low. Calculated DNBR will be high channel will not trip on valid low RCS flow.	3-channel comparison, periodic test.	3-channel redundancy. (4th channel in bypass)	RCP trip logic for lo DNBR becomes 2-out-of-2 coincident.	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	c) Low signal rate.	High resistance in lines, loss of signal strength, intermittent failure.	Low RCP speed input to CPC indicating lo RCS flow. Possible lo DNBR trip in channel.	Pre-trip/trip alarms, 3-channel comparison, periodic test.	3-channel redundancy. (4th channel in bypass)	RPS trip logic for lo DNBR would become 1-out-of-2 coincident.	To restor the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
5) Non-Target CEA Position (149)	a) Low or High	Shorted resistor, power supply malfunction.	Erroneous data input to CEA calculator.	Annunciation. Automatic sensor validity test, CEA deviation.	A penalty factor.	A penalty factor is initiated in the core protection calculators (operating temperature margins reduced).	One CEA calculator in each channel will show CEA deviation to all CPC calculators. Possible reactor trip will occur.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 4 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	b) Other than actual position.	Shorted resistors, shorted reed switches, power supply malfuction.	Erroneous data input to two CEA calculator.	Annunciation, automatic sensor validity test, CEA deviation.	A penalty factor.	A penalty factor is initiated in the core protection calculators (operating temperature margins reduced).	One CEA calculator will show CEA deviation to all CPC calculation. Possible reactor trip will occur.
	c) Off scale	Broken wire, open resistor, electrical short, power supply malfunction.	Loss of data.	Annunciation, automatic sensor validity test, CEA deviation.	A penalty factor.	A penalty factor is initiated in the core protection calculators (operating temperature margins reduced).	One CEA calculator will show CEA deviations to all CPC calculation. Possible reactor trip will occur.
	d) Single CPP failure	Module failure. CEA position data link failure	Loss of one of two redundant CEA position inputs to 1 CEAC in 1 or more channels	Annunciation and alarm	Reduadant CPP in each channel provides CEA position input to CEAC	None	There are two redundant CPPs and associated CEA position data links each CPC channel
	e) Failure of both CPPs in one channel	Power supply failure	Loss of both redundant CEA position inputs to 1 CEAC in all four channels. Loss of CEA position display if that channel is selected for display	CEAC Fail alarm and annunciation	Two channel redundancy (two CEACs per channel) CPC uses other CEAC.	None	CPC uses data from the other CEAC and annunciates failure CPP failure will also cause loss of target CEA position input in the failed channel
6) Target CEA Position (87)	a) Low	Shorted resistor, power supply malfunction	Erroneous data input affects DNBR and LPD calculation	Annunciation, automatic sensor validity test, 3-channel comparison	3-channel redundancy. (4th channel in bypass)	Makes reactor trip logic for LO DNBR and HI power density 1-out-of-2 coincidence	Possible trip in one safety channel. Trip effected will show CEA deviation.
	b) High	Shorted resistor, power supply malfunction	Erroneous data input to CPC Calculator and (two) CEA Calculators	Annunciation, automatic sensor validity test, CEA deviation.	3-channel redundancy. (4th channel in bypass)	Makes reactor trip logic for LO DNBR and HI power density 1-out-of-2 coincidence.	Possible trip in one safety channel. Trip effected will show CEA deviation.
	c) Other than actual position.	Shorted resistor, shorted reed switches,power supply malfunction.	Erroneous data input to Core Protection Calculators and (two) CEA Calculators.	Annunciation, automatic sensor validity test. CEA deviation.	3-channel redundancy. (4th channel in bypass)	Makes reactor trip logic for LO DNBR and HI POWER DENS 1-out-of-2 coincidence.	Possible trip in one safety channel. Trip effected will show CEA deviation.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 5 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	d) Off scale	Broken wire, open resistor, electrical short, power supply mal-function	Loss of data	Annunciation; automatic sensor validity test. CEA deviation.	3-channel redun-dancy. (4th channel in bypass)	Makes reactor trip logic for LO DNBR and HI PWER DENS 1-out-of-2 coinci-dence.	Possible trip in one safety channel. Trip effected will show CEA deviation.
	e) Single CPP failure	Module failure. CEAC to CPC data link failure	Loss on one of two redundant CEA position inputs to CPC in the same channels	Annunciation and alarm	Redundant Target CEA position input from other CEAC to CPC data link provides CEA position input to CPC	None	There are two redundant CPPs and CEAC to CPC data links in each CPC channel. Target CEA position is redundantly transmitted.
	f) Failure of both CPPs in one channel	Power supply failure	Loss of both redundant Target CEA position inputs to one CPC channel	CPC Fail. Low DNBR and High power density channel trips, alarm and annunciation	Three channel redundancy (4th channel in bypass)	Makes reactor trip logic for Low DNBR and High Power Density 1-out-of-2 coincidence	Diagnostic message identify cause of trip
7) Wide Range PZR pressure (press) signal (61)	a) One fails on. (High pressure signal level)	Sensor failure, component failure.	High PZR press signal to: LP PZR Press P/S. LO PZR pressure B/S does not trip for a bona fide condition	Periodic test; 3 channel comparison	3-channel redun-dancy. (4th channel in bypass)	Reactor Trip logic for LP PZR Press is coverted to 2-out-of-2 concidence and CSAS, SIAS logic LO PZR Press 2-out-of-2 coincidence	Back-up for SIAS is the containment pressure measurement channel. To restore the system logic to 2-out-of-3 coinci-dence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) One fails off. (Low pressure signal level).	Sensor failure; dc power supply fall; open circuit	Low PZR Press signal to LO PZR. Press B/S. Bistable changes logic state and initiates channel trip	Annunciating; pre-trip and trip alarm in channel	3-channel redun-dancy Trip Channel Bypass	Reactor trip logic for LO PZR Press is converted to 1-out-of-2 coincidence and CSAS, SIAS logic 1-out-of-2 coincidence	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 6 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
8) PZR Narrow Range Pressure (PRESS) Signal (91)	a) On (High pressure signal level)	Sensor failure, component failure	High PZR press signal to HI PZR Press B/S and calculator HI PZR PRESS B/S will change logic state and initiate channel trip	Annunciating, Pre-trip and trip alarms in HI PZR channel.	3-channel redundancy (4th channel in bypass)	Reactor TRIP logic for LO DNBR is converted to 2-out-of-2 coincidence for HI PZR PRESS. CWP becomes 1-out-of-2 coincidence for HI PZR PRESS	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Off (Low Pressure signal level)	Sensor failure, dc power supply fail open circuit	LO PZR PRESS B/S will decrease DNBR Margin and initiate LO DNBR channel trip. HI PZR PRESS B/S will not trip for bona fide condition	Annunciating; pre-trip and trip alarms in LO DNBR channel	3-channel redundancy (4th channel in bypass)	Reactor TRIP logic for LO DNBR is coverted to 1-out-of-2 coincidence. CWP logic becomes 2-out-of-2 coincidence for this parameter.	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
9) SG No.2 Level Signal (51) SG NO.1 Level signal (55) (Wide Range)	a) Off (Low signal level)	Sensor failure, dc power supply fail; open circuit	Low steam generator water level signal to channel bistables. Low level bistables (B/S) change logic state and trip channel for affected steam generator	Annunciation; Pre-trip and trip alarms on low steam generator water level	3-channel redundancy. (4th channel in bypass)	Reactor TRIP and AFAS logic for affected steam generator low water level is converted to 1-out-of-2 coincidence	One channel inoperative for affected steam generator To restore the system logic to 2-out of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 7 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	b) On (High Signal level)	Sensor failure, component failure	High steam generator water level signal to channel bistables. Lo level bistables for affected steam generator will not trip on LO level	Annunciation on high S/G level. Periodic test, 3-channel comparision	3-channel redundancy. (4th channel in bypass)	Reactor TRIP and AFAS logic for low steam generator water level is converted to 2-out-of-2 coincidence for affected steam generator. System will still operate on non-failed SG level	One channel inoperative for affected steam generator. To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
10) Narrow Range level Sensor, Steam Generator No. 1 (20); Narrow Range Level Sensor, Steam Generator No. 2 (19)	a) Off (Low Signal Level)	Sensor failure, dc power supply fail open circuit	Lo Level Signal to one High SG level bistable for the affected steam generator. Bistable will not trip on actual HI level in steam generator	Periodic test, 3-channel comparison	3-channel redundancy (4th channel in bypass)	Reactor Trip Logic for HI steam generator level and the MSIS actuation Logic for HI steam Generator Level will be changed to 2-out-of-2	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) On (High Level Signal)	Sensor failure component failure	False HI Level Signal sent to one steam generator HI Level Bistable for affected steam generator. Bistable will change logic state and trip the channel	Channel pre-trip and trip alarms	3-channel redundancy (4th channel in bypass)	Reactor Trip Logic and MSIS actuation logic for HI steam generator logic on the affected steam generator will be changed to 1-out-of-2	Same as above

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 8 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
11) S/G Pressure Signal No. 2 (27) S/G Pressure signal No. 1 (42)	a) One spurious off, (Low signal level)	Sensor failure, dc power fail; open circuit	Low steam generator pressure signal to SG Low Pressure (LO PRESS) bistable (B/S) in RPS and ESFS channels, SG Low Pressure, SG1.SG2, and SG2.SG1 B/S's. B/S's change their logic state and initiates channel trip in SG LO PRESS for reactor TRIP, and MSIS actuation. Also, differential 8 SG pressure signal input to one AFAS train actuation logic.	Annunciating; pre-trip and trip alarm on low steam generator pressure	3-channel redundancy (4th channel in bypass)	Reactor TRIP logic for steam generator steam pressure is converted to 1-out-of-2 coincidence	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) One spurious on, (High signal level)	Sensor fails component failure	High steam generator pressure signal to SG LO PRESS and SG1.SG2 Press or SG2.SG1 Press Bistables. One SG LO Press Channel for affected SG will not trip for valid LO Press condition. The SG1.SG2 Press (or SG2.SG1) Bistables will change state	Annunciating; periodic rest. 3-channel comparison	3-channel redundancy (4th channel in bypass)	AFAS Reactor Trip and MSIS actuation Logic for LO SG Press changes to 2-out-of-2. AFAS actuation logic for opposite SG changes to 2-out-of-2	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 9 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
12) SG1 Diff.Pres. Signal, (13) SG2 Diff. Pres. Signal (12)	a) One fails on (High signal level)	Sensor failure, other component failure	HI or normal differential pres. Signal received by one SG LO FLOW bistable for affected steam generator. One channel will not trip on valid LO flow condition in affected steam generator	Periodic test, 3-channel comparison	3-channel redundancy (4th channel in bypass)	Reactor Trip Logic for LO flow in affected SG changes to 2-out-of-2	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) One fails off (LO signal level)	Sensor fails dc power failure, open circuit	LO Differential pres. signal received by one SG LO Flow bistable for affected steam generator. Bistable will change state, initiating a channel trip	Annunciating	3-channel redundancy (4th channel in bypass)	Reactor Trip Logic for LO flow in affected SG changes to 1-out-of-2	Same as above
13) Con-tainment Pressure Signal (6)	a) ON (goes high)	Component failure	High CONT PRESS signal to: HI CONT PRESS bistable in RPS channel and in ESFS channel. B/S change logic state, and initiates channel trip for high containment pressure for RPS TRIP, SIAS, CIAS, and MSIS actuation	Annunciating; pre-trip, and alarm on high containment pressure ESF channel indication	3-channel redundancy (4th channel in bypass)	Reactor Trip Logic redundancy pressure is converted to 1-out-of-2 coincidence and CIAS, SIAS and MSIS logic for HI containment pressure 1-out-of-2 coincidence	Same as above

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 10 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	b) Off goes low)	Component failure, dc power supply failure open circuit.	Low CONT PRESS signal to: HI CONT PRESS B/S in RPS channel, and ESFS channel. B/S in channel do not change their logic state and trip for bona fide high contanment condition	Periodic test 3-channel comparison	3-channel redundancy (4th channel in bypass)	Reactor Trip logic for HI containment pressure is con-verted to 2-out-of-2 coincidence, and CIAS, SIAS, and SMIS logic for HI containment pressure 2-out-of-2 coincidence	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
14) Con-tainment Pressure Signal (10)	a) ON (HI Signal Level)	Sensor failure other component failure	HI Cont. Pres. Signal received by one HI-HI cont. pres. bi-stable changes state, initiating channel trip for CSAS actuation	Annunciating	3-channel redundancy (4th channel in bypass)	Actuation logic for CSAS becomes 1-out-of-2	Same as above
	b) Off (LO signal level)	Sensor dc power supply failure, open circuit	One HI-HI Cont. Pres. bistable constantly receives a LO or normal containment pres. signal. Bistable will not change logic state for a valid HI-HI cont. pres. condition	Periodic test 3-channel comparison	3-channel redundancy (4th channel in bypass)	Actuation logic for CSAS changes to 2-out-of-2	Same as above
15) RWT Level Signal (1)	a) Off (goes low)	Failed Sensor dc power supply fails	Low RWT level signal to REFUEL TANK LO LEVEL Bistable in ESFS channel. Bistable changes logic state and initiates channel trip for RAS actuation in ESFS	Annunciating; pre-trip and trip PPS alarms	3-channel redundancy (4th channel in bypass)	Makes RAS logic for low refueling water tank level 1-out-of-2 coincidence	Same as above
	b) On (goes high)	Sensor fails; component failure	High RWT level signal to REFUEL TANK LO LEVEL Bistable in ESFS channel. Bistable will not change logic state in RAS channel when bona fide low RWT level condition exists	Periodic test 3-channel comparison	3-channel redundancy (4th channel in bypass)	Makes RAS logic for low refueling water tank level 2-out-of-2 coincidence	Same as above

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 11 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
16) Refuel-ing Water Tank LO Level Bistable (2), Channel A typical)	a) Setpoint power fails off	Component failure, open circuit.	Refueling Water Tank (RWT) level setpoint drops to zero Bistable will not change state on valid LO level signal	Periodic test	3-channel redundancy (4th channel in bypass)	RAS Actuation Logic changes to 2-out-of-2	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Trip Setpoint fails low	Component failure	Same as 16 a)	Same as 16 a)	Same as 16 a)	Same as 16 a)	Same as 16 a)
	c) Trip setpoint set fails high	Component failure	Bistable will trip at a greater than desired RWT level	Periodic test	3-channel redundancy (4th channel in bypass)	No impact on RAS actuation logic unless bistable trips at normal RWT level, then actuation logic will become 1-out-of-2	Same as above
	d) Trip voltage comparator fails off	Open circuit, component failure	Bistable relays will be deenergized resulting in half trips in the AB, AC and AD RAS Actuation Logic matrices	Annunciating	3-channel redundancy (4th channel in bypass)	RAS actuation logic becomes 1-out-of-2	Same as above
	e) Trip voltage comparator fails on	Component failure	Bistable relays will not be deenergized for a valid LO RWT Level Signal	Periodic test	3-channel redundancy (4th channel in bypass)	RAS actuation logic becomes 2-out-of-2	Same as above
	f) Pre-trip setpoint set fails low or off	Component failure, open circuit	Pre-trip setpoint decreases, pre-trip relay will not de-energize when RWT level reaches desired pre-trip level	Periodic test	3-channel redundancy (4th channel in bypass)	RAS Pre-trip indication logic will change to 1-out-of-2. No impact on RAS actuation logic	Same as above

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 12 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	g) Pre-Trip setpoint set fails HI	Component failure	Pre-trip relay will be de-energized at a higher than desired RWT level	Pre-trip alarm and test	None	Spurious RAS Pre-trip alarms. No impact on RAS actuation logic	Same as 16 c)
	h) Pre-trip voltage comparator fails off	Open circuit component failure	Same as 16 g)	Same as 16 g)	Same as 16 g)	Same as 16 g)	Same as 16 g)
	i) Pre-trip voltage comparator fails on	Component failure	Pre-trip relay will not be deenergized when RWT level reached pre-trip setpoint level	Periodic test	3-channel redundancy (4th channel in bypass)	RAS Pre-trip indication logic changes to 1-out-of-2	Same as above
	j) Pre-trip Opto-isolator fails off	Open circuit, component	Pre-trip relay will be deenergized	Annunciating	None	Spurious Pre-trip alarms. RAS actuation logic not affected	Same as above
	k) Pre-trip relay driver fails off	Open circuit transistor failure	Same as 16 j)	Same as 16 j)	Same as 16 j)	Same as 16 j)	Same as 16 j)
	l) Pre-trip relay driver fails on	Emittor to collector short circuit	Same as 16 i)	Same as 16 i)	Same as 16 i)	Same as 16 i)	Same as 16 i)
	m) Pre-trip relay coil fails open	Mechanical failure	Same as 16 j)	Same as 16 j)	Same as 16 j)	Same as 16 j)	Same as 16 j)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 13 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	n) Pre-trip relay NC contact in annunciator circuit fails open	Corrosion mechanical damage	RAS pre-trip for channel A will not be annunciated	Periodic test	Visual indication not affected, 3-channel redundancy (4th channel in bypass)	RAS actuation logic unaffected, Pre-trip annunciation logic becomes 1-out-of-2	Same as 16 j)
	o) Pre-trip relay NC contact in annunciator circuit fails closed	Contact arcing	Spurious pre-trip alarm for RAS	Annunciating	None	RAS Actuation logic unaffected	Same as above
	p) Pre-trip relay NC contact in indicator circuit fails open	Mechanical damage corrosion	No visual indication of channel A pre-trip	Periodic test	Audible annun-ciation not affected, 3-channel redundancy (4th channel in bypass)	RAS Actuation logic unaffected pre-trip indication log becomes 1-out-of-2	Same as above
	q) Pre-trip relay NC contact in indicator circuit fails closed	Contact arcing	Spurious RAS pre-trip indication	Visual pre-trip indication	None	RAS Actuation logic unaffected	Same as above
	r) Trip Opto-isolator fails off	Open circuit, component failure	Same as 16 d)	Same as 16 d)	Same as 16 d)	Same as 16 d)	Same as 16 d)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 14 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	s) Trip Relay Driver (TR1, TR2 TR3 or R4) fails off	Open circuit, transistor failure	One bistable relay coil de-energized resulting in a spurious half trip in one logic matrix (i.e. AB, AC, or AD) or a spurious trip indication.	Trouble annunciator for TR-1, 2 and 3 and trip indication for R4	3-channel redundancy for TR-1, 2, and 3 (4th channel in bypass)	RAS Actuation logic becomes 1-out-of-2 selective or any 2-out-of-3	Same as 16 j)
	t) Trip Relay Driver fails on	Emittor to collector short on transistor	Affected trip relay will not deenergize for valid RWT LO level signal, one RAS actuation logic matrix, (i.e., AB, AC or AD) will not deenergize	Periodic test	3-channel redundancy (4th channel in bypass)	RAS Actuation logic becomes 2-out-of-2	Same as above
	u) Trip Relay Coil (TR-1 TR-2, TR-3, or R-4) fails open	Mechanical failure	Same as 16 s)	Same as 16 s)	Same as 16 s)	Same as 16 s)	Same as 16 s)
	v) Trip Relay Form C contacts in logic matrix fail to the NC Pole	Contacts welded by arcing, fuse failure	Affected RAS actuation logic matrix becomes half tripped, and Channel A trip indicator in affected matrix illuminated	Visual indication	3-channel redundancy (4th channel in bypass)	RAS Actuation logic remains 2-out-of-3 with one logic matrix half tripped	Same as above
	w) Trip Relay form C contacts in logic matrix fail to the NO Pole	Contacts welded	The affected RAS Actuation logic matrix (AB, AC or AD) will not deenergize for valid RWT LO Level signal, and channel A trip indicator in affected matrix will not illuminate	Periodic test	3-channel redundancy (4th channel in bypass)	RAS actuation logic becomes 2-out-of-2	Same as above

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 15 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	x) Trip Relay Form C contacts in trouble annun. circuit fail to the NO Pole	Contacts welded	Relay coil or relay driver failure will not be annunciated by trouble annunciator	Periodic test	Channel trip indictors in logic matrixes will indicate possible relay coil or relay driver failures	RAS Actuation logic not affected	Same as 16 j)
	y) Trip Relay Form C Contacts in trouble annun. circuit fail to the NC Pole	Fuse failure contacts	Spurious relay coil/relay driver failure indications	Annunciating	None	RAS Actuation logic not affected	Same as above
17) SG1 LO Level Bistable (59) SG2 LO level Bistable (52)(Channel A typical)			Failure modes and the effects on RPS Trip Logic for LO steam generator level trips are equivalent to the failure modes and effects on RAS Actuation Logic provided in line item 16, Failure modes a) through y).				
18) HI-HI Cont. Pres. Bistable (7) (Channel A typical)	a) Trip setpoint power supply fails off	Open circuit, component failure	HI-HI cont pres. setpoint goes to zero, and all Channel A bistable relays are de-energized by trip voltage comparator	Annunciating	3-channel redundancy (4th channel in bypass)	CSAS Actuation logic is converted to 1-out-of-2	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	Failure Modes b) through y), and the effects on CSAS Actuation Logic are equivalent to the Failure Modes and effects on RAS Actuation Logic provided in Line item 16, Failure Modes b) through y).						

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 16 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
19) SG1 HI Level Bistable (135), SG2 HI Level Bistable (134) (Channel A Typical)	a) Trip setpoint power supply fails off	Open circuit, component failure	HI SG Level setpoint goes to zero. All channel A bistable relays for RPS Trip Logic and ESF Actuation Logic for HI SG level are deenergized	Annunciating	3-channel redundancy (4th channel in bypass)	RPS Trip Logic and ESF Actuation Logic for HI SG Level is converted to 1-out-of-2.	To restore the system logic to 2-out-of-3 coincidence the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Trip setpoint set fails low	Component failure	Same as 19 a)	Same as 19 a)	Same as 19 a)	Same as 19 a)	Same as 19 a)
	c) Trip setpoint set fails high	Component failure	Bistable will not change states for valid SG HI Level	Periodic test	3-channel redundancy (4th channel in bypass)	RPS Trip and ESF Actuation Logic for HI SG Level changes to 2-out-of-2	Same as 19 a)
	d) Trip Voltage Comparator fails off	Open circuit component failure	All Channel A bistable relays for RPS Trip and ESF Actuation Logic for HI SG Level will be deenergized. AB, AC and AD Logic matrixes will be half tripped	Annunciating	3-channel redundancy (4th channel in bypass)	RPS Trip and ESF Actuation Logic for HI SG Level changes to 1-out-of-2	Same as 19 a)
	e) Trip Voltage Comparator fails on	Component failure	Same as 19 c)	Same as 19 c)	Same as 19 c)	Same as 19 c)	Same as 19 a)
	f) Pre-trip setpoint set fails off or low	Open circuit, component failure	Pre-trip relay for HI SG Level deenergized. Spurious HI SG Level Pre-trip indication	Annunciating	None	No impact on RPS Trip or ESF Actuation Logic. Spurious pre-trip indication	Same as 19 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 17 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	g) Pre-Trip setpoint set fails HI	Component failure	Pre-trip relay will not be de-energized when SG Level reaches pre-trip level. No pre-trip indic. From Channel A	Periodic test	3-channel redundancy (4th channel in bypass)	No impact on RPS Trip or ESF Actuation Logic, Pre-trip Logic changes to 1-out-of-2	Same as 19 a)
	h) Pre-Trip Voltage Comparator fails off	Open circuit, component failure	Same as 19 f)	Same as 19 f)	Same as 19 f)	Same as 19 f)	Same as 19 a)
	i) Pre-Trip Voltage Comparator fails on	Component failure	Same as 19 g)	Same as 19 g)	Same as 19 g)	Same as 19 g)	Same as 19 a)
	j) Pre-Trip Opto-Isolator fails off	Component failure	Same as 19 f)	Same as 19 f)	Same as 19 f)	Same as 19 f)	Same as 19 a)
	k) Pre-Trip Relay driver fails off	Open circuit, transistor failure	Same as 19 f)	Same as 19 f)	Same as 19 f)	Same as 19 f)	Same as 19 a)
	l) Pre-Trip Relay driver fails on	Emitter-to-collector short	Same as 19 g)	Same as 19 g)	Same as 19 g	Same as 19 g)	Same as 19 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 18 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	m) Pre-Trip Relay Coil fails open	Mechanical failure	Same as 19 f)	Same as 19 f)	Same as 19 f)	Same as 19 f)	Same as 19 a)
	n) Pre-Trip Relay Form C Contact in Annunc. Circuit fails open	Corrosion, mechanical damage	Channel A pre-trip on HI SG Level will not be annunciated	Periodic test	3-channel redundancy, visual pre-trip indicator (4th channel in bypass)	No impact on RPS or ESF actuation Logic	Same as 19 a)
	o) Pre-Trip Relay Form C Contacts in Annunc. circuit fail closed	Contact weld	Spurious HI SG Level pre-trip alarm	Annunciating	None	RPS trip and ESF Actuation Logic not affected	Same as 19 a)
	p) Pre-Trip Relay Form C Contact in Indicator Circuit fails open	Mechanical damage corrosion	No visual indication of Channel A pre-trip	Periodic test	3-channel redundancy, pre-trip annunciator (4th channel in bypass)	Same as 19 o)	Same as 19 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 19 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	q) Pre-Trip Relay Form C Contacts in indica-tor circuit fails closed	Contact weld	Spurious visual pre-trip indication	Visual pre-trip indication	None	Same as 19 o)	Same as 19 a)
	r) Trip Opto-iso-lator fails off	Open circuit, transistor failure	Same as 19 d)	Same as 19 d)	Same as 19 d)	Same as 19 d)	Same as 19 a)
	s) Actua-tion Relay Driver (TR1, TR2 TR3, R4, R9, R10, or R11) fails off	Open circuit, transistor failure	One actuation relay coil is deenergized, resulting in spurious half trip in one RPS Trip Logic Matrix (i.e. AB, AC, or AD), a spurious trip indication, or a half trip in one ESF Actuation Logic Matrix	Annunciating	3-channel redundancy, for TR1, TR2, TR3 R9, R10, and R11. (4th channel in bypass)	RPS Trip and ESF Actuation Logic remains 2-out-of-3	Same as 19 a)
	t) Actua-tion Relay Driver fails on	Short circuit	One actuation relay coil will not be deenergized for valid HI SG Level. One RPS Trip, or one ESF actuation logic matrix (i.e., AB, AC, or AD) will not de-energize	Periodic test	3-channel redundancy (4th channel in bypass)	Either RPS trip or ESF actuation logic will change to 2-out-of-2	Same as 19 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 20 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	u) Actuation Relay Coil fails open	Mechanical failure	Same as 19 s)	Same as 19 s)	Same as 19 s)	Same as 19 s)	Same as 19 a)
	v) Actuation Relay (TR1, TR2 TR3, R9, R10, or R11) Form C contacts in Logic Matrix fail to NC Pole	Contact weld, fuse failure	Affected logic matrix (AB, AC, or AD for RPS Trip or ESF Actuation) becomes half tripped, Channel A trip indicator in affected matrix is illuminated	Visual indication	3-channel redundancy (4th channel in bypass)	RPS Trip or ESF Actuation Logic for HI SG Level remains 2-out-of-3 with one logic matrix half tripped	Same as 19 a)
	w) Actuation Relay Form C Contacts in Logic Matrix fail to NC Pole	Contact weld	Affected Logic Matrix (AB, AC, or AD for RPS Trip or ESF Actuation) will not be de-energized for a valid HI SG Level signal	Periodic test	3-channel redundancy (4th channel in bypass)	RPS trip or ESF Actuation Logic for HI SG Level becomes 2-out-of-2	Same as 19 a)
	x) Actuation Relay Form C Contacts in trouble annunc. Circuit fail to NC Pole	Contacts welded	Relay coil or relay driver failure will not be annunciated by trouble annunciator	Periodic test	Channel trip indicators in logic matrices will indicate possible relay coil or driver failures	RPS Trip and ESF Actuation Logic not affected	Same as 19 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 21 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	y) Actuation Relay Form C contacts in trouble annunc. circuit fail to NC Pole	Fuse failure contact weld	Spurious relay coil/driver failure indication	Annunciating	None	Same as 19 x)	Same as 19 a)
20) HI Containment Pressure Bistable(24) (Channel A typical)			The Failure Modes and the Effects on RPS Trip and ESF Actuation (SIAS, MSIS, and CIAS) Logic for HI containment pressure are equivalent to the failure modes and the effects on RPS Trip and ESF Actuation (MSIS Logic for HI SG LVL) provided in line Item 19, failure modes a) through y).				
21) HI Pressure Bistable (65) (Channel A Typical)			The failure modes and the effects on RPS Trip Logic for HI Pressurizer Pressure are equivalent to the failure modes and the effects on RPS Trip Logic for HI SG Level provided in line Item 19, failure modes a) through e) and n) through y). Failure modes f) through m), and z) through aa) are provided below.				
	f) Pre-Trip setpoint set fails off	Component failure	Pre-trip relay and CWP relay for HI PZR PRES. and de-energized spurious pre-trip alarm and CWP Logic Matrix half trip	Annunciating	None	No impact on RPS Trip Logic	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 22 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	g) Pre-Trip setpoint Set fails HI	Component failure	Pre-trip and CWP Relays for Channel A will not be de-energized at the proper PZR pres. no pre-trip alarm or CWP from Channel A	Periodic test	3-channel redundancy (4th channel in bypass)	HI PZR Pres. Pre-trip logic converts to 1-out-of-2, and CWP on PZR Pres. coverts to 2-out-of-2	Same as 21 f)
	h) Pre-trip Voltage Comparator fails off	Open circuit, component failure	Same as 21 f)	Same as 21 f)	Same as 21 f)	Same as 21 f)	Same as 21 f)
	i) Pre-Trip Voltage Comparator fails on	Component failure	Same as 21 g)	Same as 21 g)	Same as 21 g)	Same as 21 g)	Same as 21 f)
	j) Pre-Trip Opto-isolator fails off	Component failure	Same as 21 f)	Same as 21 f)	Same as 21 f)	Same as 21 f)	Same as 21 f)
	k) Relay Driver (Pre-trip or CWP) fails off	Open circuit transistor failure	Affected relay coil de-energized resulting in either a spurious HI PZR Pres. pre-trip alarm or half trip of the CWP Logic Matrix	Annunciating for pre-trip relay, periodic test for CWP	3-channel redundancy (4th channel in bypass)	Spurious pre-trip alarm, or CWP on HI PZR Pres. converts to 1-out-of-2	Same as 21 f)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 23 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	l) Relay Driver (Pre-trip of CWP) fails on	Emitter-to-collector short	Affected relay coil will not deenergize for valid HI PZR Pres. Pre-trip signal	Periodic test	3-channel redundancy (4th channel in bypass)	CWP Logic goes to 2-out-of-2, or pre-trip alarm goes to 1-out-of-2	Same as 21 f)
	m)Relay Coil (Pre-trip of CWP) Fails open	Mechanical failure	Same as 21 k)	Same as 21 k)	Same as 21 k)	Same as 21 k)	Same as 21 k)
	• • •						
	z) CWP Relay Form C Contacts (one of two) fails open	Mechanical failure, corrosion	Part of CWP Logic Matrix is half tripped	Annunciating	3-channel redundancy (4th channel in bypass)	CWP Actuation logic remains 2-out-of-3 with a half trip in one logic matrix	Same as 21 f)
	AA) CWP Relay Form C Contacts (one of two) fails closed	Contact weld	One A Channel contact in CWP logic matrix remains closed on valid HI PZR Pres. pre-trip signal	Periodic test	3-channel reduncancy (4th channel in bypass)	CWP Actuation logic becomes 2-out-of-2	Same as 21 f)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 24 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
22) Hi Log PWR Level Bistable(75)			Failure modes for this bistable, and the effects on the RPS Trip Logic for HI Log PWR are equivalent to the failure modes and the effects on RPS Trip Logic for HI SG Level as provided in Line Item 19, failure modes a) through y).				
23) HI Local Power Density Bistable (96) (Channel A typical)	a) Trip input contact from CPC fails closed	Contacts welded	Bistable trip relays not de-energized for valid HI local PWR density signal	Periodic test	3-channel redundancy, (4th channel in bypass)	RPS Trip Logic for HI local power density changes to 2-out-of-2	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Trip input contacts from CPC fails open	Open circuit, mechanical failure corrosion	Bistable trip relays for Channel A will be de-energized	Annunciating	3-channel redundancy, (4th channel in bypass)	RPS Trip Logic for HI local power density becomes 1-out-of-2	Same as 23 a)
	c) Pre-trip Input contacts from CPC fails closed	Contacts welded	Pre-trip relay will not deenergize for valid HI local power density pre-trip signal	Periodic test	3-channel redundancy, (4th channel in bypass)	Pre-trip alarm logic for HI local power density becomes 1-out-of-2	Same as 23 a)
	d) Pre-trip input contacts form CPC fails open	Open circuit, Mechanical failure	HI local power density pre-trip relay is deenergized, spurious pre-trip alarm	Annunciating	None	Spurious pre-trip alarm, no impact on RPS trip logic	
	Failure modes e through r for this “bistable”, and their effects on RPS Trip Logic for HI Local Power Density are equivalent to Failure Modes k) through q), and s) through y) of line Item 19.						

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 25 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
24) LO DNBR Bistable Relay Cards (92) (Channel A typical)		The Failure Modes for these bistable relay cards, and their effect on RPS Trip Logic are equivalent to the failure modes and effect on RPS Trip Logic Power Density as presented in Line Item 23.					
25) SG1 Low Level Bistable (104), SG2 Low Level Bistable (103) (Channel A typical)	a) Trip setpoint power supply fails off	Open circuit, component failure	LO SG LVL Pre-trip and trip setpoints go to zero LO SG LVL bistable relays will not deenergize for valid LO SG LVL	Periodic test	3-channel (4th channel in bypass)	AFAS-1 actuation logic goes to 2-out-of-2	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Trip setpoint set fails low	Component failure	If LO SG LVL Trip setpoint goes to zero, pullup resistor changes effective setpoint to +10V, deenergizing bistable relays Otherwise B/S will trip at a lower level than desired.	Annunciating, Periodic Test.	3-channel redundancy (4th channel in bypass)	If setpoint goes to zero, AFAS-1 actuation for Channel A changes to "SG2.SG1 pres. and not (SG1.SG2 pres. and SG2 LO LVL)" Actuation logic remains 2-out-of-3, otherwise, none.	Same as 25 a)
	c) Trip setpoint set fails HI	Component failure	Bistable relays will be deenergized at a higher than desired SG LVL	Annunciating	3-channel redundancy (4th channel in bypass)	Same as above	Same as 25 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 26 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	d) Trip Voltage comparator fails off	Component failure, open circuit	SG LO LVL bistable relays will be deenergized. Spurious LO SG Level input to AFAS actuation logic	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 25 b)	Same as 25 a)
	e) Trip Voltage comparator fails on	Component failure	Same as 25 a)	Same as 25 a)	Same as 25 a)	Same as 25 a)	Same as 25 a)
	f) Pre-trip setpoint set fails off	Open circuit, component fail	LO SG LVL Pre-trip setpoint goes to zero. Pullup resistor changes effective pre-trip set point, relays are deenergized. Spurious pre-trip alarm.	Annunciating	None	No impact on AFAS actuation logic	Same as 25 a)
	g) Pre-trip setpoint set fails HI	Component failure	SG Low Level Pre-trip bistable relays deenergized at higher than desired SG Level. Spurious pre-trip alarms	Annunciating	None	Same as above	Same as 25 a)
	h) Pre-trip voltage comparator fails off	Open circuit, component failure	Same as 25 f)	Same as 25 f)	Same as 25 f)	Same as 25 f)	Same as 25 f)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 27 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	i) Pre-trip voltage comparator fails on	Component failure	Channel A pre-trip relay will not be deenergized when SG Level reaches pre-trip level	Periodic test	3-channel redundancy (4th channel in bypass)	No impact on AFAS act. logic. Pre-trip logic for LO SG LVL changes to 1-out-of-2	Same as 25 a)
	j) Pre-trip Opto-Isolator fails off	Component failure, open circuit	Same as 25 f)	Same as 25 f)	Same as 25 f)	Same as 25 f)	Same as 25 f)
	k) Pre-trip relay driver fails off	Open circuit, transistor failure	Same as 25 f)	Same as 25 f)	Same as 25 f)	Same as 25 f)	Same as 25 f)
	l) Pre-trip relay driver fails on	Emittor-to-collector short	Same as 25 i)	Same as 25 i)	Same as 25 i)	Same as 25 i)	Same as 25 i)
	m) Pre-trip relay coil fails open	Corrosion, mechanical damage	Same as 25 f)	Same as 25 f)	Same as 25 f)	Same as 25 f)	Same as 25 f)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 28 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	n) Pre-trip relay Form C contact in annunc. circuit fails open	Corrosion, mechanical damage	Channel A pre-trip on LO SG Level will not be annunciated	Periodic test	3-channel redundancy visual pre-trip indication (4th channel in bypass)	No impact on AFAS Act. Logic	Same as 25 a)
	o) Pre-trip relay Form C contact in annunc. circuit fails closed	Contact arcing	Spurious LO SG LVL pre-trip alarm	Annunciating	None	Same as above	Same as 25 a)
	p) Pre-trip relay Form C contact in indic. circuit fails open	Mechanical damage, corrosion	No visual indic. of Channel A pre-trip on LO SG LVL	Periodic test	3-channel redundancy audible pre-trip alarm (4th channel in bypass)	Same as above	Same as 25 a)
	q) Pre-trip relay Form C. contacts in indic. circuit fail closed	Contact arc and weld	Spurious LO SG LVL pre-trip indic.	Visual indication	None	Same as above	Same as 25 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 29 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	r) Trip Opto-Isolator fails off	Open circuit, component failure	Same as 25 d)	Same as 25 d)	Same as 25 d)	Same as 25 d)	Same as 25 d)
	s) Trip Relay 1 Driver fails off	Open circuit, transistor failure	Trip relay 1 is deenergized, closing contacts in AFAS Logic circuit for Channel A	Annunciating	3-channel redundancy (4th channel in bypass)	AFAS Logic for Channel A remains the same with one set of contacts “actuated”, Actuation logic remains 2-out-of-3	Same as 25 a)
	t) Trip Relay 1 Driver fails on	Collector-to-emitter short	Trip relay 1 will not be de-energized on valid LO SG LVL signal	Periodic test	3-channel redundancy (4th channel in bypass)	Channel A AFAS logic becomes “LO SG LVL” logic for other channels unaffected. Actuation Logic remains 2-out-of-3	Same as 25 a)
	u) Trip Relay 2 Driver fails off	Open circuit, transistor failure	Trip relay 2 is deenergized, opening contacts in AFAS logic circuit. AFAS Channel A actuation logic trip	Annunciating	3-channel redundancy (4th channel in bypass)	AFAS Act. Logic becomes 1-out-of-2	Same as 25 a)
	v) Trip Relay 2 Driver fails on	Emitter-to-collector short	Trip relay 2 will not be deenergized on valid LO SG LVL signal AFAS Act. Channel A will not trip	Periodic test	3-channel redundancy (4th channel in bypass)	AFAS actuation logic becomes 2-out-of-2	Same as 25 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 30 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	w) Trip Relay Form C Contacts in trouble annunc. circuit fails open	Mechanical damage, open circuit	Relay coil/relay driver failure will not be annunciated by trouble annunciator	Periodic test	None	No impact on AFAS actuation logic	Same as 25 a)
	x) Trip Relay Form C Contacts in trouble annunc. circuit fail closed	Contact arcing and weld	Spurious relay/relay driver trouble indication	Annunciating	None	Same as above	Same as above
26) SG1>SG2 Pres. bistable (48) SG2>SG1 Pres. bistable (102) (Channel A typical)	a) Setpoint power supply fails off	Component failure, open circuit	Diff. voltage goes to zero, bistable relays 4 and 6 will deenergize. Trip alarm and SG diff. pres. input to Channel A AFAS logic	Annunciating	3-channel redundancy (4th channel in bypass)	AFAS logic for Channel A (AFAS 1 typical) becomes “LO SG 1 LVL and not AFAS 2)” AFAS actuation logic remains 2-out-of-3	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 31 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	b) Set-point PWR supply fails HI	Short circuit, component	Trip and pre-trip setpoint voltages go to +15V, pulldown resistors change effective setpoints to 0V and bistable relays 4 and 6 are deenergized	Annunicating	3-channel redundancy (4th channel in bypass)	Same as 26 a)	Same as 26 a)
	c) Trip setpoint set fails low	Short circuit, component fail	Equiv. to 25 b)	Equiv. to 25 b)	Equiv. to 25 b)	Equiv. to 25 b)	Equiv. to 25 b)
	d) Trip setpoint set fails HI	Component failure	Trip setpoint voltage goes to +10V, pulldown resistor changes effective setpoint to 0V and bistable relays 4 and 6 are deenergized	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 26 a)	Same as 26 a)
	e)Process "A" input buffer fails off	Open circuit, component failure	Ref. pres. signal goes to zero trip and pre-trip comparators deenergize bistable relays 4, 6, and 7.	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 26 a)	Same as 26 a)
	f) Process "A" input buffer fails HI	Short circuit, component failure	Ref. pres. signal goes HI, bistable will not change state for valid HI diff. SG pres.	Periodic test	3-channel redundancy (4th channel in bypass)	Channel A AFAS logic becomes "LO SG LVL" AFAS actuation logic remains 2-out-of-3	Same as 26 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 32 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	g) Process "B" input buffer fails off	Open circuit, component failure	Measured SG diff. pres. goes, negative. Bistable will not change state for valid HI diff. SG pres.	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 26 f)	Same as 26 a)
	h) Process "B" input buffer fails HI	Short circuit, component failure	Measured SG pres. diff. goes Hi and bistable relays 4, 6 and 7 are deenergized	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 26 a)	Same as 26 a)
	Failure modes i) through t) (for pre-trip portion of bistable) are equivalent to failure modes f) through q) of Line Item 25						
	u) Trip voltage comparator fails off	Component failure, open circuit	Same as 26 a)	Same as 26 a)	Same as 26 a)	Same as 26 a)	Same as 26 a)
	v) Trip voltage comparator fails on	Short circuit, component failure	Same as 26 f)	Same as 26 f)	Same as 26 f)	Same as 26 f)	Same as 26 f)
	w) Trip Opto-Isolator fails off	Open circuit, component failure	Same as 26 a)	Same as 26 a)	Same as 26 a)	Same as 26 a)	Same as 26 a)
	x) Trip Relay 4 Driver fails off	Transistor failure	Trip relay 4 deenergized spurious SG diff. pres. trip indication	Annunciating	None	No impact on AFAS logic or AFAS actuation logic	Same as 26 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 33 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	y) Trip Relay 4, Driver fails on	Emitter to collector short	Trip relay 4 will not de-energize for valid HI SG diff. pres. signal. Channel A trip not annunciated	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 26 x)	Same as 26 a)
	z) Trip Relay 6, Driver fails off	Transistor failure	Trip relay 6 is deenergized False “SG diff. pres.” input to Channel A AFAS logic	Trouble annunicator	3-channel redundancy (4th channel in bypass)	Same as 26 a)	Same as 26 a)
	AA) Trip Relay 6, Driver fails on	Emitter to collector short	Trip relay 6 will not de-energize for valid “SG Diff. Pres.” signal	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 26 f)	Same as 26 f)
	AB) Trip Relay 6, Coil fails open	Mechanical failure	Same as 26 z)	Same as 26 z)	Same as 26 z)	Same as 26 z)	Same as 26 z)
	AC) AFAS Logic Relay (AK40, or AK41), Coil fails open	Mechanical failure	Relay will not energize for valid SG LVL, SG diff. pres. and opposite AFAS Act. False AFAS sig. to opposite AFAS logic	Periodic test	3-channel redundancy (4th channel in bypass)	AFAS (AFAS2) Channel A logic becomes “LO SG LVL”, and AFAS2 (AFAS1) logic becomes “LO SG LVL and not SG Diff. Pres” AFAS actuation remains 2-out-of-3	Same as 26 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 34 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	AD) AFAS Logic Relay (AK40 or AK41) Contacts in same AFAS Train Logic fails open	Open circuit, mechanical failure	Contact will not be closed for valid SG LVL, SG diff. and opposite AFAS Act. Inputs	Periodic test	3-channel redundancy (4th channel in bypass) affected	Channel A logic for affect AFAS train becomes “LO SG LVL” Channel A logic for other AFAS train and AFAS act. logic not	Same as 26 a)
	AE) AFAS Logic Relay (AK40 or AK41) Contacts in same AFAS Train Logic fail closed	Contact arcing and weld	Contact will be closed regardless of input for affected AFAS train. Unable to deenergize Channel A AFAS bistable trip relays for affected AFAS train	Periodic test	3-channel redundancy (4th channel in bypass)	AFAS actuation logic for affected AFAS train becomes 2-out-of-2	Same as 26 a)
	AF) Bistable Trip Relay Driver (TR1, TR2, or TR3) fails off	Transistor failure, open circuit	One bistable trip relay deenergized, including half trip of one logic matrix (AB, AC, or AD) for one AFAS train	Annunciating	3-channel redundancy (4th channel in bypass)	AFAS actuation logic remains 2-out-of-3 with one matrix half-tripped for one AFAS train	Same as 26 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 35 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	AG) Bi-stable Trip Relay Driver (TR1, TR2 TR3) fails on	Emitter to collector short	One Channel A bistable trip for one AFAS train will not deenergize for valid input. One AFAS Logic Matrix (AB, AC, or AD) for one AFAS train will not trip	Periodic test	3-channel redundancy (4th channel in bypass)	Actuation logic for one AFAS train becomes 2-out-of-2	Same as 26 a)
	AH) Bi-stable Trip Relay Coil (TR1 TR2 or TR3) fails open	Mechanical failure	Same as 26 AF)	Same as 26 AF)	Same as 26 AF)	Same as 26 AF)	Same as 26 AF)
	AI) Bi-stable Trip Relay Contact in Logic Matrix fails open	Open circuit, Mechanical failure	Same as 26 AF)	Same as 26 AF)	Same as 26 AF)	Same as 26 AF)	Same as 26 AF)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 36 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	AJ) Bi-stable Trip Relay Contacts in Logic Matrix fails closed	Contact arcing and weld	Same as 26 AG)	Same as 26 AG)	Same as 26 AG)	Same as 26 AG)	Same as 26 AG)
	AK) Bi-stable Trip Relay Contacts in Trouble Annunc. Circuit fail open	Mechanical damage open circuit	Trip Relay/Relay Driver failure (off) not annunciated by trouble annunciator.	Periodic test	Logic matrix indicator lights	No impact on AFAS actuation logic	Same as 26 a)
	AL) Bi-stable Trip Relay Contact in Trouble Annunc. Circuit fail closed	Contact arcing and weld	Spurious TRIP Relay/Relay Driver Trouble Annunciator	Annunciating	None	Same as above	Same as 26 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 37 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
27) SG1 LO Pres. Bi-stable (45) SG LO Pres. Bistable (30) (Channel A typical)	a) Bi-stable setpoint power supply fails off	Component failure open circuit	Step adjust, min. adjust and max. adjust for trip and pre-trip setpoints go to zero Trip and pre-trip setpoints equiv. to last process input. Bistable trip will occur on any momentary process input decrease.	Annunciating	3-channel redundancy (4th channel in bypass)	RPS trip and MSIS logic becomes 1-out-of-2	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Bi-stable setpoint Power Supply fails HI	Component failure, short circuit	Step adjust, min. adjust and max. adjust for trip and pre-trip setpoints go high. Set-points go high, and compara-tors initiate bistable trip.	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 27 a)	Same as 27 a)
	c) 15V Power Supply fails off	Component failure open circuit	Loss of bistable setpoint power supply. See 27 a)	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 27 a)	Same as 27 a)
	d) 15V Power Supply fails HI	Component failure	HI volt input to clock circuit digital representation circuit limiter circuit, and setpoint power supply. Probable over-stress and loss of setpoint power supply. See 27 a)	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 27 a)	Same as 27 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	e) Setpoint step adjust fails open	Mechanical damage component failure	Setpoint step goes to zero, and setpoint equals last process input. Decrease in process input will cause bistable trip.	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 27 a)	Same as 27 a)
	f) Setpoint step adjust fails high	Short circuit	Setpoint step goes to +10V and setpoint goes LO. Pullup circuit in comparator initiates bistable trip	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 27 a)	Same as 27 a)
	g) Setpoint max. adjust fails open	Component failure open circuit	Max. setpoint goes ot 0Vs and stays there. Pullup circuit in comparator initiates bistable trip	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 27 a)	Same as 27 a)
	h) Setpoint max. adjust shorted	Component failure	Max. setpoint goes HI, Set-point will continue to track process input above desired max. Possible bistable trip in SG press. operating range.	Periodic test, annunciating for trip	3-channel redundancy (4th channel in bypass)	No effect unless channel trip occurs, then trip logic becomes 1-out-of-2	Same as 27 a)
	i) Setpoint min. adjust fails open	Component failure open circuit	Setpoint min. goes to zero, setpoint can drop below desired minimum during power decreases. Possible failure to initiate channel trip on loss of SG pres. at LO PWR LVLs	Periodic test	3-channel redundancy (4th channel in bypass)	RPS trip and MSIS logic for LO SG Pres. becomes 2-out-of-2 at LO PWR LVLs	Same as 27 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 39 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	j) Setpoint min. adjust shorted.	Comp. failure.	Setpoint minimum goes hi. Unable to reset setpoint during power decreases. Possi-ble channel trip during power decrease.	Periodic test, annunciating during power decreases.	3-channel redundancy (4th channel in bypass)	RPS trip and MSIS logic for LO SG press. becomes 1-out-of-2 during power decreases.	Same as 27 a)
	k) Pre-trip setpoint adjust fails open	Comp. failure, open circuit.	Pre-trip bias voltage goes to zero. Pre-trip and trip set-points become identical. Loss of pre-trip indication for channel.	Periodic test.	3-channel redundancy (4th channel in bypass)	RPS trip and MSIS logic unaffected. Pre-trip logic becomes 1-out-of-2.	Same as 27 a)
	l) Pre-trip setpoint adjust shorted.	Comp. failure.	Pre-trip bias voltage goes hi, driving pre-trip setpoint hi. Spurious pre-trip alarm.	Annunciating.	None.	No impact on RPS trip and MSIS logic.	Same as 27 a)
	m) Reset button (1 of 3) fails open.	Mech. damage, corrosion.	Unable to reset trip and pre-trip setpoints from 1 location during power decrease. Proba-ble ch. trip during power decrease.	Periodic test, annunc. ch. trip during power decrease.	3-channel redun-dancy, reset buttons at other locations. (4th channel in bypass)	RPS trip and MSIS logic for LO SG press. becomes 1-out-of-2 during power decrease.	Same as 27 a)
	n) Reset button (1 of 3) shorted.	Contact weld.	Contacts remain closed after reset, and reset logic becomes disabled for all locations. Ch. trip on power decrease.	Periodic test, ch. trip alarm during power decrease.	Same as above.	Same as above.	Same as 27 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	o) Clock circuit fails HI	Comp. failure.	Faster generation of digital representation of process input. No other impact.	Periodic test.	None required.	No impact on RPS trip or MSIS logic.	Same as 27 a)
	p) Clock circuit fails Low	Comp. failure.	Slower generation of digital representation of process input. Setpoint lags input during power increase. No adverse effect.	Periodic test.	None required.	No impact on RPS trip or MSIS logic.	Same as 27 a)
	P1) 15VDC variable setpoint power supply fails low or off	Component failure in power supply	15 VCD power to clock and other circuits on variable setpoint card lost. Setpoint output from card goes to 0 VDC. Trip set-point goes to zero. Bistable will not trip on valid low pressure condition.	Periodic test	3-channel redundancy (4th channel in bypass)	RPS trip logic for LO-SG-Press. becomes 2-out-of-2 coincident	Same as 27 a)
	P2) 15VDC variable setpoint power supply output goes high	Component tolerance buildup, component failure.	Voltage to clock and other circuits on variable setpoint exceeds 15V. Clock frequency may increase and setpoint output voltage may increase. If setpoint increases, bistable will trip at a higher pressure.	Periodic test, annunciating if bistable trips.	3-channel redundancy (4th channel in bypass)	If bistable trips, RPS trip logic for LO-SG-Press will becomes 1-out-of-2 coincident	Same as 27 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 41 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
27) SG1 Lo Press. Bi-stable (45), SG2 Lo Pres. Bistable (30) (Ch. A Typ.) (Cont.)	q) Digital represent. circuit fails off.	Comp. failure.	Bias voltage to setpoint generators goes to zero. Set-points track process input up and down. Unable to trip ch.	Periodic test.	3-channel redundancy (4th channel in bypass)	RPS trip and MSIS logic goes to 2-out-of-2.	Same as 27 a)
	r) Digital represent. Circuit fails hi.	Comp. failure.	Bias voltage to setpoint generators goes hi, driving setpoints up. Possible ch. trip if setpoints exceed process input.	Periodic test, annunciating for ch. trip.	3-channel redundancy (4th channel in bypass))	RPS trip and MSIS logic for LO SG press. becomes 1-out-of-2.	Same as 27 a)
	s) Setpoint limiter fails off.	Open circuit, comp. failure.	Trip and/or pre-trip setpoint goes to zero. Pullup circuit in comparator initiates ch. trip.	Annunciating.	3-channel redundancy (4th channel in bypass)	Same as 27 a)	Same as 27 a)
	t) Setpoint limiter fails low	Comp. failure.	Trip and/or pre-trip setpoints are limited at too low a value Bistable will not trip at proper SG press.	Periodic test.	3-channel redundancy (4th channel in bypass)	RPS trip and MSIS logic changes to 2-out-of-2.	Same as 27 a)
	u) Setpoint limiter fails HI.	Comp. failure, short circuit.	Trip and/or pre-trip setpoint limit values go hi. Trip set-point can follow process input into normal operating range. Possible spurious ch. trip under normal SG pressure fluctuations.	Periodic test, annunc. for ch. trip.	3-channel redundancy (4th channel in bypass)	Same as 27 a)	Same as 27 a)
	Failure modes v) through an) and their effects on RPS trip and MSIS logic for LO SG Press. are equivalent to Line Item 19s Failure modes d), e), and h) through y) and their effects on RPS trip and MSIS logic for HI SG Level.						

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 42 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
28) LO PZR Pres. Bi-stable (62) (Ch. A Typ.)	The Failure Modes for this bistable and their effects on RPS trip logic for LO PZR Press. are equivalent to the failure modes and their effects on RPS trip logic for Lo SG Press. as presented in Line Item 27.						
29) Variable Overpower Bistable (72) (Ch. A. Typ.)	a) Bi-stable setpoint power supply fails off	Comp. failure, open circuit.	Step adjust, max. adjust, and min. adjust voltages for trip and pre-trip setpoints go to zero. Trip and pre-trip set-points go to zero and bi-stable trips.	Annunciating.	3-channel redundancy (4th channel in bypass)	RPS trip logic for overpwr. Goes to 1-out-of-2.	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Bi-stable setpoint power supply fails HI	Comp. failure, short circuit.	Step adjust, max. adjust, and min. adjust voltages for trip and pre-trip setpoints go high. Trip and pre-trip setpoint values increase, as do the limit values. Ch. bistable not respond properly to increasing power level or to HI power level.	Periodic trip.	3-channel redundancy (4th channel in bypass)	RPS trip logic for variable power goes to 2-out-of-2.	Same as 29 a)
	c) 15 V power supply fails off.	Open circuit, comp. failure.	Loss of bistable setpoint power supply. See 29 a).	Same as 29 a)	Same as 29 a)	Same as 29 a)	Same as 29 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 43 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
29) (Cont.)	d) 15 V power supply fails HI	Comp. failure.	HI voltage input to clock circuit, digital representation circuit, limiter circuit and bistable setpoint power supply. Possible overstress of clock circuit or setpoint power supply. Probable Ch. trip.	Annunciating	3-channel redundancy (4th channel in bypass)	RPS trip logic for overpower goes to 1-out-of-2.	Same as 29 a)
	e) Setpoint step adjust fails open	Mech. damage, comp. failure.	Offset between process input and trip setpoint goes to zero and bistable trips.	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 29 a)	Same as 29 a)
	f) Setpoint step adjust fails HI	Short circuit, comp. failure.	Offset between process input and trip setpoint goes hi. Time to reach setpoint during power increase transient slightly longer than it should be. No effect during steady state operation as setpoint is limited by max. adjust.	Periodic test.	3-channel redundancy (4th channel in bypass) in bypass)	Same as 29 b)	Same as 29 a)
	g) Setpoint max. adjust fails open	Mechanical damage component failure	Max. setpoint value for power goes to zero. Bistable trips	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 29 a)	Same as 29 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 44 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
29) (Cont.)	h) Setpoint max adjust fails HI	Component failure	Max. setpoint value for over-power goes HI, setpoint will continue to track power into safety limit range. Bistablemay not trip for valid overpower condit.	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 29 b)	Same as 20 a)
	i) Setpoint min. adjust fails open	Mechanical damage component failure	Overpower setpoint minimum goes to zero, setpoint will continue to track linear power at LO Power Levels. Possible spurious channel trips at LO power	Periodic test Annunc. for channel trip at Low PWR	3-channel redundancy (4th channel in bypass)	No impact on RPS trip logic except at LO PWR LVLs where it becomes 1-out-of-2	Same as 29 a)
	j) Setpoint min. adjust fails HI	Component failure short circuit	Overpower setpoint minimum goes HI therby driving setpoint HI bistable may not trip for valid power excursion	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 29 b)	Same as 29 a)
	k) Pre-trip Setpoint adjust fails open	Mechanical damage component failure	Pre-trip setpoint bias voltage goes to zero, pre-trip and trip setpoint becomes identical loss of pre-trip indic. for channel	Periodic test	3-channel redundancy (4th channel in bypass)	RPS trip logic not affected. Pre-trip logic becomes 1-out-of-2	Same as 29 a)
	l) Pre-trip Setpoint adjust shorted	Component failure	Pre-trip bias volt. goes low driving pre-trip setpoing low. Spurious pre-trip alarms	Annunciating	None	No impact on RPS trip logic	Same as 29 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 45 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
29) (Cont.)	m) Clcok Circuit Freq. goes HI	Component failure	Setpoint generation time is decreased, and setpoint tracks process input quicker. Bistable will not trip on power excursion.	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 29 b)	Same as 20 a)
	n) Clock Circuit freq. goes Low	Component failure	Setpoint generation time increases and setpoint tracks process input slower. Possible spurious channel trips during PWR increase	Annunc. For channel trip, otherwise periodic test	3-channel redundancy (4th channel in bypass)	Same as 29 a)	Same as 29 a)
	o) Digital repre-sentation Circuit fails off	Component failure	Loss of process input ref. for setpoint generation. Setpoint drops to offset (step) value. Spurious channel trip	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 29 a)	Same as 29 a)
	p) Digital repre. Circuit fails HI	Component failure	Erroneous HI valves for process input used for setpoint generation	Same as 29 f)	Same as 29 f)	Same as 29 f)	Same as 29 f)
	q) Setpoint limiter fails low	Component failure open circuit	Setpoint limited below max. setpoint, spurious channel trip during power increase	Annunciating	3-channel redundancy (4th channel in bypass)	Same as 29 a)	Same as 29 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 46 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	r) Setpoint Limiter fails HI	Component failure	Same as 29 h)	Same as 29 h)	Same as 29 h)	Same as 29 h)	Same as 29 h)
	Failure Modes s) through AK) and their effect on RPS Trip Logic for variable overpower are equivalent to Line Item 19, Failure Modes d), e), and h) through y) and their effects on RPS Trip Logic on HI SG LVL.						
30) SG1 LO Flow Bistable (101) SG2 LO Flow Bistable (100)	a) Bi-stable setpoint PWR supply fails off	Component failure open circuit	Step adjust, max. adjust and min. adjust voltages for trip and pre-trip go to zero. Digital representation goes to zero. Trip setpoint goes to zero. Bistable not respond to SG flow decrease	Annunc. for P/S fail	3-channel redundancy (4th channel in bypass))	RPS Trip Logic for LO flow becomes 2-out-of-2	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Bi-stable Setpoint PWR supply fails HI	Component failure short circuit	Step adjust, max. adjust, and min. adjust voltages go more negative. Trip and pre-trip setpoints decrease bistable not trip on decreasing SG flow	Periodic test	3-channel redundancy (4th channel in bypass)	RPS Trip Logic for LO flow becomes 2-out-of-2	Same as 30 a)
	c) 15V Power fails off	Open circuit, Component circuit	Loss of bistable setpoint power supply.	See 30 a)	See 30 a)	See 30 a)	See 30 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 47 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
30) (Cont.)	d) 15V Power Supply fails high	Component failure	HI voltage input to variable setpoint card and bistable setpoint power supply. Probable overstress of setpoint power supply or clock circuit. See 30 a)	Annunciating	3-channel redundancy (4th channel in bypass)	RPS trip logic for LO flow becomes 2-out-of-2	Same as 30 a)
	e) Setpoint step adjust fails open	Mechanical failure component failure	Setpoint offset voltage goes to zero and setpoint rises to the process input value, bistable trips	Annunciating	3-channel redundancy (4th channel in bypass)	RPS Trip Logic for LO flow becomes 1-out-of-2	Same as 30 a)
	e1) Set-point step adjust fails low	Component failure, component out-of-tolerance.	Setpoint offset voltage goes low, offset between process input and setpoint decreases. No impact during normal opera-tion, but bistable will trip earlier than expected on decreasing flow.	Periodic Test	3-channel redundancy (4th channel in bypass)	RPS trip logic for SG-LO-Flow unaffected, but one bistable will trip earlier than others.	See 30 a)
	f) Setpoint adjust fails high	Component failure short circuit	Setpoint offset voltage goes more negative. Difference between process input and setpoint increases. See 30 b)	See 30 b)	See 30 b)	See 30 b)	See 30 b)
	g) Setpoint max. adjust fails open	Mechanical failure component	Max. setpoint offset voltage goes to zero, setpoint held at 0v. See 30 a)	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 30 a)	Same as 30 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 48 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
30) (Cont.)	h) Setpoint max. adjust fails HI	Component failure	Max. adjust bias voltage goes more negative setpoint max. limit increases. Setpoint can track process input into operating range. Possible spur. channel trip under normal flow fluctuations	Periodic tests annunc. for channel trip	3-channel redundancy (4th channel in bypass)	Same as 30 e)	Same as 30 a)
	i) Setpoint min. adjust fails open	Mechanical damage component failure	Min. setpoint ref. voltage goes to zero. Min. setpoint limit goes to zero bistable not respond to loss of flow at LO power	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 30 a)	Same as 30 a)
	j) Setpoint min. adjust fails high	Component failure	Min. setpoint ref. voltage goes more negative and min. setpoint limit increases. Possible spurious channel trips at LO power and LO flow	Periodic test, annunciating for channel trip	3-channel redundancy (4th channel in bypass)	Same as 30 e)	Same as 30 a)
	k) Pre-trip setpoint adjust fails open	Mechanical damage open circuit	Pre-trip setpoint bias voltage goes to zero, and pre-trip and trip setpoints become identical. Loss of channel pre-trip capability	Periodic test	3-channel redundancy (4th channel in bypass)	No impact on RPS Trip Logic. Pre-trip logic becomes 1-out-of-2	Same as 30 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 49 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
30) (Cont.)	l) Pre-trip setpoint adjust fails high	Component failure	Pre-trip setpoint bias voltage goes high and pre-trip setpoint increases possible spurious pre-trip alarm	Annunciating	None	No impact on RPS Trip Logic	Same as 30 a)
	m) Clock circuit freq. goes high	Component failure	Setpoint generation time decreases and setpoint can track process input quicker Bistable may not trip on flow decrease	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 30 a)	Same as 30 a)
	n) Clock circuit freq. goes low	Component failure	Setpoint generation time increases and setpoint does not track process input as fast as it should. Possible channel trip during power/flow decrease	Periodic test, annunc. for channel trip	3-channel redundancy (4th channel in bypass)	Same as 30 e)	Same as 30 a)
	o) Digital repre-sentation circuit fails off	Component failure	Loss of process input reference for setpoint generation. Setpoint drops to step value. Bistable not respond to flow decrease	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 30 a)	Same as 30 a)
	p) Digital repre-sentation circuit fails high	Component failure	Erroneous, high ref. values used for setpoint generation Possible spurious channel trip	Annunciating for channel trip	3-channel redundancy (4th channel in bypass)	Same as 30 e)	Same as 30 a)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 50 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
30) (Cont.)	q) Setpoint limiter fails low	Component failure	Setpoint limited to artificially LO value. Bistable not respond properly to decrease in RCS flow	Periodic test	3-channel redundancy (4th channel in bypass)	Same as 30 a)	Same as 30 a)
	r) Setpoint limiter fails hi	Component failure	Same as 30 h)	Same as 30 h)	Same as 30 h)	Same as 30 h)	Same as 30 h)
	Failure Modes s) through AK) and their effect on RPS Trip Logic for Low Flow are equivalent to Line Item 19, Failure Modes d), e), and h) through y) and their effect on RPS Trip Logic for HI SG LVL.						
31) Control Element Assembly Calculator (88)	a) No data output	Loss of AC power. Input/ output failure Data link failure. Arithmetic, logic or memory failure	Loss of CEA position display	Annunciating alarm on CPC operator's module.	Two-channel redundancy	None	CPC uses data from the other CEAC and annunciates failure
	b) Erroneous data output	CEA position sensor failure input/output failure. Data link failure Arithmetic, logic or memory failure	Erroneous calculated values. Possible DNBR or LPD trip	Annunciating alarm on CPC operator's module. Comparison of CEA position displays, comparison of like parameters on operator's modules	CPC uses worst case data from the two CEAC's	Possible DNBR or LPD trip	CPC compares data from the two CEACs and annunciates

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 51 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
32) Core Protection Calculator (89)	a) Tripped	Loss of AC power input/ output failure arithmetic, logic or memory failure sensor failure	Loss of control board displays Erroneous calculated results	Annunciating PPS alarm on channel trip. 3-channel comparisons annun- ciating watchdog timer	3-channel redundancy (4th channel in bypass)	Reactor trip logic for DNBR, LPD and CWP is converted to 1-out-of-2 coincidence	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Stays in untripped state	Input/output failure Arithmetic, logic or memory failure sensor failure	Erroneous calculated results	3-channel compari- sons Annunciating watchdog timer	3-channel redundancy (4th channel in bypass)	Reactor trip logic for DNBR, LPD and CWP is on coinci- dence of 2-out- of-2 remaining channels	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
33) LO PZR Pressure Operating Bypass (33, 36, 60, 34) Channel A typical	a) Bi-stable PWR supply fails off	Component failure open circuit	Trip setpoint goes to zero. Operator unable to bypass LO PZR Pres. Bistable at LO pres. or operating bypass automatically removed, Possible channel trip on LO PZR Pres.	Annunc., Periodic test, operator when initiate operating bypass	3-channel redundancy (4th channel in bypass)	RPS Trip Logic for LO PZR Pres. goes to 1-out-of-2 at LO PWR/ Pres. operator	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel
	b) Bi-stable setpoint PWR supply fails HI	Component failure	Trip setpoint voltage goes HI, The pre-set point at which the LO PZR Pres. operating bypass is automatically removed increases LO PZR Pres. bistable will remain bypassed.	Periodic test. bypass indicator lit at power	3-channel redundancy (4th channel in bypass)	RPS Trip Logic for LO PZR Pres. becomes 2-out-of-2	Same as 33 a)
	c) 15V PWR supply fails off	Component failure open circuit	Loss of bistable setpoint PWR supply. See 33 a)	See 33 a)	See 33 a)	See 33 a)	See 33 a)
	d) 15V PWR supply fails HI	Component failure short circuit	Overstress of bistable setpoint PWR supply. Setpoint power supply output may go hi (see 33 b) for effects) or setpoint power supply may burn out and its output go to 0 VDC (see 33 a) for effects)	See 33 a) and 33 b)	See 33 a) and 33 b)	See 33 a) and 33 b)	See 33 a) and 33 b)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
33) (Cont.)	e) Setpoint set fails open	Component failure	See 33 a)	See 33 a)	See 33 a)	See 33 a)	See 33 a)
	f) Setpoint set fails HI	Component failure	See 33 b)	See 33 b)	See 33 b)	See 33 b)	See 33 b)
	g) Trip voltage comparator fails off	Component failure,	Bistable Relay, AK21, is de-energized and PZR Pres. operating bypass is removed. Probable channel trip on LO PZR Pres.	Annunc. for channel trip, periodic test	3-channel redundancy (4th channel in bypass)	Same as 33 a)	Same as 33 a)
	h) Trip voltage comparator fails on	Short circuit component failure	Bistable Relay AK21 will not be de-energized when PZR Pres. reaches setpoint. Operating bypass will remain engaged. LO PZR Pres. bistable remains bypassed	Periodic test, by-pass indicator on when it should not be	3-channel redundancy (4th channel in bypass)	Same as 33 b)	Same as 33 b)
	i) Opto-isolator fails off	Open circuit component failure	Same as 33 g)	Same as 33 g)	Same as 33 g)	Same as 33 g)	Same as 33 g)
	j) Relay Driver, (Relay AK21) fails off	Open circuit, transistor failure	Same as 33 g)	Same as 33 g)	Same as 33 g)	Same as 33 g)	Same as 33 g)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 54 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
33) (Cont.)	k) Relay Driver (Relay AK21) fails on	Emitter-to-collector short	Same as 33 h)	Same as 33 h)	Same as 33 h)	Same as 33 h)	Same as 33 h)
	l) AK21 Coil open	Sustained Overvoltage	The low pressurizer pressure trip cannot be bypassed in Channel A	Periodic PPS testing or when attempting to initiate bypass	None required. Failure will not cause trip and will not prevent trip	During a condition of low pressurizer pressure, the bistable will be tripped in that channel regardless of the position of the bypass switch	
	m) AK21 Coil short	Deterioration of Insulation	Attempting to bypass low pressurizer pressure under conditions of low pressure will place a severe load on the relay driver. Under this abnormal load the relay driver may fail. If the driver fails short the results will be the same as those listed for item 33 k)	Same as 33 k)	Same as 33 k)	Same as 33 k)	
			If the driver fails open the results will be the same as those listed for an open relay coil.	Same as 33 l)	Same as 33 l)	Same as 33 l)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
33) (Cont.)	n) AK21 Contact in Relay Latching Circuit open	Deterioration of contact	Low Pressurizer Pressure cannot be bypassed in Channel A	Periodic PPS testing or when attempting to initiate a bypass on this function	Same as 33 l)	During a condition of low pressurizer pressure the bistable will be tripped	
	o) AK21 Contact in Relay Latching Circuit short	Welded Contact	Bypass will not lock out automatically	Periodic PPS testing	3-channel redundancy (4th channel in bypass)	Unless the bypass is removed manually, bypass will be in effect whenever there is low pressurizer pressure	
	p) AK21 Contacts in permissive indic. circuit fail open	Mechanical damage open circuit	Permissive indicator will not be lit when PZR Pres. goes below operator bypass setpoint LO PZR Pres.	Periodic test visual at LO PZR Pres.	3-channel redundancy (4th channel in bypass)	Same as 33 a)	Same as 33 a)
	q) AK21 Contacts in permissive indic. circuit fail closed	Corrosion contact weld	Permissive indicator will remain on even when permissive not available. No impact on bypass capability	Visual indication, test	None required	No impact on RPS Trip Logic for LO PZR Pres.	Same as 33 a)
	r) Permissive indicator fails off	Light burn out	Same as 33 p)	Same as 33 p)	Same as 33 p)	Same as 33 p)	Same as 33 p)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	s) AK22 Driver fails off	Transistor failure	AK22 cannot be energized even when permissive available. Unable to place operating bypass on LO PZR Pres. bistable (Ch. A) possible channel trip	Periodic test, bypass indicator will not come on. Annunc. for channel trip	3-channel redundancy for LO PZR Pres. bistable (4th channel in bypass)	Same as 33 a)	Same as 33 a)
	t) AK22 Driver fails on	Emitter-to-collector short	AK22 will be energized whenever AK21 is energized. Lo PZR Pres. Bistable will be automatically bypassed below operating bypass setpoint	Periodic test. Oper. bypass light comes on when no bypass placed by operator	3-channel redundancy (4th channel in bypass)	Same as 33 b)	Same as 33 a)
	u) AK22 Coil open	Sustained overvoltage	Low pressurizer pressure trip bypass for the affected channel will not be actuated when demanded.	Periodic PPS testing status light not lit	3-channel redundancy (4th channel in bypass)	Same as 33 a)	Same as 33 a)
	v) AK22 Coil short	Deterioration or Insulation	Attempting to bypass log pressurizer pressure under conditions of low pressure will place a severe load on the relay driver. With this abnormal load the relay driver may fail. If the driver fails short the results will be the same as those listed for an open relay coil.	Same as 33 u)	Same as 33 u)	Same as 33 u)	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
33) (Cont.)	w) Contact in Latch Circuit shorts	Mechanical failure	Bypass transistor will remain latched "on" after bypass switched is turned to "normal" Low PZR Press. trip will be bypassed.	Unable to unlatch transistor manually status light lit	Redundant channel	Bypass	Same as 33 a)
	x) Contact in Latch Circuit opens	Mechanical failure	Unable to latch bypass transistor "on"; Low PZR Press. trip will not bypass	Status light not lit	Redundant channel	None	Same as 33 a)
	y) Contact in Annun-ciated Circuit short	Mechanical failure	Annunciator and status light actuated	Alarm	None required	Nuisance Alarms and indications	Same as 33 a)
	z) Contact in Annun-ciated Circuit open		No annunciation	No status indication		Redundant channel	None
	aa) Low PZR Pressure Trip Bypass Switch Contact Bypass Circuit short	Mechanical failure	Low pressurizer pressure trip automatically bypassed in the affected channel when PZR Pres. aux. B/S permits bypass condition	Periodic PPS test-ing. Bypass condi-tion before manual action	3-channel redundancy (4th channel in bypass)	During a condition of low pressurizer pressure the bi-stable will be bypassed	If a bypass is required the other 2-channels may be bypassed as they are unaffected by the fault

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
33) (Cont.)	ab) Low PZR Pressure Trip Bypass Switch Contact Bypass Circuit Open	Mechanical failure	Bypass transistor will not switch “ON”. Low PZR Pres. trip will not be bypassed when desired	Unable to bypass. Status light not lit	One bistable alone cannot cause trip. Other two channels can be bypassed (4th channel already in bypass)	None	The low pressurizer pressure bypass circuits in the other 2 channels are unaffected and will respond properly.
	ac) Contact Normal Circuit shorts	Mechanical failure	Bypass transistor remains “OFF” and bypass condition will not latch on	Status light not lit	Same as 33 ab)	None	Operator would have to hold bypass switch in bypass position to maintain bypass in this channel
	ad) Contact Normal Circuit open	Mechanical failure	Bypass transistor will not switch “OFF” manually	Unable to manually remove bypass status light status	Same as 33 ab)	None	Function of circuit is not impaired, nuisance

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
34) Safety Channel Nuclear Instument (83) (Ch. A Typical)	a) Trouble annunc. bistable fails off.	Failure causes equiv. to trip ch. bistable fail modes.	Trouble annunc. relays de-energized. Spurious N.I. trouble indication and spurious LPS and DNBR ch. trips.	Annunciating.	3-channel redundancy for LPD and DNBR. None for trouble annunc. (4th channel in bypass)	RPS trip logic for LPD and DNBR goes to 1-out-of-2.	To restore the system logic ot 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) Trouble annunc. bistable fails on.	Failure causes equiv. to trip ch. bistable fail. modes.	Trouble annunc. relays not de-energize during NI test or when there is trouble in the NI Drawer. Loss of trouble annunc. LPD and DNBR bistables not tripped. LPD and DNBR bistables may not trip during NI test due to erroneous data.	Periodic test, lack of annunc. during NI test.	3-channel redundancy (4th channel in bypass)	RPS trip logic for LPD and DNBR may go to 2-out-of-2.	Same as 34 a)
	c) Trouble bistable relay contacts in annunc. circuit fail closed	Contact arc and weld.	NI test or trouble in NI not annunciated.	Periodic test, lack of annunc. during NI test.	None.	RPS trip logic not affected.	Same as 34 a)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
34) (Cont.)	d) Trouble bistable relay contacts in annunc. fail open.	Open circuit, mech. failure.	Spurious NI trouble alarms.	Annunciating.	None.	RPS trip logic not affected.	Same as 34 a)
	e) Trouble bistable relay contacts in power trip test interlock fail closed.	Contact arc and weld.	LPD and DNBR bistables in affected ch. will not be tripped during NI ch. test or when there is trouble in the NI drawer. LPD and DNBR bistables may not trip due to erroneous data.	Periodic test, lack of LPD/DNBR trip indic. during NI test.	3-channel redundancy (4th channel in bypass)	RPS trip logic may go to 2-out-of-2.	Same as 34 a)
	f) Trouble bistable relay contacts in power trip test interlock fail open.	Open circuit, mech. failure.	Spurious ch. trips for LPD and DNBR if bypass relays are not engaged.	Annunciating.	3-channel redundancy (4th channel in bypass)	RPS trip logic for LPD and DNBR goes to 1-out-of-2.	Same as 34 a)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
34) (Cont.)	g) 10^{-4} % log power bistable fails off.	Failure causes equiv. to trip ch. bistable fail modes.	Bistable will not energize when power exceeds 10^{-4}%. One HI log power trip ch. cannot be bypassed. Probable ch. trip for high log power.	Periodic test, annunc. ch. trip HI log power bypass permissive light not come on at power.	3-channel redundancy. (4th channel in bypass)	One ch. of HI log power tripped at power. Other 2 channels can still be bypassed for operation.	Same as 34 a)
	h) 10^{-4} % log power bistable fails on.	Fail. causes equiv. to trip ch. bistable failure modes.	Bistable will be energized at all power levels. Operator can bypass HI log power bistable at less than 10^{-4} % power.	3-channel comparison, periodic test.	3-channel redundancy. (4th channel in bypass)	RPS trip logic for high log power becomes 2-out-of-2 if ch. is bypassed.	Same as 34 a)
	i) 10^{-4} % log power bistable fails off.	Fail. causes equiv. to trip ch. bistable failure modes.	Bistable relay will not be energized below 10^{-4} % power. CWP will not be bypassed and CPC cannot be bypassed. Spurious LPD and DNBR ch. trips at Lo power plus spurious CWP's at Lo power.	Periodic test, 3-channel comparison.	3-channel redundancy. (4th channel in bypass)	One ch. for LPD, DNBR and CWP tripped at Lo power. Other 2 channels can still be bypassed.	Same as 34 a)
	j) 10^{-4} % log power bistable fails on.	Fail. causes equiv. to trip ch. bistable failure modes.	Bistable relay will remain energized above 10^{-4} % power. One CPC will remain bypassed and one ch. for CWP will remain bypassed.	CPC bypass permissive indication, test	3-channel redundancy. (4th channel in bypass)	RPS trip logic and CWP logic for LPD or DNBR beomes 2-out-of-2.	Same as 34 a)
	k) 10^{-4} % log power bistable contacts in CWP fail open.	Mech. failure, open circuit.	CWP will not be bypassed for LPD and DNBR below 10^{-4} % power. Possible spurious CWP ch. trip at Lo power if CPS is not bypassed.	Periodic test, annunc. for CWP ch. trip.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic or CWP as other chs. Are bypassed.	Same as 34 a)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
34) (Cont.)	l) 10^{-4} % log power bistable contacts in CWP fail closed.	Contact arc and weld.	CWP for LPD and DNBR will remain bypassed all power levels.	Periodic test.	3-channel redundancy. (4th channel in bypass)	CWP on LPD or DNBR pre-trip goes to 2-out-of-2.	Same as 34 a)
	m) 10^{-4} % log power bistable contacts in CPC fail open.	Mech. failure, open circuit.	CPC bypass permissive for one channel not enabled below 10^{-4} % power. Unable to bypass one CPC. Possible LPD and DNBR ch. trips at low power.	Periodic test, annunc. for ch. trip.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic as other CPC's can still be bypassed.	Same as 34 a)
	n) 10^{-4} % log power bistable contacts in CPC fail closed.	Contact arc and weld.	CPC bypass will not be automatically removed at 10^{-4} % power. CPC will be bypassed.	CPC bypass indic. test	3-channel redundancy. (4th channel in bypass)	RPS trip logic for LPD and DNBR becomes 2-out-of-2.	Same as 34 a)
	o) Rate of change of power bistable fails on.	Fail. causes equiv. to trip ch. bistable fail. modes.	Loss of annunc. at HI rate of change of power for on channel.	Periodic test.	3-channel redundancy. (4th channel in bypass)	HI rate of change of power annunc. logic goes to 1-out-of-2.	Same as 34 a)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
34) (Cont.)	d) Rate of change of power bistable fails off.	Fail. causes equiv. to trip ch. bistable fail. modes.	Spurious HI rate of change of power alarms.	Annunciating.	None.	No impact on RPS trip logic.	Same as 34 a)
	q) Log power level summers fail HI.	Comp. failure.	Erroneous log power level indic. at main control board or remote shutdown area.	3-channel comparison, periodic test.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic.	
	r) Log power level summers fail off.	Comp. failure, open circuit.	Loss of log power level indic. at main control board or remote shutdown area.	Operator.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic.	
	s) Calibrated linear power level summer fails HI.	Comp. failure.	HI linear power indic. at main control board.	3-channel comparison, periodic test.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic.	
	t) Calibrated linear power level summer fails off.	Comp. failure, open circuit.	Loss of one channel of linear power indic. on main control board.	Operator.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 64 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
34) (Cont.)	u) Rate of change of power summer fails HI.	Comp. failure.	Erroneous power change rate indic. at main control board.	3-channel comparison, periodic test.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic.	
	v) Rate of change of power summer fails off.	Comp. failure, open circuit.	Loss of rate of change of power indic. for one channel.	Operator.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic.	
35) High Log Power Operating Bypass (70, 71, 79) (Ch. A Typ.)	a) Bypass relay AK27 coil open.	Sustained overvoltage.	High log power trip bypass cannot be obtained in Ch. A.	Whenever a bypass of high log power is attempted in the affected channel. Periodic PPS testing.	3-channel redundancy. (4th channel already in bypass)	Bistable will be tripped when the power level exceeds 1 to 2% full power.	The other 2 channels are unaffected and can be bypassed. Bypassing the other 2 channels precludes a trip caused by high LOG power as a coincidence of at least two channels is required to produce a trip.
	b) Bypass relay AK27 coil short		Shorted coil will cause auxiliary logic power supply voltage to be reduced to approximately zero when the power level exceeds 10^{-4}% full power.	Periodic test annunciation of power supply failure	3-channel redundancy. (4th channel in bypass)	High log power bistable cannot be bypassed above 10^{-4}% power, channel will trip	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
35) (Cont.)	c) Bypass relay AK27 N.O. contact in bistable bypass circuit short.	Welded contact	High LOG power trip can be bypassed in the affected channel regardless of power level. Bypass not auto. removed.	Periodci PPS testing.	3-channel redundancy. (4th channel in bypass))	Bistableis continually bypassed. Logic becomes 2-out-of-2 for Hi Log Power	System becomes 2-out-of-2 for that parameter at low power.
	d) Bypass relay AK27 N.O. contact in bistable bypass circuit open.	Deterioration of contact.	High LOG power trip cannot be bypassed in the affected channel.	Whenever a bypass of high LOG power is attempted in the affected channel. Periodic PPS testing.	3-channel redundancy. (4th channel in bypass)	Bistable will be tripped when the power level exceeds 1 to 2% full power.	
	e) Relay AK27 N.O. contacts in permissive indic. circuit fail open.	Corrosion, mech. damage, open circuit.	Loss of bypass permissive indic. for ch. Operator not bypass HI log power bistable above 10^{-4}% power. Probable channel trip.	3-channel comparison, annunc. for ch. trip, periodic test.	Bypasses not affected for other 2 channels (4th channel in bypass)	Trip logic for HI log power not affected as other 2 chs. will be bypassed.	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
35) (Cont.)	f) Relay AK27 N.O. contacts in permissive indic. circuit fail closed.	Contact weld.	Spurious operating bypass permissive indication. Bypass cannot be initiated.	Visual indication, 4-channel comparison.	Bypass capability not affected.	RPS trip logic not affected. Bypass cannot be initiated at less than 10^{-4}% power	Same as 35 e)
	g) Relay AK27 N.C. contacts in bypass annunc. circuit fail closed.	Contact weld, open circuit	Operating bypass permissive will not be annunciated when it is initiated.	Visual bypass permissive indic. with no annunc., periodic test.	Visual indication of ch. bypass permissive, bypass capability not affected.	RPS trip logic not affected as bypass can still be initated.	
	h) Bypass relay driver fails off.	Open circuit, transistor failure.	Operating bypass for channel cannot be initiated. Probable HI log power channel trip above 10^{-4}% power.	Operator when initiating bypass.	Bypasses in other 2 channels not affected. (4th channel already bypassed)	Trip logic for HI log power will not be affected as other 2 channels can be bypassed.	Same as 35 e)
	i) Bypass relay driver fails on.	Emitter-to-collector short.	One channel operating bypass for HI log power will be automatically generated whenever power exceeds 10^{-4}% power.	Bypass annunc. before Operator initiates bypass.	Other 2 channels still must be manually bypassed. (4th channel already bypassed)	RPS trip logic for HI log power not affected. This trip normally bypassed above 10^{-4}% power. Bypasses automatically removed below 10^{-4}% power.	Same as 35 e)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
35) (Cont.)	j) Bypass relay AK20 fails open.	Mech. damage, overstress.	Same as 35 h)	Same as 35 h)	Same as 35 h)	Same as 35 h)	Same as 35 e)
	k) Relay AK20 contacts in bypass circuit fail open.	Mech. damage, corrosion, open circuit.	Same as 35 h)	Same as 35 h)	Same as 35 h)	Same as 35 h)	Same as 35 e)
	l) Relay AK20 contacts in bypass circuit fail closed.	Contact weld.	Hi log power operating bypass for Ch. A will be engaged at all times. HI log power bistable will be bypassed at all power levels.	Visual bypass indic. at low power.	3-channel redundancy for HI log power trip. (4th channel in bypass)	RPS trip logic for HI log power goes to 2-out-or-2.	Same as 35 e)
	m) Relay AK20 N.C. contacts in "Bypass OFF" circuit fail closed.	Open circuit, contact weld.	Spurious and erroneous "Bypass OFF" indic. when bypass is in effect.	Concurrent "Bypass" and "Bypass OFF" indications.	Bypass not affected.	No impact on RPS trip logic.	Same as 35 e)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
35) (Cont.)	n) Relay AK20 N.C. contacts in "Bypass OFF" cir-cuit fail open.	Corrosion, mech damage.	Loss of "Bypass OFF" indic. for one channel. Bypass not affected.	"Bypass OFF" and "Bypass" lamps off at same time.	Bypass not affected.	No impact on RPS trip logic.	
	o) Relay AK20 N.O. contacts in annunc. circuit fail open.	Open circuit, contact weld, corrosion.	Operating bypass permissive annunciator will not be turned off when the HI log power bypass is initiated.	Operator when initiating bypass.	None required.	No impact on RPS trip logic or bypass capability	
	p) Relay AK20 N.O. contacts in annunc. circuit fail closed.	Contact weld.	Same as 35 g)	Same as 35 g)	Same as 35 g)	Same as 35 g)	
	q) Manual bypass init. Switch (2 locations) open.	Comp. failure, contact corrosion.	Unable to manually initiate or remove HI log power operating bypass. (Bypass automatically removed below 10^{-4}% power.)	Operator when attempting to initiate or remove bypass.	Redundant bypass switches.	No impact on RPS trip logic. Bypass can be initiated from alternate locations.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
35) (Cont.)	r) Manual bypass switch (2 locations) fails to "bypass) position.	Contact weld.	Same as 35 i)	Same as 35 i)	Same as 35 i)	Same as 35 i)	Same as 35 i)
	s) Manual bypass switch (2 locations) fails to "OFF" position.	Contact weld.	Unable to manually initiate operating bypass using either switch. HI log power bistable in ch. will not be bypassed above 10^{-4}% power. Probable ch. trip at power.	Operator when attempting to initiate bypass, annunc. for channel trip.	3-channel redundancy for HI log power and operating bypass. (4^{th} channel in bypass)	No impact on RPS trip logic. Other 2 channels can still be bypassed so reactor trip will not be initiated.	
	t) Aux. logic power supply fails off.	Open circuit, comp. failure.	Unable to bypass HI log power bistable. Probable ch. trip for HI log power above 10^{-4}% power.	Power supply trouble alarm, loss of all bypass indic. lamps in channel.	Separate power supplies used for bypasses in other channels.	No impact on RPS trip logic as other 2 channels can still by bypassed. (4^{th} channel already in bypass)	
36) Power Trip Test Interlock (90, 95) (Ch. A Typ.)	a) 12 V aux. logic power supply fails off.	Open circuit, comp. failure.	Relay AK28 will be deener-gize and its contacts will open, deenergizing (tripping) the Ch A bistables for DNBR and LPD, if they are not bypassed.	Power supply trouble annunc. channel trip annunciation.	3-channel redundancy for LPD and DNBR. (4th channel in bypass)	RPS trip logic for LPD and DNBR goes to 1-out-of-2.	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
36) (Cont.)	b) Relay AK38 fails open.	Mech. damage, overstress.	Same as 36 a)	Same as 36 a)	Same as 36 a)	Same as 36 a)	Same as 36 a)
	c) Relay AK28 N.O. contacts in LPD circuit fail open.	Contact corrosion, open circuit.	Power to Ch. A LPD bistable will be interrupted, resulting in spurious Ch. A LPD trip.	Annunciating.	3-channel redundancy for LPD. (4th channel in bypass)	RPS trip logic for LPD goes to 1-out-of-2.	Same as 36 a)
	d) Relay AK28 N.O. contacts in LPD circuit fail closed.	Contact weld.	Ch. A LPD bistable will not be tripped when there is trouble in the NI drawer. Ch. A LPD bistable may not trip due to erroneous input if there is trouble in NI drawer.	Periodic test, no LPD ch. trip when NI trouble occurs.	3-channel redundancy for LPD. (4th channel in bypass)	RPS trip logic for LPD goes to 2-out-of-2.	Same as 36 a)
	e) Relay AK28 N.O. contacts in DNBR circuit fail open.	Contact corrosion, open circuit.	Equivalent to 36 c) for DNBR trip.	Equiv. to 36 c) for DNBR trip.	Equiv. to 36 c) for DNBR trip.	Equiv. to 36 c) for DNBR trip.	Equiv. to 36 a) for DNBR trip.
	f) Relay AK28 N.O. contacts in DNBR circuit fail closed.	Contact weld.	Equivalent to 36 d) for DNBR trip.	Equiv. to 36 d) for DNBR trip.	Equiv. to 36 d) for DNBR trip.	Equiv. to 36 d) for DNBR trip.	Equiv. to 36 a) for DNBR trip.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 71 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
36) (Cont.)	g) Trip channel bypass relay AXCK4-6 N.O. contacts in LPD circuit fail open.	Open circuit, contact corrosion.	Power trip test interlock for LPD will not be overridden when Ch. A LPD bistable is bypassed. Probable spurious LPD bistable trips during CPC tests or NI tests. Ch. trip will not occur because bistable is bypassed.	Periodic test, LPD bistable trip indic. on NI test while bistable bypassed.	3-channel redundancy (4th channel also bypassed)	RPS trip logic is 2-out-of-2 with bistable bypassed.	
	h) Trip channel bypass relay AXK4-6 N.O. contacts in DNBR circuit fail closed.	Contact weld.	Same as 36 d)	Same as 36 d)	Same as 36 d)	Same as 36 d)	Same as 36 a)
	i) Trip channel bypass relay AXK3-6 N.O. contacts in DNBR circuit fail open.	Open circuit, contact corrosion.	Equivalent to 36 g) for DNBR.	Equivalent to 36 g) for DNBR.	Equiv. to 36 g) for DNBR.	Equiv. to 36 g) for DNBR.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 72 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
36) (Cont.)	j) Trip channel bypass relay AXCK3-6 N.O. contacts in DNBR circuit fail closed.	Contact weld.	Same as 36 f)	Same as 36 f)	Same as 36 f)	Same as 36 f)	
37) CWP Logic (69, 99, 121) (Ch. A Typ.)	a) CWP contact from CPC fails open.	Open circuit, mech. damage, contact cor-rosion.	Relay AK11 is deenergized and contacts in the CWP logic matrix are opened. Spurious CWP ch. trip.	Visual indication.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic, CWP logic goes to 1-out-of-2.	To restore the system logic to 2-out-of-3 coincidence, the operator must restore the bypassed channel to operation and then bypass the failed channel.
	b) CWP contact from CPC fails closed.	Contact weld.	Relay AK11 will not be de-energized on LPD and DNBR pre-trip signals.	Periodic test, LPD or DNBR pre-trip indic. with no ch. A CWP indication.	3-channel redundancy. (4th channel in bypass)	No impact on RPS trip logic. CWP logic goes to 2-out-of-2.	
	c) CWP indic. lamp burn out	Overstress, end natural life.	No visual indication of Ch. A CWP trip.	Periodic test.	None required.	No impact on CWP logic or RPS trip logic.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 73 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
37) (Cont.)	d) Relay AK11 fails open.	Mech. damage, overstress.	Same as 37 a)	Same as 37 a)	Same as 37 a)	Same as 37 a)	Same as 37 a)
	e) Relay AK11 contacts in CWP logic, one set fails open.	Contact corrosion, open circuit.	CWP 2-of-4 logic matrix partially enabled (for CWP on low DNBR or HI LPD).	Periodic test.	3-channel redundancy. (4th channel in bypass)	CWP logic remains 2-out-of-3 with one contact set open.	
	f) Relay AK11 contacts in CWP logic, one set fails closed.	Contact weld.	One set of contacts in CWP logic matrix (for CWP on LO DNBR or HI LPD) will not open for valid signal. One “2-out-of-4” combination no longer valid.	Periodic test.	3-channel redundancy. (4th channel in bypass)	CWP logic for DNBR or LPD becomes 2-out-of-2.	
	g) 12 V aux. logic power supply fails off.	Comp failure, open circuit.	Relay AK11 will be deenergized and contacts in CWP 2-of-4 ladder will open. Spurious CWP “Ch.” trip.	Power supply fail annunc., visual CWP ch. trip indication.	3-channel redundancy. (4th channel in bypass)	CWP logic goes to 1-out-of-2.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 74 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
38) CPC Test Enable (Ch. A Typ.)	a) Bypass relay AXK2-6, N.O. contacts in enable circuit fail open.	Contact corrosion, open circuit.	Relay AK56 will not be energized when Ch. A DNBR bistable bypassed. Unable to test CPC.	Operator when attempting to test CPC.	None.	No impact on RPS trip logic.	
	b) Bypass relay AXK3-6 N.O. contacts in CPC test enable circuit fail closed.	Contact weld.	Relay AK56 will be energized, and the CPC test enable circuit will be partially enabled.	Annunciating.	HI LPD bistable must still be bypassed to enable the CPC test.	No direct impact on RPS trip logic.	
	c) Bypass relay AXK4-6 N.O. contacts in CPC test enable circuit fail open.	Contact corrosion, open circuit.	Equivalent to 38 a)	Equiv. to 38 a)	Equiv. to 38 a)	Equiv. to 38 a)	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 75 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
38) (Cont.)	d) Bypass relay AXK4-6, N.O. contacts in CPC test enable circuit fail closed.	Contact weld.	Equivalent to 38 b)	Equiv. to 38 b)	Equiv. to 38 b)	Equiv. to 38 b)	
	e) Relay AK56 fails open.	Mech. damage, overstress.	Equivalent to 38 a)	Equiv. to 38 a)	Equiv. to 38 a)	Equiv. to 38 a)	
	f) Relay AK57 fails open.	Mech. damage, overstress.	Equivalent to 38 a)	Equiv. to 38 a)	Equiv. to 38 a)	Equiv. to 38 a)	
	g) Relay AK56 N.O. contacts fail open.	Contact corrosion, open circuit.	Equivalent to 38 a)	Equiv. to 38 a)	Equiv. to 38 a)	Equiv. to 38 a)	
	h) Relay AK56 N.O. contacts fail closed.	Contact weld.	Equivalent to 38 b)	Equiv. to 38 b)	Equiv. to 38 b)	Equiv. to 38 b)	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 76 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
38) (Cont.)	i) Relay AK57 N.O. contacts fail open.	Contact corrosion, open circuit.	Equivalent to 38 a)	Equiv. to 38 a)	Equiv. to 38 a)	Equiv. to 38a)	
	j) Relay AK57 N.O. contacts fail closed.	Contact weld.	Equivalent to 38 b)	Equiv. to 38 b)	Equiv. to 38 b)	Equiv. to 38 b)	
	k) Aux logic power supply (Ch. A) fails off.	Comp. failure, open circuit.	Equivalent to 38 a)	Power supply trouble annunication.	None.	No impact on RPS logic	
39) Trip Input By-pass Switch AXS-1 (BXS-1, CXS-1 DXS-1)	a) Switch fails in normally off posi-tion	Mechanical binding of switch	Switch cannot be turned to the “trip input bypass” position for testing of the channel A (B, C, or D) bistable for trip parameter 1	Operator when pre-paring to test bistable, visual indication	None for bypass. 3 channel redun-dancy for PPS trip logic (4th channel in bypass)	No direct effect on PPS trip logic. However, will not be able to test the bistable in channel A.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 77 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
39) (Cont.)	b) Switch fails in the on “bypass” position	Mechanical binding or other mechanical failure of switch	Switch cannot be returned to the off position. The trip inputs to the AB, AC and AD logic matrices will be bypassed for Trip Parameter 1. Also, trip input bypass capability for trip parameter 1, channels B, C and D will be lost.	Operator when attempting to remove trip input bypass after test, visual indication	None for trip input bypass switch. 3 channel redundancy for PPS (4th channel is bypassed at the bistable)	PPS trip logic for trip parameter 1 becomes 2-out-of-2 coincident.	To restore PPS trip logic to 2-out-of-3 coincident, the channel that is bypassed at the bistable must be restored to service and channel A bypassed at the bistable until the trip input bypass switch is repaired.
40)	This item left blank intentionally.						
41)	This item left blank intentionally.						

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 78 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
42) Bypass Relay Coil AXK-1	a) Open	Sustained overvoltage.	Bistable “1” in Ch. A cannot be bypassed.	Periodic PPS testing or when attempting to bypass the bistable.	Noise for bypass, 3 channel redundancy for PPS Trip Logic (4th channel bypassed at bistable)	If the bistable is tripped, the system becomes any 1-out-of-2 logic for the affected function.	
	b) Short.	Deterioration of insulation.	No symptoms until an attempt is made to bypass bistable “1” in Ch. A. Inserting the bypass will force the supply voltage down and cause all bypasses in channel A to be removed.	Periodic PPS testing or when attempting to bypass the bistable.	Same as 42 a)	If the bypass is attempted it will result in the loss of all bypass capability for that channel.	If that particular bypass is not attempted there will be no effect upon the other bypass circuits in that channel.
43) Bypass relay (AXK1 Typcial) N.O. Contacts Set 1, Set 2 or Set 3	a) Contacts fail open.	Contact corrosion, open circuit.	Bistable trip relay contacts in one logic matrix will not be bypassed. Affected logic matrix will be half-tripped during bistable test.	Periodic test.	3-channel redundancy. (4th channel bypassed at bistable)	RPS trip logic for affected parameter is essentially 2-out-of-2 or 1-out-of-2 selective.	
	b) Contacts shorted.	Contact weld.	Bistable trip relay contacts in one logic matrix will be permanently bypassed. Affected logic matrix will not trip for valid signal coincidence.	Periodic test.	3-channel redundancy. (4th channel bypassed at bistable)	RPS trip logic for affected parameter becomes 2-out-of-2.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 79 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
44) Bypass Relay (AXK1 Typical) N.O. Contacts in Indicator Circuit	a) Contacts fail open.	Contact corrosion.	No visual indication of channel bypass.	Operator when by-passing channel.	Audible bypass annunciation.	RPS trip logic not affected.	
	b) Contacts shorted.	Contact weld. Open circuit.	Spurious visual indication of channel bypass.	Visual indication.	None.	No impact on RPS trip logic.	
45) Bypass Relay (AXK1 Typical) N.O. Contact in Annunc. Circuit	a) Contacts fail open.	Contact corrosion, open circuit.	No annunciation when channel is bypassed.	Operator when by-passing channel.	Visible bypass indication.	No impact on RPS trip logic.	
	b) Contacts shorted.	Contact weld.	Spurious channel bypass alarms.	Annunciating.	None.	No impact on RPS trip logic.	
46) Bypass Relay Cotnact Set 6A, 6B	These contact sets (1 N.O. and 1 N.C.) are spares for all parameters except HI LPD and LO DNBR. For these two parameters, these contact sets are used in the Power Trip Test Interlock and the CPC Test enable. See Line Items 36 and 38.						
47) Auxil-iary Bypass Relay AXKB6, AXKB9, AXKB10, AXKB11, AXKB12 or AXKB13.	a) Coil fails open.	Mech. damage, overstress.	The ESFS actuation relays associated with the affected parameter (LO PZR press. for AXKB6, etc.) will not be by-passed when the trip bistable is tested. Three ESFS actu-ation logic mtrices (i.e., AB, AC and AD for Ch. A bi-stable) for a specific ESFS function (i.e., SIAS for LO PZR press, AXKB6) will be half-tripped.	Periodic test.	3-channel redundancy. (4th channel bypassed at bistable)	Actuation logic for a given ESF function goes to 1-out-of-2.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 80 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
48) Auxil-iary Bypass Relay Contact Sets 1, 2 or 3	a) Contact set fails open.	Corrosion, mech. damage, open circuit.	Bistable trip relay contacts in one ESF actuation logic matrix will not be bypassed when the bistable is tested. Affected logic matrix is half-tripped during bistable test.	Periodic test, visual indication	3-channel redundancy. (4th channel bypassed at bistable)	Actuation logic for one ESF function becomes 1-out-of-2 selective or any 2-out-of-2.	
	b) Cont-tacts shorted.	Contact weld.	Bistable trip relay contacts in one ESF actuation logic matrix will be permanently bypassed. ESF logic matrix will not trip for valid signal coincidence.	Periodic test.	3-channel redundancy. (4th channel bypassed at bistable)	Actuation logic for one ESF function becomes 2-out-of-2.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 81 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
49) Trip Channel Bypass Power Supplies (PS-49, PS-52, Ch. A Typ.)	One Fails off	Comp. failure, open circuit.	Loss of one of two redundant power supplies for the trip channel bypass relays.	Visual indication	Redundant power supply.	No impact RPS Trip or ESFS Actuation logic.	
50) Trip Channel By-pass Power Supply Indi-cator Lamp	Fails off	Broken Fila-ment, end of natural life, open circuit.	Spurious trip channel bypass power supply failure indica-tion.	Visual indication.	None required.	No impact on trip logic.	
51) RPS 2-of-4 Trip Logic Matrix (AB Typical)	a) One of two matrix power sup-plies (PS9 or PS-4 Typ.) fails off	Comp. failure, open circuit.	Loss of one of two logic matrix power supplies. Two of the four matrix relays will be de-energized.	Power supply trouble alarm, visual indication.	Second power supply provides power to both sides of “Logic Ladder”, and to the two remaining logic matrix relays.	RPS trip logic remains 2-out-of-3. Two “Series” trip paths are tripped. (4th channel bypassed at bistables)	RPS trip path logic is 2-out-of-3 selective.
	b) One of two matrix power sup-plies fail HI.	Component failure.	Possible overstress of 2-of-4 logic matrix relays. Relays may fail open and logic matrix will become half tripped.	Visual indication if matrix relays fail open.	Same as above.	Same as above.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 82 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
51) RPS 2-of-4 Trip Logic Matrix (AB Typical) (Cont.)	c) Logic Matrix Power Supply Indicator Lamp Fails off	Open filament, natural end of life.	Spurious visual indication of failure of one logic matrix power supply.	Visual indication of power supply failure without alarm.	None required. trip logic.	No impact on RPS	
	d) Logic Matrix Power Supply Trouble Annunc. Relay Fails Open.	Overstress, mech. damage coil spool cracked, open coil winding	Spurious logic matrix power supply trouble alarms.	Annunciating.	None required.	No impact on RPS trip logic.	
	e) Logic matrix power supply trouble annunc. relay contacts fail open.	Mech. damage, corrosion, open circuit.	Same as 51 d)	Same as 51 d)	Same as 51 d)	Same as 51 d)	Same as 51 d)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 83 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
51) RPS 2-of-4 Trip Logic Matrix (AB Typical) (Cont.)	f) Logic matrix power supply trouble annunc. relay contacts fail closed.	Contact weld.	P/S trouble alarm will not sound if power supply fails.	None unless power supply fails, then lamp goes out but alarm doesn’t sound.	Visual power supply operability indication.	No impact on RPS trip logic.	
	g) Logic Matrix Power supply diode fails open.	Overstress, mech. damage.	Equivalent to 51 a)	Equivalent to 51 a)	Equivalent to 51 a)	Equivalent to 51 a)	
	h) Logic matrix power supply diode shorted.	Overstress	No impact during normal operation, loss of isolation for power supplies.	None.	Redundant power supplies.	None.	
	i) Logic matrix power supply fuses fail open.	Overstress, mech. damage.	Equivalent to 51 a)	Equiv. to 51 a)	Equiv. to 51 a)	Equiv. to 51 a)	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 84 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
51) RPS 2-of-4 Trip Logic Matrix (AB Typical) (Cont.)	j) Bi-stable relay trip indicator lamp (A1 Typ.) fails off.	Broken fila-ment.	Loss of visual indication for bistable relay trip in affected matrix.	Periodic test.	Bistable relay trip annunicator.	No impact on RPS trip logic.	
	k) Bi-stable Relay trip indicator lamp transistor driver fails off.	Comp. fail-ure, open circuit.	Same as 51 j)	Same as 51 j)	Same as 51 j)	Same as 51 j)	
	l) Bi-stable trip indicator lamp tran-sistor driver fails on.	Emitter to collector short.	Spurious indication of bi-stable relay trip in affected matrix.	Visual indication.	None required.	No impact on RPS trip logic.	
	m) Logic matrix relay driver fails open (AB-1 Typ.)	Transistor failure, open circuit.	One matrix relay will be de-energized, inducing a trip in one of the four RPS trip paths. One set of trip breakers open.	Visual indication.	A minimum of two RPS trip paths must be de-energized to produce a trip.	RPS trip still requires a 2-of-3 signal coincidence. (4th channel bypassed at bistable)	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 85 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
51) RPS 2-of-4 Trip Logic Matrix (AB Typical) (Cont.)	n) Logic matrix relay driver fails on.	Emitter ot collector short.	One logic matrix relay will not deenergize on a valid signal coincidence.	Periodic test.	Four redundant logic matrix relays.	RPS trip remains 2-out-of-3. Affected logic matrix can still generate a trip. (4th channel bypassed at bistable)	Other two active logic matrices are unaffected, and can also generate a trip on a valid signal coincidence. (Three logic matrices associated with the bypassed channel are not active.)
	o) Logic matrix relay fails open.	Open circuit, overstress.	Equiv. to 51 m)	Equiv. to 51 m)	Equiv. to 51 m)	Equiv. to 51 m)	Equiv. to 51 m)
	p) “Logic Ladder” diode (1-of-4) shorted.	Open circuit, overstress.	Same as 51 m)	Same as 51 m)	Same as 51 m)	Same as 51 m)	Same as 51 m)
	q) “Logic Ladder) diode (1-of-4) shorted.	Comp. failure.	No impact on logic matrix.	None.	None required.	No impact on RPS trip logic.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 86 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
51) RPS 2-of-4 Logic Matrix (AB Typical) (Cont.)	r) Logic matrix relay indicator lamp fails off.	Broken filament.	Spurious indication that one logic matrix relay has been de-energized.	Visual indication.	None required.	No impact on RPS trip logic.	
	s) Logic matrix relay (1AB-1 Typ.) contacts in trip path fail open.	Open circuit, mech. damage, contact corrosion.	Same as 51 m)	Same as 51 m)	Same as 51 m)	Same as 51 m)	
	t) Logic matrix relay (1AB-1 Typ.) contacts in RPS trip path fail closed.	Contact weld.	Same as 51 n)	Same as 51 n)	Same as 51 n)	Same as 51 n)	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 87 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
52) EFSAS Actuation Logic Matrix (AB Typical)	Failure Modes a through i and their effects on the ESFAS Actuation Logic for all ESF functions are equivalent to failure modes a) through i) of Line item 51, and their effects on RPS trip logic.						
	j) Bistable relay trip indicator lamp fails off.	Broken fila-ment, burnt out.	Loss of visual indication for a bistable relay trip for one ESF function (i.e., CSAS) in the AB matrix.	Periodic test.	Bistable relay trouble annunci-ator.	No impact on ESFAS actuation logic for any ESF function.	
	k) Bistable relay trip indicator lamp tran-sistor driver fails off.	Transistor failure, open circuit.	Same as 52 j)	Same as 52 j)	Same as 52 j)	Same as 52 j)	
	l) Bistable relay trip indicator lamp transistor driver fails on.	Emitter-to-collector short.	Spurious visual indication of the trip of one bistable relay for one ESF function in the AB matrix.	Visual indication.	None required.	No impact on ESFAS actuation logic for any ESF function.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 88 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
	m) One logic matrix relay driver for one ESF function fails off.	Open circuit, transistor failure.	One logic matrix relay for the affected ESF function is de-energized, tripping 1 of 4 actuation paths.	Visual indication.	ESF actuation path logic is 2-of-3 selective. The other 2 actuation paths are not affected. (4th channel bypassed)	ESF actuation still requires a 2-of-3 signal coincidence.	
	n) One logic matrix relay driver for one ESF function fails on.	Emitter-to-collector short.	One logic matrix relay for the affected ESF function will not be deenergized for a valid signal coincidence, and the associated trip path will not trip.	Periodic test.	The remaining 2 logic matrix relays for the ESF function (in matrix AB) are not affected and can still generate a ESF trip on a valid signal coincidence.	ESFAS actuation logic remains 2-of-3, but the trip path logic for the AB matrix for the affected ESF becomes 2-out-of-2 selective. (4th channel in bypass)	
	o) One logic matrix relay for one ESF function fails open.	Overstress, mech. damage, coil open, coil shorted	Same as 52 m)	Same as 52 m)	Same as 52 m)	Same as 52 m)	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 89 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
52) ESFAS Actuation Logic Matrix (AB Typical) (Cont.)	p) One logic matrix relay's contacts in ESF actuation path fail open.	Mech. damage, corrosion, open circuit.	Same as 52 m)	Same as 52 m)	Same as 52 m)	Same as 52 m)	Same as 52 m)
	q) One logic matrix relay's contacts in ESF actuation path fail closed.	Contact weld.	Same as 52 n)	Same as 52 n)	Same as 52 n)	Same as 52 n)	Same as 52 m)
	r) One "Logic Ladder" diode for one ESF function fails open.	Open circuit, overstress.	Same as 52 m)	Same as 52 m)	Same as 52 m)	Same as 52 m)	Same as 52 m)
	s) One logic matrix relay indicator lamp fails off.	Burnt out, broken fila-ment.	Spurious indication that one logic matrix relay for one ESF function has de-energized.	Visual indication.	None required.	No impact on ESFAS actuation logic.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 90 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
53) RPS Trip Path (Path A Typ.)	a) Trip path power supply (PS-34 Typ.) fails off.	Comp. failure.	RPS trip A Relay and all ESF actuation path A Relays are deenergized. One trip path for RPS trip and ESF actuation is tripped.	Multiple visual and audible alarms.	The remaining 3 trip paths for RPS trip and ESF actu-ation are not affected.	Trip path logic for all functions changes from 2-of-4 selective to 1-of-3 selective.	
	b) Trip path power suuply (PS-34 Typ.) fails HI.	Failure internal to power supply.	Possible overstress of trip relays in one of the Ch. A trip paths (RPS trip or ESF actuation).	None.	P/S output Zener will maintain 12 VDC to trip paths.	None.	
	c) Trip path power supply indicator lamp fails off.	Burnt out, broken fila-ment.	Spurious visual indication of power supply failure.	Visual indication.	None required.	No impact on trip path.	
	d) Trip path power supply output Zener fails open.	Comp. failure.	Loss of overpower protection for Ch. A trip paths. If power supply fails high, trip path fuses will blow. Effect equivalent to 53 a).	None, unless P/S fails high, then trip path trip indications.	Same as 53 a)	Same as 53 a)	
	e). Trip path power supply output Zener shorted.	Overstress, comp. failure.	The trip path power supply will be shorted. See 53 a)	See 53 a)	See 53 a)	See 53 a)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 91 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
53) RPS Trip Path (Ch. A Typ.) (Cont.)	f) RPS trip path fuse fails open.	Overstress, mech. damage.	Loss of power to RPS trip relay K1, one set of trip breakers open.	Annunciting.	The 3 remaining trip breakers are not affected.	Trip path logic becomes 1-of-3 selective, but a 2-out-of-3 signal coincidence is still required for RPS trip.	
	g) Ground detection circuit shorted.	Mech, failure, comp. failure.	Spurious indication of grounded trip path.	Annunciating.	None required.	No impact on RPS trip logic or RPS trip path.	
	h) Ground detection, circuit fails open.	Comp. failure, open circuit.	Loss of ground detection capa- bility for one trip path. If ground occurs, power supply will be loaded down. Fuse will probably blow. See 53 f)	None.	See 53 f)	See 53 f)	
	i) Trip relay (K-1 Typ.) fails open.	Mech. damage, overstress, open circuit, coil shorted.	K-1 relay contacts in trip breaker actuation circuits will change state and one set of trip circuit breakers (TCBs) will open.	Breaker status indication.	Other three TCBs are not affected.	Trip path logic becomes 1-of-3 selective, but 2-out-of-3 signal coincidence still required for trip.	
	j). Trip relay con- tacts in undervolt- age trip circuit fail open.	Mech. damage, open circuit.	Undervoltage trip circuit will deenergize, causing the trip circuit breaker to open.	Same as 53 i)	Same as 53 i)	Same as 53 i)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 92 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
53) RPS Trip Path (Ch. A Typ.) (Cont.)	k) Trip relay contacts in undervoltage trip circuit fail closed.	Contact weld.	Undervoltage trip circuit for one TCB will not deenergize for valid trip signal. One TCB will not open.	Periodic test.	Other 3 TCBs are not affected and are sufficient to produce trip.	Trip path logic becomes 2-of-3 selectives, but 2-out-of-3 signal coincidence still required for trip.	
	l) Trip Relay contacts in shunt trip circuit fail closed.	Open circuit, contact weld, contamination.	Shunt trip circuit will be energized and one TCB will open.	Same as 53 i)	Same as 53 i)	Same as 53 i)	
	m) Trip relay contacts in shunt trip circuit fail open.	Contact corrosion.	Shunt trip circuit for one TCB will not be energized for valid trip signal.	Same as 53 k)	Same as 53 k)	Same as 53 k)	
	n) Remote indicator SSR fails open.	LED failure, SS transistor failure.	Spurious remote indicator of trip path A trip.	Visual indication.	None required.	No impact on RPS trip path or RPS trip logic.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 93 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
53) RPS Trip Path (Path A Typ.) (Cont.)	o) Remote indicator SSR fails on.	Emitter-to-collector short.	Loss of remote visual indication of trip path A trip.	Periodic test.	Local indication and plant annunc.	Same as above.	
	p) Local indicator SSR fails off.	LED failure, SS transistor failure.	Spurious local indication of trip path A trip.	Visual indication.	None required.	Same as above.	
	q) Local indicator SSR fails on.	Emitter-to-collector short.	Loss of local indication of trip path A trip.	Periodic test.	Remote indication and plant annunc.	Same as above.	
	r) Plant Annunc. SSR fails off.	LED failure, SS transistor failure.	Spurious annunciation of trip path A trip.	Annunciation	None required.	Same as above.	
	s) Plant annunc. SSR fails on.	Emitter-to-collector short.	Loss of annunciation for trip path A trip.	Periodic test.	Remote and local indication.	Same as above.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 94 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
53) RPS Trip Path (Path A Typ.) (Cont.)	t) One dropping resistor for one SSR fails open.	Mech. damage, overstress, open lead.	The affected SSR will be de-energized. See 53 n), p), or r) for affects.	See 53 n),p), or r)	See 53 n),p), or r)	See 53 n),p),or r)	
	u) One dropping resistor for one SSR shorted.	Comp. failure.	The affected SSR will see a higher control signal voltage SSR will probably fail open due to overstress.	See 53 n),p) or r)	See 53 n),p) or r)	See 53 n),p) or r)	
54) Trip Circuit Breaker Actuation (TCB-1 Typ.)	a) Bus 1, 125 VDC, fails off.	Mech. damage, ground.	TCB-1 undervoltage trip circuit will be deenergized, and TCB-1 will open.	Breaker status indication.	Other 3 TCBs are not affected.	One TCB open RPS trip still requires 2-out-of-3 signal coincidence.	
	b) Bus 1, fuse fails open.	Mech. damage, overstress.	Same as 54 a)	Same as 54 a)	Same as 54 a)	Same as 54 a)	
	c) Manual trip push-button contacts in undervolt-age trip circuit fail closed.	Mech binding, contact weld.	Undervoltage trip circuit for one TCB will not be deenergized by its manual trip button. Shunt trip circuit can still open TCB.	Periodic test.	Auto trip function not affected, shunt grip circuit not affected. Other 3 TCBs not affected.	No impact on trip function.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 95 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
54) Trip Circuit Breaker Actuation (TCB-1 Typ.) (Cont.)	d) Manual Trip button contacts in under-voltage circuit fail open.	Open circuit	Undervoltage trip circuit will be deenergized and the TCB will open.	Breaker status indication.	Other 3 TCBs are not affected.	Same as 54 a)	
	e) Manual trip button contacts in shunt trip circuit fail open.	Open circuit, mech. damage. contact corrosion.	Shunt trip circuit for the TCB will not be energized by manual trip button. Shunt trip circuit will not trip TCB.	Periodic test.	Underfreq. trip circuit will still open TCB. Other 3 TCBs not affected. Auto trip function not affected.	Same as 54 b)	
	f) Manual trip button conttacts in shunt trip circuit fail closed.	Short circuit.	Shunt trip circuit will be energized and one TCB will open.	Breaker status indication.	Same as 54 a)	Same as 54 a)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 96 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
54) Trip Circuit Breaker Actuation (TCB-1 Typ.) (Cont.)	g) Supplementary protection system (SPS) contacts in undervoltage trip circuit fail open.	Open circuit, mech. damage, SPS failure.	Undervoltage trip circuit for the TCB will be deenergized and the TCB will open.	Same as 54 a)	Same as 54 a)	Same as 54 a)	
	h) SPS contacts in undervoltage trip circuit fail closed.	Contact weld, SPS failure.	SPS will not deenergize the undervoltage trip circuit for one TCB on a valid trip signal.	Periodic test.	SPS still energizes shunt trip circuit to trip TCB auto and manual trip functions not affected. Other 3 TCB s not affected.	Same as 54 c)	
	i) SPS contacts in shunt trip circuit fail closed.	Short circuit, contact weld.	Shunt trip circuit for the TCB will energize and the TCB will open.	Same as 54 a)	Same as 54 a)	Same as 54 a)	
	j) SPS contacts in shunt trip circuit fail open.	Open circuit, mech. damage.	SPS will not energize shunt trip circuit for one TCB on valid trip signal.	Periodic test.	SPS will deenergize undervoltage trip circuit to trip TCB auto and manual trip funct. not affected.	Same as 54 c)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
54) Trip Circuit Breaker Actuation (TCB-1) (Cont.)	k) Under-voltage trip circuit fails open.	Open circuit, comp. failure.	Same as 54 d)	Same as 54 d)	Same as 54 d)	Same as 54 d)	
	l) Shunt trip circuit fails open.	Open circuit, comp. failure.	Unable to energize shunt trip circuit on valid trip signal, shunt trip circuit will not open TCB.	Periodic test.	Undervoltage trip circuit will open TCB. Other 3 TCBs unaffected.	Same as 54 c)	
	m) Closing circuit pushbutton fails closed.	Contact corrosion, mech. damage, open circuit.	Unable to energize TCB closing circuit to close TCB after test or trip.	Operator, TCB status indicator.	Other 3 TCBs are not affected.	Same as 54 a)	
	n) Closing circuit pushbutton fails closed.	Short circuit, mech. damage, contact weld.	Closing circuit will remain energized, and oppose the shunt trip circuit. TCB opening will rely on spring for trip signal.	Periodic test.	TCB will still open on trip signal. Other 3 TCBs are not affected, circuit breaker spring loaded to open.	Trip actuation logic remains 2-of-4 selective. Trip still requires a 2-out-of-3 signal coincidence.	No impact on RPS Trip Logic or trip actuation.
	o) Closing circuit fails off.	Open circuit, comp. failure.	Same as 54 m)	Same as 54 m)	Same as 54 m)	Same as 54 m)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 98 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
54) Trip Circuit Breaker Actuation (TCB-1 Typ.) (Cont.)	p) TCB fails closed.	Mech. binding, contact weld, short circuit.	TCB will not open in response to trip actuation signal.	Periodic test.	Other 3 TCBs not affected.	Same as 54 n)	
	q) TCB fails open.	Open circuit, mech. damage.	TCB will be open.	Breaker status indication.	Other 3 TCBs not affected.	Same as 54 a)	
	r) TCB N.O. contacts in status circuit fails open.	Mech. damage, contact cor-rosion, open circuit.	Loss of visual indication for closed TCB.	Visual indication.	“TCB Open” lamp will come on when breaker opens. TCB function not affected.	No impact on RPS trip function.	
	s) TCB N.O. contacts in status circuit fail closed.	Short circuit, contact weld.	“TCB Closed” lamp remains on when TCB opens.	Periodic test, “TCB Open” and “TCB Closed” lamps on at same time.	None required.	Same as above.	
	t) TCB NC contacts in status circuit fail closed.	Open circuit, contact weld.	“TCB Open” lamp stays on when breaker is closed.	Visual indication.	None required, TCB funct. not affected.	Same as 54 r)	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 99 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
54) Trip Circuit Breaker Actuation (TCB-1 Typ.) (Cont.)	u) TCB NC contacts in status circuit fail open.	Contact corrosion, mech. damage.	“TCB Open” lamp will not come on when breaker opens.	Periodic test.	“TCB Closed” lamp goes off when breaker opens, TCB not affected.	Same as 54 r)	
	v) “TCB Open” lamp fails off.	Burnt out, mech. damage.	Same as 54 u)	Same as 54 u)	Same as 54 u)	Same as 54 u)	
	x) “TCB Closed” lamp fails off.	Burnt out, mech. damage.	Same as 54 r)	Same as 54 r)	Same as 54 r)	Same as 54 r)	
55) 480 V ac Bus (Bus 1 Typ.)	Fails off.	Short mech. damage.	Loss of one of two redundant 480 V ac supplies to the CEDMs	Bus current indic.	Redundant bus.	None.	
56) MG Set Input Breaker (MG-1 Typ.)	a) Fails Open.	Open circuit, mech. damage	Loss of 480 V ac input to 1 MG set. Loss of 1 of 2 redund. Supplies to CEDMs.	Input breaker status indication.	Redundant MG set and bus.	None.	
	b) Fails Closed.	Contact weld, Mech. binding.	No impact on normal operation. Loss of overcurrent protect, for MG set. Possible damage to MG set if overcurrent occurs.	None.	MB output breaker, redundant MG set and bus.	None.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 100 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
57) Motor-Generator Set (MG-1 Typ.)	Fails off	Motor fails, generator fails, fly-wheel failure.	Loss of 1 of 2 480 V ac inputs to the CEDMs.	MG Set status indic.	Redundant MG set.	None.	
58) MG Set Output Breaker	a) fails Open.	Open circuit, mech damage.	Same as 57 a)	Same as 57 a)	Same as 57 a)	Same as 57 a)	
	b) Fails Closed.	Contact weld, mech. binding.	No impact on normal operation, loss of overload protect for MG output. Possible damage to generator on overcurrent.	None.	Redundant MG set.	None.	
59) MG Set Load Con-tactors	a) Fails Open.	Open circuit, mech. damage, contact cor-rosion	Same as 57 a)	Same as 57 a)	Same as 57 a)	Same as 57 a)	
	b) Fails Closed.	Contact weld, short circuit.	No impact on normal operation. Possible damage to generator due to motoring when MG set is unloaded.	None.	MG set breakers, redundant MG set.	None.	
60) CEDM Ring Bus Current Status Indicator (1 of 2)	Fails off	Open circuit, comp.failure.	Spurious indication of loss of current in one side of ring bus.	Indicating.	None required.	None.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
61) Syn-chronizing Circuit (SIAS, Ch. A Typ.)	Fails HI or LOW	Comp. failure.	Unable to synchronize one MG set to the CEDM bus possible MG set.	Operator, when trying to synch. MG set.	Redundant MG set.	None.	
62) ESFAS Initiation Circuit (SIAS, Ch. A Typ.)	Failure Modes a) through e) and their effects on the ESFAS Initiation Circuit are equivalent to Line Item 53, Failure Modes a) through e) and their effect on RPS trip initiation circuit.						
	f) ESFAS initiation circuit (SIAS, Ch. A Typ) fuse fails open.	Overstress, mech. damage, degradation.	Loss of power to Ch. A initia-tion relays, one leg of the actuation circuit open for Train A and Train B.	Annunciating, visual indication.	The other 3 ESFAS init. channels are not affected.	ESFAS Init. path logic becomes 1-of-3 selective, but a 2-out-of-3 signal coincidence still required for ESFAS actuation.	
	g) Remote manual pushbutton fails open.	Mech. damage, contact cor-rosion, open circuit.	Same as 62 e)	Same as 62 e)	Same as 62 e)	Same as 62 e)	
	h) Remote manaul pushbutton fails closed.	Contact weld, short circuit, mech damage.	Unable to deenergize the Ch. A init. relays for one ESFAS function using the remote manual pushbutton.	Periodic test.	Auto init. Capa-bility not affec-ted. Other 3 init. circuits can init. desired ESFAS function manually.	Auto ESFAS init. un-affected. Manual ESFAS init. for one function becomes 2-of-3 selective.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
62) ESFAS Initiation Circuit (SIAS, Ch. A Typ.) (Cont.)	i) SSR lockout relay fails off.	LED failure, SS transistor failure.	No impact on normal operation. Unable to reset ESFAS init. relays for one ESFAS function after chan. Has been tripped.	Operator, when re-setting channel.	Same as 62 e)	Init. path logic for one ESFAS funct. be-comes 1-of-3 selec-tive, actuation requires 2-out-of-3 signal coincidence.	
	j) SSR Lockout relay fails on.	Emitter-to-collector short.	No impact on normal operation. After trip, initiation circuit for one ch. of one ESFAS function can reset itself if trip clears on all foru initi-ating bistables.	Periodic test.	Other 3 init. circuit ch. not affected and will remain locked out.	None.	
	k) Lockout reset pushbutton fails open	Contact cor-rosion, mech. damage, open circuit.	Same as 62 h)	Same as 62 h)	Same as 62 h)	Same as 62 h)	
	l) Lockout reset pushbutton fails closed.	Contact weld, short circuit, mech. damage.	No impact on normal operation. The affected init. circuit will automatically reset when the reset key switch is engaged.	Operator, when resetting ch.	Other 3 init. cir-cuit chans. for affected funct. are not affected.	None.	
	m) Lockout key switch fails open	Mech. binding. open circuit, contact cor-rosion.	Same as 62 h)	Same as 62 h)	Same as 62 h).	Same as 62 h)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
62) ESFAS Initiation Circuit (SIAS, Ch. A Typ.) (Cont.)	n) Lockout key switch fails closed.	Contact weld, mech. binding or damage, short circuit.	No impact on normal operation. Operator will be able to reset the affected init. circuit after trip without using the reset key.	None.	Other 3 init. circuits are not affected.	None.	Operator will not know that the init. circuit can be reset without the reset key.
	o) Lockout keyswitch relay (K1201) fails open.	Open circuit, mech. damage, overstress.	Same as 62 h)	Same as 62 h)	Same as 62 h)	Same as 62 h)	
	p) Lockout keyswitch relay contacts in reset circuit fail open.	Contact corrosion, open circuit, mech. damage.	Same as 62 h)	Same as 62 h)	Same as 62 h)	Same as 62 h)	
	q) Lockout keyswictch relay contacts in reset circuit fail closed.	Contact weld, short circuit.	Same as 62 m)	Same as 62 m)	Same as 62 m)	Same as 62 m)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 104 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
62) ESFAS Initiation Circuit (SIAS, Ch. A Typ.) (Cont.)	r) Train A or B initiation relay coil (SIAS, CIAS, or MSIS only) fails open.	Mech. damage, overstress, open circuit.	One set of relay contacts in the actuation circuit for one train of one ESF function will open.	Annunciating	Remaining 3 init. relays for the affected ESF func. train are still energized	ESFAS actuation still requires 2-out-of-3 signal coincidence. Initiation relay logic changed to 1-of-3 selective.	
	s) Train A or B initiation relay N.O. contact in actuation circuit fails open (SIAS, CIAS, or MSIS only).	Open circuit, contact cor-rosion, mech. damage.	Same as 62 q)	Same as 62 q)	Same as 62 q)	Same as 62 q)	
	t) Train A or b init. relay N.O. contacts in actuation circuit fail closed (SIAS, CIAS, or MSIS only).	Contact weld, short circuit.	One set of relay contacts in the actuation circuit for one train of one ESF function will not open on a valid 2-out-of-4 signal coincidence.	Periodic test.	Remaining 3 init. relays for the affected ESF func. train are capable of actuating the train.	Actuatuion for one ESF function train becomes 2-of-3 selective. ESFAS actuation still requries a 2-out-of-3 signal coincidence.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
62) ESFAS Initiation Circuit (SIAS, Ch. A Typ.) (Cont.)	u) Train A or B solid init. relay fails off. (CSAS, RAS, AFAS-1 or AFAS-2).	LED failure, SS trans. failure, open circuit, drop ping resistor failure.	Equivalent to 62 q)	Equiv. to 62 q)	Equiv. to 62 q)	Equiv. to 62 q)	
	v) Train A or B solid state initiation relay fails on. (CSAS, RAS, AFAS-1, or AFAS-2).	Emitter-to-collector short.	Equivalent to 62 s)	Equiv. to 62 s)	Equiv. to 62 s)	Equiv. to 62 s)	
	w) Remote Indication SSR fails off.	LED failure, SS transistor failure, dropping resistor fail.	Spurious indication of initiation Ch. trip on remote PPS module.	Visual indication.	None required.	None.	
	x) Remote indication SSR fails on.	Emitter-to-collector short.	Loss of remote visual indication for initiation circuit trip.	Periodic test.	Local visual indicator.	None.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
62) ESFAS Initiation Circuit (SIAS, Ch. A Typ.) (Cont.)	y) Local indication SSR fails off.	LED failure, SS transistor failure, resistor failure.	Spurious local indication of initiating circuit trip.	Visual indication.	None required.	None.	
	z) Local indication SSR fails on.	Emitter-to-collector short.	Loss of local visual indication of initiation circuit trip.	Periodic test.	Remote visual trip indicator.	None.	
	aa) Initiation reset flasher SSR fails off.	LED failure, SS transistor failure, dropping resistor failure.	Initiation reset flasher in test circuit will flash, indicating a spurious channel initiation.	Visible indication.	None required.	None.	
	ab) Initiation reset flasher SSR fails on.	Emitter-to-collector short.	Initation reset flasher in test circuit will not provide indication that a channel initiation has occurred during test. Operator may test another channel - leading to actuation.	Local and remote initiation indication without initiation reset indic. during test.	Local and remote initiation indication.	Possible ESF function actuation during test. Possible reactor trip if MSIVs are closed.	Operator error needed to produce ESF actuation during test. No adverse safety impact on plant. Failure not affect normal PPS operation.

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
63) ESFAS Actuation Circuit (SIAS, CSAS, RAS, MSIS, or CIAS).	a) One 36 V dc power supply fails off.	Component failure.	Loss of one of two redundant power supplies for one set of component actuation relays.	Annunciating.	Redundant power supply.	None.	
	b) One 120 V ac vital bus circuit breaker fails open.	Mech. damage, high current.	Equivalent to 63 a)	Equiv. to 63 a)	Equiv. to 63 a)	Equiv. to 63 a)	
	c) One 120 V ac vital bus circuit breaker fails closed.	Contact weld, mech. damage.	No impact on normal operation. Power supply is supplied with a 30 A input fuse. Fuse will open if input current exceeds 30A and the power supply will lose input power.	Periodic test, power supply failure is annunciated.	Redundant power supply.	None.	
	d) 36 V dc power supply indicator lamp fails off.	End of life, burnt out, mech. damage.	Spurious visual indication of power supply failure.	Visual indication.	None required.	None.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 108 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
63) ESFAS Actuation Circuit (SIAS, CSAS, RAS, MSIS, or CIAS). (Cont.)	e) 36 V dc power supply trouble annunciator relay fails open.	Overstress, mech. damage, open coil winding.	Spurious power supply failure alarm.	Annunciating.	None required.	None.	
	d) 36 V dc power supply trouble annunc. relay shorted.	Insulation failure.	Output of one 36 V dc P/S will be shorted. Automatic elec-tronic current limiting circuit limits output current to a preset value.	Annunciating for power supply failure.	Redundant power supply.	None.	
	g) One auction-eering diode fails open.	Overstress, open circuit, mech. damage.	Equivalent to 63 a)	Equiv. to 63 a)	Equiv. to 63 a)	Equiv. to 63 a)	
	h) Auc-tioneering diode shorted.	Overstress, internal failure.	Loss of isolation between two 36 V dc power supplies.	Periodic test.		None.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 109 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
63) ESFAS Actuation Circuit (SIAS, CSAS, RAS, MSIS, or CIAS). (Cont.)	i) One manual actuation pushbutton fails open.	Mech. damage, open circuit, contcat deteriora-tion.	One leg of the actuation cir-cuit for one ESFAS function will open up. Power for actu-ation relays will be supplied via opposite leg of circuit.	Annunciating.	Opposite leg of actuation circuit will supply power to actuation relays.	Manual ESFAS actu-ation becomes 1-of-1, auto initiation becomes 1-of-4 selective.	Auto ESFAS actuation still requires a 2-out-of-3 signal coincidence.
	j) One manual actuation pushbutton fails closed.	Contact weld, mech. damage.	The manual actuation button will not open one leg of actuation circuit.	Periodic test.	Automatic ESFAS actuation not affected.	Unable to manually actuate one ESFAS function.	
	k) Annunc-iation diodes fail open.	Overstress, open lead, mech. damage.	Equivalent to 63 i)	Equiv. to 63 i)	Equiv. to 63 i)	Equiv. to 63 i)	
	l) Annunc. diodes short.	Overstress, internal failure.	Voltage drop across diodes goes to zero, annunc. “sees” open circuit, spurious annunc. of one actuation circuit leg opening up.	Annunciating.	None required.	None.	
	m) Actuator circuit indicator lamp fails off.	Filament burnt out, mech. damage.	Spurious visual indication that one leg of the actuator circuit has opened up.	Visual indication.	None required.	None.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 110 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
63) ESFAS Actuation Circuit (SIAS, CSAS, RAS, MSIS, or CIAS). (Cont.)	n) Lockout reset button fails open.	Contact de-terioration, mech. damage, open circuit.	Unable to reset one leg of the actuation circuit after test or an actuation. Other leg can still be reset, which will reenergize lockout relay in affected leg.	Visual indication.	Reset pushbutton in other leg of actuation circuit.	None.	
	o) Lockout reset pushbutton fails closed.	Contact weld, mech. damage.	No imapct during normal opera-tion, after auto. actuation. If actuation is caused by using manual actuation button, actuation relays will auto-matically reset.	Periodic test.	Automatic actua-tion and manual ESFAS initiation capabilities not affected.	One ESFAS function cannot be manually actuated from the actuation relay level.	Auto ESFAS actuation and manual ESFAS actuation from the initiation circuit not affected.
	p) Lockout relay N.O. contacts fail open.	Open circuit, contact deteriora-tion.	Equivalent to 63 i)	Equiv. to 63 i)	Equiv. to 63 i)	Equiv. to 63 i)	Equiv. to 63 i)
	q) Lockout relay N.O. contacts fail closed.	Contact weld.	Same as 63 o)	Same as 63 o)	Same as 63 o)	Same as 63 o)	Same as 63 o)
	r) Lockout relay coil fails open.	Mech. damage, open winding.	Equivalent to 63 i)	Equiv. to 63 i)	Equiv. to 63 i)	Equiv. to 63 i)	Equiv. to 63 i)

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 111 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
63) ESFAS Actuation Circuit (SIAS, CSAS, RAS, MSIS, or CIAS). (Cont.)	s) Lockout relay coil shorted.	Insulation failure, mech. short.	One group of actuation relays (either pumps or valves) will be shorted out, and will de-energized. Circuit breaker for affected group will probably open on high current.	Annunciating.	Only pumps or only valves will be actuated, so the full safety system will not be spur-iously actuated.	Either the pumps or the valves (but not both) in one train of one ESFAS function will be actuated.	
	t) Lockout relay surge protectiond iode fails open.	Overstress, mech damage.	Loss of surge protection for lockout relay. Possible damage to relay due to inductive kick when relay deenergizes. Relay may fail open.	Periodic test.	None required.	None.	
	u) Lockout relay surge protection diode shorted.	Overstress, internal failure.	Same as 63 s)	Same as 63 s)	Same as 63 s)	Same as 63 s)	Same as 63 s)
	v) One actuation relay coil fails open.	Mech. damage, open winding, open lead.	One valve or one pump will be actuated in one train of one ESFAS function.	Status indicator for affected valve or pump.	Only one component actuated, the full train for the affected ESFAS fucntion will not be spuriously actuated by failure of one actuation relay.	Full ESFAS actuation still requires a 2-out-of-3 signal coincidence. Only a single comp. affec-ted by this failure. (4th input signal bypassed at bi-stable).	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 112 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
63) ESFAS Actuation Circuit (SIAS, CSAS, RAS, MSIS, or CIAS). (Cont.)	w) One actuation relay coil shorted.	Insulation failure, mech. short.	Actuation relay will not hold contacts, one pump or one valve actuated in one train of one ESFAS function.	Same as 63 v)	Only one component actuated, the full train for the affected ESFAS function will not be spuriously actuated by failure of one actuation relay.	Same as 63 v)	
	x) Actuation relay surge protection diode fails open.	Overstress, mech damage.	Equivalent to 63 t)	Equiv. to 63 t)	Equiv. to 63 t)	Equiv. to 63 t)	
	y) Actuation relay surge protectiond iode shorted.	Overstress, internal failure.	Same as 63 s)	Same as 63 s)	Same as 63 s)	Same as 63 s)	Same as 63 s)
	z) Actuation relay test relay fails open.	Open winding, mech. damage, overstress, open lead.	Unable to test the actuation of one pump or one valve in one Train of one ESF function.	Periodic test.	None required.	None.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 113 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
63) ESFAS Actuation Circuit (SIAS, CSAS, RAS, or CIAS). (Cont.)	aa) Actuation relay test relay N.C. contacts fail closed.	Contact weld, mech. damage.	Same as 63 z)	Same as 63 z)	Same as 63 z)	Same as 63 z)	
	ab) Actuation relay test relay N.C. contacts fail open.	Contact deterioration, mech. damage.	Same as 63 v)	Same as 63 v)	Same as 63 v)	Same as 63 v)	
	ac) Power return line circuit breaker fails open.	Contact deterioration, mech. damage.	Power return line for one group of actuation relays (pumps or valves) in one train of one ESF function opens up. Relays are de-energized.	Annunciating.	None.	All valves, or all pumps (but not both) in one train of one ESF function are actuated.	
	ad) Power return line circuit breaker fails closed.	Contact weld, mech. damage.	Loss of overcurrent protection for one leg of one actuation circuit.	Breaker test during shutdowns.	None.	None.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
64) ESFAS Actuation Circuit (AFAS-1, AFAS-2, or MSIS)	Failure Modes a) htrough h) and their effects are the same as for Line Item 63, Failure Modes a) through h).						
	i) Annunciator diodes fail open.	Overstress, mech. damage.	One actuation leg for AF pumps (or MSIVs) will open up. Corresponding aux. FW valve actuation leg not affected.	Annunciating	Opposite actuation leg for aux. FW pumps (or MSIVs) will provide power to act. relays.	AFW pump actuation becomes 1-of-2 selective. Valve act. not affected.	AFAS actuation still requires a 2-out-of-3 signal coincidence. (4th input signal bypassed at bistable)
	j) Annunc. diodes shorted.	Internal failure, overstress, mech short.	Voltage drop across annunc. diodes goesto zero. Annunc. “sees” an open circuit. Spurious AFAS (or MSIS actuation alarm.	Annunciating	None required.	None.	
	k) Actuation circuit indicator lamp fails off	Burnt out, mech. damage.	Spurious visual indication that one actuation leg has opened up.	Visual inciation.	None required.	None.	
	l) Lockout reset pushbutton fails open.	Contact deterioration, mech. damage.	No imapct on normal operation. Unable to reset the AFW pump (or MSIV) portion of one actuation leg after test or actuation. Reset button in opposite leg will provide power to reset relay and reset the affected leg.	Periodic test.	Reset pushbutton in opposite actuation leg.	None.	

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 115 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
64) ESFAS Actuation Circuit (AFAS-1, AFAS-2, or MSIS) (Cont.)	m) Lockout reset pushbutton fails closed.	Contact weld, mech. damage.	No impact during normal operation or after automatic actuation. If actuation is via manual actuation button, actuation relays for AFW pump (or MSIV) will automatically reset when manual actuation button released.	Periodic test.	Automatic actuation and manual initiation not affected.	AFW pumps (MSIVs) cannot be manually actuated from the actuation circuit for either AFAS-1 or AFAS-2 (MSIS A, MSIS B).	Auto AFAS (MSIS) actuation and manual AFAS (MSIS) actuation from the initiation circuit not affected.
	n) Manual actuation button fails closed.	Contact weld, mech. damage.	Unable to manually actuate one AFAS Train (or MsiS Train).	Periodic test.	Same as above	Unable to manually actuate AFW pumps and one set of valves from the actuation circuit.	Same as above.
	o) Manual actuation button fails open.	Contact deterioration, mech damage.	One leg of one AFAS (MSIS) actuation circuit open. AFAS valve relay will de-energize and actuate valves. Pump relays will be powered by opposite leg.	Annunciating.		One set of AFAS valves will be actuated.	Full AFAS actuation still requires a 2-out-of-3 signal coincidence. (4th input signal by passed at bistable).
	p) Lockout relay fails open.	Open winding, overstress, mech. damage.	Equivalent to 64 i)	Equiv. to 64 i)	Equiv. to 64 i)	Equiv. to 64 i)	Equiv. to 64 i)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 116 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
64) ESFAS Actuation Circuit (ESFAS-1, AFAS-2, or MSIS) (Cont.)	q) Lockout relay shorted.	Insulation failure, mech. damage.	Shorted coil will draw high current, causing return line circuit breaker to open. One AFAS valve set and one pump (MSIV) set will be actuated.	Annunciating.	None.	One AFAS valve set and one pump set (MSIV) actuated. Possible reactor trip if one MSIV closes.	
	r) Lockout relay N.O. contacts fail open.	Contact de-terioration, mech. damage, open lead.	Equivalent to 64 i)	Equiv. to 64 i)	Equiv. to 64 i)	Equiv. to 64 i)	Equiv. to 64 i)
	s) Lockout relay N.O. contacts fail closed.	Contact weld, mech. damage.	Equivalent to 64 m)	Equiv. to 64 m)	Equiv. to 64 m)	Equiv. to 64 m)	Equiv. to 64 m)
	t) Lockout relay surge protection diode shorted.	Overstress, internal failure, mech. short.	Equivalent to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 117 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
64) ESFAS Actuation Circuit (AFAS-1, AFAS-2, or MSIS) (Cont.)	u) Lockout relay surge protection diode shorted.	Mech. damage, overstress.	Loss of surge protection for lockout relay. Possible damage to relay due to inductive kick when relay deenergizes. Relay may fail open.	Periodic test.	None required.	None.	
	v) Pump actuation relay fails open.	Mech. damage, overstress, open winding.	One AFAS pump (MSIV) will be actuated.	Comp. status indic.	None.	For AFAS, one pump actuated. For MSIS, probable reactor trip due to MSIV closing.	
	w) Pump action relay shorted.	Insulation breakdown, mech. short.	Equivalent to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)
	x) Pump actuation relay surge suppres-sion diode open.	Mech. damage, overstress.	Equivalent to 64 u)	Equiv. to 64 u)	Equiv. to 64 u)	Equiv. to 64 u)	Equiv. to 64 u)
	y) Pump actuation relay surge suppress. diode shorted.	Overstress, internal failure, mech. short.	Equivalvent to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
64) ESFAS Actuation Circuit (AFAS-1, AFAS-2, or MSIS) (Cont.)	z) One test relay coil fails open.	Mech. damage, open winding, overstress, short circuit	Unable to test actuate one component.	Periodic test.	None.	None.	
	aa) Test relay N.C. contacts fail closed.	Contact weld, mech. damage.	Same as 64 z)	Same as 64 z)	Same as 64 z)	Same as 64 z)	
	bb) Test relay N.C. contacts fail open.	Contact deterioration, open lead, mech. damage.	Same as 64 v)	Same as 64 v)	Same as 64 v)	Same as 64 v)	
	cc) AFAS valve act. relay fails open.	Open winding, mech. damage, overstress.	One AFAS valve set will be actuated. One leg of pump actuation circuit will open, but opposite leg will provide power to pump act. relays.	Annunciating.	None.	One set of AFAS valves will be actuated. Full AFAS (MSIS) actuation still requires a 2-out-of-3 signal coincidence. (4th input signal bypassed at bistable)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 119 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
64) ESFAS Actuation Circuit (AFAS-1, AFAS-2, or MSIS). (Cont.)	dd) AFAS valve act. relay shorted.	Insulation breakdown mech. short.	Equivalent to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)	Equiv. to 64 q)
	ee) AFAS valve act. relay N.O. contacts in pump act. cir cuit fail open.	Open lead, mech. damage, contact deterioration.	Same as 64 i)	Same as 64 i)	Same as 64 i)	Same as 64 i)	Same as 64 i)
	ff) AFAS valve act. relay N.O. contacts in pump act. cir-cuit fail closed.	Contact weld, mech. damage.	SSR1A unable to actuate pump and valve group for one actuation leg.	Periodic test.	Manual actuation, SSR3A not affected.	Full actuation of AFAS (MSIS) requires 2-of-4 selective input from init. circuit.	AFAS actuation still requires 2-out-of-3 signal coincidence. (4th input signal bypassed at bis table).
	gg) Power return circuit breaker open.	Mech. damage, open circuit.	One entire actuation leg for one AFAS (MSIS) train is de-energized. One AFAS valve set and one pump set (MSIV) actuated.	Annunciating.	None.	For AFAS, one valve set and one pump set in one AFAS train are actuated. For MSIS, one MSIV closes, probable reactor trip.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
64) ESFAS Actuation Circuit (AFAS-1, AFAS-2, or MSIS). (Cont.)	hh) Power return line circuit breaker fails closed.	Contact weld, mech. damage.	Loss of overcurrent protection for one leg of the actuation circuit.	Periodic breaker tests.	None.	None.	
65) Test Power Supply	a) High output voltage.	Internal failure.	Depends upon ability of compo-nents to sustain overvoltage.	Possible power supply indicator light inoperative.	None required.	Unable to test PPS.	No effect upon operation of PPS. Overvoltage condition may cause failure of affected bistable test coils when matrix hold push button is depressed during test.
		Mechanical damage.	Possibilities: 1. Matrix pushbutton system channel trip select, and RPS channel trip select switch fail closed or open. 2. Bistable test coils fail open or short. 3. Bistable test coil surge suppression diodes fail open or short.	Inability to conduct bistaable relay test.	None required.		
	b) Low or no output voltage.	Internal failure, mech. damage, input under-voltage, input CRT breaker open.	No test capability.	Test power supply and matrix relay hold indicator lights in-operative.	None required.	Unable to test PPS.	No effect upon operation of PPS.

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
66) Matrix Hold Switch e.g., “AB” Matrix)	a) Open – Matrix relay circuit contacts.	Mech. failure, contact deterioration.	Unable to energize matrix relay test coils which inhibits matrix response when selected pair of contacts in “AB” logic matrix is actuated. Matrix will pass test signal as bonafide actuation signal (e.g., CSAS).	Matrix relay hold and drop-out indicator lights inoperative. Annunciation.	None required	Matrix Relay Hold Switch has a detent in the “hold” posi-tion, which allows detection of open contacts before switch is rotated to the “trip” position.	Test procedure requires matrix and channel switch at off position. The failure of these contact pairs can be deteced before channel is tested.
	b) Closed – Matrix relay circuit contacts	Mech. damage, welded contacts.	Matrix relay test coils remain energized, preventing reactor trip initiated by same matrix.	Matrix relay hold and drop-out indicator lights remain on.	Removal of test power.	Affected logic matrix cannot initiate trip when required during test.	Reactor trip logic becomes 2-out-of-2 during test period only. (4th input signal bypassed at bistable.)
	c) Open – Bistable relay circuit contacts.	Mech. failure, contact deterioration.	Unable to energize any system channel trip select switch or RPS channel trip select switch, bistable test relay coils.	Unable to release bistable relay. No trip indicator lights.	None required	None. Unable to conduct matrix logic test for “AB” matrix.	No affect on operation of PPS. Operator cannot test bistables, pair associated with matrix logic (e.g., “AB”).
	d) Closed – Bistable relay circuit contacts	Mech. damage, welded contacts	Bistable relay test coils connected to system channel trip select switch remains energzied during test.	Bistable relay trip indicator light is on	Removal of test power supply or positioning CRT switches to off.	Actuation signal is initiated when test switch is turned on.	First position of system channel trip select switch is RPS trip, and when Operator starts test sequence the reactor may trip.

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
67) System Channel Trip Select Switch	Intermit-tent contact (Open)	Mech. damage, contact deterioration.	Unable to energize bistable relay test coils associated with system channel trip select switch.	No bistable test light indication.	None required	Unable to test logic matrices for affected system channel trip.	
68) RPS Channel Trip Select Switch	Intermit-tent contact (Open)	Mech. damage, contact deterioration.	Unable to energize bistable relay test coils associated with test switch position.	No bistable test light at test switch position location.	None required	Unable to test logic matricees for affected bistable pair.	No affect on opera-tion of PPS.
69) Bi-stable relay test coil (e.g., A1-1)	a) Open	Overvoltage, mech. damage.	Unable to energize affected bistable test coil to initiate relay trip for the particular parameter under test.	Bistable test light stays off.	None required	Unable to test that portion of logic matrices completely for the parameter under test.	No effect on opera-tion of PPS.
	b) Short	Mech. damage.	Test power supply will be reduced to approx. zero.	Power supply indi-cator light inoper-ative.	None required	Unable to test logic matrices completely.	
		Deterioration of Insulation	Bistable relay test coil cannot be energized.	Bistable test light stays off.	None required		
70) Matrix Relay Trip Select Switch	Intermit-tent contact (Open) (e.g., po-sition 1).	Mech. damage, contact deterioration.	Matrix relay test coils for the affected position (e.g., “1” remain de-energized during test period.	Matrix relay hold indicator light inoperative Annunciation.	None required	Reactor trip could occur during bista-ble relay trip test.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
71) Matrix Relay Test coil (e.g., 1AB-1)	a) Open	Overvoltage, mech. damage.	Unable to energize affected test coil to inhibit matrix relay trip.	Matrix relay hold indicator lights do not illuminate.	None required	Unable to conduct test of trip path (e.g., #1) for affected matrix logic (e.g., “AB”).	No affect on operat-tion of PPS.
	b) Short	Deterioration of Insulation	Test power supply will be reduced to approx. zero.	Power supply and matrix hold indi-cator lights do not illuminate.	None required	Unable to conduct test of trip path (e.g., #1) for affected matrix logic (e.g., “AB”).	No affect on opera-tion of PPS.
72) Matrix Relay Hold Indicators	Open	Overvoltage, mech. damage.	Test coil state cannot be visually determined.	Visual, periodic test.	None.	None.	No affect on opera-tion of PPS.
73) Matrix Relay Drop-Out Indicators	Open	Overvoltage mech. damage.	Matrix relay state cannot be determined.	Visual, periodic test.	None.	None.	No affect on opera-tion of PPS.
74) Matrix Test dc/dc Converter	a) Fails off.	Comp. failure, open circuit, fuse fails open.	Unable to provide dc power to one matrix test circuit. Unable to test one matrx (i.e., “AB”).	Operator, when attempting matrix test.	None.	No impact on PPS operation.	
	b) Fails hi.	Comp. failure.	Possible damage to components on matrix test circuits, bistable test coils may fail open. Test switches may fail open. Unable to properly test one matrix.	Operator, when attempting matrix test.	None.	No impact on PPS operation.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
75) Channel A Test Switch	a) Fails open.	Mech. binding, contact deterioration.	Unable to test channel A related logic matrices or other channel A functions.	Operator, when attempting test.	None.	No impact on PPS operation.	
	b) Fails closed.	Mech. binding.	Unable to test any channel but channel A.	Operator, when attempting test on another channel.	None.	No impact on PPS operation.	
	c) Contacts to ch. A test enable relay fail open.	Contact cor-rosion, mech. binding.	Same as 74 a)	Same as 74 a)	Same as 74 a)	Same as 74 a)	
	d) Contacts to ch. A test enable relay fail closed.	Contact weld, mech. binding.	Ch. A test enable relay remains energized. Possible to test two ch's. at same time.	Ch. A test lamp stays on when switch is turned off.	Procedures pre-clude testing more than one ch. at a time.	None.	
	e) Contacts to Ch. B test switch fail open.	Contact cor-rosion, open lead, mech. damage.	Unable to provide power to Ch. B test switch, unable to test Ch. B, C, or D.	Operator, when trying to test Ch. B.	None.	None.	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
75) Channel A Test Switch (cont.)	f) Contacts to Ch. B test switch fail closed.	Contact weld, mech. damage.	Power still provided to Ch. B test switch when ch. A is in test. Possible to test two ch's. at same time.	None.	Procedures preclude testing two ch's. at same time.	None.	
	g) Contacts to test annunc. fail open	Contact deterioration, mech. damage, open lead.	Spurious "Test in Progress" alarms.	Annunciation.	None.	None.	
	h) Contacts to test annunc. fail closed.	Contact weld, mech. binding.	"Test in Progress" alarm not sound when Ch. A switch engaged.	Operator, when starting test.	Ch. A "Test in Progress" lamp comes on.	None.	
76) Ch. A Test Lamp	Fails off.	Burnt out, mech. damage.	Loss of visual indication when Ch. A is in Test.	Operator, when starting test.	Test annunc. not affected	None.	
77) Ch. A Test Relay	a) Fails open.	Overstress, open winding, mech. damage.	Relay contacts in matrix hold switch power lines will not close. Unable to test Ch. A.	Operator, when starting test	None.	None.	
	b) N.O. contacts in power circuit fail open.	Open lead, contact corrosion.	Same as 77 a)	Same as 77 a)	Same as 77 a)	Same as 77 a)	

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
77) Ch. A Test Relay	c) One N.O. contact in power circuit fails closed.	Contact weld, mech. binding	None.	None.	None.	None.	
78) PPS Calibration and Test Panel Trip Test Pushbutton (PB -) (e.g., Channel "A")	a) Open	Mech. damage, contact deterioration.	Unable to energize bistable relay trip test circuit and supply test signal to bistable selected for test.	No bistable trip indication.	None.	None.	No effect on operation of PPS. May not be able to test bistables in affected channel (e.g., Channel "A").
	b) Closed	Mech. damage welded contacts.	Bistable relay trip test circuit energized when test signal power supply is turned on.	Bistable in test indicator.	Rotating matrix hold switch to the "Hold" position and/or reducing signal level below trip level.	Half logic matrix trip could occur during testing.	Operator will be aware of problem as soon as test power supply is turned on and before test sequence starts.
79) Trip Test Circuit Relay (K-1, e.g., Channel A")	a) Open coil.	Overvoltage, mech. damage.	Unable to energize trip test circuit. The contacts which connect the bistable selected for test to the test signal will not be energized.	No trip signal indication.	None.	Selected bistable relays cannot be tested in affected channel (e.g., "A")	No effect on operation of PPS.

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PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
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Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
79) Trip Test Circuit Relay (K-1, e.g., Channel "A") (Cont.)	b) Shorted coil.	Deterioration of insulation, mech. damage.	Test power supply could be reduced to approx. zero.	Test power supply indicator light will extinguish. No signal reading on DVM.	None.	Selected bistable relays cannot be tested in affected channel (e.g., "A")	No effect on operation of PPS.
	c) Contact open.	Deterioration of contact, mech. damage.	Unable to energize trip circuit. Bistable selected for test cannot be connected to the test signal.	No trip signal indication.	None.	Selected bistable relays cannot be tested in affected channel (e.g., "A")	No effect on operation of PPS.
	d) Contact short.	Weld contact.	Trip test circuit remains energized.	Possible signal reading on DVM. Bistable trip indication.	Bistable select and meter input switch in off position.	Should test signal be inputted half logic matrix trip can occur during test only.	
80) NI Drawer Log Level Trip Test Switch (S2) (e.g., Channel "A")	a) Open contacts: "A"	Mech. damage, contact deterioration.	Unable to transmit test signal to next channel (e.g., "B") when next channel is selected for test.	No response of next channel during test. No bistable trip indication.	None. channels B, C, D	Unable to test ch. A Nuclear Drawer.	No effect on operation of PPS.
	"B"		Unable to test channel "A" when conducting channel test. Relay AK 60 will not energize when test is run.	No response from channel under test. No bistable trip indication.	None.	Unable to test ch. A Nuclear Drawer.	No effect on operation of PPS.
	"D"		Unable to transmit selected test signal to log level trip circuitry.	No bistable trip indication.a	None.	Unable to test ch. A Nuclear Drawer.	No effect on operation of PPS.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 128 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
80) NI Drawer Log Level Trip Test Switch (S2) (e.g., Channel "A") (Cont.)	b) Closed contacts: "A"	Mech. damage, welded contacts.	Unable to disconnect nest channel, when ch. "A" is in test. Interchannel interlock during test is overridden.	Multichannel bi-stable tirp indicaiton.	None	Possible reactor trip during test.	Operator must deliberately depress ch. "A" test switch coincidence with other channel to initiate inadvertent trip.
	"B"		Unable to discard channel "A" from test during test program.	Multichannel bi-stable trip indication.	None.	Possible reactor trip during test.	
81) HI Drawer Test Relay (AK60) (e.g., "A")	a) Open coil.	Overvoltage, mech. damage.	Unable to energize relay contacts which transmit test signal to log level trip circuitry when channel is under test.	No bistabel trip indication.	None.	Unable to test channel A Nuclear Drawer.	No effect on operation of PPS.
	b) Short coil.	Deterioration of insulation.	Test power supply may reduce to approximately zero.	No bistable trip light. Power supply test light not lit.	None.	Unable to test ch. A Nuclear Drawer.	No effect on operation of PPS.
	c) Open contacts.	Deterioration of contact, mech. damage.	Unable to transmit selected test signal to log level trip circuitry.	No bistable trip indication.	None.	Unable to test ch. A Nuclear Drawer.	No effect on operation of PPS.
	d) Short contacts.	Deterioration of contact, welded contact.	Interlock feature of relay AK60 is inhibited, cannot cause multi-test condition with failure in "A" channel.	Bench test.	Design of inhibit circuit would not allow trip condition if failure occurs in "A" channel.	Possible to have a reactor trip during test.	Operator must deliberately actuate two channel test switches to obtain trip effect.

Table 7.2-4A

PLANT PROTECTIVE SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Sheet 129 of 129)

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Effect Upon PPS	Remarks and Other Effects
82) Log Trip Level Adjust (R8)	Open or Intermit-tent.	Failed resis-tive element.	Operator will be unable to trim test signal level.	DVTM	None.	Unable to test ch. A, Nuclear Drawer.	
83) Initia-tion Reset Flasher Circuti	a) Fails on	Flasher failure, data coupler failure, dis-crete comp. failure.	Reset lamp will flash, giving spurious indication of a channel trip for ESFAS or a TCB trip.	Visual indication.	None.	None.	
	b) Fails off.	Comp. failure.	Reset lamp will not flash when a channel trip is induced by test.	During test, flasher not flash but trip indi-cators come on.	Trip indic. for each channel of each PPS function.	None.	

7.2.2.3.2.3 Section 4.3, Quality Control of Components and Modules. The systems which function to provide protective action are designed in accordance with Topical Report-CENPD-210A, "Description of the C-E Nuclear Steam Supply System Quality Assurance Program".[5]

7.2.2.3.2.4 Section 4.4, Equipment Qualification. The RPS meets the equipment requirements described in section 3.10 and CENPD-182, "Seismic Qualification of Instrumentation and Electrical Equipment",[4] and section 3.11 and CENPD-255, "Qualification of Combustion Engineering Class 1E Instrumentation".[3]

7.2.2.3.2.5 Section 4.5, Channel Integrity. Type testing of components, separation of sensors and channels, and qualification of the cabling are utilized to ensure that the channels will maintain their functional capability required under applicable extremes of environment, power supplied, malfunction, and fault conditions. Loss of or damage to any one channel will not prevent the protective action of the RPS. Sensors are connected so that blockage or failure of any one connection does not prevent protective system action. The process transducers located in the containment building are specified and rated for the intended service. Components which must operate during or after a limiting fault are qualified for the most limiting environment for the period of time for which they must maintain their functional capability. Results of type tests are used to verify this. Separation requirements for the components of the RPS are discussed in subsection 7.2.3.

7.2.2.3.2.6 Section 4.6, Channel Independence. Each redundant channel is independent of the other redundant channels. The sensors are separated, cabling is routed separately and, in cabinets, each redundant channel is located in a separate compartment which provides thermal and mechanical barriers. This minimizes the possibility of a single event causing more than one channel's failure. The outputs from these redundant channels are isolated from each other so that a single failure does not cause impairment of the system function. The RSPT signals are sent to separate CEA calculators. To provide the required input to the CEAC, the signals utilized as inputs are sent through isolation amplifiers (see figure 7.2-0D).

Outputs from the redundant channels to non-safety related areas are isolated so that failure in the non-safety related area does not cause loss of the safety system function. Outputs from the components of the RPS to the control boards are isolated if they go to non-1E portions of the board. The signals originating in the RPS which feed the plant monitoring system (PMS) are isolated to maintain their channel independence.

7.2.2.3.2.7 Manual Initiation

A manual trip is effected by depressing either of the pushbuttons in both trip legs on the main control board for the RPS or the pushbuttons on the RTSS. No single failure will prevent a manual trip.

7.2.2.3.2.8 Control and Protection System Inspection

A. Classification of Equipment

No portion of the RPS is used for both protective and control functions with the following exception: The RPS' DNBR, LPD, and high pressurizer pressure provide a CEA Withdrawal Prohibit (CWP) which is treated as an associated circuit, and is isolated in the CEDMCS auxiliary cabinets before going to the CEDMCS. As an associated circuit it meets the requirements of IEEE 279-1971.

B. Isolation Devices

Signals from the RPS are isolated such that a failure will not affect the protective action of the RPS. The CWP is isolated in the CEDMCS Auxiliary Cabinets to prevent a failure in the CEDMCS from propagating back into the RPS.

C. Single Random Failure

This criterion is not applicable. The CWP which is sent to the CEDMCS is only a permissive signal and does not cause a control action which could require a protective action.

D. Multiple Failures Resulting From a Credible Single Event

This cannot exist since the CWP cannot initiate a control action, only permit it.

7.2.2.3.2.9 Derivation of System Input. Insofar as is practicable, system inputs are derived from signals that are direct measures of the desired variables. Variables that are measured directly include neutron flux, temperatures, and pressures. Level information is derived from appropriate differential pressure measurements. Flow information is derived from reactor coolant pump speed measurement and coolant temperature.

7.2.2.3.2.10 Capability for Sensor Checks. RPS sensors are checked by cross-channel comparison. Each channel has a known relationship with the other channels of the same parameter.

7.2.2.3.2.11 Capability for Test and Calibration. The RPS design complies with IEEE 338-1971, "Trial Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems" and Regulatory Guide 1.22, "Periodic Testing of Protection System Actuator Functions", as discussed in section 7.2.2.3.3.

7.2.2.3.2.12 Channel Bypass or Removal From Operation. Any one of the four protection channels in the RPS may be tested, calibrated, or repaired without impairing the systems' protective action capability. In the RPS, individual trip channels may be bypassed to create a two-out-of-three logic on the remaining channels which maintains the coincidence of two required for trip. The single failure criterion is met during this condition. Testing of each of the two CEA position indication channels can be accomplished in a very brief time.

The probability of failure of the other position indication system is acceptably low during such testing periods.

7.2.2.3.2.13 Operating Bypasses. Operating bypasses are provided as shown on Table 7.2-2. The operating bypasses are automatically removed when the permissive conditions are not met. The circuitry and devices which function to remove these inhibits are designed in accordance with IEEE 279-1971.

7.2.2.3.2.14 Indication of Bypasses. Indication of test or bypass conditions, or removal of any channel from service is given by annunciators. Operating bypasses that are automatically removed at fixed setpoints are alarmed and indicated.

7.2.2.3.2.15 Access to Means for Bypassing. Trip channel bypasses have access controlled by means of key locked doors. When the first parameter is bypassed there is an audible and visible alarm to indicate which channel is being bypassed. The specific parameter or parameters which are being bypassed are indicated by lights at the PPS cabinet and its remote operator's module.

The operating bypasses have audible and visible alarms. The operating bypasses have automatic features which provide a permissive range at which they can be actuated. Should the permissive range be exceeded, the bypass will be automatically removed.

7.2.2.3.2.16 Multiple Setpoints. Manual reduction of the setpoints for low pressurizer pressure and low steam generator

pressure trips are used for the controlled reduction of pressurizer pressure and steam generator pressure as discussed in sections 7.2.1.1.1.6 and 7.2.1.1.1.8. The setpoint reductions are initiated by main control board pushbuttons for each channel, one pushbutton for the pressurizer pressure and one pushbutton for both steam generator pressures within the one channel. This method of setpoint reduction provides positive assurance that the setpoint is never decreased below the existing pressure by more than a predetermined amount.

The variable overpower trip setpoint tracks the actual reactor power from a minimum value to a high value or vice versa, if the power changes slowly enough. The variable overpower trip setpoint is designed with a maximum rate of decrease or increase. Should the actual power increase at too rapid a rate, it will catch up with the more slowly increasing setpoint and cause a trip.

The low reactor coolant flow trip setpoint automatically tracks below the input variables by a fixed margin for all decreasing inputs with a rate less than the rate limit. The setpoint decreases at a fixed rate for all decreasing input variable changes greater than the rate limit, except that there is a fixed minimum limit on the setpoint. Should the input variable decrease at too rapid a rate, it will catch up with the more slowly decreasing or limited setpoint and cause a trip. The setpoint automatically increases as the input variable increases independent of rate.

7.2.2.3.2.17 Completion of Protective Action Once it is Initiated. The system is designed to ensure that protective

action (reactor trip) will go to completion once initiated. Operator action is required to clear the trip and return to operation. Protective action is initiated when the reactor trip circuit breakers open. Protective action is completed when the CEAs arrive at their full-in position.

7.2.2.3.2.18 Access to Setpoint Adjustments, Calibration and Test Points. Keys or built-in features are provided to control setpoints, calibration, and test point adjustments. Access is indicated to the operator. The Applicant shall control access via key locks, administrative procedures, and other means to limit access.

7.2.2.3.2.19 Identification of Protective Action. Indication lights are provided for all protective actions, including identification of channel trips. The breaker status and current indication are available to the operator.

7.2.2.3.2.20 Information Readout. Means are provided to allow the operator to monitor all trip system inputs, outputs and calculations. The specific displays that are provided for continuous display are described in section 7.5.

7.2.2.3.2.21 System Repair. Identification of a defective input channel will be accomplished by observation of system status lights or by testing as described in section 7.2.1.1.9. Replacement or repair of components is accomplished with the affected input channel bypassed. The affected trip function then operates in a two-out-of-three trip logic while maintaining the coincidence of two required for trip.

7.2.2.3.2.22 Identification. All equipment, including panels, modules, and cables, associated with the trip system will be marked in order to facilitate identification. Interconnecting cabling will be color coded as discussed in section 7.1.3.16. Interface requirements of section 7.2.3 ensure that equipment supplied by the Applicant meets this requirement.

7.2.2.3.3 Testing Criteria

Conformance to IEEE 338-1971 and Regulatory Guide 1.22 are discussed in paragraphs 7.1.2.7 and 7.1.2.15. Test intervals and their bases are included in the Technical Specifications and their Bases. A complete channel can be tested without causing a reactor trip and without affecting system operability. Overlap in the RPS channel tests is provided to assure that the entire channel is functional. The testing scheme is discussed in detail in paragraph 7.2.1.1.9. For the organization for testing and documentation, refer to chapter 13.

Since operation of the RPS will be infrequent, the system is periodically and routinely tested to verify its operability. A complete channel can be individually tested without initiating a reactor trip, without violating the single failure criterion, and without inhibiting the operation of the system. The system can be checked from the sensor signal through the circuit breakers of the RTSS. The RPS can be tested during reactor operation. The sensors can be checked by comparison with similar channels or channels that involve related information. Minimum frequencies for checks, calibration, and testing of the

RPS instrumentation are given in the Technical Specifications. Overlap in the checking and testing is provided to assure that the entire channel is functional. The use of individual trip and ground detection lights, in conjunction with those provided at the supply bus, assures that possible grounds or shorts to another source of voltage will be detected.

7.2.2.4 Failure Modes and Effects Analysis (FMEA)

A FMEA for the RPS and ESFAS is provided in table 7.2-4A. The FMEA is for protection systems' sensors, and coincidence and actuating logics. The logic interface for the protection systems is shown in figure 7.2-11.

7.2.2.4.1 Potential Impacts of Control Systems Failures

Table 7.2-5 identifies the control systems that were considered in the evaluation of potential impacts on plant safety due to common power source or common sensor failures. As discussed below, the consequential malfunctioning of these systems due to a common power/sensor failure has less impact on plant safety than the bounding chapter 15 analyses.

Table 7.2-5

CONTROL SYSTEMS CONSIDERED TO HAVE POTENTIAL IMPACTS UPON PLANT SAFETY DUE TO COMMON POWER SOURCE OR COMMON SENSOR FAILURES

Control System	Acronym
Reactor regulating system	RRS
Control element drive mechanism control system	CEDMCS
Reactor power cutback system	RPCS
Boron control system	BCS
Steam bypass control system	SBCS
Turbine-generator control system	TGCS
Moisture separator reheat control system	MSRCS
Feedwater control system	FWCS
Main feedwater turbine pump control system	MFTPCS
Condenser level control system	CLCS
Pressurizer level control system	PLCS
Pressurizer pressure control system	PPCS

7.2.2.4.1.1 Power Source Failures. The power source failures which would affect more than one control system, and a brief description of the impact on each control system, are provided below. Except for the loss of offsite electrical power, which is specifically addressed by the chapter 15 analyses, no other power failures have been identified which would introduce additional control system malfunctions to those described. This is due to the degree of separation inherent in the

electrical power distribution network and the availability of backup power sources within the network.

7.2.2.4.1.1.1 Impact Due to Loss of 120 V-ac Distribution Panel E-NNN-D11.

SBCS - The control system cannot generate quick open and modulate open signals to open the turbine bypass valves. In addition, control room indication of the automatic permissive signal will be lost.

RPCS - The control system will be unable to generate CEA drop demand and turbine runback signals.

PLCS
PPCS - The letdown control valve closes and the normally running and standby charging pumps will not operate. They can be started manually from BO3. With either HS-100 and/or HS-100-3 in "Y" position, the 1E and non-1E backup heaters and the proportional heaters will trip off.

CEDMCS - Loss of one of two redundant power sources to the interlock relays. Therefore, CEDMCS will not be impacted.

7.2.2.4.1.1.2 Impact Due to Loss of 120 V-ac Distribution Panel E-NNN-D12.

SBCS - Inability to generate an automatic motion inhibit (AMI) signal. In addition, the SBCS

valves will fail closed and cannot be operated in manual due to a loss of logic power.

RRS - Inability to generate CEA motion demand signals. Loss of CEA motion demand indication in the control room

PPCS - The PPCS controller fails to zero causing the pressurizer spray valve to fail close. With either HS-100 and/or HS-100-3 in "X" position, all 1E and non-1E backup heaters and proportional heaters will trip off. With both HS-100 and HS-100-3 in "Y" position, the proportional heaters will turn fully on with no controls, while the 1E and non-1E backup heaters will be fully on with control. PPCS pressure indication on recorder PR100 in the control room goes to 0 psia.

CLCS - Inability to generate condensate storage tank control valve opening signal. The valve will remain in its normally closed state.

CEDMCS - Loss of one of two redundant power sources to the interlock relays. Therefore, CEDMCS will not be impacted.

7.2.2.4.1.1.3 Impact Due to Loss of 125 V-dc Load Center E-NKN-M45.

SBCS - Inability to actuate turbine bypass valve quick open or permissive solenoids. Loss of quick open indication in the control room.

PPCS - All the non-Class 1E backup heaters will
PLCS remain at their previous (on or off) setting. The 1E backup heaters will trip off. Silicon controlled rectifiers of proportional heaters cannot be tripped.

CLCS - Inability to open condensate storage tank control valve due to solenoid deenergization.

MSRCS - Inability to isolate the extraction lines from the high- and low-pressure turbines to the feedwater heaters.

MFTPCS - Inability to automatically trip main feedwater pumps or use pump logic. Manual trip is still available.

Table 7.2-6 identifies the control systems that share a common sensor or instrument tap. No other common sensors/taps have been identified.

Table 7.2-6
CONTROL SYSTEMS SHARING A COMMON SENSOR OR COMMON INSTRUMENT TAP

Sensor	Control Systems[a]
RCS cold leg temperature	CEDMCS, RRS, PLCS
Pressurizer level	PLCS, PPCS
Pressurizer pressure	PPCS, SBCS
Main steam flow	FWCS, SBCS
Sensors Sharing Tap	
Pressurizer level and	PPCS, PLCS
pressurizer pressure	PPCS, SBCS

a. Control system acronyms are defined in table 7.2-5.

7.2.2.4.1.2 Evaluation of Common Failures. As discussed below, the consequences of common power source, common sensor, and common instrument tap failures are bounded by chapter 15.

7.2.2.4.1.2.1 Evaluation of Common Power Source Failures.

A. Panel E-NNN-D11 Failure

The failure of distribution panel E-NNN-D11 will: 1. cause the PLCS and the PPCS to reduce letdown flow to 0 gpm, 2. stop flow from two of the three charging pumps, 3. may result in loss of control of primary system mass, and 4. may cause the 1E and non-1E pressurizer backup and proportional heaters to trip off on loss of pressurizer level control.

All charging pumps remain available if manually started, and the concurrent closing of the letdown control valves ensures primary system mass is controllable within the time frame before operator action. The loss of backup heaters is within the analysis, and they become available in any event upon switching control to the unaffected loop.

The SBCS and RPCS will be unable to automatically respond to any challenges on a failure of distribution panel E-NNN-D11.

This scenario is bounded by the CVCS Malfunction-Pressurizer Level Control System malfunction with loss of offsite power presented in subsection 15.5.2.

B. Panel E-NNN-D12 Failure

The loss of this panel will result in the loss of automatic pressurizer pressure control. However, if HS-100 and HS-100-3 are in the "Y" position, the 1E and non-1E backup heaters will be available. With either hand switch in the "X" position, backup heaters will trip off. Also, when HS-100 and HS-100-3 are in the "Y" position, proportional heaters will turn full on with no control, and with either hand switch in the "X" position, the proportional heaters will trip off. The condenser hotwell level may decrease due to the inability to automatically control it. In addition, the RRS will behave as if it is in manual mode of operation. In addition, the SBCS valves will fail closed and cannot be operated due to a loss of logic power.

The loss of heaters with closure of spray valves is not a concern. Auxiliary spray remains available to control increases in RCS pressure and all heaters will be available if control is switched to the unaffected control loop. With HS-100 or HS-100-3 in the "Y" position, proportional heaters will turn full on with no automatic control, but are still able to be deenergized from the control room. A total loss of feedwater flow (LOFW) due to the condenser hotwell level decrease may occur. However, the LOFW event presented in subsection 15.2.7 assumed that the PPCS, SBCS, and RRS are in the manual mode of operation, unable to automatically respond to challenges.

Therefore, the LOFW event bounds the panel failure event.

C. Load Center E-NKN-M45 Failure

Failure of this load center effectively results in the CLCS and MFTPCS being placed in the manual mode of operation. The SBCS valves will fail closed and cannot be operated in manual due to a loss of logic power. In addition, pressurizer pressure control will be hindered, due to lack of control of all the non-Class 1E heaters. If RCS pressure drifts below the backup heater actuation setpoint the class 1E-powered backup heaters cannot be energized due to the presence of a trip signal. The loss of backup heaters is within the bounds of chapter 15 analyses and is listed in the analyzed failures of table 15.0-0. This panel failure is not of concern with respect to peak RCS pressure, fuel performance, or radiological releases.

7.2.2.4.1.2.2 Evaluation of Common Sensor Failures.

A. RCS Cold Leg Temperature Sensor (CEDMCS, RRS, PLCS)

The PLCS receives an average reactor coolant temperature (T_{avg}) signal from the RRS based on either loop or both loop cold leg and hot leg temperatures (T_{cold} and T_{hot}) measurements. The measured T_{avg} determines the programmed pressurizer level. If a T_{cold} channel fails such that T_{avg} (indicated) does not agree with T_{avg} (actual) then the PLCS will adjust charging

and letdown to change the pressurizer level to the new programmed level within the normal operating band.

The RRS and CEDMCS have several features which protect against inadvertent CEA motion following failure of T_{cold} channel. These include input channel deviation alarm, automatic motion inhibit, and automatic withdrawal prohibit. In addition, the consequences of inadvertent CEA insertion (withdrawal) resulting from indicated T_{cold} failing higher (lower) than actual T_{cold} in combination with pressurizer level variations within the control band are bound by the CEA withdrawal event described in subsection 15.4.2.

B. Pressurizer Level Sensor (PPCS, PLCS)

In response to a high indicated pressurizer level (L_{pzr}) the PLCS will decrease charging flow and increase letdown flow resulting in a slow decrease in RCS inventory and pressurizer level. If the indicated L_{pzr} is high enough, a high level alarm will be generated, the normally running charging pump will be secured, and an insufficient charging alarm will be generated. In addition, if the pressurizer level error L_{pzr} (indicated) - L_{pzr} (programmed) is large enough, the PLCS will signal the PPCS to energize pressurizer heaters. The high indicated L_{pzr} will disable one of two channels of heater cutout. Normally, however, one channel is sufficient to activate the heater interlock and generate a low L_{pzr} alarm. Also, under the

conditions of maximum letdown flow and minimum charging flow, it would require in excess of 30 minutes for pressurizer level to drop from the full power programmed level to the level corresponding to the top of the heaters. This time interval would allow the operator to arrest the level transient prior to heater uncovery.

The thermal-hydraulic effects of the slow decrease in RCS inventory are bounded by the double-ended break of a letdown line as described in subsection 15.6.2.

If the indicated L_{pzr} fails low, the PLCS would increase charging and decrease letdown. This would result in a slow increase in RCS inventory. If the indicated L_{pzr} fails low enough, a low level alarm would be activated, as would the heater interlock in the PPCS, thus preventing pressurizer heater operation. The effects of this transient are bounded by the PLCS malfunction event described in subsection 15.5.2.

C. Pressurizer Pressure Sensor (PPCS, SBCS)

Failure of a pressurizer pressure (P_{pzr}) sensor cannot result in inadvertent operation of the SBCS. The SBCS has two independent circuits (main circuit and permissive circuit) both of which must be activated in order to generate either a turbine bypass valve (TBV) modulation signal or quick open signal. Failure of a P_{pzr} sensor, therefore, can only affect the PPCS. Failures in single control systems have already been considered in the chapter 15 safety evaluation.

D. Main Steam Flow Sensor (FWCS, SBCS)

Similarly, failure of a main steam flow (Fms) sensor cannot result in inadvertent operation of the SBCS. Failure of an Fms sensor, therefore, can only affect the FWCS. Failures in single control systems have been considered in the chapter 15 safety evaluation.

7.2.2.4.1.2.3 Evaluation of Common Instrument Tap Failure: Tap for Pressurizer Pressure and Level Sensors (PPCS, PLCS, SBCS). As previously indicated, the SBCS utilizes two independent circuits; therefore, the SBCS will not open bypass valve due to the instrument tap failure. The response to the tap failure is limited to various combinations of PPCS and PLCS malfunctions which can cause slow pressurizer pressure and level increases or decreases. The evaluation is similar to that provided above for the pressurizer level sensor failure. The potential consequences of this instrument tap failure are bounded by the PLCS malfunction event and the double-ended break of a letdown line event described in subsection 15.5.2 and subsection 15.6.2, respectively.

7.2.3 REACTOR PROTECTIVE SYSTEM INTERFACE REQUIREMENTS

The interface requirements discussed below are specific to the RPS. General interface requirements are discussed in subsection 7.1.3.

7.2.3.1 Power

Vital instrument power interface requirements are discussed in subsection 8.3.1. Power failure evaluations for the control systems are also discussed in paragraph 7.2.2.4.1.

7.2.3.2 Protection From Natural Phenomena

Refer to subsection 3.1.2. Class 1E equipment shall be located so as to be provided with the maximum protection from natural phenomena which are specific to the PVNGS site.

7.2.3.3 Protection From Pipe Failure

Refer to paragraph 7.1.3.3.

7.2.3.4 Missiles

Refer to paragraph 7.1.3.4.

7.2.3.5 Separation

Refer to paragraph 7.1.3.5.

Preamplifiers for the fission chambers shall be mounted outside the biological shield, with two inside the containment building and two outside the containment building in the auxiliary building. The preamplifiers and cabling shall be provided with physical and electrical separation.

7.2.3.6 Independence

Refer to paragraph 7.1.3.6.

7.2.3.7 Thermal Limitations

Refer to paragraph 7.1.3.7.

7.2.3.8 Monitoring

Refer to paragraph 7.1.3.8.

7.2.3.9 Operational/Controls

Administrative procedures or other suitable means shall be used to control changes to CPC constants, adjustments to variable setpoints, and the bypassing of channels which could affect operation.

7.2.3.10 Inspection and Testing

Refer to paragraph 7.1.3.10.

7.2.3.11 Chemistry/Sampling

Refer to paragraph 7.1.3.11.

7.2.3.12 Materials

Not applicable.

7.2.3.13 System Component Arrangement

Refer to paragraph 7.1.3.13. The separation, independence, etc., criteria specified in paragraph 7.2.2.3.2 shall be adhered to.

7.2.3.14 Radiological Waste

Refer to paragraph 7.1.3.14.

7.2.3.15 Overpressure Protection

Refer to paragraph 7.1.3.15.

7.2.3.16 Related Services

Refer to paragraph 7.1.3.16.

7.2.3.17 Environmental

Refer to section 3.11 and CENPD-255.[3]

7.2.3.18 Mechanical Interaction

Refer to section 3.10 and CENPD-182.[4]

7.2.4 REACTOR PROTECTIVE SYSTEM INTERFACE EVALUATION

The interface requirements listed in CESSAR Section 7.2.3 are met by the PVNGS design as discussed in paragraphs 7.2.4.1 through 7.2.4.18.

7.2.4.1 Power

Vital instrument power interface evaluations are discussed in subsection 8.3.5.

7.2.4.2 Protection From Natural Phenomena

Refer to subsection 3.1.2. Class 1E equipment has been located so as to be provided with the maximum protection from natural phenomena which are specific to the PVNGS site.

7.2.4.3 Protection From Pipe Failure

Refer to paragraph 7.1.4.3.

7.2.4.4 Missiles

Refer to paragraph 7.1.4.4.

7.2.4.5 Separation

Refer to paragraph 7.1.4.5.

Preamplifiers for the fission chambers have been mounted outside the biological shield, with two inside the containment building and two outside the containment building in the auxiliary building. The preamplifiers and cabling are provided with physical and electrical separation.

7.2.4.6 Independence

Refer to paragraph 7.1.4.6.

7.2.4.7 Thermal Limitations

Refer to paragraph 7.1.4.7.

7.2.4.8 Monitoring

Refer to paragraph 7.1.4.8.

7.2.4.9 Operational/Controls

Administrative procedures or other suitable means are used to control changes to CPC constants, adjustments to variable setpoints, and the bypassing of channels which could affect operation.

7.2.4.10 Inspection and Testing

Refer to paragraph 7.1.4.10.

7.2.4.11 Chemistry/Sampling

Refer to paragraph 7.1.4.11.

7.2.4.12 Materials

Not applicable.

7.2.4.13 System Component Arrangement

Refer to paragraph 7.1.4.13. The separation, independence, and other criteria specified in paragraph 7.2.2.3.2 have been adhered to in the PVNGS design.

7.2.4.14 Radiological Waste

Refer to paragraph 7.1.4.14.

7.2.4.15 Overpressure Protection

Refer to paragraph 7.1.4.15.

7.2.4.16 Related Services

Refer to paragraph 7.1.4.16.

7.2.4.17 Environmental

Refer to section 3.11.

7.2.4.18 Mechanical Interaction

Refer to section 3.10.

7.2.5 SUPPLEMENTARY PROTECTION SYSTEM

The supplementary protection system (SPS) augments reactor protection by utilizing a separate and diverse trip logic from the reactor protective system (RPS) for initiation of reactor trip to satisy the requirments of 10CFR50.62 for Anticipated Transient Without Scram (ATWS). The addition of the SPS provides a simple, reliable, yet diverse mechanism which is designed to increase the reliability of initiating reactor trip. The SPS will initiate a reactor trip when pressurizer pressure exceeds a predetermined value shown on Table 7.2-1. The SPS logic is shown in Figure 7.2-5.

The SPS design uses a selective two-out-of-four logic to interrupt the power supplied to the CEDM's and thereby causes the CEA's to drop into the core by gravity. The Technical Specifications provide the required actions if a channel is removed for testing or maintenance. The SPS is independent and separate from all control systems.

The SPS is designed to conform to the same criteria as the PPS. Each SPS channel is called the Supplementary Protection Logic Assembly (SPLA).

Four identical SPLA's are provided for each SPS system. Each SPLA is electrically and physically separated from each other.

7.2.5.1 Functional Description of the SPLA

Each SPLA contains an input circuit, comparator circuit, output circuit, test circuit, annunciator circuit, trip circuit breaker (TCB) control and indication circuit, and instrumentation power supplies. See figure 7.2-5.

7.2.5.1.1 Input Circuit

The input circuit receives a 4 to 20 milliampere (ma) "Process Current" signal from its pressurizer pressure transmitter. This signal is converted within the circuit to a (+) 1 to (+) 5 VDC signal via a precision dropping resistor. This "Converted Process" signal is then transmitted via conditioning circuits to the comparator circuit (as the "Process Voltage" signal) for further processing and to the digital voltmeter for displays. A second dropping resistor in the input circuit provides a (+) 1 to (+) 5 VDC "Process Indication" signal to a remote display indicator.

The input circuit also receives a 0 to (+) 5 VDC "Test" signal from the test circuit. The "Test" signal, when applied, adds a 0 to (+) 5 VDC signal to the "Converted Process" signal.

The input circuit contains conditioning circuits for overvoltage protection and noise suppression. The purpose of the overvoltage protection circuit is to protect the equipment downstream of the input circuit from damage due to a high voltage fault on the transmitter field cabling. The purpose of the noise suppression circuit is to filter out unwanted noise picked up during "Process Current" signal transmission.

7.2.5.1.2 Comparator Circuit

The comparator circuit continuously compares the 1 to 5 VDC "Process Voltage" signal to a fixed trip setpoint signal. When the "Process Voltage" signal passes through the trip setpoint level, the comparator circuit recognizes this and generates a trip output signal.

The trip signal derived from the comparator circuitry must be present for a specified period of time before it is allowed to pass through to the output circuit. When the trip signal has been present for the required period of time (adjustable from 10-150 msec), the time delay circuit recognizes this and provides the trip signal to the initiation relay drive circuit.

Upon receipt of a trip signal, the initiation relay drive circuit de-energizes the output circuit's initiation relay. When a trip signal is not present, the drive circuit maintains the initiation relay energized. A front panel tripped indicator is provided and receives its logic from the initiation relay drive circuit.

7.2.5.1.3 Output Circuit

The output circuit provides the necessary contact switching to affect the opening of a remotely located trip circuit breaker (TCB) and M-G set load output contactors.

The output circuit receives a trip signal from the comparator circuit's initiation relay drive circuit. This signal controls the application and removal of initiation relay input power. During normal operation, the initiation relay is energized and its contacts maintain the TCB and M-G set load output contactors closed. For a trip condition, the initiation relay is deenergized and its contacts change state to affect opening of the TCB and M-G set load output contactors.

The initiation relay provides two contacts which interface with the TCB undervoltage and shunt trip coils. This contact interface controls TCB opening. A third contact provided by

the initiation relay interfaces via an isolation relay with each of the M-G set load output contactors. These contact interfaces provide for opening the M-G set load output contactors upon a selective two-out-of-four SPLA channel trips. An open signal by this contact also indirectly results in a signal to the remote annunciator. The annunciator serves to inform the operator of a SPLA "trip" condition.

7.2.5.1.4 Trip Circuit Breaker (TCB) Control and Indication Circuit

This circuit provides a signal to control the closing of a remotely located trip circuit breaker. In addition, this circuit receives "OPEN" and "CLOSED" position indication signals from this same trip circuit breaker. These position indication signals are used to light indicators mounted on the front panel.

The TCB closing signal is a contact closure provided by a momentary switch. This switch is located on the front panel. Closing the switch contacts completes the TCB closing coil control circuit. Completing the TCB closing coil control circuit affects closure of the breaker.

This circuit receives two contact input position indication signals from TCB auxiliary switches. These indication signals are used to energize "OPEN" and "CLOSED" indicators on the front panel. An indicator is energized when a contact closure input is received from its respective auxiliary switch. Power to the indicators and auxiliary switch is supplied by the SPLA.

7.2.5.1.5 Test Circuit

The purpose of the test circuit is to provide the capability for testing the SPLA. Testing of the SPLA is performed to verify its proper operation.

Testing of the SPLA is accomplished by applying a 0 to 5 vdc "Test" signal to the input circuit. The "Test" signal is applied in such a way that it is added to the 1 to 5 vdc "Converted Process" signal. The "Test" signal is manually adjusted until the "Process Voltage" signal reaches the trip setpoint value. Upon reaching the trip setpoint value, the trip circuit breaker associated with the SPLA opens.

The test circuit is comprised of a voltage reference, a voltage adjust circuit, a test enable switch, a digital voltmeter (DVM), and a DVM input select switch. The voltage adjust circuit, in conjunction with the voltage reference, generates the "Test" signal. The test enable switch applies the "Test" signal to the Input Circuit. The DVM indicates the value of the "Converted Process," "Test" signal, calibration voltages, setpoint value, or external input.

7.2.5.1.6 Annunciator Circuit

The annunciator circuit provides the circuitry necessary for interfacing SPLA status signals with remote annunciators.

Three status signals are generated within the SPLA. Only two of the status signals are supplied to the annunciator circuit.

The annunciator circuit receives one status signal from the SPLA door alarm switch and one status signal from the test enable switch.

The third status signal is generated indirectly by the output circuit and is termed the "Trip" status signal. This status signal directly interfaces with its remote annunciator and therefore is not supplied by the annunciator circuit.

7.2.5.1.7 Instrumentation Power Supplies

The power supplies contain the equipment required for powering all SPLA equipment including the pressurizer pressure transmitter.

7.2.5.1.8 SPLA Test Points

The front panel has the following test jacks available for external measurement: 1) voltage reference, 2) time delay input, 3) time delay output, and 4) test jacks for each of the supply voltages provided. Also available for measurement via test jacks in the SPLA are the following: 1) the setpoint voltage value, and 2) the process input voltage value.

7.2.5.2 Supplementary Protection System (SPS) Diversity to the Reactor Protective System (RPS)

The supplementary protection logic assembly (SPLA) of the SPS is designed to be a diverse design with respect to the RPS. The following design differences between the systems outline these qualities:

Each of the SPLA circuits is described below:

A. Manufacturing Diversity - Different vendors were used which produced a (1) different design, (2) different

system production techniques, and (3) different testing procedures.

B. System Part Diversity - The vendor used different Components than the RPS, and MIL spec parts whenever possible.

C. Cabinet Diversity - The SPLA uses one cabinet per channel (4 channel system).

D. Electrical Diversity - Each SPLA channel is electrically isolated and separated from the others. There is no crosschannel communication between SPLA channels.

E. Initiation Logic Diversity - The RPS and SPLA utilize different designs for initiation logic.

F. Sensor Diversity – The sensors (pressure transmitters) used in the RPS and SPLA are produced by the same manufacturer. Both systems monitor the pressurizer pressure via a common tap per channel in the pressurizer. The instruments have separate shutoff valves and a common root valve per channel.

10CFR50.62 requires that each pressurized water reactor must have equipment from sensor output to final actuation device that is diverse from the reactor trip system. Based on this requirement, lack of diversity between the sensors is satisfactory, since the equipment from the sensor output to the actuation devices in the SPLA is diverse from that of the RPS.

G. Power Supply Diversity - The SPLA uses a custom power supply while the RPS uses a commonly available "off-the-shelf" power supply.

H. Human Factors Diversity - 1) smaller SPLA cabinet, 2) each SPLA channel is in its own cabinet, 3) front panel controls are in different locations and are much fewer in the SPLA, 4) adjustment controls for the test and setpoint voltages are different, and 5) the SPLA front panel has fewer test points than the RPS system.

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7.3 ENGINEERED SAFETY FEATURE SYSTEMS

7.3.1 DESCRIPTION

BOP ESFAS. The following actuation signals are generated by the BOP Engineered Safety Feature Actuation System (ESFAS) when the monitored variables reach levels that require protective action:

- Fuel building essential ventilation actuation signal (FBEVAS)
- Containment purge isolation actuation signal (CPIAS)
- Control room essential filtration actuation signal (CREFAS)
- Control room ventilation isolation actuation signal (CRVIAS)

These actuation signals automatically actuate the following ESF systems:

- Fuel building essential ventilation system
- Containment purge isolation system
- Control room essential ventilation system

The control room essential ventilation system is also actuated by a manually initiated ESF signal, the control room ventilation isolation actuation signal (CRVIAS).

The manually actuated ESF systems are the containment combustible gas control system and the CRVIAS.

The BOP ESFAS system hardware and software also provides load sequencing and logic for the diesel generator start signal (DGSS), loss of power (LOP), and load shed (LS) functions. These functions are described in section 8.3.

The additional automatically actuated ESF systems use one-out-of-two input signal logic. The actuation circuits for all one-out-of-two actuation systems are described in paragraph 7.3.1.1. The actuated devices for these systems are described in paragraph 7.3.1.1.10.

NSSS ESFAS. The safety-related instrumentation and controls of the Engineered Safety Features Systems (ESF Systems) are those of the NSSS and BOP Engineered Safety Features Actuation System (ESFAS) which consists of the electrical and mechanical devices and circuitry, from sensors to actuation device input terminals, involved in generating those signals that actuate the required ESF Systems.

The NSSS ESFAS includes sensors to monitor selected generating station variables. The following actuation signals use a two-out-of-four logic system and are generated by the NSSS ESFAS when the monitored variable reaches the levels that are indicative of conditions which require protective action:

A. Containment Isolation Actuation Signal (CIAS)

B. Containment Spray Actuation Signal (CSAS)

C. Main Steam Isolation Signal (MSIS)

D. Safety Injection Actuation Signal (SIAS)

E. Recirculation Actuation Signal (RAS)

F. Auxiliary Feedwater Actuation Signal (AFAS)

The ESF System actuation device circuitry receives actuation signals from the ESFAS or the operator. The ESFAS signals actuate the ESF Systems equipment. The control circuitry for the components provides sequencing necessary to provide proper ESF Systems operation.

The actuation circuitry for all ESF Systems is essentially identical, except for the sensed parameter and its setpoint. Therefore, the actuation circuits for all ESF Systems are described in one section. The specific instrumentation and controls associated with each system are described separately in section 7.3.1.1.10.

7.3.1.1 NSSS Engineered Safety Features Actuation System (ESFAS)

The ESFAS system consists of the sensors, bistables, initiation logic, and actuation logic that monitor selected plant parameters and provide an actuation signal to each individual actuated component in the ESF system if the plant parameters reach preselected setpoints. There is one actuation system for each of the ESF systems. Each actuation system is identical except that specific inputs and logic (and blocks, where provided) vary from system to system and the actuated devices are different.

Within the PPS, the matrix logic is like that shown in figures 7.3-9a, 7.3-9b and 7.3-9c. This provides the AB, AC, AD, BC, BD, and CD combinations which create the coincidence of

two logic. Each of these matrices operates an initiation circuit which opens the initiation relays. The outputs of the initiation relays go to the ESFAS auxiliary relay cabinets where they create the selective two-out-of-four logics, i.e., 1A/2A, 1A/4A, 3A/2A, or 3A/4A for the given train shown in figures 7.3-8a and 7.3-8b.

Only those ESF systems that, when actuated, do not cause a plant condition requiring protective action, or disturb reactor operations, are controlled by the one-out-of-two BOP ESFAS. The one-out-of-two BOP ESFAS logic is contained in the separate enclosures isolated from the two-out-of-four ESFAS and reactor protective system (RPS) logic. The overall logic is shown in figures 7.3-1, 7.3-2, 7.3-7a through 7.3-7d.

7.3.1.1.1 Engineered Safety Features Actuation System Measurement Channels

BOP ESFAS. Process measurement channels are used to perform the following functions:

- Continuously monitor each selected generating station variable
- Provide indication of operational availability of each sensor to the operator.
- Transmit signals to bistables within the BOP ESFAS initiating logic.

Protective parameters are measured with two independent process measurement channels.

A measurement channel consists of instrument sensing lines, sensor, transmitter, power supplies, isolation device, indicator, and interconnecting wiring. For the radiation measurement channels description see section 11.5.

Each measurement channel is separated from other like measurement channels to provide physical and electrical isolation of the signals to the ESFAS initiating logic. The isolation devices will prevent a high voltage fault to either the A or B sensor outputs from disabling both of the one-out-of-two actuation logic devices. Signal isolation is provided for computer inputs and annunciation. Each BOP ESFAS channel is supplied by two sources from a separate 120V vital ac distribution bus and its associated 125 VDC vital ESFAS.

Display information, which provides the operator with the operational availability of each measurement channel, is described and tabulated in section 7.5.

Testing of the BOP and NSSS ESFAS measurement channels is described in paragraph 7.3.1.1.8.

NSSS ESFAS. Process measurement channels, similar to those described in section 7.2.1.1.2.1 are utilized to perform continuous monitoring of each selected generating station variable, provide indication of operational availability of each sensor to the operator, and transmit analog signals to bistables within the ESFAS initiating logic. All protective parameters are measured with four independent process instrument channels.

A typical measurement channel is shown in Figure 7.2-0A. It consists of a sensor/transmitter, current loop resistors, converter/power supply, indicators, outputs for the Plant Monitoring System, and interconnecting wiring.

Each measurement channel is separated from other like measurement channels to provide physical and electrical separation of the signals to the ESFAS coincidence logic. Associated circuits are handled in accordance with the interface requirements of Section 7.3.3. Cabling is separated within the cabinets and signals to non-IE indicators are isolated. Each channel is supplied from a separate 120 volt vital AC distribution bus.

7.3.1.1.2 Logic

7.3.1.1.2.1 Engineered Safety Features Actuation System Bistable and Initiating Logic.

BOP ESFAS. The Balance of Plant Engineered Safety Features Actuation System (BOP ESFAS) provides initiation signals to components requiring automatic or manual actuation. These signals are generated whenever monitored variables reach levels that require protective action.

The BOP ESFAS uses two measurement channels for the one-out-of-two logic and four measurement channels for the two-out-of-four logic as inputs to the initiation signal.

The ESFAS initiating logic consists of bistables, bistable output relays, trip output signals, indicating lights, and

interconnecting wiring. For the radiation measurement signal initiation logic description, see section 11.5.

Signals from the protective measurement channels are sent to comparator circuits (bistables) where the input signals are compared to predetermined setpoints. Whenever a channel parameter reaches the predetermined setpoint, the channel bistable deenergizes an output relay. When the coincidence logic is satisfied an actuation signal is provided to the appropriate components. Each bistable relay (i.e., each channel) is supplied from a separate 120V vital ac distribution bus. The bistable setpoints are adjustable from the front of the cabinet. Access is limited, however, by means of a key-operated switch. Bistable setpoints are capable of being read out on a display located on the cabinet.

NSSS ESFAS Bistable and Coincidence Logic. The ESFAS Coincidence Logic compares the analog signal from the sensors with predetermined initiation setpoints in the bistable circuit (see Figure 7.2-6). If the signal exceeds the setpoint the channel bistable output relay deenergizes three trip relays.

The setpoint values are controlled administratively. The setpoints are adjusted at the PPS cabinet. Access to the adjustments is limited by means of a key-operated cover with an annunciator indicating cabinet access. The bistable setpoints are capable of being read out on a meter located on the PPS cabinet. Some setpoints are externally variable to avoid inadvertent initiation during normal operations such as startup, shutdown, and cooldown, and evolutions such as low

power testing. The steam generator and pressurizer pressure setpoints can be decreased by pushbuttons and will automatically increase as pressure increases.

The output of the trip relays is formed into the six logic matrices (refer to Figure 7.3-10). The four channels, A, B, C, and D, form into AB, AC, AD, BC, BD, and CD to create all possible coincidence of two combinations. Each logic matrix actuates four matrix relays. Six matrix relays (one from each of the six logic matrices) have their output contacts joined in series to form an initiation circuit. Four initiation circuits are used to form four channels 1, 2, 3, and 4. The output of the initiation circuits are initiation relays, A and B which send signals to the actuation logics in their respective ESF train cabinet.

Besides the automatic actuation of the initiation circuit by the matrix relays, the circuit can be tripped by remote manual switches. All ESFAS can be manually initiated by the operator in accordance with procedures provided by the Applicant. Following initiation, each ESFAS, except AFAS, must be manually reset to restore the initiation logic to the non-actuated state.

7.3.1.1.2.2 Actuating Logic.

NSSS ESFAS. The ESFAS actuation logic is physically located in two ESFAS auxiliary relay cabinets. One cabinet contains the logic for ESF train A equipment the other cabinet contains the logic for ESF train B.

The four initiation circuits in the PPS actuate a selective two-out-of-four logic in the ESFAS auxiliary relay cabinets. In an actuation matrix (see figures 7.3-8a and 7.3-8b), each signal also deenergizes the lockout relays when the selective two-out-of-four logic actuates the train's group actuation relays. The lockout relays ensure that the signal is not automatically reset once it has been initiated.

Receipt of two selective ESFAS initiation channel signals will deenergize the ESF subgroup relays, which generate the actuation channel signals. This is done independently in both ESFAS auxiliary relay cabinets, generating both train A and train B signals. The group relays are used to actuate the individual ESF components which should be actuated to mitigate the consequences of the occurrence which caused the ESFAS.

<u>BOP ESFAS</u>. The BOP ESFAS actuating logic, however performs the following functions:

- Receive ESFAS signals from the ESFAS initiating logic
- Form one-out-of-two coincidence of like ESFAS signals
- Provide a means for remote manual initiation
- Provide status information to the operator

The BOP ESFAS actuating logic is physically located in two cabinets. One cabinet contains the logic for ESF load group 1 equipment, while the other cabinet contains the logic for ESF load group 2 equipment. These two cabinets are in addition to those ESFAS auxiliary relay cabinets described above.

Actuation signals are generated following receipt of the proper combination of initiation signals, resulting in de-energizing the appropriate ESF group relay. This actuates all components required by the particular ESF system. The final actuation devices are the sub-group relays and the actuated equipment consists of valves, air handling units (AHU), air filtration units (AFU), large electrical loads as listed in section 8.3, and diesel generators.

Each actuation channel is supplied from a separate 120 V-ac distribution bus and a separate Class 1E 125 V-dc distribution bus.

Figure 7.3-3 is a simplified functional diagram of a typical one-out-of-two ESFAS logic.

Testing of logic and trip is described in paragraph 7.3.1.1.8.

7.3.1.1.2.2.1 Group Actuation.

BOP ESFAS. Components in each ESF system are actuated by actuation relays. The actuation relay contacts are in the power control circuit for the actuated components of each ESF system.

The logic described in paragraph 7.3.1.1.2 causes deenergization of the actuation relay whenever the BOP ESFAS logic is satisfied. The circuit is shown in figure 7.3-3 for a typical ESFAS. Deenergization of the actuation relay actuates the ESF system components.

NSSS ESFAS. The group relays actuate all of the ESF System components required by the ESFAS. These generally consist of either solenoid operated valves, motor operated valves, or motors of pumps. Figures 7.3-11a, b and c show how each of these components can be operated by the ESFAS signals.

In Figure 7.3-11a, a solenoid operated valve can be operated by a relay contact. If the valve control switch contact is closed and the ESFAS contact is closed the solenoid valve will open. In the circuit shown in Figure 7.3-11a, the ESFAS signal opens the contact which closes the valve.

The valve motor circuit of Figure 7.3-11b shows the valve closed. When an ESFAS actuating signal is reset, the ESFAS contact in the closing circuit is closed and the contact in the opening circuit is open, thereby restoring normal operation. Upon receipt of an ESFAS signal the valve which is normally closed would open in the following sequence. The Mc_b contact and the Ts and Ls Contacts in the Mo circuit are closed because the valve is fully closed. The ESFAS contact would close causing the Mo coil to pick up which shuts the Mo contactors driving open the valve.

The pump motor control circuit shown in Figure 7.3-11c shows that the ESFAS actuation signal will take out the time overcurrent contacts (numbered 51) but leaves in the instantaneous overcurrent contacts (numbered 50). With the circuit breaker lockout relay (numbered 86) contact closed and the ESFAS contact closed the pump motor breakers will close if

the control switch is in the automatic position. Thus an ESFAS actuation signal will cause the pump motor to start.

If components have to be sequenced the sequencing will be done in the components' control circuit. Sequencing is described in section 7.3.1.1.7.

7.3.1.1.3 Bypasses

7.3.1.1.3.1 Channel Bypasses.

BOP ESFAS. Trip channel bypasses are provided in the one-out-of-two ESFAS as shown in table 7.3-1. The trip channel bypass is similar to the RPS trip channel bypass (Section 7.2.1.1.5) and is employed to remove a trip channel from service for maintenance.

The trip logic is thus converted to a single active channel for the trip type bypassed. Other type trips that do not have bypasses in either of their two channels remain in a one-out-of-two logic. The bypass time interval for maintenance is so short that the probability of failure of the remaining channel is acceptably low during maintenance bypass periods. The bypass is manually initiated and manually removed. An electrical interlock allows only one channel for any one type trip to be bypassed at one time. Bypasses are annunciated visually and audibly to the operator.

In some cases, bypass of more than one parameter within a channel may be required in the event of an equipment failure. Specific requirements are provided in the Technical Specifications.

NSSS ESFAS. For two-out-of-four logic bypass capability, refer to section 7.2.1.1.5.

Bypasses are provided, in the PPS, as shown in table 7.3-1c. The trip channel bypass is identical to the RPS trip channel bypass (section 7.2.1.1.5) and is employed for maintenance and testing of channel.

7.3.1.1.3.2 Operating Bypasses

BOP ESFAS. For the one-out-of-two logic, there are no operating bypasses.

NSSS ESFAS. The low pressurizer pressure bypass as shown in figure 7.3-7a, is provided to allow plant depressurization without initiating protective actions when not desired. The bypass may be initiated manually in each protective channel. However, the bypass cannot be initiated if pressurizer pressure is greater than that shown in table 7.3-1c. Once the bypass is initiated, it is automatically removed when the pressurizer pressure increases above the value shown in the table.

Table 7.3-1
ONE-OUT-OF-TWO ESFAS BYPASSES

Title	Function	Initiated By	Removed By
Trip Channel Bypass[a]	Disables any given trip channel	Manually by controlled access switch	Same switch

a. Interlocks allow only one channel for any type trip to be bypassed at one time.

7.3.1.1.3.3 DAFAS Bypasses. The key-lock bypasses shown in table 7.3-1A are provided in the auxiliary relay cabinets for maintenance and test purposes. The bypasses function to block actuation of the DAFAS-1 or DAFAS-2 initiation relays in trip legs 1-3 and 2-4. There are no interlocks associated with the bypass functions other than a separate key-lock switch for each bypass. There are two key-lock bypasses for DAFAS-1 and DAFAS-2, one each for trip legs 1-3 and 2-4 in the auxiliary relay cabinet bay 5 and bay 8. The bypasses are indicated locally on the ARC status indicator assemblies, located within the ARC. The bypasses are also installed and removed by the MMI (man machine interface) automated test programs when each DAFAS PLC is placed in test by control of a key-locked test switch and the appropriate password protected automated test program command is given.

Table 7.3-1A
DAFAS BYPASSES

TITLE	FUNCTION	INITIATED BY	REMOVED BY
DADAS-1 OR DAFAS-2	DISABLE TRIP LEG 1 – 3 OR 2 – 4	DAFAS-1 OR DAFAS-2 BYPASS SWITCH IN BAY 5 OR BAY 8 OF ARC OR MMI AUTO TEST	BYPASS SWITCH OR TEST SWITCH

7.3.1.1.4 Interlocks

BOP ESFAS. The one-out-of-two ESFAS interlocks prevent the operator from bypassing more than one trip channel for one type trip at a time. Different type trips may be bypassed simultaneously, either in the same channel or in different channels.

NSSS ESFAS. The ESFAS interlocks, located in the PPS, prevent the operator from bypassing more than one trip channel of a trip parameter at a time. Different trip parameters may be bypassed simultaneously, either in the same channel or in different channels. This function is shown in figure 7.2-9.

During system testing an electrical interlock prevents more than one set of four matrix relays from being held at one time. The same circuit will allow only one process measurement loop signal to be perturbed at a time for testing. The matrix relay hold and loop perturbation switches are interlocked so that only one or the other may be used at any one time.

7.3.1.1.5 Redundancy

BOP ESFAS. Redundant features of the one-out-of-two ESFAS include:

A. Two independent channels, from process sensor/transmitter through and including bistable output relays, are provided.

B. Two trip paths are present for each actuation signal.

C. Each actuation signal actuates two output trains so that redundant system components may be actuated from separate trains.

D. Power for the system is provided from two separate buses. Power for control and operation of redundant actuated components comes from separate buses. Load group 1 components and systems are energized only by the load group 1 bus and load group 2 components and systems are energized only by the load group 2 bus.

E. Power to each BOP ESFAS division is provided from a vital AC source (PN) and a vital DC source (PK) to redundant power supplies that are auctioneered.

The result of the redundant features is a system that meets the single failure criterion and can be tested during plant operation.

NSSS ESFAS. There are many redundant features within the ESFAS. There are four independent channels for each parameter from process sensor through and including the initiation circuits located in four PPS bays. There are six logic

matrices, to actuate the initiation circuits, each of which has two power supplies for the four logic relays of each matrix.

In the ESFAS Auxiliary Relay Cabinets the selective two-out-of-four logic matrix has two power supplies per leg. Each Auxiliary Relay Cabinet controls one ESF System train and there are two totally redundant Auxiliary Relay Cabinets used to operate two totally redundant ESF trains.

Overall, the entire ESFAS receives vital AC power from four separate buses and the power for control and operation of separate trains comes from separate buses.

The result is a system which meets the single failure criterion, can be tested during operation and shifted to two-out-of-three logic, when a channel is removed for testing or maintenance without affecting system availability.

7.3.1.1.6 Diversity

BOP ESFAS. The one-out-of-two ESFAS is designed to eliminate credible dual channel failures originating from a common cause. The failure modes of redundant channels and the conditions of operation that are common to them are analyzed to ensure reasonable assurance that:

A. The monitored variables provide adequate information during the accidents.

B. The equipment can perform as required.

C. The interactions of protective actions, control actions, and the environmental changes that cause, or are caused

by, the design basis events do not prevent the mitigation of the consequences of the event.

D. The system cannot be made inoperable by the inadvertent actions of operating and maintenance personnel.

In addition, the design is not encumbered with additional components or channels without reasonable assurance that such additions are beneficial.

NSSS ESFAS. The system is designed to eliminate credible multiple channel failures originating from a common cause. The failure modes of redundant channels and the conditions of operation that are common to them are analyzed to assure that a predictable common failure mode does not exist.

The design provides reasonable assurance that the protective system cannot be made inoperable by the inadvertent actions of operating or maintenance personnel. The design is not encumbered with additional channels or components without reasonable assurance that such additions are beneficial.

7.3.1.1.7 Sequencing

There is no sequencing for any ESF equipment other than that necessary for ESF bus loading. The automatic load sequencer is discussed in paragraph 8.3.1.1.3.

7.3.1.1.8 Testing

Provisions are made to permit periodic testing of the BOP and NSSS ESFAS. These tests cover the trip actions from sensor input through the protection system and the actuation devices.

The system test does not interfere with the protective function of the system. The testing system meets the criteria of IEEE Standard 338-1971 and Regulatory Guide 1.22. Testing criteria is presented in Section 7.3.2.3.3. For the testing of the radiation measurement channels, see section 11.5 and the ODCM.

For the two-out-of-four ESFAS overlap between individual tests exist so that the entire ESFAS can be tested.

Testing of the BOP ESFAS load sequencer functions is discussed in section 8.3.1.1.3.10.1.

Since actuation of the ESF systems controlled by the BOP ESFAS does not disturb normal plant operating conditions, the one-out-of-two ESFAS is tested by complete actuation. Frequency of accomplishing the tests is listed in the Technical Specifications.

7.3.1.1.8.1 Sensor Checks. During reactor operation, the measurement channels providing an input to the BOP and NSSS ESFAS are checked by comparing the outputs of similar channels, and by cross-checking with related measurements.

During extended shutdown periods or refueling, these measurement channels are checked and calibrated against known standards.

7.3.1.1.8.2 Trip Bistable Test.

BOP ESFAS. Testing of the system is accomplished by manually varying the input signal to the trip setpoint level on one bistable at a time and observing the trip action.

When the bistable of a protective channel is in a tripped condition, the following conditions should exist:

- The bistable output relay is deenergized.
- The group relay in each actuation channel is deenergized.
- The ESF components are in the ESFAS actuation position.
- Actuation is annunciated on the control room annunciator panel.

Proper operation may be verified by the following:

- Checking the position of each ESF component
- Checking the actuation annunciation
- Checking the ESF component status indication

The test is repeated for the other bistable.

NSSS ESFAS. Testing of a trip bistable, located in the PPS, is accomplished by manually varying a simulated process input signal locally on the PPS Bistable Control Panel. This signal is increased, or decreased, until the trip setpoint is reached and the trip action is observed (See Figure 7.2-6).

Varying the simulated input signal is accomplished by means of a trip test circuit which consists of a digital voltmeter and a test circuit which can change the magnitude of the signal supplied by the measurement channel. The trip test circuit is electrically interlocked so that it can be used in only one channel at a time (See Figure 7.2-9). A switch selects the

measurement channel and a pushbutton applies the test signal. The digital voltmeter indicates the test signal value. The test circuit permits various rates of change of signal input to be used. Trip action of each of the bistable trip relays is indicated by individual lights on the front of the cabinet (See Figure 7.2-7), indicating that the contacts of these relays, which are located in the coincidence of two logic matrices, operated as required for a trip condition.

The variable setpoint test is accomplished by manually varying a simulated process input signal. Upon decreasing this input, the setpoint is verified to remain constant and the trip setpoint is within specified tolerances. By manually decreasing this input, and then depressing the setpoint reset button, the setpoint incremental change can be tested and verified. The tracking ability of the circuit can be tested by manually increasing the test input and observing that the setpoint tracks.

When one of the bistables of a protective channel is in the tripped condition, a channel trip exists and is annunciated on the control room annunciator panel. In this condition, an actuation would take place upon receipt of a trip signal in one of the other three like channels. The trip channel under test is, therefore, bypassed for this test converting the ESFAS to a two-out-of-three logic which is still a coincidence of two for the particular trip parameter.

7.3.1.1.8.3 Logic Matrix Tests. This PPS logic test is carried out to verify proper operation of the six coincidence

logic matrices, located in the PPS, any one of which will initiate a system actuation for any possible coincidence of two trip condition from the signal inputs of each measurement channel. The test circuits are shown in Figures 7.2-8 and 7.2-7.

The system is interlocked so that only one logic matrix set (i.e., all AB or all AC, etc.) can be held at a time as discussed in CESSAR Section 7.3.1.1.4. Rotating the switch to the "Hold" position will apply a test voltage to the test system hold coils of the double coil matrix relays in their energized position. The deactuation of the trip relay contacts in the matrix ladder being tested caused deenergization of the primary matrix relay coils (see Figure 7.2-7).

The logic matrix to be tested is selected using the System Channel Trip Select Switch. By holding the matrix hold switch in the "trip" position and rotating the System Channel Trip Select Switch through each of its positions, the trip relays in the logic matrix will be deenergized. The System Channel Trip Select Switch applies a test voltage of the opposite polarity to the bistable trip relay test coils so that the magnetic flux generated by these coils cancels that of the primary coil causing the relays to release.

Trip action can be observed by illumination of the trip relay indication located on the front panel and by loss of voltage to the four matrix relays, which is indicated by loss of illumination of the indicator lights connected across each matrix relay coil. During the test the matrix relay hold

lights will remain on, indicating that a test voltage has been applied to the holding coils of the matrix relays of the logic matrix under test.

This test is repeated for each actuation signal, by use of the System Channel Trip Select Switch, and for all six logic matrices. This test will verify that the logic matrix relays will deenergize if the logic matrix continuity is interrupted.

7.3.1.1.8.4 Initiation Channel Tests. Each initiation circuit, in the PPS, is tested individually by rotating a matrix hold switch to the "trip" position (holding four matrix relays), selecting any trip position on the System Trip Select Switch and selecting a matrix relay on the Matrix Relay Trip Select Switch (see Figure 7.2-11). This causes the appropriate initiation circuit to deenergize. Proper operation of both initiation relay coils and contacts is verified by monitoring the current through the appropriate leg of the actuation logics selected two-out-of-four circuit.

The matrix Relay Trip Select Switch is turned to the next position, re-energizing the test matrix relay and permitting the reset of the initiation circuit relays. The whole sequence is repeated for the remaining three initiation circuits from the selected matrix. The entire sequence is repeated for the remaining five matrices. Upon completion of testing, all six matrices, all 24 matrix relay contacts, and all eight initiation relays have been tested.

In addition, the remote manual switches for the initiation circuits can be tested. The indication of proper manual initiation will be the same as for automatic initiation. Only one switch is used at a time.

7.3.1.1.8.5 ESFAS Actuation Logic Test. This test verifies the proper operation of the ESFAS actuating logic circuits (refer to Figure 7.3-8a). The selective two-out-of-four logic circuit, located in the ESFAS Auxiliary Relay Cabinets, of each ESFAS train is tested in a manner identical to the RPS trip breaker system. (See Section 7.2.1.1.9.5). One current leg of the selective two-out-of-four logic matrix is interrupted by opening one of the current legs contacts and loss of current in that current leg is verified. Each contact in both current legs is checked in this manner.

The lockout contacts are checked via the group relay test system as described below and the PPS initiation relay contacts are checked as described in the preceding section.

7.3.1.1.8.6 ESFAS Actuating Device Test. Proper operation of the ESFAS group relays, in the ESFAS Auxiliary Relay Cabinets, is verified by deenergizing the group relays one at a time via a test relay contact (See Figure 7.3-8a) and noting proper operation of all actuated components in that group. The relay will automatically reenergize and return its components to the pretest condition when the test keylock pushbutton is removed from the test position.

The design of the test system is such that only one group relay may be deenergized at a time. The test switch must be positioned to the group to be tested; selection of more than one group is impossible. The test circuit is electrically locked out upon actuation of a particular test group and another test group cannot be actuated for one minute after selecting another switch position. This time delay is a "stop and think" feature to assist the operator in conducting tests.

Since this test causes the ESF components to actuate by interrupting the normal safety signal current leg to individual group relays, the propagation of a valid trip during test is not impeded and the system will proceed to full actuation by interrupting the current leg to all group relays.

7.3.1.1.8.7 Bypass Tests. System bypasses in the PPS, as itemized in Table 7.2-2, are tested on a channel basis using internally generated test signals. This testing includes both manual initiation and automatic removal features.

7.3.1.1.8.8 Response Time Tests. The design of the ESFAS is such that connections may be made for any of a variety of methods. The hardware design includes test connections on instrument lines for pressure and differential pressure transmitters, and test points wired out to convenient test jacks or terminal strips.

Response time testing required at refueling intervals are given in the Technical Specifications. These tests include the sensors for each ESFAS channel and are based on the criteria

defined in paragraph 7.3.2.3.3. The ESF response time limits are identified in table 7.3-1B.

7.3.1.1.9 Vital Instrument Power Supply

The vital instrument power supply for the ESFAS is described in chapter 8.

7.3.1.1.10 Actuated Systems

The ESF Systems are maintained in a standby mode during normal operations. Actuating signals, generated by the ESFAS are provided to assure that the ESF Systems provide the required protective actions. The following descriptions of the instrumentation and controls of the ESF Systems is applicable to each ESF System. Table 7.3-2 presents the Design Basis Events (DBE) which require specific ESF System action. Table 7.3-3 presents the monitored variables required for ESF System actuation. The variables and their ranges are shown on Table 7.3-3a.

7.3.1.1.10.1 Containment Isolation System. Section 6.2.4 contains a description of the Containment Isolation System. The actuation system is composed of redundant trains A and B. The instrumentation and controls of the two trains are physically and electrically separate and independent as discussed above such that the loss of one train will not impair the safety function.

The Containment Isolation System instrumentation and controls are designed for operation during all phases of plant operation as required by the Technical Specifications.

The Containment Isolation System is automatically actuated by a CIAS from the ESFAS.

A. See table 6.2.4-2 for a list of devices actuated on a containment isolation actuation signal (CIAS).

B. Figure 7.3-7B, ESFAS signal logic (CIAS).

C. Figure 6.2.4-1, containment penetration valve arrangements.

D. Figure 7.2-2, instrumentation location layout drawing for CIAS input services.

Removal of the containment isolation system from service is controlled by plant procedures.

Table 7.3-1B
ENGINEERED SAFETY FEATURES RESPONSE TIMES
(Sheet 1 of 3)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual	
a. SIAS	
Safety Injection (ECCS)	Not Applicable
Containment Isolation	Not Applicable
Containment Purge Valve Isolation	Not Applicable
b. CSAS	
Containment Spray	Not Applicable
c. CIAS	
Containment Isolation	Not Applicable
d. MSIS	
Main Steam Isolation	Not Applicable
e. RAS	
Containment Sump Recirculation	Not Applicable
f. AFAS	
Auxiliary Feedwater Pumps	Not Applicable
2. Pressurizer Pressure - Low	
a. Safety Injection (HPSI)	≤ 30[(a)]/30[(b)]
b. Safety Injection (LPSI)	≤ 30[(a)]/30[(b)]
c. Containment Isolation	
1. CIAS actuated mini-purge valves	≤ 10.6[(a)]/10.6[(b)]
2. Radwaste Drain System Inside CIV RDA-UV023	≤ 59[(a)]/59[(b)]
3. Other CIAS actuated valves	≤ 31[(a)]/31[(b)]
d. Safety Injection (Control Room Normal HVAC Isolation Dampers[(e)])	≤ 51[(a)]/51[(b)]
3. Containment Pressure - High	
a. Safety Injection (HPSI)	≤ 30[(a)]/30[(b)]
b. Safety Injection (LPSI)	≤ 30[(a)]/30[(b)]

Table 7.3-1B
ENGINEERED SAFETY FEATURES RESPONSE TIMES
(Sheet 2 of 3)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
c. Containment Isolation	
1. CIAS actuated mini-purge valves	≤ 10.6[(a)]/10.6[(b)]
2. Radwaste Drain System Inside CIV RDA-UV023	≤ 59[(a)]/59[(b)]
3. Other CIAS actuated valves	≤ 31[(a)]/31[(b)]
d. Safety Injection (Control Room Normal HVAC Isolation Dampers[(e)])	≤ 51[(a)]/51[(b)]
e. Main Steam Isolation	
1. MSIS actuated MSIV's	≤ 5.6[(a)]/5.6[(b)]
2. MSIS actuated MFIV's[(c)]	≤ 10.6[(a)]/10.6[(b)]
f. Containment Spray Pump	≤ 33[(a)]/23[(b)]
4. Containment Pressure - High-High	
a. Containment Spray	≤ 33[(a)]/23[(b)]
5. Steam Generator Pressure – Low	
a. Main Steam Isolation	
1. MSIS actuated MSIV's	≤ 5.6[(a)]/5.6[(b)]
2. MSIS actuated MFIV's[(c)]	≤ 10.6[(a)]/10.6[(b)]
6. Refueling Water Tank – Low	
a. Containment Sump Recirculation	≤ 45[(a)]/45[(b)]
7. Steam Generator Level – Low	
a. Auxiliary Feedwater (Motor Drive)	≤ 46[(a)]/23[(b)]
b. Auxiliary Feedwater (Turbine Drive)	≤ 46[(a)]/46[(b)]
8. Steam Generator Level – High	
a. Main Steam Isolation	
1. MSIS actuated MSIV's	≤ 5.6[(a)(f)]/5.6[(b)(f)]
2. MSIS actuated MFIV's(c)	≤ 10.6[(a)(f)]/10.6[(b)(f)]

Table 7.3-1B
ENGINEERED SAFETY FEATURES RESPONSE TIMES
(Sheet 3 of 3)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
9. Steam Generator ΔP-High-Coincident with Steam Generator Level Low	
a. Auxiliary Feedwater Isolation From the Ruptured Steam Generator	≤ 16[(a)]/16[(b)]
10. Control Room Essential Filtration Actuation	≤ 50[(a)(d)]/50[(b)(d)]
a. Control Room Normal HVAC Isolation Dampers	
11. 4.16 kV Emergency Bus Degraded Voltage	
LOP	≤ 35.0
12. 4.16 kV Emergency Bus Loss of Voltage	
LOP	≤ 2.4

TABLE NOTATIONS

a. Diesel generator starting and sequence loading delays included. Response time limit includes movement of valves and attainment of pump or blower discharge pressure.

b. Diesel generator starting delays not included. Offsite power available. Response time limit includes movement of valves and attainment of pump or blower discharge pressure.

c. MFIV valves tested at simulated operating conditions; valves tested at static flow conditions to ≤ 8.6[(a)]/8.6[(b)] seconds.

d. Radiation detectors are exempt from response time testing. The response time of the radiation signal portion of the channel shall be measured from the detector output or from the input of first electronic component in channel to closure of dampers M-HJA-M01, M-HA-M52, M-HJB-M01 and M-HJB-M55.

e. Dampers M-HJA-M01, M-HJA-M52, M-HJB-M01, and M-HJB-M55.

f. For Mode 3 operation, the Palo Verde Safety Analyses do not credit Main Steam Isolation due to a Steam Generator Level - High initiating signal. A 15 second response time was selected to comply with Palo Verde Technical Specification Surveillance Requirement 3.3.5.4 and Table 3.3.5-1.

TABLE 7.3-1C

NSSS ESFAS BYPASSES

Title	Function	Initiated By	Removed By	Notes
Trip Channel Bypass	Disables any given trip channel	Manually by controlled access switch	Same switch	Interlocks allow one channel for any type trip to be bypassed at one time.
Pressurizer Pressure Bypass	Disables low pressurizer pressure portion of SIAS/CIAS*	Manual switch (1 per channel) If pressure is $<$ 400 psia	Automatic if pressurizer pressure is $\geq$ 500 psia	

* SIAS/CIAS actuation due to high containment pressure not affected.

Table 7.3-2
DESIGN BASIS EVENTS REQUIRING ESF SYSTEM ACTION (Sheet 1 of 2)

Design Basis Events / Systems	Containment Isolation System	Containment Spray System	Main Steam Isolation System	Safety Injection System	Auxiliary Feedwater System (f)	Fuel Building Essential Ventilation System	Containment Purge Isolation System	Control Room essential Ventation System	Containment Combustible Gas Control System
Loss of reactor coolant -- large break	*	*		*		*(e)	*(c)	*	*(b)
Loss of reactor coolant -- small break.(a)	*	*		*	*	*(e)	*(c)	*	*(b)
Steam generator tube rupture			*(b)	*	*				
Steam line break (inside containment)	*	*	*	*	*				
Steam line break (outside containment) (d)			*	*	*				

a. Includes CEA ejection and pressurizer safety valve opening

b. Manual actuation

c. Actuated by initiation of CPIAS or CIAS

d. Includes opening of secondary safety valve

e. On SIAS the fuel building essential ventilation system starts and is aligned to exhaust from the auxiliary building

f. Design basis event not defined for an ATWS event

Table 7.3-2
DESIGN BASIS EVENTS REQUIRING ESF SYSTEM ACTION (Sheet 2 of 2)

Systems / Design Basis Events	Containment Isolation System	Containment Spray System	Main Steam Isolation System	Safety Injection System	Auxiliary Feedwater System	Fuel Building Essential Ventilation System	Containment Purge Isolation System	Control Room Essential Ventilation System	Containment Combustible Gas Control System
Fuel handling accident - - containment building							*	*	
Fuel handling accident - - spent fuel pool						*		*	
Feedwater line break (inside containment)	*	*	*	*					
Fire/smoke – plant vicinity								* (b)	
Letdown line Break (15.6.2)								* (b)	

Table 7.3-3
MONITORED VARIABLES FOR ESF SYSTEM
PROTECTIVE ACTION (Sheet 1 of 2)

Variable \ Systems	Containment Isolation System	Containment Spray System	Main Steam Isolation System	Safety Injection System	Auxiliary Feedwater System (f)	Fuel Building Essential Ventilation System	Containment Purge Isolation System	Control Room Essential Ventilation System	Containment Combustible Gas Control System
Pressurizer pressure	*			*		* (e)	* (b)	* (c)	
Containment pressure	*	*	*	*		* (e)	* (b)	* (c)	
Steam generator pressure			*		*				
Refueling water tank level		*		*					
Steam generator level			*		* (f)				

a. Manual actuation post-LOCA

b. Actuated by initiation of CRVIAS or CIAS

c. Actuated by initiation of CREFAS or SIAS

d. Manual actuation - detectors are nonsafety-related

e. Actuated by initiation of SIAS, system aligned to exhaust from the auxiliary building

f. Steam generator level is also used to initiate an ATWS DAFAS actuation if diverse scram system is present and normal ESFAS has not initiated AFAS or MSIS.

ENGINEERED SAFETY

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Table 7.3-3

MONITORED VARIABLES FOR ESF SYSTEM
PROTECTIVE ACTION (Sheet 2 of 2)

Variable \ Systems	Containment Isolation System	Containment Spray System	Main Steam Isolation System	Safety Injection System	Auxiliary Feedwater System	Fuel Building Essential Ventilation System	Containment Purge Isolation System	Control Room Essential Ventilation System	Containment Combustible Gas Control System
Containment airborne activity							*	*	
Fuel handling airborne activity						*		*	
Control room ventilation intake activity								*	
Control room ventilation intake smoke								*(d)	
Containment hydrogen									*

Table 7.3-3a
ENGINEERED SAFETY FEATURES
ACTUATION SYSTEM PLANT VARIABLE RANGES

Monitored Variable	Minimum	Typical Full Power	Maximum
Pressurizer Pressure	0 psia	2250 psia	3000 psia
Containment Pressure	-4 psig	0 psig	20 psig
Steam Generator Pressure	0 psia	1039 psia	1524 psia
Refueling Water Tank Level	0	81.2-98% (Note 1)	100%
Steam Generator Level	0%	82%	100%

Note 1: Technical Specification minimum required RWT level to high level alarm (Mode 1-4 limits).

7.3.1.1.10.2 Containment Spray System. Refer to Section 6 for a description of the containment spray system, and:

A. Table 6.2.4-2 for a list of devices actuated on a containment spray actuation signal (CSAS) and recirculation actuation signal (RAS).

B. Table 7.3-4 for additional CSAS actuated devices.

C. Table 7.3-5 for additional RAS actuated devices.

D. Figure 7.3-7b, ESFAS signal logic (CSAS and RAS).

E. P&I diagram 01, 02, 03-M-SIP-001,-002 and -003(safety injection system)

F. Figure 7.2-2 and Engineering drawing 13-J-ZYF-009, instrumentation location layout drawing for CSAS and RAS input devices.

G. Subsection 6.5.2 for a discussion of iodine removal capabilities of the CSS.

Table 7.3-4
CONTAINMENT SPRAY ACTUATION SIGNAL
ACTUATED DEVICES LIST

P&ID	Description	Function
01, 02, 03-M-DGP-001	Diesel Generator System	Refer to Paragraph 7.4.1.1.1
01, 02, 03-M-SIP-001, -002 and -003	Containment spray pumps and pump room cooling unit (2)	Start

Table 7.3-5
RECIRCULATION ACTUATION SIGNAL
ACTUATED DEVICES LIST

P&ID	Description	Function
01, 02, 03-M-SIP-001, -002 and -003	Low pressure safety injection pumps (2)	Stop
01, 02, 03-M-SIP-001, -002 and -003	LPSI pump miniflow valves (2)	Close
01, 02, 03-M-SIP-001, -002 and -003	HPSI pump miniflow valves (2)	Close
01, 02, 03-M-SIP-001, -002 and -003	Containment spray miniflow valves (2)	Close
01, 02, 03-M-SIP-001, -002 and -003	Combined SI miniflow return to RWT valves (2)	Close

Removal of the containment spray system from service is controlled by plant procedures.

7.3.1.1.10.3 IODINE REMOVAL SYSTEM(Abandoned in Place)

7.3.1.1.10.4 Main Steam Isolation System. Refer to Section 10.3, "Main Steam Supply System," for a description of the Main Steam Isolation System. Refer to Section 10.4.7, "Condensate and Feedwater System," for a description of the Main Feedwater Isolation System. Refer to Section 10.4.8, "Steam Generator Blowdown System," for a description of the Blowdown Isolation System. Interface requirements for the Main Steam Isolation System are provided in Section 5.1.4.

The actuation system is composed of redundant trains A and B. The instrumentation and controls of the train A valve actuators are physically and electrically separate and independent of the instrumentation and control of the train B valve actuators.

The separation and independence are such that a failure of one train will not impair the protective action.

The Main Steam Isolation Valves (MSIV), Main Feedwater Isolation Valves (MFIV) and the isolation valves for the blowdown lines are actuated by an MSIS.

These valves effectively isolate the steam generators from the rest of the main steam and feed systems.

A variable steam generator pressure setpoint is implemented to allow controlled pressure reductions, such as shutdown depressurization, without initiating an MSIS. The pressure setpoint will track the pressure up until it reaches its normal setpoint value. Also, refer to figures and tables listed below:

A. Table 6.2.4-2 for a list of devices actuated on a main steam isolation signal (MSIS)

B. Figure 7.3-7c, ESFAS signal logic (MSIS)

C. P&I diagram 01, 02, 03-M-SGP-002 and –001 (main steam system)

D. Figures 7.2-2 and 7.2-3, instrumentation location layout drawing for MSIS input devices

7.3.1.1.10.5 <u>Safety Injection System</u>. Refer to Section 6.3, "Emergency Core Cooling System," for a description of the Safety Injection System (SIS). The SIS is actuated by an SIAS. Interface requirements for the Safety Injection System are provided in Section 6.3.1.3.

The actuation system is composed of redundant trains A and B. The instrumentation and controls of train A are physically and electrically separate and independent of instrumentation and controls in train B. Since each train is a 100% capacity system the SIS can sustain the loss of an entire train and still provide its required protective action. The SIS instrumentation and controls are designed to operate under all plant conditions. The low pressurizer pressure setpoint can be decreased as described in section 7.2.1.1.1.6 to avoid inadvertent operation during startup and shutdown. As pressurizer pressure increases, the setpoint will follow up to its normal value. Also refer to figures and tables listed below:

A. Table 6.2.4-2 for a list of devices actuated on a safety injection actuation signal (SIAS)

B. Table 7.3-6 for additional SIAS actuated devices

C. Figure 7.3-7a, ESFAS signal logic (SIAS)

D. P&I diagram 01, 02, 03-M-SIP-001, -002 and -003 (safety injection system)

E. Figures 7.2-1 and 7.2-2, instrumentation location layout drawing for SIAS input devices

In addition, the procedure for removing the safety injection system from service is controlled by plant procedures.

7.3.1.1.10.6 Recirculation Actuation. An RAS is generated when the level in the RWT falls below a predetermined level. When an RAS is received the LPSI pumps are stopped and the HPSI

and CSS pumps shift suction to the containment recirculation sump. Refer to Section 7.3.1.1.10.2 for references applicable to the recirculation actuation signal.

In addition, removing a RAS from the LPSI pumps to allow them to be used for the shutdown cooling system is controlled by plant procedures.

7.3.1.1.10.7 Auxiliary Feedwater System. Interface requirements are provided in section 5.1.4.

The AFWS is actuated by an AFAS. The instrumentation and controls of train A are physically and electrically separate and independent of the instrumentation and controls of train B. Thus, if a single failure prevents actuation of one train the other train will still receive an actuation signal.

The AFAS signal latches the pumps in either the manual or automatic mode and will cycle the valves on the steam generator level signals.

The Seismic Category I portion of the auxiliary feedwater system is provided to automatically initiate residual heat removal capability during emergency conditions such as a steam line rupture, loss of normal feedwater, or loss of offsite and normal onsite power. The non-Seismic Category I portion of the auxiliary feedwater system is provided for normal nonemergency operation during startup, cooldown, and hot standby. The non-Seismic Category I portion of the auxiliary feedwater system is not an engineered safety feature system and, therefore, is not addressed in this section. Subsequent references in this

section to the auxiliary feedwater system apply to the Seismic Category I portions only. The Seismic Category I portion of the auxiliary feedwater system is described in subsection 10.4.9.

Table 7.3-6
SAFETY INJECTION ACTUATION SIGNAL ACTUATED
DEVICES LIST (Sheet 1 of 2)

P&ID	Description	Function
01, 02, 03-M-SIP-001 -002 -003	SI tanks No. 1 through 4 fill and sample isolation valves (4)	Close
01, 02, 03-M-SIP-001 -002 -003	SI tanks No. 1 through 4 check valve leakage line isolation valves (4)	Close
01, 02, 03-M-SIP-001 -002 -003	HPSI pumps and pump room essential cooling units (2)	Start
01, 02, 03-M-SIP-001 -002 -003	LPSI pumps and pump room essential cooling units (2)	Start
01, 02, 03-M-SIP-001 -002 -003	CS pumps and pump room essential cooling units (2)	Start
01, 02, 03-M-SIP-001 -002 -003	SI tanks No. 1 through 4 isolation valves (4)	Open
01, 02, 03-M-CHP-001, 002 -003, -004 and -005	Letdown line isolation valve (1)	Close
01, 02, 03-M-IAP-001 and -002	Hot leg injection check valve leak isolation valve (2)	Close
01, 02, 03-M-NCP-001, -002 and -003	Essential cooling water system and pump room essential cooling units	Refer to paragraph 7.4.1.1.5
01, 02, 03-M-SPP-001	Essential spray pond system	Refer to paragraph 7.4.1.1.1
01, 02, 03-M-DGP-001	Diesel generator system	Refer to paragraph 7.4.1.1.1
01, 02, 03-M-HJP-001, -002 and 03-M-HJP-003	Control room essential filtration system	Refer to table 7.3-9 and paragraph 7.3.1.1.10.10
01, 02, 03-M-TCP-001, -002 and -003	Condensate transfer system	Refer to subsection 9.2.6

Table 7.3-6
SAFETY INJECTION ACTUATION SIGNAL ACTUATED DEVICES LIST (Sheet 2 of 2)

Figure No.	Description	Function
01, 02, 03-M-PWP-001	Essential chilled water system	Start
01, 02, 03-M-ECP-001	Normal chilled water system	Stop
01, 02, 03-M-HFP-001	Fuel building essential ventilation system	Refer to paragraph 9.4.5.2
01, 02, 03-M-HTP-001	Containment normal reactor cavity cooling units (4)	Stop
01, 02, 03-M-HTP-001	Containment normal cooling unit (4)	Stop
01, 02, 03-M-HTP-001	Containment CEDM cooling unit (2)	Stop
01, 02, 03-M-HAP-001, -002, -003 and -004	Elect penetration room ESS Acu (2)	Start
	PZR backup heaters (6)	Trip
	480V MCC incoming feeders (4)	Trip
	Essential lighting panel (2)	Trip
01, 02, 03-M-AFP-001	Non safety related Aux Feedwater pump	Stop

The safety-related display instrumentation for the auxiliary feedwater system, which provides the operator with sufficient information to monitor and perform the required safety features, is described in section 7.5.

Further information on the actuation system is provided by the following:

A. Table 6.2.4-2 for a list of valves actuated on an AFAS

B. Table 7.3-7 for additional AFAS actuated devices.

C. FSAR figure 7.4-4, ESFAS signal logic

D. P&I diagram 01, 02, 03-M-AFP-001

E. Figure 7.2-2, instrumentation location layout drawing for AFAS input devices

7.3.1.1.10.8 Fuel Building Essential Ventilation Systems. Radioactive contamination may occur in the spent fuel area in the unlikely event that a spent fuel element is severely damaged during handling. If a fuel handling accident occurs, sensors in the fuel building detect the fission products released from the fuel and initiate appropriate action, as discussed in section 9.4, to reduce the release of fission products into the environment.

Table 7.3-7
AUXILIARY FEEDWATER ACTUATION SIGNAL
ACTUATED DEVICES LIST (Sheet 1 of 2)

P&ID	Description	Function
01, 02, 03-M-AFP-001	Seismic Category I motor-driven auxiliary feedwater pump and pump room cooling unit (1)	Start
01, 02, 03-M-AFP-001	Seismic Category I steam turbine driven auxiliary feedwater pump and pump room cooling unit (1)	Start (b)
01, 02, 03-M-AFP-001	Auxiliary feedwater regulating valves SG1 (2)	(a)
01, 02, 03-M-AFP-001	Auxiliary feedwater regulating valves SG2 (2)	(a)
01, 02, 03-M-AFP-001	Auxiliary feedwater isolation valves SG1 (2)	(c)
01, 02, 03-M-AFP-001	Auxiliary feedwater isolation valves SG2 (2)	(c)
01, 02, 03-M-DGP-001	Diesel generator system	Refer to paragraph 7.4.1.1
01, 02, 03-M-NCP-001, -002 and -003	Essential cooling water system	Refer to paragraph 9.2.2

a. Cycles open and close to intact steam generator.

b. SGA-UV134 and SGA-UV134A; steam supply valves from steam generator No. 1 to the turbine-driven AFS pump, both open on either an AFAS-1 or AFAS-2.

SGA-UV138 and SGA-UV138A; steam supply valves from steam generator No. 2 to the turbine-driven AFS pump, both open on either an AFAS-1 or AFAS-2.

c. Isolates damaged steam generator and allows flow to undamaged steam generator.

Table 7.3-7
AUXILIARY FEEDWATER ACTUATION SIGNAL
ACTUATED DEVICES LIST (Sheet 2 of 2)

P&ID	Description	Function
01, 02, 03-M-PWP-001	Essential chilled water system	Refer to paragraph 9.2.9
01, 02, 03-M-SCP-004	Steam generator blowdown isolation valves (4)	Close

The fuel building essential ventilation system, as described in section 9.4, is composed of components in redundant load groups, load group 1 and load group 2. The instrumentation and controls of the components and equipment in load group 1 are physically and electrically separate and independent of the instrumentation and controls of the components and equipment in load group 2. Independence is adequate to retain the redundancy required to maintain equipment functional capability following those design basis events shown in table 7.3-2 that require fuel building ventilation isolation.

The fuel building essential ventilation system is automatically actuated by a FBEVAS from the ESFAS. The FBEVAS is initiated by one-out-of-two high airborne activity signals from radiation monitors, one of which is a gaseous monitor in the fuel building normal exhaust duct, and the other of which is an area radiation monitor on a wall overlooking the fuel pool. The system is designed so that loss of electric power to one-out-of-two electronic remote indication and control units or to the actuating logic actuates the fuel building essential ventilation system.

Manual initiation of the fuel building essential ventilation system is provided in the control room.

The safety-related display instrumentation for the fuel building essential ventilation system, which provides the operator with sufficient information to monitor and perform the required safety functions, is described in section 7.5. Further information on the actuation system is provided by the following:

A. Table 7.3-8(A), fuel building essential ventilation actuation signal actuated devices list during FBEVAS

B. Table 7.3-8(B), fuel building/auxiliary building essential ventilation actuated devices list during SIAS

C. Figure 7.3-1, ESFAS signal logic (FBEVAS)

D. P&I diagram 01, 02, 03-M-HFP-001 (fuel building HVAC)

E. Section 12.3, instrument location layout drawing for FBEVAS input devices

The FBEVAS is combined with the SIAS in the device control circuits so that any one of the signals (logical OR) activate the devices listed in table 7.3-8B. During SIAS operation, the fuel building/auxiliary building essential ventilation system is aligned to exhaust from the auxiliary building. The SIAS signal takes precedence over FBEVAS should both signals be present at the same time.

Table 7.3-8
FUEL BUILDING ESSENTIAL VENTILATION
ACTUATION SIGNAL ACTUATED DEVICES LIST
(P&ID 01, 02, 03-M-HFP-001)

Description	Function
A. DURING FBEVAS	
Fuel building normal supply dampers (4)	Close
Fuel building normal supply AHU	Stop
Fuel building normal exhaust dampers (4)	Close
Fuel building normal exhaust fans (2)	Stop
Fuel building exhaust to fuel building/auxiliary building essential AFU isolation dampers (2)	Open
Fuel building/auxiliary building essential exhaust AFU (2)	Start
Auxiliary building exhaust to fuel building/auxiliary building essential exhaust AFU isolation dampers (2)	Close
B. DURING SIAS	
Fuel building exhaust to fuel building/auxiliary building essential exhaust AFU iso-lation dampers (2)	Close
Fuel building/auxiliary building essential exhaust AFU (2)	Start
Auxiliary building exhaust to fuel building/auxiliary building essential exhaust AFU isolation dampers (2)	Open

7.3.1.1.10.9 Containment Purge Isolation System. Radioactive contamination may occur in the containment building in the event that a spent fuel element is severely damaged during handling. The containment purge isolation system detects abnormal amounts of radioactive material in the containment building and initiates appropriate action to prohibit the release of radioactive material into the environment. Refer to section 9.4 for a description of the containment purge isolation system.

The containment purge isolation system is composed of components in redundant load groups, load group 1 and load group 2. Instrumentation and controls of the components and equipment in load group 1 are physically and electrically separate and independent of instrumentation and controls of the components and equipment in load group 2. Independence is adequate to retain the redundancy required to maintain equipment functional capability following those design basis events shown in table 7.3-2 that are mitigated by the containment purge isolation system.

The containment purge isolation system is automatically actuated by the CPIAS from the ESFAS. CPIAS is initiated by one-out-of-two high airborne activity signals from two redundant radiation monitors located in close proximity to the power access purge exhaust duct and the refueling purge exhaust duct. The monitors are identified as the "PAPA-A" and "PAPA-B" monitors.

The system is designed so that loss of electric power to one-out-of-two electronic remote indication and control units or to the actuating logic actuates the containment purge isolation system.

The CPIAS is combined with the CIAS in the control circuits of the isolation valving common to both the containment purge isolation system and the containment isolation system so that either signal (logical OR) can actuate these valves. Figure 7.3-4 presents a typical control logic for these valves.

The safety-related display instrumentation for the containment purge isolation system that provides the operator with sufficient information to monitor and perform the required safety functions is described in section 7.5.

Further information on the actuation system is provided by the following:

A. Table 6.2.4-2 for a list of devices actuated on a CPIAS

B. Figure 7.3-1, ESFAS signal logic (CPIAS)

C. P&I diagram 01, 02, 03-M-HTP-001 (containment purge system)

D. Section 12.3, instrument location layout drawing for CPIAS input devices

7.3.1.1.10.10 Control Room Essential Ventilation Systems.

The control room essential ventilation systems are the control room ventilation isolation system and the control room essential filtration system.

Upon detection of a high airborne activity signal in the normal air intake, the control room essential filtration system is actuated. Both control room essential ventilation systems, as discussed in section 6.4, are composed of components in redundant load groups, load group 1 and load group 2. Instrumentation and controls of the components and equipment in load group 1 are physically and electrically separate and independent of instrumentation and controls of the components and equipment in load group 2. Independence is adequate to retain the redundancy required to maintain control room habitability following those design basis events shown in table 7.3-2.

The control room essential filtration system is automatically actuated by a CREFAS. The CREFAS is initiated by one-out-of-two air intake high airborne activity signals, a FBEVAS, or a CPIAS as shown in figure 7.3-2. The CPIAS is discussed in paragraph 7.3.1.1.10.9. The FBEVAS is discussed in paragraph 7.3.1.1.10.8. The system is designed so that loss of electrical power to one-out-of-two electronic remote indication and control units or to the actuating logic actuates the control room essential filtration system.

The CREFAS is combined with the SIAS in the device control circuits so that any one of the signals (logical OR) actuates

the devices listed in table 7.3-9. The development of the SIAS is discussed in CESSAR Section 7.3.2.2.1. Figure 7.3-5 presents a typical control logic to show the combination of these signals.

In addition to the automatic initiating signals, two independent smoke detectors are provided in the outside air intake plenum.

Upon detection of smoke, an audible and visible alarm will alert the operator to manually initiate the control room ventilation isolation system.

Manual initiation of the control room ventilation isolation system and the control room essential filtration system is provided in the control room.

The safety-related display instrumentation for the control room essential ventilation systems, which provides the operator with sufficient information to monitor and perform the required safety functions, is described in section 7.5.

Further information on the actuation system is provided by the following:

A. Table 7.3-9, Control Room Essential Filtration Actuation Signal Actuated Devices List

B. Table 7.3-10, Control Room Ventilation Isolation Actuation Signal Actuated Devices List

C. Figure 7.3-2, ESFAS signal logic (CREFAS and CRVIAS)

D. P&I diagram 01, 03-M-HJP-001, -002 and 02-M-HJP-001, -002 and -003 (control building HVAC)

7.3.1.1.10.11 Containment Combustible Gas Control System. The containment hydrogen gas concentration may increase to a combustible concentration following a LOCA. In the unlikely event that a LOCA does occur, the containment hydrogen gas concentration is maintained less than the lower combustible limit by operation of the containment combustible gas control system.

The containment combustible gas control system, as described in subsection 6.2.5, is composed of components in redundant load groups, load group 1 and load group 2. Instrumentation and controls of components and equipment in load group 1 are physically and electrically separate and independent of instrumentation and controls of components and equipment in load group 2. Independence is adequate to retain the redundancy required to maintain equipment functional capability following those design basis events in table 7.3-2 that are mitigated by the containment combustible gas control system.

The containment combustible gas control system components are controlled manually from control switches located at local panels. The local panel(s) will be accessible after a design basis accident (DBA).

The safety-related display instrumentation for the combustible gas control system that provides the operator with sufficient information to monitor and perform the required safety functions is described in section 7.5.

Table 7.3-9
CONTROL ROOM ESSENTIAL FILTRATION ACTUATION SIGNAL
ACTUATED DEVICES LIST

P&ID	Description	Function
01, 03-M-HJP-001, -002, 02-M-HJP-001, -002 & -003	Outside air smoke exhaust makeup dampers (2)	Close
01, 03-M-HJP-001, -002, 02-M-HJP-001, -002 & -003	Normal exhaust isolation dampers (6)	Close
01, 03-M-HJP-001, -002, 02-M-HJP-001, -002 & -003	Normal HVAC unit discharge isolation dampers (2)	Close
01, 03-M-HJP-001, -002, 02-M-HJP-001, -002 & -003	Normal recirculation isolation dampers (2)	Close
01, 03-M-HJP-001, -002, 02-M-HJP-001, -002 & -003	Essential supply duct dampers (4)	Open
01, 03-M-HJP-001, -002, 02-M-HJP-001, -002 & -003	Essential HVAC units (2)	Start
01, 03-M-HJP-001, -002, 02-M-HJP-001, -002 & -003	Normal supply unit	Stop
01, 03-M-HJP-001, -002, 02-M-HJP-001, -002 & -003	Communication room inlet dampers (2)	Close
01, 03-M-HJP-001, -002, 02-M-HJP-001, -002 & -003	Communication room outlet dampers (2)	Close
01, 02, 03-M-TCP-001, -002 and -003	Condensate transfer system	Refer to paragraph 9.2.6
01, 02, 03-M-SPP-001	Essential spray pond system	Refer to paragraph 7.4.1.1.4
01, 02, 03-M-NCP-001 -002 and -003	Essential cooling water system	Refer to paragraph 7.4.1.1.5
01, 02, 03-M-PWP-001	Essential chilled water system	Refer to paragraph 9.2-9
01, 02, 03-M-HAP-001 -002, -003 and -004	Essential cooling water pump rooms cooling units (2)	Start
01, 02, 03-M-HAP-001, -002, -003 and -004	Essential cooling water pump rooms isolation dampers (8)	Close

Table 7.3-10
CONTROL ROOM VENTILATION ISOLATION ACTUATION SIGNAL
ACTUATED DEVICES LIST

P&ID	Description	Function
01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003	Normal HVAC unit discharge isolation dampers (2)	Close
01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003	Outside air smoke exhaust makeup dampers (2)	Close
01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003	Normal exhaust isolation dampers (6)	Close
01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003	Normal recirculation isolation dampers (2)	Close
01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003	Essential supply duct dampers (4)	Close
01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003	Essential HVAC units (2)	Start
01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003	Normal supply unit	Stop
01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003	Communication room inlet dampers (2)	Close
01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003	Communication room outlet dampers (2)	Close
01, 02, 03-M-TCP-001, -002 and -003	Condensate transfer system	Refer to paragraph 9.2.6
01, 02, 03-M-SPP-001	Essential spray pond system	Refer to paragraph 7.4.1.1.4
01, 02, 03-M-NCP-001, -002 and -003	Essential cooling water system	Refer to paragraph 7.4.1.1.5
01, 02, 03-M-PWP-001	Essential chilled water system	Refer to paragraph 9.2-9
01, 02, 03-M-HAP-001, -002, -003 and –004	Essential cooling water pump rooms cooling units (2)	Start
01, 02, 03-M-HAP-001, -002, -003 and –004	Essential cooling water pump rooms isolation dampers (8)	Close

The principal parameter monitored, for determining when the containment combustible gas control system is to be placed in service, is hydrogen. The containment hydrogen analyzer is not normally in service; however, following a DBA, the hydrogen analyzer is placed in service with controls mounted in the main control room.

A control switch with an override feature is provided for each of the containment combustible gas control system isolation valves. This control switch override feature is functional only after receipt of the CIAS, and permits control of each valve independent of the CIAS. The open and closed positions of these valves, in addition to the override status, are indicated in the control room. A typical logic diagram showing implementation of the override signal is shown in figure 7.3-6.

The containment combustible gas control system test pressure is greater than the peak containment design pressure. This precludes system overpressurization by the inadvertent opening of the isolation valves.

Further information on the system is provided by the following:

A. Table 7.3-11, Containment Combustible Gas Control System Actuated Devices List

B. P&I diagram 01, 02, 03-M-HPP-001 (containment combustible gas control system)

7.3.1.2 Design Basis Information

BOP ESFAS. The actuation setpoints are given in table 7.3-12. The design bases for the additional one-out-of-two ESFAS are as follows.

The one-out-of-two ESFAS is designed to provide initiating signals for components that require automatic actuation following a DBA.

The systems are designed on the following bases to ensure adequate performance of their protective functions:

A. The system is designed in compliance with the applicable criteria of Appendix A of 10CFR50, 1971.

B. System testing conforms to the requirements of IEEE Standard 338-1971 and Regulatory Guide 1.22.

C. IEEE 279-1971 establishes specific protection system design bases. The following paragraphs describe how the design bases listed in Section 3 of IEEE 279-1971 are implemented.

   1. The additional generating station condition that requires protective action is:

      a. Fuel handling accident

      b. Fire/smoke-plant vicinity

   2. The system is designed to monitor the following additional parameters in order to provide protective actions:

      a. Containment radiation/airborne activity

   b. Fuel building radiation/airborne activity

   c. Control room air intake activity

   d. Control room air intake smoke

3. The number and location of the sensors required to monitor the variables listed in sublisting C.2 above are contained in table 7.3-13A.

4. The normal operation limits for each variable are provided in table 7.3-12.

5. The margin between the operation limits and actuation setpoints are provided in table 7.3-12.

6. The actuation setpoints are provided in table 7.3-12.

Table 7.3-11
CONTAINMENT COMBUSTIBLE GAS CONTROL SYSTEM ACTUATED DEVICES LIST

P&ID	Description	Relation to Containment	Function
01, 02, 03-M-HPP-001	Containment combustible gas control hydrogen purge exhaust air filtration unit heater (1)	Outside	Start[a]
01, 02, 03-M-HPP-001	Containment combustible gas control hydrogen purge exhaust air filtration unit inlet (2)	Outside	Open[a]
01, 02, 03-M-HPP-001	Containment combustible gas control system inlet isolation valves (2)	Inside	Open[b]
01, 02, 03-M-HPP-001	Containment combustible gas control recombiner and hydrogen purge air filteration unit inlet isolation valves (2)	Outside	Open[b]
01, 02, 03-M-HPP-001	Containment combustible gas control recombiner outlet isolation valves (2)	Outside	Open[b]
01, 02, 03-M-HPP-001	Containment combustible gas control analyzer valves (4)	Outside	Open[a]
01, 02, 03-M-HPP-001	Containment hydrogen recombiners (2)	Outside	Start[a]

a. Manually actuated

b. CIAS overridden

Table 7.3-11A

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM SETPOINTS AND MARGINS TO ACTUATION

Actuation Signal	Typical Full Power	Normal Operation Range	Trip Setpoint	Margin to Actuation
SIAS & CIAS				
Low pressurizer pressure	2,250 psia	2,100-2,350 psia	≥ 1,837 psia[a]	263 psi
High containment pressure	0 psig	0 psig	≤ 3 psig	3 psi
CSAS				
High-High containment pressure	0 psig	0 psig	≤ 8.5 psig	8.5 psi
RAS				
Low refueling water tank level	--	81.2-98%[h]	9.4% of span	71.8%
MSIS				
Low steam generator pressure	1039 psia	1010-1170 psia	960 psia[d]	79 psi
High containment pressure	0 psig	0 psig	≤ 3 psig	3 psi
High steam generator level	55%	30-74%	≤ 91% NR[e]	17%
AFAS				
Low steam generator level and	82%	72-90%	≥ 25.8% WR[f]	46.2
Steam generator differential pressure[b]	0 psid	0 psid	≤ 185 psid	185 psi
DAFAS				
Low steam generator level[c]	82%	72-90%	20.3%	51.7
LOP				
4.16 kV Emergency Bus Loss of Voltage	4160 V		[g]	
4.16 kV Emergency Bus Degraded voltage	4160 V		3744 V	

a. In MODES 3-4, the value may be decreased manually, to a minimum of 100 psia, as pressurizer pressure is reduced, provided:

(a) the margin between the pressurizer pressure and this value is maintained at less than or equal to 400 psi; and

(b) when the RCS cold leg temperature is greater than or equal to 485 degrees F, this value is maintained at least 140 psi greater than the saturation pressure corresponding to the RCS cold leg temperature.

The setpoint shall be increased automatically as pressurizer pressure is increased until the trip setpoint is reached. Trip may be manually bypassed below 400 psia; bypass shall be automatically removed whenever pressurizer pressure is greater than or equal to 500 psia.

b. This is a calculated, not sensed, variable.

c. Low steam generator levels, diverse scram signals present without normal ESFAS initiation of AFAS or MSIS (ATWS requirements).

d. In MODES 3-4, value may be decreased manually as steam generator pressure is reduced, provided the margin between the steam generator pressure and this value is maintained at less than or equal to 200 psi; the setpoint shall be increased automatically as steam generator pressure is increased until the trip setpoint is reached.

e. % of the distance between steam generator upper and lower level narrow range instrument nozzles.

f. % of the distance between steam generator upper and lower level wide range instrument nozzles.

g. See figure 8.3-3.

h. Technical Specification minimum required RWT level to high level alarm (Mode 1-4 limits).

Table 7.3-12
BOP ESF SYSTEM ACTUATION SETPOINTS AND
MARGINS TO ACTUATION (Sheet 1 of 2)

Actuation Signal	(Full Power) Nominal	Normal Operation Limit	Actuation Setpoint Refer to Table 11.5-1	Margin to Actuation
FBEVAS				
Fuel building exhaust duct high activity	Less than sensitivity $\left(< 10^{-6}\ \frac{\mu Ci}{cm^3}\right)$	Less than sensitivity $\left(< 10^{-6}\ \frac{\mu Ci}{cm^3}\right)$	$2x10^{-6}\ \frac{\mu Ci}{cm^3}$	$1x10^{-6}\ \frac{\mu Ci}{cm^3}$
Fuel pool high radiation level	0.5mr/h	0.5 mr/h	$<$ 15 mr/h	14.5 mr/h
CPIAS				
Power access purge exhaust area radiation level	$<$2.5 mr/h	$<$2.5 mr/h	2.5 mr/h	Negligible
CREFAS				
Control room air intake high activity level	Less than sensitivity $\left(< 10^{-6}\ \frac{\mu Ci}{cm^3}\right)$	Less than sensitivity $\left(< 10^{-6}\ \frac{\mu Ci}{cm^3}\right)$	$2x10^{-5}\ \frac{\mu Ci}{cm^3}$	$1.9x10^{-5}\ \frac{\mu Ci}{cm^3}$

Table 7.3-12
BOP ESF SYSTEM ACTUATION SETPOINTS AND MARGINS TO ACTUATION (Sheet 2 of 2)

Actuation Signal	(Full Power) Nominal	Normal Operation Limit	Actuation Setpoint	Margin to Actuation
CRVIAS				
Control room air intake high smoke level (manual initiation of CRVIAS upon detection of smoke)	Less than sensitivity	Less than sensitivity	1.25% obscuration	1.25% obscuration

7. System components are qualified for the environmental conditions discussed in section 3.11. In addition, the system is capable of performing its intended functions under the most degraded conditions of the electric support system as discussed in section 8.3.

8. The one-out-of-two ESFAS is designed with consideration given to unusual events that could degrade system performance so that:

   a. A loss of power to the measurement channels and/or to the logic system causes system actuation.

   b. Any single failure within the system shall not prevent proper protective action at the system level. The single failure criterion is discussed in paragraph 7.3.2.3.2.

   c. The environmental conditions under which the ESFAS shall be capable of performing its intended function are described in section 3.11.

   d. The seismic conditions under which the ESFAS shall be capable of performing its intended function are described in section 3.10.

Table 7.3-13A
BOP ESF SYSTEMS ACTUATION SENSORS

Monitored Variable	Type	Number of Sensors	Location
Power access purge exhaust area radiation level	Geiger-Mueller	2	Outside containment between power access purge exhaust duct and refueling purge exhaust duct
Fuel building exhaust duct radiation level	β-Scintillation	1	Fuel building exhaust duct
Fuel pool area radiation level	Geiger-Mueller	1	Overlooking spent fuel pool
Control room air intake activity level	β-Scintillation	2	Control room outside air intake duct
Control room air intake smoke detector	Ionization (Products of combustion detector)	2	Control room outside air intake duct

TABLE 7.3-13B
NSSS ENGINEERED SAFETY FEATURES ACTUATION SYSTEM SENSORS

Monitored Variable	Sensor Type	Number of Sensors	Location
Pressurizer Pressure	Pressure Transducer	4* (wide range)	Pressurizer
Containment Pressure	Pressure Transducer (Wide and Narrow range)	8*	Enclosure Complex
Steam Generator Pressure	Pressure Transducer	4/Steam Generator*	Steam Generator
Refueling Water Tank Level	Differential Pressure Transducer	4	Refueling Water Tank
Steam Generator Level	Differential Pressure Transducer (Wide and Narrow Range)	8/Steam Generator*	Steam Generator

*Shared with the Reactor Protective System

9. The minimum performance requirements of the one-out-of-two ESFAS are as follows:

   a. The ESFAS system response times are provided below. The total ESFAS response times represent the sum of the sensor response time plus the one-out-of-two ESFAS response time.

		Sensor Response Time	One-Out-of-Two ESFAS Response Time
(1)	Containment power access purge exhaust area radiation	Ref.table 11.5-1 note aa +	2.0s
(2)	Fuel pool area radiation	Ref.table 11.5-1 +	2.0s
(3)	Fuel building exhaust air-borne activity	Ref.table 11.5-1 +	2.0s
(4)	Control room air intake airborne activity	Ref. table 11.5-1 +	2.0s
(5)	Control room air intake smoke	50s	N.A. (Manual Initiation)

b. The accuracies of the ESFAS measurement channels are:

(1)	Containment power access purge exhaust area radiation	$\pm 20\%$
(2)	Fuel pool area radiation	$\pm 20\%$
(3)	Fuel building exhaust airborne activity	$\pm 25\%$
(4)	Control room air intake airborne activity	$\pm 25\%$
(5)	Control room air intake smoke	$\pm 10\%$

<u>NSSS ESFAS</u>. The design bases of the ESF Systems are discussed in Chapter 6.0. The ESFAS is designed to provide initiating signals for ESF components which require automatic actuation following the design bases events shown on Table 7.3-2.

The systems are designed in compliance with the applicable criteria of the NRC, "General Design Criteria for Nuclear Power Plants," Appendix A, 10CFR50. System testing conforms to the requirements of IEEE 338-1971, "Trial Use Criteria for Periodic Testing of Nuclear Power Generating Station Protection Systems," and Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Functions."

Specific design criteria for the ESFAS are detailed in IEEE 279-1971 "Criteria for Protection Systems for Nuclear Power Generating Stations," Section 3. The following is a discussion of the specific items in IEEE 279-1971 and their implementation.

The generating station conditions requiring actuation of the ESFAS are listed on Table 7.3-2, which also shows which system will actuate for each event. The monitored variables required for ESF System protective action are listed on Table 7.3-3, which also shows which signals are generated by the variable. The number and location of the sensors required to monitor the variables are listed in Table 7.3-13B. The normal operating ranges, actuation setpoints, the nominal full power value, and the margin between the last two are listed on Table 7.3-11A.

The ESFAS is designed with consideration given to unusual events which could degrade system performance. System components are qualified for the environmental conditions discussed in Section 3.11 and the seismic conditions discussed in Section 3.10. These two topics are discussed in Combustion Engineering Topical Reports CENPD-182, "Seismic Qualification of Instrumentation and Electrical Equipment," and CENPD 255, "Qualification of Combustion Engineering Class IE Instrumentation," (References 2 and 3). A single failure within the system will not prevent proper protective action at the system level. The single failure criterion is discussed in section 7.3.2.3.2.

7.3.1.3 Final System Drawings

The signal logic and typical control circuits are shown in figures following this section.

The RAS has added manual actuation which gives the operator greater operational flexibility.

The MSIS logic (Refer to Figure 7.3-7c) has added the high steam generator water level and high containment pressure. This protects downstream equipment from two-phase flow and reduces the amount the Reactor Coolant System could be cooled due to excessive feedwater flow.

For a list of applicable design drawings and diagrams, see section 1.7.

7.3.1.4 Engineered Safety Features Actuation System Supporting Systems

The systems required to support the ESFAS are discussed in Section 7.4. The electrical power distribution is discussed in Section 8.3.

7.3.2 ANALYSIS

7.3.2.1 Introduction

BOP ESFAS. The analysis for the additional one-out-of-two ESFAS and instrumentation is similar to that presented for the NSSS ESFAS as is the ESF manual actuation of the combustible gas control system.

NSSS ESFAS. The ESFAS is designed to provide protection against the Design Basis Events listed on Table 7.3-2. The ESF Systems that are actuated are discussed in Chapter 6.0, along with their design bases and evaluations.

The signals which will cause each ESFAS are listed on Table 7.3-3; the bases are discussed in Section 7.3.1.2; the actuation setpoints are given on Table 7.3-11a. Most ESFAS signals are single parameter, fixed setpoint actuations. The ESFAS that do not fall into this category are:

A. Low pressurizer pressure - can be decreased to 400 psi below the existing pressurizer pressure by the operator;

B. Low steam generator pressure - can be decreased to 200 psi below the existing steam generator pressure by the operator.

These resets are controlled by administrative procedures.

Additionally, several ESFAS can be actuated by more than one parameter. That is, different parameters can cause the same ESFAS. The ESFAS which fall into this category are:

A. SIAS by either low pressurizer pressure or high containment pressure;

B. CIAS by receiving the SIAS for that channel so that it actuates on low pressurizer pressure or high containment pressure;

C. MSIS by high steam generator water level in either steam generator, low steam generator pressure in either steam generator, or high containment pressure.

One ESFAS is, essentially, a multi-parameter actuation. An AFAS is generated on low steam generator water level unless that steam generator has been identified as being ruptured. A steam generator is identified as being ruptured when its pressure is some differential value below the pressure of the other steam generator, coincident with its own low level signal and with the other steam generator being identified as not ruptured.

Each ESFAS setpoint is selected to be consistent with the function of the respective ESF System requirements. The setpoints are selected to provide ESF actuation in sufficient time to provide the necessary actions to mitigate the consequences of the Design Basis Events which caused the ESFAS.

The adequacy of all ESFAS trip setpoints is verified through an analysis of the pertinent system transients reported in Chapter 15.0. These analyses utilize an Analysis Setpoint (assumed trip initiation point) and system delay times associated with the respective trip functions. The Analysis Setpoint along with instrument uncertainties provides the basis for the calculation of the final equipment setpoints to be reported in the Technical Specifications. Limiting trip delay times are given in Table 7.3-1B. The manner by which these delay times and uncertainties will be verified is discussed in Section 7.2.1.2.

7.3.2.1.1 Design Basis Events (DBE)

The DBE conditions for which the system will take action are those unplanned events under conditions that may occur once during the life of several nuclear generating stations, and certain combinations of unplanned events and degraded systems that are never expected to occur during the life of all nuclear power plants. The consequences of these events should be limited by the ESF Systems. The ESF Systems have a major responsibility to mitigate the consequences of the events listed below. This includes minimizing fuel damage and subsequent release of fission products or other related effects. The limiting fault conditions for which the ESFAS actuate are:

A. RCS pipe rupture including a double ended rupture;

B. Single CEA ejection;

C. Steam system pipe rupture, including a double ended rupture;

D. Depressurization due to inadvertent actuation of primary or secondary safety valves at 100% power; and

E. Feedwater system pipe rupture including a double-ended rupture.

The ESFAS will also act to mitigate the consequences of Incidents of Moderate Frequency (IMF) and Infrequent Events as follows:

A. Excess heat removal due to secondary system malfunctions;

B. Inadvertent pressurization or depressurization of the RCS;

C. Change in normal heat transfer capability between steam and reactor coolant systems including:

   1. Improper main feedwater; and

   2. Loss of external load; and

D. Steam generator tube rupture.

7.3.2.2 Actuation Bases

NSSS ESFAS. The ESFAS consists of six signals based on five parameters. Each ESFAS has manual actuation switches locally on the main control board or at the ESFAS Auxiliary Relay Cabinets.

7.3.2.2.1 Safety Injection Actuation Signal (SIAS)

Input

Pressurizer pressure, containment pressure, or manual pushbuttons. The pressure signals are shared with the RPS.

Function

The SIAS actuates the components necessary to inject borated water into the reactor coolant system and actuates components for emergency cooling. SIAS is also initiated by a loss of power to two channels.

7.3.2.2.2 Containment Spray Actuation Signal (CSAS)

Input

Containment pressure signals or manual pushbuttons.

Function

The CSAS actuates the Containment Spray System. CSAS is also initiated by a loss of power to two channels.

7.3.2.2.3 Recirculation Actuation Signal (RAS)

Input

Refueling Water Tank (RWT) Level, or manual pushbuttons.

Function

The RAS is provided to actuate the recirculation mode of operation of the Emergency Core Cooling System. RAS is also initiated by a loss of power to two channels.

7.3.2.2.4 Containment Isolation Actuation Signal (CIAS)

Input

Pressurizer pressure, containment pressure, or manual pushbuttons. The pressurizer and containment pressure signals are provided via the SIAS.

Function

The CIAS actuates the isolation of lines penetrating the containment. CIAS is also initiated by a loss of power to two channels.

7.3.2.2.5 Main Steam Isolation Signal (MSIS)

Input

Pressure from each steam generator, containment pressure, level from each steam generator, or manual pushbuttons.

Function

The MSIS is provided to actuate the isolation of each steam generator. MSIS is also initiated by a loss of power to two channels.

7.3.2.2.6 Auxiliary Feedwater Actuation Signal (AFAS)

Input

Level and pressure from each steam generator with "not ruptured" calculated signal or manual switches.

Function

The AFAS actuates auxiliary feedwater on low water level to the intact steam generator(s). AFAS is also initiated by a loss of power to two channels. The AFAS is based on the following conditions: where low steam generator water level trip exists, its pressure is greater than the other steam generator's pressure by a predetermined value or the other steam generator is identified as not ruptured.

Actuation circuit AFAS I pertains to steam generator 1 and AFAS II actuation circuit pertains to steam generator 2.

7.3.2.3 Design

7.3.2.3.1 General Design Criteria

BOP ESFAS

A. Criterion 16: Containment Design

Refer to subsection 3.1.12.

B. Criterion 20: Protection System Functions

Engineered safety features action will be automatically initiated upon sensing the presence of accident conditions except for the combustible gas control system and the control room ventilation isolation system. Engineered safety features actuation system action will be manually initiated for this section since it is not required immediately after a DBA. Sufficient information is provided to allow the operator to make a timely decision as to system operating requirements.

C. Criterion 22: Protection System Independence

Independence is ensured through the redundance and diversity described in paragraphs 7.3.1.1.6 and 7.3.1.1.7. Two independent sensor channels are provided for the one-out-of-two ESFAS inputs. Two independent output paths are provided for the one-out-of-two ESFAS outputs.

NSSS ESFAS

Appendix A, 10CFR50, "General Design Criteria for Nuclear Power Plants," established minimum requirements for the principle design criteria for water cooled nuclear power plants. This section describes the requirements that are applicable to the ESFAS. Most references will be to Section 3.1 where the criteria are first addressed. Section 7.2.2.3.1 will be referenced if other comments from the RPS are applicable.

Criterion 1 - Quality Standards and Records:

Refer to Section 3.1.1 for compliance.

Criterion 2 - Design Bases for Protection Against Natural Phenomena:

Refer to Section 3.1.2 for compliance.

Criterion 3 - Fire Protection:

Refer to Section 3.1.3 for compliance

Criterion 4 - Environmental and Missile Design Bases:

Refer to Section 3.1.4 for compliance.

Criterion 13 - Instrumentation and Control:

Refer to Section 3.1.9 for compliance. Variables monitored are those which affect ESF Systems.

Criterion 16 - Containment Design:

Refer to Section 3.1.12 for compliance.

Criterion 20 - Protective System Functions:

Refer to Section 3.1.16 for compliance.

Criterion 21 - Protection System Reliability and Testability:

Refer to Section 3.1.17 for compliance.

Criterion 22 - Protection System Independence:

Refer to Section 3.1.18 for compliance.

Criterion 23 - Protection System Failure Modes:

Refer to Section 3.1.19 for compliance.

From the PPS cabinet the signals are sent to two ESFAS Auxiliary Relay Cabinets. In each cabinet is the selective actuation logic for each train. There is no interconnection between the two Auxiliary Relay Cabinets or the trains they actuate so that train A is completely independent of train B.

Criterion 24 - Separation of Protection and Control Systems:

Refer to Section 3.1.20 for compliance.

Criteria 34, 35, 37, 38, 40, 41, 43, 44 and 46:

Refer to Sections 3.1.30, 31, 33, 34, 36, 37, 39, 40 and 42 for compliance.

The ESFAS provides the actuation which meets the requirements of IEEE 279-1971 and IEEE 338-1971. The single failure criterion is met for all ESFAS. The ESFAS is fully testable. Those components which cannot be tested during power operations are tested when the plant is shutdown.

7.3.2.3.2 Equipment Design Criteria

BOP ESFAS. IEEE Standard 279-1971 establishes minimum requirements for safety-related functional performance and reliability of the ESFAS. The following additional paragraphs provide the IEEE 279, Section 4, criteria numbers and titles followed by an explanation as to how they are satisfied.

4.2 Single Failure Criterion

The one-out-of-two ESFAS is designed so that any single failure within the protection system shall not prevent proper protective action at the system level when required. No single failure will defeat more than one of the two protective channels associated with any one trip function.

Although no single failure will defeat more than one of the two protective channels, a single failure may cause spurious actuation. However, this spurious actuation is allowable since it does not create plant conditions requiring protective action nor does it interfere with normal reactor operations.

A complete analysis of single failures for one-out-of-two is presented in tables 7.3-14 through 7.3-17. The worst case single failure is the failure of a group actuation relay to

deenergize. This condition causes loss of one of the two redundant sets of associated ESF equipment.

4.10 Capability for Test and Calibration

Testing is described in paragraph 7.3.1.1.8 and is in compliance with IEEE 338 as discussed in paragraph 7.3.2.3.3.

4.11 Channel Bypass or Removal from Operation

Testing of the one-out-of-two ESFAS is done by channel actuation. Either one of the two channels may be calibrated or repaired without detrimental effects on the system. Individual trip channels may be bypassed to effect a single channel logic on the ESFAS signal. Maintenance and calibration of the bypassed channel can be accomplished in a short time interval. Probability of failure of the remaining channel is acceptably low during such maintenance periods.

4.12 Operating Bypasses

There are no operating bypasses.

4.15 Multiple Setpoints

There are no multiple setpoints.

4.21 System Repair

Identification of a defective channel will be accomplished by observation of system status lights or by testing as described in paragraph 7.3.1.1.8. Replacement or repair of components in the actuation logic is accomplished with the affected channel bypassed. The affected trip function then operates in a single active channel trip logic.

NSSS ESFAS

Many of the design criteria for protection systems are discussed in section 7.1.2. IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," establishes minimum requirements for safety-related functional performance and reliability of the ESFAS. This section describes how the requirements of Section 4 of IEEE 279-1971 are satisfied. The following heading numbers correspond to the section numbers of IEEE 279-1971.

4.1 General Functional Requirements

The ESFAS is designed to actuate the appropriate ESF Systems, when required, to mitigate the consequences of the specified Design Basis Events. Instrument performance characteristics, response times, and accuracies are selected for compatibility with, and adequacy for, the particular function. Actuation setpoints are established by analysis of the RCS parameters, steam generator parameters and containment pressure. Factors such as instrument inaccuracies, bistable trip delay times, valve travel times and pump starting times, are considered in establishing the margin between the actuation setpoints and the safety limits. In addition, the possible loss of AC power and the time required to start standby power and to sequence loads must also be considered. The final determination of all of these times is the Applicant's responsibility. The time response of the sensors or protection systems are evaluated for abnormal conditions. Since all uncertainty factors are considered as cumulative for the derivation of these times, the

actual response time may be more rapid. However, even at the maximum times, the system provides conservative protection.

4.2 Single Failure Criterion

The ESFAS is designed so that any single failure within the system will not prevent proper protective action at the system level. No single failure will defeat more than one of the four protective channels associated with any one trip function.

The effects of single faults in the RPS are discussed in section 7.2.2.3.2. A similar analysis is applicable to that portion of the ESFAS located in the PPS cabinet. The initiating signal from the PPS goes to two separate ESFAS Auxiliary Relay Cabinets. Each cabinet contains the actuation circuitry and group relays for each train, therefore, a failure in one cabinet cannot affect the circuitry and actuated equipment of the other cabinet.

Single faults of initiation relay or actuation relay buses have no effect, as a selective two-out-of-four logic is required for actuation.

Single faults of the actuation (or control) circuitry will cause, at worst, only a failure of a component, group of components, or actuation of a system within one of the two redundant actuation trains; actuation of the remaining redundant train components is sufficient for the protective action.

4.3 Quality Control of Components and Modules

The system is designed in accordance with the Topical Report CENPD-210A, "Description of the C-E Nuclear Steam Supply System Quality Assurance Program" (Reference 4).

4.4 Equipment Qualification

The ESFAS equipment is qualified in accordance with the methodology discussed in Sections 3.10 and 3.11.

4.5 Channel Integrity

Type testing of components, separation of sensors and channels, and qualification of cabling are utilized to ensure that the channels will maintain their functional capability required under applicable extremes of environment, power supplied, malfunction, and DBE conditions. Loss or damage of any one path will not prevent the protective action of the ESFAS. Sensors are piped using materials of comparable quality to the systems to which they are attached so that, in the unlikely event of blockage or failure of any one connection, protective action is not prevented. The process sensors located in the containment building are specified and rated for the intended service. Components which must operate during or after DBEs are rated for the expected post-event environment. Results of type tests are used to verify these ratings.

The separation requirements for the components not within the CESSAR Licensing scope are discussed in section 7.3.3 "Engineered Safety Features Actuation System Interface Requirements".

4.6 Channel Independence

The location of the sensors, for the ESFAS, and the points at which the sensing lines are connected to the process loop have been selected to provide physical separation of the channels within the system, thereby precluding a situation in which a single event could remove or negate a protective action. The routing of cables from protection system transmitters is arranged so that the cables are separated from each other, and from power cabling, to minimize the likelihood of common event failures. This includes separation of the containment penetration areas. The initiation paths are located in four bays of the PPS cabinet and the actuation devices are fed from the two ESFAS Auxiliary Relay Cabinets. Mechanical and thermal barriers within these cabinets minimize the possibility of a common mode failure. Common mode failure is addressed in Topical Report CENPD-148, "Review of Reactor Shutdown System (PPS Design) for Common Mode Failure Susceptibility" (Reference 5).

The output from these redundant channels are isolated from each other so that loss of a channel does not cause loss of the system. The signals from the ESFAS which supply the PMS are isolated at the PMS input. The ESFAS annunciators are isolated as necessary to ensure the ESFAS maintains its channel independence.

The criteria for separation and physical independence of channels are based on the need for decoupling the effects of DBE consequences and power supply transients, and for reducing

the likelihood of channel interaction during testing or in the event of a channel malfunction.

4.7 Control and Protection System Interaction

4.7.1 Classification of Equipment

No portion of the ESFAS is used for both protective and control functions.

4.7.2 Isolation Devices

Signals sent from the ESFAS to the PMS are isolated at the PMS and annunciators are isolated at the annunciators such that a failure in these areas will not affect the protective action of the ESFAS.

4.7.3 Single Random Failure

This criterion is not applicable since there are no channels used for both control and protection. Therefore a single random failure can only occur in either a control or a protection channel.

4.7.4 Multiple Failures Resulting from a Credible Single Event

This cannot exist because control and protection channels have nothing in common.

4.8 Derivation of Signal Inputs

Insofar as possible, inputs are derived from signals that are direct measurements of the desired variable. Directly measured variables include pressurizer, containment, and steam generator pressures. The steam generator and refueling water tank levels

are derived from differential pressure signals. The differential between the steam generator pressures, for the AFAS, is a calculated value.

4.9 Capability for Sensor Checks

ESFAS sensors are checked by cross-channel comparison. Each channel has a known relationship with the other channels of the same parameter.

4.10 Capability for Test and Calibration

The ESFAS design complies with IEEE 338-1971, "Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection System Actuation Functions," as discussed in section 7.3.2.3.3.

4.11 Channel Bypass or Removal from Operation

Any one of the four protection channels in the ESFAS may be tested, calibrated, or repaired without detrimental effect on the system. Individual actuation channels (i.e., pressurizer pressure, containment pressure, steam generator level) may be bypassed to create a two-out-of-three logic while maintaining the coincidence of two on the remaining channels. The single failure criterion is met during this condition.

4.12 Operating Bypasses

Operating bypass is provided as shown on Table 7.3-1c. The operating bypass is automatically removed when the permissive condition is not met. The circuitry and devices which function to remove this inhibit are designed in accordance with IEEE 279-1971.

4.13 Indication of Bypasses

Indication of test or bypass conditions, or removal of any channel from service is given by annunciators. The operating bypass that is automatically removed at a fixed setpoint, is alarmed and indicated.

4.14 Access to Means for Bypassing

Trip channel bypasses have access controlled by means of key locked doors. When the first parameter is bypassed there is an audible and visible alarm to indicate which channel is being bypassed. The specific parameter or parameters which are being bypassed are indicated by lights at the PPS cabinet and its remote operator's module.

The operating bypasses also have audible and visible alarms. The operating bypasses have automatic features which provide a permissive level at which they can be actuated and a second level at which they are automatically removed.

4.15 Multiple Setpoints

Manual reduction of the setpoints for low pressurizer and low steam generator pressures are used for the controlled reduction of pressures as discussed in sections 7.3.1.1.10.4 and 7.3.1.1.10.5. The setpoint reductions are initiated by main control board pushbuttons for each channel, one pushbutton for the pressurizer pressure and one pushbutton for both steam generator pressures within the one channel. Operation of the pushbutton will reduce the pressure actuation setpoint a selected increment below the existing system pressure. As the pressurizer or steam generator pressure increases the actuation

setpoint will increase automatically with the pressure, maintaining a fixed increment, until the setpoint reaches its normal actuation setpoint value.

4.16 Completion of Protective Action Once It is Initiated

The ESFAS is designed to ensure that protective action will go to completion once initiated. Actuation of an ESFAS can be cleared by the operator manually resetting the ESFAS at the PPS cabinet and the ESFAS Auxiliary Relay Cabinets. A protective action is initiated when the selective two-out-of-four logic reaches the proper coincidence of two state. A protective action is completed when all of the appropriate ESF actuated components have assumed the proper state for their ESF function. The AFAS valves are not locked into its actuation but the pumps are locked in. AFAS is designed to cycle based on the steam generator level signal. When the low level signal clears, the AFAS is lost, until the level drops to the actuation setpoint again.

4.17 Manual Initiation

A manual initiation is effected by operating manual switches in the main control room or at the ESFAS Auxiliary Relay Cabinets. These are arranged in a selective two-out-of-four logic. No single failure will prevent a manual actuation at the system level.

4.18 Access to Setpoint Adjustments, Calibration and Test Points

A key is required for access to setpoint adjustments, calibration and test points. Access is also annunciated. Setpoints are continuously monitored by the PMS.

4.19 Identification of Protective Action

Indication lights are provided for all protective actions, including identification of the channel trips.

4.20 Information Readout

Means are provided to allow the operator to monitor all actuation system inputs, outputs, and calculations. The specific displays that are provided for continuous display are described in Section 7.5.

4.21 System Repair

Identification of a defective channel will be accomplished by observation of system status lights, or by testing as described in section 7.3.1.1.8. Replacement or repair of components is accomplished with the affected channel bypassed. The affected function is then in a two-out-of-three logic, but still maintaining a coincidence of two for actuation.

4.22 Identification

All equipment associated with the actuation system, including panels, modules, and cables, is marked in order to facilitate identification. Interconnecting cabling will be color coded as discussed in section 7.1.3.16. The equipment to be supplied by the Applicant shall have this requirement specified in the interface section.

Table 7.3-14
ONE-OUT-OF-TWO-ESFAS
FUEL BUILDING ESSENTIAL VENTILATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 1 of 3)

Failure Mode	Effect on System	Detection	Remarks
Loss of one ac load group (diesel)	System isolates (fuel building normal supply and exhaust dampers close)	Immediate annunciator	Redundant system actuates (fuel building essential exhaust)
Loss of one dc load group (1E)	System actuates (fuel building essential exhaust)	Immediate annunciator	Actuation of both load groups (fuel building essential exhaust)
Loss of instrument air system	System isolates	Immediate annunciator	Closure of fuel building normal supply and exhaust dampers
Input sensor fails:			
High	System actuates (fuel building essential exhaust)	Immediate annunciator and periodic testing	Actuation of both load groups (fuel building essential exhaust)
Low	None	Immediate annunciator and periodic testing	Manual actuation available to the operator

Table 7.3-14
ONE-OUT-OF-TWO-ESFAS
FUEL BUILDING ESSENTIAL VENTILATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 2 of 3)

Failure Mode	Effect on System	Detection	Remarks
Input sensor wiring fails:			
Open	System actuates (fuel building essential exhaust)	Immediate annunciator and periodic testing	Actuation of both load groups (fuel building essential exhaust)
Short	Loss of one sensing channel	Periodic testing	Other sensor channel and system level manual actuation available to actuate both load groups
Manual input fails:			
Open	Loss of system level manual initiation of one load group (fuel building essential exhaust)	Periodic testing	Automatic actuation available for both load groups, system level manual actuation available for redundant load group, and manual device level control fully operable

Table 7.3-14
ONE-OUT-OF-TWO-ESFAS
FUEL BUILDING ESSENTIAL VENTILATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 3 of 3)

Failure Mode	Effect on System	Detection	Remarks
Manual input fails: (continued)			
Short	System actuation of one load group (fuel building essential exhaust)	Immediate annunciator	Actuation of one load group (fuel building essential exhaust)
Output relay mechanically jammed	Loss of system level actuation of one load group (fuel building essential exhaust)	Periodic testing	Other load group available and manual device control fully operable
Output relay fails de-energized	System actuation of one load group (fuel building essential exhaust)	Visual observation of system status	Actuation of one load group (fuel building essential exhaust)

Table 7.3-15
ONE-OUT-OF-TWO-ESFAS
CONTAINMENT PURGE ISOLATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 1 of 3)

Failure Mode	Effect on System	Detection	Remarks
Loss of one ac load group (diesel)	Loss of system level actuation of one load group	Immediate annunciator	Redundant system actuates
Loss of one dc load group (1E)	System actuates	Immediate annunciator	Actuation of both load groups
Loss of instrument air system	No effect	Immediate annunciator	Instrument air not required for use in this system
Input sensor fails:			
High	System actuates	Immediate annunciator and periodic testing	Actuation of both load groups
Low	None	Immediate annunciator and periodic testing	Manual actuation available to the operator
Input sensor wiring fails:			
Open	System actuates	Immediate annunciator and periodic testing	Actuation of both load groups

Table 7.3-15
ONE-OUT-OF-TWO ESFAS
CONTAINMENT PURGE ISOLATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 2 of 3)

Failure Mode	Effect on System	Detection	Remarks
Input sensor wiring fails: (continued)			
Short	Loss of one sensing channel	Periodic testing	Other sensor channel and system level manual actuation available to actuate both load groups
Manual input fails:			
Open	Loss of system level manual initiation of one load group	Periodic testing	Automatic actuation available for both load groups, system level manual actuation available for redundant load group, and manual device level control fully operable
Short	System actuation of one load group	Immediate annunciator	Actuation of one load group

Table 7.3-15
ONE-OUT-OF-TWO ESFAS
CONTAINMENT PURGE ISOLATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 3 of 3)

Failure Mode	Effect on System	Detection	Remarks
Output relay mechanically jammed	Loss of system level actuation of one load group	Periodic testing	Other load group available and manual device control fully operable
Output relay fails deenergized	System actuation of one load group	Visual observation of system status	Actuation of one load group

Table 7.3-16
ONE-OUT-OF-TWO ESFAS
CONTROL ROOM VENTILATION ISOLATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 1 of 3)

Failure Mode	Effect on System	Detection	Remarks
Loss of one ac load group (diesel)	System isolates	Immediate annunciator	Redundant system actuates
Loss of one dc load group (1E)	System isolates	Immediate annunciator	Redundant system actuates
Loss of instrument air system	System isolates	Immediate annunciator	Closure of control room normal supply dampers

Table 7.3-16
ONE-OUT-OF-TWO ESFAS
CONTROL ROOM VENTILATION ISOLATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 2 of 3)

Failure Mode	Effect on System	Detection	Remarks
Manual input fails:			
Open	Loss of system level manual initiation of one load group	Periodic testing	Automatic actuation available for both load groups, system level manual actuation available for redundant load group, and manual devicelevel control fully operable
Short	System actuation of one load group	Immediate annunciator	Actuation of one load group

Table 7.3-16
ONE-OUT-OF-TWO ESFAS
CONTROL ROOM VENTILATION ISOLATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 3 of 3)

Failure Mode	Effect on System	Detection	Remarks
Output relay mechanically jammed	Loss of system level actuation of one load group	Periodic testing	Other load group available and manual device control fully operable
Output relay fails deenergized	System actuation of one load group	Visual observation of system status	Actuation of one load group

Table 7.3-17
ONE-OUT-OF-TWO-ESFAS
CONTROL ROOM ESSENTIAL FILTRATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 1 of 3)

Failure Mode	Effect on System	Detection	Remarks
Loss of one ac load group (diesel)	System isolates	Immediate annunciator	Redundant system actuates
Loss of one dc load group (1E)	System isolates	Immediate annunciator	Redundant system actuates
Loss of instrument air system	System isolates	Immediate annunciator	Closure of control room normal supply dampers
Input sensor fails:			
High	System actuates	Immediate annunciator and periodic testing	Actuation of both load groups
Low	None	Immediate annunciator and periodic testing	Manual actuator available to the operator
Input sensor wiring fails:			
Open	System actuates	Immediate annunciator	Actuation of both load groups

Table 7.3-17
ONE-OUT-OF-TWO ESFAS
CONTROL ROOM ESSENTIAL FILTRATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 2 of 3)

Failure Mode	Effect on System	Detection	Remarks
Input sensor wiring fails: (continued)			
Short	Loss of one sensing channel	Periodic testing	Other sensor channel and system level manual actuation available to actuate both load groups
Manual input fails:			
Open	Loss of system level manual initiation of one load group	Periodic testing	Automatic actuation available for both load groups, system level manual actuation available for redundant load group, and manual device level control fully operable
Short	System actuation of one load group	Immediate annunciator	Actuation of one load group

Table 7.3-17
ONE-OUT-OF-TWO ESFAS
CONTROL ROOM ESSENTIAL FILTRATION ACTUATION SIGNAL
FAILURE MODES AND EFFECTS ANALYSIS (Sheet 3 of 3)

Failure Mode	Effect on System	Detection	Remarks
Output relay mechanically jammed	Loss of system level actuation of one load group	Periodic testing	Other load group available and manual device control fully operable
Output relay fails deenergized	System actuation of one load group	Visual observation of system status	Actuation of one load group

The compliance of the ESFAS to the requirements of IEEE 384-1974, "IEEE Trial-Use Standard Criteria for Separation of Class IE Equipment and Circuits," and Regulatory Guide 1.75, "Physical Independence of Electric Systems," is discussed in section 7.1.2.10.

7.3.2.3.3 NSSS and BOP ESF Testing Criteria

IEEE Standard 338-1971 and Regulatory Guide 1.22 provide guidance for development of procedures, equipment, and documentation of periodic testing. The basis for the scope and means of testing are described in this section. Test intervals and their bases are included in the Technical Specifications. The organization for testing and for documentation is described in chapter 13. Since operation of the ESF system is not expected, the systems are periodically tested to verify operability. Complete channels can be individually tested without violating the single failure criterion and without inhibiting the operation of the systems. The system can be checked from the sensor signal through the actuation devices during reactor operation, except as noted below, since most ESF system actuations do not damage equipment or disturb reactor operation. Thus, testing completely simulates valid actuation. Minimum frequencies for checks, calibration, and periodic testing of the ESFAS instrumentation and control are given in the Technical Specifications.

Additional basis documents for NSSS ESFAS and BOP ESFAS testing criteria include CEN-403, Rev. 1 and the companion NRC SER, NRC Letter from B.A. Boger to CEOG, dated 2/27/1996. The SER

includes criteria developed from a study NUREG-1366, "Improvements to Technical Specifications Surveillance Requirements". The study found that while some testing at-power is essential, 1.) safety can be improved, 2.) equipment degradation decreased, and 3.) unnecessary personnel burden can be prevented by reducing the amount of testing at-power. These three conclusions were formed using the following four criteria that were used to justify changes in surveillance test intervals. These same criteria may be used to justify changes in the surveillance test procedures that control at-power or refueling outage testing of ESFAS relays, "actionuation devices" and "actuated equipment". Criterion that may be used with procedure changes supporting the above conclusions are as follows:

- Criterion 1 – The surveillance could lead to plant transient.
- Criterion 2 – The surveillance results in unnecessary wear to equipment
- Criterion 3 – The surveillance results in radiation exposure to plant personnel not justified by the safety significance of the surveillance.
- Criterion 4 – The surveillance places an unnecessary burden on plant personnel because the time required is not justified by the safety significance of the surveillance.

Most ESF relays are tested during power operation along with all actuated equipment. However, some ESF relays tested

at-power have equipment that cannot be actuated, but can be racked out, bypassed or otherwise prevented from actuating while the actuation device/relay is being tested at-power. This will not preclude the relay from being tested but will not actuate the locked-out equipment associated with the relay. These exceptions are controlled within the surveillance procedures and are acceptable given that one or more of the criteria listed above would potentially be challenged by at-power testing of the actuated equipment. In those instances, the actuated equipment will still be tested in accordance with the test bases in judiciously selected groups during refueling outage tests.

Certain ESF subgroup relays are exempt from testing during at-power operation but shall be tested in accordance with the Technical Specification SR 3.3.6.2 note. These exemptions are controlled within the surveillance procedures and are acceptable because one or more of the four criterion listed above would be challenged by at-power testing. In those instances, the relays will still be tested in accordance with the test bases in judiciously selected groups during refueling outage tests.

The use of individual trip and ground detection lights, in conjunction with those provided at the supply bus, ensure that possible grounds or shorts to another source of voltage will be detected.

The response time from an input signal to protect system trip bistables through the opening of the actuation relays is

verified by measurement during plant startup testing. Sensor responses are measured during factory acceptance tests. Paragraph 7.3.1.1.8.8 provides additional information on response time testing.

7.3.2.4 Failure Modes and Effects Analysis

Refer to CESSAR Table 7.2-5. The failure modes and effects analysis for the additional ESF systems is given in tables 7.3-14 through 7.3-18.

7.3.3 CESSAR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INTERFACE REQUIREMENTS

The following interface requirements are repeated from CESSAR Section 7.3.3:

The interface requirements discussed below are specific to the ESFAS.

General requirements are discussed in Section 7.1.3. Those items specific to the RPS are discussed in Section 7.2.3.

7.3.3.1 Power

Refer to Section 8.3.

7.3.3.2 Protection from Natural Phenomena

Refer to Sections 3.1.2 and 7.1.3.2.

7.3.3.3 Protection from Pipe Failure

Refer to Section 7.1.3.3.

Table 7.3-18
FAILURE MODES AND EFFECTS ANALYSIS
CONTAINMENT COMBUSTIBLE GAS CONTROL SYSTEM

Failure	Effect on System	Detection	Remarks
Loss of one channel ac control power (motorized valve control)	Loss of redundancy	Immediate--indicator lights	Remaining channel fully functional
Control switch or wiring failure (motorized valve control)			
Open	Loss of redundancy	Periodic testing or spurious operation	Remaining channel fully functional
Short	Spurious operation may occur		Remaining channel fully functional

7.3.3.4 Missiles

Refer to Section 7.1.3.4.

7.3.3.5 Separation

Refer to Section 7.1.3.5.

7.3.3.6 Independence

Refer to Section 7.1.3.6.

7.3.3.7 Thermal Limitations

Refer to Section 7.1.3.7.

7.3.3.8 Monitoring

Refer to Section 7.1.3.8.

7.3.3.9 Operational/Controls

Refer to Section 7.1.3.9.

7.3.3.10 Inspection and Testing

Refer to Section 7.1.3.10.

7.3.3.11 Chemistry/Sampling

Refer to Section 7.1.3.11.

7.3.3.12 Materials

Not applicable to the safety-related instrument and control equipment.

7.3.3.13 System Component Arrangement

Refer to Section 7.1.3.13.

7.3.3.14 Radiological Waste

Refer to Section 7.1.3.14.

7.3.3.15 Overpressure Protection

Refer to Section 7.1.3.15.

7.3.3.16 Related Services

Refer to Section 7.1.3.16.

7.3.3.17 Environmental

Refer to Section 7.1.3.17.

7.3.3.18 Mechanical Interaction

Refer to Section 7.1.3.18.

7.3.3.19 Plant Monitoring System Inputs

Refer to Section 7.1.3.19.

7.3.4 CESSAR INTERFACE EVALUATION

The CESSAR interface requirements listed in subsection 7.3.3 are met by PVNGS design as follows:

7.3.4.1 Power

Refer to subsection 8.3.1.

7.3.4.2 Protection from Natural Phenomena

Refer to paragraph 7.1.4.2.

7.3.4.3 Protection from Pipe Failure

Refer to paragraph 7.1.4.3.

7.3.4.4 Missiles

Refer to paragraph 7.1.4.4.

7.3.4.5 Separation

Refer to paragraph 7.1.4.5.

7.3.4.6 Independence

Refer to paragraph 7.1.4.6.

7.3.4.7 Thermal Limitations

Refer to paragraph 7.1.4.7.

7.3.4.8 Monitoring

Refer to paragraph 7.1.4.8.

7.3.4.9 Operational/Controls

Refer to paragraph 7.1.4.9.

7.3.4.10 Inspection and Testing

Refer to paragraph 7.1.4.10.

7.3.4.11 Chemistry/Sampling

Refer to paragraph 7.1.4.11.

7.3.4.12 Materials

Not applicable

7.3.4.13 System Component Arrangement

Refer to paragraph 7.1.4.13.

7.3.4.14 Radiological Waste

Refer to paragraph 7.1.4.14.

7.3.4.15 Overpressure Protection

Refer to paragraph 7.1.4.15.

7.3.4.16 Related Services

Refer to paragraph 7.1.4.16.

7.3.4.17 Environmental

Refer to paragraph 7.1.4.17.

7.3.4.18 Mechanical Interaction

Refer to paragraph 7.1.4.18.

7.3.4.19 Plant Monitoring System Inputs

Refer to paragraph 7.1.4.19.

7.3.5 DIVERSE AUXILIARY FEEDWATER ACTUATION SYSTEM (DAFAS)

The DAFAS monitors plant conditions and actuates auxiliary feedwater during conditions indicative of an ATWS event and S/G low level conditions. The DAFAS interfaces with the process protective cabinets(PPC), the auxiliary relay cabinet (ARC), and the diverse scram system (DSS). The interface with the DSS is accomplished through a connection with the supplementary protection system (SPS) trip signal in the Class 1E portions of the electronic isolation system (EIS).

There are two channels of DAFAS, train A and train B. The two DAFAS channels are independent and isolated from each other as well as from the interfacing systems noted above by the use of fiber optic data links.

A DAFAS block diagram is shown in figure 7.3-7e.

7.3.5.1 Design Bases and Design Considerations

The PVNGS DAFAS is designed to be a highly reliable system that initiates auxiliary feedwater flow upon conditions indicative of an ATWS combined with selective low S/G level signals. DAFAS will stop AFW flow to the affected S/G after reaching a predetermined level setpoint (about 30 minutes after actuation) at which time manual operator intervention will control the system. The DAFAS is designed to meet the intent of 10CFR50.62 and is diverse and independent from the existing reactor protective system. The DAFAS design further complies with NRC guidance provided with 10CFR50.62 and the quality assurance requirement of Generic Letter 85-06. Compliance with the

guidelines are integrated into the design for PVNGS DAFAS as discussed below.

7.3.5.1.1 Safety Related (IEEE-279)

The DAFAS is not required to be safety related. However, the implementation of DAFAS is such that the existing protection system continues to meet all applicable safety related criteria.

The DAFAS consists of several equipment groups. The DAFAS sub-assembly in the process protective cabinets (J-SBA-C02A, J-SBB-C02A, J-SBC-C02A and J-SBD-C02A), the DAFAS cabinets (J-SAA-C05 and J-SAB-C06), the DAFAS sub-assembly in the auxiliary relay cabinets (J-SAA-C01 and J-SAB-C01), and the DAFAS sub-assembly in the electronic isolation system (EIS) cabinets (J-SAA-C04, J-SAB-C04, J-SAC-C04 and J-SAD-C04). The DAFAS equipment in the PPC, ARC and EIS cabinets are considered safety related equipment since they interface directly with class 1E systems. The DAFAS equipment in the existing 1E cabinets are designed, constructed, and installed in accordance with the requirements for PVNGS safety related equipment.

The DAFAS cabinets are considered safety related. They are designed, constructed, and installed in accordance to the requirements for PVNGS safety related equipment which exceeds requirements of 10CFR50.62. However, the DAFAS does not have a manual trip and utilizes the manual trip capability of the existing AFAS. PVNGS has elected to classify the DAFAS as a safety related system to provide enhanced functionality and availability.

The DAFAS power supplies that power the fiber optic transmitters (FOTs) and receivers (FORs) are grounded. The justification for the grounding of the power supplies is discussed below.

IEEE-279 requires that each redundant channel of a safety system be independent from its redundant counterpart. Independence is measured by the ability of a redundant system to perform its function when confronted by a credible "single failure." The single failure, if it compromises the function of the safety system, must be able to be detected by periodic testing. From these criteria, it can be seen that grounding the power supply that powers the fiber optic transmitters and receivers does not compromise the independence of the DAFAS. Postulated single failures, that are credible for the DAFAS in terms of fault voltage and energy, will, at worst, cause a channel failure that is either self annunciating or detectable during periodic testing. There is no failure or fault in the DAFAS that prevent the system from performing its intended function.

7.3.5.1.2 Redundancy

Redundancy alone does not preclude common mode failure occurrences. Therefore, there are no requirements for redundancy of the DAFAS. However, the system should be reliable and minimize the possibility of spurious actuation. PVNGS has elected to install a two train DAFAS for PVNGS units 1, 2, and 3 to increase system reliability and decrease the probability of spurious actuation. The installation of a two

train system also permits testing at full power, allowing the remaining DAFAS channel to provide a measure of protection.

7.3.5.1.3 Physical Separation From Existing Reactor Protective System

DAFAS physical separation from existing reactor protective system is not required unless redundant divisions and channels in the existing reactor protective system are not physically separated. The DAFAS implementation must be such that separation criteria applied to the existing protection system are not violated.

DAFAS physical separation from the existing PPS is provided. The DAFAS is isolated via qualified fiber optic devices and is physically and electrically separate from the existing PPS. The DAFAS does not degrade the existing separation criteria of the PPS or the ARC cabinets. Physical separation is maintained and electrical protection is provided for the channel (division) A, B, C and D vital instrument busses providing power to the DAFAS ARC control panel assemblies. The DAFAS ARC control panels are part of the train (division) A or B ARC in which they are located. The required isolation is provided by the circuit breakers in the ARC. These isolation devices have been evaluated as acceptable per IEEE-384, 1981, by calculation 13-JC-SA-202.

7.3.5.1.4 Seismic Qualification (IEEE-344)

The DAFAS equipment mounted inside the PPC, EIS and ARC cabinets are tested and qualified to meet or exceed the seismic

qualification criteria of the existing cabinets so that the qualification of the existing safety related cabinets remain valid. Although the DAFAS system is not required to be Class 1E qualified, the DAFAS equipment will be constructed and mounted consistent with the existing requirements of PVNGS Class 1E safety related equipment. DAFAS equipment will be tested and qualified in accordance with IEEE-344, 1975 to enhance the system performance and reliability.

7.3.5.1.5 Environmental Qualification (IEEE-323)

The DAFAS equipment is not located in a harsh environment. Therefore, environmental qualification requirements of 10 CFR 50.49 are not applicable. However, the equipment inside the DAFAS cabinets and the DAFAS equipment housed inside the PPC, ARC and EIS cabinets will be qualified for the environmental conditions inside the cabinets resulting from AOO's. The environmental qualification is in accordance with IEEE-323, 1974.

7.3.5.1.6 Quality Assurance For Test, Maintenance And Surveillance

Compliance with Generic Letter 85-06 is addressed in section 7.3.5.1.12. Testing, maintenance and surveillance are addressed in section 7.3.5.1.8 below.

7.3.5.1.7 Safety Related Power Supply

The power required to operate the DAFAS is provided by the following sources:

- Two Class 1E 120 VAC vital instrument buses Channel A to the DAFAS A cabinet and Channel B to the DAFAS B cabinet.
- The four existing cabinet Class 1E power sources (A, B, C and D) in the EIS, PPC and ARC.

The power required for the DAFAS cabinets and the DAFAS sub-assembly mounted inside the ARC cabinets is supplied from the 120 VAC vital instrument buses. The 120 VAC vital buses are required to supply power to its respective DAFAS equipment channel. The power required for the DAFAS sub-assembly mounted inside the EIS cabinets is supplied by the existing 24 VDC power supplies in the EIS cabinets. The use of existing DC power supplies was considered to minimize the space required for interfacing with the existing plant equipment. In such cases, a load calculation was performed to verify that the additional load required by the DAFAS would not cause an overload condition to exist.

Power supply faults such as over-voltage and under-voltage conditions, degraded frequencies, and over-current will not compromise the RPS, AFAS or safety related equipment in the ARC cabinets. Loss-of-power to a DAFAS train will cause the "DAFAS Trouble" alarm in the control room. The vital 120 VAC system faults are alarmed in the control room along with battery charger and inverter faults. The control room alarms

provide for early detection of degraded voltage and frequency conditions to allow for operator corrective action while the affected circuits/components are still capable of performing their intended functions.

7.3.5.1.8 Testability At Power

The DAFAS provides for both on-line and off-line testing. The on-line testing of the system is performed one train at a time, and is manually initiated at the DAFAS, and the Auxiliary Relay Cabinets.

The DAFAS cabinet testing involves testing the logic system. Testing at the ARC cabinets involves verifying proper operation of the DAFAS circuitry and the initiation relays. The DAFAS total functional testing and calibration will be performed prior to operation to demonstrate that the hardware and software conform to the design specifications. The DAFAS equipment will be periodically tested and calibrated to ensure that the testing requirements established by PVNGS are satisfied. The measuring and test equipment which will be used to determine the DAFAS functionality will be controlled in accordance with existing procedures. A system level test will be conducted each refueling outage, which will consist of functional testing from the sensor output to and including the DAFAS initiation relays. This test will include a check of the input calibration, simulating the inputs, verifying DAFAS initiations, bypasses and alarms.

Maintenance and test bypasses for the DAFAS will not involve installing jumpers, lifting leads, pulling fuses or other

circuit modifications. The test bypasses will be provided as an integral part of the DAFAS design.

7.3.5.1.9 Diversity From Existing Reactor Protective System (RPS)

The equipment used in the design of the DAFAS is entirely diverse from the existing PPS (plant protection system) except for the S/G level sensors and the final actuation devices, both of which are not required to be diverse in accordance with the ATWS Rule and guidance. The DAFAS uses programmable logic controllers with solid state I/O modules as compared to the PPS which uses analog bistable trip units to perform the same function. The DAFAS uses fiber optic communication links to receive and transmit signals to and from its distributed DAFAS subsystems.

The DAFAS final interface devices with the AFAS are the DAFAS initiation relays located on the DAFAS ARC control panel assemblies in the auxiliary relay cabinet. These relays energize to actuate auxiliary feedwater flow while the existing AFAS is a de-energize to actuate system. These relays are of a different manufacturer from the existing PPS/RPS initiation relays, and their use, therefore, is diverse from the existing RPS. The DAFAS and AFAS use the same final actuation devices. The final actuation devices are the existing cycling and subgroup relays used to control the pumps and valves in the auxiliary feedwater system.

7.3.5.1.10 Electrical Independence From Existing Reactor Protective System

The power required to operate the DAFAS is provided by Class 1E power sources which are independent channelized sources. The DAFAS logic is isolated from the auxiliary relay cabinet logic, process protective cabinets, and electronic isolation system cabinets through the use of fiber optic isolation which meets the intent of the guidance for isolation between safety related circuits. The NRC has accepted this configuration to be in compliance with the intent of the ATWS Rule (reference 1).

7.3.5.1.11 Inadvertent Actuation

The DAFAS is designed with features to minimize inadvertent actuations and challenges to the safety system. The DAFAS actuation setpoint is set at a level below the existing AFAS setpoint in the PPS and the DAFAS response time will be longer than the PPS AFAS response time in order to prevent the possibility of the DAFAS initiating auxiliary feedwater (AFW) flow before the properly operating PPS. The DAFAS initiates AFW flow upon energizing the DAFAS initiation relays while the AFAS initiates AFW flow upon de-energizing the PPS initiation relays. Both signals deenergize the AFW subgroup and cycling relays. The energize-to-actuate design of the DAFAS initiation relays minimizes relay power failures or I/O system power failures from causing an inadvertent actuation since these relays are normally de-energized.

The DAFAS is blocked by AFAS-1 or AFAS-2 signals, if the DAFAS has not actuated since this would indicate normal protection system operation and therefore no need for this ATWS mitigation system actuation. If DAFAS actuates before an AFAS, the DAFAS protection signal will go to completion as required by IEEE-279, unless blocked by an MSIS. The MSIS signals will block a DAFAS actuation prior to, during or after a DAFAS actuation in order to prevent interference with the MSIS capability for S/G high energy line break protection. When the PPS initiates AFAS or MSIS, indicating that PPS is operating normally and that conditions for an ATWS do not exist, blocking logic is activated which disables the DAFAS initiation relay. The DAFAS is further blocked until a selective 2/4 diverse scram system (DSS) logic matrix is satisfied, such that the DAFAS can operate only if a DSS actuation is in progress.

If an inadvertent actuation of the DAFAS were to occur, thus initiating AFW flow, an increase in feedwater flow to the steam generator secondary side could result. Although undesirable, this event has been considered in the analysis of the plant in section 15.1.2, Increase in Feedwater Flow.

7.3.5.1.12 Conformance to Generic Letter 85-06

Generic Letter 85-06 was issued by the NRC to provide explicit quality assurance (QA) guidance required for non-safety related ATWS equipment. The PVNGS DAFAS is in compliance with the QA guidance of this generic letter by invoking on PVNGS the requirements of a 10CFR50, Appendix B, QA program on the DAFAS and its equipment.

7.3.5.1.13 Conformance to ANSI 45.2.11

The DAFAS was designed in accordance with the PVNGS configuration management program. In addition, ABB-Combustion Engineering (ABB-CE) support was performed in accordance with the ABB-CE Quality Assurance Manual (QAM-100) which complies with ANSI/ASME NQA-1-1983 which is based on the contents of ANSI/ASME N45.211-1977

7.3.5.1.14 Conformance to 10CFR50, Appendix A

The DAFAS is designed in compliance with the applicable criteria of the NRC, "General Design Criteria for Nuclear Power Plants," 10CFR50 Appendix A.

7.3.5.1.15 Conformance to 10CFR50, Appendix B

The DAFAS was designed in accordance with the PVNGS configuration management program. In addition, ABB-CE provided support using their quality assurance program (QAM-100) and is in compliance with the NRC, "Quality Assurance criteria for Nuclear Power Plants and Fuel Reprocessing Plants," 10CFR50, Appendix B.

7.3.5.1.16 Conformance to Regulatory Guide 1.75

The DAFAS design is in compliance with the "Physical Independence of Electrical System", Regulatory Guide 1.75.

7.3.5.1.17 Conformance to Regulatory Guide 1.22

The DAFAS is in compliance with Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Function", in conjunction with the current AFAS actuation devices.

7.3.5.1.18 Conformance to Regulatory Guide 1.53

The DAFAS is in compliance with Regulatory Guide 1.53, "Application of the Single-Failure Criterion to Nuclear Power Plant Protection System."

7.3.5.1.19 Conformance to IEEE-338, 1971

The DAFAS system testing conforms to the IEEE-338 Standard, "Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems."

7.3.5.1.20 Conformance to IEEE-384

The DAFAS fiber optic and internal module connection wiring conforms to IEEE-384, 1981, "Criteria for Independence of Class 1E Equipment and Circuits." The interfaces with the DAFAS in the PPC, EIS and ARC are also in compliance with this standard.

7.3.5.1.21 Conformance to IEEE-379

The DAFAS is in compliance with the applicable criteria of IEEE-379, 1977, "Application of the Single Failure Criterion to Nuclear Power Generating Station Class 1E System."

7.3.5.2 Functional Description of the DAFAS

The DAFAS actuation mitigates the consequence of an ATWS event. This consequence is high RCS pressure due to reduced heat removal through the S/Gs. The DAFAS actuation is provided following an ATWS, which is characterized as an Anticipated Operational Occurrence (AOO) requiring auxiliary feedwater, coincident with a failure of the PPS to initiate a reactor trip. Failure of the PPS is indicated by a reactor trip initiated on high-high pressurizer pressure by the supplementary protection system (SPS), also known as (AKA) the supplementary protection logic assemblies (SPLA), AKA the diverse scram system (DSS). The DAFAS initiation signals cause actuation of the auxiliary feedwater systems (train A and B) only if there is a demand for auxiliary feed as indicated by low S/G level, and there is an SPS initiated reactor trip, and there is no MSIS and an AFAS-1 or -2 has not been generated by the PPS. Indication of an MSIS or an AFAS in the PPS concurrent with the absence of an enable from the DSS indicates that conditions indicative of an ATWS have not occurred and the DAFAS actuation is not necessary. Therefore, under these conditions the DAFAS actuation will be blocked through DAFAS logic in the auxiliary Relay Cabinets.

7.3.5.2.1 DAFAS Input

The DAFAS uses four existing wide range safety channels (A, B, C and D) level sensor inputs from each of the two steam generators at the process protective cabinets (PPC) JSBA-C02A, JSBB-C02A, JSBC-C02A and JSBD-C02A. Each of the DAFAS channels

(A and B) receive these eight steam generator level inputs. These level signals are input to a fiber optic transmitter (FOT) which converts the analog voltage signal to an optical signal. The optical signals are then split by fiber optic splitters (FOS) for transmission to both of the DAFAS cabinets over FO cables. These fiber optics communications links provide the required isolation between the PPC signals (Divisions A, B, C, D) and the DAFAS (Divisions A and B).

Similarly, each DAFAS train also receives indication of the four DSS trip inputs from the four channels A, B, C, and D of the SPS via FO cables. Channels A, B, C and D of the EIS (cabinets J-SAA-CO4, J-SAB-CO4, J-SAC-CO4 and J-SAD-CO4) each contains a FOT and a FOS to transmit the associated DSS permissive signals to each DAFAS train. These signals are input to the digital input modules (DIM's) and the selective two-out-of-four logic is performed by the PLC. Channels A and B of the EIS also contain two FOR modules per channel to receive the status of the respective DAFAS train. One FOR carries the TRIP information while the other contains TEST/TROUBLE status. These signals are transmitted to the plant annunciator via the EIS. These fiber optics communications links provide the required isolation between the EIS signals (Divisions A, B, C, D) and the DAFAS (Divisions A and B).

In the ARC (J-SAA-C01 and J-SAB-C01) the DAFAS logic solvers read status of the relays in the ARC through FO links from the I/O systems located within the ARC. These inputs include AFAS and MSIS cycling relay status, initiation relay status, and bypass relay status. The logic solver output logic controls the

DAFAS initiation and bypass relays. Isolation between divisions is provided in the ARC by similar (to the EIS and PPC) fiber optic communications links. And for the power systems, the DAFAS is isolated by use of circuit breakers on the vital bus feeder cables.

7.3.5.2.2 DAFAS Logic

Each of the two DAFAS cabinets (J-SAA-C05 and J-SAB-C06) contains the logic for one DAFAS train. Each train consists of F.O. receiver (FOR) modules, F.O. modems (FOM), fiber optic transmitter (FOT) modules, power supplies, the status and test panel or man machine interface (MMI), I/O modules, and two programmable logic controllers (PLC). Each of the DAFAS cabinets contains eight FOR modules that convert the optical input signals from the PPC FOT modules to analog voltage signals. The eight (8) analog signals are sent to input modules for the two PLC systems, which perform the logic to determine if conditions for a DAFAS initiation exist. The FOR modules contain a fault indicator LED and contact output that is activated upon loss of the optical signal (e.g., severed F.O. cable). This fault indication is provided to assist in troubleshooting problems that may be encountered with the input signals. The isolated analog input signals (0-5 VDC) are directed to analog input modules where analog to digital (A/D) conversion is performed. Digitized analog values are automatically reported to the PLC upon interrogation during each PLC scan cycle. Analog input modules include self test and auto calibration features to minimize the need for periodic

calibration of inputs. The converted analog values are compared to the low S/G level setpoint in the PLC processor. The PLC generates a DAFAS-1 or DAFAS-2 initiation signal when the setpoint is exceeded, provided the requisite permissives and block conditions previously discussed are satisfied.

Four DSS trip permissive signals, channels A, B, C, and D are received by digital input modules (DIM's) from the EIS. The DAFAS then performs the same selective two-out-of-four logic that is performed by the DSS supplementary protection logic assembly (SPLA). The DAFAS trip output signal is disabled if the DSS logic indicates DSS has not actuated.

The DAFAS PLC outputs are set up as a two-out-of-two logic system where a DAFAS signal from both PLCs is required to initiate auxiliary feedwater flow. Each PLC provides a trip signal to one of the two AFAS trip legs of each ARC. Putting one of the channels into test will not result in initiating feedwater flow as a DAFAS signal from both PLCs is required to cause feedwater flow and the bypass relay contact is enabled prior to cycling each leg's initiation relay by the automated test features in the MMI. A DAFAS signal from one of the PLCs results in only one ARC trip leg, 1-3 or 2-4, to be tripped. However, both trip legs are required to be tripped in order to drop out the subgroup relays resulting in feedwater flow.

The DAFAS initiation signals cause actuation of the feedwater pumps and valves only if there is a demand for auxiliary feedwater and an AFAS or MSIS has not been generated. The occurrence of AFAS without the DSS enable indicates that

conditions indicative of an ATWS have not occurred and DAFAS actuation is not necessary. Under these conditions, DAFAS actuation is blocked by AFAS through logic in the ARC's.

DAFAS will also be blocked by a MSIS to prevent undesired interactions during non-ATWS events when conditions for a MSIS exist. The MSIS signals initiate isolation of each steam generator to rapidly terminate blowdown and feedwater flow if a high energy line rupture occurs. The MSIS block of DAFAS is done to minimize interference with this type event by preventing DAFAS initiated auxiliary feedwater flow.

The overall logic is shown in figure 7.3-7f.

7.3.5.2.3 DAFAS Output

The auxiliary relay cabinet (ARC) DAFAS equipment includes four I/O systems, two interfacing with DAFAS A (PLC-A1 and PLC-A2) and two with DAFAS B (PLC-B1 and PLC-B2). The I/O systems consist of FOMs, high speed logic solver (HSLS) assemblies with a discrete input and output capacity, initiation relays, bypass relays and power supplies. The I/O systems are located in Bay 5 and Bay 8 of each ARC. The I/O systems receive inputs from the DAFAS cabinet through a serial F.O. data link. The HSLS then generates discrete outputs which control the DAFAS-1 and DAFAS-2 initiation and bypass relays. The bypass relays may be activated through the HSLS using a key-lock switch or by the MMI during a manually initiated automated test. The I/O system also acquires inputs and makes them available to be read by the PLC through the serial data link. The inputs include AFAS-1, AFAS-2, MSIS, as well as initiation and bypass relay status.

DAFAS initiation demand is directed to the ARC via RS-232 F. O. data links. The data links are supported by ASCII/Basic modules in the PLC chassis. The trip demand is received by the HSLS which energizes the initiation relay thereby interrupting power to the existing 1-3 or 2-4 trip paths. These HSLS also accept AFAS and MSIS actuation status signals from the ARC logic to block a DAFAS actuation as required.

7.3.5.3 DAFAS Diversity From Existing Reactor Protective System

Refer to Section 7.3.5.1.9

7.3.5.4 Failure Modes and Effects

As previously discussed, the DAFAS is designed to be a highly reliable system and the equipment used in the system will be qualified to the requirements of PVNGS Class 1E safety related equipment. The qualification includes seismic, environmental, electro-magnetic interference (EMI) and fault testing. The DAFAS design includes circuits that allow the plant operators to periodically test the overall operational status of the system. Controls and indicators located on the DAFAS test and control panel permit actuation of one train at a time to demonstrate the functionality of the components in that train. Any failures of the DAFAS will be detected during periodic testing of the system.

The provisions inherent in the DAFAS design which compensate for component failures include the following:

- The redundancy provided by the four S/G level signal paths which permit the system to still function in the event of a channel failure.
- The redundant PLCs within each DAFAS channel. Two-out-of-two ARC initiation logic which minimizes inadvertent operation of the system and is compatible with the existing ARC logic scheme in the event of a spurious actuation signal.
- Power is required for the energize-to-actuate DAFAS initiation relays. Therefore, the relay and the system are normally in a similar mode to the failure mode, which is consistent with the ATWS guidance.
- There is an interlock between the DAFAS and the AFAS which prevents activation of the DAFAS if the AFAS has been activated.
- There is a selective two-out-of-four permissive signal from the DSS which enables the DAFAS for a condition of abnormally high RCS pressure.
- There is a DAFAS inhibit on a MSIS which prevents actuation of the DAFAS in the event of a S/G high energy line break.

The DAFAS is designed so that any single failure within the system will not prevent protection action at the system level. No single failure will defeat more than one of the two DAFAS

trains. The failure modes analyzed for the design of the DAFAS include DAFAS initiation relay failure to actuate, and DAFAS inadvertent actuation. These failure modes are discussed below.

7.3.5.4.1 DAFAS Initiation Relay Failure to Actuate

A failure to actuate either a train A or train B DAFAS initiation relay (mounted in the ARC cabinets J-SAA-C01 or J-SAB-C01) could be caused by the following component failures:

- Failure of the fiber optic modems or cables used for transmitting input and output signals to the DAFAS cabinets.
- Failure of one of the programmable logic controllers (PLC) or supporting equipment located in either one of the two DAFAS cabinets.
- Failure of one of the HSLS modules located in the ARC cabinets.

A single failure described above could result in disabling one of the two DAFAS trains. Each of the two DAFAS trains is capable of performing the intended function of the system. The DAFAS initiation relay which is added to the ARC cabinets has its output contact located in series with a string of relay contacts. These contacts are normally held closed and open to initiate auxiliary feedwater flow. The added DAFAS relay contacts are closed when the relay is not energized. The failures with the highest probability for one of the DAFAS trains would leave the DAFAS relay in the de-energized state

(contacts closed) and thereby have no effect on the normal operation of AFAS, nor would this cause an inadvertent actuation of auxiliary feedwater flow. Therefore, the postulated failure is in a safe direction.

7.3.5.4.2 DAFAS Inadvertent Actuation

As discussed in section 7.3.5.1.11, the DAFAS is designed with features to minimize inadvertent actuations. However, per the Standard Review Plan (NUREG 0800 Sections 7.1, 7.3 and 7.7) and IEEE-279 and IEEE-379, it is required to assume the DAFAS will fail to a mode which will result in a DAFAS actuation signal at the system level.

If an inadvertent actuation of the DAFAS were to occur, thus initiating auxiliary feedwater flow, an increase in feedwater flow to the steam generator secondary side could result. Although this event has been considered in the analysis of the plant (section 15.1.2, Increase in Feedwater Flow), it is undesirable, and the addition of another auxiliary feedwater initiation system will increase the probability of the occurrence of the event. However, the number of system interlocks has provided sufficient protection from inadvertent actuation. The NRC has concluded in a Safety Evaluation (reference 1) that this design is acceptable.

7.3.6 REFERENCES

1. Letter from S. R. Peterson, NRC, to W. F. Conway, APS, dated October 18, 1990, "Compliance With the Anticipated Transients Without Scram (ATWS) Rule, Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 (TAC NOS. 59124, 62698, 67168)."

2. CENPD-182, "Seismic Qualification of Instrumentation and Electrical Equipment", Combustion Engineering, Inc.

3. CENPD-255, "Qualification of Combustion Engineering Class IE Instrumentation", Combustion Engineering, Inc.

4. CENPD-210A, "Description of the C-E Nuclear Steam Supply System Quality Assurance Program", Combustion Engineering, Inc.

5. CENPD-148 "Review of Reactor Shutdown System (PPS Design) for Common Mode Failure Susceptibility", Combustion Engineering, Inc.

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

A listing of systems fulfilling the functional requirements for safe shutdown in the event of a fire (per 10CFR50, Appendix R) is provided in appendix 9B.

The instrumentation and control functions which are required to be aligned for maintaining safe shutdown of the reactor are discussed in this section. These functions will permit the necessary operations that will:

A. Prevent the reactor from achieving criticality in violation of the Technical Specifications.

B. Provide an adequate heat sink such that design and safety limits are not exceeded.

7.4.1 DESCRIPTION

The following systems are required for safe shutdown of the reactor:

- Auxiliary feedwater system (AFS) (paragraph 7.4.1.1.6)
- Atmospheric steam dump system (ASDS) (paragraph 7.4.1.1.7)
- Shutdown cooling system (SCS) (paragraph 7.4.1.1.8)
- Chemical and volume control system (CVCS), boron addition portion (paragraph 7.4.1.1.9)
- Condensate storage system (CSS) (subsection 9.2.6)

The following auxiliary support systems are also required to function.

- Essential spray pond system (ESPS) (subsection 9.2.1 and paragraph 7.4.1.1.4)
- Essential cooling water system (ECWS) (subsection 9.2.2 and paragraph 7.4.1.1.5)
- Onsite power system (OPS) (paragraph 8.3.1.1.2), including diesel generator systems (DGSs) (subsections 9.5.4 through 9.5.8 and paragraph 7.4.1.1.1)
- Heating, ventilating, and air conditioning (HVAC) systems (sections 6.4 and 9.4)

7.4.1.1 System Description

7.4.1.1.1 Emergency Generators

Two independent, 100% capacity diesel generators provide a dependable onsite power source capable of starting and supplying the essential loads necessary to shut down the plant safely and to maintain it in a safe shutdown condition under loss of offsite power (LOP) conditions (voltage degradation to the 4.16 kV ESF bus). Load sequencers are provided to sequentially load the diesel generators and are a part of the engineered safety features (ESF) system actuation.

The diesel generators are started automatically by a loss of offsite power (LOP), by an auxiliary feedwater actuation signal (AFAS), by a safety injection actuation signal (SIAS), or by a

containment spray actuation signal (CSAS). All are DG emergency mode starts with the exception of CSAS, which starts the DG in test mode. A LOP also initiates automatic load sequencing of the diesel generators.

The actuation system instrumentation and controls for the diesel generators are described below. Refer to paragraph 8.3.1.1.3 for a description of the ESF power system, including automatic load shedding and load sequencing. Paragraph 8.3.1.1.4 describes the standby power supply (diesel generator) and the diesel generator starting system is described in subsection 9.5.6. Additional information on diesel generator supporting auxiliaries may be found in subsections 9.5.4, 9.5.5, 9.5.7, and 9.5.8.

A. Sensors

The undervoltage monitors consist of four sensor circuits for each 4.16 kV ESF bus. The components and operation of the undervoltage monitors are described in section 8.3.1.1.3.13, subsection B.

The sensors for AFAS, CSAS and SIAS signals are described in section 7.3.

B. Initiating Circuits and Logic

The undervoltage starting signal (LOP) for the diesel generators is produced by coincidence of two-out-of-four trip of the undervoltage sensors described in section 8.3.1.1.3.13, subsection B.

There is no time delay in initiating start of the diesel generator for loss of offsite power except for an inverse time response lag and delayed time lag provided in the undervoltage monitors. Manual starting control also is provided at the diesel generator and in the control room to facilitate testing.

C. Interlocks and Bypasses

The various interlocks and actuation bypasses built into the diesel generator system are presented in paragraphs 8.3.1.1.4.4 and 8.3.1.1.4.5, respectively.

D. Redundancy

Redundant sensing with two-out-of-four coincidence logic and control is provided for diesel generator automatic actuation. Independent actuation is provided so that each diesel generator is started by its own actuation system.

E. Actuated Devices and Automatic Load Sequencing System

The actuated devices for automatic diesel generator starting are the diesel air starting solenoid valves.

In the event that diesel generators are required to power ESF or safe shutdown loads, sequential loading must be employed to avoid diesel generator

overloading. Loads to be supplied and the loading sequences are described in subsection 8.3.1.

Diesel generator load sequencing is actuated when the diesel generator output breakers close. The signal to close the diesel generator output breaker is blocked by circuit breaker interlocks that are provided to prevent automatic closing of a diesel generator breaker to an energized or faulted bus. A faulted bus is detected by inverse time overcurrent relays in the main feeder circuits of each 4.16 kV ESF bus. A sequencer is provided for each load group. The sequencer loads safe shutdown and ESF equipment onto the ESF bus so that essential loads are started within the time limits specified in Table 8.3-3.

Undervoltage trip outputs are delayed in accordance with the inverse time characteristics of the loss of voltage relays and the discrete time delay setting of the degraded voltage relays. These relays are used to confirm that a power failure has occurred. The time delays prevent spurious diesel generator actuation.

Undervoltage on the ESF bus trips all bus load automatically. After the diesel generator attains rated speed and voltage, its own circuit breaker is ready to close automatically without delay, but automatic or manual closure is blocked whenever an

ESF bus fault exists. A diesel generator breaker closed signal starts the loading sequence.

Redundant actuation and control are provided for diesel generator automatic load sequencing in that each load group is provided with its own independent automatic load sequencing system. The time at which energization of the various loads is permitted by the automatic ESF load sequencers is given in table 8.3-3. The automatic ESF load sequencing system is supported by independent 120V vital ac and Class 1E 125 V-dc sources described in paragraphs 8.3.1.1.6 and 8.3.2.1.2. The automatic load sequencing system logic is shown in figure 8.3-1.

7.4.1.1.1.1 Design Bases Information. The design bases for the diesel generator automatic load sequencing are the emergency power source requirements listed in subsection 8.3.1.

Design bases for diesel generator automatic actuation are listed in paragraph 8.1.4.2.

The diagrams used to support the design bases are given by the following:

- Logic diagram, figure 8.3-1
- P&I diagram, 01, 02, 03-M-DGP-001
- Electrical one-line diagram, 13-E-MAA-001 and 01, 02, 03-E-MAA-002

7.4.1.1.2 Emergency Generator Fuel Oil Storage and Transfer System

The controls and instrumentation for this system are discussed in paragraphs 9.5.4.3 and 9.5.4.6. The diagrams used to support the design bases are given by the following:

- Logic diagram, figure 7.4-1
- P&I diagram, 01, 02, 03-M-DFP-001

7.4.1.1.3 Class 1E AC System

This system is described in paragraph 8.3.1.1.3.

7.4.1.1.4 Essential Spray Ponds System

The controls and instrumentation for this system are discussed in paragraphs 9.2.1.6 and 9.2.1.9. The diagrams used to support the design bases are given by the following:

- Logic diagram, 01, 02, 03-M-SPP-001
- P&I diagram, figure 9.2-1

7.4.1.1.5 Essential Cooling Water System

The controls and instrumentation for this system are discussed in paragraphs 9.2.2.1.6 and 9.2.2.1.9. The diagrams used to support the design bases are given by the following:

- Logic diagram, figure 7.4-3
- P&I diagram, 01, 02, 03-M-NCP-001, -002 and -003

7.4.1.1.6 Auxiliary Feedwater System (Emergency Feedwater System) and Condensate Storage System

The safe shutdown features of these systems are discussed in subsections 10.4.9 and 9.2.6, respectively. The controls and instrumentation for the auxiliary feedwater system are discussed in paragraph 7.3.1.1.10.7. The diagram used to support the design bases are given by the following:

- Logic diagram, figure 7.4-4
- P&I diagram, 01, 02, 03-M-AFP-001 and 01, 02, 03-M-CTP-001

7.4.1.1.7 Atmospheric Dump System

The atmospheric dump valves are discussed in subsection 10.3.2. The valves are located outside the containment upstream of the main steam isolation valves.

The valves are used to remove decay heat from the steam generator in the event that the main condenser is unavailable for service for any reason, including a loss of ac power. The decay heat is dissipated by venting steam to the atmosphere. In this way, the reactor coolant system (RCS) can either be maintained at hot standby conditions or cooled down. The system instrumentation and controls for the atmospheric dump valves are described below and are shown on in engineering drawings 01, 02, 03-M-SGP-002 and -001.

A. Initiating Circuits and Logic

   There are no automatic initiating circuits for operation of the atmospheric dump valves.

The atmospheric dump valves are positioned manually by a controller (manual loading station) from either the main control room or the remote shutdown panel as part of the capability for emergency shutdown from outside the control room (see Section 7.4.1.1.10). Each valve has two separate permissive control circuits. Valve position indication is provided at each remote control station. A handwheel is also provided with the atmospheric dump valve for hand operation.

B. Bypasses, Interlocks, and Sequencing

No bypasses, interlocks, or sequencing are provided for the atmospheric dump valves.

C. Redundancy

Atmospheric dump valves are provided to maintain the reactor at hot standby or to initiate a plant cool-down. Two redundant atmospheric dump valves are provided for each steam generator, one per main steam line. However, in the event of failure of these valves, reactor decay heat will be removed through the main steam line safety valves, which will be opened when pressure in the steam generator reaches the pressure relief setpoint. Steam release will continue until the pressure is reduced to the safety valve reset pressure. The safety valves will continue to cycle in this manner as steam generator pressure rises and is relieved. The RCS will remain at hot standby conditions during this pressure relief cycling. Cooldown of the reactor coolant can be

accomplished through remote manual operation of the atmospheric dump valves. Each valve has a handwheel that can be operated locally.

D. Design Bases

1. Refer to section 10.3 for design bases for the atmospheric dump valves.

2. The two separate permissive control circuits are designed to IEEE Standards 279-1971 and 308-1974. This ensures that no single failure of the control circuits will cause a spurious opening of a valve or prevent the operation of at least one atmospheric dump valve on each steam generator.

3. The operation of the atmospheric dump valves is considered in determining the release of iodine due to steam escaping from the dumps during cooldown.

7.4.1.1.8 Shutdown Cooling System

The Shutdown Cooling System (SCS) and its interface requirements are discussed in section 5.4.7. The SCS instrumentation and control necessary to achieve cold shutdown are discussed below. The logic and piping are shown on Figure 7.4-6 and engineering drawings 01, 02, 03-M-SIP-001, -002 and -003.

7.4.1.1.8.1 Initiating Circuits And Logic. The SCS is designed to be manually initiated upon the attainment of the required Reactor Coolant System (RCS) conditions of temperature

(less than 350°F) and pressure (less than 400 psia). The SCS valve interlocks are discussed in Section 7.6; they prevent overpressurization of the low pressure portion of the system.

Control board process indication and status instrumentation is provided to enable the operator to determine system status, to evaluate system performance, and detect malfunctions. Control panel hand switches and valve position limit indication lights are provided for the isolation valves and the heat exchanger inlet, outlet, and bypass valves. Indication is provided of Low Pressure Safety Injection (LPSI) pump discharge header pressure and temperature, heat exchanger outlet temperature, and shutdown cooling injection flow and pressure. LPSI pump operating status is also indicated on the control board.

7.4.1.1.8.2 Interlocks, Sequencing And Bypasses. The SCS has overpressure protection interlocks as discussed in Section 7.6.

The system sequencing will be in approved operating procedures provided by the Applicant for the manually controlled equipment. There are no bypasses in the SCS instrumentation which would jeopardize the protection afforded by the interlocks.

7.4.1.1.8.3 Redundancy And Diversity. Each of the two SCS trains has sufficient instrumentation to assure adequate monitoring during all modes of operation. The isolation valves are discussed in Section 7.6.

7.4.1.1.8.4 Supporting Systems. The SCS has four independent power supplies for the SCS Isolation Valve Interlocks. Pumps, valves, etc. are required to be capable of being powered by the normal 1E and emergency power sources.

Also, refer to UFSAR section 7.6.1.1.1 for SCS interlocks.

7.4.1.1.9 Chemical and Volume Control System (Boron Addition Portion

The boron addition portion of the CVCS is used in the hot and cold shutdown processes. The CVCS is discussed in section 9.3.4. The system instrumentation and controls which are utilized to achieve cold shutdown are described below. The piping and logic are shown in engineering drawings 01, 02, 03-M-CHP-001, -002, -003, -004, -005 and 03-M-GHP-001.

7.4.1.1.9.1 Initiating Circuits And Logic. To aid in achieving cold shutdown the CVCS component actuation steps required are:

A. Coordinated control of the charging pumps, letdown control valves, and letdown back pressure valves to adjust and maintain the correct pressurizer water level;

B. Periodic sampling and adjustment of the boron concentration to compensate for the temperature decrease and other variables until shutdown concentration is reached.

Pressurizer level is automatically controlled during normal operation by the Pressurizer Level Control System (PLCS) as

discussed in section 7.7.1.1.3. The operation of the CVCS system is discussed in section 9.3.4. Boric acid is injected to ensure that sufficient shutdown margin is maintained as the RCS is cooled down. Control board process indication and status instrumentation is provided to enable the operator to evaluate system performance and control system operation manually.

7.4.1.1.9.2 Interlocks, Sequencing And Bypasses. The interlocks, sequence of operation, and bypasses of the CVCS are discussed in section 9.3.4.

7.4.1.1.9.3 Redundancy And Diversity. The CVCS uses multiple signals as discussed in section 9.3.4.

7.4.1.1.9.4 Supporting Systems. The major powered components of the system are required to be capable of being powered from two separate electrical buses.

7.4.1.1.10 Emergency Shutdown from Outside the Control Room

In the unlikely event that the control room should become inaccessible, sufficient instrumentation and controls are provided outside the control room to:

A. Achieve prompt hot shutdown of the reactor (hot shutdown, as used here, means the reactor is subcritical at operating pressure and temperature);

B. Maintain the unit in a safe condition during hot shutdown; and

C. Achieve cold shutdown of the reactor through the use of suitable procedures.

Postulated conditions or events resulting in control room inaccessibility are not defined; however, it is assumed these circumstances are not attended by destruction of any equipment within the control room.

See engineering drawing 13-P-OOB-003 for location of remote shutdown panels.

7.4.1.1.10.1 Hot Shutdown. Sufficient instrumentation and controls are provided external to the control room to achieve and maintain hot shutdown of the reactor should the control room become inaccessible and under the assumption that (1) the operator trips the reactor prior to evacuation from the control room, and (2) that no other adverse consequences occur in addition to the evacuation (i.e., events proceed as expected as a result of a reactor trip). For shutdown outside the control room under postulated 10CFR50, Appendix R considerations, refer to appendix 9B. Hot shutdown, as used here, means that the reactor is subcritical at normal operating pressure and temperature.

Table 7.4-1 lists the instrumentation and controls available at the remote shutdown station on PVNGS.

The atmospheric dump valve manual loading stations and the auxiliary feedwater turbine speed controller are provided with control transfer from the main control room to the remote shutdown panel.

7.4.1.1.10.2 Cold Shutdown. Cold shutdown can be achieved from outside the control room through the use of suitable procedures and by virtue of local control of the equipment listed in tables 7.4-1 and 7.1-2. No further equipment controls are needed to achieve cold shutdown.

Table 7.4-1
REMOTE SHUTDOWN PANEL INSTRUMENTATION AND CONTROLS
(Sheet 1 of 2)

Instrumentation
1. Auxiliary FW regulating valve position indicators (4)
2. Auxiliary FW turbine speed indicator (1)
3. Channel A and B neutron power level (2)
4. Channel A and B reactor coolant hot/cold leg dual temperature indicators (2)
5. Channel A and B pressurizer pressure (2)
6. Channel A and B pressurizer level (2)
7. Channel A and B safety injection tank pressure (4)
8. Channel A and B steam generator pressure (4)
9. Channel A and B steam generator level (4)
10. Channel A and B refueling water tank level (2)
11. Letdown system pressure (1)
12. Letdown system flow (1)
13. Letdown system temperature (2)
14. Volume control tank level (1)
15. Channel A charging line pressure (1)
16. Channel B charging line flow (1)
17. Channel A and B shutdown cooling heat exchanger outlet temperatures (2)
18. Channel A and B shutdown cooling flow (2)
19. Condensate storage tank level (2)
20. Auxiliary FW flow to steam generators 1/2 (2 duals)
21. Channel A and B LPSI pump discharge temperature (2)

Table 7.4-1
REMOTE SHUTDOWN PANEL INSTRUMENTATION AND CONTROLS
(Sheet 2 of 2)

Controls
1. SG atmospheric dump valve permissive controls (8)
2. Auxiliary FW regulating valve controls (4)
3. Auxiliary FW isolation valve controls (4)
4. SG atmospheric steam dump modulating controllers (4)
NOTE:
The tripping of RCPs can be performed at the switchgear.
5. Auxiliary FW turbine steam supply valve control (2)
6. Auxiliary FW turbine speed control transfer switch (1)
7. Auxiliary FW turbine speed control potentiometer (1)
8. Auxiliary FW turbine trip valve control (1)
9. Auxiliary FW turbine trip pushbutton (1)
10. All channels of MSIS actuation pushbuttons (4)
11. Channel A and B auxiliary pressurizer spray valve controls (2)
12. RCP controlled bleedoff containment isolation valve controls (2)
13. RCP controlled and bleedoff relief isolation valve control (1)
14. Letdown isolation valve controls (2)
15. Backup heater groups 1 and 2 controls (2)
16. Safety injection tank vent valve control and power disconnect switch (10)
17. Shutdown cooling pumps recirculation valve controls (2)
18. Steam generator pressure variable setpoint reset (4)
19. Pressurizer pressure variable setpoint reset (4)
20. Low pressurizer pressure bypass (4)

7.4.1.2 Design Basis Information

Refer to the design bases discussion in the appropriate section of this chapter. In addition, see section 5.4.7 for discussion of SCS design basis and section 9.3.4 for CVCS design basis.

7.4.1.3 Final System Drawings

Section 1.7 includes a list of applicable electrical and instrumentation drawings and piping and instrumentation diagrams which have been provided. Furthermore, equipment location layout drawings are included in section 1.2. Logic diagrams are shown in figures 7.4-1 through 7.4-4, and 7.4-6.

7.4.2 ANALYSIS

7.4.2.1 Conformance to IEEE 279-1971

IEEE 279-1971, "Criteria For Protection Systems For Nuclear Power Generating Station," establishes minimum requirements for protection systems. The instrumentation and controls associated with the safe shutdown systems are not protection systems as defined in IEEE 279-1971; however, many criteria of IEEE 279-1971 have been incorporated in the design of the instrumentation and controls of the safe shutdown systems. Conformance of the instrumentation and controls to Section 4 of IEEE 279-1971 is discussed below.

The discussion below only pertains to those instrument and control systems and components within the CESSAR Licensing scope.

4.1 General Functional Requirements:

The instrumentation and controls of the safe shutdown systems enable the operator to:

a. Determine when a condition monitored by display instrumentation reaches a predetermined level requiring action; and

b. Manually accomplish the appropriate safety action(s).

4.2 Single Failure Criterion:

The instrumentation and controls required for safe shutdown are designed and arranged such that no single failure can prevent a safe shutdown. Single failures considered include electrical faults and physical events resulting in mechanical damage. Each system is composed of redundant trains, including instrumentation and controls which are physically separated.

4.3 Quality Control of Components:

The instrumentation and controls associated with the safe shutdown systems within the CESSAR Licensing scope are designed in accordance with The Combustion Engineering Topical Report CENPD 210A "Description of C-E Nuclear Steam Supply System Quality Assurance Program."

4.4 Equipment Qualification:

The instrumentation and controls associated with the safe shutdown systems are designed for the normal ambient conditions of the area in which they are located. Those components located in the control room, which is normally air conditioned,

are designed to operate with a loss of air conditioning for the time necessary to achieve safe shutdown.

4.5 Channel Integrity:

Section 14.2 provides description of procedure for pre-operational tests and inspections to verify that all automatic and manual controls, and sequences of the integrated systems provided for safe shutdown, accomplish the intended design function. Essential instrumentation and controls are designed as Seismic Category I to ensure their ability to operate during and following a design basis earthquake.

4.6 Channel Independence:

Safe shutdown instrumentation and control channel independence is achieved by electrical and physical separation. This independence precludes a single event causing multiple channel failures.

4.7 Control and Protection System Interaction:

This does not apply to safe shutdown systems since they are not protection systems and do not interact with protection systems.

4.8 Derivation of System Inputs:

Pressure and temperature are directly measured. Level and flow signals are derived from differential pressure signals. Valve position signals are provided by limit switches. The derivations of various other signals are discussed in the sections where the safe shutdown systems are discussed.

4.9 Capability for Sensor Check:

Sensor checking is discussed in the sections where the safe shutdown systems are discussed.

4.10 Capability for Test and Calibration:

The instrumentation and control components required for safe shutdown which are not normally in operation are capable of being periodically tested. This includes instrumentation and controls for the SCS and CVCS. All automatic and manual actuation devices are capable of being tested to verify their operability. See section 13.5 and the Technical Specifications for periodic testing.

4.11 through 4.14 Bypassing:

There are no bypasses in the instrumentation and controls for the safe shutdown systems that apply to the operation of the safe shutdown systems.

4.15 Multiple Set Points:

This does not apply to the instrumentation and controls for the safe shutdown systems.

4.16 Completion of Protective Action Once it is Initiated:

These are not protection systems and do not take protective action.

4.17 Manual Initiation:

The safe shutdown systems are manually actuated. No single failure in the instrumentation and controls for the safe shutdown systems will prevent achieving a safe shutdown.

4.18 and 4.19 Access to Setpoint Adjustment and Identification of Protective Action:

Do not apply to the instrumentation and controls for the safe shutdown systems.

4.20 Information Readouts:

All safe shutdown system monitoring and control channels have appropriate indicators to provide the operator with sufficient, accurate information to evaluate system performance and to perform necessary actions.

4.21 System Repair:

The safe shutdown systems are actuated manually; therefore, replacement or repair of instrumentation and controls components can be accomplished, in reasonable time, when the systems are not actuated. Outage of system instrumentation and controls components for replacement or repair will be limited by the Technical Specifications.

4.22 Identification:

Identification of redundant channels is as described in sections 7.1.3.16 and 8.3.1.

7.4.2.2 Conformance to IEEE 308-1971

The electrical circuitry of the instrumentation and controls conforms to the criteria of IEEE 308-1971, "IEEE Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations." The instrumentation and controls

associated with systems and components not within the CESSAR Licensing scope are discussed in section 8.3.

7.4.2.3 Conformance to General Design Criterion 19

Conformance to GDC 19 is discussed in section 3.1.15. Remote instrumentation enables hot shutdown to be achieved if the control room is not habitable. Hot shutdown, as used here, means the reactor is subcritical at normal operating pressure and temperature. The reactor can be brought to cold shutdown, outside of the control room, by use of appropriate procedures. See section 6.4 for additional information.

7.4.2.4 Consideration of Selected Plant Contingencies

7.4.2.4.1 Loss of Instrument Air System

None of the essential control or monitoring instrumentation is pneumatic; therefore, loss of instrument air will not degrade instrumentation and control systems associated with systems required for shutdown of the plant.

7.4.2.4.2 Loss Of Cooling Water To Vital Equipment

None of the instrumentation and control equipment relies on cooling water for operation.

7.4.2.4.3 Plant Load Rejection, Turbine Trip, And Loss Of Offsite Power

In the event of loss of offsite power associated with plant load rejection or turbine trip, power for safe shutdown is

provided by the onsite emergency diesel generators. The emergency diesel generators will provide power for operation of pumps and valves; the batteries and emergency diesel generators via the battery chargers will provide power for operation of instrumentation and controls systems required to actuate and control essential components.

7.4.2.5 Emergency Shutdown From Outside The Control Room

Equipment and arrangements discussed in section 7.4.1 are in response to GDC 19 which requires certain functional capabilities outside of the control room, which are met as discussed below.

7.4.2.5.1 Design Capability for Prompt Hot Shutdown and to Maintain Hot Shutdown

Should the control room become inaccessible, the reactor may be manually tripped from the control room, as it is being evacuated, or from the Reactor Trip Switchgear System (RTSS).

Hot shutdown conditions can be maintained from outside the control room as described in section 7.4.1.1.10 by control of pressurizer pressure and level, feedwater flow, and atmospheric steam dump. Hot shutdown, as used here, means the reactor is subcritical at normal operating pressure and temperature.

7.4.2.5.2 Cold Shutdown

Cold shutdown of the reactor without access to the control room is possible by use of instrumentation and controls described in section 7.4.1.1.10 and applicable station procedures.

7.5 SAFETY-RELATED DISPLAY INSTRUMENTATION

7.5.1 DESCRIPTION

This section includes a description of that safety-related display instrumentation which is available to the operator to allow him to monitor conditions in the reactor, the Reactor Coolant System, containment, and safety-related process systems, throughout all operating conditions of the plant so that he may perform manual actions important to plant safety.

Display information identified on Tables 7.5-1, 7.5-2 and 1.8-1, within the Reactor Coolant System, steam generating system and the containment, provides for the remote monitoring of process variables during and following design basis events.

The safety-related display instrumentation is tabulated in the following categories:

A. Safety-Related Plant Process Display Instrumentation

   Information available to the operator for monitoring conditions in the reactor and related systems.

B. Reactor Trip System (RTS) Monitoring

   Information available to the operator for monitoring the status of the RTS.

C. Engineered Safety Feature (ESF) System Monitoring

   Information available to the operator for monitoring the status of each ESF system.

D. CEA Position Indication

Information available to the operator for monitoring the position of the CEAs.

E. Post-Accident Monitoring

Information available to the operator for monitoring the NSSS conditions following an accident.

F. Automatic Bypass Indication

Refer to section 7.5.2.6.

7.5.1.1 System Description

7.5.1.1.1 Safety-Related Plant Process Display Instrumentation

Table 7.5-2 lists the significant process instrumentation which is provided to inform the operator of the status of the reactor plant. This information which is used for the startup, operation, and shutdown of the plant, is provided in the Control Room. The information is provided in a form that is useful to the operator and may be indicated, recorded, or monitored in conjunction with a controlling function. Alternate indication and control instrumentation is provided at local stations outside the control room to allow reactor shutdown and maintenance of the reactor in a safe condition during hot shutdown should the control room become uninhabitable. (Refer to section 7.4.1.1.10). The control room layout is shown in figure 7.5-1.

7.5.1.1.2 Reactor Trip System Monitoring

Even though the RTS is automatic and does not require operator action (with the exception of a manual trip capability), sufficient information is provided to the operator in the control room to allow him to confirm that a Limiting Safety System Setting (LSSS) has been reached and a trip has taken place. This information consists of indication of; 1) process parameters which initiate reactor trip; 2) trip, pretrip, and bypass lights; 3) audible alarms; 4) Control Element Assembly (CEA) "dropped rod" information; and 5) trip switchgear circuit breaker position. Operating bypass indication as described in section 7.1.2.19 is provided on the remote modules which are located in the main control room. Individual trip channel bypass indication is provided locally at the PPS as well as on the remote modules in the main control room. (Refer to sections 7.1.2.19, 7.2, 7.5.1.1.1 and 7.5.1.1.4).

7.5.1.1.3 Engineered Safety Features Monitoring

The Engineered Safety Features Actuation System (ESFAS) continuously monitors the system input parameters and employs an actuation logic to initiate the Engineered Safety Features (ESF) Systems should these inputs reach their trip setpoints.

After automatic actuation, the ESF Systems will continue to function properly with limited operator action. When the transfer of safety injection pump suction from the Refueling Water Tank to the containment sump is required, the Recirculation Actuation Signal (RAS) will automatically actuate

this transfer. Following the RAS, timely operator action is required to close the RWT isolation valves to prevent ingress of air in the ESF pump suction piping during switchover to recirculation. Operator action is also taken to start other systems such as the Shutdown Cooling System (SCS). The RAS has to be manually overridden to allow certain SCS components to be operated for a plant cooldown.

Information is provided to the operator in the control room to allow him to monitor the operation of the ESF and related systems in the post-accident period. This information consists of valve position indication, pump operating status, tank level indication, flow indication, and indication of the process parameters which actuate Engineered Safety Feature Systems, (Refer to Table 7.5-1). In addition, four control modules provide indication of the pretrip, trip, bypass, and operating bypass condition of each of the associated actuation system input signals. Individual trip channel bypass indication is provided at the PPS cabinet as well as on the modules in the main control room.

Table 7.5-1 requires two Class 1E channels for the refueling water tank level indicators. The PVNGS design has two Class 1E channels with Class 1E level indicators on the remote shutdown panel, but only one Class 1E level indicator in the control room. The other level indicator in the control room is isolated and powered from a non-Class 1E power supply. Refer to section 1.9.

The following additional discussion relates to:

- Monitoring of equipment automatically actuated by the one-out-of-two engineered safety features actuation signal (BOP-ESFAS) (paragraph 7.1.1.3)
- Monitoring of equipment manually actuated (the containment combustible gas control system) (paragraph 7.1.1.3)
- Monitoring of equipment automatically actuated by an auxiliary feedwater actuation signal (AFAS).

Additional engineered safety features (ESF Class 1E, except as noted) information is presented in table 7.5-1.

A. Monitoring of Equipment Actuated by One-Out-of-Two ESFAS

The systems actuated by the one-out-of-two ESFAS are:

- Fuel building essential ventilation system
- Containment purge isolation system
- Control room/building essential ventilation system

The one-out-of-two ESFAS continuously monitors the system input parameters and performs actuation logic to initiate safeguards should these inputs reach their trip setpoints.

After the automatic actuation of the ESF systems, they will continue to function properly without operator action.

Information is provided in the control room to allow the operator to monitor and evaluate the operation of the active system components during system operation, including periodic tests. Table 7.5-1 lists parameters monitored in each system. In addition, the trip status of each actuation signal in each of the two channels, as well as indication of the process parameters which actuate these ESF systems, is indicated in the control room.

B. Monitoring of Manually Actuated Containment Combustible Gas Control System

Information is provided in the control room to allow the operator to monitor process conditions necessary for manual actuation of the containment combustible gas control system. Redundant analog instrument channels provide the required information.

Control room indications are provided to allow the operator to monitor and evaluate the operation of active system components during system operation, including periodic tests and the post-accident period. Table 7.5-1 lists parameters monitored in this system.

Control of the containment combustible gas control system is local and indication of system air flow and temperature is provided at the local panel.

C. Monitoring of Auxiliary Feedwater System

Refer to paragraph 7.3.1.1.10.7. Information is provided in the control room to allow the operator to monitor and evaluate the operation of the active system components during system operation including periodic tests and the post-accident period. Table 7.5-1 lists parameters monitored in this system.

7.5.1.1.4 Control Element Assembly Position Indication

Two independent CEA position indication systems provide CEA position information to the operator. The systems are the pulse counting CEA position indication system and the reed switch CEA position indication system. The pulse counting system is discussed in section 7.7.1.3.2; the reed switch system is discussed below. CEA position displays are located on the main control board.

The reed switch CEA position indication system utilizes a series of magnetically actuated reed switches (reed switch position transmitters) to provide signals representing CEA position. Two independent reed switch position transmitters (RSPT) are provided for each CEA. The RSPT provides an analog position indication signal and three physically separate discrete reed switch position signals. The analog position indication system utilizes a series of magnetically actuated reed switches spaced at 1-1/2-inch intervals along the RSPT assembly and arranged with precision resistors in a voltage divider network. The RSPT is affixed adjacent to the CEDM

pressure housing, which contains the CEA extension shaft and actuating magnet. The analog output signal is proportional to the CEA position within the reactor core. The three discrete reed switch position signals are contact closure signals from three separately located reed switches. These signals are an Upper Electrical Limit, a Lower Electrical Limit and a rod drop contact.

The analog reed switch CEA position signals are input to the DNBR/LPD Calculator System (See Section 7.2). CEA position information is provided to the Core Protection Calculators (CPCs) indirectly via a high speed communication bus connecting the CEACs and the CPCs. This analog CEA positional data is sent to the CEA Calculators (CEACs) in each safety channel via the CEA Position Processors (CPPs). Each of the two CEACs in each safety channel has its own CPP, thus supporting the concept of redundancy to increase the margin of error should an input to the CEAC fail.

The CEA Calculators display the position of each regulating, shutdown, and part-strength CEA to the operator in a numeric format on a visual display on the Operator Modules (OMs) from which the operator can address any analog position signal for display.

Additionally, this information is displayed in both graphical and numeric display on main control board CEA Position Display System (CEAPDS). The CEAPDS also displays in numerical format penalty factor, CEA deviation, and a user adjustable alarm setpoint for various CEA and CPC related functions including

deviation. The operator has the capability to select any safety channel for display or any regulating group.

In addition the displays, CEA deviation information is provided by the CEA Calculators to the CPCs and a CEA deviation alarm. The CEA deviation alarm is provided to the plant annunciator system in the event a CEA Calculator indicates that the difference between the highest and lowest CEA positions in a subgroup exceeds a predetermined allowable deviation. The CEA deviation information is used in the CPCs determination of power distribution. The power distribution is then factored into the low DNBR and high local power density trip function. Pre-trip alarms are initiated if the DNBR or Local Power Density trip limits are approached. A pre-trip alarm light is provided on the PPS control panel (both local and remote). Also, a pre-trip alarm is provided to the plant annunciator system.

The three discrete CEA position switches provide signals (contact closure signals) to the Control Element Drive Mechanism Control System (CEDMCS). The signals are utilized to provide CEA limit indication on the main control board and also to provide input to the CEA control interlocks. Each of the three discrete reed switch contacts actuates an interface relay located within the CEDMCS. These relays provide contact signals for indication and control and, in the case of the rod drop switch, an additional contact signal is provided to the Plant Monitoring System to set the pulse counting system (see section 7.7.1.3.2.3). The upper and lower electrical limits

indication appears as two separate lights on the CEDMCS control panel mounted on the main control board. The CEA drop indication appears on the core mimic display mounted on the main control board.

7.5.1.1.4.1 CEA Limit Lights Indication. A light display is provided on the control board to indicate the fully withdrawn and fully inserted position of each CEA and provides indication of a dropped CEA.

Table 7.5-1

ENGINEERED SAFETY FEATURE SYSTEM MONITORING (Sheet 1 of 7)

Parameter	Type of Readout	Number of Channels	Location	Range	Displayed Accuracy
Fuel Building (FB) Essential Ventilation System					
FB ventilation isolation damper position	Indicating lights	1 pair/ damper	Control room	NA	NA
FB essential exhaust fans motor starter contact position	Indicating lights	1 pair/fan	Control room	NA	NA
Fuel pool area radiation monitor	Indicator	1	Control room	10^{-1} - 10^{4} mr/h	±20%[(a)]
Fuel building exhaust gas activity monitor	Indicator	1	Control room	10^{-6} - 10^{-1} $\mu Ci/cm^{3}$	±25%[(a)]
Fuel building AFU charcoal differential temperature monitor	Indicator	2	Control room	0 to 50F	±1%[(b)]

a. Accuracy as a percentage of the displayed value.

b. Accuracy as a percentage of the monitors full scale.

Table 7.5-1

ENGINEERED SAFETY FEATURE SYSTEM MONITORING (Sheet 2 of 7)

Parameter	Type of Readout	Number of Channels	Location	Range	Displayed Accuracy
Fuel Building negative pressure (diff press across inside of bldg and ambient)	Indicator	1	Control room	0 to 0.27 in. H_2O	+1%[b]
Containment Purge Isolation System					
Normal purge isolation valve position	Indicating lights	1 pair/ valve	Control room	NA	NA
Power access purge area monitors	Indicator	2	Control room	10^{-1} – 10^{4} mr/h	±20%[a]
Control Room/ Building Essential Ventilation System					
Control room/ building ventilation isolation damper position	Indicating lights	1 pair/ damper	Control room	NA	NA
Control room/ building essential fan motor breaker position	Indicating lights	1 pair/fan	Control room	NA	NA

Table 7.5-1

ENGINEERED SAFETY FEATURE SYSTEM MONITORING (Sheet 3 of 7)

Parameter	Type of Readout	Number of Channels	Location	Range	Displayed Accuracy
Control room ventilation intake gas activity monitors	Indicator	2	Control room	10^{-6} to 10^{-1} $\mu Ci/cm^3$	± 25%(a)
Control room temperature monitors	Indicator	2	Control room	0 to 150F	± 2%(b)
Containment Combustible Gas Control System					
Containment hydrogen monitors	Indicator Recorder	2 1	Control room	0 to 10%	± 10.0%(b,c) ± 10.0%(b,d)
Hydrogen control containment isolation valve position	Indicating lights	1 pair/ valve	Control room	NA	NA
Auxiliary Feedwater System					
Auxiliary feedwater pump discharge pressure	Indicator	1/pump	Control room	0 to 2000 psig	± 2.25%(b)

c. Displayed accuracy of control room indicator.

d. Displayed accuracy of control room recorder.

Table 7.5-1

ENGINEERED SAFETY FEATURE SYSTEM MONITORING (Sheet 4 of 7)

Parameter	Type of Readout	Number of Channels	Location	Range	Displayed Accuracy
Auxiliary feedwater flow	Indicator	2 (redundant/each auxiliary feedwater line	Control room	0 to 2000 gal/min	± 35%[b][e]
Auxiliary feedwater regulating valves	Indicating lights	1 pair/valve	Control room	NA	NA
Auxiliary feedwater pump turbine speed	Indicator	1	Control room	0 to 6000 r/min	± 2.5[b]
Auxiliary feedwater suction from CST isolation valves	Indicating lights	1 pair/valve	Control room	NA	NA
ESF Status Panel					
System availability	Indicating lights	1 light/system/trip	Control room	NA	NA

e. Accuracy given is for the rated flow of one AFW pump.

Table 7.5-1

ENGINEERED SAFETY FEATURE SYSTEM MONITORING (Sheet 5 of 7)

Parameter	Type of Readout	Number of Channels	Number of IE Channels	Range	Indicator Accuracy	Location
Containment Isolation System[f]						
Containment Isolation Valve Position	Indicating Lights	1 pair/valve		N/A	N/A	Control Room
Safety Injection System						
Safety Injection/ Shutdown Cooling Valve Position	Indication Lights/ Indicator	1 pair/ valve 1 per valve	(g)	N/A	N/A	Control Room[h]
Safety Injection Tank Level	Indicator Indicator	1/Tank 2/Tank	1/Tank --	0-100% (34 ft. scale) 0-100% (4 ft. scale)	± 2-1/2% ± 2-1/2%	Control Room Control Room
High Pressure Safety Injection Cold Leg Flow	Indicator	4	4	0-750 gpm	± 2-1/2%	Control Room
High Pressure Safety Injection Hot Leg Flow	Indicator	2	2	0-750 gpm	± 2-1/2%	Control Room/ Local
Low Pressure Safety Injection Flow	Indicator	2	2	0-10,000 gpm	± 2-1/2%	Control Room/ Local
Shutdown Cooling Heat Exchanger Inlet Pressure	Indicator	2	--	0-750 psig	± 2-1/2%	Control Room

Table 7.5-1 (Cont'd)

ENGINEERED SAFETY FEATURE SYSTEM MONITORING (Sheet 6 of 7)

Parameter	Type of Readout	Number of Channels	Number of IE Channels	Range	Indicator Accuracy	Location
High Pressure Safety Injection Pump Discharge Header Pressure	Indicator	2	--	(#1) 0-3000 psig (#2) 0-2500 psig	± 2-1/2%	Control Room
Low Pressure Safety Injection Pump Header Pressure	Indicator	2	--	0-750 psig	± 2-1/2%	Control Room
Safety Injection Tank Pressure	Indicator Indicator	1/Tank 2/Tank	1/Tank 1/Tank	0-750 psig 450-650 psig	± 2-1/2% ± 2-1/2%	Control Room/Local Control Room
Safety Injection Line Pressure	Indicator	6	--	0-2500 psig	± 2-1/2%	Control Room
Shutdown Cooling Inlet and Outlet Temperature	Indicator/ Recorder	2	2	40-400F	± 2-1/2%	Control Room/Local
Shutdown Cooling Heat Exchanger Outlet Temperature	Indicator	2	2	40-400F	± 2-1/2%	Control Room
<u>Main Steam Isolation Systems</u>						
Main Steam Isolation Valve Position	Indicating Lights	1 pair/ valve	--	N/A	N/A	Control Room
Main Steam Isolation Valve Bypass Valve Position	Indicating Lights	1 pair/ valve	--	N/A	N/A	Control Room
Main Feedwater Isolation Valve Position	Indicating Lights	1 pair/ valve	--	N/A	N/A	Control Room

Table 7.5-1 (Cont'd)

ENGINEERED SAFETY FEATURE SYSTEM MONITORING (Sheet 7 of 7)

Parameter	Type of Readout	Number of Channels	Number of IE Channels	Range	Indicator Accuracy	Location
Chemical Volume Control System[f]						
Refueling Water Tank Isolation Valve Position	Indicating Lights	1 pair/ valve	1	N/A	N/A	Control Room
Refueling Water Tank Level	Indicator	4	4	0-100%	± 2%	Control Room
Refueling Water Tank Level	Indicator	2	1[i]	0-100%	± 2%	Control Room

NOTES:

f. All CVCS containment isolation valves are open/close type valves.

g. All indication on electrically actuated valves in the Safety Injection/Shutdown Cooling System, with exception of SI-661, receive IE power.

h. Valves which are required to bring the plant to cold shutdown have open/close position indicated outside the Control Room also.

i. Only one indicator is class 1E. The other indicator is non-1E and isolated.

Table 7.5-2

SAFETY-RELATED PLANT PROCESS DISPLAY INSTRUMENTATION (Sheet 1 of 2)

Parameter	Type of Readout	Number of Channels	Range	Indicator Accuracy	Location[(b)]
Pressurizer Pressure	Indicator	4	1500-2500 psia	± 2%	Control Room
Pressurizer Pressure	Indicator	4	0-3000 psia	± 2%	Control Room
Pressurizer Pressure	Recorder	1	0-3000 psia	± 2%	Control Room
Pressurizer Pressure	Indicator	4	0-750 psia	± 2%	Control Room
Containment Pressure	Indicator	4	-4 to +85 psig	± 2%	Control Room
Containment Pressure	Indicator	4	-4 to +20 psig	± 2%	Control Room
Refueling Water Tank Level	Indicator/Alarm	2	0-100%	± 2%	Control Room
Refueling Water Tank Level	Indicator	4	0-100%	± 2%	Control Room
Steam Generator Pressure	Indicator	4/S.G.	0-1524 psia	± 2%	Control Room
Steam Generator Level (Wide Range)	Recorder	1/S.G.	0-100%	± 2%	Control Room
Steam Generator Level (Wide Range)	Indicator	4/S.G.	0-100%	± 2%	Control Room
Steam Generator Level (Narrow Range)	Indicator	4/S.G.	0-100%	± 2%	Control Room
Pressurizer Level	Indicator	2	0-100%	± 2%	Control Room
Coolant Temperature (Hot)	Indicator	8*	375-675°F	± 2%	Control Room
	Indicator	4	50-750°F	± 2%	Control Room
	Recorder	2	50-750°F	± 2%	Control Room
Coolant Temperature (Cold)	Indicator	8*	465-615°F	± 2%	Control Room
	Indicator	4	50-750°F	± 2%	Control Room
	Recorder	2	50-750°F	± 2%	Control Room
Local Power Density	Indicator	4	0-25 Kw/ft.	± 2% †	Control Room
DNBR[a]	Indicator	4	0-2[a]	± 2% †	Control Room
Neutron Flux Level Rate of Change	Indicator	4	-1 to +7 DPM	± 2%	Control Room
Neutron Flux Power Level	Indicator	4	2×10^{-8} to 200% power	± 2%	Control Room
(Safety Channels)	Recorder	4	0 to 200% power	± 2%	Control Room

* equally divided between Loops 1 & 2.

† indicator accuracy

a. CPC Point ID 107 can display the full 0-10 range on either the operator module or maintenance and test panel.

b. Refer to Table 7.4-1 for channels that also provide indication at the Remote Shutdown Panel.

Table 7.5-2 (Cont'd)

SAFETY-RELATED PLANT PROCESS DISPLAY INSTRUMENTATION (Sheet 2 of 2)

Parameter	Type of Readout	Number of Channels	Range	Indicator Accuracy	Location[(b)]
Neutron Flux Power Level (Safety Channels)	Recorder	4	0-200% power	$\pm$ 2%	Control Room
Neutron Flux Power Level (DNBR/LPD Calculators)	Recorder	4	0-200% power	± 2%	Control Room
Charging Pump Discharge Pressure	Indicator	1	0-3000 psig	± 2%	Control Room
Charging Flow	Indicator	1	0-150 gpm	± 2%	Control Room

7.5.1.1.5 Post-Accident Monitoring

The Post-Accident Monitoring (PAM) instrumentation is provided to allow the operator to assess the state of the NSSS following Design Basis Events. Most of these instruments monitor instruments or equipment, or systems which provide automatic action for the Design Basis Event.

Refer to Table 1.8-1, in addition the following are also required as post-accident monitoring instrumentation: extended range noble gas effluent radiation monitoring, containment high-range radiation monitoring, containment pressure monitoring, containment water level monitoring, and containment hydrogen monitoring. Refer to section 18.II.F.1 for TMI-related information pertaining to post-accident monitoring instrumentation.

A detailed discussion on radiation monitoring is provided in section 11.5.

A discussion on hydrogen monitoring is provided in paragraph 6.2.5.2.2.2.

7.5.1.1.6 Automatic Bypass Indication on a System Level

A status monitoring panel in the control room displays the availability of the CESSAR ESFAS, the one-out-of-two ESFAS, all the ESF systems (including the NSSS ESF systems and the containment combustible gas control system), and the automatic ESF supporting systems. The reactor protective system (RPS) has no bypasses or inoperable conditions on a system level; therefore, no RPS condition is indicated on the panel.

The number of bypass features or devices provided for operational purposes or routine testing is minimized by design, but wherever such features or devices are an integral part of the design and are used more frequently than once a year, a means of indication is provided in the main control room. Each ESF system component (such as pump, valve, or fan, including vital support system equipment) that must operate upon automatic or manual ESF actuation is monitored by a system level annunciator indicating inoperability of that ESF system. A bypass of a component in a given system by operation of a control switch, loss of control circuit power, pulling of a fuse, "racking-out" a breaker, or loss of vital supporting auxiliary systems is annunciated with an audible alarm. Any other piece of plant equipment in a system, not part of the ESF equipment, but that performs some required function in support of a piece of ESF equipment, provides a contact to annunciate the bypass status of the dependent ESF system.

Equipment rendered inoperative because of infrequent maintenance functions (performed on a frequency of once a year or less) is not specifically and automatically indicated. The capability to manually initiate a system inoperable signal is, however, included. Such maintenance activities include manual valves provided for isolation of equipment for repair, electrical cable connectors, screw terminals, motor-pump couplings, or other manual disconnects.

See figure 7.5-2 for panel layout for the safety equipment status system.

7.5.2 ANALYSIS

7.5.2.1 Analysis of Safety-Related Plant Process Display Instrumentation

Plant Process Instrumentation is provided to give the operator information to monitor conditions in the plant and perform operations important to plant safety. In addition, the information allows the operator to perform the cross-checking of Plant Protection System measurement channels to assure operational availability of these channels as discussed in section 7.2.1.1.9 and 7.3.1.1.8. The following design criteria were used in the selection of plant instrumentation:

A. Provide continuous monitoring of process parameters required by the operator;

B. Provide a permanent record of those parameters for which trend information is useful, from a safety standpoint;

C. Provide display information to the operator that is reliable, comprehensible, and timely;

D. Provide multiple channels of indication for the RPS and ESFAS process parameters to allow cross-checking of channels; and

E. Provide instrumentation display that adequately monitors the parameters over the ranges required for various conditions.

The information provided is sufficient to allow the operator to accurately assess the conditions within the reactor systems,

and in a timely manner perform those appropriate actions to maintain the reactor systems within the conditions assumed by the safety analysis in Chapter 15. In addition, the information allows the operator to perform the cross-checking of measurement channels to assure operational availability of these channels as discussed in section 7.2.1.1.9 and 7.3.1.1.8.

7.5.2.2 Analysis of Reactor Trip System Monitoring

Sufficient information is provided to the operator to allow confirmation that a trip has occurred and to determine the process parameter that has provided a trip input.

CEA insertion information can be determined by the operator after a trip by visual display bar chart information and CEA Limit Indication (refer to section 7.5.1.1.4).

Indication of neutron levels in the reactor core as well as other reactor and Reactor Coolant System information are provided for the operator.

The following design criteria were used in the selection of information that is provided to the operator:

A. System conditions requiring operator attention during routine plant operations and at the time of reactor trip are available in the control room;

B. Annunciation in the control room of all operations performed at the RPS cabinet affecting the function of the system;

C. Indication of any selected plant variables that are manually bypassed; and

D. Indication of automatic removal of a bypass.

7.5.2.3 Analysis of Engineered Safety Features Monitoring

Information is provided to the operator so that he may monitor the status of the Engineered Safety Features Systems. The following design criteria were used in the selection of information that is provided to the operator:

A. System conditions requiring operator attention or action during routine plant operators are displayed and/or controlled in the control room;

B. Annunciation is provided in the control room of all operations performed at the ESFAS cabinet affecting the function of the system;

C. Indication of any selected plant variable that is manually blocked or bypassed is provided; and

D. Indication of automatic removal of block or bypass status is provided.

Consistent with the above criteria, the information shown in Table 7.5-1 is provided for the operator's use. The information is provided to aid the operator in determining that manual actuation of an Engineered Safety Features System is required (which he may then perform) and to aid him in confirming proper system operation after automatic initiation. Input parameters used for actuation are indicated in the

control room as are positive indications that pump and valves have actuated and that flows have been established.

BOP ESFAS. Information is provided to the operator to allow monitoring of the status of the one-out-of-two ESF systems. The design criteria provided in CESSAR Section 7.5.2.3 were used in the selection of information that is provided to the operator. Consistent with these criteria, the information shown in table 7.5-1 is provided for operator use.

The display instrumentation for the containment combustible gas control system is supplied in such a manner that the operator has time to make reasoned judgment before his action is essential. Consistent with this criterion, the information shown on table 7.5-1 is provided for operator use.

The ESFAS actuation parameter displays provide information to enable the operator to assess accident conditions and to perform the necessary operation of the containment combustible gas control system. Containment hydrogen concentration monitors provide information necessary for manual combustible gas control through the use of the containment hydrogen recombiners. Refer to Table 1.8-1 and subsections 6.2.5 and 18.II.F.1.6 for further information.

7.5.2.4 Analysis of CEA Position Indication

CEA Position Indication allows the operator to easily determine the position of all of the CEAs within the reactor core. The information is presented in a form that can be assessed by the operator to easily determine that the CEAs are in the required

position, that a CEA has dropped into the core, or that the CEA positions are as required after a reactor trip.

The following design criteria were used in selection of the CEA position indication:

A. Position readouts of all CEAs may be obtained.

B. Continuous position indication of all CEAs is available.

C. A means is provided to alert the operator to deviation of CEAs within a group.

D. A permanent record may be made of the position of any or all CEAs.

E. Separate "full-in" and "full-out" indications are provided for each CEA.

F. Redundant and diverse means of indicating CEA position are provided.

7.5.2.5 Analysis of Post-Accident Monitoring Instrumentation

The Post-Accident Monitoring (PAM) instrumentation which is identified in table 1.8-1 is provided for remote monitoring of post-accident conditions within the Reactor Coolant System, steam generating system and the containment. Post-accident conditions are defined as those conditions which exist after the NSSS has reached a stable configuration following an accident.

The extensive instrumentation and controls required by table 1.8-1 provide the plant operator with long-term

monitoring and surveillance capabilities and provide redundancy and appropriate wide-range indication of post-accident conditions within the primary containment.

The requirements of IEEE 279-1971 "Criteria for Protections System for Nuclear Power Generating Station" are not completely applicable to the design of the post-accident monitoring instrumentation in that this instrumentation is not part of a protection system. However, the intent of some of the design criteria contained therein will be applied to the design of those systems used to monitor post-accident conditions to the extent appropriate as follows (heading numbers correspond to the Section numbers in IEEE 279-1971):

4.1 General Functional Requirement:

The PAM instrumentation is not designed to limit reactor fuel, fuel cladding and coolant conditions to levels within plant and fuel design limits. Each instrument's performance characteristic, response time and accuracy have been selected for compatibility with the design goal of providing the operator with long-term monitoring and surveillance capabilities after the plant has reached a stable condition.

4.2 Single Failure Criterion:

The PAM instrumentation is designed so that any single failure shall not result in the loss of the surveillance function on the system level after an incident. The wiring is arranged so that no single fault or failure, including either an open or shorted circuit will result in the loss of surveillance capability at the system level.

4.3 Quality Control of Components and Modules:

The Quality Assurance program is described in Topical Report CENPD 210A "Description of the C-E Nuclear Steam Supply System Quality Assurance Program" (Reference 1). This program includes appropriate requirements for design review, procurement, inspection and testing to ensure that PAM components shall be of a quality consistent with minimum maintenance requirements and low failure rates.

4.4 Equipment Qualifications:

The PAM instrumentation meets the equipment qualification requirements described in Section 3.10 and 3.11.

4.5 Channel Integrity:

Type testing of components, separation of sensors and channels, and qualification of cabling are utilized to ensure that the channels will maintain the functional capability required under applicable extreme conditions.

4.6 Channel Independence:

The locations of the sensors and the points at which the sensing lines are connected to the process loop have been selected to provide physical separation of the channels to the maximum extent practicable, thereby precluding a situation in which a single event could fail both PAM channels. See section 8.3.1.4 for cable routing.

4.7 Control and Protection System Interaction:

Where PAM instrumentation is also used for control purposes an isolation device shall be used to prevent any credible failure in the control portion from affecting the PAM readout.

4.8 Derivation of System Inputs:

All system inputs are derived from signals that are direct measures of the desired variables.

4.9 Capability for Sensor Checks:

Performance of the surveillance instrumentation will be verified during reactor operation subject to the following:

a. Testing will not adversely affect the safety or operability of the plant;

b. Normal system operation will be considered an acceptable method of verifying surveillance instrumentation performance if system operating parameters are similar to those anticipated following a LOCA:

c. In the event that the surveillance instrument performance cannot be verified under the conditions of a and b above, periodic testing will be performed during reactor shutdown periods.

4.10 Capability for Test and Calibration:

The PAM instrumentation can be checked from the sensor signal through the indication located in the main control room. Many of the sensors used for PAM are also used in the PPS and

therefore will be tested during PPS testing. For those sensors that are not part of the PPS, testing will be performed on a periodic basis.

4.11 Channel Bypass or Removal from Operation:

Any one of the two PAM channels may be tested, calibrated or repaired without detrimental effects on the other channel. The limitations specified in Technical Specifications should be adhered to.

4.12 Operating Bypasses:

This Section is not applicable to PAM instrumentation.

4.13 Indication of Bypasses:

This section is not applicable to PAM instrumentation.

4.14 Access to Means for Bypassing:

This section is not applicable to PAM instrumentation.

4.15 Multiple Set Points:

This section is not applicable to PAM instrumentation.

4.16 Completion of Protective Action Once it is Initiated:

This section is not applicable to PAM instrumentation.

4.17 Manual Initiation:

This section is not applicable to PAM instrumentation.

4.18 Access to Set Point Adjustments, Calibration and Test Points:

See section 13.5 for a discussion of administrative control for access to setpoint adjustments.

4.19 Identification of Protective Actions:

This section is not applicable to PAM instrumentation.

4.20 Information Readout:

Indicators capable of displaying both current reading and historical trend information are provided for each redundant post-accident monitoring (PAM) channel. Outputs are provided for continuously recording one channel of each analog variable.

4.21 System Repair:

A defective PAM channel can be detected by testing as previously discussed. Replacement or repair of one PAM channel will not affect the other channel. (Refer to Technical Specifications for limitations).

4.22 Identification:

The PAM instrumentation channels will not be uniquely identified as such. The channels will be identified to distinguish between redundant channels for the same variable. Refer to section 1.8 for a discussion of Regulatory Guide 1.97, Post Accident Monitoring Instrumentation.

7.5.2.6 Analysis of Automatic Bypass Indication on a System Level

The automatic bypass/inoperable indication status panel provides a means for the operator to easily determine the availability of ESF and ESF-supporting systems. The following design criteria were used in the design to conform to Regulatory Guide 1.47 and Branch Technical Position ICSB-21.

A. The system consists of two portions; one reporting the status of safety train A equipment, the other reporting the status of safety train B equipment. The system accepts channelized (channel A, B, C, or D) Class 1E inputs. The system is nonsafety-related, but since inputs are Class 1E, the system is powered from Class 1E 125 V-dc power supplies.

B. Status contacts continuously monitor the availability of control power and the position of circuit breakers of all automatically actuated ESF devices. A loss of control power or deliberate racking out of a breaker automatically initiates a system level indication with audible alarm, except for the containment purge refueling mode isolation valves. The circuit breakers for these valves are locked open during normal operation. An alarm is not initiated when the valve circuit breakers are locked open and the valve is in the safe position (closed). An alarm will be initiated if the valve is not in a safe position and a loss of power develops, or the valve is not in a safe position and its circuit breaker is open.

C. The capability for initiating a manual bypass indication and alarm is provided via a system level manual bypass switch used to indicate the bypass condition to the operator for those manual valves and other components which are not automatically monitored. The initiation and removal of manual bypass indication will be under administrative control.

D. All systems affected by the bypassing/inoperability of a given component that are shared by multiple systems automatically generate a bypass/inoperable audible and visual alarm in each system affected.

E. Indication and annunciation test capability is provided by simulating a trouble contact condition when the test button is depressed. The test feature generates the audible alarm and causes all windows to flash in unison. The test feature is independent for each channel.

7.5.3 REFERENCES

1. CENPD 210A "Description of the C-E Nuclear Steam Supply System Quality Assurance Program" Combustion Engineering, Inc.

7.6 ALL OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY

7.6.1 INTRODUCTION

This section describes the Shutdown Cooling System Suction Line Valve Interlocks and the Safety Injection Tank Isolation Valve Interlocks. The Shutdown Cooling System (SCS) is discussed in section 5.4.7; the Safety Injection System (SIS) is discussed in section 6.3.

The interlocks on the SCS and on the Safety Injection Tanks (SIT) are designed to act as permissives. The Shutdown Cooling System Suction Line Valve Interlocks permit the isolation valves to be opened below a certain pressure. The Safety Injection Tank Isolation Valve Interlocks are designed to permit the operator to isolate the SITs at low pressure and automatically open them above a certain pressure. This allows the SITs to be maintained at a given pressure when the balance of the RCS is depressurized.

Since there are no reactor coolant loop isolation valves, there will always be some flow in an idle loop so that there is no need for a cold water interlock.

The refueling interlocks are discussed in section 9.1.4.

The Shutdown Cooling System Suction Line Valve Interlocks and the Safety Injection Tank Isolation Valve Interlocks are automatically connected to the emergency busses if there should be a loss of all AC power. This is to assure that the interlocks and valves will be able to operate under all operating conditions.

7.6.1.1 System Description

7.6.1.1.1 Shutdown Cooling System suction Line valve Interlocks

The SCS is a low temperature, low pressure system used to remove decay heat from the RCS. Cooldown of the RCS is accomplished via the steam generator down to about 350°F and about 400 psia. Below these values the SCS is used to cool the RCS to refueling temperatures and to maintain these conditions for extended periods of time.

To preclude overpressurization, there are redundant, motor driven, interlocked, isolation valves on each suction line. The interlocks prevent the suction line isolation valves from being opened if RCS pressure has not decreased below 410 psia.

These interlocks are redundant so that any single failure will not cause a suction line and heat exchanger to be subjected to pressures greater than design pressure. The interlock cannot be overridden so that operator action cannot inadvertently subject the SCS to RCS pressure. In addition, no single failure can prevent the operator from aligning the valves, on at least one suction line, for shutdown cooling after RCS pressure requirements are satisfied.

Redundant relief valves are provided on the suction lines to prevent or mitigate overpressurization from pressure transients. These transients can be caused by inadvertent starting of HPSI pumps, charging pumps, inadvertent energizing of pressurizer backup heaters, or a combination of these. The

relief valves are set at 467 psig to insure the system stays below its design limits.

7.6.1.1.2 Safety Injection Tank Isolation Valve Interlocks

The SIS is designed to inject borated water into the RCS upon receipt of an SIAS (refer to Section 7.3) and to provide long term cooling in conjunction with other systems following an accident. The Safety Injection Tanks (SIT) inject borated water if system pressure drops below their internal pressure. During normal operation each tank has a motor operated isolation valve that is open and power to its motor circuit is removed to eliminate the possibility of spurious actuation. As the RCS pressure is reduced during plant shutdown, the low pressurizer pressure trip setpoint is reduced to avoid inadvertent initiation of Safety Injection, the SITs are depressurized to a value below the SCS design pressure, and the valves have their power restored and are closed.

The SIT interlocks are used to prevent the SITs from inadvertently pressurizing the SCS while maintaining SIT availability in case of a LOCA. Refer to Figure 7.6-2 for the interlock logic. The isolation valves are manually closed when RCS pressure drops below the value shown on Table 7.6-1 so that the SITs cannot cause overpressurization of the SCS, and also so that the SITs can be maintained at some pressure above atmospheric. The valves will automatically reopen when RCS pressure exceeds 515 psia; this is not a problem for the SCS since SIT pressure is less than SCS design pressure at this time. This opening of the SIT isolation valves insures that

the SITs are available for injection during plant startup. If the isolation valves are closed and an SIAS is initiated, the isolation valves will automatically open. The SIAS overrides the interlock or any manual signal.

There is an alarm associated with the SITs. The alarm will sound if the RCS pressure is increased to 700 psig and the SITs have not been repressurized. This insures that the SITs will be available for injection at the RCS pressure specified in the ECCS analysis (See section 6.3.3).

7.6.1.1.3 Class 1E Alarm System

A Class 1E alarm system is provided for a limited number of operational occurrences for which no specific automatic actuation of a safety system is required. The Class 1E alarm system alerts the operator to keep the plant operating within technical specification limits and prevent equipment damage.

The 1E alarm system consists of individual visual status indicators dedicated to each instrument channel. An audible alarm is provided for each alarm channel. The alarmed condition requires manual reset, once initiated.

The 1E alarm system is independent of the normal plant annunciation system and the redundant channels are powered from separate 1E power trains.

Operator acknowledgment of 1E alarms follows the same procedure used for the normal plant annunciator, with the exception that the audible alarms for each channel can be "silenced" with the use of a keylock switch (see 7.6.2.1.3).

7.6.1.1.3.1 Reactor Coolant Pump Cooling Water Supply Monitoring. Safety grade instrumentation is provided to detect the loss of cooling water to the reactor coolant pumps in order to ensure that the operator will have sufficient time to initiate manual tripping of the pumps to protect the pumps from seal failure. The cooling water flowrate to each pump is monitored by two redundant flow transmitters. If the cooling water flowrate is reduced below the minimum required for pump operation, a low flow signal will be initiated in each flow channel for the affected pump. The low flow signals will independently actuate their respective Class 1E redundant alarm system channels in the control room. The setpoint for alarming will be selected with sufficient margin to assure that proper operator notification is given. The alarm system utilizes a one-out-of-one logic for each channel.

7.6.1.1.3.2 Safety Injection Tank Pressure Monitoring. Safety grade instrumentation is provided to alert the operator of the unavailability of the safety injection tanks (SITs) to perform their core flooding function in the event of a LOCA.

The pressure in each SIT is independently monitored by a pressure sensor.

Reactor coolant system pressure is monitored by pressurizer pressure sensors.

If SIT pressure is reduced below that required for core flooding, a low-pressure signal will be initiated in the respective pressure channel for the affected tank.

The low-pressure signal will independently actuate its respective Class 1E redundant alarm system for channel B (tanks 1 and 2) or for channel A (tanks 3 and 4) in the control room.

The alarm for low SIT pressure is based upon an indication of pressurizer pressure above 715 psia coincident with SIT pressure below 600 psig. The alarm system utilizes a one-out-of-one logic for each SIT pressure sensor, with a one-out-of-two logic for each visual alarm window.

7.6.1.1.3.3 Auxiliary Building ESF Pump Room Level Monitoring. Safety grade instrumentation is provided to alert the operator of a leak in an auxiliary building ESF pump room (containment spray, high-pressure safety injection, and low-pressure safety injection). The level in each ESF pump room is independently monitored by a level switch mounted in the drain basin of each room. A high level signal, from the level switch, will independently actuate the respective Class 1E alarm in the control room.

7.6.1.1.4 Other Systems

7.6.1.1.4.1 Fire Protection Instrumentation and Detection System. The instrumentation utilized to detect, alarm, or mitigate the consequences of fires is discussed in subsection 9.5.1.

Table 7.6-1
SHUTDOWN COOLING (SDC) SYSTEM AND SAFETY INJECTION TANK (SIT) INTERLOCKS (Page 1 of 3)

SYSTEM	SETPOINT[a]	FUNCTION and Value[b]
Shutdown Cooling System		
SDC Suction Line Valves	≤ 385 psia	Open Permissive Interlock: prevents SDC isolation valves from opening until RCS pressure is less than the setpoint value and allows operator to open valves only when pressure is < 410 psia. Technical Specifications (TS): Verify SDC System open permissive interlock prevents the valves from being opened every 18 months with a simulated or actual RCS pressure signal ≥ 410 psia (S.R. 3.4.15.2). Test description in UFSAR section 7.6.2.2.1; 4.10
Shutdown Cooling Relief Valves	467 psig	Prevents or mitigates over-pressurization of the SCS; an LTOP design feature.
Safety Injection Tank SIT Isolation Valves	≥ 410 psia	Auto-Open Interlocks: SIT isolation valves automatically open prior to exceeding RCS pressure of 515 psia OR on a SIAS, if the valves are closed. Sends an open signal if valves are open, or closed, and overrides a closing signal.[d]

Table 7.6-1
SHUTDOWN COOLING (SDC) SYSTEM AND SAFETY INJECTION TANK (SIT) INTERLOCKS (Page 2 of 3)

SYSTEM	SETPOINT[a]	FUNCTION and Value[b]
Shutdown Cooling System		
Safety Injection Tank SIT Isolation Valves (continued)		Technical Requirements Manual (TRM): Verify that each SIT MOV opens automatically prior to actual or simulated RCS pressure exceeding 515 PSIA and upon receipt of a SIAS test signal; every 18 months. (TRM TSR 3.5.200.4) (SIAS Variable Setpoint: see Table 7.2-1 & Table 7.3-11A) Test description in USFAR section 7.6.2.2.2; 4.10
	$\leq$ 420 psia[c]	SIT Valves must be fully open when PZR pressure is $\geq$ 430 psia. Power to the MOVs must be removed when PZR pressure is $\geq$ 1500 psia. (LCO 3.5.2)
	< 405 psia	SIT Valve Closure Permissive: allows valves to be closed by the operator only when RCS pressure is less than 430 psia. (T.S. Basis for LCOs 3.5.1 and 3.5.2) With RCS pressure less than the setpoint, the SIT motor operated isolation valves may be closed to isolate the SITs from the RCS but must remain energized. This allows RCS cooldown and depressurization without discharging the SITs into the RCS or requiring depressurization of the SITs. Test description in UFSAR section 7.6.2.2.2; 4.10

Table 7.6-1
SHUTDOWN COOLING (SDC) SYSTEM AND SAFETY INJECTION TANK (SIT) INTERLOCKS
(Page 3 of 3)

SYSTEM Shutdown Cooling System	SETPOINT[a]	FUNCTION and Value[b]
Safety Injection Tank SIT Isolation Valves (continued)		TS: Verify SIT MOV power is removed every 31 days from each required SIT isolation valve operator when RCS pressure is $\geq$ 1500 psia. (SRs 3.5.1.5 and 3.5.2.5).[c] TS: Verify each required SIT isolation MOV is fully open every 12 hours when RCS pressure is $\geq$ 430 psia. (SRs 3.5.1.1 and 3.5.2.1).[c]
SIT - RCS 1E Differential Alarm	RCS > 690 psia AND SIT < 610 psig	SIT-RCS Differential pressure alarm. 1E alarm if RCS pressure is greater than 715 psia with SIT pressure less than 600 psig. (TSR 3.5.200.5)

(a) Setpoint values listed are the presently installed values determined by the applicable design calculation.

(b) Values listed with the function are from License documents such as the TRM or Technical Specifications.

(c) Acceptance criteria of $\leq$ 420 psia is used for valves open and power to MOVs removed with breakers locked open, before exceeding 430 psia.

(d) Above the SIT isolation valves auto-open interlock, the maximum pressure at which the SIAS open signal will open a closed valve is limited by the valve operator differential pressure design capability.

7.6.1.2 Design Bases

7.6.1.2.1 Shutdown Cooling System Suction Line Valve Interlocks

The SCS interlocks conform to the following design criteria:

A. Each suction line shall have at least two valves in series to provide isolation between the RCS and the SCS;

B. The isolation valves shall have interlocks to prevent opening the isolation valves while the RCS pressure is above that which would result in the allowable SCS pressure being exceeded;

C. The interlocks shall operate even after a single failure;

D. The interlocks shall not prevent achieving cold shutdown from the control room after a single failure;

E. Pressurizer pressure shall be used to provide the interlock functions;

F. Separate, physically independent sensors, located on separate pressurizer sensing nozzles, shall be provided; and

G. The interlocks must not fail so as to preclude opening of at least one SCS path (if RCS pressure permits), or closing of both suction paths after a LOCA.

7.6.1.2.2 Safety Injection Tank Isolation Valve Interlocks

The SIT Isolation Valve Interlocks are designed consistent with the balance of the SIS. Because the SIS is an ESF System, the ESF criteria take precedence over any applied to the interlocks. The interlocks conform, generally, to the SIS criteria specified in Section 6.3. The SIT interlocks meet the following criteria:

A. The SITs shall not be isolated from the RCS when RCS pressure exceeds a preset value; the interlocks shall function to automatically open the isolation valves when RCS pressure exceeds a preset value;

B. Pressurizer pressure shall provide the required function;

C. Separate, physically independent, sensors, located on separate pressurizer sensing nozzles, shall be provided;

D. Operating procedures, administrative controls, and the interlocks all insure that the isolation valves are open when pressure in the RCS is greater than a preset value;

E. When system pressure exceeds the setpoint the interlock opens the valve; the SITs must be repressurized prior to RCS pressure reaching 700 psig.

7.6.1.3 <u>Final System Drawings</u>

Refer to section 1.7 for a list of figures applicable to this section and figure 7.6-2.

7.6.2 ANALYSIS

7.6.2.1 Analysis of Design Criteria

7.6.2.1.1 Shutdown Cooling System Suction Line Valve Interlocks

A. The isolation valve interlocks are redundant in that there are two trains; train A has three valves, two receiving their signal from one pressure sensor and the third valve receives its signal from an independent sensor; train B also has three valves but using two different pressure sensors. Each path to each valve will be physically independent and separate from the others. With this degree of redundancy and independence, the interlocks can sustain a single failure and can still isolate both heat exchangers or make one available when required.

B. The interlocks and valves can be tested in accordance with General Design Criteria 1 and 21; Regulatory Guides 1.22, 1.47 and 1.68; and the appropriate sections of IEEE standards 279-1971, 336-1971 and 338-1971.

C. The method for identifying power and signal cables and cable trays dedicated to the instrumentation, control, and electrical equipment associated with the isolation valves will be as discussed in Section 7.1.3.16 and will conform to R.G 1.75 as discussed in Section 7.1.2.10.

D. The instrumentation, control, and electrical equipment associated with the SCS interlocks are seismically and environmentally qualified to operate under all required design basis events in accordance with the requirements stated in Section 3.10 and 3.11.

7.6.2.1.2 Safety Injection Tank Isolation Valve Interlocks

Because the SIS is an ESF System, the requirements of the General Design Criteria, Regulatory Guides, and IEEE standards appropriate for ESF Systems are used for all of the instrumentation and controls. The interlocks are designed to be consistent with the balance of the system and its requirements. Refer to Section 6.3 for a discussion of the SIS and Section 7.3 for a discussion of the ESFAS.

7.6.2.1.3 Class 1E Alarm System

The Class 1E alarm system utilizes two independent alarm systems, one for each channel. There are no operating bypasses for the 1E alarm system or inputs. An input signal will sound an audible alarm that can be acknowledged (muted) with a switch in the control room. Additionally, the audible alarms for each channel can be "silenced" with the use of a key which is under administrative control. The silence function disables the 1E annunciator system audible alarm which will prevent it from sounding for any new input signal until it is reset.

The instrumentation and input signals are provided in compliance with the requirements of IEEE Standard 279-1971.

7.6.2.1.3.1 Reactor Coolant Pump Cooling Water Supply Monitoring. Monitoring the cooling water flowrate to the reactor coolant pumps with two visual status alarms for each pump on low cooling water flow provides sufficient information to the operator to determine if cooling water is available to each pump and to take appropriate action in less than 30 minutes to protect the reactor coolant pump affected.

The instrumentation is provided in compliance with the requirements of IEEE Standard 279-1971.

7.6.2.1.3.2 Safety Injection Tank Pressure Monitoring. Monitoring the SIT pressure with two visual status alarms for each channel on low SIT pressure provides information to the operator to determine the unavailability of the SITs to perform their core flooding function in the event of a LOCA. The instrumentation is provided in compliance with the requirements of IEEE 279-1971.

7.6.2.1.3.3 Auxiliary Building ESF Pump Room Level Monitoring. Monitoring each ESF pump room level with one visual status alarm for each room provides sufficient information and 30 minutes of time for the operator to take appropriate action to prevent equipment flooding at a leakage rate of 50 gallons per minute. The instrumentation is provided in compliance with the requirements of IEEE 279-1971, except for the redundancy requirements. These level switches are not required to be environmentally qualified since flooding of these pump rooms will not occur as a result of an initiating event considered by the PVNGS EQ program.

7.6.2.2 Analysis of Equipment Design Criteria

7.6.2.2.1 Shutdown Cooling System Suction Line Valve Interlocks

This description is only of the interlocks. The valves and piping are discussed in Section 5.4.7. The requirements of IEEE 279-1971 are written expressly for protection systems; as such, they are not directly applicable to these interlocks. However, a discussion of the extent to which these interlocks comply with Section 4 of this standard is provided below:

4.1 General Functional Requirement:

The interlocks are designed to operate during accident environmental conditions.

4.2 Single Failure Criterion:

Any single failure leading to loss of one channel will not result in opening of all of the isolation valves installed in series in one SCS suction line. Loss of two selective interlock channels (both part of one SCS suction line) and violation of administrative controls and procedures is required to open all three isolation valves.

4.3 Quality Control of Components:

The sensors for these interlocks meet the same quality requirements imposed on the protection system sensors.

4.4 Equipment Qualification:

Type tests will be performed on the instrumentation to ensure its operation during expected environmental conditions.

4.5 Channel Integrity:

The interlocks are designed to maintain functional capability during accident environments. Failure of an interlock will not preclude opening a path or closing both paths of the SCS.

4.6 Channel Independence:

The pressure transmitters are located on separate pressurizer nozzles. Separation is maintained between channels.

4.7 Control and Protection System Interaction:

The interlocks have no non-safety control function.

4.8 Derivation of System Inputs:

Pressurizer pressure is the sensed parameter.

4.9 Capability for Sensor Check:

The operational availability of the four pressure sensing channels can be determined by comparing their outputs once pressurizer pressure has come within the range of the sensors.

4.10 Capability for Test and Calibration:

Complete testing capability of the SCS isolation valve interlock exists. The tests will be performed in conjunction with periodic in-service testing and inspection of the valves. The test will include testing of the logic, valve control circuits, and actuation of the individual valves. This testability will be equivalent to the testability required for ESF circuits. A simplified diagram of the logic circuit is shown on Figure 7.6-1.

Testing may be accomplished sequentially for each series valve by inserting a test signal to the bistables, simulating a decreased pressure condition, while holding the control switch in the open position, to the point where the valve partially opens, manually reclosing the valve, simulating an increased pressure condition and observing that the valve does not open when the hand switch is moved to open position.

4.11 Capability for Bypass or Removal from Operation:

Removal of one channel for test does not compromise system reliability. Failure of one of the remaining channels during a test outage would not create an unacceptable situation, since administrative controls (key locks) effectively preclude inadvertent opening of the valves by the operator.

4.12 through 4.14 Bypassing:

There are no bypasses.

4.15 Multiple Setpoints:

This requirement is not applicable.

4.16 Completion of Protective Action Once it is Initiated:

This requirement is not applicable.

4.17 Manual Initiation:

This requirement is not applicable.

4.18 Access to Setpoint Adjustments, Calibration and Test Points:

Access is controlled by administrative procedures.

4.19 Identification of the Protective Action:

Indication of isolation is provided by redundant valve position indication.

4.20 Information Readout:

The readout consists of four pressure indicators and position indication for four of the six valves.

4.21 System Repair:

Components are accessible for repair, one channel can be placed out of service for maintenance without jeopardizing the isolation of the SCS.

4.22 Identification:

The instrumentation and cables associated with the SCS interlocks will not be uniquely identified as such. The channels will be identified to distinguish between redundant channels of safety-related equipment (See Section 7.1.3.16).

7.6.2.2.2 Safety Injection Tank Isolation Valve Interlocks

The SIS and its design requirements are discussed in Section 6.3. The requirements of IEEE 279-1971 are written expressly for protection systems, and as such, they are not directly applicable to these interlocks. The following discussion refers to the requirements set forth in the respective items of Section 4 of IEEE 279-1971 as they relate to the SIT isolation valve interlocks:

4.1 General Function Requirement:

The interlocks have been designed to operate during accident environmental conditions.

4.2 Single Failure Criterion:

Loss of an interlock channel, at operating pressure, will not cause a valve to close since the valve motor circuit breaker is racked out. At low pressure, if the interlock should fail and an SIT starts to pressurize the RCS, the SCS is protected since the SITs are depressurized to 400 psia prior to initiation of shutdown cooling to prevent an interlock failure from causing such a problem.

4.3 Quality Control of Components:

The sensors for these interlocks meet the same quality requirements imposed on the protection system sensors.

4.4 Equipment Qualification:

Type tests will be performed on the instrumentation to ensure its operation during expected environmental conditions.

4.5 Channel Integrity:

The interlocks have been designed to maintain functional capability when exposed to accident environments. They will not preclude Safety Injection during accident conditions.

4.6 Channel Independence:

The pressure transmitters are located on separate pressurizer nozzles. Separation is maintained between channels.

4.7 Control and Protection System Interaction:

4.8 Derivation of System Inputs:

Pressurizer pressure is the sensed parameter.

4.9 Capability for Sensor Checks:

The operational availability of the two pressure sensing channels can be determined by comparing their outputs.

4.10 Capability for Test and Calibration:

Complete testing capability of the SIT isolation valve interlocks exists. The tests will be performed in conjunction with periodic in-service testing and inspection of the valves. The tests will include testing of the logic, valve control circuits, and actuation of the individual valves. A simplified diagram of the logic circuit is shown on Figure 7.6-1.

Testing may be accomplished sequentially for each valve by inserting a test signal to the bistables, simulating a decreased pressure condition while holding the control switch in the close position, to the point where the valve partially closes, and then simulating an increased pressure condition to the point where the interlock circuit causes the valve to return to the fully open position. This procedure will then be repeated to allow testing of the SIAS signal to the valve.

4.11 Capability for Bypass or Removal from Operation:

Removal of one channel for test does not compromise system reliability. Failure of one of the remaining channels during a test outage would not create an unacceptable situation, since administrative controls (key locks, racked out breakers, locked

open breakers) preclude inadvertent closing of the valves by the operator.

4.12 through 4.14 bypassing:

There are no bypasses.

4.15 Multiple Set Points:

This requirement is not applicable.

4.16 Completion of Protective Action Once Initiated:

This requirement is not applicable.

4.17 Manual Initiation:

This requirement is not applicable.

4.18 Access to Setpoint Adjustments, Calibration and Test Points:

Access is controlled by administrative procedures.

4.19 Identification of the Protective Action:

Identification of isolation is provided by redundant valve position indication.

4.20 Information Readout:

The readout consists of two pressure indicators and position indication for each valve. This provides the operator with clear, concise information.

4.21 System Repair:

The components are accessible for repair. One channel can be placed out of service without jeopardizing the availability of the SITs.

4.22 Identification:

The instrumentation and cables associated with the SIT isolation valve interlocks will not be uniquely identified as such. The channels will be identified to distinguish between channels of safety related equipment (See Section 7.1.3.16).

In addition, for periodic testing requirements, see the Technical Specifications and Technical Requirements Manual (TRM); for access procedures for setpoint adjustments, calibration, and test points, see section 13.5.

7.6.2.3 Fire Protection Instrumentation and Detection System

An analysis of the fire protection system is discussed in subsection 9.5.1.

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

Refer to paragraph 7.2.2.4.1 for additional discussion of control systems not required for safety.

7.7.1 DESCRIPTION

The control and instrumentation systems, whose functions are not essential for the safety of the plant, include plant instrumentation and control equipment not addressed in Section 7.2 through 7.6. The general description given below permits an understanding of the reactor and important subsystem control methodology.

The design reactivity feedback properties of the NSSS will inherently cause reactor power to match the total NSSS load. The resulting reactor coolant temperature at which this occurs is a controlled parameter and is adjusted by changes in total reactivity as implemented through CEA position changes or through boric acid concentration changes in the primary coolant.

The ability of the NSSS to follow turbine load changes is dependent on the ability of the control systems or operator to adjust reactivity, feedwater flow, bypass steam flow, reactor coolant inventory, and energy content of the pressurizer such that NSSS conditions remain within normal operating limits.

Except as limited by Xenon conditions, the major control systems described below provide the capability to automatically follow limited load changes. Additionally, these automatic systems provide the capability to accommodate load rejections

of any magnitude or the loss of one of two operating feedwater pumps.

7.7.1.1 Control Systems

7.7.1.1.1 Reactivity Control Systems

The reactor's reactivity is controlled by adjustments of CEAs for rapid reactivity changes or by adjustment of boric acid concentration for slow reactivity changes. The boric acid is used to compensate for such long term effects as fuel burnup and changes in fission product concentration. The boric acid concentration can be used to do some load following. Since these long term changes occur slowly, operator action is suitable for boric acid concentration control. The CEAs can either be controlled manually by the operator or automatically to maintain the programmed reactor coolant temperature and power level during boric acid concentration changes, within the limits of CEA travel.

The Reactor Regulating System (RRS) is used to automatically adjust reactor power and reactor coolant temperature to follow turbine load transients within established limits. The RRS receives a turbine load index signal (linear indication of load) and reactor coolant temperature signals (see Figure 7.7-5). The turbine load index is supplied to a reference temperature (T_{REF}) program which establishes the desired average temperature. The hot leg and cold leg temperature signals are averaged (T_{AVG}) in the RRS. The T_{REF} signal is then subtracted from the T_{AVG}, signal to provide a

temperature error signal. Power range neutron flux is subtracted from the turbine load index to provide compensation to the T_{AVG} - T_{REF} error signal generated.

This resulting error signal is fed to a CEA rate program, to determine whether the CEAs are to be moved at a high or low rate, and to a CEA status program which determines if the CEAs are to be withdrawn, inserted or held. The outputs of the rate and status programs are sent to the Control Element Drive Mechanism Control System (CEDMCS).

If the temperature error signal is very high, that is T_{AVG} is much higher than T_{REF}, an Automatic Withdrawal Prohibit (AWP) signal will be sent to the CEDMCS. Since the withdrawal of CEAs causes T_{AVG} to increase, prohibiting a withdrawal prevents an increase in the error signal.

The Control Element Drive Mechanism Control System (CEDMCS) accepts automatic CEA motion demand signals from the Reactor Regulating System or manual motion signals from the CEDMCS Operators Module and converts these signals to direct current pulses that are transmitted to the CEDM coils to cause CEA motion.

A reactor trip initiated by the Reactor Protective System causes the input motive power to be removed from the CEDMCS by the trip switchgear, which in turn causes all CEAs to be inserted by gravity. The CEDMCS is thus not required for safety. (See Figure 7.7-6).

There are four different modes of control; sequential group movement in manual and automatic control, manual group movement and manual individual CEA movement. Sequential group movement functions such that, when the moving group reaches a programmed low (high) position, the next group begins inserting (withdrawing), thus providing for overlapping motion of the regulating groups. The initial group stops upon reaching its lower (upper) limit. Applied successively to all regulating groups, the procedure allows a smooth continuous rate of change of reactivity. The CEDMCS accepts signals from the Plant Monitoring System (PMS) to effect this sequencing of regulating CEA group motion. The CEDMCS utilizes sequencing signals from the PMS that are derived from the CEDMCS up-down pulse counters. The shutdown CEAs are moved in the manual control mode only, with either individual or group-movement. A selector switch permits withdrawal of no more than one shutdown group at any time.

The part-strength CEAs may be moved manually, with either individual or group movement.

During plant startup and shutdown, and all cases where power is below 15%, manual control is used. Automatic control of the regulating CEAs by the RRS may be selected by the operator only when above 15% power. Manual control may be used to override automatic control at any time.

7.7.1.1.2 Reactor Coolant System Pressure Control System

The Pressurizer Pressure Control System (PPCS) maintains the Reactor Coolant System pressure within specified limits by the

use of pressurizer heaters and spray valves. The pressurizer provides a water/steam surge volume to minimize pressure variations due to density changes in the coolant. The pressurizer is described in Section 5.4.10.

A pressurizer pressure signal is used in a proportional controller to control the proportional heaters (see Figure 7.7-7). The heaters will be operated to maintain the pressurizer pressure as required. The operator can take manual control to regulate the pressure.

The pressurizer pressure signal is also sent to a spray valve controller. This provides a signal to the spray valves to control their opening. Since reactor coolant is somewhat cooler than the water/steam mixture, reactor coolant sprayed in will cause some steam to condense and thereby reduce the system pressure. The operator can take manual control of the spray valves to control the pressure.

If the proportional heaters are being used, and system pressure is still decreasing, the backup heaters would be automatically energized. The operator can also manually energize these backup heaters.

The control system has a low level interlock and a high pressure interlock. The low level interlock shuts off the heaters when the level falls below a setpoint.

If the pressurizer pressure reaches a high setpoint, all heaters will be deenergized; this is to ensure that the heaters will not cause the pressure to increase further.

7.7.1.1.3 Pressurizer Level Control System

The Pressurizer Level Control System (PLCS) minimizes changes in RCS coolant inventory by using the charging pumps and letdown control valves in the Chemical and Volume Control System (CVCS) discussed in Section 9.3.4. It also maintains a vapor volume in the pressurizer to accommodate surges during transients. Figure 7.7-8 shows the PLCS diagram.

During normal operations the level is programmed as a function of reactor coolant average temperature (T_{AVG}) in order to minimize charging and letdown flow requirements. The T_{AVG} goes through a level setpoint program and the setpoint program signal is compared to the actual level signal. The level error signal is sent to a level error program which is used to control the charging pumps.

If the level error program shows that the level is very high it will deenergize a normally running pump leaving only one pump (the always running pump) running. If the level is very low the level error program will cause the standby pump to start, thereby having three pumps charging the system.

The level error signal is sent to a Proportional plus Integral plus Derivative (PID) controller which generates an error signal. This signal is passed through a lag circuit which prevents rapid changes in the letdown flow. The output of the lag circuit is passed to the selected letdown valve via the auto-manual control and the letdown valve selector. The auto-manual control allows the operator to control level manually by controlling the letdown valve. The letdown valve

selector switch allows the operator to select which valve will be operated by the PLCS.

7.7.1.1.4 Feedwater Control System

The Digital Feedwater Control System (DFWCS) has a separate compound, or software control strategy, for each steam generator. The discussion of the FWCS will refer to only one steam generator. Refer to Figure 7.7-1 for the FWCS block diagram.

The DFWCS is based on a two-mode control strategy. At low power levels, the DFWCS is designed to automatically control the steam generator downcomer water level in a Single-Element mode. The DFWCS performs dynamic compensation on the level signal to generate an output signal indicative of the required feedwater flow. The output signal is used to generate the downcomer valve position demand signal. When in this control mode the economizer valve will be closed and the pump speed setpoint will be at its minimum value. Steam generator level will be controlled during 1% per minute turbine load ramps in this mode (assuming that all other control systems are operating in automatic).

The DFWCS is designed to automatically control the steam generator downcomer water level at higher levels in a Three-Element mode. The Three-Element mode continuously solves the steam generator mass balance equation to keep the feedwater input equal to the steam flow output. The level measurement acts as a trim on this mass balance and assures that the level is reset to its proper setpoint value following any system

disturbances. Thus, the three modes are level, feedwater flow, and steam flow. The gain and reset control settings are adaptively adjusted by reactor power and feedwater temperature to adjust control response for the "shrink/swell" phenomenon. Steam generator level will be controlled during the following conditions (assuming that all other control systems are operating in automatic):

A. Steady state operations;

B. 5% per minute turbine load ramps between 15 and 100% NSSS power;

C. 10% turbine load steps;

D. Loss of one of two operating feedwater pumps; and

E. Load rejection of any magnitude.

Transfer from Single-Element to Three-Element control, and back, is performed bumplessly without any need for operator balancing or other intervention. The transfer occurs automatically and is based on NSSS power. The transfer to Three-Element control occurs as soon as the stability of the steam and feedwater measurement will allow.

Panel Display Stations provide the operator interface with the DFWCS. The operator may use either interface to provide the steam generator level setpoint at the master control station or manually control the economizer and downcomer valve positions.

The signal from the master control station also goes to a high select circuit which selects the higher of the total feedwater demand signals from both feedwater systems and passes it to the

pump program. The pump program generates a pump speed setpoint signal. A panel display station provides the operator with access to the pump speed bias to allow balancing of the pumps. The operator can also manually control the pump speed at this station.

7.7.1.1.5 Steam Bypass Control System

The Turbine Bypass System consists primarily of the turbine bypass valves and the Steam Bypass Control System (SBCS). The SBCS controls the positioning of the turbine bypass valves, through which steam is bypassed around the turbine into the unit condenser, with exception of two valves which dump steam to atmosphere. These two valves are the last to open and first to close during steam bypass operation.

The system is designed to increase plant availability by making full utilization of turbine bypass capacity to remove excess NSSS thermal energy following turbine load rejections with condenser available. This is achieved by the selective use of turbine bypass valves and the controlled release of steam. This avoids unnecessary reactor trips, and prevents the opening of pressurizer or secondary safety valves.

Refer to Figure 7.7-2 for the SBCS block diagram. The Reactor Power Cutback System, discussed below, is used in conjunction with the SBCS to reduce the required turbine bypass valve capacity. Additionally, the SBCS is used during turbine loading to provide an even load on the reactor as the turbine is brought up to load. The system is also used during reactor

heatup and cooldown to remove excess NSSS energy, and control the rate of temperature change.

The following three types of valve signals are generated for each turbine bypass valve a modulation signal which controls the flow rate through the valve; a quick opening signal which causes the valve to fully open in a short time; and a valve permissive signal which is required for the preceding two signals to operate the bypass valve.

In the modulation mode a steam flow signal is sent to a program which develops a main steam header pressure program signal. At the same time the pressurizer pressure is used to generate a pressurizer pressure bias program. The two program signals and the measured main steam header pressure are compared to provide an error signal which goes to the controller. The controller demand, or a manual signal provided by the operator, is passed to an electro-pneumatic converter on each turbine bypass valve. This converts the electrical signal to an air signal which is passed through the first solenoid valve to the air actuated turbine bypass valve shown on Figure 7.7-2.

In the quick opening mode the pressurizer pressure and steam flow signals are compared and the difference signal produced is sent to a change detector. The change detector output is compared to a threshold value; if the change signal exceeds the threshold a quick opening signal is produced. The quick opening signal energizes the solenoid which then blocks the modulated air signal and applies the full air system pressure, to quick open the valve.

A permissive signal is also produced by the SBCS. This signal is provided by circuitry identical to that described above except that the output of the permissive controller is converted to a binary signal and fed into an OR gate with the permissive quick opening signal. If a permissive signal is present it will open the second solenoid valve and allow either the modulated or the quick open air signal to be applied to the pneumatically operated bypass valves. When the permissive signal is removed the control air is vented to atmosphere and the valve closes. When turbine condenser pressure exceeds a present value, the turbine bypass valves are prevented from opening.

Reactor Power Cutback demand signals are generated by the same circuitry that produces the valve quick opening signals. These redundant signals are sent to the Reactor Power Cutback System (RPCS).

7.7.1.1.6 Reactor Power Cutback System

The NSSS normally operates with minor perturbations in power and flow. These can be handled by the control systems discussed above. Certain large plant imbalances can occur however, such as a large turbine load rejection, turbine trip or loss of one of two main feedwater pumps. Under these conditions maintaining the NSSS within the control band ranges can be accomplished by rapid reduction of NSSS power at a rate which is greater than that provided by the normal high speed CEA insertion. Refer to Figure 7.7-4 for the block diagram of the Reactor Power Cutback System (RPCS).

The RPCS is a control system designed to accommodate certain types of imbalances by providing a "step" reduction in reactor power. The step reduction in reactor power is accomplished by the simultaneous dropping of one or more preselected groups of full strength regulating CEAs into the core. The CEA groups are dropped in their normal sequence of insertion. The RPCS also provides control signals to the turbine to rebalance turbine and reactor power following the initial reduction in reactor power as well as to restore steam generator water level and pressure to their normal controlled values. The system is designed to accommodate either large load rejections or the loss of one feedwater pump.

The RPCS receives two of each of the following signals; loss of feedwater pump 1, loss of feedwater pump 2 and two cutback demand signals from the SBCS. A two-out-of-two logic is required to actuate the system. The operator has the capability to manually actuate the system.

The operator inputs the CEA group drop selection through the RPCS operator's console. Input indication is provided for selection of all CEA subgroups. However, only CEA groups 4 and/or 5 (subgroups 22, 5 and/or 4) are capable of selection for drop.

The RPCS is actuated upon receiving coincident two-out-of-two sensor logic signals indicating either large turbine load rejection or loss of one main feedwater pump. The actuation initiates the dropping of the preselected pattern of CEAs. There are inhibits in the Control Element Drive Mechanisms

Control System (CEDMCS) to prevent the possibility of the RPCS dropping CEA groups which are not intended to drop for a reactor power cutback (e.g., Part-Strength groups, Shutdown Groups, etc.). Subsequent insertion of other groups either automatically by the Reactor Regulating System (RRS) or manually by the operator occurs as necessary. The actuation logic also temporarily changes plant control to a turbine follow mode by first initiating a rapid turbine power reduction to approximately 60% power, followed by a further reduction if necessary to balance turbine power with reactor power.

7.7.1.1.7 Boron Control System

Boron Concentration, via regular sampling of the reactor coolant is supplied to the operator to allow regulation and monitoring of the boron concentration in the reactor coolant. The means by which RCS boron control is accomplished is by dilution and boration. Refer to Section 9.3.4 for a discussion of the Chemical and Volume Control System (CVCS). To allow the operator to maintain the required boron concentration in the reactor coolant, the Volume Control Tank contents may be maintained at a prescribed boron concentration either manually or automatically. Additional recorders indicate reactor makeup water flow and boric acid makeup flow, which can be used to determine whether boration or dilution is occurring.

At power, the boron concentration, in addition to CEA position determines reactor coolant temperature. Because of the long time required to change the boron concentration, the boron is used for long term effects such as fuel burnup and fission

product build up. Boron concentration control can also be used for load following. By adjusting the boron concentration, the CEAs can be withdrawn to provide an adequate shutdown margin.

7.7.1.1.8 Loose Parts Monitoring System

Refer to Section 4.2.5.H.2.

A loose parts monitoring system (LPMS) is installed at PVNGS. The LPMS is designed to detect and record signals resulting from impacts occurring within the reactor coolant system. Eight transducers will be located in the areas where loose parts are most likely to become entrapped. These are:

A. Two redundant transducers clamp-mounted on the incore instrument guide tubes on the reactor vessel lower head, diametrically opposed.

B. Two redundant transducers mounted diametrically opposed on the reactor head.

C. Two redundant transducers on each steam generator. The transducers are mounted on the outer diameter in the tube sheet region.

Experience has shown that the exact location of the accelerometers is not critical since the acoustic wave that results from an impact propagates throughout the entire head. The transducers will be high temperature piezoelectric accelerometers.

A high temperature, low noise, radiation hardened, flame-retardant coaxial cable will connect the accelerometer to a

preamplifier located in a junction box outside of the biological shield. From the preamplifier the signals are sent via suitable wires, such as a twisted shielded pair, to the data acquisition panel in the control room. Cabling between redundant sensor channels from the sensor to the preamplifier located outside the secondary shield wall will be physically separated from each other.

A data acquisition panel located in the control room area contains alarm modules that continually monitor the incoming signals from the preamplifier for the presence of impacting.

The alarm level for each accelerometer is determined by a setpoint adjustment. Alarm levels were initially set above background levels established during baseline "signature" testing. Further baseline testing will be conducted from time to time and alarm levels may be adjusted to compensate for age-related noise generation at 100% power. The system sensitivity is better than 0.05 ft-lb at the sensors. Initial alarm setting is 0.5 $\pm$0.25 ft-lb. The occurrence of a loose part impacting on the inside of the structure causes bursts of signals that exceed the alarm setpoint and trigger the alarm. The data acquisition panel includes signal recording with playback and an audio monitor of live signal.

7.7.1.1.8.1 Recording. A digital recording system is provided, which includes an event analysis computer for analyzing the collected data. Signals from all channels are continually sampled. Storage time intervals are dependent upon the sampling rate and memory capacity of the analysis computer.

This computer performs data acquisition and recording and provides alarm indication on a control room annunciator to indicate a loose part event. It is capable of real-time analysis, spectrum analysis, and produces X-Y plot displays including an amplitude and frequency cursor with digital readout on an oscilloscope-type display.

7.7.1.1.8.2 Audio Monitoring. The audio monitoring shall consist of a speaker, independent volume control, and a selector switch for monitoring the loose parts channels.

7.7.1.1.8.3 Sensor Channel Functional Test. A preoperational calibration and functional test will be performed. Baseline "signatures" of each channel will be obtained to establish background levels. Provision is made for channel functional tests. System calibration shall be performed at least once each 18 months. Diagnostic procedures to confirm the presence of loose parts will make use of the baseline "signatures" to verify that recorded impact signals are above background.

7.7.1.1.8.4 Functionality for Seismic Conditions. The loose part detection system has been shown to be adequate for the OBE by test. Power is supplied from a 120 V-ac normal (nonseismically qualified) instrument bus, which has a Class 1E backup source.

All components of the system are high reliability items. They are to remain functional under normal environmental conditions of

the plant and are readily accessible for servicing (except sensors). Replacement of components, if any, at full power operation would be limited to the channel preamplifiers located outside the secondary shield wall. The preamplifiers are replaceable during full power operation. The only other components of the loose parts monitoring system located in containment are cables and the sensors. Equipment located in the control room is not subject to the environment of the containment and is readily accessible and repairable at all times.

7.7.1.1.8.5 Training Program for Plant Personnel. See paragraph 13.2.1.

7.7.1.1.9 In-Core Instrumentation System

The in-core instrumentation system is used to monitor the core power distribution.

There are 53 in-core monitoring assemblies with five self-powered Rhodium detectors in each location. The 53 assemblies are strategically distributed about the reactor core, and the five detectors are axially distributed along the length of the core at 10, 30, 50, 70 and 90% of core height. This permits representative three dimensional flux mapping of the core. The Rhodium detectors produce a delayed beta current proportional to the neutron activation of the detectors which is proportional to the neutron flux in the detector region.

The signals from the in-core detectors are converted to usable voltage signals by the In-Core Amplifier System which sends

these signals to the Plant Monitoring Systems (PMS) by way of multiplexers. The PMS converts these analog voltages to equivalent digital signals and performs the background, beta decay delay and Rhodium depletion compensation using digital signal processing routines.

The fixed in-core instrumentation system is designed to perform the following functions:

A. To determine the gross power distribution in the core during different operating conditions from 20% to 100% power;

B. To provide data to estimate fuel burn-up in each fuel assembly;

C. To provide data for the evaluation of thermal margins in the core;

The fixed in-core detectors can be used to assist in the calibration of the ex-core detectors by providing azimuthal and axial power distribution information. The ex-core system is used to provide indication of the flux power and axial distribution for the Reactor Protective System.

7.7.1.1.10 Excore Neutron Flux Monitoring System (Non-Safety Channels)

The ex-core neutron flux monitoring system includes neutron detectors located around the reactor core and signal conditioning equipment located in the control room area. Neutron flux is monitored from source levels through full power

operation and signal outputs are provided for reactor control and for information display.

Two startup channels provide source level neutron flux information to the reactor operator for use during extended shutdown periods, initial reactor startup, startups after extended shutdown periods, and following reactor refueling operations. Each channel consists of a dual section proportional counter assembly, with each section having multiple BF_3 proportional counters, one preamplifier located outside the reactor shield, and a signal processing drawer containing power supplies, a logarithmic amplifier, and test circuitry. High voltage power to the proportional counters is terminated several decades of neutron flux above the source level to extend detector life. These channels provide readout and audio count rate information but have no direct control or protective functions.

Two control channels provide neutron flux information, in the power operating range of 1% to 125%, to the Reactor Regulating System for use during automatic turbine load-following operation (see Section 7.7.1.1.1). Each control channel consists of a dual section uncompensated ionization chamber detector and a signal conditioning drawer containing power supplies, a linear amplifier, and test circuitry. The detector is operated in the current mode only. These channels are completely independent of the safety channels.

7.7.1.1.11 Boron Dilution Alarm System

Reactivity control in the reactor core is effected, in part, by soluble boron in reactor coolant system. The Boron Dilution Alarm System (Figure 7.7-11) utilizes the startup channel nuclear instrumentation signals to detect a possible inadvertent boron dilution event while in Modes 3-6. There are two redundant and independent channels in the Boron Dilution Alarm System (BDAS) to ensure detection and alarming of the event.

The BDAS contains logic which will detect a possible inadvertent boron dilution event by monitoring the startup channel neutron flux indications. When these neutron flux signals increase (during shutdown) to equal or greater than the calculated alarm setpoint, alarm signals are initiated to the Plant Annunciation System. The alarm setpoint is periodically, automatically lowered to be a fixed amount above the current neutron flux signal. The alarm setpoint will only follow decreasing or steady flux levels, not an increasing signal. The current neutron flux indication and alarm setpoint (per channel) are displayed. There is also a reset capability to allow the operator to acknowledge the alarm and initialize the system.

7.7.1.1.12 Feedwater Ultrasonic Flowmeter System.

The Feedwater Ultrasonic Flowmeter (UFM) System is an externally mounted flow measurement system utilizing an ultrasonic transit time method to measure fluid velocity and

volumetric flow rate. One externally mounted Ultrasonic Flowmeter system is installed on each Steam Generator Feedwater line to provide a measurement of Feedwater flowrate. The Ultrasonic Flowmeter Feedwater flowrate signal is then input to the Core Operating Limit Supervisory System (COLSS) software and used to calculate the secondary power calorimetric. Refer to Section 7.7.1.3.1.3.2 for discussion of the Core Power Calculations. The Feedwater flowrate signal to COLSS can be provided either by the Feedwater Ultrasonic Flowmeter, or the alternate Feedwater venturi flow meter. The Feedwater flowrate signal to COLSS is selectable via a manual switch. The primary reason that the Ultrasonic Flowmeter is preferred is that externally mounted ultrasonic flow measurement systems are not prone to the venturi fouling phenomena which causes an increase in differential pressure across venturi flow elements that is not related to an actual increase in Feedwater flow. This false increase in differential pressure for venturi flow meters results in a higher COLSS calculated mass flow and in turn a higher secondary power calorimetric.

7.7.1.2 Design Comparison

The functional design of the following, non-safety, control systems was performed by Combustion Engineering. The design differences between the control systems in the CESSAR Licensing scope and the control systems provided for the reference plant (Arkansas Nuclear One - Unit 2 - (ANO-2) NRC Docket No. 50-368) are discussed in this section.

7.7.1.2.1 Reactivity Control Systems

The RRS is functionally identical to that of the reference plant with the following changes:

A. It does not use pressurizer pressure for compensation;

B. An AMI signal is produced to prevent CEA motion whenever there is a deviation between any pair of redundant input signals; and

C. There is only one RRS instead of two.

The CEDMCS is functionally identically to that of the reference plant with the following changes:

A. The CEDMs can be deenergized in groups, by signals from the RPCS;

B. The two power buses are tied together within the CEDMCS cabinets;

C. System has a four coil, double-step CEDM instead of a five coil, single step;

D. Only one subgroup can be transferred to the hold bus at any one time;

E. The CWP is effective in all modes, and CWP can be bypassed at the Operator's Module;

F. UCL and LCL are replaced with UGS and LGS for the PLCEA; and

G. System can handle up to 97 CEAs as opposed to 81.

None of the design differences in the RRS or CEDMCS have been taken credit for in the safety analysis since they have no safety significance.

7.7.1.2.2 Reactor Coolant Pressure Control System

The PPCS is functionally identical to that used in the reference plant.

7.7.1.2.3 Pressurizer Level Control System

The PLCS is functionally identical to that used in the reference plant.

7.7.1.2.4 Feedwater Control System

The FWCS is functionally identical to the reference plant with the following exceptions:

A. This system is designed for a U-tube steam generator with an integral economizer, the reference system's U-tube steam generators do not have an economizer;

B. This system controls feedwater to the upper (downcomer) and lower (economizer) steam generator nozzles; and

C. Each nozzle has one valve to control instead of a main and bypass valve for a single nozzle.

None of these design differences discussed above have been taken credit for in the safety analysis since they have no safety significance.

7.7.1.2.5 Steam Bypass Control System

The SBCS has the following design differences from the Steam Dump and Bypass Control System (SDBCS) of the reference plant.

A. This system controls eight turbine bypass valves, the SDBCS controls three turbine bypass valves and four atmospheric dump valves;

B. Signals are provided to the RPCS upon a major load rejection.

Neither of these design differences have been taken credit for in the safety analysis since they have no safety significance.

7.7.1.2.6 Reactor Power Cutback System

The RPCS did not exist in the reference plant. It has not been taken credit for in the Safety Analysis.

7.7.1.2.7 Boron Control System

The BCS is functionally identical to that used in the reference plant.

7.7.1.2.8 In-Core Instrumentation System

The in-core instrumentation system is functionally identical to that of the reference plant with the following changes:

A. There are 53 in-core instrument assemblies being credited rather than 44; and

B. The in-core instrumentation system is designed for bottom rather than top entry.

None of these design differences have been taken credit for in the safety analysis since they have no safety significance.

7.7.1.2.9 Ex-Core Neutron Flux Monitoring System

The ex-core monitoring system is identical to the reference plant except that it uses uncompensated ion chambers instead of fission chambers for the control channel detectors. This difference has no impact on the functioning of the system and has no safety significance.

7.7.1.2.10 Boron Dilution Alarm System

The Boron Dilution Alarm System is an addition to the CESSAR design. There is no functional comparison to the reference plant.

7.7.1.3 Monitoring Systems

7.7.1.3.1 Core Operating Limit Supervisory System (COLSS)

7.7.1.3.1.1. General. The core operating limit supervisory system (COLSS) consists of process instrumentation and algorithms used to continually monitor the limiting conditions for operation on:

- Linear heat rate margin
- DNBR margin
- Total core power
- Azimuthal tilt
- Axial shape index

The COLSS continually calculates DNBR margin, linear heat rate margin, total core power, core average axial shape index, and azimuthal tilt magnitude, and compares the calculated values to the limiting condition for operation on these parameters. If a limiting condition for operation is exceeded for any of these parameters, COLSS alarms are initiated and operator action is taken as required by Technical Specifications.

The limiting safety system settings, core power operating limits, axial shape index, and the azimuthal tilt operating limit are specified such that the following criteria are met:

- No safety limit will be exceeded as a result of anticipated operational occurrences (AOOs).
- The consequences of postulated accidents will be acceptable.

The reactor protective system functions to initiate a reactor trip at the specified limiting safety system settings. The COLSS is not required for plant safety since it does not initiate any direct safety-related function during AOOs or postulated accidents. The Technical Specifications define the limiting conditions for operation (LCO) required to ensure that reactor core conditions during operation are no more severe than the initial conditions assumed in the safety analyses and in the design of the low DNBR and high LPD trips. The COLSS serves to monitor reactor core conditions in an efficient manner and provides indication and alarm functions to aid the operator in maintenance of core conditions within the LCOs given in the Technical Specifications.

The COLSS algorithms are executed in the plant monitoring system (PMS). The calculational speed and capacity of the PMS computer enable numerous separate plant operating parameters to be integrated into three easily monitored parameters: (1) margin to core power limit (based upon DNBR, linear heat rate, and power limits), (2) azimuthal tilt, and (3) axial shape index. If COLSS were not provided, maintenance of reactor core parameters within the LCOs, as defined by the Technical Specifications, would be accomplished by monitoring and alarming based on the separate nonsafety-related process parameters used in the COLSS calculations. Therefore, the essential difference in using COLSS in lieu of previous monitoring concepts is the integration of many separate process parameters into a few easily monitored parameters. The conciseness of the COLSS displays has distinct operational advantages, since the number of parameters that must be monitored by the operator is reduced.

Detailed process testing of COLSS is conducted to ensure proper system performance as described below:

A. After installation of revised COLSS software algorithms in the PMS computer, appropriate test cases are run on the computer to verify the COLSS implementation; the number of test cases may vary from 1 to approximately 43 depending on the software change(s) made. In test tests, COLSS is off-line (in the TEST mode) and sets of stored constants are substituted for live sensor inputs. These test cases are designed to test the functionality of the

module(s) containing the algorithm(s). Agreement of test case results to within round-off errors indicates that the COLSS software is functioning and implemented properly.

B. Just prior to startup from a refueling outage, new constants from a Quality Assured analysis are installed in the PMS.

C. When COLSS is on-line (in the SCHEDULED mode), a detailed report of the COLSS inputs, intermediate calculated values, and results may be printed upon request. Comparison of this information with intermediate calculated values and results from an off-line COLSS program using the same input values can provide additional assurance of proper operability of the COLSS program. Testing can be performed on an as needed basis under administrative control to assure proper performance of COLSS. Since COLSS is not required for plant safety, COLSS testing requirements are not included in the Technical Specifications (however, the Technical Specifications do include verification of certain COLSS alarms).

7.7.1.3.1.2 System Description. Sensor validity checks are performed by COLSS on those measured input parameters used in the COLSS calculations. The validity checks consist of checking sensor inputs for the following conditions:

- Sensor out-of-range

- Excessive deviation between like sensors

One of the following actions is taken for out of range sensors:

A. Automatic replacement of the failed sensor by an equivalent sensor (when available).

B. Automatic function termination when adequate process information is not available.

C. Substitution of constants for selected COLSS inputs (performed under administrative control).

If an out-of-range sensor is detected, an alarm to the operator is actuated and corrective action is automatically initiated.

A more detailed discussion of sensor validity checks is included in CEN-312, Revision 01-P.(1)

The core power distribution is continually monitored by COLSS, and the core average axial shape index is computed. Operation of the reactor with the calculated ASI within the specified axial shape index limits assures that the actual value of core average axial shape index is within the range of values used in the safety analysis. A core power operating limit based on linear heat rate is computed from the core power distribution. Operation of the reactor at or below this power operating limit assures that the peak linear heat rate is never more adverse than that postulated in the loss of coolant analyses.

Core parameters affecting the DNBR margin are continually monitored by COLSS, and a core power operating limit based on DNBR is computed. Operation of the reactor at or below this operating limit power level ensures that the most limiting DNB

transient that can result from an AOO does not result in a DNBR reduction to a value less than the DNBR SAFDL.

A core power operating limit based on licensed power level is also monitored by COLSS. When the COLSS-auctioneered reactor power exceeds the license power limit setpoint (COLSS addressable constant NKLPL), an alarm is generated. Due to normal fluctuations in the process variables used to calculate reactor power from COLSS, normal full power operation without alarm actuation requires an NKLPL setpoint > 100%. The NKLPL setpoint is determined by station procedures using a statistical analysis of COLSS calculated plant powers, with the objective to avoid nuisance alarms and still provide early warning to the operators of the need to reduce power. As required by station procedures, the Licensed Operators have the responsibility to ensure that steady state reactor power is maintained less than or equal to the licensed power limit.

Operation of the reactor at or below 100% power ensures that the total core power is never greater than that assumed as an initial condition in the safety analysis.

Axial shape index, core power, and the core power operating limits based on peak linear heat rate and DNBR are continually indicated on the control board. The margin between the core power and the lowest core power operating limit is also displayed on the control board indicator. An alarm is initiated if the COLSS calculated core power level exceeds a COLSS calculated core power operating limit or if the calculated axial shape index exceeds its limits.

In addition to the above calculations, the azimuthal flux tilt is calculated in COLSS. The azimuthal flux is not directly monitored by the plant protection system; rather an azimuthal flux tilt allowance, based on the maximum tilt anticipated to exist during normal operation, is provided as an addressable constant in the protection system. This tilt allowance is used in the low DNBR and high local power density trip calculations. The azimuthal flux tilt is continually monitored by COLSS and an alarm initiated in the event that the azimuthal flux tilt exceeds the azimuthal flux tilt allowance setting in the plant protection system.

The following are calculated by COLSS:

- Reactor coolant volumetric flowrate
- Core power as determined by:

  Reactor coolant ΔT

  Secondary system calorimetric

  Turbine first stage pressure
- Axial shape index
- Azimuthal tilt
- Linear heat rate core power operating limit
- DNBR core power operating limit
- Margin to each core power operating limit

Control board indication of the following COLSS parameters is continually available to the operator.

- Linear heat rate core power operating limit
- DNBR core power operating limit
- Total core power
- Margin between core power and lowest core power operating limit
- Axial shape index

The algorithms are executed in the PMS. Technical Specifications for the reactor core provide an alternate means of monitoring the limiting conditions for operation in the event that the PMS is out of service.

COLSS alarms are initiated if:

- Core power exceeds a core power operating limit
- Axial shape index exceeds its limits
- Azimuthal flux tilt exceeds azimuthal flux tilt limit

A description of COLSS algorithms and a discussion of the treatment of COLSS input information are included in reference 1. Table 7.7-1 provides a listing of the types, quantities, and ranges of sensors that provide input information for the COLSS algorithms.

A functional block diagram of the core operating limit supervisory system is presented in Figure 7.7-3.

7.7.1.3.1.3 <u>Description of COLSS Algorithms</u>.

7.7.1.3.1.3.1 Reactor Coolant Volumetric Flowrate. The DNBR margin is a function of the reactor coolant volumetric

flowrate. The four reactor coolant pump rotational speed signals and four RCP differential pressure instruments are monitored by COLSS and used to calculate the volumetric flowrate. The pump characteristics are determined from testing conducted at the pump manufacturer's test facility and correlations between the pump rotational speed, pump differential pressure, and the volumetric flowrate are developed. Measurement uncertainties in the pump testing and COLSS measurement channel uncertainties are factored into the calculation of the margin to a power operating limit. The four pump volumetric flowrates are summed to obtain the reactor vessel volumetric flowrate. Necessary allowances for core bypass flow, flow factors, reactor coolant temperature, etc., are factored into the value of flow used in the DNBR calculation.

7.7.1.3.1.3.2 Core Power Calculation. The reactor coolant ΔT power, turbine power, and the secondary calorimetric power are computed in COLSS. The reactor coolant ΔT power and turbine power are less complex algorithms than the secondary calorimetric power and are performed at a more frequent interval. The secondary calorimetric power is used as a standard against which reactor coolant ΔT power and turbine power are continually calibrated. The secondary calorimetric power is also used as a standard against which the Excore Safety and Control Channels are calibrated.

Table 7.7-1

COLSS MONITORED PLANT VARIABLES

Monitored Parameters	COLSS Sensors	Number of Sensors	Sensor Range
Core volumetric flow	RCP rotational speed RCP differential pressure	2 per pump 2 per pump	0 to 1,320 rpm 0 to 150 psid
Core power Primary calorimetric	Cold leg temperature	1 per cold leg	Narrow range (2) 500 to 650F Wide range (2) 0 to 600F
	Hot leg temperature	1 per hot leg	500 to 650F
Secondary calorimetric	Feedwater flow Steam flow Feedwater temperature Steam pressure	1 per generator 2 per generator 1 per generator 1 per generator	0 to 10.0×10^6 lbm/hr 0 to 5.0×10^6 lbm/hr 0 to 500F 900 to 1,300 psia
Core power distribution	In-core monitoring system	53 in-core assemblies each containing 5 axial stacked detectors	NA[a]
	CEA group position	1 per CEA group	0 to 150 inches
Reactor coolant pressure	Pressurizer pressure	2 (on pressurizer)	1,500 to 2,500 psia
Turbine power	Turbine first stage pressure	1 (on turbine)	0 to 800 psig

a. Core power distribution is provided in a graphic format.

This arrangement provides the benefits of the secondary calorimetric accuracy and the faster dynamic response characteristics of the reactor coolant ΔT power and turbine power.

The reactor coolant ΔT power is calculated based on the reactor coolant volumetric flowrate, the reactor coolant cold leg temperature, and the reactor coolant hot leg temperature. ΔT power provides a leading indication of core power changes in response to reactivity changes.

The turbine power is calculated based on turbine first stage pressure. Turbine power provides a leading indication of core power changes in response to load changes.

The secondary calorimetric power is based on measurements of feedwater flowrate, feedwater temperature, steam flow, and steam pressure. A detailed energy balance is performed for each steam generator. The energy output of the two steam generators is summed and allowances made for reactor coolant pump heat, pressurizer heaters, and primary and secondary system energy losses.

7.7.1.3.1.3.3 COLSS Determination of Power Distribution. The determination of the 3-D peaking factor, the integrated radial peaking factor, the power shape in the hottest channel, and the azimuthal tilt magnitude is performed based on in-core measurements of the flux distribution, processed by pre-programmed algorithms and stored constants. A brief description is given here of the data processing approach

employed by COLSS to yield the desired power distribution information. This analysis is repeated at least once per minute, and thus represents continual on-line monitoring.

The dynamic response characteristic of the self-powered rhodium in-core detectors is a function of both prompt and delayed components of electrical current generated in the detector and cabling. The delayed portion of the current signal is governed by the decay of isotopes of rhodium having half-lives of 0.7 minutes and 4.4 minutes. To provide the capability to compensate for the delayed portion of the signal, the COLSS power distribution determination includes a compensation algorithm for the in-core signals used as input to COLSS. The algorithm approximately represents the inverse of the in-core detector dynamic response, such that the combination of detector response and dynamic compensation produces a signal representative of the actual neutron flux response.

The capability for signal filtering is provided through selection of algorithm constants. With the capability for dynamic compensation and filtering on the in-core signals, changes in local flux level during operational load follow transients are adequately represented by the COLSS power distribution determination.

Following correction of the fixed detector signals for background and burnup, five axially distinct region-average power integrals corresponding to the five rhodium detector segments are constructed, taking into account signal-to-power conversion factors which are a function of burnup in the

surrounding fuel. The five power integrals are expanded into a forty node core average axial power distribution using a Fourier series technique.

Employing tables of factors relating power in the hot pin to the core average, the axial power profile in the hot pin is computed.

Malpositioning of a CEA or CEA group, the uncontrolled insertion or withdrawal of a CEA or CEA group, or a dropped CEA will be detected by COLSS with inputs received from the pulse-counting CEA position indicating system. Should these deviations occur, adjustments to the planar radial peaking factors are performed to ensure that the COLSS DNBR and peak linear heat rate calculations remain conservative. It is noted that COLSS only provides a monitoring function and therefore has only the function of informing the operator of such deviations. Any protective action required for the CEA-related events is provided by the RPS.

Flux tilts are detected by comparison of signals from symmetrically located sets of fixed in-core detectors, at various levels in the core. The flux tilts are included in the computation of margin to the power operating limit. In this way, postulated nonseparable asymmetric xenon shifts are identified and reflected in the power distribution assessment. Alarms are provided by COLSS when the xenon tilt exceeds the allowances for these effects carried in the core protection calculators as a penalty, or when it exceeds an absolute limit

(imposed by the Technical Specifications) indicating possible power distribution abnormality.

The possibility of nonfunctional fixed in-core detectors is allowed for by provision of redundant detector strings within each region of the core. If a nonfunctional fixed in-core detector is identified during internal consistency checks of the data, that detector is dropped from COLSS calculations prior to replacement, e.g., at a subsequent refueling.

After the inception of operation, periodic confirmation of the COLSS assessment of the power distribution, including the suitability of any updated stored constants, is obtained by comparison with a more detailed, off-line processing of an extensive in-core flux map produced by the fixed in-core instrument systems. One means of analyzing the detailed flux map is to compare it with detailed calculations of the power distribution which include computations of the flux at the instrument location. Folding this together with other analyses of the ability of the detailed calculation to estimate the local pin-by-pin power distribution enables an overall assessment of the COLSS power distribution error.

7.7.1.3.1.3.4 Core Power Operating Limit Based on Linear Heat Rate. The core power operating limit based on linear heat rate is calculated as a function of the core power distribution. The power level that results from this calculation corresponds to the limiting condition for operation of peak linear heat rate margin.

7.7.1.3.1.3.5 Core Power Operating Limit Based on DNBR. The core power operating limit based on DNBR is calculated as a function of the reactor coolant volumetric flowrate, the core power distribution, the maximum value of the four reactor coolant cold leg temperatures, and the reactor coolant system pressure. The CE-1 correlation is used in conjunction with an iterative scheme to compute the operating limit power level. (See section 4.4 for a detailed discussion of the CE-1 correlation). The power level that results from this calculation corresponds to the limiting conditions for operation on DNBR margin.

7.7.1.3.1.4 Calculation and Measurement Uncertainties. Three uncertainty penalty factors are calculated for COLSS, one which is used in calculating the linear heat rate power operating limit and two which are used in calculating the DNBR power operating limit.

The LHR adjustment accounts for the composite modeling uncertainty in the COLSS determination of the 3-D peak and for the various engineering factors. This modeling error is determined from a set of several thousand comparison cases between COLSS and design codes covering suitable ranges of power level, core burnup, CEA position, and primary system fluid properties. The overall adjustment factor accounts for the effects of fuel rod bow, poison rod bow, design code modeling uncertainty, COLSS power algorithm uncertainty, CECOR measurement uncertainty, and computer processing uncertainties.

Similarly, the DNBR adjustments account for the composite modeling uncertainty in the COLSS calculation of the power distribution and DNBR. This composite modeling error is based on the same set of comparison cases between COLSS and design codes used for the LHR uncertainty calculation. The overall adjustment factors include the effects of fuel rod bow, poison rod bow, design code modeling uncertainty, CECOR measurement uncertainty, COLSS DNB algorithm uncertainty, and computer processing uncertainties.

7.7.1.3.2 Plant Monitoring System (PMS)

The PMS is designed and configured as a general purpose facility for plant monitoring, alarming, and reporting purposes. It includes the capability of direct interaction with plant control systems to provide permissive or control inputs to these systems based upon calculational determination of plant conditions.

7.7.1.3.2.1 Application Programs. The PMS application programs, exclusive of COLSS, that provide either a reactor monitoring or Plant Protection System monitoring function are described below:

A. Power Dependent Insertion Limits (PDILs) are operating limits on allowable insertion of full-strength CEAs as a function of reactor power, PDILs are used to maintain operation consistent with shutdown margin (when the reactor is critical) and ejected CEA worth

(when the reactor is critical) constraints. PDILs utilize reactor power and CEA position signals.

B. Isolated output signals from each DNBR/LPD Calculator System channel (including calibrated ex-core neutron flux power and margin to DNBR and local power density trip setpoints) are sent to the computer. The difference between the maximum and minimum values of the four channels for each parameter is compared to a predetermined constant. An alarm is initiated if the constant is exceeded.

C. The post-trip review program monitors pre-selected process inputs at selected intervals before and after a reactor trip. This program provides a means of monitoring events before and after a plant trip.

D. The sequence-of-events program monitors PPS bistable trip units and records status of changes (channel trips) with a resolution of several milliseconds as a means of monitoring events before and after plant trip.

Each of these PMS functions is intended to assist the plant operator in supervision or analysis of plant conditions. None of these functions is required to ensure plant safety or permit plant operation.

7.7.1.3.2.2 NSSS Programs. The NSSS programs which utilize the PMS that provide input to plant control systems are described below:

A. The CEA group sequencing program provides input to the Control Element Drive Mechanism Control System (CEDMCS) in the form of permissive signals. These signals permit sequential insertion and withdrawal of regulating CEA groups by the CEDMCS, with a pre-programmed overlap between consecutive groups during Automatic Sequential and Manual Sequential modes of operation.

   The PMS monitors the following functions during sequential modes of CEA group operation: (1) withdrawal sequence which starts with group 1 and ends with the last regulating group in consecutively increasing numbers, and (2) the insertion sequence starts with the last regulating group and ends with group 1 in consecutively decreasing numbers. Proper sequencing of the group necessitates that the preceding group reach a specified limit before the next group is permitted to move. One sequential permissive contact output is initiated for each regulating group when the permissive conditions for that group have been met. In addition to sequential permissive outputs for each regulating group, one contact output for out-of-sequence alarming is provided, which does not pass through the CEDMCS Auxiliary Cabinets.

B. The PMS also provides normal CEA control limits for all FSCEAs/PSCEAs. These limits include the Upper (Lower) Group Stops for full-strength CEAs and the Upper (Lower) Group Stops for the PSCEAs. These control limits are provided to the CEDMCS to automatically terminate CEA motion upon reaching the CEA limits of travel.

Each of these functions is intended to enhance flexibility of plant operation. None are required to ensure plant safety or permit plant operation.

All other functions presently implemented in the PMS are solely for operator and administrative convenience and involve neither the Plant Protection System nor plant control. None of the PMS functions are required to ensure plant safety or permit plant operation.

7.7.1.3.2.3 Pulse Counting CEA Position Indication System. The pulse counting CEA position indication system infers each CEA position by maintaining a record of the "raise" and "lower" control pulses sent to each magnetic jack Control Element Drive Mechanism (CEDM). The pulse counting CEA position signal associated with each CEA is reset to zero whenever the rod drop contact (located within the reed switch position transmitter housing) is closed. This permits the pulse counting system to automatically reset the position to zero, whenever a reactor trip occurs or whenever a CEA is dropped into the core. This system is incorporated in the Plant Monitoring System (PMS) which feeds control board digital displays. One digital

display provides CEA group information. A second digital display provides individual CEA position information. The position of each CEA is periodically printed out for a permanent record. A printout is available, on operator demand, of selected CEA positions.

The pulse counting CEA position indication system provides position information to CEA related alarm programs and the Core Operating Limit Supervisory System (COLSS) contained in the PMS. The PMS CEA and COLSS alarms are indicated on an alarm display, which contains both audible and visible indication, and by hard copy printout on the printer. The alarms are included in the system design to provide information to the operator to assist in maintaining proper CEA control and to aid in the monitoring of CEA limits. The following alarms are provided by the pulse counting CEA position indication system:

A. Power Dependent Insertion Limits (PDILs) Alarms

   An alarm is provided on PC and CMC COLSS after CMC/COLSS upgrade, in the event CEA insertion exceeds predetermined limits required to maintain adequate shutdown margin and to ensure CEA insertion consistent with the CEA ejection analysis. Further definition of the PDIL function is provided in Paragraph 7.7.1.3.2.1.

B. Pre-Power Dependent Insertion Limits (PPDILs) Alarm

   This alarm is provided to advise the operator of an impending approach to PDILs.

C. Out of Sequence Alarm

An alarm is provided to alert the operator in the event the CEA groups are inserted in a sequence other than the pre-determined acceptable sequence.

D. CEA Deviation Alarm

An alarm is provided to alert the operator in the event the deviation in position between the highest and lowest CEA in any group exceeds a predetermined allowable deviation.

E. Core Operating Limit Supervisory System Alarms

The pulse counting CEA position indication system provides input data to COLSS. These data are used in the COLSS power distribution calculations, and alarms are initiated in the event the affected COLSS limits are reached. The basis for the COLSS alarms and the use of the pulse count CEA position information is discussed in Section 7.7.1.3.1.

7.7.2 ANALYSIS

The plant control system and equipment are designed to provide high reliability during steady state operation and anticipated transient conditions. The RPS analysis of Section 7.2.2 encompasses the failure modes of these control systems and demonstrates that these systems are not required for safety.

The safety analyses of Chapter 15.0 do not require these systems to remain functional.

7.7.3 REFERENCES

1. "Overview Description of the Core Operating Limit Supervisory System," CEN-312, Revision 01-P, November 1986

APPENDIX 7A

RESPONSES TO NRC REQUESTS FOR INFORMATION

CONTENTS

APPENDIX 7A

QUESTION 7A.1 (NRC Question 222.01)

Loss of Non-Class 1E Instrumentation and Control Power System Bus During Power Operation (IE Bulletin 79-27)

If reactor controls and vital instruments derive power from common electrical distribution systems, the failure of such electrical distribution systems may result in an event requiring operator action concurrent with failure of important instrumentation upon which these operator actions should be based. This concern was addressed in IE Bulletin 79-27. On November 30, 1979, IE Bulletin 79-27 was sent to operating license (OL) holders, the near term OL applicants (North Anna 2, Diablo Canyon, McGuire, Salem 2, Sequoyah, and Zimmer), and other holders of construction permits (CPs), including Palo Verde. Of these recipients, the CP holders were not given explicit direction for making a submittal as part of the licensing review. However, they were informed that the issue would be addressed later.

You are requested to address this issue by taking IE Bulletin 79-27 Actions 1 through 3 under "Actions to be Taken by Licensees". Within the response time called for in the attached transmittal letter, complete the review and evaluation required by Actions 1 through 3 and provide a written response describing your reviews and actions. This report should be in the form of an amendment to your FSAR and submitted to the NRC Office of Nuclear Reactor Regulations as a licensing submittal.

RESPONSE:

The response is given in amended paragraph 7.1.2.33.

QUESTION 7A.2 (NRC Question 222.02)

If safety equipment does not remain in its emergency mode upon reset of an engineered safeguards actuation signal, system modification, design change or other protective action of the affected equipment is not compromised once the associated actuation signal is reset. This issue was addressed in IE Bulletin 80-06 (enclosed). For facilities with operating licenses as of March 13, 1980, IE Bulletin 80-06 required that reviews be conducted by the licensees to determine which, if any, safety functions might be unavailable after reset, and what changes could be implemented to correct the problem.

For facilities with a construction permit, including OL applicants, Bulletin 80-06 was issued for information only.

The NRC staff has determined that all CP holders, as a part of the OL review process are to be requested to address this issue. Accordingly, you are requested to take the actions called for in Bulletin 80-06 Actions 1 through 4 under "Actions to be Taken by Licensees". Within the response time called for in the attached transmittal letter, complete the review verifications and descriptions of corrective actions taken or planned as stated in Actions 1 through 3 and submit the report called for in Action Item 4. The report should be submitted to the NRC Office of Nuclear Regulation as a licensing submittal in the form of an FSAR amendment.

RESPONSE:

The response is given in amended paragraph 7.1.2.34.

QUESTION 7A.3 (NRC Question 222.03)

Operating reactor licensees were informed by IE Information Notice 79-22, issued September 19, 1979, that certain non-safety grade or control equipment, if subjected to the adverse environment of a high energy line break, could impact the safety analyses and the adequacy of the protection functions performed by the safety grade equipment. Enclosed is a copy of IE Information Notice 79-22, and reprinted copies of an August 20, 1979, Westinghouse letter and a September 10, 1979, Public Service Electric and Gas Company letter which address this matter. Operating reactor licensees conducted reviews to determine whether such problems could exist at operating facilities.

We are concerned that a similar potential may exist at light water facilities now under construction. You are, therefore, requested to perform a review to determine what, if any, design changes or operator actions would be necessary to assure that high energy line breaks will not cause system failures to complicate the event beyond your FSAR analysis. Provide the results of your reviews including all identified problems and the manner in which you have resolved them to NRR.

The specific "scenarios" discussed in the above referenced Westinghouse letter are to be considered as examples of the kind of interactions which might occur. Your review should include those scenarios, where applicable, but should not necessarily be limited to them. Applicants with other LWR designs should consider analogous interactions as relevant to their designs.

RESPONSE:

The response is given in amended paragraph 7.1.2.35.

QUESTION 7A.4 (NRC Question 222.04)

The analysis reported in chapter 15 of the FSAR are intended to demonstrate the adequacy of safety systems in mitigating anticipated operational occurrences and accidents.

Based on the conservative assumptions made in defining these design basis events and the detailed review of the analyses by the staff, it is likely that they adequately bound the consequences of single control system failures.

To provide assurance that the design basis event analyses adequately bound other more fundamental credible failures, you are requested to provide the following information:

1. Identify those control systems whose failure or malfunction could seriously impact plant safety.

2. Indicate which, if any, of the control systems identified in (1) receive power from common power sources. The power sources considered should include all power sources whose failure or malfunction could lead to failure or malfunction of more than one control system and should extend to the effects of cascading power losses due to the failure of higher level distribution panels and load centers.

3. Indicate which, if any, of the control systems identified in (1) receive input signals from common sensors. The sensors considered should include, but

should not necessarily be limited to, common hydraulic headers or impulse lines feeding pressure, temperature, level or other signals to two or more control systems.

4. Provide justification that any simultaneous malfunctions of the control systems identified in (2) and (3) resulting from failures or malfunctions of the applicable common power source or sensor are bounded by the analyses in chapter 15 and would not require action or response beyond the capability of operators or safety systems.

RESPONSE: Refer to Section 7.2.2.4.1 for a detailed response.

<u>QUESTION 7A.5</u> (NRC Question 492.3)[a]

CEN-251(V)-P, Revision 00 - "PVNGS-1 Cycle 1 CPC and CEAC Data Base Listing," June 1983 provides data base values for the Palo Verde, Unit 1, CPC and CEAC.

The data base document states that - "the purpose of this document is to specify the CPC and CEAC data base constants applicable to the PVNGS-1 Cycle 1 software described in Reference 1, the CPC Functional Design Specification, and Reference 2, the CEAC Calculator Functional Design Specification."

References 1 and 2 are the functional specifications for a CPC and CEAC for San Onofre. In addition, Reference 3 is a software modification for Waterford, although not mentioned in the text.

a. Submitted by NRC as Question 492.1

(a) Are the referenced data base constants for San Onofre applicable to Palo Verde?

(b) Why is a reference given for a Waterford modification? Does this apply to Palo Verde?

RESPONSE:

A. The references listed in CEN-251(V)-P have been reviewed, and none of the four references relates to San Onofre data base constants. Furthermore, the San Onofre data base constants are not applicable to Palo Verde.

B. The reference to a document defining the Waterford modifications was incorrect. The referenced document applies only to Waterford CPC/CEAC software. The correct Reference 3 to CEN-251(V)-P should be Reference 7A-1 to this response. Reference 7A-1 incorporates the Waterford modifications and defines additional changes that were made specifically for Palo Verde. The last complete versions of the CPC and CEAC functional descriptions submitted to the NRC were References 7A-2 and 7A-3. References 7A-1 through 7A-3 completely define the functional design for the Palo Verde CPC/CEAC software. Therefore, the first paragraph of Section 1.2 in CEN-251(V)-P should read as follows:

"The CPC/CEAC system, as functionally described in References 1 and 2 and as modified by Reference 3, is implemented in assembly language and also exists as a FORTRAN simulation. This document provides..."

In addition, Subparagraph (1) of Section 1.3 in CEN-251(V)-P should read as follows:

"(1) The CPC and CEAC protection systems described in References 1, 2, and 3."

References

7A-1 CPC/CEAC Software Modifications for System 80, Enclosure 1-P to LD-82-039, March 1982.

7A-2 Functional Design Specification for a Core Protection Calculator, CEN-147(S)-P, January 1981.

7A-3 Functional Design Specification for a Control Element Assembly Calculator, CEN-148(S)-P, January 1981.

QUESTION 7A.6 (NRC Question 492.4)[a]

CEN-251(V)-P, revision 00 - "PVNGS-1 Cycle 1 and CEAC Data Base Listing," June 1983 provides data base values for CPC and CEAC. However, the BERR values (addressable constants) are not consistent with the approved CESSAR-80 values described in Enclosure 1-P to LD-83-010, "Statistical Combination of Uncertainties Part V," January 1983. Specifically, a comparison is shown in the following table for BERR values given for Palo Verde and CESSAR-80:

____

a. Submitted by NRC as Question 492.2

	Palo Verde	CESSAR-80
BERR0	8.5	9.0
BERR1	1.065	1.099
BERR2	8.5	7.48
BERR3	1.074	1.139
BERR4	8.5	12.48

(a) Explain why the Palo Verde BERRs differ from the CESSAR-80 values and justify their acceptability.

RESPONSE:

The Palo Verde BERRs do not differ from the CESSAR-80 values. The BERR values are calculated toward the end of the CPC software testing and, therefore, are not available at the time the CPC/CEAC data base is generated. The BERR values given in CEN-251(V)-P are preliminary values. These preliminary values are required in order to generate and certify a data base for use in phase I and phase II testing. In addition, certain outputs of the CPC/CEAC software testing are required as inputs to the uncertainty analysis which determines the correct BERR values for plant power operations. Since the BERR values are addressable constants, the final values can be loaded when the software is loaded.

The BERR values given for Palo Verde are not the correct values. The values certified for power operations are the same as those given for CESSAR-80. The letter (Reference 7A-4) which transmitted the CPC/CEAC disks and software documentation also transmitted the correct BERR

values. These values are listed in Attachment 3 of the letter, which is a table of correct addressable constant values. The letter also transmitted comments on the addressable constants which include the following guidance:

> "Attachment (3) lists the addressable constants and their values. The values of some of the addressable constants in Attachment (3) are different than the values for the equivalent constants contained in the data base listing and the software data base. The values listed in Attachment (3) supersede those values listed in the data base and are to be implemented when the software is loaded."

<u>Reference</u>

7A-4 Letter from C. Ferguson (C-E) to G.C. Andognini (APS), V-CE-18963, dated September 7, 1983.

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CHAPTER 8

ELECTRIC POWER

CONTENTS

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TABLES

FIGURES

8. ELECTRIC POWER

8.1 INTRODUCTION

8.1.1 TRANSMISSION NETWORK DESCRIPTION

The Palo Verde Nuclear Generating Station (PVNGS), Units 1, 2, and 3, is connected to the Western Interconnection, one of the two major power grids in North America.

Eight 525 kV transmission lines connect the Palo Verde 525 kV switchyard with the RUDD, Colorado River, Westwing, Hassayampa and Delaney switchyards.

8.1.2 ONSITE POWER SYSTEM DESCRIPTION

The onsite power system for each unit is shown in engineering drawing 01, 02, 03-E-MAA-002. Six circuits supply offsite (preferred) power to the three units through secondary windings of three startup transformers (refer to engineering drawing 13-E-MAA-001). The onsite power system of each unit is divided into two separate systems: the non-Class 1E power system and the Class 1E power system which is divided into two separate load groups, also referred to as subsystems and/or trains. Power is supplied to the auxiliaries at 13.8 kV, 4.16 kV, and 480V levels. The onsite power system includes the Class 1E power system which provides auxiliary ac and dc power for equipment used to shut down the reactor safely following a design basis event. The Class 1E buses of each unit must be energized in order to provide preferred or standby power to the safety-related loads of each unit. The Class 1E power systems are designed in accordance with IEEE 308-1974. A Class 1E dc system provides four channels of 125 V-dc control power for

Class 1E switchgear, essential ac power inverters, and other engineered safety feature (ESF) equipment (refer to engineering drawing 01, 02, 03-E-PKA-001).

8.1.3 SAFETY-RELATED LOADS

The Class 1E loads supplied by the Class 1E ac systems are listed in table 8.3-1. Class 1E loads supplied by the Class 1E dc system are listed in table 8.3-6.

8.1.4 DESIGN BASES, STANDARDS, AND GUIDES

The following principal design bases are applied to the design of offsite and onsite power systems.

8.1.4.1 Offsite Power System

The offsite (preferred) power supply provides ac power from the transmission network described in subsection 8.1.1 to the 4.16 kV Class 1E buses. The following principal design bases are applied to the offsite power system:

A. Electric power to the Palo Verde 525 kV switchyard is supplied by eight physically independent transmission lines designed and located to minimize the likelihood of simultaneous failure. Refer to section 8.2 for details.

B. Three physically independent startup transformers are provided to supply the onsite electric distribution system during startup. After startup, the normal unit auxiliaries are supplied from the unit auxiliary transformer and the Class 1E equipment is supplied from

the startup transformers. Refer engineering drawing 13-E-MAA-001 for details.

C. The outage of a single startup transformer does not jeopardize continued plant operation, i.e., when loads are administratively controlled between units at least one offsite source to plant auxiliaries and ESF buses is available with a single startup transformer outage.

D. The Palo Verde 525 kV switchyard is designed with duplicate and redundant systems; i.e., two trip coils per breaker, two protective relay schemes, and two ac supplies from the 13.8 kV intermediate buses.

E. The loss of a nuclear unit or the most critical unit on the transmission network does not result in loss of offsite power to the safety-related buses.

8.1.4.2 Onsite Power System

A. The onsite Class 1E power system for each unit is split into two independent load groups, each with its own offsite and onsite power supplies, buses, transformers, loads, and associated 125 V-dc control power. Either load group is independently capable of safely shutting down the unit.

B. The onsite power system includes two redundant Class 1E electric systems for each unit. The Class 1E systems supply power at 4.16 kV ac, 480 V-ac, 120 V-ac, and 125 V-dc, as required, to plant safety-related systems.

C. One independent emergency diesel generator is provided for each Class 1E ac load group.

D. No automatic transfers are provided between redundant load groups.

E. There is complete independence of onsite electric systems between units.

F. The Class 1E power systems are designed to satisfy the single failure criterion.

G. For each protection and control channel, one independent 125 V-dc power source and one 120V vital ac power source are provided. Batteries are sized for a minimum of 2 hours of operation without support of a battery charger.

H. A separate nonsafety-related dc system is provided for nonsafety-related controls and pump motors.

I. Raceways are not shared by safety and nonsafety cables. However, the nonsafety cables that are supplied from or are derived from Class 1E sources are treated as safety-related cables up to and including the isolation device with regard to redundant system separation and identification criteria in conformance with Regulatory Guide 1.75 as qualified in section 1.8.

J. Special identification criteria apply for Class 1E equipment cabling and raceways (see paragraph 8.3.1.3).

K. Separation criteria, which establish requirements for preserving the independence of redundant Class 1E electric systems, comply with Regulatory Guide 1.75 as qualified in section 1.8.

L. Safety-related equipment is designed with the capacity to be tested periodically.

M. 10CFR50, Appendix A, is followed in the design of the electric power system.

N. A non-safety related Alternate AC (AAC) power source consisting of two redundant station blackout generators is available to provide power to cope with a 16 hour station blackout event in any one nuclear unit.

8.1.4.3 Design Criteria, Regulatory Guides, and IEEE Standards

A discussion of General Design Criteria 17 and 18 and IEEE standards is provided in paragraphs 8.3.1.2 and 8.3.2.2. Consistency of design with the recommendations of NRC Regulatory Guides 1.6, 1.9, 1.22, 1.29, 1.30, 1.32, 1.40, 1.41, 1.47, 1.53, 1.62, 1.63, 1.73, 1.75, 1.81, 1.89, 1.93, and IEEE 387-1972 are discussed in paragraphs 8.3.1.2 and 8.3.2.2. In addition, Regulatory Guides 1.100, 1.118, and 1.155 are discussed in section 1.8.

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8.2 OFFSITE POWER SYSTEM

8.2.1 DESCRIPTION

Eight physically independent 525 kV transmission lines of the Western Interconnection are connected to the Palo Verde 525 kV switchyard. Three 525 kV tie lines supply power from the switchyard to three startup transformers, which supply power to six 13.8 kV intermediate buses. Two physically independent circuits supply offsite (preferred) power to the onsite power system of each unit. The offsite power system is described in this section and is depicted in figures 8.1-1 and 8.2-1.

8.2.1.1 Transmission Network

The transmission network associated with PVNGS supplies offsite (preferred) ac power at 525 kV for startup, normal operation, and safe shutdown of Units 1, 2, and 3. The eight 525 kV lines of this system that are associated with the Palo Verde 525 kV switchyard are: PVNGS to RUDD, PVNGS to Westwing I, PVNGS to Westwing II, PVNGS to Colorado River, PVNGS to Hassayampa I, PVNGS to Hassayampa II, PVNGS to Hassayampa III, and PVNGS to Delaney. They cover distances of approximately 37, 44, 44, 128, 3, 3, 3, and 15 miles, respectively.

All eight transmission lines associated with the Palo Verde 525 kV switchyard traverse relatively flat terrain and their design meets grade B requirements specified by the National Electrical Safety Code, sixth edition.

The Code specifies loading areas, wind loads for towers and conductors, and safety factors to be used. The conductors and the overhead ground wires are dampened to maintain acceptable

levels of vibration. There is a crossing of the Westwing I and Westwing II lines by a 525 kV line not associated with PVNGS, approximately 43 miles from PVNGS. There is a crossing of the Delaney line by the Colorado River line, approximately 15 miles from PVNGS.

The eight transmission lines associated with the Palo Verde 525 kV switchyard, and their rights-of-way, are designed so as to minimize line proximities that could result in simultaneous failure of more than one circuit. Based on historical transmission system data, the frequency of occurrence for breakage of the span of line that crosses the two Westwing lines is 1.1×10^{-5} per year and for the breakage of the span of the Colorado River line that crosses the Delaney line is 6.9×10^{-6} per year. In the highly unlikely event of transmission network instability resulting from simultaneous short-circuiting of both Westwing lines or simultaneous short-circuiting of the Delaney and Colorado River lines, a loss of all nonemergency AC power event could result. This design basis event is evaluated in chapter 15.

8.2.1.2 Switchyard and Connections to the Onsite Power System

The Palo Verde 525 kV switchyard utilizes a breaker-and-a-half design in which three breakers are provided for every two terminations, either line or transformers. The switchyard is connected to the eight 525 kV transmission lines discussed in Section 8.2.1.1, the 525/24 kV turbine-generator main transformers, and the 525/13.8 kV startup transformers, as shown in figure 8.2-2.

Each turbine-generator connects to the Palo Verde 525 kV switchyard through a main transformer, a 525 kV tie line, and two 525 kV switchyard breakers, as shown in figure 8.2-2. Physical connections between the units and the Palo Verde 525 kV switchyard are shown in figure 8.2-1.

The three startup transformers connect to the Palo Verde 525 kV switchyard through two 525 kV switchyard breakers each, and feed six 13.8 kV intermediate buses. These buses are arranged in three pairs, each pair feeding only one unit.

The intermediate buses for Units 1, 2, and 3 are interconnected to the startup transformers so that each unit's buses can access all three startup transformers when all startup transformers are connected to the switchyard.

The intermediate buses are connected to the onsite power system by one 13.8 kV transmission line per bus (two per unit). These lines are physically separated to minimize the possibility of simultaneous failure of the lines.

8.2.1.2.1 Switchyard and Offsite Power System Development

Figure 8.2-2 depicts the switchyard and 13.8 kV bus arrangements.

Necessary 525 kV breaker installation is accomplished during refueling, if possible, or during operation. All operating 525 kV positions are transferred to the opposite bus: thus, continuity of offsite power is maintained.

8.2.1.2.2 Water Reclamation Facility Load Shedding

The Water Reclamation Facility loads are load shed from the Unit 1 intermediate buses upon a Unit 1 BOP ESFAS Mode 1 signal concurrent with switchyard voltage at or below a value which could result in a trip of offsite power in the event of a safe shutdown or emergency event.

8.2.1.3 Compliance with Design Criteria and Standards

The following analysis demonstrates compliance with General Design Criteria 17 and 18 of 10CFR50, Appendix A, and Regulatory Guide 1.32.

8.2.1.3.1 Criterion 17 -- Electric Power Systems

In addition to the features detailed in paragraphs 8.2.1.1 and 8.2.1.2, compliance with Criterion 17 is further demonstrated by the following:

A. If one of the two 13.8 kV physically independent circuits per unit from the intermediate buses to the onsite power system is interrupted, the remaining circuit can supply offsite power to both load groups of the onsite Class 1E power system, as shown in engineering drawing 01, 02, 03-E-MAA-002.

B. The two physically independent circuits, supported on independent structures, are separated so as to avoid the possibility that the structural collapse of one will cause an outage of the other 13.8 kV circuit.

C. The 13.8 kV circuits are protected from lightning and switching surges by lightning protective equipment and by overhead static lines.

D. Design of the 125 V-dc system for the Palo Verde 525 kV switchyard consists of two independent dc systems. Each of the two systems consist of a separate 125 V-dc battery, battery charger, and distribution system. Cable separation is maintained between the two systems. A single failure caused by a malfunction of either of the two 125 V-dc systems does not affect the performance of the other system. The ability of the switchyard to supply off-site power to the plant is not affected by the loss of one of the two 125 V-dc systems.

E. Two isolated 13.8 kV supplies from the intermediate 13.8 kV buses are provided to the Palo Verde 525 kV switchyard. The ac load is divided between two power panels and loss of one feeder from the plant does not jeopardize continued operation of the switchyard equipment.

F. For reliability and operating flexibility, the Palo Verde 525 kV switchyard design includes a breaker-and-a-half arrangement for each circuit along with breaker failure backup protection. Each breaker has two trip coils on separate, isolated dc control circuits. These provisions permit the following:

1. Any transmission line can be cleared under normal or fault conditions without affecting any other transmission line.

2. Any circuit breaker can be isolated for maintenance without interrupting the power or protection to any circuit (subject to limitations of power system development paragraph 8.2.1.2.1).

3. Short circuits on a section of bus can be isolated without interrupting service to any circuit other than that connected to the faulty bus section.

G. The offsite (preferred) power supplies from the 525 kV switchyard to the startup transformers are separate and independent. The failure or structural collapse of one system or structure does not affect other offsite sources.

H. The offsite (preferred) power supplies from the startup transformers to the 13.8 kV intermediate buses NAN-S03 and NAN-S04 are independently and separately routed.

I. Two physically independent circuits are provided for offsite (preferred) power to the onsite power system for each unit. The offsite (preferred) power supply normally connected to each load group of the onsite Class 1E ac power system is immediately available to supply components important to safety following a postulated loss-of-coolant accident. Either of the

two offsite (preferred) power supplies to each load group, if available, can be connected by control switch operation in the control room. (subject to the limitations of power system development paragraph 8.2.1.2.1).

8.2.1.3.2 Criterion 18 -- Inspection and Testing of Electric Power Systems

The 13.8 kV intermediate bus circuit breakers can be inspected, maintained, and tested on a routine basis. This can be accomplished without removing the generators, transformers, or transmission lines from service (subject to limitations of power system development paragraph 8.2.1.2.1).

Transmission line protective relays can be tested on a routine basis. This can be accomplished without removing the transmission lines from service. Generator, main transformer, and startup transformer relays are tested on a routine basis when the generator is offline.

Onsite power system components will be periodically inspected and maintained as required. This can be accomplished without removing the transmission lines, generators, or transformers from service.

8.2.1.3.3 Regulatory Guide 1.32

As described in paragraph 8.2.1.3.1, listing I, an independent immediate access circuit is provided to each load group of the onsite Class 1E ac power system bus for each unit.

8.2.1.3.4 Industry Standards

The design complies with applicable standards and recommendations of:

- Institute of Electrical and Electronics Engineers, Inc. (IEEE) National Electrical Manufacturer's Association (NEMA)
- National Electrical Code (NEC)
- American Society of Civil Engineers (ASCE)
- Underwriters' Laboratory, Inc. (UL)
- American Iron and Steel Institute (AISI)

8.2.2 ANALYSIS

The transmission network is planned so that the loss of a single transmission element (i.e., line or transformer) does not result in loss of load, transmission overload, undervoltage condition, or loss of system stability. Offsite power supply reliability is determined by the performance of the eight 525 kV transmission lines associated with the Palo Verde 525 kV switchyard. The source stations for the lines all have three or more connected circuits of 230 kV and above.

Power flow studies conducted for the described system indicate that the system can reliably deliver power to all project participants using the above planning criteria. Dynamic stability studies(3) have established safe power generation levels for the generating units in the PVNGS area to ensure that the system can withstand the following disturbances without loss of system stability or loss of load:

A. A permanent 3-phase fault on the Palo Verde 525 kV switchyard bus with subsequent loss of the critical 525 kV line.

B. A sudden loss of one of the three PVNGS units with no underfrequency load shedding measures in effect.

C. The sudden loss of the largest single load in Arizona, New Mexico, Southern California, or Southern Nevada.

These studies include a 7% PVNGS generation margin.

A transmission network operating procedure controls the level of power generation in the PVNGS area to ensure that the safe levels are not exceeded.

Although these studies conclude that a PVNGS unit trip would not cause transmission network instability, certain chapter 15 accident analyses conservatively assume that offsite power is lost as a consequence of a PVNGS turbine trip. Refer to section 8.3.4 and table 15.0-0.

Transmission network availability data on 525 kV transmission lines in the area indicate an outage rate of 2.08 total outages per year per 100 line miles. Of these, 1.08 are due to planned outages and 1.00 are due to forced outages. Due to all causes, the outage ratio for 525 kV lines in the area is 0.00180.

On 230 kV transmission lines in the area, similar data indicate outage rates of 6.59 total outages per year per 100 line miles. Of these, 2.97 are due to planned outages and 3.61 are due to forced outages. Due to all causes, the outage ratio for 230 kV lines in the area is 0.0394.

These outages are most commonly attributable to lightning. Other causes are fog, contamination, flooding, other aspects of weather, falling objects, equipment failure, emergency maintenance, employee error, and, hypothetically, dust contamination. The chief constituents of dust storms are nonconducting clay dust (usually quartz) and conducting gypsum (calcium sulphate) which can contaminate the insulators. This contamination increases the probability of flashover, especially with fog or dew, by disclosing the salts to form an electrolyte.

However, dust buildup is reduced by the self-clearing action of the "V" string insulator configuration used in EHV line construction and by the abrasive action of the dust and sand. Also, any adverse conditions resulting from insulator contamination within the switchyard can be corrected by washing the insulators.

APS has never experienced a flashover in any of its EHV switchyards due strictly to dust on insulators and has found that dust storms contribute little to the outage frequency of EHV transmission lines.

Likewise, APS has not experienced any known dust-caused insulation failures at the 15 kV or 4 kV voltage levels in either open substation facilities or enclosed switchgear.

Therefore, it is felt that dust loading on the 13.8 kV system will not be a problem. The system is designed such that, with rare exceptions, forced outages do not result in loss of load.

Other forms of contamination that increase the probability of flashover in certain areas, especially near the Pacific coast,

are sea-salt deposits and industrial contaminations. The insulators can become contaminated by the salt deposits and when fogging conditions exist, flashovers are more likely to occur.

To minimize the effect of both salt and industrial contamination, the insulators are washed with demineralized water. The frequency of washing depends on the area. Some areas near the Pacific Coast require washing once a month while areas farther inland require washing every 90 days. The use of semi-conducting glazed insulators also reduces the flashover rates in areas of high contamination. No washing of insulators is anticipated in the desert regions.

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8.3 ONSITE POWER SYSTEMS

8.3.1 AC POWER SYSTEMS

8.3.1.1 Description

The onsite ac power system includes a Class 1E and a non-Class 1E power system. Engineering drawings 13-E-MAA-001 and 01, 02, 03-E-MAA-002 are one-line diagrams of the ac power system.

8.3.1.1.1 Non-Class 1E AC Power System

The non-Class 1E ac power system is that part of the onsite power system outside the dotted-line enclosures indicated in engineering drawings 13-E-MAA-001 and 01, 02, 03-E-MAA-002. The non-Class 1E ac power system distributes power at 13.8 kV, 4.16 kV, 480V, and 208/120V for nonsafety-related loads. Only nonsafety-related loads are supplied by the non-Class 1E ac power system. There will be an interconnection during startup between the offsite (preferred) power supply, the non-Class 1E ac system associated with 13.8 kV buses NAN-S01 and NAN-S02 and the Class 1E ac system.

During normal plant operation, power for the onsite non-Class 1E ac power system associated with buses NAN-S01 and NAN-S02 is supplied through the unit auxiliary transformer connected to the generator isolated phase bus. Two offsite power sources are provided to meet startup, shutdown, and post-shutdown requirements of the unit. Each unit's non-Class 1E ac power system is divided into two parts arranged so that the possibility of a forced shutdown due to loss of one part will be minimized. Each of the two parts supplies a load group including approximately half of the unit auxiliaries.

Three startup transformers connected to the Palo Verde 525 kV switchyard are shared between Units 1, 2, and 3 and are connected to 13.8 kV intermediate buses of the units. Each startup transformer is capable of supplying 100% of the startup or normally operating loads of one unit simultaneously with the engineered safety feature (ESF) loads associated with two load groups of another unit. The non-Class 1E ac buses NAN-S01 and NAN-S02 normally are supplied through the unit auxiliary transformer, and the Class 1E buses normally are supplied through the startup transformers. In the event of loss of supply from the unit auxiliary transformer (except for overcurrent trip), an automatic fast transfer of 13.8 kV buses NAN-S01 and NAN-S02 to the startup transformers is initiated to provide power to the auxiliary loads. Transfers of these buses can be initiated by the operator from the control room. Engineering drawings 13-E-MAA-001 and 01, 02, 03-E-MAA-002 show connections of power supply feeders and busing arrangements of the ac power system. Offsite (preferred) power for the onsite Class 1E power system is supplied through the startup transformers, the 13.8 kV switchgear, and the 13.8 to 4.16 kV ESF transformers.

Reactor coolant pumps 1A and 2A are connected to 13.8 kV bus NAN-S01 and 1B and 2B are connected to 13.8 kV bus NAN-S02. Electrical supply for reactor coolant pumps is arranged so that the pumps will normally remain electrically connected to the turbine-generator for 20 to 30 seconds following a turbine trip should offsite power not be available. Credit is not taken for this feature.

8.3.1.1.2 Non-Class 1E Equipment Capacities

A. 13.8 kV Switchgear

Buses	NAN-S01 NAN-S02 NAN-S03 NAN-S04 NAN-S05 NAN-S06	3000A Continuous rating - 1000 MVA bracing.
Incoming Breakers		3000A Continuous, 40.2 kA interrupting at 13.8 kV voltage
Feeder Breakers		1200A Continuous, 40.2 kA interrupting at 13.8 kV voltage

B. 4.16 kV Switchgear

Buses	NBN-S01 NBN-S02	3000A Continuous rating - 350 MVA bracing
Incoming and Tie		3000A Continuous rating – 47 kA

Breakers interrupting at 4.16 kV voltage

Feeder Breakers	1200A Continuous rating - 47 kA interrupting rating at 4.16 kV voltage

C. 480 Volt Unit Load Centers

Transformers

1500 kVA	13.8 kV/480V, three phase, 60 Hz
1000 kVA	13.8 kV/480V, three phase, 60 Hz
300 kVA	13.8 kV/480V, three phase, 60 Hz

Buses

3000A Continuous (1500 kVA rating)
1600A Continuous (1000 kVA rating)
600A Continuous (300 kVA rating)

Breakers (Metal Clad)

600A (nonfused)	30 kA interrupting rating at 480V
600A (fused)	200 kA interrupting rating at 480V
1600A	50 kA interrupting rating at 480V
2000A	55 kA interrupting rating at 480V
3000A	65 kA interrupting rating at 480V

D. 480V Motor Control Centers

Horizontal bus	600A Continuous
Vertical bus	300A Continuous
Breakers (100/150/225A Frame)	
	10000/25000/22000A (Magnetic)
	25000A (Thermal Magnetic)
Breakers (600A)	
	30000A (Magnetic)

8.3.1.1.3 Class 1E AC Power System

The Class 1E ac power system is that part of the onsite power system inside the dotted-line enclosures shown in engineering drawings 13-E-MAA-001 and 01, 02, 03-E-MAA-002.

The Class 1E ac power system distributes power at 4.16 kV, 480V, and 120V to all Class 1E loads. Also, the Class 1E ac

power system supplies power to certain selected loads that are not directly safety-related but are important to the plant. Table 8.3-1 lists the safety-related loads supplied from the Class 1E ac power system.

The Class 1E ac power system contains standby power sources (emergency diesel generators) that automatically provide the power required for safe shutdown in the event of loss of the 4.16 kV Class 1E bus voltage.

Voltage levels at the safety-related buses are optimized for the full load and minimum load conditions that are expected throughout the anticipated range of voltage variations of the power source by the adjustments of the voltage tap settings on the transformers.

An analysis was conducted and is maintained as follows. The maximum load conditions at the minimum anticipated offsite voltage are analyzed to ensure that voltages present at the terminals of the loads are above the manufacturer's minimum voltage rating. Additionally, the minimum load conditions at the maximum anticipated offsite voltage (102.0% of the switchyard voltage) are analyzed to ensure the voltages present at the terminals of the loads are below the manufacturer’s maximum voltage rating. Where this is not the case, the loads are evaluated individually and the rationale for operation is documented.

The following describes various features of the Class 1E systems.

8.3.1.1.3.1 Power Supply Feeders. Each 4.16 kV load group is supplied by two offsite (preferred) power supply feeders and one diesel generator (standby) supply feeder. Each 4.16 kV bus supplies three 750 kVA, 4.16 kV, 480V station service transformers and associated load centers. Transformers EPGAL31X and EPGBL32X have a power rating of 750/1000 kVA (AA/FA) due to the addition of fan cooling packages.

8.3.1.1.3.2 Power Feeder Cables. Power feeder cables for the Class 1E 4.16 kV power system are copper, rated at 5 kV, 3/C nonshielded armored and 1/C shielded with flame-retardant jacket. Power cables for use at 480 volts and less are rated at 600 volts. All conductors are insulated with ethylene propylene rubber or cross-linked polyethylene rated for 90C conductor temperature. All 5 kV and 600 volt cables have been designed for operation as follows:

A. Cables are suitable for installation in metal trays, in conduits, in underground duct banks, and are suitable for the environment in which they are installed as defined in Appendix A of the Equipment Qualification Program Manual.

TABLE 8.3-1[a]
CLASS 1E LOADS (SHEET 1 OF 10)

ID	DESCRIPTION	RATING
LOAD GROUP 1 (TRAIN A)		
4160 VOLT LOADS		
MECAE01	ESSENTIAL CHILLER	524.1 BHP
MEWAP01	ESSENTIAL COOLING WATER SYSTEM PUMP	665.4 BHP (U1) 680 BHP (U2) 670.8 BHP (U3)
MSIAP01	LOW PRESSURE SAFETY INJECTION PUMP	532.3 BHP (U1) 529.4 BHP (U2) 529.4 BHP (U3)
MSIAP02	HIGH PRESSURE SAFETY INJECTION PUMP	1026.3 BHP (U1) 986.4 BHP (U2) 1021.1 BHP (U3)
MSIAP03	CONTAINMENT SPRAY PUMP	757.6 BHP (U1) 748.4 BHP (U2) 745.7 BHP (U3)
MSPAP01	ESSENTIAL SPRAY POND PUMP	613.4 BHP (U1) 613.4 BHP (U2) 578.9 BHP (U3)
480 VOLT LOADS		
ENNAV13	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	24 KVA (U1) 21 KVA (U2) 21 KVA (U3)
EPHAM3119/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	25 KVA
EPHAM3331/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	25 KVA
EPHAM3728/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	25 KVA
EPKAH11	BATTERY CHARGER	80 KVA
EPKAH15	BATTERY CHARGER	92 KVA
EPKCH13	BATTERY CHARGER	58 KVA
EPNAV25	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	17 KVA (U1) 16 KVA (U2) 15 KVA (U3)
EPNCV27	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	11 KVA
EQBAV01	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	25 KVA
EQMAV31	SINGLE PHASE REGULATING TRANSFORMER	6 KVA
JCHAHV524	CHARGING PUMPS TO REGENERATE HEAT EXCHANGER VALVE	1.00 HP
JCHAHV531	REFUELING WATER TANK TO TRAIN A SAFETY INJECTION PUMPS VALVE	7.90 HP
JCHEHV536	REFUELING WATER TANK GRAVITY FEED TO CHARGING PUMPS VALVE	0.70 HP

TABLE 8.3-1[a]
CLASS 1E LOADS (SHEET 2 OF 10)

ID	DESCRIPTION	RATING
JCPAUV2A	CONTAINMENT BUILDING DUCT ISOLATION DAMPER	2.60 HP
JCPAUV2B	CONTAINMENT BUILDING DUCT ISOLATION DAMPER	2.60 HP
JCTAHV1	CONDENSATE TANK TO AUXILIARY FEEDWATER PUMP ISOLATION VALVE	0.33 HP
JECAE01	ESSENTIAL CHILLER AUXILIARY POWER PANEL	5.03 KVA
JECATV29	HYDROMOTOR ACTUATOR	0.23 KVA
JEWAUV145	CROSSITE FROM NON-SAFETY RELATED NUCLEAR COOLING WATER SYSTEM VALVE	0.33 HP
JEWAUV65	CROSSTIE FROM NON-SAFETY RELATED NUCLEAR COOLING WATER SYSTEM VALVE	0.33 HP
JGRAUV1	REACTOR DRAIN TIME/GAS SURGE HEADER IN CONTAINMENT ISOLATED VALVE	0.13 HP
JHPAE02	POST LOCA HYDROGEN MONITOR	1.00 HP
JHPAUV1	CONTAINMENT HYDROGEN CONTROL UPSTREAM ISOLATION VALVE	0.13 HP
JHPAUV3	CONTAINMENT HYDROGEN CONTROL DOWNSTREAM ISOLATION VALVE	0.13 HP
JHPAUV5	CONTAINMENT HYDROGEN CONTROL RETURN ISOLATION VALVE	0.13 HP
JNCAUV402	NCWS RETURN CONTAINMENT ISOLATION VALVE	0.33 HP
JRDAUV23	RADWASTE SUMP PUMP IN CONTAINMENT ISOLATION VALVE	0.33 HP
JSIAHV306	LOW PRESSURE SAFETY INJECTION PUMP HEADER DISCHARGE VALVE	2.60 HP
JSIAHV604	HIGH PRESSURE SAFETY INJECTION PUMP LONG TERM COOLING VALVE	1.00 HP
JSIAHV657	SHUTDOWN COOLING TEMPERATURE CONTROL VALVE	0.67 HP
JSIAHV678	SHUTDOWN COOLING ISOLATION VALVE	0.33 HP
JSIAHV683	LOW PRESSURE SAFETY INJECTION PUMP ISOLATION VALVE	4.00 HP
JSIAHV684	SHUTDOWN COOLING HEAT EXCHANGER ISOLATION VALVE	1.60 HP

TABLE 8.3-1[a]
CLASS 1E LOADS (SHEET 3 OF 10)

ID	DESCRIPTION	RATING
JSIAHV685	LOW PRESSURE SAFETY INJECTION-CONTAINMENT SPRAY PUMP CROSS CONNECT VALVE	1.60 HP
JSIAHV686	SDCHX DISCHARGE VALVE	4.00 HP
JSIAHV687	CONTAINMENT SPRAY ISOLATION VALVE	1.60 HP
JSIAHV688	SHUTDOWN COOLING BYPASS VALVE	1.60 HP
JSIAHV691	SHUTDOWN COOLING LOOP WARM-UP BYPASS VALVE	2.60 HP
JSIAHV698	HIGH PRESSURE SAFETY INJECTION PUMP DISCHARGE VALVE	0.70 HP
JSIAUV617	HPSI FLOW CONTROL TO REACTOR COOLANT LOOP 2A CONTAINMENT ISOLATION VALVE	0.67 HP
JSIAUV627	HPSI FLOW CONTROL TO REACTOR COOLANT LOOP 2B CONTAINMENT ISOLATION VALVE	0.67 HP
JSIAUV634	SAFETY INJECTION TANK 1A DISCHARGE ISOLATION VALVE	4.00 HP
JSIAUV635	LPSI TO REACTOR COOLANT LOOP 1A CONTAINMENT ISOLATION FLOW CONTROL VALVE	19.9 HP
JSIAUV637	HPSI TO REACTOR COOLANT LOOP 1A CONTAINMENT ISOLATION FLOW CONTROL VALVE	0.67 HP
JSIAUV644	SAFETY INJECTION TANK 1B DISCHARGE ISOLATION VALVE	4.00 HP
JSIAUV645	LPSI TO REACTOR COOLANT LOOP 1B CONTAINMENT ISOLATION FLOW CONTROL VALVE	19.9 HP
JSIAUV647	HPSI TO REACTOR COOLANT LOOP 1B CONTAINMENT ISOLATION FLOW CONTROL VALVE	0.67 HP
JSIAUV651	SHUTDOWN COOLING LOOP ISOLATION VALVE	13 HP
JSIAUV655	SHUTDOWN COOLING LOOP CONTAINMENT ISOLATION VALVE	2.60 HP
JSIAUV664	CONTAINMENT SPRAY PUMP TO REFUELING WATER TANK ISOL RECIRCULATE VALVE	0.67 H
JSIAUV666	HPSI PUMP TO REFUELING WATER TANK ISOLATION RECIRCULATE VALVE	0.67 HP
JSIAUV669	LPSI PUMP TO REFUELING WATER TANK ISOLATION RECIRCULATE VALVE	0.67 HP
JSIAUV672	CONTAINMENT SPRAY CONTAINMENT ISOLATION VALVE	5.30 HP
JSIAUV673	CONTAINMENT SUMP ISOLATION VALVE	0.70 HP

TABLE 8.3-1[a]
CLASS 1E LOADS (SHEET 4 OF 10)

ID	DESCRIPTION	RATING
JSIAUV674	CONTAINMENT SUMP ISOLATION VALVE	2.60 HP
JSQARU29	RADIATION MONITOR BLOWER MOTOR FOR CONTROL ROOM	1.50 HP
JWCAUV62	NORMAL CHILLED WATER RETURN CONTAINMENT ISOLATION VALVE	2.00 HP
MCHAP01	CHARGING PUMP	79.9 BHP
MCHEP01	CHARGING PUMP (BUS A OR B)	79.9 BHP
MCTAP01	CONDENSATE TRANSFER PUMP	3.6 BHP (U1) 3.7 BHP (U2) 3.7 BHP (U3)
MDFAP01	DIESEL GENERATOR FUEL OIL TRANSFER PUMP	1.5 BHP
MDGAM01	DIESEL GENERATOR JACKET WATER HEATER	40 KW
MDGAM02	DIESEL GENERATOR ‘A’ LUBE OIL WARM-UP HEATER	19 KW
MDGAM03	DIESEL GENERATOR ‘A’ CRANKCASE HEATER	4.00 KW
MDGAP01	DIESEL GENERATOR WATER JACKET HEATER PUMP	5.00 HP
MDGAP04	DIESEL GENERATOR PRE-LUBE PUMP	20 HP
MECAP01	ESSENTIAL CHILLED WATER PUMP	14.4 BHP (U1) 13.9 BHP (U2) 14.2 BHP (U3)
MHAAZ01	AUXILIARY BUILDING HPSI PUMP ROOM ESSENTIAL AIR COOLING UNIT	3.2 BHP
MHAAZ02	AUXILIARY BUILDING LPSI PUMP ROOM ESSENTIAL AIR COOLING UNIT	1.2 BHP
MHAAZ03	AUX BUILDING CONTAINMENT SPRAY PUMP ROOM ESSENTIAL AIR COOLING UNIT	1.9 BHP
MHAAZ04	AUXILIARY FEEDWATER PUMP ROOM ESSENTIAL AIR COOLING UNIT	3 BHP

TABLE 8.3-1[(a)]
CLASS 1E LOADS (SHEET 5 OF 10)

ID	DESCRIPTION	RATING
MHAAZ05	AUX BUILDING ESSENTIAL COOLING WATER PUMP ROOM ESSENTIAL AIR COOLING UNIT	1.9 BHP
MHAAZ06	AUXILIARY BUILDING ELECTRIC PENETRATION ROOM ESSENTIAL AIR COOLING UNIT	1.1 BHP
MHDAA01	DIESEL GENERATOR BUILDING CONTROL ROOM ESSENTIAL AIR HANDLING UNIT	14.9 BHP
MHDAJ01	DIESEL GENERATOR BUILDING GENERATOR ROOM ESSENTIAL EXHAUST FAN	98.2 BHP
MHFAE01	FUEL & AUXILIARY BUILDING ESSENTIAL AIR FILTRATION UNIT HEATER	26 KW
MHFAJ01	FUEL AND AUXILIARY BUILDING ESSENTIAL AIR FILTRATION UNIT FAN	30.2 BHP
MHJAF04	CONTROL ROOM ESSENTIAL AIR HANDLING UNIT	114.5 BHP
MHJAJ01A	CONTROL BUILDING BATTERY ROOM A ESSENTIAL EXHAUST FAN	0.3 BHP
MHJAJ01B	CONTROL BUILDING BATTERY ROOM C ESSENTIAL EXHAUST FAN	0.3 BHP
MHJAZ03	CONTROL BUILDING ESF SWITCHGEAR ESSENTIAL AIR HANDLING UNIT	5.3 BHP
MHJAZ04	CONTROL BUILDING ESF EQUIPMENT ESSENTIAL AIR HANDLING UNIT	6.1 BHP
MHSAJ01	SPRAY POND PUMP HOUSE EXHAUST FAN	10.1 BHP
MPCAP01	FUEL POOL COOLING PUMP	68.6 BHP (U1) 65.5 BHP (U2) 73.9 BHP (U3)
AJHPAE01	HYDROGEN (H2) RECOMBINER CONTROL PANEL	50 KW

TABLE 8.3-1[(a)]
CLASS 1E LOADS (SHEET 6 OF 10)

ID	DESCRIPTION	RATING
LOAD GROUP 2 (TRAIN B)		
4160 VOLT LOADS		
MAFBP01	ESSENTIAL AUXILIARY FEEDWATER PUMP	1199.2 BHP(U1) 1163.8 BHP(U2) 1168.6 BHP(U3)
MECBE01	ESSENTIAL CHILLER	524.1 BHP
MEWBP01	ESSENTIAL COOLING WATER SYSTEM PUMP	680.8 BHP (U1) 687.5 BHP (U2) 662.5 BHP (U3)
MSIBP01	LOW PRESSURE SAFETY INJECTION PUMP	529.4 BHP
MSIBP02	HIGH PRESSURE SAFETY INJECTION PUMP	1001.1 BHP (U1) 1002.1 BHP (U2) 1022.1 BHP (U3)
MSIBP03	CONTAINMENT SPRAY PUMP	748.8 BHP (U1) 748.4 BHP (U2) 781.3 BHP (U3)
MSPBP01	ESSENTIAL SPRAY POND PUMP	595.6 BHP (U1) 616.5 BHP (U2) 590.4 BHP (U3)
480 VOLT LOADS		
ENNBV14	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	23 KVA (U1) 22 KVA (U2) 22 KVA (U3)
EPHBM3218/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	25 KVA
EPHBM3637/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	25 KVA
EPHBM3830/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	25 KVA
EPKBH12	BATTERY CHARGER	92 KVA
EPKBH16	BATTERY CHARGER	80 KVA
EPKDH14	BATTERY CHARGER	70 KVA
EPNBV26	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	19 KVA (U1) 18 KVA (U2) 18 KVA (U3)
EPNDV28	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	11 KVA (U1) 10 KVA (U2) 10 KVA (U3)
EQBBV02	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	25 KVA
EQMBV30	SINGLE PHASE REGULATING TRANSFORMER	6 KVA
JAFBHV30	AUXILIARY FEEDWATER FLOW CONTROL VALVE: PUMP B TO STEAM GENERATOR 1	2 HP (U1) 1.9 HP (U2) 1.9 HP (U3)
JAFBHV31	AUXILIARY FEEDWATER FLOW CONTROL VALVE: PUMP B TO STEAM GENERATOR 2	2 HP (U1) 1.9 HP (U2) 1.9 HP (U3)

TABLE 8.3-1[a]
CLASS 1E LOADS (SHEET 7 OF 10)

ID	DESCRIPTION	RATING
JAFBUV34	AUXILIARY FEEDWATER ISOLATION VALVE: PUMP B TO STEAM GENERATOR 1	4 HP
JAFBUV35	AUXILIARY FEEDWATER ISOLATION VALVE: PUMP B TO STEAM GENERATOR 2	4 HP
JCHBHV255	SEAL INJECTION CONTAINMENT ISOLATION VALVE	0.7 HP
JCHBHV530	REFUELING WATER TANK TO TRAIN B SAFETY INJECTION PUMPS VALVE	7.9 HP
JCHEHV536	REFUELING WATER TANK GRAVITY FEED TO CHARGING PUMPS VALVE	0.7 HP
JCPBUV3A	CONTAINMENT BUILDING DUCT ISOLATION DAMPER	2.6 HP
JCPBUV3B	CONTAINMENT BUILDING DUCT ISOLATION DAMPER	2.6 HP
JECBE02	ESSENTIAL CHILLER AUXILIARY POWER PANEL	5.03 KVA
JECBTV30	HYDROMOTOR ACTUATOR	0.23 KVA
JHPBE02	POST LOCA HYDROGEN MONITOR	1 HP
JHPBUV2	CONTAINMENT HYDROGEN CONTROL UPSTREAM ISOLATION VALVE	0.13 HP
JHPBUV4	CONTAINMENT HYDROGEN CONTROL DOWNSTREAM ISOLATION VALVE	0.13 HP
JHPBUV6	CONTAINMENT HYDROGEN CONTROL RETURN ISOLATION VALVE	0.13 HP (U1) 0.13 HP (U2) 0.48 HP (U3)
JNCBUV401	NCWS RETURN CONTAINMENT ISOLATION VALVE	0.33 HP
JNCBUV403	NCWS RETURN CONTAINMENT ISOLATION VALVE	0.33 HP
JSIBHV307	LOW PRESSURE SAFETY INJECTION PUMP HEADER DISCHARGE VALVE	2.6 HP
JSIBHV609	HIGH PRESSURE SAFETY INJECTION PUMP LONG TERM COOLING VALVE	1 HP
JSIBHV658	SHUTDOWN COOLING TEMPERATURE CONTROL VALVE	0.67 HP
JSIBHV679	SHUTDOWN COOLING ISOLATION VALVE	0.33 HP
JSIBHV689	SHUTDOWN COOLING ISOLATION VALVE	1.6 HP
JSIBHV690	SHUTDOWN COOLING LOOP WARM-UP BYPASS VALVE	2.6 HP
JSIBHV692	LOW PRESSURE SAFETY INJECTION PUMP ISOLATION VALVE	4 HP
JSIBHV693	SHUTDOWN COOLING HEAT EXCHANGER BYPASS VALVE	1.6 HP

TABLE 8.3-1[a]
CLASS 1E LOADS (SHEET 8 OF 10)

ID	DESCRIPTION	RATING
JSIBHV694	LPSI-CONTAINMENT SPRAY PUMP CROSS CONNECT VALVE	1.6 HP
JSIBHV695	CONTAINMENT SPRAY ISOLATION VALVE	1.6 HP
JSIBHV696	SDCHX DISCHARGE VALVE	4 HP
JSIBHV699	HIGH PRESSURE SAFETY INJECTION PUMP DISCHARGE VALVE	0.7 HP
JSIBUV614	SAFETY INJECTION TANK 2A DISCHARGE ISOLATION VALVE	4 HP
JSIBUV615	LPSI FLOW CONTROL TO REACTOR COOLANT LOOP 2A CONTAINMENT ISOLATION VALVE	19.9 HP
JSIBUV616	HPSI 2 FLOW CONTROL TO REACTOR COOLANT LOOP 2A CONTAINMENT ISOLATION VALVE	0.67 HP
JSIBUV624	SAFETY INJECTION TANK 2B DISCHARGE ISOLATION VALVE	4 HP
JSIBUV625	LPSI FLOW CONTROL TO REACTOR COOLANT LOOP 2B CONTAINMENT ISOLATION VALVE	19.9 HP
JSIBUV626	HPSI TO REACTOR COOLANT LOOP 2B CONTAINMENT ISOLATION FLOW CONTROL VALVE	0.67 HP
JSIBUV636	HPSI TO REACTOR COOLANT LOOP 1A CONTAINMENT ISOLATION FLOW CONTROL VALVE	0.67 HP
JSIBUV646	HPSI TO REACTOR COOLANT LOOP 1B CONTAINMENT ISOLATION FLOW CONTROL VALVE	0.67 HP
JSIBUV652	SHUTDOWN COOLING LOOP ISOLATION VALVE	13 HP
JSIBUV656	SHUTDOWN COOLING LOOP CONTAINMENT ISOLATION VALVE	2.6 HP
JSIBUV665	CONTAINMENT SPRAY PUMP TO REFUELING WATER TANK ISOLATION VALVE	0.67 HP
JSIBUV667	HPSI PUMP TO REFUELING WATER TANK ISOLATE RECIRCULATE VALVE	0.67 HP
JSIBUV668	LPSI PUMP TO REFUELING WATER TANK ISOLATION VALVE	0.67 HP
JSIBUV671	CONTAINMENT SPRAY CONTAINMENT ISOLATION VALVE	5.3 HP
JSIBUV675	CONTAINMENT SUMP ISOLATION VALVE	0.7 HP
JSIBUV676	CONTAINMENT SUMP ISOLATION VALVE	2.60 HP
JSQBRE145	FUEL BUILDING RADIATION MONITOR	1.7 KVA

TABLE 8.3-1[(a)]
CLASS 1E LOADS (SHEET 9 OF 10)

ID	DESCRIPTION	RATING
JSQBRE146	FUEL BUILDING RADIATION MONITOR	1.7 KVA
JSQBRU01	CONTAINMENT BUILDING RADIATION MONITOR BLOWER MOTOR	1.7 HP (U1) 1.5 HP (U2) 1.5 HP (U3)
JSQBRU30	CONTROL ROOM RADIATION MONITOR BLOWER MOTOR	1.5 HP
JSQBRU34	CONTAINMENT BUILDING REFUEL RADIATION MONITOR BLOWER MOTOR	1.5 HP
JWCBUV61	CHILLED WATER RETURN CONTAINMENT ISOLATION VALVE	2 HP
JWCBUV63	NORMAL CHILLED WATER SUPPLY CONTAINMENT ISOLATION VALVE	2 HP
MCHBP01	CHARGING PUMP	79.9 BHP
MCHEP01	CHARGING PUMP (BUS A OR B)	79.9 BHP
MCTBP01	CONDENSATE TRANSFER PUMP	3.6 BHP (U1) 3.7 BHP (U2) 3.7 BHP (U3)
MDFBP01	DIESEL GENERATOR FUEL OIL TRANSFER PUMP	1.5 BHP
MDGBM01	DIESEL GENERATOR ‘B’ JACKET WATER WARM-UP HEATER	40 KW
MDGBM02	DIESEL GENERATOR ‘B’ LUBE OIL ENGINE WARM-UP HEATER	19 KW
MDGBM03	DIESEL GENERATOR ‘B’ CRANK CASE HEATER	4.00 KW
MDGBP01	DIESEL GENERATOR WATER JACKET HEATER PUMP	3.2 BHP
MDGBP04	DIESEL GENERATOR PRE-LUBE PUMP	7.1 BHP
MECBP01	ESSENTIAL CHILLED WATER PUMP	14.7 BHP (U1) 14.3 BHP (U2) 14.2 BHP (U3)
MHABZ01	AUXILIARY BUILDING HPSI PUMP ROOM ESSENTIAL AIR COOLING UNIT	3.2 BHP
MHABZ02	AUXILIARY BUILDING LPSI PUMP ROOM ESSENTIAL AIR COOLING UNIT	1.2 BHP
MHABZ03	AUX BUILDING CONTAINMENT SPRAY PUMP ROOM ESSENTIAL AIR COOLING UNIT	1.9 BHP

TABLE 8.3-1[a]
CLASS 1E LOADS (SHEET 10 OF 10)

ID	DESCRIPTION	RATING
MHABZ04	AUXILIARY FEEDWATER PUMP ROOM ESSENTIAL AIR COOLING UNIT	3 BHP
MHABZ05	AUX BUILDING ESSENTIAL COOLING WATER PUMP ROOM ESSENTIAL AIR COOLING UNIT	1.9 BHP
MHABZ06	AUXILIARY BUILDING ELECTRIC PENETRATION ROOM ESSENTIAL AIR COOLING UNIT	0.8 BHP
MHDBA01	DIESEL GENERATOR BUILDING CONTROL ROOM ESSENTIAL AIR HANDLING UNIT	14.9 BHP
MHDBJ01	DIESEL GENERATOR BUILDING GENERATOR ROOM ESSENTIAL EXHAUST FAN	98.2 BHP
MHFBE01	FUEL & AUXILIARY BUILDING ESSENTIAL AIR FILTRATION UNIT HEATER	26 KW
MHFBJ01	FUEL AND AUXILIARY BUILDING ESSENTIAL AIR FILTRATION UNIT FAN	30.2 BHP
MHJBF04	CONTROL ROOM ESSENTIAL AIR HANDLING UNIT	114.5 BHP
MHJBJ01A	CONTROL BUILDING BATTERY ROOM D ESSENTIAL EXHAUST FAN	0.3 BHP
MHJBJ01B	CONTROL BUILDING BATTERY ROOM B ESSENTIAL EXHAUST FAN	0.3 BHP
MHJBZ03	CONTROL BUILDING ESF SWITCHGEAR ESSENTIAL AIR HANDLING UNIT	5.3 BHP
MHJBZ04	CONTROL BUILDING ESF EQUIPMENT ESSENTIAL AIR HANDLING UNIT	6.1 BHP
MHSBJ01	SPRAY POND PUMP HOUSE EXHAUST FAN	10.1 BHP
MPCBP01	FUEL POOL COOLING PUMP	68.6 BHP (U1) 65.5 BHP (U2) 73.9 BHP (U3)
AJHPBE01	HYDROGEN (H2) RECOMBINER CONTROL PANEL	50 KW

(a) The horsepower ratings listed in this table are for reference only. The actual ratings can be found in the Electrical Equipment Database X-E-ZZI-0003. The ZZI-0003 database is controlled and lists the actual electrical equipment ratings.

B. The Class 1E and non-Class 1E cables are intended for use at a normal conductor temperature not to exceed 90°C for all area-specific ambient temperatures, at 100% relative humidity. The ambient temperature(s) may be assumed to equal the maximum (non-LOCA) temperatures for the building, area or room in which the respective cables are installed. Where the maximum design temperature is less than 40°C (104°F), the 40°C value is assumed. These "Enveloping Design Temperature" values are defined in UFSAR Table 9.4-2 and Appendix A of the Equipment Qualification Program Manual.

8.3.1.1.3.3 Bus Arrangements. The safety-related equipment is divided into two load groups per unit (load groups 1 and 2). For each unit, either one of the associated load groups is capable of providing power for safely shutting down the unit. Each ac load group consists of one 4.16 kV bus, three 480V load centers, and four 480V motor control centers (MCCs). Two non-Class 1E MCCs are connected to each load group and are tripped on a safety injection actuation signal (SIAS).

8.3.1.1.3.4 Loads Supplied From Each Bus. Refer to table 8.3-1 for a listing of Class 1E loads and to engineering drawing 01, 02, 03-E-MAA-002 for their respective buses.

8.3.1.1.3.5 Manual and Automatic Interconnections Between Buses, Buses and Loads, and Buses and Supplies. No provisions exist for automatically connecting one load group to another redundant load group or for automatically transferring loads between load groups. There are provisions for manually

connecting both ESF buses to either preferred source as shown in engineering drawing 01, 02, 03-E-MAA-002. Loss of offsite power when both buses are connected to the same preferred source results in an automatic trip of both ESF bus main breakers. Thus, failure of one breaker to trip will not result in paralleling the diesel generators. Circuit breaker interlocks are provided to prevent manually paralleling the diesel generators. During manually initiated testing, only one diesel generator at a time may be paralleled with the offsite source power.

There are provisions for manually connecting both ESF buses to a single standby power source during emergency conditions. Additionally, power can be supplied to a single ESF bus of one unit from a standby power source of another PVNGS unit. Restrictions and instructions governing the use of these two abnormal electrical lineups are given in the applicable emergency and abnormal operating procedures.

8.3.1.1.3.6 Third-of-a-Kind ESF Loads. The charging pump is third-of-a-kind ESF equipment which is supplied power from the redundant Class 1E buses. Power is supplied through a manual transfer switch. Only one breaker is available for supplying power to the third pump. When power is required to be switched to the accompanying redundant load group, the breaker previously serving the charging pump from the load group is removed and inserted in the accompanying redundant load group prior to switching the load into the source. Control power for the third charging pump is provided from the load group from which power is being supplied.

The 120V-ac Class 1E vital instrumentation and control power (PN) system train swing inverters, if implemented per DMWO 3232547, are also third-of-a-kind ESF components (power sources). They are designed as back-ups for each train of the PN system normal inverters. They are supplied power from independent channels of Class 1E DC buses (see subsection 8.2.3) and supply power to Class 1E PN distribution panels. Power is supplied through manual swing line-up switches. When power is required, a designated Class 1E DC feed breaker is manually closed and the swing line-up switch is manually aligned to the designated PN system channel. Power is then manually connected to the aligned PN distribution panel through a Manual Bypass Switch.

8.3.1.1.3.7 Interconnections Between Safety- and Nonsafety-Related Buses. There are no interconnections between the safety- and nonsafety-related buses except through the preferred power system (offsite power system).

8.3.1.1.3.8 Redundant Bus Separation. The Class 1E switchgear, load centers, and motor control centers for the redundant load groups are located in separate rooms of the control or auxiliary building in such a way as to ensure physical and electrical independence. Refer to paragraph 8.3.1.4.1 for criteria governing redundant bus separation.

8.3.1.1.3.9 Equipment Capacities. The capacities of the equipment are shown in table 8.3-2.

8.3.1.1.3.10 Automatic Loading and Load Shedding. The automatic loading sequence of the diesel generator buses is shown in table 8.3-3.

If preferred power is available to the Class 1E bus following an engineered safety features actuation signal (ESFAS), the required Class 1E loads will be started through a solid-state sequencer. However, in the event that preferred power is lost, the Class 1E system functions to shed Class 1E loads and to connect the standby power source to the Class 1E bus. The load sequencer then functions to start the required Class 1E loads in programmed time increments.

No credible sneak circuits can occur to render sensors, power supplies, or actuated devices in redundant channels or load groups inoperable through unplanned interconnections. Redundant channels and load groups are isolated and separated in accordance with Regulatory Guide 1.75 as discussed in section 1.8. Each ESF load sequencer, one for each load group, has independent sensor channels, power supplies, and actuated devices.

8.3.1.1.3.10.1 Load Sequencer Design and Testing. Each redundant ESF load sequencer system performs logic functions to generate the loss of offsite power (LOP) signal/load shed signal, the diesel generator start signal (DGSS), and the load sequencer start and permissive signals.

Each redundant ESF load sequencer system is supplied from a separate 120V vital ac distribution bus and a separate Class 1E 125 V-dc distribution bus.

The LOP signal/load shed signal logic continuously monitors the Class 1E 4.16 kV bus for an undervoltage condition using four undervoltage relays. If an undervoltage trip occurs, annunciation and indication is provided to the operator. On a two-out-of-four coincidence of undervoltage relay trips or upon manual actuation, an LOP signal and load shed pulse are generated. The LOP signal is sent to the DGSS logic. The LOP signal (maintained through a 60-second off delay) also actuates forced shutdown system loads by deenergizing actuation relays. The load shed pulse (1 second) sheds 4.16 kV and selected 480V loads from the Class 1E 4.16 kV bus and trips the 4.16 kV Class 1E bus preferred (offsite) power supply breakers by energizing actuation relays.

Table 8.3-2
EQUIPMENT CAPACITIES

Equipment	Description	Continuous Capacity	Symmetrical Fault Capacity
4160V Switchgear	Bus	1200A	58,000A RMS bracing
	Incoming breakers	1200A	33,000A RMS at 4.16kV
	Feeder breakers	1200A	33,000A RMS at 4.16kV
480V Load center	Transformers 3 phase, 60 Hz 4160/480V	750 kVA*	N/A
	Bus	1600A	55,000A RMS bracing
	Incoming breakers	1600A	50,000A RMS at 480V
	Feeder breakers	600A	30,000A RMS, 480V, with instantaneous trip
		600A	22,000A RMS 480V
480V Motor control center	Horizontal bus	600A	22,000A RMS bracing
	Vertical bus	300A	22,000A RMS bracing
	Breakers (molded case)	150,225AF	10,000/25,000 RMS minimum

Hz = Hertz
V = Volt
A = Ampere
kVA = Kilovoltampere
RMS = Root mean square
MVA = Megavoltampere

* Note: Transformers EPGAL31X and EPGBL32X have a power rating of 750/1000 kVA (AA/FA) due to the addition of fan cooling packages.

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 1 of 12)

ID[i]	DESCRIPTION	MODE 2[b]	MODE 3[c]
ENHNM1913/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER (BUS A)	Manual	0 Second
ENHNM2012/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER (BUS B)	Manual	0 Second
ENNAV13	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	0 Second	0 Second
ENNBV14	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	0 Second	0 Second
ENNNV17	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER (BUS A)	Manual	0 Second
ENNNV18	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER (BUS B)	0 Second[m]	0 Second
ENQNN01	NON-1E UNINTERRUPTABLE PWR SUPPLY INVERTER	Manual	Manual
EPHAM3119/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	0 Second	0 Second
EPHAM3331/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	0 Second	0 Second
EPHAM3728/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	0 Second	0 Second
EPHBM3218/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	0 Second	0 Second
EPHBM3637/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	0 Second	0 Second
EPHBM3830/T	120/240 AC DISTRIBUTION PANEL TRANSFORMER	0 Second	0 Second
EQBAV01	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	0 Second	0 Second
EQBBV02	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	0 Second	0 Second
EQJNX05	CONDENSATE STORAGE TANK FREEZE PROTECTION TRANSFORMER (BUS B)	N/A	0 Second
EQMAV31	SINGLE PHASE REGULATING TRANSFORMER	0 Second	0 Second
EQMBV30	SINGLE PHASE REGULATING TRANSFORMER	0 Second	0 Second
EQMNX04B3	LIQUID RADWASTE HEAT TRACING SECONDARY TRANSFORMER (BUS A)	Manual	0 Second
EQMNX08A	REFUELING TANK HEAT TRACING PRIMARY TRANSFORMER (BUS A)	Manual	0 Second
EQMNX08B	REFUELING TANK HEAT TRACING SECONDARY TRANSFORMER (BUS B)	Manual	0 Second
ESQND01	RADIATION MONITOR DISTRIBUTION PANEL (BUS A)	0 Second	0 Second
ESQND08	RADIATION MONITOR DISTRIBUTION PANEL (BUS B)	0 Second	0 Second
JAFBUV34[j]	AUXILIARY FEEDWATER ISOLATION VALVE: PUMP B TO STEAM GENERATOR 1	0 Second	0 Second
JAFBUV35[j]	AUXILIARY FEEDWATER ISOLATION VALVE: PUMP B TO STEAM GENERATOR 2	0 Second	0 Second
JCHEHV536[g][j]	REFUELING WATER TANK GRAVITY FEED TO CHARGING PUMPS VALVE (BUS A)	Manual	0 Second
JCHNUV501[g][j]	VOLUME CONTROL TANK OUTLET VALVE (BUS A)	Manual	0 Second
JCPAUV2A[j]	CONTAINMENT BUILDING DUCT ISOLATION DAMPER	0 Second	0 Second
JCPAUV2B[j]	CONTAINMENT BUILDING DUCT ISOLATION DAMPER	0 Second	0 Second
JCPBUV3A[j]	CONTAINMENT BUILDING DUCT ISOLATION DAMPER	0 Second	0 Second
JCPBUV3B[j]	CONTAINMENT BUILDING DUCT ISOLATION DAMPER	0 Second	0 Second
JECAE01	ESSENTIAL CHILLER AUXILIARY POWER PANEL	0 Second	0 Second
JECBE02	ESSENTIAL CHILLER AUXILIARY POWER PANEL	0 Second	0 Second
JEWAUV145[j]	CROSSITE FROM NON-SAFETY RELATED NUCLEAR COOLING WATER SYSTEM VALVE	0 Second	0 Second

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 2 of 12)

ID[i]	DESCRIPTION	RATING	MODE 3[c]
JEWAUV65[j]	CROSSTIE FROM NON-SAFETY RELATED NUCLEAR COOLING WATER SYSTEM VALVE	0.33 HP	0 Second
JGRAUV1[j]	REACTOR DRAIN TIME/GAS SURGE HEADER IN CONTAINMENT ISOLATED VALVE	0.13 HP	0 Second
JHPAUV1[j]	CONTAINMENT HYDROGEN CONTROL UPSTREAM ISOLATION VALVE	0.13 HP	0 Second
JHPAUV3[j]	CONTAINMENT HYDROGEN CONTROL DOWNSTREAM ISOLATION VALVE	0.13 HP	0 Second
JHPAUV5[j]	CONTAINMENT HYDROGEN CONTROL RETURN ISOLATION VALVE	0.13 HP	0 Second
JHPBUV2[j]	CONTAINMENT HYDROGEN CONTROL UPSTREAM ISOLATION VALVE	0.13 HP	0 Second
JHPBUV4[j]	CONTAINMENT HYDROGEN CONTROL DOWNSTREAM ISOLATION VALVE	0.13 HP	0 Second
JHPBUV6[j]	CONTAINMENT HYDROGEN CONTROL RETURN ISOLATION VALVE	0.13 HP	0 Second
JNCAUV402[j]	NCWS RETURN CONTAINMENT ISOLATION VALVE	0.33 HP	0 Second
JNCBUV401[j]	NCWS RETURN CONTAINMENT ISOLATION VALVE	0.33 HP	0 Second
JNCBUV403[j]	NCWS RETURN CONTAINMENT ISOLATION VALVE	0.33 HP	0 Second
JRDAUV23[j]	RADWASTE SUMP PUMP IN CONTAINMENT ISOLATION VALVE	0.33 HP	0 Second
JSIAUV617[j]	HPSI 1 FLOW CONTROL TO REACTOR COOLANT LOOP 2A CONTAINMENT ISOLATION VALVE	0.67 HP	N/A
JSIAUV627[j]	HPSI 1 FLOW CONTROL TO REACTOR COOLANT LOOP 2B CONTAINMENT ISOLATION VALVE	0.67 HP	N/A
JSIAUV634[j]	SAFETY INJECTION TANK 1A DISCHARGE ISOLATION VALVE	4.00 HP	0 Second
JSIAUV635[j]	LPSI TO REACTOR COOLANT LOOP 1A CONTAINMENT ISOLATION FLOW CONTROL VALVE	20 HP	0 Second
JSIAUV637[j]	HPSI TO REACTOR COOLANT LOOP 1A CONTAINMENT ISOLATION FLOW CONTROL VALVE	0.67 HP	N/A
JSIAUV644[j]	SAFETY INJECTION TANK 1B DISCHARGE ISOLATION VALVE	4.00 HP	0 Second
JSIAUV645[j]	LPSI TO REACTOR COOLANT LOOP 1B CONTAINMENT ISOLATION FLOW CONTROL VALVE	20 HP	0 Second
JSIAUV647[j]	HPSI 1 TO REACTOR COOLANT LOOP 1B CONTAINMENT ISOLATION FLOW CONTROL VALVE	0.67 HP	N/A
JSIAUV651[j]	SHUTDOWN COOLING LOOP 1 ISOLATION VALVE	13 HP	0 Second
JSIAUV655[j]	SHUTDOWN COOLING LOOP 1 CONTAINMENT ISOLATION VALVE	2.60 HP	0 Second
JSIAUV664[j]	CONTAINMENT SPRAY PUMP A TO REFUELING WATER TANK MINI-FLOW VALVE	0.67 HP	0 Second
JSIAUV666[j]	HPSI PUMP A TO REFUELING WATER TANK MINI-FLOW VALVE	0.67 HP	0 Second
JSIAUV669[j]	LPSI PUMP A TO REFUELING WATER TANK MINI-FLOW VALVE	0.67 HP	0 Second
JSIAUV672[j]	CONTAINMENT SPRAY CONTAINMENT ISOLATION VALVE	5.30 HP	0 Second
JSIAUV673[j]	CONTAINMENT SUMP ISOLATION VALVE	0.70 HP	0 Second
JSIAUV674[j]	CONTAINMENT SUMP ISOLATION VALVE	2.60 HP	0 Second
JSIBUV614[j]	SAFETY INJECTION TANK 2A DISCHARGE ISOLATION VALVE	4.00 HP	0 Second

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 3 of 12)

ID[i]	DESCRIPTION	MODE 2[b]	MODE 3[c]
JSIBUV615[j]	LPSI FLOW CONTROL TO REACTOR COOLANT LOOP 2A CONTAINMENT ISOLATION VALVE	0 Second	0 Second
JSIBUV616[j]	HPSI 2 FLOW CONTROL TO REACTOR COOLANT LOOP 2A CONTAINMENT ISOLATION VALVE	0 Second	N/A
JSIBUV624[j]	SAFETY INJECTION TANK 2 DISCHARGE ISOLATION VALVE	0 Second	0 Second
JSIBUV625[j]	LPSI FLOW CONTROL TO REACTOR COOLANT LOOP 2B CONTAINMENT ISOLATION VALVE	0 Second	0 Second
JSIBUV626[j]	HPSI 2 TO REACTOR COOLANT LOOP 2B CONTAINMENT ISOLATION FLOW CONTROL VALVE	0 Second	N/A
JSIBUV636[j]	HPSI B TO REACTOR COOLANT LOOP 1A CONTAINMENT ISOLATION FLOW CONTROL VALVE	0 Second	N/A
JSIBUV646[j]	HPSI 2 TO REACTOR COOLANT LOOP 1B CONTAINMENT ISOLATION FLOW CONTROL VALVE	0 Second	N/A
JSIBUV652[j]	SHUTDOWN COOLING LOOP 2 ISOLATION VALVE	0 Second	0 Second
JSIBUV656[j]	SHUTDOWN COOLING LOOP 2 CONTAINMENT ISOLATION VALVE	0 Second	0 Second
JSIBUV665[j]	CONTAINMENT SPRAY PUMP B TO REFUELING WATER TANK MINI-FLOW VALVE	0 Second	0 Second
JSIBUV667[j]	HPSI PUMP B TO REFUELING WATER TANK MINI-FLOW VALVE	0 Second	0 Second
JSIBUV668[j]	LPSI PUMP B TO REFUELING WATER TANK MINI-FLOW VALVE	0 Second	0 Second
JSIBUV671[j]	CONTAINMENT SPRAY CONTAINMENT ISOLATION VALVE	0 Second	0 Second
JSIBUV675[j]	CONTAINMENT SUMP ISOLATION VALVE	0 Second	0 Second
JSIBUV676[j]	CONTAINMENT SUMP ISOLATION VALVE	0 Second	0 Second
JSQARU29	RADIATION MONITOR BLOWER MOTOR FOR CONTROL ROOM	0 Second	0 Second
JSQBRE145	FUEL BUILDING RADIATION MONITOR	N/A	0 Second
JSQBRE146	FUEL BUILDING RADIATION MONITOR	0 Second	N/A
JSQBRU01	CONTAINMENT BUILDING RADIATION MONITOR BLOWER MOTOR	0 Second	0 Second
JSQBRU30	CONTROL ROOM RADIATION MONITOR BLOWER MOTOR	0 Second	0 Second
JSQBRU34	CONTAINMENT BUILDING REFUEL RADIATION MONITOR BLOWER MOTOR	0 Second	0 Second
JWCAUV62[j]	NORMAL CHILLED WATER RETURN CONTAINMENT ISOLATION VALVE	0 Second	0 Second
JWCBUV61[j]	CHILLED WATER RETURN CONTAINMENT ISOLATION VALVE	0 Second	0 Second
JWCBUV63[j]	NORMAL CHILLED WATER SUPPLY CONTAINMENT ISOLATION VALVE	0 Second	0 Second
MCHAP01[h]	CHARGING PUMP	40 Seconds or Manual	0 Second
MCHBP01[h]	CHARGING PUMP	40 Seconds or Manual	0 Second
MCHEP01[h]	CHARGING PUMP (BUS A OR B)	40 Seconds or Manual	0 Second
MCTAP01	CONDENSATE TRANSFER PUMP	0 Second	0 Second
MCTBP01	CONDENSATE TRANSFER PUMP	0 Second	0 Second

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 4 of 12)

ID[i]	DESCRIPTION	MODE 2[b]	MODE 3[c]
MDFAP01	DIESEL GENERATOR FUEL OIL TRANSFER PUMP	0 Second	0 Second
MDFBP01	DIESEL GENERATOR FUEL OIL TRANSFER PUMP	0 Second	0 Second
MDGAM01	DIESEL GENERATOR JACKET WATER HEATER	0 Second	0 Second
MDGAP01	DIESEL GENERATOR WATER JACKET HEATER PUMP	0 Second	0 Second
MDGBM01	DIESEL GENERATOR ‘B’ JACKET WATER WARM-UP HEATER	0 Second	0 Second
MDGBP01	DIESEL GENERATOR WATER JACKET HEATER PUMP	0 Second	0 Second
MHAAZ01	AUXILIARY BUILDING HPSI PUMP ROOM ESSENTIAL AIR COOLING UNIT	0 Second	N/A
MHAAZ04	AUXILIARY FEEDWATER PUMP ROOM ESSENTIAL AIR COOLING UNIT	0 Second	0 Second
MHAAZ06	AUXILIARY BUILDING ELECTRIC PENETRATION ROOM ESSENTIAL AIR COOLING UNIT	0 Second	0 Second
MHABZ01	AUXILIARY BUILDING HPSI PUMP ROOM ESSENTIAL AIR COOLING UNIT	0 Second	N/A
MHABZ06	AUXILIARY BUILDING ELECTRIC PENETRATION ROOM ESSENTIAL AIR COOLING UNIT	0 Second	0 Second
MHCNA03A	CONTAINMENT BUILDING REACTOR CAVITY NORMAL COOLING FAN (BUS A)	N/A	0 Second
MHCNA03B	CONTAINMENT BUILDING REACTOR CAVITY NORMAL COOLING FAN (BUS B)	N/A	0 Second
MHCNA03C	CONTAINMENT BUILDING REACTOR CAVITY NORMAL COOLING FAN (BUS A)	N/A	0 Second
MHCNA03D	CONTAINMENT BUILDING REACTOR CAVITY NORMAL COOLING FAN (BUS B)	N/A	0 Second
MHCNA06A	CONTAINMENT BUILDING PRESSURIZER NORMAL COOLING FAN (BUS A)	N/A	0 Second
MHCNA06B	CONTAINMENT BUILDING PRESSURIZER NORMAL COOLING FAN (BUS B)	N/A	0 Second
MHJAJ01A	CONTROL BUILDING BATTERY ROOM A ESSENTIAL EXHAUST FAN	0 Second	0 Second
MHJAJ01B	CONTROL BUILDING BATTERY ROOM C ESSENTIAL EXHAUST FAN	0 Second	0 Second
MHJAZ03	CONTROL BUILDING ESF SWITCHGEAR ESSENTIAL AIR HANDLING UNIT	0 Second	0 Second
MHJAZ04	CONTROL BUILDING ESF EQUIPMENT ESSENTIAL AIR HANDLING UNIT	0 Second	0 Second
MHJBJ01A	CONTROL BUILDING BATTERY ROOM D ESSENTIAL EXHAUST FAN	0 Second	0 Second
MHJBJ01B	CONTROL BUILDING BATTERY ROOM B ESSENTIAL EXHAUST FAN	0 Second	0 Second

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 5 of 12)

ID[i]	DESCRIPTION	MODE 2[b]	MODE 3[c]
MHJBZ03	CONTROL BUILDING ESF SWITCHGEAR ESSENTIAL AIR HANDLING UNIT	0 Second	0 Second
MHJBZ04	CONTROL BUILDING ESF EQUIPMENT ESSENTIAL AIR HANDLING UNIT	0 Second	0 Second
MSCNP24A	SAMPLE COOLANT PUMP (BUS A)	N/A	0 Second
MSIAP02	HIGH PRESSURE SAFETY INJECTION PUMP 1	0.5 Second	N/A
MSIBP02	HIGH PRESSURE SAFETY INJECTION PUMP 2	0.5 Second	N/A
EPKAH11	BATTERY CHARGER	5 Seconds	5 Seconds
EPKBH12	BATTERY CHARGER	5 Seconds	5 Seconds
EPKCH13	BATTERY CHARGER (BUS A)	5 Seconds	5 Seconds
EPKDH14	BATTERY CHARGER (BUS B)	5 Seconds	5 Seconds
JECATV29[j]	HYDROMOTOR ACTUATOR	5 Seconds	5 Seconds
JECBTV30[j]	HYDROMOTOR ACTUATOR	5 Seconds	5 Seconds
JNCNHV485[j]	CEDM NORMAL AIR COOLING UNIT NCWS OUTLET ISOLATION VALVE (BUS A)	N/A	5 Seconds
JNCNHV486[j]	CEDM NORMAL AIR COOLING UNIT NCWS OUTLET ISOLATION VALVE (BUS B)	N/A	5 Seconds
JWCNHV57[j]	CONTAINMENT NORMAL AIR COOLING UNIT A CHILLED WATER ISOLATION VALVE (BUS A)	N/A	5 Seconds
JWCNHV58[j]	CONTAINMENT NORMAL AIR COOLING UNIT B CHILLED WATER ISOLATION VALVE (BUS B)	N/A	5 Seconds
JWCNHV59[j]	CONTAINMENT NORMAL AIR COOLING UNIT C CHILLED WATER ISOLATION VALVE (BUS A)	N/A	5 Seconds
JWCNHV60[j]	CONTAINMENT NORMAL AIR COOLING UNIT D CHILLED WATER ISOLATION VALVE (BUS B)	N/A	5 Seconds
MHAAZ02	AUXILIARY BUILDING LPSI PUMP ROOM ESSENTIAL AIR COOLING UNIT	5 Seconds	Manual
MHABZ02	AUXILIARY BUILDING LPSI PUMP ROOM ESSENTIAL AIR COOLING UNIT	5 Seconds	Manual
MHCNA01A	CONTAINMENT BUILDING NORMAL AIR COOLING UNIT (BUS A)	N/A	5 Seconds
MHCNA01B	CONTAINMENT BUILDING NORMAL AIR COOLING UNIT (BUS B)	N/A	5 Seconds
MHCNA01C	CONTAINMENT BUILDING NORMAL AIR COOLING UNIT (BUS A)	N/A	5 Seconds
MHCNA01D	CONTAINMENT BUILDING NORMAL AIR COOLING UNIT (BUS B)	N/A	5 Seconds
MHCNM01A	CONTAINMENT BUILDING AIR COOLING UNIT RETURN DUCT ISOLATION DAMPER (BUS A)	N/A	5 Seconds
MHCNM01B	CONTAINMENT BUILDING AIR COOLING UNIT RETURN DUCT ISOLATION DAMPER (BUS B)	N/A	5 Seconds
MHCNM01C	CONTAINMENT BUILDING AIR COOLING UNIT RETURN DUCT ISOLATION DAMPER (BUS A)	N/A	5 Seconds

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 6 of 12)

ID[i]	DESCRIPTION	MODE 2[b]	MODE 3[c]
MHCNM01D	CONTAINMENT BUILDING AIR COOLING UNIT RETURN DUCT ISOLATION DAMPER (BUS B)	N/A	5 Seconds
MHFAE01	FUEL & AUXILIARY BUILDING ESSENTIAL AIR FILTRATION UNIT HEATER	5 Seconds	N/A
MHFAJ01	FUEL AND AUXILIARY BUILDING ESSENTIAL AIR FILTRATION UNIT FAN	5 Seconds	N/A
MHFBE01	FUEL & AUXILIARY BUILDING ESSENTIAL AIR FILTRATION UNIT HEATER	5 Seconds	N/A
MHFBJ01	FUEL AND AUXILIARY BUILDING ESSENTIAL AIR FILTRATION UNIT FAN	5 Seconds	N/A
MHJAF04	CONTROL ROOM ESSENTIAL AIR HANDLING UNIT	5 Seconds	5 Seconds
MHJBF04	CONTROL ROOM ESSENTIAL AIR HANDLING UNIT	5 Seconds	5 Seconds
MSIAP01	LOW PRESSURE SAFETY INJECTION PUMP 1	5 Seconds	Manual
MSIBP01	LOW PRESSURE SAFETY INJECTION PUMP 2	5 Seconds	Manual
JAFBHV30[j]	AUXILIARY FEEDWATER FLOW CONTROL VALVE: PUMP B TO STEAM GENERATOR 1	10 Seconds	10 Seconds
JAFBHV31[j]	AUXILIARY FEEDWATER FLOW CONTROL VALVE: PUMP B TO STEAM GENERATOR 2	10 Seconds	10 Seconds
MAFBP01	ESSENTIAL AUXILIARY FEEDWATER PUMP	10 Seconds	10 Seconds
MHABZ04	AUXILIARY FEEDWATER PUMP ROOM ESSENTIAL AIR COOLING UNIT	10 Seconds	10 Seconds
MHAAZ03	AUX BUILDING CONTAINMENT SPRAY PUMP ROOM ESSENTIAL AIR COOLING UNIT	15 Seconds	N/A
MHABZ03	AUX BUILDING CONTAINMENT SPRAY PUMP ROOM ESSENTIAL AIR COOLING UNIT	15 Seconds	N/A
MSIAP03	CONTAINMENT SPRAY PUMP 1	15 Seconds	N/A
MSIBP03	CONTAINMENT SPRAY PUMP 2	15 Seconds	N/A
MEWAP01	ESSENTIAL COOLING WATER SYSTEM PUMP	20 Seconds	20 Seconds
MEWBP01	ESSENTIAL COOLING WATER SYSTEM PUMP	20 Seconds	20 Seconds
MHAAZ05	AUX BUILDING ESSENTIAL COOLING WATER PUMP ROOM ESSENTIAL AIR COOLING UNIT	20 Seconds	20 Seconds
MHABZ05	AUX BUILDING ESSENTIAL COOLING WATER PUMP ROOM ESSENTIAL AIR COOLING UNIT	20 Seconds	20 Seconds

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 7 of 12)

ID[i]	DESCRIPTION	MODE 2[b]	MODE 3[c]
MHDAJ01	DIESEL GENERATOR BUILDING GENERATOR ROOM ESSENTIAL EXHAUST FAN	25 Seconds	25 Seconds
MHDBJ01	DIESEL GENERATOR BUILDING GENERATOR ROOM ESSENTIAL EXHAUST FAN	25 Seconds	25 Seconds
MHDAA01	DIESEL GENERATOR BUILDING CONTROL ROOM ESSENTIAL AIR HANDLING UNIT	25 Seconds	25 Seconds
MHDBA01	DIESEL GENERATOR BUILDING CONTROL ROOM ESSENTIAL AIR HANDLING UNIT	25 Seconds	25 Seconds
MHSAJ01	SPRAY POND PUMP HOUSE EXHAUST FAN	25 Seconds	25 Seconds
MHSBJ01	SPRAY POND PUMP HOUSE EXHAUST FAN	25 Seconds	25 Seconds
MSPAP01	ESSENTIAL SPRAY POND PUMP	25 Seconds	25 Seconds
MSPBP01	ESSENTIAL SPRAY POND PUMP	25 Seconds	25 Seconds
MECAE01[d]	ESSENTIAL CHILLER	30 Seconds	30 Seconds
MECAP01	ESSENTIAL CHILLED WATER PUMP	30 Seconds	30 Seconds
MECBE01[d]	ESSENTIAL CHILLER	30 Seconds	30 Seconds
MECBP01	ESSENTIAL CHILLED WATER PUMP	30 Seconds	30 Seconds
MHCNA02A	CONTAINMENT BUILDING CEDM NORMAL AIR COOLING UNIT (BUS A)	N/A	55 Seconds
MHCNA02B	CONTAINMENT BUILDING CEDM NORMAL AIR COOLING UNIT (BUS B)	N/A	55 Seconds
MHCNA02C	CONTAINMENT BUILDING CEDM NORMAL AIR COOLING UNIT (BUS A)	N/A	55 Seconds
MHCNA02D	CONTAINMENT BUILDING CEDM NORMAL AIR COOLING UNIT (BUS B)	N/A	55 Seconds
EPNAV25	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	Manual	Manual
EPNBV26	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER	Manual	Manual
EPNCV27	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER (BUS A)	Manual	Manual
EPNDV28	SINGLE PHASE VOLTAGE REGULATING TRANSFORMER (BUS B)	Manual	Manual
EQBND90	MAIN ESSENTIAL LIGHTING PANEL (BUS B)	Manual	Manual
EQBND91	MAIN ESSENTIAL LIGHTING PANEL (BUS A)	Manual	Manual
ERCNJ01A	PRESSURIZER BACKUP HEATERS JUNCTION BOX (BUS A)	Manual	Manual
ERCNJ01B	PRESSURIZER BACKUP HEATERS JUNCTION BOX (BUS B)	Manual	Manual
JAFNHV95[j]	NON-ESSENTIAL AUXILIARY FEEDWATER PUMP MINI-FLOW RECIRCULATION VALVE TO CST (BUS A)	Manual	Manual
JCHAHV524[j]	CHARGING PUMPS TO REGENERATE HEAT EXCHANGER VALVE	Manual	Manual
JCHAHV531[j]	REFUELING WATER TANK TO TRAIN A SAFETY INJECTION PUMPS VALVE	Manual	Manual

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 8 of 12)

ID[i]	DESCRIPTION	MODE 2[b]	MODE 3[c]
JCHBHV255[j]	SEAL INJECTION CONTAINMENT ISOLATION VALVE	Manual	N/A
JCHBHV530[j]	REFUELING WATER TANK TO TRAIN B SAFETY INJECTION PUMPS VALVE	Manual	Manual
JCTAHV1[j]	CONDENSATE TANK TO AUXILIARY FEEDWATER PUMP ISOLATION VALVE	Manual	Manual
JCTAHV4[j]	CONDENSATE TANK TO AUXILIARY FEEDWATER PUMP ISOLATION VALVE	Manual	Manual
JCWNHV11[j]	CIRCULATING WATER LOOP AB/CD CROSSTIE VALVE (BUS B)	Manual	Manual
JHPAE02	POST LOCA HYDROGEN MONITOR	Manual	N/A
JHPBE02	POST LOCA HYDROGEN MONITOR	Manual	N/A
JNCNUV103[j]	NORMAL CHILLER A OUTLET ISOLATION VALVE (BUS A)	Manual	Manual
JNCNUV99[j]	NCWS RETURN CONTAINMENT ISOLATION VALVE (BUS A)	Manual	Manual
JSGNHV1142[j]	FEEDWATER ISOLATION BLOCK VALVE (BUS A)	Manual	Manual
JSGNHV1143[j]	FEEDWATER ISOLATION BYPASS VALVE (BUS A)	Manual	Manual
JSGNHV1144[j]	FEEDWATER ISOLATION BLOCK VALVE (BUS A)	Manual	Manual
JSGNHV1145[j]	FEEDWATER ISOLATION BYPASS VALVE (BUS A)	Manual	Manual
JSIAHV306[j]	LOW PRESSURE SAFETY INJECTION PUMP HEADER DISCHARGE VALVE	Manual	Manual
JSIAHV604[j]	HIGH PRESSURE SAFETY INJECTION PUMP A LONG TERM COOLING VALVE	Manual	Manual
JSIAHV657[j]	SHUTDOWN COOLING TEMPERATURE CONTROL VALVE	Manual	Manual
JSIAHV678[j]	SHUTDOWN COOLING ISOLATION VALVE	Manual	Manual
JSIAHV683[j]	LOW PRESSURE SAFETY INJECTION PUMP A ISOLATION VALVE	Manual	Manual
JSIAHV684[j]	SHUTDOWN COOLING ISOLATION VALVE	Manual	Manual
JSIAHV685[j]	LOW PRESSURE SAFETY INJECTION-CONTAINMENT SPRAY PUMP CROSS CONNECT VALVE	Manual	Manual
JSIAHV686[j]	SDCHX DISCHARGE VALVE	Manual	Manual
JSIAHV687[j]	CONTAINMENT SPRAY ISOLATION VALVE	Manual	Manual
JSIAHV688[j]	SHUTDOWN COOLING BYPASS VALVE	Manual	Manual
JSIAHV691[j]	SHUTDOWN COOLING LOOP A WARM-UP BYPASS VALVE	Manual	Manual
JSIAHV698[j]	HIGH PRESSURE SAFETY INJECTION PUMP A DISCHARGE VALVE	Manual	N/A
JSIBHV307[j]	LOW PRESSURE SAFETY INJECTION PUMP B HEADER DISCHARGE VALVE	Manual	Manual
JSIBHV609[j]	HIGH PRESSURE SAFETY INJECTION PUMP B LONG TERM COOLING VALVE	Manual	Manual
JSIBHV658[j]	SHUTDOWN COOLING TEMPERATURE CONTROL VALVE	Manual	Manual
JSIBHV679[j]	SHUTDOWN COOLING ISOLATION VALVE	Manual	Manual
JSIBHV689[j]	SHUTDOWN COOLING ISOLATION VALVE	Manual	Manual
JSIBHV690[j]	SHUTDOWN COOLING LOOP B WARM-UP BYPASS VALVE	Manual	Manual

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 9 of 12)

ID[i]	DESCRIPTION	MODE 2[b]	MODE 3[c]
JSIBHV692[j]	LOW PRESSURE SAFETY INJECTION PUMP B ISOLATION VALVE	Manual	Manual
JSIBHV693[j]	SHUTDOWN COOLING HEAT EXCHANGER BYPASS VALVE	Manual	Manual
JSIBHV694[j]	LPSI-CONTAINMENT SPRAY PUMP CROSS CONNECT B VALVE	Manual	Manual
JSIBHV695[j]	CONTAINMENT SPRAY ISOLATION VALVE	Manual	Manual
JSIBHV696[j]	SDCHX DISCHARGE VALVE	Manual	Manual
JSIBHV699[j]	HIGH PRESSURE SAFETY INJECTION PUMP B DISCHARGE VALVE	Manual	N/A
JWCNE01	NORMAL CHILLER AUXILIARY POWER PANEL (BUS A)	N/A	Manual
MAFNP01	NON-ESSENTIAL AUXILIARY FEEDWATER PUMP (BUS A)	Manual	Manual
MPCAP01[e]	FUEL POOL COOLING PUMP 1	Manual	Manual
MPCBP01[e]	FUEL POOL COOLING PUMP 2	Manual	Manual
MWCNE01A	NORMAL CHILLER (BUS A)	N/A	Manual
MWCNP01A	NORMAL CHILLED WATER PUMP (BUS A)	N/A	Manual
AJHPAE01	HYDROGEN (H2) RECOMBINER CONTROL PANEL	Manual	N/A
AJHPBE01	HYDROGEN (H2) RECOMBINER CONTROL PANEL	Manual	N/A
EPKAH15[l]	BATTERY CHARGER	N/A	N/A
EPKBH16[l]	BATTERY CHARGER	N/A	N/A
MDGAM02[f]	DIESEL GENERATOR ‘A’ LUBE OIL WARM-UP HEATER	N/A	N/A
MDGAM03[f]	DIESEL GENERATOR ‘A’ CRANKCASE HEATER	N/A	N/A
MDGAP04[f]	DIESEL GENERATOR PRE-LUBE PUMP	N/A	N/A
MDGBM02[f]	DIESEL GENERATOR ‘B’ LUBE OIL ENGINE WARM-UP HEATER	N/A	N/A
MDGBM03[f]	DIESEL GENERATOR ‘B’ CRANK CASE HEATER	N/A	N/A
MDGBP04[f]	DIESEL GENERATOR PRE-LUBE PUMP	N/A	N/A

TABLE 8.3-3[(a)]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 10 of 12)

a. See ZZI-003 Electrical Equipment Database for HP, KW, or KVA rating of individual loads. See EC-MA-221 AC Distribution Calculation for DG total loading for loss of offsite power with forced shutdown and loss of offsite power with LOCA.

b. Sequencer mode 2 is a Loss of coolant accident (LOCA) and a loss of offsite power (LOP) and diesel generator breaker closed. LOCA can be either a Containment Spray Actuation Signal (CSAS) or Safety Injection Actuation Signal (SIAS). Start time is counted from the generator breaker closure instant (sequencer time 0.0) and does not include the 10 second maximum start time for the diesel generator to accelerate up to nominal voltage and frequency and the time to close the breaker. This mode begins sequencing of loads onto the diesel generator (load step 1) at .5 seconds. The .5 second delay allows initial energization of the three safety-related 4160-480 volt load center transformers (E-PGA-L31X,33X,35X, E-PGB-L32X,34X,36X). Load step 2 begins at 5 seconds, and the remaining load steps (3 through 7) occur at 5 second intervals for a total of 30 seconds. Manual loading begins after 30 seconds. One additional load step permissive occurs at 40 seconds (see note h).

c. Sequencer mode 3 is a Forced shutdown (FS) and a loss of offsite power (LOP) and diesel generator breaker closed. Forced shutdown is <u>not</u> a LOCA and is an unscheduled shutdown

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 11 of 12)

of a unit. Start time is counted from the generator breaker closure instant and does not include the 10 second maximum start time for the diesel generator to accelerate up to nominal voltage and frequency and the time to close the breaker. This mode begins sequencing of loads onto the diesel generator (load step 1) at .5 seconds. The 5 second delay allows initial energization of the three safety-related 4160-480 volt load center transformers (E-PGA-L31X,33X,35X, E-PGB-L32X,34X,36X). Load step 2 begins at 5 seconds, and the remaining load steps (3 through 7) occur at 5 second intervals for a total of 30 seconds. Manual loading begins after 30 seconds. One additional load step occurs at 55 seconds.

d. Initial start of essential chiller is delayed 71 seconds maximum. Subsequent starts are delayed 2-1/4 minutes maximum due to chiller internal control.

e. Will be started manually at operator’s discretion.

f. These loads are not on when the diesel generator is running.

g. Non-Class IE loads fed from Class IE power through Class IE interrupting devices connected in series.

h. The load will automatically sequence on in 40 seconds for a LOCA (SIAS OR CSAS) if the following conditions are met: sequencer permissive and auto (after stop) and pressurizer level low. There is no time constraint or permissives required for manual loading.

TABLE 8.3-3[a]
DIESEL GENERATOR LOAD SEQUENCING
(Sheet 12 of 12)

i. Plant numbering system identification. Example: EPKAH11. E is the discipline designator, PK is the system designator, A is the separation group (A, B, C, and D for separation groups, E is a non-separation group but meets separation criteria, N for non-Class 1E separation group), H is the commodity or device designator, and 11 is the sequence number. See the Plant Numbering Procedure, 80DP-0CC04 for more details.

j. The motor operated valves (MOV) are modeled as constant impedance intermittent loads. These loads are included for the duration of their load sequence to model the effect of their inrush current on voltage during load sequencing.

k. Sequenced loading and steady state loading summary, which includes the distribution effects of cable and transformer losses. The actual calculations are performed by ECALC, the qualified electrical calculation software. The maximum continuous steady state load rating for the diesel generator is 5.500 MW and 4.125 MVAR (6.875 MVA).

l. EPKAH15 backs up EPKAH11 and EPKBH16 backs up EPKBH12.

N/A - Not Applicable

m. The automatic loading of E-NNN-V18 onto the Diesel Generator within 0.5 seconds is only applicable for Unit 3. E-NNN-V18 for Units 1 and 2 will remain as a manual function for Diesel Generator loading. In either case, the total steady state Diesel Generator loading has not been increased.

The DGSS logic combines the LOP, SIAS, AFAS, CSAS, and manual actuation in a logical "OR" to generate a DGSS to start the diesel generator.

The load sequencer start and permissive signal logic monitors input signals, determine the appropriate mode of operation, and generate sequentially timed start and permissive signals to ESF and forced shutdown loads as required to prevent instability of Class 1E buses. Start signals actuate devices by deenergizing actuation relays. The permissive signals, however, allow loading of devices by energizing actuation relays. The load sequencer controls only pumps, fans, and chillers, and does not control any valves or dampers.

As such, the load sequencer does not cause complete ESF system actuation. The load sequencer responds to the following conditions:

- LOCA, with or without offsite power available
- Accident other than LOCA, with or without offsite power available
- LOP with or without an accident other than LOCA, but followed at a later time by a LOCA
- LOCA that is followed at a later time by an LOP

The load sequencer has a normal mode (Mode 0) and the following four operating modes:

A. SIAS/CSAS without an LOP

B. SIAS/CSAS coincident with an LOP. Sequencing is started on a diesel generator breaker closure signal.

C. LOP without an SIAS/CSAS. Sequencing is started on a diesel generator breaker closure signal.

D. Other signals without an SIAS/CSAS and without an LOP. These signals are:

- CRVIAS or CREFAS
- FBEVAS
- AFAS-1 or AFAS-2
- Diesel generator running

Receipt of subsequent input signals requiring a change of operating mode causes the load sequencer to reset, transfer to the required mode, and initiate sequencing of the required loads.

The devices sequentially actuated through the load sequencer receive a load shed signal on bus undervoltage to trip the device load, and a load sequencer start signal to start the device at the appropriate time. Reset of the load sequencer and its actuation relays does not stop or shed actuated devices. Devices are shed only on the load shed signal.

A sequencer design demonstration test was performed to test the sequencer to assure that no credible sneak circuits or common mode failures could render both onsite and offsite power sources unavailable. The testing included approximately 130 credible scenarios combining accident situations with and without offsite power available. The test results were satisfactory and demonstrated that no sneak logic paths exist in the design that could result in failure of the sequencer to perform its required function. The test report, ESF Load

Sequencer Design Demonstration Test Report, E160972, February 1981, was submitted to the NRC (Supplier Document Register No. 13-J-104-85).

Provisions are made to permit periodic testing of the ESF load sequencer system. Tests cover the trip actions from input signals through the system and the actuation devices. System test does not interfere with the protective function of the system. Actuation of the components controlled by the ESF load sequencer system does not disturb normal plant operating conditions; therefore, the ESF load sequencer system is tested by complete actuation. Proper operation may be verified by the following:

- Checking the position of each ESF component
- Checking the actuation annunciation
- Checking the ESF component status indication
- Checking the load sequencer timing
- Checking all sequencer modes
- Checking all logic circuits

This testing will be performed as specified by the PVNGS Technical Specifications.

The ESF load sequencer for each logic train contains the necessary hardware and associated software programs stored in read-only memory to determine that each functional channel within that train will respond to field initiated input contact action and that the ESF load sequencer in the opposite train is operative.

The auto test function does not check:

A. The Cross Logic Train Actuation Signal Operation - Response times dictated by specified signal filtering bandpass limit of 30 Hz do not allow test pulses to propagate to the opposite train.

B. Actual Actuation Relay Contact Transfer - Only the relay drive current response is monitored.

C. Manually Initiated Actuation Inputs

The auto-test feature is normally off. A 24-day test interval that either manually activates the auto-test feature or performs a system test in at least one sequencer mode is sufficient to maintain the system reliability goal.

8.3.1.1.3.10.2 Module Selection and Test Scheme.

A. Address Select and Test Enable Bus

Each module has an address code associated with its position in the system (e.g., FBEVAS-01, CREFAS-02, CPIAS-03, LOP/LS-04, CRVIAS-05, DGSS-06) which is set within the module via a minidip switch unit. As the module address select signal bus (four lines) is strobed with each successive code, the selected module will admit test pulses (10 msec wide; 250 msec apart; four per test) which propagate through the logic and are sensed in such a way as to prepare a return signal to be sent back to the auto test function contained within the ESF load sequencer for interpretation. The LOP/LS module requires an additional four lines (test enable)

to interpret the module response to all possible two of four pairs.

B. Module Test Response Return Interpretation

As the modules are successively selected, the auto test features within the sequencer examines the test returns and active signals received from the modules and looks for a particular pattern based upon the system configuration, and within the time frame of the test. The auto test feature is then able to determine if the module has passed or failed a test, or if a field-related signal (actual input) has been received. In the case of a failed test or an actual input, the auto test feature will cease operation.

C. Test Failure Indication

Each module contains a test indicator lamp that illuminates in a steady-state while that module is under test. As the auto test feature strobes each module, the test indication will appear to "walk" across the face of the bin assembly containing the modules. If the auto test feature determines an erroneous response, it will cause the test indicator on the module where the failure was detected to flash. The error may or may not be within that module dependent upon the system configuration and the position of the module in the test order (e.g., if the FBEVAS module correctly responded to the test, yet a failure in the CREFAS module failed to provide its required automatic output, the auto test feature would flash the error indicator in the FBEVAS

module). Further manual tests might be required to isolate the fault. When the auto test feature terminates testing under either an error detection or receipt of an actual input, the required auto test terminate (fail) annunciator contacts will transfer to the alarm state. During auto test operation, the "auto test on" annunciator contacts are transferred.

D. Test Success Indication

As the modules are strobed into test by the module select bus (solid test indicator illumination), the test pulses propagating through the module actuation logic will cause the associated indicators to "flicker." As the module successfully completes its test, the next module in line is strobed and its actuation associated indicators "flicker," until all modules are tested, including the ESF load sequencer itself.

Refer to paragraph 8.3.1.1.4.6 for additional information on load shedding and sequencing.

8.3.1.1.3.11 Class 1E Equipment Identification. Refer to paragraph 8.3.1.3 for details regarding the physical identification of Class 1E equipment.

8.3.1.1.3.12 Instrumentation and Control Systems for the Applicable Power Systems with the Assigned Power Supply Identified. The dc control power supplies for redundant Class 1E controls are physically and electrically separate and independent so that dc subsystem A supplies Class 1E load group 1 switchgear. The battery chargers for dc subsystem A are fed

from the same load group 1 switchgear. The dc subsystem B supplies Class 1E load group 2 switchgear in a similar manner.

Each 4.16 kV bus and 480V load center bus is equipped with an undervoltage relay for annunciation in the control room. The voltage of each Class 1E 4.16 kV bus and 480V load center bus is monitored by instruments in the control room.

8.3.1.1.3.13 Electric Circuit Protection Systems. Protective relay schemes and direct-acting trip devices on primary and backup circuit breakers are provided throughout the Class 1E onsite power system to:

- Isolate faulted equipment and/or circuits from unfaulted equipment and/or circuits
- Prevent damage to equipment in abnormal operation
- Protect personnel
- Prevent system disturbances

The direct-acting trip device, installed on PVNGS Load Center breakers, is an adjustable overcurrent trip apparatus, which relies on the current flowing through the circuit breaker to provide the required tripping power in the event of circuit fault or overload. Since the unit is self-contained, no external dc or ac control power is required to support this protective trip function. The direct-acting trip device monitors the primary current flow in each phase and trips the breaker when that primary current exceeds selected current magnitudes and associated time delay(s) over the range of postulated faulted and circuit overload conditions.

The molded case circuit breakers of the Motor Control Centers, DC Control Centers and Low Voltage (AC and DC) Distribution Panels are likewise not dependent upon external control power to perform their respective protective trip function.

Major types of protection applications that are used consist of the following:

A. 4.16 kV Overcurrent Relaying

Each radial feeder into and out of the 4.16 kV buses is protected by three inverse-time phase relays and one inverse-time ground overcurrent relay. Motor protection is provided by relays that alarm in the control room on overloads set between 115 and 145% of motor full load current and trip only on heavy faults or sustained overcurrents above 145% of motor full load current.

B. Undervoltage Relaying

Each 4.16 kV switchgear bus is equipped with an undervoltage relay for load shedding, diesel generator starting, and undervoltage annunciation in the control room.

The Palo Verde design has four, 4160 volt safety-related bus induction disc loss of voltage relays, and four solid-state undervoltage relays with built-in time delays. The loss of voltage relays have a drop out voltage that varies with time, so that they will commence time out if the voltage falls below 78% for a long time or below 70% for a short time (12.6 seconds or less) (See Figure 8.3-3). The degraded voltage relays will commence a maximum 35 second time-out when the bus

voltage drops to less than 90% (nominal) of design. Recovery of the bus voltage before time-out is completed will reset the degraded voltage relays.

A fifth degraded voltage relay, on each 4160 volt safety-related bus, will provide an annunciation in the control room after bus voltage drops to less than 90% after 10 seconds.

The undervoltage monitors consist of four separate sensor signal circuits (i.e., four potential transformers across phases as follows: A-B, B-C, A-C, and A-B with the associated circuitry) for each 4.16 kV ESF bus. The undervoltage signals are redundant sensor signals within the affected train (the design for each train employs coincident logic to prevent spurious actuation and unnecessary isolation from the preferred power supply). The installation associated with each sensor includes potential transformers, voltage level monitors, trip signal isolation, bus voltage indication, set point adjustment, and trip signal annunciation output. The degraded voltage relays require 125 Vdc control power, which is provided from the same source as the breaker control power for the 4.16 kV switchgear.

The degraded voltage relays satisfy the following criteria:

1. The selection of voltage and time setpoints was determined from an analysis of the voltage requirements of the safety-related loads at all onsite system distribution levels.

2. Coincident (two-out-of-four) logic is used to preclude the spurious trip of the offsite source.

3. The time delays are such that:

   - The selected time delay minimizes the ability of short duration disturbances to reduce the availability of the offsite power source(s).

   - The allowed time duration of a degraded voltage condition at all distribution system levels does not result in failure of safety systems or components.

4. The voltage sensors will automatically initiate the disconnection of offsite power sources whenever the voltage setpoint and time delay limits have been exceeded.

5. The voltage sensors are designed to satisfy the applicable requirements of IEEE Standard 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations.

6. The Technical Specifications include limiting conditions for operation, surveillance requirements, and allowable values for the degraded voltage relay voltage and time settings.

Each 480V load center bus is equipped with an undervoltage relay for annunciation in the control room.

C. Differential Relaying

Circulating water pumps, reactor coolant pump motors, diesel generators, and transformers larger than 10 MVA are equipped with differential relays. These relays provide high speed disconnection to prevent severe damage in case of internal circuit faults.

D. 480V Load Center Protection

Each load center main feeder circuit is protected by three-phase relays and one ground overcurrent relay. Each motor control center main feeder circuit is analyzed for adequate protection or is protected by a circuit breaker and an adjustable, selective overcurrent relay. Protection for the class 1E motor is provided by three-phase relays that alarm on overload and a ground overcurrent relay that trips the breaker on ground faults.

Trip will occur only on faults or sustained overcurrents substantially greater than full load current.

E. 480V Motor Control Center Relaying

Molded-case circuit breakers provide time overcurrent and/or instantaneous short circuit protection for all connected loads. For motor circuits, the molded-case circuit breakers are equipped with instantaneous trip only. Motor overload protection is provided by heater-element trip units in the motor starter. The molded case breakers for nonmotor feeder circuits provide thermal time overcurrent protection as well as instantaneous short circuit protection. Thermal

overload protection of safety-related motors essential to safe shutdown of the plant is automatically bypassed following an ESFAS, except for the diesel generator fuel transfer pump motors [M-DFA(B)-P01] and the spray pond pump house exhaust fan motors [M-HSA(B)-J01], and the spray pond margin bypass valves [J-SPA(B)-V0075(76)].

When thermal overload protection for motor-operated valves below 1 horsepower inside the containment is bypassed, ensure adequate fault level/time characteristics for proper backup protection for the electrical penetration is provided. The bypass circuitry is designed to IEEE 279-1971 criteria.

The starter thermal overload relay contact for a motor-operated valve is bypassed by a contact of the same initiating relay that activates the motor-operated valve in the event of a LOCA. The bypass remains in effect until the initiating signal is manually reset.

The short circuit protective system is analyzed to ensure that the various adjustable devices are applied within their ratings and are set to be coordinated with each other to attain selectivity in their operation. The combination of devices and settings applied affords the selectivity necessary to isolate a faulted area quickly with a minimum of disturbance to the rest of the system.

Preoperational test of the protective devices is performed to demonstrate that they are properly calibrated and adjusted to alarm or trip as required. After the plant is in operation,

periodic tests are performed at scheduled intervals to verify the protective device calibration, setpoints, and correct operation. A random sample of molded case circuit breakers required for the protection of containment electrical penetrations will be tested periodically to verify the overcurrent trip setpoint in accordance with NEMA AB 2-1980. The PVNGS design has a combination of fuse and circuit breaker, two fuses, or two circuit breakers for circuits being fed through containment electrical penetrations.

8.3.1.1.3.14 Testing of the AC Systems During Power Operation. During periodic Class 1E system tests, subsystems of the Class 1E system such as safety injection, containment spray, and containment isolation are actuated, thereby causing appropriate circuit breaker or contactor operation. The 4.16 kV switchgear and 480V load center circuit breakers and control circuits also can be tested independently while individual equipment is shut down. The circuit breakers can be placed in the test position and exercised without operation of the associated equipment.

8.3.1.1.4 Standby Power Supply

The standby power supply for each safety-related load group consists of one diesel generator complete with its accessories and fuel storage and transfer systems. The standby power supply functions as a source of ac power for safe plant shutdown in the event of loss of preferred power and for post-accident operation of ESF loads. Each diesel generator is rated at 5500 kW at 0.8 pf for continuous operation and 6050 kW

for 2 hours out of 24 hours. There are no provisions for automatically paralleling the two diesel generators within a unit. Interlocks are provided to prevent manual paralleling of the diesel generators. There are no direct interconnections between the standby power supplies of the individual units.

Each diesel generator is normally connected to a single 4.16 kV safety features bus of a load group. However, there are provisions for connecting both ESF buses to a single diesel generator during emergency conditions. Each load group is independently capable of safely shutting down the unit or mitigating the consequences of a loss-of-coolant-accident (LOCA).

The diesel generators are physically and electrically isolated from each other. Physical separation for fire and missile protection is provided by installing the diesel generators in separate rooms in a Seismic Category I structure. Power and control cables for the diesel generators and associated switchgear are routed in separate raceways.

Ratings for the diesel generators are calculated consistent with the recommendations of NRC Regulatory Guide 1.9 (discussed in paragraph 8.3.1.2). Loads to be supplied by the diesel generator are determined on the basis of nameplate or service factor rating, pump pressure and flow conditions, pump runout conditions, and starting inrush. The loads for each diesel generator are listed in table 8.3-1. The continuous rating of the diesel generator is based on the maximum total load required at one time. The diesel generator starting and ESF bus loading sequence logic diagram is given in figure 8.3-1.

The diesel generators are controlled from the electric mimic bus panel in the main control room or from a local panel within each diesel generator control room. Controls and instrumentation are provided in both locations for starting, stopping, and for governor and excitation system adjustments. A key-locked "OFF-LOCAL-REMOTE" switch is provided at each local panel with the key removable in the OFF and REMOTE positions only. Manual control from the local panel is possible in the LOCAL position only. Manual control from the main control room is possible in the REMOTE position only. Automatic starting of the diesel generator is possible in the LOCAL and REMOTE positions of the key-locked switch. No automatic or manual start is possible in the OFF position and a DIESEL GENERATOR INOPERABLE alarm is initiated at the safety equipment status system annunciator.

Three switches are provided on the engine front panel for diesel generator testing. Two pushbutton switches are provided for emergency starts: one simulates a LOP; the other simulates a SIAS and AFAS. The third switch defeats the emergency mode interlocks, allowing the diesel generator to be taken out of the emergency mode condition, without stopping the diesel engine. This switch is used at the completion of the LOP and ESFAS tests. It is an "off-on" key-lock switch, with the key removable in “off” only (non-defeat).

The generator is driven by a turbocharged, four-cycle, 20-cylinder diesel engine. The engine produces 7670 horsepower at continuous rated output and 8437 horsepower at short-time rated output. For a discussion of the engine fuel oil system,

cooling water system, air-start system, and lube oil system, see subsections 9.5.4, 9.5.5, 9.5.6 and 9.5.7.

All components of the standby power supply system, including related controls, required to supply power to ESF and safe shutdown loads conform to the requirements of General Design Criterion 17, IEEE 308, and IEEE 279. The functional aspects of the standby power supply system are presented in the following paragraphs.

8.3.1.1.4.1 Automatic Starting Initiation Circuits. Each diesel generator is automatically started on any of the following conditions:

- Undervoltage on the 4.16 kV, Class 1E bus to which the generator is connected, loss or sustained degradation of offsite power (LOP)
- Safety injection actuation signal (SIAS)
- Auxiliary feedwater actuation signal (AFAS)
- Containment spray actuation signal (CSAS); DG starts in test mode

8.3.1.1.4.2 Diesel Generator Starting Mechanism and System. The diesel generator starting system is described in subsection 9.5.6. The design basis and analysis for diesel generator systems, controls, and instrumentation are described in section 7.3.

8.3.1.1.4.3 Tripping Devices. Devices are provided for the following protective functions for each diesel generator:

- Incomplete sequence (start failure)
- Engine overspeed
- High jacket coolant temperature
- High bearing temperature
- High crankcase pressure
- Turbocharger thrust bearing failure
- Low lube oil pressure
- Turbocharger low lube oil pressure
- Loss of field
- Generator differential
- Generator ground overcurrent
- Generator voltage restrained overcurrent
- Reverse power
- Load unbalance (negative sequence)
- Underfrequency
- Manual emergency trip

The incomplete sequence relay functions to interrupt the starting of the diesel generator if a predetermined speed is not reached.

During diesel generator starting sequences, the low lube oil pressure trips are bypassed for a predetermined period. The manual emergency trip is initiated by depressing a pushbutton at the diesel generator local control panel. An automatic or manual start is not possible unless the pushbutton is manually reset. A transparent, hinged cover is provided over the emergency trip pushbutton as protection against accidental actuation.

The critical protective devices that function to shut down the diesel generator during testing and are also retained during emergency operation consist of:

- Engine overspeed
- Low lube oil pressure (one-out-of-two-taken-twice logic)
- Generator differential
- Manual emergency trip

All other protective device trips are bypassed and annunciated during emergency (SIAS or AFAS or LOP) operation and function to shut down the diesel generator only during testing operation.

Automatic bypass is not provided around the protective devices that function during an accident because each load group is provided with one diesel generator. Therefore, should one diesel generator be tripped by a protective device, the other redundant load group is still available. Since the malfunctioning diesel generator is isolated before it can be

seriously damaged, repairs can be made while the redundant diesel generator is in operation.

The tripping devices that are in effect in both the test mode and emergency mode of operation require control air to function, except the engine over speed trip, which also shuts off combustion air to the EDG. If EDG control air is not available, the EDG can still be tripped manually to shut off the fuel racks by activating a lever on the side of the engine.

The associated DG 4.16 KV output breakers have generator protective devices in place during testing that are also bypassed during EDG emergency operations.

To provide additional reliability, shutdown due to low lube oil pressure will be initiated by one-out-of-two-taken-twice logic. That is, a false trip on one channel does not erroneously isolate the diesel generator. These protective trips and their logic conform to IEEE 279-1971.

The diesel generators are monitored from the control room and each device, when actuated, initiates an annunciator in the control room as well as locally. The alarms are set so that they provide a warning of impending trouble prior to trip of the diesel generator.

8.3.1.1.4.4 Interlocks. Diesel generator circuit breaker interlocks are provided to protect against the following:

- Automatic energizing of electrical devices during maintenance

- Automatic closing of the diesel generator breaker to an energized or faulted bus
- Automatic connection of two sources out of synchronism
- Automatic connection of the ESF loads without voltage on the associated ESF bus
- Automatically or manually paralleling the diesel generators

8.3.1.1.4.5 Permissives. A single three-position, key-locked switch is provided at each diesel generator local control panel. When this switch is in the REMOTE position, the diesel generator may be started automatically, or manually from the control room. When the switch is in the LOCAL position, the diesel generator may be started automatically, or manually from the diesel generator local control panel and a LOCAL position alarm is initiated in the control room. When the switch is in the OFF position, no automatic or manual start is possible and a DIESEL GENERATOR INOPERABLE alarm is initiated at the safety equipment status system annunciator. Blocking of automatic and manual starting of the diesel generator by the local manual emergency trip pushbutton is discussed in paragraph 8.3.1.1.4.3. A switch in the control room and a local switch are provided to allow a manual start capability in addition to the automatic start contacts. An override of a SIAS/CSAS, AFAS, or LOP is provided to allow the operator to parallel with offsite power and stop a diesel generator when offsite power is available.

During periodic diesel generator tests, permissives and interlocks are aligned to permit manual synchronization and loading of the diesel generator with the preferred power source.

8.3.1.1.4.6 Load-Shedding Circuits. Load shedding of the Class 1E, 4.16 kV bus is initiated by detection of undervoltage on this bus using a two-out-of-four coincidence logic of undervoltage relays. Paragraph 8.3.1.1.3.13, listing B, summarizes the design and setpoint criteria for these relays. The load shed signal is a single, 1-second pulse generated upon detection of an undervoltage occurrence. This pulse acts to:

A. Shed all 4.16 KV and selected 480 V loads from the Class 1E 4.16 KV bus.

B. Trip the 4.16 KV Class IE bus preferred (offsite) power supply breakers.

In conjunction with the load shed signal is the loss of offsite power signal which acts to:

C. Send a signal to start the diesel.

D. Send a signal to the sequential actuation system (refer to figure 8.3-1 for undervoltage and sequential actuation system logic).

Tripping of the offsite breakers isolates the Class 1E onsite power system, including the undervoltage relays, from the offsite power system. There is, therefore, no possibility of subsequent interaction between the load shed and the offsite power system. The return of the Class 1E, 4.16 kV bus to offsite power must be done manually. After load shedding,

tripping of the Class 1E, 4.16 kV bus offsite supply breaker, and subsequent closing of the diesel generator breaker to the Class 1E 4.16 kV bus, the undervoltage relays monitor the standby (onsite) power supply for an undervoltage occurrence. The load shed feature is blocked for 60 seconds during sequencing of ESF loads. Should an undervoltage occur after this interval, the Class 1E, 4.16 kV loads are shed and the loading sequence restarted.

As the undervoltage relays are transferred with the Class 1E 4.16 kV bus from offsite (preferred) to onsite (standby) power on a loss of offsite power, no bypass of these relays to prevent interaction of offsite power with the shed feature is required.

The sequencer, upon closure of the diesel generator breaker, will sequence the equipment in programmed steps, which prevents diesel generator instability and minimizes load accelerating time. A fast-responding exciter and voltage regulator ensures voltage recovery of the diesel generator after a load step. The generators use field flashing for voltage buildup during the start sequence.

As each generator reaches rated voltage and frequency, the generator breaker connecting it to the corresponding 4.16 kV bus closes. With the SIAS/CSAS or AFAS a diesel start is initiated; however, connection of the diesel generator to the 4.16 kV bus cannot be made unless the preferred source of power is lost. If the preferred source of power is not lost, the appropriate ESF loads will be sequenced on to the preferred powered bus and the diesel will be left running for a period of

at least 1 hour. With an SIAS or AFAS signal present and no loss of preferred power, the operator can manually override the SIAS or AFAS signal from the control room. The diesel generator can then be manually shut down from the control room or locally. In a subsequent loss of preferred power, load shedding and load sequencing will be initiated. The diesel generator will start, accelerate to at least the minimum acceptable voltage and frequency and have its output breaker close to commence accepting loads within 10 seconds of the diesel generator start signal and be completely loaded within 60 seconds after closure of the diesel generator breaker. The ESF loads required for the operation of components within the CESSAR scope in table 8.3-1 will be sequenced on within 30 seconds after closure of the generator breakers and ESF bus re-energization, as identified in table 8.3-3. Relays at the diesel generator detect generator rated voltage and frequency conditions and provide a permissive interlock for the closing of the respective generator circuit breaker. Upon loss of the preferred source of power without LOCA, the undervoltage system initiates the starting of the diesel generators and sheds all loads. The sequencer then automatically initiates the starting of the safe shutdown loads upon closure of the diesel generator breaker.

If the diesel generator is supplying power to the ESF bus, a subsequent accident signal initiates starting of the loads associated with the subsequent accident signal without shedding any operating equipment.

If offsite power is lost at some time after an accident and the required ESF equipment is running and the diesel generator is up to rated voltage and speed, the sequencer initiates restart of the safety injection pumps within 6 seconds and the auxiliary feedwater pump within 11 seconds of the closure of the diesel generator breaker such that:

A. Interrupted flow to the core is fully reestablished within 13 seconds.

B. Interrupted auxiliary feedwater flow to the steam generator(s) is fully reestablished within 23 seconds. The deviation from the CESSAR requirement of 15 seconds is acceptable to Combustion Engineering as discussed in paragraph 1.9.2.4.10.

8.3.1.1.4.7 Testability. Refer to section 14.2, and the Technical Specifications for testing requirements.

During testing, if an SIAS/CSAS or AFAS occurs while the diesel generator is paralleled to the preferred power supply with the control switch in the REMOTE or LOCAL position, the diesel generator breaker will be automatically tripped by a momentary tripping pulse. The diesel generator will continue running and automatically revert to the isochronous mode. All noncritical protective devices are bypassed. If a noncritical trip occurs during testing, the diesel generator will trip. On a subsequent SIAS/CSAS, AFAS, or LOP, the diesel generator will automatically start and run in the isochronous mode.

The LOCAL control position is selected from the local control panel for diesel generator maintenance testing. A diesel

generator LOCAL POSITION alarm will be annunciated in the control room. To prevent any starting of the diesel generator during maintenance, the OFF position is selected at the local control panel and a DIESEL GENERATOR INOPERABLE alarm is initiated at the safety equipment status system annunciator.

If the preferred power source is lost while paralleled to the diesel generator during testing, the diesel generator either trips on overcurrent or continues to run, depending upon if the resulting load is in excess of the diesel generator's load rating. If the load is excessive, the diesel generator will trip on overcurrent and the diesel generator breaker will trip automatically on a diesel generator shutdown signal. Upon detection of undervoltage on the Class 1E, 4.16 kV bus, load shedding and sequencing will be initiated as described in paragraph 8.3.1.1.4.6. If the load does not exceed the diesel generator's load rating, the diesel generator continues to run and supply the ESF bus. The operators receive indication and alarms in the control room that the preferred power source is lost.

8.3.1.1.4.8 Diesel Generator Fuel Oil Storage and Transfer Systems. Refer to subsection 9.5.4 for system description.

8.3.1.1.4.9 Cooling and Heating Systems. Refer to subsection 9.5.5 for system description.

8.3.1.1.4.10 Instrumentation and Control Systems for Standby Diesel Power Supply. Pertinent instrumentation and control systems are as follows:

A. Equipment is provided in the control room for each diesel generator for the following operations:

- Remote manual starting and stopping
- Remote manual synchronization
- Remote manual frequency and voltage regulation
- Governor and voltage droop selection
- Automatic or manual voltage regulator selection [For Units/Trains that have not installed DMWO 2859190]
- Automatic 1 or Automatic 2 voltage regulator selection [For Units/Trains that have installed DMWO 2859190]

B. Equipment is provided at each local control panel for the following operations:

- Manual starting and stopping
- Frequency and voltage regulation
- Automatic or manual regulator selection [For Units/Trains that have not installed DMWO 2859190]
- Automatic 1 or Automatic 2 voltage regulator selection [For Units/Trains that have installed DMWO 2859190]

- Exciter field removal and reset
- Manual emergency start, simulated LOP
- Manual emergency start, simulated ESFAS (SIAS/CIAS)
- Manual emergency stop
- OFF-LOCAL-REMOTE control selection
- Emergency mode interlock defeat switch

The local control operation is annunciated in the control room. The dc power source for the Class 1E diesel generator instrumentation and control system is associated with the same load group as the diesel generator.

C. Each diesel generator is equipped with the following alarms on the local control panel:

- Lube oil low pressure (engine, turbo)
- Lube oil high or low temperature
- Jacket coolant low pressure
- Jacket coolant high or low temperature (Jacket water temp. high or off normal)
- Fuel oil high level in day tank
- Fuel oil low level in day tank
- Fuel oil low level in storage tank
- Fuel oil low pressure
- Fuel oil transfer pump low discharge pressure

- Incomplete sequence (start failure)
- Generator field ground
- Generator undervoltage
- Generator overvoltage
- Generator underfrequency
- Crankcase low oil level
- Starting air solenoid or system malfunction
- Excitation bridge failure (This alarm has been removed in those units/trains where DMWO 4465038 has been implemented)
- Crankcase high pressure
- Generator overcurrent (voltage restrained overcurrent)
- Engine overspeed
- Diesel generator bypassed or inoperable (common alarm)
- Turbo thrust bearing failure
- Bearing high temperature (main and conn. rod or gen-bearing)
- Generator neutral overvoltage (ground overcurrent)
- Loss of field
- Generator differential
- Reverse power

- Fuel oil filter high differential pressure
- Fuel oil strainer differential pressure high
- Fuel oil supply to day tank high differential pressure
- Generator or high voltage cubicle space heater trouble (common alarm)
- Essential exhaust fan overload pretrip
- Annunciator ground
- Any switch not in auto (common alarm)
- Lube oil filter high differential pressure
- Generator load unbalance (negative sequence trip and pre-trip alarm)
- Starting air receiver "A" malfunction
- Starting air receiver "B" malfunction

The local annunciator provides first out indication for all alarms initiated by the diesel generator protective devices listed in paragraph 8.3.1.1.4.3.

D. The following alarms are annunciated in the control room:

- Diesel generator trip (common alarm)
- Diesel generator running
- Diesel generator differential trip
- Diesel generator overspeed trip

- Diesel generator low lube oil pressure trip
- Diesel generator emergency manual trip
- Diesel generator high priority trouble (common alarm)
- Diesel generator low priority trouble (common alarm)
- Diesel generator fuel system trouble (common alarm)
- Diesel generator in local mode

The following alarms will be annunciated on the control room safety equipment status annunciator:

- Diesel generator inoperable
- Diesel generator failed to start

The common diesel generator trip alarm is initiated only when the diesel generator is actually shutdown by a protective device. The diesel generator high priority trouble alarm is initiated by any of the protective devices listed in paragraph 8.3.1.1.4.3 whether a diesel generator shutdown results or not. The diesel generator low priority trouble alarm is initiated by any alarm condition listed in paragraph 8.3.1.1.4.10, listing C, other than the high priority and bypass, or inoperable alarms.

The diesel generator fuel system trouble alarm is initiated by any of the following:

- Diesel generator day tank low level

- Diesel generator fuel oil transfer pump low discharge pressure

The diesel generator inoperable and failed to start alarms are annunciated on a common DIESEL GENERATOR SYSTEM safety equipment status system window. This window is horizontally split, with the top half illuminated in white for an inoperable condition and the bottom half in blue for a start failure.

Conditions that render a diesel generator inoperable on an automatic start signal are:

- Low starting air pressure
- Diesel generator turning gear engaged
- Loss of dc control power
- Manual emergency trip pushbutton not reset
- Control mode selector switch in OFF position
- Emergency mode interlock defeat switch in ON position (renders LOP inoperable only)
- Generator differential lockout relay not reset
- Fuel oil supply valve closed

Low starting air pressure or turning gear engaged are indicated by a white AIR START SYSTEM indicator light. Loss of dc, selector switch in OFF, lockout relay not reset, or emergency trip switch not reset are indicated by a white START LOGIC SYSTEM indicator light. Fuel oil supply valve closed is indicated by a

white FUEL OIL SUPPLY VALVE indicator light. In addition, a DIESEL GENERATOR indicator light is provided to indicate loss of breaker control power (white) or failed to close (blue), or diesel generator failed to start (blue).

Electrical metering instruments are provided in the control room and at the local control panel for surveillance of generator voltage, current, frequency, power and reactive power. Fuel oil day tank level indicators are also provided.

8.3.1.1.4.11 Prototype Qualification Program. A start and load reliability test program was performed to certify 0.99 reliability for the diesel generators in accordance with IEEE 387-1977. A valid start and load test was defined as a start from design cold ambient conditions with loading to at least 50% of the continuous rating within the required time interval, and continued operation until temperature equilibrium is attained. At least 300 qualification tests were performed on one PVNGS diesel. The failure rate was less than 1 per 100.

A reliability testing program was performed on emergency diesel generator 2-M-DGB-H01, serial number 7183, at the manufacturer's shop during July 7, 1978 through September 10, 1978. The test period included standard shop tests to determine fuel and oil consumption, checkout, and engine break-in.

The report of the tests was provided by the manufacturer, Cooper Energy Services. Following are excerpts from that report. Included is the time-to-rated speed for the

first 24 starts. All starts reached rated speed between 5.6 and 5.9 seconds.

Requirement:

A total of at least 300 start and load tests shall be conducted to demonstrate reliability. A failure rate in excess of one per 100 will require complete retesting and a review of the system design adequacy.

A. 90% of the start and load tests will be performed with lube oil and jacket water temperatures initially at 120°F ± 10°F. The engine-generator set must achieve rated frequency and voltage within 10 seconds of the start initiation signal and be loaded to 2750 KW (resistive) min within 20 seconds of the start initiation signal. 2750 KW min load will be maintained until the engine jacket water and lube oil temperatures do not vary more than ±5F from design within a 5-minute interval. The engine will then be shut down and force cooled until jacket water and lube oil temperatures are less than 130°F at which time the next test cycle may begin.

B. 10% of the start and load tests will be performed from design hot equilibrium temperature conditions. The engine-generator set will be operated at 100% load for eight (8) hours to establish the required equilibrium condition. The engine will then be shut down.

   The engine will be started and loaded within limits outlined in (A) above. After verification that jacket

water and lube oil temperatures are within the required limits, the engine will then be shut down and the next test cycle may begin. If the engine is down for an extended period of time, the engine must be operated at 100% load to reestablish the design hot equilibrium temperature conditions.

Discussion

The test was started on August 25, 1978, and successfully completed on September 10, 1978 with a total of 303 starts.

Cooling the engine was accomplished with the engine running. To force cool the engine between starts, temporary valving was added to oil and jacket water piping to by-pass the oil and water thermostats.

During each official start and load test the thermostats were operative.

Starts No. 1 through 271 were cold starts.

Starts No. 272 through 303 were hot starts.

Before running the hot starts the engine was run for 8 hours at 100% load to establish the hot temperature conditions. During the 8-hour run the thermostats in the oil and water systems were operative.

Discussion of Starts Not Counted:

During the start and load tests the following starts were not counted because they resulted from shop facility equipment problems, operator error or from intermittent circuit operation of equipment which is by-passed when in the LOCA mode. This is in accordance with Regulatory Guide 1.108 paragraph B.2.e.2.

Between starts No. 14 and 15 a good start was made but not counted. A facility power failure in our shop caused a shutdown before the temperature stabilization run under load was completed.

Between starts No. 104 and 105 a good start was made but not counted because of an incomplete Visicorder chart. This was an operator mistake in running the Visicorder.

Between starts No. 165 and 166 a second start failure occurred with an incomplete sequence light indication on the engine panel. This was not counted as a failure as the problem was identified as the same as in the previous start failure.

Between starts No. 166 and 167 a good start was made but not counted because of an incomplete Visicorder chart. This was an operator mistake in running the Visicorder.

Between starts No. 215 and 216 a good start was made but not counted because of an operator mistake in setting up the shop facility switchgear for automatic operation. Only two steps of the three step loading came on resulting in low load during the temperature stabilization run.

During start No. 238 and through the remaining starts the voltage trace on the Visicorder chart does not appear. This is because of a failure in the recording equipment which has no effect on the engine-generator set operation.

Between starts No. 251 and 252 a good start was made but not counted because of an operator mistake in adjusting the water rheostats for the proper load. The load was too light.

<u>Investigation of Circuitry Problems:</u>

In accordance with Regulatory Guide 1.108, the following tests were made to pinpoint problem circuitry.

A. After the start failure between starts No. 155 and 156, five trial engine starts were made to see if the problem would repeat or if it was intermittent. They were all successful but were not counted because they were not continued through the loaded part of the official tests.

B. After the start failure between starts No. 165 and 166, the failures were judged to be an intermittent fiber optics component or a contact associated with 2-68B1 alarm shutdown by-pass timer and the following action taken to confirm that judgment.

   1. After all wire connections were checked for tightness, air to the engine was shut off and 32 starts simulated without starting the engine. All were good starts.

   2. Several trials were then made to show that the suspected fault would have caused the problem. This was done by removing the wire from contact 4 of 2-68B1 on some trial starts.

      1st Trial - DGS Mode - wire connected – good start.

      2nd Trial - DGS Mode - wire disconnected.

      3rd Trial - Incomplete sequence light came on

      4th Trial - and unit failed to start.

6th Trial - LOCA Mode - wire disconnected.

7th Trial - Incomplete sequence light came on and unit made a good start.

3. Instrumentation was added to the Visicorder to monitor 268B1 relay and the fiber optics components associated with this circuit in order to pinpoint the problem if any further shutdowns should occur. However, no more shutdowns occurred during the remainder of the start and load tests.

Prior to delivery to the site, the diesel generator sets are fully assembled at the supplier's factory, and each is subjected to the required factory production tests and break-in run. The following qualification tests are performed:

A. Load Capability Qualification

This test demonstrates the capability of the diesel generator set to carry the rated loads at rated power factor and to successfully reject rated load. One successful completion of the following test sequence is required:

1. Carry the continuous rated load after the time required to reach engine temperature equilibrium

2. Carry the rated short-time load for an additional 2 hours following step 1

3. Reduce load to the continuous rating. Reject continuous rated load

B. Margin Qualification

This test demonstrates the diesel generator set capability to start and carry loads that are greater than the most severe step load change within the plant design loading sequence. Two margin tests are performed using an inductive type load at least 10% greater than the most severe single inductive type step load. The margin qualification test demonstrates the following:

1. That there is sufficient engine torque available to prevent engine stall and to permit the engine speed to recover when experiencing the most severe load requirement

2. That the generator and excitation system can accept the most severe electrical inductive load without experiencing an instability that could lead to generator voltage collapse

8.3.1.1.4.12 Operation and Maintenance Program. The emergency diesel generators are operated by shift managers, control room supervisors, and Nuclear Auxiliary operators. Maintenance of these units is supervised by the section leaders and department leaders under the maintenance director. Actual maintenance is performed by plant mechanics, plant electricians, and plant instrumentation and control technicians. The level of education and minimum experience requirements for these positions are given in amended paragraph 13.1.3.1.

The emergency diesel generator operator and maintenance training program is described in amended paragraph 13.2.1. Maintenance operating and surveillance procedures for the emergency diesel generator specify the minimum qualification of personnel required to perform specific portions of these procedures. These qualifications are based on experience and the completion of specific training. Because appropriately qualified persons will be specified to operate, maintain, and test the emergency diesel generators, dedicated operators and maintenance persons are not assigned.

The design specification for the diesel generator requires that the diesel must be capable of operating at no-load for 1 hour without deterioration of the engine, generator or auxiliaries. The Palo Verde operating and surveillance procedures for the emergency diesel generators include guidance regarding the manufacturer’s recommendations for loading and unloading. This guidance is intended to apply load gradually, provide some cooldown period and limit unloaded diesel generator operation. A Safety Injection Actuation Signal without a Loss of Power is the only postulated operating event that would allow the diesel generator to run unloaded for extended time intervals. While managing the SIAS event, Operations would strive to limit the time that the diesel generator was operated unloaded. After an operating event caused the diesel generator to run unloaded for greater than 6 hours, the diesel generator will be run loaded to at least 75% of its full load value for at least 15 minutes.

Maintenance procedures for the emergency diesel generators will require investigation and correction of causes of malfunctions and will require preventive maintenance procedures tailored to

monitor performance of components discovered to have highest failure rates.

Maintenance and surveillance procedures will include post-maintenance or surveillance restoration to operability, and, in the case of the emergency diesel generators, shall specify a final equipment check. When actions have been accomplished that could affect engine operability, maintenance and surveillance procedures will include a load test prior to declaring a generator operational.

Emergency diesel generator operating, maintenance, and surveillance procedures are available onsite.

8.3.1.1.5 Control Element Drive Mechanism Power Supply

Electric power to control element drive mechanisms is supplied by two motor-generator sets operating from two separate non-Class 1E, 480V load centers.

8.3.1.1.6 Vital Instrumentation and Control Power Supply

Four independent Class 1E, 120Vac vital instrumentation and control ac power supplies are provided to supply the four channels of the reactor protective and ESF actuation systems (see engineering drawings 01, 02, 03-E-PKA-001). The power supplies are designed to regulate the steady-state voltage within +/-2% at full power output for a load power factor of 0.8 at a frequency of 60 +/-0.5 Hz. The four-bus arrangement provides a single-phase, ungrounded, electric power to each of the four protection channels of the reactor protective system that is electrically and physically isolated from the other

protection channels. Each of the four channels of vital AC instrumentation and control power supply consists of one inverter rated at 25 kVA (20 kVA if DMWO 3232547 has been implemented), a transfer switch, a backup voltage regulator, and one distribution panel. Additionally, each of the two trains of vital AC instrumentation and control power supply contains a swing inverter and swing line-up switch, if implemented per DMWO 3232547.

Currently, PVNGS Units 2 and 3 have installed an automatic static transfer switch and PVNGS Unit 1 utilizes a manual transfer switch or static transfer switch if implemented per DMWO 3232547. Normally, each distribution panel is supplied by the inverter. Each inverter is supplied by a separate Class 1E 125 V-dc subsystem as described in subsection 8.3.2. If an inverter is inoperable, its output is outside the acceptable operating range, or it is to be removed from service for maintenance or testing, a backup supply is provided from a switch. Additionally, a swing inverter and swing line-up switch, if implemented per DMWO 3232547, may be aligned as a class 1E vital supply, as well. Busing arrangements are shown in engineering drawings 01, 02, 03-E-PKA-001 and system loads are listed in table 8.3-4.

Identification of equipment, raceway, and cabling associated with the vital ac instrumentation and control power supply is as described in paragraph 8.3.1.3.

There is no manual or automatic transfer between the buses. No connection exists between the independent supplies.

There is no provision for automatic loading or load shedding of the buses.

Inverter trouble and bus undervoltage are annunciated in the control room.

In addition to the four inverter power supplies, two additional 480 volt, three-phase inverters from channel C and D batteries supply dedicated power to the shutdown cooling motor-operated valves.

8.3.1.1.7 Nonvital AC Instrumentation and Control Power Supply

The 120V nonvital ac instrumentation and control power supply furnishes power to non-Class 1E instrumentation and controls. The supply consists of four normal supply voltage regulators, four backup supply voltage regulators, auto and manual transfer switches between the supplies, and four distribution panels.

The four distribution panels are normally aligned with the normal supply voltage regulators. These voltage regulators are

Table 8.3-4
120 V-AC VITAL POWER SYSTEM LOADS (Sheet 1 of 3)

Channel A (E-PNA-D25)
DAFAS A Cabinets and inputs
NSSS ESFAS auxiliary relay cabinet
NSSS process protective instrument cabinet and indicators
Supplementary protection logic cabinet
Remote shutdown panel
BOP analog instrument cabinet and indicators
Auxiliary protective cabinet
Plant protection system
BOP ESFAS and load sequencer
Main control room control board
MOV position indicators at auxiliary relay cabinet
ESFAS digital radiation monitoring system (RU-29, RU-31 and RU-37)
Safety injection system level transmitter (containment bldg. water level)
Radiation monitoring system (cabinets and RU-33, RU-148 and RU-150)
QSPDS cabinet
Position transmitter on ADVs 179 and 184
Channel B (E-PNB-D26)
DAFAS B Cabinets and inputs
NSSS ESFAS auxiliary relay cabinet
NSSS process protective instrument cabinets and indicators
Supplementary protection logic cabinet
Remote shutdown panel
BOP analog instrument cabinet and indicators
Auxiliary protective cabinet
Plant protection system
BOP ESFAS and load sequencer
Main control room control board
MOV position indicators at auxiliary relay cabinet

Table 8.3-4
120 V-AC VITAL POWER SYSTEM LOADS (Sheet 2 of 3)

ESFAS digital radiation monitoring system (RU-30, RU-38 and RU-145)
Safety injection system level transmitter (containment bldg. water level)
Radiation monitoring system (Cabinets and RU-1, RU-34, RU-146, RU-149 and RU-151)
QSPDS cabinet
Position transmitter ADVs 178 and 185
Channel C (E-PNC-D27)
DAFAS Inputs
NSSS ESFAS auxiliary relay cabinet
NSSS process protective instrument cabinet and indicators
Supplementary protection logic cabinet
Three-phase inverter space heater
CEDMCS auxiliary cabinet
Auxiliary protective cabinet
Plant protection system
MOV position indicators at 125 V-dc control center
Single-phase inverter space heater, unless removed per DMWO 3232547
125V-dc control center E-PKC-M43 space heater
Shutdown cooling isolation valve position indication
QSPDS cabinet
Main control room control board
Channel D (E-PND-D28)
DAFAS Inputs
NSSS ESFAS auxiliary relay cabinet
NSSS process protective instrument cabinet and indicators
Supplementary protection logic cabinet
Three-phase inverter space heater
CEDMCS auxiliary cabinet
Auxiliary protective cabinet
Plant protection system
Main control room control board
125 V-dc control center E-PKD-M44 space heater

Table 8.3-4
120 V-AC VITAL POWER SYSTEM LOADS (Sheet 3 of 3)

MOV position indicators at 125 V-dc control center
Single-phase inverter space heater, unless removed per DMWO 3232547
Shutdown cooling isolation valve position indicator
QSPDS cabinet

Table 8.3-4a
120 V-AC UNGROUNDED NON-VITAL POWER SYSTEM LOADS

E-NNN-D11
RCS-2 and CVCS-2 Process Instrument J-ZJN-C01B and D
SIS/RCP-1 Process Instrument J-ZJN-C01F
NSSS Radiation Monitor Cabinet J-SQN-C02 (Process and Gas Stripper Eff. Rad. Mon., Reactor Power Cutback, S/U and Control Ch. 1)
BOP Analog Instrument Cabinet J-ZJN-C02B and D
BOP Analog Instrument Cabinet J-ZJN-C02F
Radwaste Instrument Cabinet J-ZRN-C01 and C02
CEDMCS (including core mimic)
NSSS Control System J-SFN-C03 (FWCS-1 and 2 and SBCS)
Reactor Trip Switchgear Current Monitor C
Loose Parts and Vibration Monitor
Gen. Pyrolysate Collector
CEAC Display
Generator Temperature Monitor (GTM) Processor and Scanner Cabinet
Diesel Generator Fuel Oil Storage Tank (DFOST) Level Transmitter and Switch
Unit Evacuation Command Unit PA's and Sirens
Nuclear Sampling System Control Panel
CPC Test Cart Receptacle
Downcomer and Economizer Control and Indication Power
Boric Acid Batch Tank Temp and HPSI Discharge Flow Instrument Indication
WRF Electrical Supply Meters and Trip
Control Board Indications
E-NNN-D12
RCS-1 and CVCS-1 Process Instrument J-ZJN-C01A and C
NSSS Radiation Monitor Cabinet J-SQN-C02 (M1CD Amp., CEA Display, S/U & Control Ch. 2)
CVCS-3 and SIS/RCP-2 Process Instrument J-ZJN-C01E and G
BOP Analog Instrument Cabinet J-ZJN-C02A and C and -C07
BOP Analog Instrument Cabinet J-ZJN-C02E and G
Fuel Pool Instrumentation J-PCN-E02
CEDMCS
NSSS Control System J-SFN-C03 (RRS, SBCS permissives, and AMI setpoint display)
Reactor Trip Switchgear Current Monitor D
Control Board Indications
Diesel Generator Fuel Oil Storage Tank (DFOST) Level Transmitter and Switch
CPC Test Receptacle
Radio System Phone Lights for Control Room, STSC, and Remote Shutdown Panel

non-Class 1E and are supplied by non-Class 1E power. Two are grounded and two are ungrounded.

The backup supply for the distribution panels for each unit consists of four voltage regulators (two non-Class 1E and grounded and two Class 1E and ungrounded. Each backup regulator has the capability of being supplied by the diesel. Power to the two grounded voltage regulators is tripped on an SIAS signal and can be reestablished manually after the sequential loading of the diesel generator (except for one regulator in unit three which is automatically loaded onto the Diesel Generator during a LOCA/LOP).

8.3.1.1.8 Electric Equipment Layout

The following are the general features of the electrical equipment layout:

A. Class 1E switchgear, load centers, and motor control centers of redundant load groups are located in separate rooms of the control building or the auxiliary building. Separate ventilation systems are used for the two switchgear rooms supplied from the appropriate load group.

B. Class 1E battery supplies are located in the control building. Each battery is located in a separate room, and each room is equipped with a separate ventilation system.

C. Two cable spreading rooms are provided -- one above and one below the control room. This enhances redundant cable separation. Channel A and C cables

are fed from above and channels B and D are fed from below.

D. Redundant diesel generators and associated equipment are located in separate rooms of the Seismic Category I diesel generator building.

E. The normal battery chargers, normal inverters, DC buses, AC distribution panels and line voltage regulators associated with each of the four channels of the reactor protective and ESF actuation subsystems are located in separate equipment rooms (A, B, C and D). The train (A and B) backup battery chargers are located in the A and B equipment rooms respectively. The train (A and B) swing inverter and swing line-up switches, if implemented per DMWO 3232547, are located in the C and D equipment rooms respectively.

Refer to engineering drawings 13-P-OOB-002, 13-P-OOB-003, 13-P-OOB-004 and 13-P-OOB-005 for the location of electrical equipment and main cable routes to the Class 1E switchgear, load centers, and motor control centers.

8.3.1.1.9 Design Criteria for Class 1E Equipment

Design criteria and bases for the Class 1E equipment are:

A. Motor Size

Motor size (horsepower capability) is equal to or greater than the maximum horsepower required by the driven load under normal running, runout, or discharge valve (or damper) closed condition.

B. Motor Starting Torque

The motor starting torque is capable of starting and accelerating the connected load to normal speed within sufficient time to perform its safety function for all expected operating conditions, including the design minimum terminal voltage.

C. Motor Insulation

Insulation systems are selected on the basis of the particular ambient conditions to which the insulation is exposed. For Class 1 motors located within the containment, the insulation system is selected to withstand the postulated accident environment.

D. Minimum Motor Accelerating Voltage

The electrical system is designed such that the total voltage drop on the Class 1E motor circuits is not more than 25% of the nominal motor voltage during starting. The Class 1E motors are specified with accelerating capability at 75% nominal voltage at their terminals. If analysis based on as-built conditions indicates the lowest motor terminal voltage which may exist is greater than the specified 75%, then performance evaluations may be based on the as-built minimum voltage determined. If analysis based on as-built conditions indicates the lowest motor terminal voltage is less than 75%, additional evaluations will be performed to determine if its performance is acceptable.

E. Interrupting Capacities

The interrupting capacities of the protective equipment are determined as follows:

1. Switchgear

   Switchgear interrupting capacities are greater than the maximum short circuit current available at the point of application. The magnitude of short circuit currents in high-voltage systems is determined in accordance with ANSI C37.010, 1972. The power system, diesel generator, and running motor contributions are considered in determining the fault level. High-voltage power circuit breaker interrupting capacity ratings are selected in accordance with ANSI C37.06.

2. Load Centers, Motor Control Centers, and Distribution Panels

   Load center, motor control center, and distribution panel interrupting capacities are greater than the maximum short circuit current available at the point of application. The magnitude of short circuit currents in low-voltage systems is determined in accordance with ANSI C37.13-1973, and NEMA AB1. Low-voltage power circuit breaker interrupting capacity ratings are selected in accordance with ANSI C37.16-1973. Molded-case circuit breaker interrupting capacities are determined in accordance with NEMA AB1.

F. Electric Circuit Protection

Refer to paragraph 8.3.1.1.3.13 for criteria regarding the electric circuit protection.

G. Grounding Requirements

Equipment and system grounding are designed in accordance with IEEE 80 and IEEE 142.

8.3.1.1.10 Alternate AC Power System

10 CFR Part 50.63 requires that each light water-cooled nuclear power plant be able to withstand and recover from a station blackout (SBO) of a specified duration.

The SBO 16 hour copying evaluation was submitted to the NRC in APS letter 102-05370, dated October 28, 2005. Supplemental information was provided in APS letter 102-05465, dated April 19, 2006. The NRC approved the 16-hour SBO coping evaluation in a Safety Evaluation dated October 31, 2006.

The 16 hour coping strategy analysis assumes that one of the two Station Blackout Generators (SBOG), which serves as the Alternate AC (AAC) for PVNGS, is started and loaded to E-NAN-S03 for the respective Unit during the first hour to allow the analyzed SBO loads to be powered in accordance with administrative or emergency procedures.

Should a station blackout event (SBO) occur in any one unit, i.e., a loss of offsite power coincident with the unavailability of both emergency diesel generators in that unit, an alternate AC (AAC) power source is available to provide the power necessary to cope with a SBO for a minimum of

16 hours. The PVNGS response to a SBO has been developed in accordance with Regulatory Guide 1.155 (Table 1.8-4) and NUMARC 87-00. (See exceptions to Regulatory Guide 1.155 and NUMARC 87-00 in Section 1.8).

The non-safety related AAC power source consists of two 100 percent capacity, black start station blackout generators (SBOGs) that can be connected to each unit at switchgear E-NAN-S03 via the primary winding of the ESF transformer that is normally aligned to the train A 4.16kV bus as shown in engineering drawings 01, 02, 03-E-MAA-002. One SBOG is analyzed to supply all required station blackout loads, which are located on the A train. The AAC starting system and diesel fuel oil supply is independent from the black-out unit's power systems and fuel oil supply systems, however, switchgear E-NAN-S03 at each unit is dependent upon the unit's non-safety related 125V dc power system. This dc system is energized from the AAC power source to maintain its operability during the SBO event. Any inservice fuel oil storage tank associated with the SBOGs is maintained with sufficient fuel to support full load operation of the two SBOGs for 16 hours.

The AAC power system is not normally connected to the onsite power distribution system, therefore, failure of the AAC components cannot adversly affect the class 1E power systems.

The AAC power system is physically located and physically protected so that a likely event initiating a SBO will not also affect the AAC system. Connections from the SBOGs to the units are made via cables routed through underground duct banks.

Each SBOG has a minimum continuous output rating of 3400kW at 13.8kV under worst case anticipated site environmental conditions. This rating is sufficient to provide power to the loads identified as being important for coping with the SBO.

Starting and loading of the AAC power system is performed manually; no autostart or automatic loading capability is provided.

The AAC power system has been demonstrated by test as being capable of energizing the required loads within one hour after the onset of the SBO. A study has been performed that concludes that PVNGS is capable of coping with SBO for that initial one hour period. An ongoing inspection, maintenance, and periodic test program has been implemented for the AAC power system to demonstrate system operability and provide confidence that system reliability is maintained at or above 0.95 per demand.

The normal standby configuration of the SBOGs as well as the unit electrical configuration does not change when the SBOGs are used for Shutdown Cooling Operations. The use of the SBOGs during Shutdown Cooling Operations does not change the following:

1) The power configuration to the units.

2) The electrical fault protection associated with the SBOGs.

3) The manner in which power is supplied in the event of an SBO.

4) The manner in which the SBOGs are tested.

The systems required to cope with blackout conditions with the unit in Shutdown Cooling Operation are different than the required systems in Mode 3 (blackout condition initiating with the unit at power). Even though the systems are different, the KW and KVAR loading on the SBOGs is comparable.

8.3.1.2 Analysis

8.3.1.2.1 Failure Mode and Effects Analysis

A failure mode and effects analysis for the ESF ac and dc load groups is given in table 8.3-5. Table 8.3-5 shows that no single component failure will result in the simultaneous loss of ac power to both load groups. In accordance with single failure criteria, only one failure is assumed to occur in the system following a LOCA. Refer to figure 8.3-2.

8.3.1.2.2 Compliance with Design Criteria and Guides

The following analysis demonstrates compliance with General Design Criteria 17 and 18, Regulatory Guides 1.6, 1.9, 1.22, 1.29, 1.30, 1.32, 1.40, 1.41, 1.47, 1.53, 1.62, 1.63, 1.73, 1.75, 1.81, 1.89, 1.93, and IEEE Standards 308, 317, 323, 334, 344, 383, 384, and 387.

8.3.1.2.2.1 Criterion 17, Electric Power Systems. An onsite electric power system is provided to permit functioning of structure, systems, and components important to safety. With total loss of offsite power, the onsite power system provides sufficient capacity and capability to assure that:

A. Specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary

are not exceeded as a result of anticipated operational occurrences.

B. The core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

Refer to section 3.2 for a list of structures, systems, and components required to assure these requirements are met. Refer to table 8.3-1 for a list of the loads important to safety which are supplied from the onsite electric power supplies.

The onsite electric power system includes a two-load group Class 1E system. The two load groups are redundant in that each load group, independent of the other, is capable of assuring the requirements of paragraph 8.3.1.2.2.1, listings A, and B. Sufficient independence is provided between redundant load groups to ensure that the postulated single failures affect only a single load group to the extent of total loss of that load group. The redundant load group, however, remains intact.

In the case of loss of 4.16 kV bus voltage, the affected Class 1E load group is automatically isolated from the remaining portion of the onsite power system. Under frequency relays are provided to trip the diesel generator if abnormal conditions occur while the diesel generator is synchronized to the preferred power source during a test. Also, each load group of the Class 1E power system is automatically and inherently isolated from the redundant load group. The combination of these factors minimizes the probability of

losing electric power from the onsite power supplies as a result of the loss of power generated by the nuclear unit or loss of power from the transmission network.

The turbine-generator is automatically isolated from the switchyard following a generator trip by opening the generator switchyard circuit breakers. The loss of the turbine-generator does not affect the ability of either the transmission network or the onsite power supplies to provide power to the Class 1E system. Transmission network stability studies indicate that the trip of the most critical fully-loaded generating unit would not impair the ability of the system to supply plant station service. Refer to subsection 8.2.2.

Table 8.3-5

FAILURE MODE AND EFFECTS ANALYSIS[a] (Sheet 1 of 9)

Identification No.[b]	Component Name	Component Function	Failure Mode	Effect on Subsystem	Effect on System
1	Offsite power source (any line feeding startup transformer)	Supplies power to one ESF bus of two units	Loss of power	Loss of preferred power to one redundant bus of two units (PBS-S03 or PBB-S04)	No effect – Power to the redundant bus available through one of the other two lines feeding two other startup transformers (1A or 1C). In addition diesel generator provides standby power.
2	Startup transformer	Supplies power to one ESF bus of two units	Fails to provide power	Loss of preferred power to one redundant bus of two units (PBS-S03 or PBB-S04)	No effect - Power to the redundant bus is available through one of the other startup tran-formers feeding the redundant load group. In addition standby power available from diesel generator (12)
3	Circuit breaker (NC)	Supplies power to one ESF bus under normal condi-tions, and provides protec-tion under fault conditions	Fails open	Loss of preferred power to one redundant bus	No effect - Power to the redundant bus is available through breaker 3A. In addition diesel generator provides standby power.
4	Intermediate bus	Distributes power to one ESF load group	Fault	Loss of power to one load group	No effect - Power to the redundant load group is available through intermediate bus 4A
5	Circuit breaker (NC)	Supplies power to one ESF bus.	Fails open	Loss of preferred power to one redundant bus	No effect - Breaker 5A supplies power to the redundant load group. In addition diesel generator provides standby power.

a. The FMEA is performed for one channel or one train only.

b. Identification numbers are shown on figure 8.3-2.

Table 8.3-5

FAILURE MODE AND EFFECTS ANALYSIS[a] (Sheet 2 of 9)

Identification No.[b]	Component Name	Component Function	Failure Mode	Effect on Subsystem	Effect on System
6	Bus NAN-S03 or NAN-S04	Distributes power to one ESF bus	Fault	Loss of preferred power to one redundant load group	No effect - Bus 6A is available to supply power to the redundant load group.
7	Breaker NC	Supplies power to one ESF bus	Fails open	Loss of preferred power to one redundant load group	No effect - Breaker 7A of the redundant switch-gear supplies power to the redundant load group. In addition diesel generator provides stand-by power.
8	ESF service transformer	Supplies power to one ESF bus.	Fails to provide power	Loss of power to one ESF bus	No effect - ESF transformer 8A provides power to the redundant load group.
9	Main breaker (NC)	Provides protection to ESF bus during normal operation.	Fails open	Loss of preferred power to one bus	No effect - Redundant bus (9A) is available to supply power to its ESF load group. In addition diesel generator provides standby power.
10	4.16 ESF switchgear	Distributes power to all ESF loads of one load group	Fault	Loss of power to one load group.	No effect - Redundant bus 10A provides power to its ESF load group.
11	Diesel generator breaker (NO)	Closes to connect diesel generator to the bus	Fails to close	Loss of emergency power to one of the load groups	No effect - Redundant diesel generator supplies power to its load group through breaker 11A

Table 8.3-5

FAILURE MODE AND EFFECTS ANALYSIS[a] (Sheet 3 of 9)

Identification No.[b]	Component Name	Component Function	Failure Mode	Effect on Subsystem	Effect on System
			Fails open	Loss of emergency power to one of the load group.	No effect - Redundant diesel generator supplies power to its load group through breaker 11A
			Closes on spurious signal	Loss of diesel generator, hence loss of emergency power to one of the load groups.	No effect - Redundant diesel generator supplies power to its load group through breaker 11A
12	Diesel generator	Provides standby power to ESF bus (PBA-S03 or PBB-S04)	No output	Loss of emergency power to the one ESF bus.	No effect - Redundant diesel generator 12A supplies power to the redundant load group.
13	Circuit breaker (NC)	Provides protection to 4.16 kV bus and provides power to the load center transformer	Fails opens	Loss of power to some 480 volt ESF loads of one load group	No effect - Redundant circuit breaker 13A of the redundant load group provides power to its loads.
14	Load center transformer	Provides power at 480 volts to ESF loads.	Fails to provide power	Loss of power to some 480 volt ESF loads of one load group	No effect - Redundant circuit breaker 14A of the redundant load group provides power to its loads.
15	Load center main feeder breaker	Provides protection to 480 volt bus.	Fails open	Loss of power to some 480 volt ESF loads of one load group	No effect - Redundant circuit breaker 15A of the redundant load group provides power to its loads.

Table 8.3-5

FAILURE MODE AND EFFECTS ANALYSIS[a] (Sheet 4 of 9)

Identification No.[b]	Component Name	Component Function	Failure Mode	Effect on Subsystem	Effect on System
16	Load center bus	Distributes power to 480 volt loads.	Fault	Loss of 480 volt power to loads connected to the bus.	No effect - Redundant load center 16A supplies power to its loads.
17	Load center feeder to a third of a kind load (NC)	Provides protection to the bus in case of a fault	Fails open	Loss of power to the charging pump motor	No effect - The third charging pump motor is not required to perform a safety function.
18	MCC feeder breaker (NC)	Provides protection to the bus in case of a fault	Fails open	Loss of power to some MCC loads	No effect - The corresponding MCC of the redundant load group 18A provides power to its loads.
19	MCC bus	Distributes power to MCC loads	Fault	Loss of power to one MCC	No effect - The corresponding MCC of the redundant load group (19A) provides power to its loads.
20	Third of a kind transfer switch	Transfers power from one redundant power source to the other	Fails open	Loss of power to the third charging pump	No effect - The third charging pump motor is not required to perform a safety function.
			Fault in the transfer switch	Loss of third charging pump motor	No effect - No breaker is available in breaker space 17A to affect the redundant switchgear

Table 8.3-5

FAILURE MODE AND EFFECTS ANALYSIS[a] (Sheet 5 of 9)

Identification No.[b]	Component Name	Component Function	Failure Mode	Effect on Subsystem	Effect on System
21	Feeder breaker to voltage regulator (NC)	Provides protection to the bus under fault conditions and provides power to the voltage regulator under normal conditions	Fails open	Loss of power to the voltage regulator	No effect - The voltage regulator is on standby basis in case of inverter failure.
22	Feeder breaker to battery charger (NC)	Provides protection to the bus under fault conditions and provides power to the battery charger under normal conditions	Fails open	Loss of power to one battery charger.	No effect - The battery provides power to the dc bus. In addition the standby battery charger can be connected to the dc bus.
23	Battery	Provides dc power to the bus	Fails to provide dc power	Loss of standby power to the bus	No effect - The batteries serve as the source of standby dc power to the bus. The charger provides the dc power under normal conditions
24	Battery charger	Provides dc power to the bus.	Fails to provide dc power	Loss of primary dc power.	No effect - The battery provides power to the bus and the standby charger can be connected to provide power for extended period of time.
			Impresses ac voltage on dc system	Malfunction of components in one channel.	No effect - Power is available to other three redundant channels. Potential instrument error (due to noise) on one channel. Other channel(s) available.

Table 8.3-5

FAILURE MODE AND EFFECTS ANALYSIS[a] (Sheet 6 of 9)

Identification No.[b]	Component Name	Component Function	Failure Mode	Effect on Subsystem	Effect on System
25	Battery circuit breaker	Provides protection to the battery under fault conditions and provides power to the bus under normal conditions.	Fails open	Loss of standby dc power	No effect - The battery provides standby power to the bus. The charger provides the dc power.
26	Battery charger circuit breaker (NC)	Provides protection to the charger under fault conditions and supplies power to the dc bus under normal conditions.	Fails open	Loss of dc power to the bus	No effect - The battery supplies power to the dc bus through its breaker. Standby battery charger breaker can be closed to supply power to the loads and battery.
27	DC bus	Distributes dc power to ESF loads	Fault	Loss of dc power to one channel	No effect - Power available to the other three redundant channels. No actuation of ESFAS system due to 2/4 logic.
28	Inverter feeder breaker (NC)	Provides protection to the dc bus under fault conditions and provides power to the inverter under normal conditions	Fails open	Loss of power to the inverter	No effect - Power can be provided to the vital instrumentation bus by means of regulated transformer through the transfer switch. No actuation of safety system source to the other three inverters is available (2/4 Logic).

Table 8.3-5

FAILURE MODE AND EFFECTS ANALYSIS[a] (Sheet 7 of 9)

Identification No.[b]	Component Name	Component Function	Failure Mode	Effect on Subsystem	Effect on System
29	Voltage regulator	Provides power to the vital instrumentation bus	Fails to provide power	Loss of standby ac power to the vital bus.	No effect - The voltage regulator provides standby power in case of loss of inverter power. Power to the vital bus is available through the inverter.
30	Single phase inverter	Provides precise power to vital instrumentation bus	Fails to provide power	Loss of power to one vital instrumentation channel	No effect - Power is available from voltage regulator through the transfer switch.
31	Transfer switch (Manual or Static)	Transfers power from the inverter to the voltage regulator source	Fails to transfer	Loss of power to one channel	No effect - The other three channels are provided with power from their respective inverters. No actuation of safety systems since the actuation logic is 2/4.
			Fails to conduct	Loss of power to one channel	No effect - The other three channels are provided with power from their respective inverters. No actuation of safety systems since the actuation logic is 2/4.
32	Vital instrumentation panel circuit breaker (NC)	Provides protection to the inverter in case of fault and provides power during normal conditions.	Fails open	Loss of power to the vital instrumentation bus.	No effect - Power is available to the other three redundant channels. No actuation of safety system due to 2/4 logic.

Table 8.3-5

FAILURE MODE AND EFFECTS ANALYSIS[a] (Sheet 8 of 9)

Identification No.[b]	Component Name	Component Function	Failure Mode	Effect on Subsystem	Effect on System
33	Vital instrument bus	Distributes power to the vital instrumentation loads.	Fault	Loss of power to the vital instrument loads.	No effect - The other three channels distribute power to their redundant loads. No actuation of safety systems due to 2/4 logic.
34	Three phase inverter feeder breaker (NC)	Provides power to the three phase inverter	Fails open	Loss of power to the shutdown cooling valve.	No effect - There are three other redundant shutdown cooling valves fed from their respective channels (2 of them from MCC channels A & B). No actuation of safety systems due to 2/4 logic.
35	Three phase inverter	Provides power to the shutdown cooling valves.	Fails to provide power	Loss of power to the shutdown cooling valve	No effect - (see item 34)
36	Manual Swing Line-up Switch (when energizing swing inverter)	Aligns swing inverter to one of two channels of DC power, one of two voltage regulators and one of two train inverters	Fails to operate	Failure to align or isolate swing inverter	No effect – Power available from voltage regulator through the normal static transfer switch
			Fault in the switch	Loss of swing inverter and loss of power to the vital instrumentation bus	No effect – Power is available to the other three redundant channels. No actuation of safety system due to 2/4 logic.

Table 8.3-5

FAILURE MODE AND EFFECTS ANALYSIS[a] (Sheet 9 of 9)

37	Manual Bypass Switch (when in Bypass to Load position)	Aligns swing inverter to 120Vac vital bus via one of two train inverters	Fails to operate	Failure to align swing inverter to train inverter	No effect - Power available from voltage regulator through the normal static transfer switch
			Fault in the switch	Loss of power to the vital instrumentation bus	No effect - Power is available to the other three redundant channels. No actuation of safety system due to 2/4 logic.

8.3.1.2.2.2 Criterion 18, Inspection and Testing of Electrical Power Systems. The Class 1E system is designed to permit:

A. Periodic inspection and testing, during equipment shutdown, of wiring, insulation, connections, and relays to assess the continuity of the systems and the condition of components.

B. Periodic testing, during normal plant operation, of the operability and functional performance of onsite power supplies, circuit breakers, and associated control circuits, relays, and buses.

C. Testing, during plant shutdown, of the operability of the Class 1E system as a whole. Under conditions as close to design as practical, the full operation sequence that brings the system into operation, including operation of signals of the ESF actuation system and the transfer of power between the offsite and the onsite power system, will be tested.

D. The following switchyard systems and components have been tested and are periodically inspected and maintained as required by 10CFR50, Appendix A, Criterion 18.

   1. Systems

      a. The offsite power system (in the transfer of power among the units itself, and the onsite power system)

      b. The protection system

2. Components (including areas and features)

   a. Wiring

   b. Insulation

   c. Connections

   d. Switchboards

   e. Onsite power sources

   f. Relays

   g. Switches

   h. Buses

   The inspection and maintenance frequencies vary, depending on system and component history at Palo Verde and at other locations.

8.3.1.2.2.3 Regulatory Guide 1.6, Independence Between Redundant Standby (Onsite) Power Supplies and Between Their Distribution Systems. The Class 1E system is divided into redundant load groups so that loss of any one group does not prevent the minimum safety functions from being performed. Refer to engineering drawing 01, 02, 03-E-MAA-002. The requirements of Regulatory Guide 1.6 are met as discussed in this paragraph.

Each ac load group has connections to two preferred (offsite) power supplies and to a single diesel generator. Each diesel generator is normally connected to a single 4.16 kV load group.

The two ac load groups each incorporate a Class 1E dc power train. Each Class 1E dc power train consists of two Class 1E

dc power channels. Each Class 1E dc power channel is energized by one battery and one battery charger. The battery is exclusively associated with a single 125 V-dc bus and each battery charger is supplied by its respective ac load group. A third, redundant battery charger is also provided which can provide power to either of the two Class 1E dc power channels within the respective ac load group, but not simultaneously.

The diesel generator of one load group cannot be automatically or manually paralleled with the diesel generator of the redundant load group.

No provisions exist for connecting one load group to the redundant load group when operating from both diesel generators. However, there are provisions for connecting both load groups to a single diesel generator during emergency conditions.

No provisions exist for automatically transferring loads between redundant onsite power supplies. When "maintenance spare" equipment is used, it is connected to either load group manually.

8.3.1.2.2.4 Regulatory Guide 1.9, Selection of Diesel Generator Set Capacity for Standby Power Supplies. The continuous rating of each diesel generator is greater than the sum of the conservatively estimated loads needed to be supplied following any design basis event. See tables 8.3-1 and 8.3-3 for loading requirements.

The diesel generators conform to Regulatory Guide 1.9, Rev. 3 with the exceptions discussed in section 1.8.

8.3.1.2.2.5 Regulatory Guide 1.22, Periodic Testing of Protection System Actuation Functions. The requirements of Regulatory Guide 1.22 are met. Refer to paragraph 8.3.1.1.3.14 for compliance of the Class 1E electric system with Regulatory Guide 1.22.

8.3.1.2.2.6 Regulatory Guide 1.29, Seismic Design Classification. The requirements of Regulatory Guide 1.29 are met. The Class 1E electric system and the auxiliary systems for the diesel generators are designed to withstand the effects of the SSE. Seismic qualification of Class 1E electric equipment is discussed in section 3.10.

8.3.1.2.2.7 Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment. Comparison of the design with the recommendations of Regulatory Guide 1.30 is discussed in section 1.8.

8.3.1.2.2.8 Regulatory Guide 1.32, Use of IEEE Standard 308-1971. The requirements of Regulatory Guide 1.32 are met with the clarifications discussed in section 1.8.

8.3.1.2.2.9 Regulatory Guide 1.40, Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants. There are no Class 1E continuous-duty motors installed inside the containment at PVNGS.

8.3.1.2.2.10 Regulatory Guide 1.41, Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments. The requirements of Regulatory Guide 1.41 are met. The Class 1E onsite electric power systems, designed in accordance with Regulatory Guides 1.6 and 1.32, are tested as part of the preoperational testing program and also after major modifications. The tests are performed in accordance with the procedures outlined in section 14.2.

8.3.1.2.2.11 Regulatory Guide 1.47, Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems. Comparison of the design with the recommendations of Regulatory Guide 1.47 is discussed in section 7.5.

8.3.1.2.2.12 Regulatory Guide 1.53, Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems. Comparison of the design with the recommendations of Regulatory Guide 1.53 is discussed in subsection 7.1.2.

8.3.1.2.2.13 Regulatory Guide 1.62, Manual Initiation of Protective Actions. Comparison of the design with the recommendations of Regulatory Guide 1.62 is discussed in subsection 7.1.2 and section 7.3.

8.3.1.2.2.14 Regulatory Guide 1.63, Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants. The electric penetration assemblies are described in paragraph 8.3.1.2.2.21 and conform to IEEE 317-1976 and Regulatory Guide 1.63 with the exceptions discussed in section 1.8.

8.3.1.2.2.15 Regulatory Guide 1.73, Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants. Refer to section 3.11 for compliance with Regulatory Guide 1.73.

8.3.1.2.2.16 Regulatory Guide 1.75, Physical Independence of Electric Systems. The separation of electrical equipment and circuits and physical independence of electric systems meets the requirements of IEEE 384-1974 and Regulatory Guide 1.75 with the clarifications and exceptions discussed in section 1.8.

8.3.1.2.2.17 Regulatory Guide 1.81, Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants. The requirements of Regulatory Guide 1.81 are met. Each unit has separate and independent onsite ac and dc electric systems capable of supplying minimum ESF loads and loads required for attaining a safe and orderly cold shutdown of the unit assuming a single failure and loss of offsite power. No emergency and shutdown electric systems are shared between units.

8.3.1.2.2.18 Regulatory Guide 1.89, Revision 1, Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants. Regulatory Guide 1.89, Rev. 1, endorses IEEE Standard 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations. Comparison of the design with the recommendations of Regulatory Guide 1.89, Revision 1, is discussed in section 1.8.

8.3.1.2.2.19 Regulatory Guide 1.93, Availability of Electric Power Sources. The position of Regulatory Guide 1.93 is accepted (refer to the Technical Specifications Bases).

8.3.1.2.2.20 IEEE 308-1974, IEEE Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations. The Class 1E ac power systems are designed to assure that any design basis event, as listed in Table 1 of IEEE 308, does not cause the following:

A. A loss of electric power to more than one load group, surveillance devices, or protection system devices sufficient to jeopardize the safety of the unit.

B. A loss of electric power to equipment that could result in a reactor power transient capable of causing significant damage to the fuel or to the reactor coolant system.

The Class 1E system is capable of performing its function when subjected to the effects of any of the design basis events.

The Class 1E loads are designed to perform their functions adequately for the design variations of voltage and frequency in the Class 1E systems.

Controls and indicators for the Class 1E, 4.16 kV bus supply breakers are provided in the control room and on the switchgear. Controls and indicators for the standby diesel generator power supplies are provided in the control room and in the diesel generator control rooms.

Class 1E equipment and associated design, operating, and maintenance documents are distinctly identified as described in paragraph 8.3.1.3.

Each type of Class 1E equipment is qualified either by analysis, by successful use under similar conditions, by actual test or by a combination of analysis and test to demonstrate its ability to perform its function under applicable design basis events.

Supplementary design criteria of IEEE 308 are addressed in the applicable sections describing specific Class 1E equipment.

The surveillance requirements of IEEE 308 are followed in the design, installation, and operation of Class 1E systems. Pre-operational tests are performed in accordance with the procedures described in section 14.2. Periodic equipment tests are performed as discussed in the Technical Specifications.

With regard to Section 7 of IEEE 308, refer to the Technical Specifications for operating alternatives under degraded Class 1E ac system conditions

With regard to Section 8 of IEEE 308, the following applies:

A. The preferred power supply has the capacity to operate the ESF on one unit and those ESF systems required for concurrent safe shutdown on the other units.

B. The Class 1E battery supplies are not shared by the units.

8.3.1.2.2.21 IEEE 317-1976, IEEE Standard for Electric Penetration Assemblies in Containment Structures for Nuclear-Fueled Power Generating Stations. Electric penetration assemblies are used for all electric cables that pass through the containment exterior wall. These assemblies are designed and tested in accordance with IEEE Standard 317-1976.

Principal design criteria for these assemblies include the following:

A. The mechanical design, materials, fabrication, inspection and testing of the pressure-retaining boundary of the electric penetration assembly, excluding electric compounds and gaskets, are in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Subsection NE, for Class MC components.

B. Electric penetration assemblies are designed to meet electrical requirements for the specified service environment without dielectric breakdown or overheating.

C. The electric penetration assembly is designed to have a total gas leakage rate through its pressure-retaining boundary, exclusive of the aperture seal, not greater than 1×10^{-6} standard cubic centimeters per second[a] of dry helium (or equivalent means of measurement) at the maximum specified containment design temperature and pressure as defined in subsection 6.2.1.

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a. 20C at one atmosphere of pressure.

D. A leak test shall be performed on each penetration assembly as discussed in section 14.2.

E. The design and installation is such as to facilitate periodic individual penetration assembly gas leak rate testing after installation, including both aperture and conductor seals.

F. The penetration assembly design is qualified for the intended service within the service environment by testing and analysis.

G. DC circuits utilizing penetrations are of the low voltage control type. These circuits are self-limiting in that the circuit resistance limits the fault current to a level that does not damage the penetration.

H. PVNGS periodically tests the primary and secondary protective devices.

8.3.1.2.2.22 IEEE 323-1974, Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations. The qualification methods and documentation requirements of IEEE 323 are followed to the extent discussed in section 1.8 for Class 1E electric equipment in the Bechtel scope of supply. Qualification consists of:

A. All Class 1E BOP safety-related instrumentation, control, and electrical equipment and its associated design, operating, and maintenance documents are identified.

B. Specifications reflecting the requirements of these documents are prepared.

C. Type tests, operating experience, analysis, a combination of these, or ongoing qualification are used to demonstrate the capability of equipment meeting performance specifications under the service conditions.

D. Documentation is prepared in a manner that permits an independent evaluation of the qualification methods.

8.3.1.2.2.23 IEEE 334-1971, Type Tests of Continuous-Duty Class 1 Motors Installed Inside the Containment of Nuclear Power Generating Stations. There are no Class 1E continuous-duty motors installed inside the PVNGS containment.

8.3.1.2.2.24 IEEE 344-1975, Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations. Seismic qualification of Class 1E electric equipment and the extent of compliance with IEEE 344 are discussed in section 3.10.

8.3.1.2.2.25 IEEE 383-1974, Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generation Stations. Class 1E cable, field splices, and connections are in accordance with IEEE 383-1974 requirements.

Cable assemblies for the reed switch position transmitters and fixed incore system are in accordance with IEEE 383-1974 except that following environmental qualification testing they were

tested at 750 volts ac for 5 minutes while immersed in water at room temperature. This value meets the system requirements.

8.3.1.2.2.26 IEEE 384-1974, Criteria for Separation of Class 1E Equipment and Circuits. Refer to paragraph 8.3.1.4 for compliance. Also refer to appendix 8A, Question 8A.10 response.

8.3.1.2.2.27 IEEE 387-1977, Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations.

A. Service Environment

Diesel engine cooling and building ventilation equipment is provided to maintain an acceptable environment within the diesel generator rooms during and after any design basis event even without support from the preferred power supply.

B. Starting and Loading

The diesel generator is capable of starting, accelerating, and accepting load as described in paragraph 8.3.1.1.3. The diesel generator automatic loading will be in accordance with Section 5.1.2(2) of IEEE 387.

C. Quality of Power

Refer to paragraphs 8.3.1.2.2.4 and 8.3.2.2.1 for frequency and voltage limits.

D. Ratings

Refer to paragraphs 8.3.1.2.2.4 and 8.3.2.2.1 for the basis of the continuous rating of the diesel generator.

E. Interactions

Refer to paragraphs 8.3.1.2.2.4 and 8.3.2.2.1 for assurance that independence is provided between the redundant Class 1E ac load groups. Mechanical and electric systems are designed so that a single failure affects the operation of only a single diesel generator.

F. Design and Application Considerations

Design conditions such as vibration, torsional vibration, and overspeed are considered in accordance with the requirements of IEEE 387.

G. Governor and Voltage Regulator Operation

The diesel can operate in the droop mode and the voltage regulator can operate in the paralleled mode during diesel generator testing. If an underfrequency condition occurs while the diesel generator is paralleled with the preferred (offsite) power supply (testing mode), the diesel generator will trip. If an SIAS signal is received while the diesel generator is being tested, the governor and voltage are automatically restored to the isochronous mode and the diesel generator breaker is automatically tripped.

Refer to figure 8.3-1 for the diesel generator logic diagram.

H. Control

Each diesel generator is provided with control systems permitting automatic and manual control. The automatic start signal is functional except when the diesel generator is in the maintenance mode. Provision is made for controlling the diesel generator from the control room and from the diesel generator room. Refer to paragraph 8.3.1.1.4.10 for further description of the control systems.

I. Surveillance

Voltage, current, frequency, and output power metering are provided in the control room to permit assessment of the operating condition of each diesel generator.

Surveillance instrumentation is provided in accordance with IEEE 387.

J. Testing

Tests as listed in paragraph 8.3.1.1.4.7 are conducted on each diesel generator in accordance with IEEE 387.

8.3.1.3 Physical Identification of Safety-Related Equipment

Each circuit and raceway is given a unique alphanumeric identification. This identification provides a means of distinguishing a circuit or raceway associated with a particular voltage or function as well as with a particular channel or load group. The identification contains the

appropriate separation group letter and is assigned on the basis of the following criteria:

Separation Group A

A Class 1E instrumentation, control, or power cable, raceway, or equipment associated with load group 1, dc subsystem A, or vital ac instrumentation and control channel A.

Separation Group B

A Class 1E instrumentation, control, or power cable, raceway, or equipment associated with load group 2, dc subsystem B, or vital ac instrumentation and control channel B.

Separation Group C

A Class 1E instrumentation, control, or power cable, raceway, or equipment associated with vital ac instrumentation and control channel C and dc subsystem C.

Separation Group D

A Class 1E instrumentation, control, or power cable, raceway, or equipment associated with vital ac instrumentation and control channel D and dc subsystem D.

Separation groups A through D are color-coded as follows:

Group A: Red

Group B: Green

Group C: Yellow

Group D: Blue

All equipment is provided with a tag number that includes the applicable separation group identification. Nameplates of color background are provided for all Class 1E cabinets.

Class 1E raceways are identified at the ends with colored nameplate stickers or stenciled markings, and along their lengths by colored diamonds or dots of separation group designation at intervals not exceeding 15 feet.

Identification is provided for safety-related field cables by color coding along the cable. Cable markers with the separation group identification are provided at each end of each cable.

Associated circuit cables are uniquely identified per section 1.8 and paragraph 7.1.3.16. In addition, interconnecting cables between the safety equipment status system (SESS) logic cabinet and the SESS status panels on the main control boards are uniquely identified as associated cables in accordance with section 1.8 and paragraph 7.1.3.16.

Power cable for the standby third-of-a-kind components is Class 1E with black jacket and is routed in conduit. This cable and conduit are assigned a separation group E identifier only for the purpose of indicating the unique separation group condition and are marked with the impacted separation group assigned color-codes (see subsection 8.3.14.3). The "E" charging pump cable and conduit are marked with red and green stripes to identify the connections to A or B redundant train power supplies. The swing inverter and swing line-up switch

cable and conduit, if implemented per DMWO 3232547, are marked to identify the connections to their independent power supplies with red and yellow stripes for A or C, respectively, and green and blue stripes for B or D, respectively.

Within control panels where more than one separation group is present, field wiring is identified by separation group color code, or, if enclosed by conduit, the conduit is identified by separation group designation and color code.

Within a cabinet or panel that is associated and identified with a single separation group, the internal wiring is exclusively associated with the same separation group, and, therefore, requires no further identification.

Design drawings provide distinct identification of Class 1E equipment. The applicable channel or load group designation is also identified.

8.3.1.4 Independence of Redundant Systems

8.3.1.4.1 Separation Criteria

This paragraph establishes the criteria and their bases for the physical separation of Class 1E circuits in preserving the independence of redundant circuits in accordance with R.G. 1.75, Rev. 1 (IEEE 384-1974).

8.3.1.4.1.1 Raceway and Cable Routing. Raceway configuration, cable routing, and barrier installation within the plant adheres to the following practices to minimize a fire in one separation group from propagating to another separation group:

A. Wherever possible, cable trays are arranged from top to bottom, with trays containing the highest voltage cables at the top and trays containing the lowest voltage cables at the bottom. Raceways are grouped by voltage levels: Medium voltage, Power and Control, Instrumentation and Communication. Individual raceways contain cables of similar voltage levels. Voltage levels are listed below:

   1. Higher medium voltage, 13.8KV (non-Class 1E only)
   2. Lower medium voltage, 4.16KV
   3. 480V load center power
   4. 480 MCC & DC power & control
   5. 120V Control and digital
   6. Instrumentation
   7. Communications

B. Cables associated with each separation group, as defined in paragraph 8.3.1.3 are run in separate conduits, cable trays, ducts, or penetrations.

C. In areas of the plant where the only source of fire is electrical and without a confirming analyses to support less stringent requirements, the following general requirements are applicable:

   1. In areas other than the main control or cable spreading rooms, Class 1E cable trays of different separation groups have a minimum:

a. Horizontal separation distance of 3 feet if no damage limiting barrier exists between redundant trays (raceways).

   In configurations where the 3 foot horizontal separation in unattainable, 1 inch minimum separation is acceptable provided redundant circuits are:

   - Contained within an enclosed raceway (i.e., conduit, tray with both solid top and bottom, or wireway, etc.),
   - Encircled within a damage limiting barrier material,
   - Separated by a damage limiting barrier extending at least 1 foot above the top of the tray (or to the ceiling) and 1 foot below the bottom of the tray (or to the floor), or,
   - A combination of the above.

b. Vertical separation distance of 5 feet if no damaging limiting barrier exists between redundant trays (raceways).

   In configurations where the 5 foot vertical separation is unattainable, 1 inch minimum separation is acceptable provided redundant circuits are:

- Contained within an enclosed raceway (i.e., conduit, tray with both solid top and bottom, wireway, etc.),
- Separated by solid bottoms on upper tray and solid tops on lower tray,
- Encircled within a damage limiting barrier material,
- Separated by a damage limiting barrier extending at least 1 foot beyond the area of unattainable separation (including tray rails), or
- A combination of the above.

2. In the main control or cable spreading rooms, cable trays of different separation groups have a minimum:

   a. Horizontal separation distance of 1 foot if no damage limiting barrier exists between redundant trays (raceways).

      In configurations where the 1 foot horizontal separation is unattainable, 1 inch minimum separation is acceptable provided redundant circuits are:

      - Contained within enclosed raceway,
      - Encircled within a damage limiting barrier material,
      - Separated by a damage limiting barrier extending at least 1 foot above the top of

the tray (or to the ceiling)and 1 foot below the bottom of the tray (or to the floor), or,

- A combination of the above.

b. Vertical separation distance of 3 feet if no damage limiting barrier exists between redundant trays (raceways).

In configurations where 3-foot vertical separation is unattainable, 1-inch minimum separation is acceptable provided redundant circuits are:

- Contained within enclosed raceway,
- Separated by solid bottoms on upper tray and solid tops of lower tray,
- Encircled within a damage limiting barrier material,
- Separated by a damage limiting barrier extending at least 1 foot beyond the area of unattainable separation (including the tray rails), or
- A combination of the above.

3. Minimum separation distances between Class 1E and exposed non-Class 1E circuits is the same as the minimum separation distances described in 1 and 2 above, while the minimum separation distance between

exposed Class 1E and enclosed non-Class 1E raceways is 1 inch.

4. Openings in the floors for vertical runs of raceways are sealed with fire resistant material. Fire stops are also provided at fire-rated wall penetrations.

5. Where it is necessary that cables of different separation groups approach the same or adjacent control panels with less than the minimum horizontal and/or vertical separation distances, isolation is maintained by installing cables of the redundant separation groups in separate enclosed raceways with 1-inch minimum separation between raceways, or by installing suitable damage limiting barriers. The raceways have a least 1 inch distance between separation groups prior to installation of the barrier.

D. Arrangement and/or protective barriers preclude locally generated forces or missiles from destroying redundant systems. In the absence of confirming analyses to support less stringent requirements, the following rules are applied:

1. In rooms or compartments containing cranes or heavy rotating machinery (such as the reactor coolant pumps) or in rooms containing high-pressure piping (such as reactor coolant piping, high-pressure feedwater piping, or high-pressure steam lines), a degree of separation commensurate with the criteria of Regulatory Guide 1.75 is provided such that the

independence of redundant Class 1E systems is maintained at an acceptable level.

2. Redundant load groups of 4.16 kV switchgear, 480V load centers, and motor control centers are separated by a protective barrier equivalent to a 6-inch thick reinforced concrete wall.

E. Non-Class 1E cables are not normally routed in Class 1E raceways. However, if a non-Class 1E cable is routed in a Class 1E raceway, it is considered an associated cable and treated as if it were a Class 1E cable of the same separation group as the raceway.

F. Load group 1 and protection channels A and C and load group 2 and protection channels B and D cables are routed through separate cable chases and cable spreading rooms. The former circuits enter the upper cable spreading room, while the latter circuits enter the lower cable spreading room.

G. Specific circuits (cables and wiring) have been analyzed on a case by case basis (per IEEE 384-1974, sections 4.5, 4.6.2, and 5.1.1.2) in Engineering Study 13-ES-A041[1] and identified as being low energy circuits. As such, these circuits are incapable of degrading redundant circuits within their vicinity. Circuits analyzed as low energy circuits are not applicable to Reg. Guide 1.75 separation requirements are as follows:

Non-Class 1E

- Fiber optic circuits

- Fire detection Protectowire circuits
- Fire detection circuits within panels
- Radiation monitoring system computer signal and information circuits
- Plant telephone system circuits
- Plant paging system circuits
- Main Steam and Feedwater Isolation System (MSFIS) trouble alarm circuits
- RCP temperature sensor monitoring system (Spec. 13-JM-111) circuits
- RCP temperature recording system (Spec. 13-JM-304) circuits
- RCP shaft speed sensing system circuits
- Radio system coaxial cable
- RCP vibration monitoring system (Spec. 13-JM-803) circuits
- Valve vibration monitoring system (Spec. 13-JM-366) circuits
- Containment sump level transmitter and converter circuits
- Fire Protection system dampers (Specs 13-MM-652 and 13-MM-658) circuits
- Fuel Building Air Filtration Units (AFU) temperature elements (Spec. 13-MM-721B) circuits

- Non-Class 1E run time meter circuits[(2)]

Class 1E cables

- Radiation monitoring system detector circuits
- RCP shaft speed sensing system circuits
- Reed Switch Position Transmitter (RSPT) system power supply circuits
- Class 1E instrument AC power system Inverter alarm circuitry[(1)]

H. Exposed non-class 1E festoons, pendants, bus bar feeder rails, etc. supplies with cranes, monorail hoists, and the refueling machine may not meet the separation requirements of Regulatory Guide 1.75, depending on crane position. When unattended, this equipment shall be de-energized by means of a disconnect device or feeder circuit breaker whenever Regulatory Guide 1.75 compliance cannot be satisfied. The cranes may be energized as needed for plant or crane maintenance activities as applicable, and locally controlled. The crane operator would detect any crane malfunction.

I. Outside the PKA-F11 battery room is a permanently mounted Non-Class 1E battery charger used to charge spare battery cells for the Class 1E batteries. The spare cells sit in the PKA-F11 battery racks. The Non-Class cables that feed the spare cells do not meet the cable separation requirements of 8.3.1.4.1.1.C.1 with respect to the Class 1E battery cables. These cables however, meet the separation requirements of IEEE 384 1992 and Reg.

Guide 1.75 Revision 3. The reduced separation required distances are 6 inches horizontal and 12 inches vertical as per IEEE 384 1992 Section 6.1.4.

8.3.1.4.1.2 Control Board and Other Panels. Single control devices to which different separation groups are connected are avoided. Within the main control boards, non-Class 1E wiring is run separated from Class 1E wiring. Harnesses of different separation groups are separated physically by a minimum distance of 6 inches, or where physical separation is impractical, barriers (metal barriers, metallic conduit, metallic gutter, or wire duct) with 1-inch air gap are used for maintenance of independence. Where 1-inch air gap cannot be maintained, ceramic fiber insulation equivalent to a 1-inch air gap is used.

A. A 6-inch minimum physical separation is maintained between field cables of different separation groups entering an enclosure (main control boards, switchboards, equipment cabinets, panels, and termination cabinets) between any of these cables and internal wiring of the separation groups within the enclosure and between the internal wiring of different separation groups within the enclosure. Where a 6-inch minimum physical separation between two separation groups cannot be maintained, one of the following is performed:

    1. The cables or cable conductors of redundant safety-related separation groups are installed in separate enclosed raceway (rigid steel conduit,

flexible conduit, EMT, or enclosed metallic gutter) maintaining a 1-inch minimum separation between enclosed raceways. The enclosed raceways are installed over the entire length of the cables or cable conductors from/to the point where a 6-inch minimum separation distance can be established.

2. A metal barrier is erected between the cabling, terminal boxes, or components of the separation groups, and a 1-inch air gap is maintained between the barrier and the separation group component.

B. Non-Class 1E circuits within Class 1E enclosures (switchboards, equipment cabinets, panels and termination boxes, etc.) or devices, which contain non-Class 1E instrumentation and/or control wiring (field cabling or internal wiring) and wiring (field or internal wiring) of only a single Class 1E separation group, are considered as associated circuits and are treated as Class 1E wiring if minimum separation between the Class 1E devices and wiring and the non-Class 1E devices and wiring cannot be maintained.

C. When non-Class 1E cables enter an enclosure containing Class 1E wiring (field or internal wiring), a 6-inch minimum physical separation is maintained between the non-Class 1E cables and any Class 1E wiring. Where a 6-inch separation cannot be maintained, the

non-Class 1E cables are installed in enclosed raceways (rigid steel conduit, flex conduit, EMT, or enclosed metallic gutter) and a minimum of 1-inch separation is maintained between the non-Class 1E enclosed raceways and the Class 1E cables.

D. Within the main control board only, in the event a 6-inch separation cannot be maintained, either the non-Class 1E cables will be enclosed and separated as noted in listing C above or the Class 1E cables will be installed in enclosed raceways (rigid steel conduit, flex conduit, EMT, or enclosed metallic gutter) and a minimum of 1-inch separation is maintained between the enclosed Class 1E raceway and the nonenclosed non-Class 1E cables. When the Class 1E cables of a particular separation group are enclosed in a raceway group, then the non-Class 1E cables that are routed within 6 inches of that given Class 1E separation group shall not be routed within 6 inches of any other Class 1E separation group.

E. Six-inch separation between separation groups for control and instrument circuits within the plant protection system cabinet is not provided. Justification for this exception was provided by a letter from Mr. E. E. Van Brunt, Jr., APS, to Mr. G. W. Knighton, NRC, ANPP-31526, dated December 18, 1984.

8.3.1.4.1.3 Reactor Containment Penetration Areas. Four separate penetration areas are provided for all cables that

must pass through the containment wall. The two southeast penetration areas contain cable for separation groups B and D at two levels, each located in a separate area. The two southwest penetration areas contain cable for separation groups A and C, at two levels each located in a separate area. Raceway separation criteria, as described in this section, apply in routing cable through the penetration areas. Non-safety-related penetration assemblies are located in each of the four areas.

8.3.1.4.2 Administrative Responsibilities and Controls for Assuring Separation Criteria

The cable and raceway channel identification described in paragraph 8.3.1.3 facilitates and ensures the maintenance of separation in the routing of cables and the connection of control boards and panels. At the time of the cable routing assignment during design, those responsible for cable and raceway scheduling check to ensure that the separation group designation in the cable number is compatible with a single-line diagram load group designation. Extensive use of computer facilities assists in ensuring separation. Each cable and raceway is identified in the computer program, and the identification includes the applicable separation group designation. Auxiliary programs are made available specifically to ensure that cables of a particular separation group are routed through the appropriate raceways. The routing is also confirmed by inspection personnel during installation to be consistent with the design document. Color

identification of equipment and cabling (refer to paragraph 8.3.1.3) assists field personnel in this effort.

8.3.1.4.3 Cable and Raceway Installation

Information pertinent to cable and raceway installation is as follows:

A. Cable Derating and Cable Tray Fill

To limit cable temperatures to 90°C, cable ampacity ratings and group derating factors are generally in accordance with ICEA P-46-426 for cables in conduit, ducts, or maintained spacing trays and to ICEA P-54-440 for cables in randomly filled trays.

In trays containing:

- Power cables rated 5kV and 15kV, cables are generally spaced in the tray with a one cable diameter spacing maintained.
- Power cables rated 600 volts and below, tray fill is generally limited to a calculated tray depth of 1.15 inches.
- Control or instrumentation cables only or a mixture of low voltage power, control, and/or communication cables; cables are installed with a 40% fill limitation applied.

Trays not meeting the above requirements are reviewed by Design (Electrical) Engineering on a case-by-case basis for adequacy of design and acceptability, and

documented in PDMS (Plant Data Management System) as an override.

To ensure 90°C cable ratings are not exceeded, the sizing of power cables in electrical raceways is based on all cables being fully loaded simultaneously to their rated ampacity with correction factors for ambient temperatures other than 40C incorporated in accordance with ICEA Publication P-54-440. When this conservative approach indicates cable temperatures exceeding 90°C, a more detailed method based on plant 'As Built' conditions is utilized to ensure the 90°C criteria is not exceeded.

Cables installed in Class 1E and non-Class 1E trays are further required to meet, as a minimum, the 70,000 BTU/hr IEEE 383 flame test. There are 27 cables installed at PVNGS that do not meet the IEEE 383 flame test. These 27 cables have been evaluated, for both electrical and fire protection properties, and "Accepted-As-Is" by Material Engineering Evaluation (MEE) 02480.

Conduit fill is in compliance with the provisions of Chapter 9 of the National Electrical Code (1975). In cases where this condition is exceeded, a design engineer reviews each individual case for adequacy of design.

B. Cable Routing in Congested Areas and Hostile Environment

Separation or barriers are provided as described in paragraph 8.3.1.4.1 to ensure adequate independence of redundant cable routings in congested and hostile areas.

C. Sharing of Cable Trays

Raceways are not shared by Class 1E cables and non-Class 1E cables except where a non-Class 1E is supplied from a Class 1E bus. In this case, the circuit from the bus to the terminal or isolation device is installed as if it were a Class 1E circuit of the associated separation group.

D. Fire Detection and Protection

Adequate fire detection and protection are provided in areas where cables are installed as described in subsection 9.5.1.

E. Cable and Cable Tray Markings

Color identification is used for trays and cables as described in paragraph 8.3.1.3.

F. Spacing of Wiring and Components in Control Boards, Panels, and Relay Racks

Physical separation or installation of barriers or conduit provides adequate independence of wiring and components in panels as described in paragraph 8.3.1.4.1.2.

G. Fire Barriers and Separation Between Redundant Groups

Refer to paragraph 8.3.1.4.1 for information regarding utilization of fire barriers and separation between redundant cable trays.

Fire barriers in the upper cable spreading room floor will be MCT (multicable transit). Fire barriers in other areas shall consist of Kaowool, silicone foam, or material of similar construction.

8.3.2 DC POWER SYSTEMS

8.3.2.1 Description

The Class 1E 125 Volt direct current (dc) systems for each unit is located in the control building and is made up of two trains (A & B) of four independent channels (A, B, C & D). Channels A & C are designated as Load Group 1 or Train A; Channels B & D are designated as Load Group 2 or Train B. The Class 1E dc trains and channels are identified on plant drawing 01, 02, 03-E-PKA-001. Channels A & B provide control power to ac load groups 1 (Train A) & 2 (Train B), to vital instrumentation and control power for Channels A & B of the reactor protective and engineered safety feature (ESF) systems and diesel generators A & B. Channels C & D also provide instrumentation and control power to the reactor protective and ESF systems and other safety related loads. Each channel contains a battery bank, hereby referred to as a battery, a battery charger, a control center, a distribution panel, and is supplied with Class 1E 480 V-ac power from a different Motor Control Center (MCC) within its associated load group. Each load group or train

additionally contains a back-up battery charger aligned to their respective A and B dc train which can be manually connected to channels A or C for Load Group 1 and channels B or D for Load Group 2 (see drawing 01, 02, 03-E-PKA-001). The Class 1E back-up chargers are mechanically interlocked to prevent channels A or C and B or D from being simultaneously connected. Four inverters, supplied from the dc channel provide four independent 120 V-ac vital instrumentation and control power for the four channels of the reactor protective and ESF systems.

Non-Class 1E dc loads are not fed from Class 1E dc buses.

The non-Class 1E loads for the station are supplied by a separate dc system. The non-Class 1E dc system consists of two 125V batteries, two dc control centers, three battery chargers, and four dc distribution panels for control and power loads. A spare battery charger is provided as a backup to primary battery chargers. The spare charger shall not provide power to both systems simultaneously. The non-Class 1E DC system is identified on plant drawings 01, 03, 03-E-NKA-001.

8.3.2.1.1 Safety-Related DC Loads

Table 8.3-6 identifies loads related to each Class 1E 125 V-dc channel.

8.3.2.1.2 Class 1E Station Batteries and Battery Chargers

8.3.2.1.2.1 Battery Capacity. Each Class 1E battery has sufficient capacity to independently supply the required loads as shown in table 8.3-6 for 2 hours. The sizing of the batteries is based on a minimum temperature of 60F in the

battery room for the 2-hour service period. In accordance with IEEE Standard 450-2002 battery replacement criteria, initial battery capacity is at least 25% greater than required. This margin allows a battery replacement criterion of 80% rated capacity. The battery sizing calculation includes factors for design margin and temperature as well as an additional 5% margin reserved for the uncertainties related to using 2 amps of float current as the designation that the battery is at least 95% charged.

Table 8.3-6

CLASS 1E DC SYSTEM LOADS[f] (amperes)

(Sheet 1 of 4)

CIRCUIT	ID[e]	DESCRIPTION	0-1 minutes	1-3 minutes	3-4 minutes	4-6 minutes	6-120 minutes
		DC Channel A					
Control Center Loads							
1EPKAM4106	1EPNAN11	INVERTER A	85.8	85.8	85.8	85.8	85.8
1EPKAM4108	1JSBAC03	REACTOR TRIP SWGR A	11.2	0	0	0	0
1EPKAM4110	1JSGAC01-MSIS	MAIN STM ISOL VV LOG CAB	1.7	1.7	1.7	1.7	1.7
1EPKAM4111	1JSGAUV134A	SG-1 TO AUX FDW PMP-A BYPASS SS V	0.3	0.3	19.3	0.3	0.3
1EPKAM4112	1JAFAHV32[g]	AUX FDW RGLTR VALVE	0.6	0.6	54.6	0.6	54[a]
1EPKAM4113	1JAFAUV37[g]	AUX FDW ISOL VALVE	0.6	0.6	117.8	0.6	117.3[a]
1EPKAM4114	1JAFAHV54	AUX FDW TRIP & THROT VV	0.7[C]	0.7[C]	0.7[C]	0.7[C]	0.7[C]
1EPKAM4115	1JSGAUV134[g]	SG1 TO AUX FDW PMP-A SS V	0.7	0.7	148.1	0.5	0.5
1EPKAM4116	1JSGAUV138[g]	SG2 TO AUX FDW PMP-A SS V	0.7	0.7	148.1	0.5	0.5
1EPKAM4117	1JSGAUV138A	SG2 TO AUX FDW PMP-A BYPASS SS V	0.3	0.3	19.3	0.3	0.3
1EPKAM4121	1EPKAD21	DISTRIBUTION PANEL (see below)	543.6	88.5	88.2	88.1	172.8
Distribution Panel Loads							
1EPKAD2101	1EZJAC01	AUX RELAY CABINET	3.6	2.2	2.2	2.1	2.1
1EPKAD2102	1EZAAC04-2	AUX RELAY CABINET	3.2	3.2	3.2	3.2	3.2
1EPKAD2103	1EPGAL33B	480V LOAD CENTER	141.7	1.4	1.4	1.4	1.6
1EPKAD2104	1EPBAS03A	4.16KV SWITCHGEAR	88.2	6.6	6.4	6.4	88.5
1EPKAD2105	1EPGAL35B	480V LOAD CENTER	140.6	1.1	1.1	1.1	1.5
1EPKAD2106	1EPGAL31B	480V LOAD CENTER	175.9	1.4	1.4	1.4	3.5
1EPKAD2107	1JESAC01	SAFETY EQPT STAT LOG CAB	10.8	10.8	10.8	10.8	10.8
1EPKAD2109	1EZAAC03	AUX RELAY CABINET	2.9	2.5	2.5	2.5	2.5
1EPKAD2110	1EZAAC01	AUX RELAY CABINET	5.3	5.3	5.3	5.3	5.3
1EPKAD2111	1EZJAC03	AUX RELAY CABINET	4.4	4.1	4.1	4.1	4.1
1EPKAD2112	1JDGAB02-59A	DG LV PNL & FIELD FLASH	57.1	0.0	0.0	0.0	57.1[b]
1EPKAD2113	1EZJAC02	ISOLATION CABINET	0.1	0.1	0.1	0.1	0.1
1EPKAD2114	1EZAAC05	AUX RELAY CABINET	4.7	4.7	4.7	4.7	4.7
1EPKAD2115	1JDGAB02	DG PROT CKT	1	1	1	1	1
1EPKAD2116	1JSAAC02AE	BOP ESFAS & LOAD SEQ	5.8	5.8	5.8	5.8	5.8
1EPKAD2117	1JSAAC04	ELECTRONIC ISOL CAB	7.8	7.8	7.8	7.8	7.8
1EPKAD2118	1JAFAE01	AUX FDW TURB GOV CNT PNL	7.1	7.1	7.1	7.1	7.1

Table 8.3-6

CLASS 1E DC SYSTEM LOADS(f) (amperes)

(Sheet 2 of 4)

CIRCUIT	ID[e]	DESCRIPTION	0-1 minutes	1-3 minutes	3-4 minutes	4-6 minutes	6-120 minutes
DC Channel A **Distribution Panel Loads (continued)**							
1EPKAD2121	1EZAAC06	AUX RELAY CABINET	2.4	2.4	2.4	2.4	2.4
1EPKAD2122	1JDGAB01	DG CONT & STARTING CKT	5.9	5.9	5.9	5.9	5.9
1EPKAD2126	1JDGAB01	DG CONT & STARTING CKT	5.9	5.9	5.9	5.9	5.9
1EPKAD2128	1JRKAUA2C-4D	CLASS 1E ANNUNCIATORS	5.6	5.6	5.6	5.6	5.6
1EPKAD2130	1EZAAC04	AUX RELAY CABINET	3.5	3.4	3.4	3.4	3.4
Total load on bus A			647(d)	181(d)	475(d)	181(d)	350(d)

DC Channel B

Control Center Loads

CIRCUIT	ID[e]	DESCRIPTION	0-1 minutes	1-119 minutes	119-120 minutes
1EPKMB4206	1EPNBN12	INVERTER B	89.9	89.9	89.9
1EPKBM4208	1JSBBC03	REACTOR TRIP SWGR B	11.3	0	0
1EPKBM4209A	1JSGBC01	MAIN STM ISOL VV LOG CAB	1.7	1.7	1.7
1EPKBM4212	1EPKBD22	DISTRIBUTION PANEL (see below)	526.7	81.9	170
<u>**Distribution Panel Loads**</u>					
1EPKBD2201	1EZJBC01	AUX RELAY CABINET	3.1	1.9	1.9
1EPKBD2202	1EZABC04-2	AUX RELAY CABINET	5.7	5.5	5.5
1EPKBD2203	1EPGBL34B	480V LOAD CENTER	138.4	1.2	1.4
1EPKBD2204	1EPBBS04A	4.16KV SWITCHGEAR	87.4	6.1	89.5
1EPKBD2205	1EPGBL36B	480V LOAD CENTER	171.7	1.3	3.7
1EPKBD2206	1EPGBL32B	480V LOAD CENTER	137.4	1.6	3.7
1EPKBD2207	1JESBC01	SAFETY EQPT STAT LOG CAB	10.8	10.8	10.8
1EPKBD2209	1EZABC03	AUX RELAY CABINET	3.5	3	3
1EPKBD2210	1EZABC01	AUX RELAY CABINET	6	6	6
1EPKBD2211	1EZJBC03	AUX RELAY CABINET	4.6	4.1	4.1
1EPKBD2212	1JDGBB02-59A	DG LV PNL & FIELD FLASH	57.4	0.0	57.4(b)
1EPKBD2214	1EZABC05	AUX RELAY CABINET	6	5.9	5.9
1EPKBD2215	1JDGBB02	DG PROT CKT	1	1	1

Table 8.3-6

CLASS 1E DC SYSTEM LOADS[f] (amperes)

(Sheet 3 of 4)

CIRCUIT	ID[e]	DESCRIPTION	0-1 minutes	1-119 minutes	119-120 minutes
DC Channel B **Distribution Panel Loads (continued)**					
1EPKBD2216	1JSABC02BG	BOP ESFAS & LOAD SEQ	5.8	5.8	5.8
1EPKBD2217	1JSABC04	ELECTRONIC ISOL CAB	7.9	7.9	7.9
1EPKBD2218	1EZJBC02	ISOLATION CABINET	0.1	0.1	0.1
1EPKBD2221	1EZABC06	AUX RELAY CABINET	2.2	2.2	2.2
1EPKBD2222	1JDGBB01	DG CONT & STARTING CKT	5.9	5.9	5.9
1EPKBD2226	1JDGBB01	DG CONT & STARTING CKT	5.9	5.9	5.9
1EPKBD2228	1JRKBUA2D-4E	CLASS 1E ANNUNCIATORS	5.8	5.8	5.8
Total loads on bus B			631[d]	175[d]	263[d]

DC Channel C

Control Center Loads

CIRCUIT	ID[e]	DESCRIPTION	0-1 minutes	1-2 minutes	2-3 minutes	3-5 minutes	5-120 minutes
1EPKCM4306	1EPNCN13	INVERTER C	55.9	55.9	55.9	55.9	55.9
1EPKCM4308	1JSBCC03	REACTOR TRIP SWGR C	11.5	0	0	0	0
1EPKCM4311	1JSICUV653	SD CLG ISOL VV 3-PH INV	20.4	20.4	20.4	20.4	20.4
1EPKCM4313	1JSICHV321	HPSI PMP LONG TERM CLG VV	1	1	1	1	1
1EPKCM4314	1JAFCUV36[g]	AUX FDW ISOLATION VALVE	1.2	1.2	117.5	0.9	117.5[a]
1EPKCM4315	1JAFCHV33[g]	AUX FDW REGULATOR VALVE	0.9	0.9	49.4	0.6	49.2[a]
1EPKCM4320	1EPKCD23	DISTRIBUTION PANEL (see below)	3.8	3.8	3.8	3.8	3.8
Distribution Panel Loads							
1EPKCD2301	1EPKCM4322	AUX RELAY SECTION	0.6	0.6	0.6	0.6	0.6
1EPKCD2303	1JSACC04	ELECTRONIC ISOL CAB	2.4	2.4	2.4	2.4	2.4
1EPKCD2305	1EPKCM4322	AUX RELAY SECTION	0.4	0.4	0.4	0.4	0.4
1EPKCD2306	1EPKCM4322	AUX RELAY SECTION	0.4	0.4	0.4	0.4	0.4
Total loads on bus C			96[d]	84[d]	249[d]	84[d]	249[d]

Table 8.3-6

CLASS 1E DC SYSTEM LOADS(f) (amperes)

(Sheet 4 of 4)

DC Channel D Control Panel Loads				
CIRCUIT	**ID[e]**	**DESCRIPTION**	**0-1 minutes**	**1-120 minutes**
1EPKDM4406	1EPNDN14	INVERTER D	62.2	62.2
1EPKDM4408	1JSBDC03	REACTOR TRIP SWGR D	11.4	0
1EPKDM4411	1JSIDUV654	SD CLG ISOL VV 3-PH INV	20.6	20.6
1EPKDM4416	1JSIDHV331	HPSI PMP LONG TERM CLG VV	1	1
1EPKDM4419	1EPKDD24	DISTRIBUTION PANE (see below)	4	4
Distribution Panel Loads				
1EPKDD2401	1EPKDM4421	AUX RELAY SECTION	0.6	0.6
1EPKDD2403	1JSADC04	ELECTRONIC ISOL CAB	2.4	2.4
1EPKDD2405	1EPKDB4421	AUX RELAY SECTION	0.4	0.4
1EPKDD2406	1EPKDM4421	AUX RELAY SECTION	0.6	0.6
Total loads on bus D			101(d)	89(d)

Notes:

(a) Intermittent loads, which may occur randomly several times during the 2-hour period.

(b) Random loads and the second DG field flash are assumed to occur at 119-120 minutes. For “A” channel, the 119-120 (last) minute loads are conservatively enveloped in 6-120 minute column. For ‘B’ channel, these loads are shown in 119–120 minute column. (Ref. Calculation 01-EC-PK-0207, Rev. 06, section 3.2.3, and 3.2.4)

(c) These loads are not expected to operate during the 2-hour period. Fractional amperes represent control circuit load only.

(d) These values are taken from “Battery Load Profiles” (Calculation 01-EC-PK-207, Rev. 06, which is representative of all three units). This calculation models the DC system network and switching operations during LOCA in much greater detail than is depicted in this Table. The Table reflects only the peak loadings during a specific switching mode of operation which may occur for one second only and is not the total of all the loads occurring for the entire one minute. Therefore, the net battery loading does not equate to the sum of the individual load currents, but is derived more precisely in the calculation. Load amperes are rounded to one decimal place only. Numeric values in this table are nominal in nature, provided to give the reader a sense of the value of the parameter and should not be viewed as actual value in the field as discussed in the FOREWORD to the UFSAR.

(e) Only the major loads are shown on this table. Smaller loads or the details of the loads are reflected in the calculation 01-EC-PK-0207, Rev. 06.

(f) Above table is based on 2 hours of LOCA event consistent with the applicable safety analyses in UFSAR chapter 6,15 and 8.3.2.1.2.1.

(g) Thermal overload protection is automatically bypassed upon receipt of an ESFAS actuation.

8.3.2.1.2.2 Battery Charger Capacity. The capacity of each Class 1E battery charger is based on the largest combined demand of all the steady-state loads and the charging current required to restore the battery from the design minimum charge state to the fully charged state within 12 hours regardless of the status of the plant during which these demands occur. This is in accordance with Regulatory Guide 1.32. The float voltage is maintained at or above the manufacturers recommended value and is periodically verified in accordance with the battery maintenance program. For the GNB NCN-33 cells this is 2.17 volts per cell.

8.3.2.1.2.3 Inspection, Maintenance, and Testing. Testing of the dc power system was performed prior to plant operation in accordance with IEEE 450-1972 as described in section 14.2. Subsequent tests and inspections are as described in the Technical Specifications or the battery maintenance program.

8.3.2.1.3 Separation and Ventilation

The Class 1E batteries, chargers, and dc switchgear are located in separate rooms of the Seismic Category I control building, as described in paragraph 8.3.1.1.8.

Each battery room is provided with separate and independent exhaust fans. The ventilation system is designed to preclude the possibility of hydrogen accumulation. Refer to paragraph 8.3.1.1.8 and section 9.4 for details regarding the battery room ventilation system.

8.3.2.2 Analysis

8.3.2.2.1 Compliance with Design Criteria and Guides

The analysis in this section demonstrates compliance of the Class 1E dc power system with General Design Criteria 17 and 18, Regulatory Guides 1.6, 1.22, 1.29, 1.30, 1.32, 1.40, 1.41, 1.47, 1.53, 1.75, 1.81, 1.89, 1.93, and IEEE Standards 308, 323, 344, 383, 384, and 450.

8.3.2.2.1.1 General Design Criterion 17, Electric Power Systems. Consideration of Criterion 17 leads to the inclusion of the following factors in the design of the dc power system:

A. Separate Class 1E 125 V-dc trains supply control power for each of the two Class 1E ac load groups.

B. The ac power for the battery chargers in each of these dc trains is supplied from the same ac load group for which the dc trains supplies the control power.

C. The Class 1E dc channels, including batteries, chargers, dc switchgear and distribution equipment, are physically separate and independent.

D. Sufficient capacity, capability, independence, redundancy, and testability are provided in the Class 1E dc channels, ensuring the performance of safety functions assuming a single failure.

8.3.2.2.1.2 General Design Criterion 18, Inspection and Testing of Electric Power Systems. Each of the four Class 1E 125 V-dc channels is designed to permit the following:

A. Inspection and testing, during equipment shutdown, of wiring, insulation, and connections to assess the continuity of the subsystem and condition of its components.

B. Periodic testing, during normal plant operation, of the operability and functional performance of the subsystem, by isolating the subsystem.

As described in paragraph 8.3.2.1.2.3, the battery and charger of each Class 1E 125 V-dc subsystem is periodically inspected and tested to assess the condition of battery cells and other components. Moreover, all important system components can be tested during service to detect faults. Abnormal conditions of important system parameters are annunciated in the unit control room. Refer to paragraph 8.3.2.2.1.7 for preoperational testing.

8.3.2.2.1.3 Regulatory Guide 1.6, Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems. The requirements of Regulatory Guide 1.6 are met. Two of the four separate Class 1E 125 V-dc channels, one per each load group, supply control power for their respective Class 1E ac load groups. Complete loss of either one of these channels does not prevent the minimum safety functions from being performed.

Each of the four dc channels is energized by one battery and one battery charger. Each battery is exclusively associated with a single 125 V-dc bus. The battery and the battery charger exclusively associated with one of these four 125 V-dc channels cannot be interconnected with any other 125 V-dc

channel. The battery chargers are supplied from the same ac load group for which the associated dc channel supplies the control power. No provision exists for transferring loads between redundant 125 V-dc channels. Thus, sufficient independence and redundancy exist between the 125 V-dc subsystems to ensure performance of minimum safety functions assuming a single failure.

8.3.2.2.1.4 Regulatory Guide 1.22, Periodic Testing of Protection System Actuation Functions. The requirements of Regulatory Guide 1.22 are met. Refer to paragraph 8.3.1.1.3.14 for compliance of the Class 1E electrical system with Regulatory Guide 1.22.

8.3.2.2.1.5 Regulatory Guide 1.29, Seismic Design Classification. Refer to section 3.10 for a discussion of compliance with Regulatory Guide 1.29.

8.3.2.2.1.6 Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment. Comparison of the design with the recommendations of Regulatory Guide 1.30 is discussed in section 1.8.

8.3.2.2.1.7 Regulatory Guide 1.32, Use of IEEE Standard 308-1971, Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations. Refer to section 1.8.

8.3.2.2.1.8 Regulatory Guide 1.40, Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of

Water-Cooled Nuclear Power Plants. There are no Class 1E continuous-duty motors installed inside the containment.

8.3.2.2.1.9 Regulatory Guide 1.41, Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments. In compliance with this regulatory guide, the Class 1E 125 V-dc channels designed in accordance with Regulatory Guides 1.6 and 1.32 are tested as described in section 14.2.

8.3.2.2.1.10 Regulatory Guide 1.47, Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems. Comparison of the design with the recommendations of Regulatory Guide 1.47 is discussed in section 7.5.

8.3.2.2.1.11 Regulatory Guide 1.53, Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems. Comparison of the design with the recommendations of Regulatory Guide 1.53 is discussed in subsection 7.1.2.

8.3.2.2.1.12 Regulatory Guide 1.75, Physical Independence of Electrical Systems. Refer to paragraph 8.3.1.2.2.16.

8.3.2.2.1.13 Regulatory Guide 1.81, Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants. The requirements of Regulatory Guide 1.81 are met. Each unit has separate and independent onsite ac and dc electric systems capable of supplying minimum ESF loads and loads required for attaining a safe and orderly cold shutdown of the unit assuming

a single failure and loss of offsite power. No emergency and shutdown electric systems are shared between units.

8.3.2.2.1.14 Regulatory Guide 1.89, Revision 1, Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants. Regulatory Guide 1.89, Rev. 1 endorses IEEE Standard 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations. Comparison of the design with the recommendations of Regulatory Guide 1.89, Revision 1, is discussed in section 1.8.

8.3.2.2.1.15 Regulatory Guide 1.93, Availability of Electric Power Sources. The position of Regulatory Guide 1.93 is accepted (refer to the Technical Specifications Bases).

8.3.2.2.1.16 IEEE 308-1974, IEEE Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations. The Class 1E dc system provides dc electric power to the Class 1E dc loads and for control and switching of the Class 1E systems. Physical separation, electrical isolation, and redundancy are provided to prevent the occurrence of common failure modes. Design of the Class 1E dc system includes the following:

A. The dc system is separated into two load groups (trains) broken into four independent channels.

B. The safety actions by each group of loads are independent of the safety actions provided by its redundant counterpart.

C. Each dc subsystem includes power supplies that consist of one battery and one battery charger.

D. The batteries are not interconnected between channels.

E. The redundant batteries cannot be made inoperative by a single design basis event.

Each Class 1E distribution circuit is capable of transmitting sufficient energy to start and operate all required loads in that circuit. Distribution circuits to redundant equipment are independent of each other. The distribution system is monitored to the extent that it is shown to be ready to perform its intended function. The dc auxiliary devices required to operate equipment of a specific ac load group are supplied from the same load group.

Some nonsafety-related circuits may be supplied from the safety-related dc buses. When this is done, those circuits are treated as safety-related up to the equipment terminations or isolation devices.

Each battery supply is continuously available during normal operations and following the loss of power from the ac system to start and operate all required loads.

Control room instrumentation is provided to monitor the status of the battery supply as follows:

- DC bus undervoltage alarm[a]
- Battery current indication
- DC voltage indication
- DC ground indication

a. Via alarm typewriter, alarm displays, and plant annunciator.

- Battery breaker open alarm[a]

The plant monitoring system (PMS) provides a common dc system trouble annunciator.

The batteries are maintained in a fully-charged condition and have sufficient stored energy to operate all necessary circuit breakers and to provide an adequate amount of energy for all required emergency loads for 2 hours after loss of ac power.

Each Class 1E battery charger has sufficient capacity to restore the battery from the design minimum charge to its fully-charged state while supplying the maximum demand of the steady-state loads. The battery charger of one subsystem is independent of the battery charger for the redundant subsystem. Instrumentation is provided to monitor the status of the battery charger as follows:

A. Output voltage at the charger and in the control room

B. Output current at the charger and in the control room

C. AC and dc breaker position indications at the charger

D. Charger malfunction alarm in control room, including input ac undervoltage, dc undervoltage, dc overvoltage, and output breaker open

Each battery charger has an input ac and output dc circuit breaker for isolation of the charger. Each battery charger power supply is designed to prevent the ac supply from becoming a load on the battery due to a power feedback as the result of

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a. Via alarm typewriter, alarm displays, and plant annunciator.

the loss of ac power to the chargers. Battery chargers are provided with built-in overvoltage shutdown protection that is capable of tripping the ac input breaker in the event of dc overvoltage.

Equipment of the Class 1E dc system is protected and isolated by fuses or circuit breakers in case of short circuit or overload conditions. Indication is provided to identify equipment that is made unavailable (refer to table 8.3-7).

The Class 1E 125 V-dc subsystem is designed to meet Seismic Category I requirements as stated in section 3.10. The batteries, battery chargers, inverters, and other components of dc subsystem are housed in the control building, which is a Seismic Category I structure

The periodic testing and surveillance requirements for the Class 1E batteries are detailed in the Technical Specifications.

Table 8.3-7

CLASS 1E DC SYSTEM EQUIPMENT FAILURE AND INDICATION

Event	Available Indication[a]
Battery charger ac input breaker trip	Charger trouble alarm
Battery charger dc output breaker open	Charger trouble alarm
Battery breaker trip or open	Breaker trip/open alarm
Loss of 125 V-dc bus voltage	Bus undervoltage alarm
125 V-dc distribution panel supply breaker trip	Breaker trip alarm
Inverter dc supply breaker trip	Inverter trouble alarm

a. Via alarm typewriter, alarm displays, and plant annunciator.

8.3.2.2.1.17 IEEE 323-1974, Standard for Quality Class 1E Equipment for Nuclear Power Generating Stations. Refer to paragraph 8.3.1.2.2.22.

8.3.2.2.1.18 IEEE 344-1975, Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations. Seismic qualification of Class 1E electric equipment and the extent of compliance with IEEE 344 are discussed in section 3.10.

8.3.2.2.1.19 IEEE 383-1974, Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generation Stations. Class 1E cable, field splices, and connections are in accordance with IEEE 383-1974.

Cable assemblies for the reed switch position transmitters and fixed incore system are in accordance with IEEE 383-1974 except that following environmental qualification testing they were tested at 750 volts ac for 5 minutes while immersed in water at room temperature. This value meets the system requirements.

8.3.2.2.1.20 IEEE 384-1974, Criteria for Separation of Class 1E Equipment and Circuits. Refer to paragraph 8.3.1.4 for compliance. Also refer to appendix 8A, Question 8A.10 response.

8.3.2.2.1.21 IEEE 450-2002, Recommended Practice for Maintenance, Testing, Replacement of Large Stationary Type Power Plant and Substation Lead Storage Batteries. Recommended practices of IEEE 450 for maintenance, testing, and replacement of batteries are implemented as follows:

A. Maintenance and inspections are carried out on a regularly scheduled basis to comply with the requirements of IEEE 450-2002 (refer to the Technical Specifications and battery maintenance program).

B. Performance discharge tests are carried out as discussed in the Technical Specifications.

C. The rating of the battery is at least 25% greater than that required to supply the emergency load requirements.

D. An acceptance test of battery capacity is performed at the factory to determine if it meets the specified discharge rate and duration.

E. A performance test of the battery capacity is performed within the first 2 years of service to determine if it meets the specified discharge rate and duration.

F. Records of the data obtained from inspections and tests are kept along with test procedures to comply with the requirements.

G. Whenever any cell’s electrolyte level reaches the low level mark, water will be added to increase the level to approximately the midpoint between the high and low electrolyte level marks.

8.3.2.3 Physical Identification of Safety-Related Equipment

Refer to paragraph 8.3.1.3 for physical identification of Class 1E equipment.

8.3.2.4 Independence of Redundant Systems

The general considerations for the independence of Class 1E dc power subsystems are described in paragraph 8.3.1.4.

8.3.3 FIRE PROTECTION FOR CABLE SYSTEMS

Refer to subsection 9.5.1. In addition, for a discussion of cable derating and cable tray fill, refer to paragraph 8.3.1.4.3. Fire barriers and separation between redundant trays are discussed in paragraph 8.3.1.4.1.

8.3.4 CESSAR INTERFACES

The following NSSS interface requirements are repeated from CESSAR Section 8.3.1.

1. Following a turbine or reactor trip, power shall be provided to the auxiliary loads as specified in Table 8.3.1-3.

2. Standby, onsite power shall be provided by two or more independent standby generators. Each standby generator shall supply equipment in one ESF train. This insures that the loss of one standby generator would only affect one ESF train. These standby generators shall be designed to attain rated voltage and speed within 12 seconds following either a loss of offsite power to the ESF bus, or initiation of the CSAS, SIAS, or AFAS of the ESFAS.

3. The design of automatic sequencing features for loading the standby generators shall be consistent with the following requirements:

   a. If the standby generators are the only source of power to the ESF bus when an ESFAS is generated the ESF loads which are appropriate to the particular ESFAS shall be automatically sequenced on, see Table 8.3.1-4.

   b. In the event that offsite power is unavailable and the standby generators are not yet up to rated voltage and speed at the time that an ESFAS is generated, there can be a delay of up to 12 seconds before the standby generator output breakers close and power is supplied to the ESF buses. After the generators are supplying the ESF buses, the ESF loads which are appropriate to

the particular ESFAS shall be automatically sequenced on, see Table 8.3.1-4.

c. If a standby generator is supplying power to an ESF bus (offsite power not available) and appropriate ESF equipment is operating on that bus, the operating ESF equipment shall not be shed if another ESFAS is generated. The ESF loads associated with the second ESFAS shall have no additional sequencing imposed but shall be sequenced if that is the normal way that the components are operated.

d. If offsite power is lost at some time after the standby generators are up to rated voltage and speed, and after the required ESF equipment is running following one or more ESFAS, the following requirements shall be met:

    1) Interrupted ECCS flow to the core shall be fully reestablished within thirteen seconds.

    2) Interrupted auxiliary feedwater flow to the steam generator(s) shall be fully reestablished within fifteen seconds.

e. If offsite power is available and the standby generators are started on an ESFAS initiated by a plant condition actually requiring operation of the ESF loads appropriate to the ESFAS, the standby generators shall be left running for a period of at least one hour.

f. If offsite power is the source of power to an emergency bus when an ESFAS is generated, the ESF loads which are appropriate to the particular ESFAS shall be started by sequencing, on the offsite powered emergency bus. See Table 8.3.1-4.

4. Four physically and electrically independent 120 volt, 60 Hz, single phase, ungrounded vital instrument sources are required to provide power to NSSS instrumentation used for protection. The output frequency shall be 60 ± 0.5 Hz and the output voltage shall be regulated to within ±2% at full output for a load power factor greater than 0.8 (towards unity).

5. The Engineered Safety Features electric system shall be designed on a two independent train basis. Each train shall be capable of furnishing power to equipment load groups of the ESF Systems. The ESF buses and associated cabling shall be physically separated and electrically isolated to allow for redundancy.

6. When redundant "third of a kind" components are included as part of the safety system design, it is required that these components be capable of receiving power from either of the redundant emergency buses. The transfer from one redundant source to another shall be capable of being accomplished manually. This transfer (if required) would be necessary within approximately two hours after a loss of offsite power.

7. The consequences of frequency decays of up to 3 Hz/sec (with bus voltage at its nominal value and with all RCPs connected to their buses) on the Reactor Coolant Pump buses are not more severe than the consequences of loss of flow of the four RCPs due to loss of power. The Applicant's RCP buses, therefore, shall not subject the RCPs to sustained frequency decays of greater than 3 Hz/sec.

8. The following tables provide electrical data for the safety-related equipment which is generally supplied by Combustion Engineering. Complete tables and responsibilities for supply will be provided in the Applicant's Safety Analysis Report.

   a. Table 8.3.1-1 Power Requirements for CESSAR Design Scope Safety-Related Equipment.

   b. Table 8.3.1-2 Power Requirements for CESSAR Design Scope Safety-Related Equipment at Various Operating Conditions.

   c. Table 8.3.1-3 Power Requirements for CESSAR Design Scope Safety-Related Electrical Equipment During Emergency Operation.

   d. Table 8.3.1-4 Required Standby Generator Loads

9. The vital instrument buses shall be designed such that the maximum voltage fault shall not exceed 480 VAC + 10% or 325 VDC + 10%.

10. Cabling shall meet the requirements specified in Sections 7.1.3, 7.2.3, and 7.3.3 for separation and

independence so that no credible fault in one channel can be propagated.

The following NSSS interface requirement is derived from CESSAR Sections 15.3.3, 15.3.4, and 15.6.3.2.

11. Offsite power shall be available for at least 3 seconds following a turbine trip resulting from a RCP rotor seizure, RCP shaft break, or steam generator tube rupture.

8.3.5 CESSAR INTERFACE EVALUATION

Interface design requirements in CESSAR Section 8.3.1 are applicable but do not contain all requirements for the onsite power system. The onsite power system design meets the CESSAR interface requirements presented in subsection 8.3.4 as discussed in the following sections corresponding to the interface requirements.

1. Refer to paragraph 8.3.1.1.3 and table 8.3-1.
2. Refer to paragraph 8.3.1.1.3, 8.3.1.1.4, and 8.3.1.1.4.6.
3. Refer to paragraph 8.3.1.1.3.10, 8.3.1.1.4.6 table 8.3-3, and figure 8.3-1.
4. Refer to paragraph 8.3.1.1.6.
5. Refer to paragraph 8.3.1.1.3.3 and 8.3.1.1.3.8.
6. Refer to paragraph 8.3.1.1.3.6.
7. The reactor coolant pump electrical power supply, which is part of the 13.8 kV non-Class 1E onsite power system, is normally electronically connected through

the unit main and auxiliary transformer to the transmission network. The electrical characteristics of the transmission network are classified as such that underfrequency transient perturbations are anticipated operational occurrences that will affect the reactor coolant pumps. The rate of frequency decay of these perturbations, based on presently available information, is calculated not to exceed 1.5 Hz. The transmission network frequency decay rate allowable by low DNBR and fuel damage considerations as given in CESSAR is 3 Hz at nominal bus voltage with all reactor coolant pumps running. Consequently, the expected rate of 1.5 Hz will not cause a more severe effect on coolant flow than would be caused by a complete loss of electric power to the pumps starting at 100% flow. Therefore, the assumptions of CESSAR Section 7.2.1.1.2.4 are satisfied and are applicable to the PVNGS plant and transmission network. In view of the preceding analysis, disconnection of the reactor coolant pumps on underfrequency is not required.

8. Refer to tables 8.3-1, 8.3-3, 8.3-4, 8.3-6, engineering drawing 01, 02, 03-E-MAA-002, and paragraph 7.4.1.1.1.

   Loads indicated as requiring emergency power in CESSAR Table 8.3.1-1 are included in table 8.3-1. Also, Class 1E loads not supplied by C-E have been added. CESSAR Tables 8.3.1-2 and 8.3.1-3 are applicable but do not contain all requirements for Class 1E ac system

loads. Loads from CESSAR Tables 8.3.1-2 and 8.3.1-3 are included in table 8.3-1.

Loads from CESSAR Table 8.3.1-2 are also included in UFSAR Table 8.3-3. This CESSAR table lists power requirements for four scenarios: startup, shutdown, refueling, and normal. UFSAR table 8.3-3 provides the load requirements for forced shutdown and LOCA shutdown. Forced shutdown loads provides the worst case loading of the four scenarios and thus envelopes the other three.

CESSAR Table 8.3.1-4 is used as a guide for preparation of table 8.3-3. CESSAR Figure 8.3.1-1 is not applicable in detail and is replaced by figure 8.3-2. Loading of buses in figure 8.3-2 is similar to the CESSAR figure.

9. The vital instrument buses are described in paragraph 8.3.1.1.6. The maximum voltage fault values given (480 VAC + 10% and 325 VDC + 10%) come from the specifications given by CE for the Plant Protection System (PPS) Cabinets. It is an isolation/separation requirement between channels to comply with IEEE 279, 379, and 384. They are worst case postulated high energy fault values. The cabinets were analyzed and tested showing that these values applied to a channel cannot affect another channel.

   The only potential sources for these fault voltages are the 125 Vdc supply to the vital ac inverter and the 480 Vac supply to the vital ac regulator. The dc power

system cannot physically generate 325 Vdc +10%. Paragraph 8.3.1.1.3 describes voltage optimization requirements that are within the 480 Vac +10%. Therefore, the design of the vital ac bus and its supply power sources meet the criterion.

10. Refer to paragraph 8.3.1.4.

11. Following a turbine trip resulting from a design basis accident, offsite power remains available for at least 3 seconds. During this time, the unit auxiliary transformer continues to supply offsite power to the non-Class 1E distribution system. Refer to section 8.2.2, 10.2.2.4, and table 15.0-0.

8.3.6 REFERENCES

1. Engineering Study 13-ES-A041, "Regulatory Guide 1.75 Low Energy Circuit Analysis".

2. APS Study 13-ES-A13, Revision 0, "Regulatory Guide 1.75 Lower Energy Circuit Analysis for Run Time Meter/Cycle Counter (RTM/CC) Sensor Cable."

3. Transient Stability Study as updated.

APPENDIX 8A

RESPONSES TO NRC REQUESTS FOR INFORMATION

CONTENTS

CONTENTS (Cont.)

<u>QUESTION 8A.1</u> (NRC Question 430.1) (8.3)

Provide a detail discussion (or plan) of the level of training proposed for your operators, maintenance crew, quality assurance, and supervisory personnel responsible for the operation and maintenance of the emergency diesel generators. Identify the number and type of personnel that will be dedicated to the operations and maintenance of the emergency diesel generators and the number and type that will be assigned from your general plant operations and maintenance groups to assist when needed.

In your discussion identify the amount and kind of training that will be received by each of the above categories and the type of ongoing training program planned to assure optimum availability of the emergency generators.

Also discuss the level of education and minimum experience requirements for the various categories of operations and maintenance personnel associated with the emergency diesel generators.

RESPONSE: The response is given in paragraph 8.3.1.1.4.12.

<u>QUESTION 8A.2</u> (NRC Question 430.2) (8.3)

Periodic testing and test loading of an emergency diesel generator in a nuclear power plant is a necessary function to demonstrate the operability, capability and availability of the unit on demand. Periodic testing coupled with good preventive maintenance practices will assure optimum equipment readiness and availability on demand. This is the desired goal.

To achieve this optimum equipment readiness status the following requirements should be met:

1. The equipment should be tested with a minimum loading of 25% of rated load. No load or light load operation will cause incomplete combustion of fuel resulting in the formation of gum and varnish deposits on the cylinder walls, intake and exhaust valves, pistons and piston rings, etc., and accumulation of unburned fuel in the turbocharger and exhaust system. The consequences of no load or light load operation are potential equipment failure due to the gum and varnish deposits and fire in the engine exhaust system.

2. Periodic surveillance testing should be performed in accordance with the applicable NRC guidelines (R.G. 1.108), and with the recommendations of the engine manufacturer. Conflicts between any such recommendations and the NRC guidelines, particularly with respect to test frequency, loading and duration, should be identified and justified.

3. Preventive maintenance should go beyond the normal routine adjustments, servicing and repair of components when a malfunction occurs. Preventive maintenance should encompass investigative testing of components which have a history of repeated malfunctioning and require constant attention and repair. In such cases consideration should be given to replacement of those components with other products which have a record of demonstrated reliability, rather than repetitive repair and maintenance of the existing components. Testing of the unit after adjustments or repairs have been made only confirms that the equipment is

operable and does not necessarily mean that the root cause of the problem has been eliminated or alleviated.

4. Upon completion of repairs or maintenance and prior to an actual start, run, and load test a final equipment check should be made to assure that all electrical circuits are functional, i.e., fuses are in place, switches and circuit breakers are in their proper position, no loose wires, all test loads have been removed, and all valves are in the proper position to permit a manual start of the equipment. After the unit has been satisfactorily started and load tested, return the unit to ready automatic standby service and under the control of the control room operator.

Provide a discussion of how the above requirements have been implemented in the emergency diesel generator system design and how they will be considered when the plant is in commercial operation, i.e., by what means will the above requirements be enforced.

RESPONSE:

1. The response is given in paragraph 8.3.1.1.4.12.
2. Periodic surveillance testing of the emergency diesel generators will be conducted in accordance with the recommendations of Regulatory Guide 1.108 as interpreted by section 1.8, and with the recommendations of the engine manufacturer. The engine manufacturer's recommendations for periodic testing do not conflict with Regulatory Guide 1.108 as interpreted.
3. The response is given in paragraph 8.3.1.1.4.12.

4. The response is given in paragraph 8.3.1.1.4.12.

QUESTION 8A.3 (NRC Question 430.3) (8.3)

The availability on demand of an emergency diesel generator is dependent upon, among other things, the proper functioning of its controls and monitoring instrumentation. This equipment is generally panel mounted and in some instances the panels are mounted directly on the diesel generator skid. Major diesel engine damage has occurred at some operating plants from vibration induced wear on skid mounted control and monitoring instrumentation. This sensitive instrumentation is not made to withstand and function accurately for prolonged periods under continuous vibrational stresses normally encountered with internal combustion engines. Operation of sensitive instrumentation under this environment rapidly deteriorates calibration, accuracy and control signal output.

Therefore, except for sensors and other equipment that must be directly mounted on the engine or associated piping, the controls and monitoring instrumentation should be installed on a free standing floor mounted panel separate from the engine skids, and located on a vibration free floor area. If the floor is not vibration free, the panel shall be equipped with vibration mounts.

Confirm your compliance with the above requirement or provide justification for noncompliance.

RESPONSE: Controls and monitoring equipment are located on the floor, separate from the engine foundation, to eliminate engine vibration effects. Refer to engineering

drawings 13-P-ZGL-701 and -702 (diesel generator control room).

QUESTION 8A.4 (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

Final approval of the overall offsite power system is withheld pending receipt of the following additional information:

1. A discussion of transmission line rights-of-way, height, as well as spacing, between transmission towers, etc.
2. Physical layout drawings of the circuits that connect the onsite distribution system to the offsite power system.
3. A description of the instrumentation provided for monitoring and indicating the status of the offsite power system and switchyard batteries.

RESPONSE:

Item 1. The following drawings have been provided to the NRC in response to this request:

1. Overall map showing the transmission system 500 kV lines
2. Drawing K-675-503, Palo Verde/Kyrene line route map
3. Bechtel drawings 13-E-ZYP-012, ZVU-009, and 13-C-ZVA-001 showing line routing on the plant property.
4. Typical tower, pole, and double tower right-of-way usage.

The plan and profile sheets for the Palo Verde/Kyrene line show the double right-of-way obtained for a portion of the line length for a future Saguaro line. Right-of-way acquisition beyond this common corridor has not yet been acquired.

Item 2. The circuits connecting the onsite distribution system to the offsite power system are shown in drawings 13-E-ZYP-012 (Rev. 3) and 13-E-ZVU-009 (Rev. 10), which have been provided to the NRC.

Item 3. The instrumentation provided for monitoring and indicating status of the offsite power system is presented in the following drawings, which have been provided to the NRC:

A. Bechtel drawings -- 13-E-MAA-001 Rev. 4
01-E-NAA-001 Rev. 3
01-E-NAA-002 Rev. 3
02-E-NAA-001 Rev. 2
02-E-NAA-002 Rev. 3
03-E-NAA-001 Rev. 2
13-E-NAA-002 Rev. 3
13-E-NAA-003 Rev. 3
13-E-PBA-001 Rev. 3
13-E-PBA-002 Rev. 3

B. Vendor drawings -- J200-205
J200-206
J200-263
J200-264
J200-265

<u>QUESTION 8A.5</u> (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

Revise the FSAR to include switchyard components for testing and perform periodic inspection and maintenance on all the switchyard and onsite power components.

RESPONSE: The response is given in paragraph 8.3.1.2.2.2, listing D.

<u>QUESTION 8A.6</u> (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

Provide the transmission load flow diagram associated with the transient stability cases assumed in the FSAR.

RESPONSE: The load flow diagram has been submitted to the NRC under separate cover (see section 8.2.2 for current load flow analysis).

<u>QUESTION 8A.7</u> (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

We require that new diesel generator designs to be used in nuclear power plant service undergo a reliability establishment testing program in accordance with IEEE 387. The applicant should submit the results of the reliability testing program for our review.

RESPONSE: The response is given in paragraph 8.3.1.1.4.11.

<u>QUESTION 8A.8</u> (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

Local and control room alarms are provided for each diesel generator. The local annunciator provides first out indication for all alarms initiated by the diesel generator protective devices; this conforms with the guidance of Regulatory Guide 1.9, Position C.8, and is acceptable. The control room annunciation consists of single input alarms and common alarms. In addition the following alarms are annunciated on the control room safety equipment status annunciator for each diesel generator:

1. Diesel generator inoperable.
2. Diesel generator failed to start.

The applicant should provide additional information in this area.

RESPONSE: The response is given in amended paragraph 8.3.1.1.4.10.

<u>QUESTION 8A.9</u> (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

Revise the separation criteria in the following areas:

a. Where cable of different separation groups approach the same or adjacent control panels with less than the minimum horizontal and vertical separation distance, isolation is maintained by installing cables of one of the separation groups in metallic conduit. This is inconsistent with the recommendations of IEEE 384 and

is unacceptable. Therefore, we require that cables of both separation groups be installed in metallic conduit or a barrier be installed between separation groups.

b. If a 6-inch minimum physical separation between two separation groups inside the control boards or other panels cannot be maintained, the cables of at least one of the separation groups is installed in an enclosed raceway. This is inconsistent with the recommendations of IEEE 384 and is unacceptable. Therefore, we require that 1) cables of both separation groups be installed in enclosed raceways or, 2) a barrier be installed between separation groups, or, 3) provide an analysis to justify that the separation is adequate.

Also, the applicant should document the interval at which these cables and raceways are marked for physical identification.

RESPONSE: The response is given in amended paragraphs 8.3.1.3, 8.3.1.4.1.1, and 8.3.1.4.1.2.

QUESTION 8A.10 (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

Based on our evaluation of the information provided by the applicant, we conclude that in order to accept current limiting transformers as isolation devices we require a clear demonstration that these transformers are current limiting under faulted conditions and their limiting current will not compromise the remainder of the Class 1E system. In addition, we also require the applicant to provide a discussion of those

non-Class 1E circuits that are connected to the Class 1E batteries.

RESPONSE: IEEE 384, Section 6.1.2.3, states "devices which will limit the input current to an acceptable value under faulted conditions of the output qualify as isolation devices .... Note: Devices in this category may include inverters, regulating transformers, "... etc. Voltage regulators used in PVNGS utilize a ferro-resonant transformer, which operates at saturated (magnetic core) condition and has current limiting characteristics in the overload region.

The transformer supplier has stated that "the current on the primary when a bolted short is applied to output is less than the high line full load primary current." This statement is based on supplier's review of test data sheets for this equipment.

Refer to paragraph 8.3.2.1 for a discussion on Class 1E dc loads.

QUESTION 8A.11 (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

Part A

It is stated in the FSAR that separate control power is not required for these breakers. We disagree with this statement and require that control power from separate sources be provided to the load feeder breakers and bus feeder breakers so

that failure of either source will not violate the single failure criterion.

RESPONSE: The statement in the FSAR is correct in that load center breaker overcurrent trip is independent of the 125 V-dc (control) power. Breaker trip units are direct acting, i.e., "breaker latch release is powered by the line overcurrent." Additional response is given in paragraph 8.3.1.1.3.13.

Part B

For circuits fed from motor control centers, the load feeder breaker is coordinated with, and backed up by, the bus feeder breaker, control power of bus feeder breakers is separate from that of load feeder breakers.

The low-voltage control systems, power circuits and high energy level control circuits use self-fusing characteristics of field cables to ensure that under all circumstances the penetration maintain its integrity. We have informed the applicant that this is unacceptable; we do not permit self-fusing of cables as backup protection. Subsequently, the applicant committed to provide two breakers in series for each control circuit that passes through a containment penetration.

We have reviewed the above information and conclude that the applicant has not provided enough information on this subject for us to make an evaluation, therefore, we would require the applicant to provide the following additional information on this subject.

1. A discussion of (1) the direct current circuits and (2) circuits that are required for short periods of time during startup refueling or a maintenance shutdown that pass through the containment penetrations and describe how these circuits meet the guidance of Regulatory Guide 1.63, Position 1.
2. Submit time-current characteristic curves of protective devices provided for each size of penetration to demonstrate that adequate time-current coordination exists between the motor primary and backup protection devices and the penetration itself.
3. A commitment to periodically test the primary and secondary protective devices.

RESPONSE: Refer to amended section 1.8, describing PVNGS compliance with Regulatory Guide 1.63.

Item 1(1)

The response is given in paragraph 8.3.1.2.2.21, listing G.

Item 1(2)

Circuits that are required for short periods of time during startup, refueling or maintenance shutdown that pass through the containment penetrations and are permanently installed meet the guidance of Regulatory Guide 1.63 (Position 1) with exceptions as stated in section 1.8.

Item 2

Thirty-three time-current characteristic curves were submitted to the NRC under separate cover.

Item 3

The response is given in paragraph 8.3.1.2.2.21, listing H.

QUESTION 8A.12 (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

The Palo Verde station design motor-operated valves activated by a safety injection signal in the event of a LOCA have their respective thermal overload protection devices bypassed during accident conditions. This conforms with the guidance of Regulatory Guide 1.106, Positions C.1 and C.2, and is acceptable. However, to complete our evaluation and verification of this design feature, the applicant should provide a description and drawings indicating how this is accomplished.

RESPONSE: The response is given in paragraph 8.3.1.1.3.13. Drawings 13-E-SIB-012, -020, and -022, which have been provided to the NRC, indicate how thermal overload devices are bypassed during accident condition.

QUESTION 8A.13 (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

It is not clear from the information provided in the FSAR how the Palo Verde design meets the guidelines of Branch Technical Position ICSB 18 (PSB) concerning power lockout to selected ESF valve actuators as means of designing against a single failure that might cause an undesirable valve motion in the fluid system. In addition, this position requires that all such valves be listed in the Technical Specifications and that the

position indication for these valves meet the single failure criterion. We therefore, require the applicant to provide the following specific information on this item.

1. A list in the Technical Specifications of all valves that require power lockout in order to meet the single failure criterion in the fluid system.

2. A description of (1) the design feature for locking out control power to these valves, (2) how electrical power can be restored to the valves from the control room if valve repositioning is required at a later time, and (3) the testability of the power lockout feature. In addition, provide the associated schematic diagrams showing these design features.

3. Redundant and independent valve position indication in the control room which meets the single failure criterion.

RESPONSE:

The response is given in paragraph 6.3.1.4 (including valve list) and PVNGS Technical Specifications, that specifies power removal to the valves.

<u>QUESTION 8A.14</u> (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

In order to accept the use of a single load sequencer for both offsite and onsite power sources, the applicant should provide a detailed analyses to assure that there are no credible sneak circuits or common mode failures in the sequencer design that

could render both onsite and offsite power sources unavailable. Furthermore, we would require the applicant to provide the following additional information:

1. A full description of the load sequencer design feature in the FSAR. This should include sequencer power supplies, test features and alarms.
2. A reliability study on the sequencer.

RESPONSE:

Item 1: The response is given in paragraph 8.3.1.1.3.10.1.

Item 2: The response is given in the submitted report, Reliability Analysis Report for Balance of Plant Engineered Safety Features Actuation System, E-115-751 (Rev.), January 1979 (Supplier Document Number J104-52-3).

QUESTION 8A.15 (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

The analytical techniques and assumptions used in the voltage analyses must be verified by actual measurement. The verification and test should be performed prior to initial full power reactor operation on all sources of offsite power by:

a. Loading the station distribution buses, including all Class 1E buses down to the 120/208V level, at least 30%
b. Recording the existing grid and Class 1E bus voltages and bus loading down to the 120/208 volt level at steady-state conditions and during the starting of both a large Class 1E and non-Class 1E motor (not concurrently)

NOTE: To minimize the number of instrumented locations (recorders) during the motor starting transient test, the bus voltages and loading need only be recorded on that string of buses which previously showed the lowest analyzed voltages from item above.

RESPONSE: PVNGS will measure the station distribution buses including Class 1E buses unloaded and record voltages. PVNGS will also measure and record the station distribution buses, including Class 1E buses, upon loading the bus to at least 30%. This will occur prior to completion of the initial test program. CATS RCTS 035303 closed 11/18/87, letter ANPP-34491.

PVNGS will measure and record grid and Class 1E bus voltages and bus loading during the startup of a large Class 1E motor and also during the starting of a large non-Class 1E motor. The above information will be reviewed to verify analytic data. CATS RCTS 031430 closed 9/6/84, letter ANPP-18670-P26.

QUESTION 8A.16 (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

Part 1

Provide the time delay settings for the two 4160 volt safety related bus undervoltage relays.

RESPONSE: The response is given in paragraph 8.3.1.1.3.13.

Part 2

Submit the following information: the voltage levels at the safety-related buses optimized for the maximum and minimum load conditions that are expected throughout the anticipated range of voltage variations of the offsite power sources by appropriate adjustment of the voltage tap settings of the intervening transformers. The tap settings selected should be based on an analysis of the voltage at the terminals of the Class 1E loads. The analyses performed to determine minimum operating voltages should typically consider maximum unit steady state and transient loads for events such as a unit trip, loss of coolant accident, startup or shutdown; with the offsite power supply (grid) at minimum anticipated voltage and only the offsite source being considered available. Maximum voltages should be analyzed with the offsite power supply (grid) at maximum expected voltage concurrent with minimum unit loads (e.g., cold shutdown, refueling). A separate set of the above analyses should be performed for each available connection to the offsite power supply.

RESPONSE: The response is given in paragraph 8.3.1.1.3.

<u>QUESTION 8A.17</u> (Letter from R. L. Tedesco of June 17, 1981 on AC Power)

One of the CESSAR interface requirements is to provide 480 volt power supply to the six shutdown cooling isolation valves such that no single failure of power supply can open the valves to connect the reactor coolant system and shutdown cooling system inadvertently, nor can a single failure of power supply prevent

opening all the valves of, at least, one section line during initiation of shutdown cooling. The Palo Verde design provides 480 volt power to four of these valves only. The other two valves are not included in table 8.3-1 of the FSAR. This is unacceptable. Therefore, we require that the remaining valves be included in this table. In addition, the following additional information on this subject shall be provided for our review:

1. A description of how the power supply to these valves meet the single failure criterion to prevent over-pressurization of the low-pressure system piping and achieve cold shutdown.
2. A sketch that shows how the power supply to the three series shutdown cooling isolation valves in each train is arranged.

RESPONSE: The two remaining cooling isolation valves, having tag numbers J-SIC-UV-653 and J-SID-UV-654, are shown in table 8.3-6.

Additional response is given in section 5.4.7.2. PVNGS meets the single failure criterion.

APPENDIX 8B

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CHAPTER 9

AUXILIARY SYSTEMS

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FIGURES

FIGURES (cont)

9. AUXILIARY SYSTEMS

9.1 FUEL STORAGE AND HANDLING

9.1.1 NEW FUEL STORAGE

9.1.1.1 Design Bases

The following design bases are imposed on the storage of new fuel:

A. Accidental criticality shall be prevented for the most reactive arrangement of new fuel stored, with optimum moderation, by assuring that K_{eff} is less than 0.98. This design basis shall be met under any normal or accident conditions.

B. The requirements of Regulatory Guide 1.13 shall be met.

C. The storage racks and facilities shall be qualified as Seismic Category 1.

D. Storage shall be provided for at least one-third core of new fuel.

9.1.1.2 Facilities Description

The rack assemblies are made up of individual racks similar to those shown in figure 9.1-1. A minimum edge-to-edge spacing between fuel assemblies, as required by paragraph 9.1.1.3.1, is maintained between assemblies in adjacent rows. These spacings are the minimum values after allowances are made for rack fabrication tolerances and the predicted deflections resulting from postulated accident conditions, discussed in paragraph 9.1.1.3.1.

The specific location of the new fuel racks in the fuel building is shown in engineering drawings 13-P-OOB-004, 13-P-OOB-005, 13-P-OOB-010 and figure 9.1-2.

The stainless steel construction of the storage racks is compatible with water and zirconium clad fuel.

The top structure of the racks is designed such that there is no opening between adjacent fuel cavities that is as large as the cross-section of the fuel bundle. In addition, the outer structure of the racks precludes the inadvertent placement of a bundle against the rack closer than the prescribed edge-to-edge spacing.

9.1.1.3 Safety Evaluation

The new fuel storage rack design and location, discussed in paragraph 9.1.1.2, ensures that the design bases of paragraph 9.1.1.1 are met. The capability of PVNGS new fuel storage is described below.

9.1.1.3.1 Criticality Safety

The following postulated accidents were considered in the design of the new fuel storage racks:

A. Flooding; complete immersion of the entire storage array in pure, unborated, room temperature water.

B. Envelopment of the entire array in a uniform density aqueous foam or mist of optimum density that maximizes the reactivity of the finite array as described in listing D of the criticality safety assumptions. It is

postulated that these conditions could be present as a result of fire fighting.

C. A fuel assembly dropped from a height of 4-1/2 feet onto the rack which then falls horizontally across the top of the rack.

D. Tensile load on the rack of 5000 pounds (limited by adjustment of the motor stall torque or load limiting device of the crane used to load fuel into the racks.)

Although the above accident conditions have been postulated, the fuel handling equipment, new fuel racks, and the building arrangement are designed to minimize the possibility of these accidents or the effects resulting from these accidents by:

A. Providing positive hoist travel limits and interlocks to ensure proper equipment operation and sequencing.

B. Limiting the crane loads when installing fuel into or removing fuel from the fuel rack.

C. Designing the new fuel racks for SSE conditions and dropped fuel bundle conditions.

D. Maintaining K_{eff} less than 0.95 in the event the fuel area becomes flooded.

E. Designing the new fuel handling crane to preclude the new fuel handling crane, or any part thereof, from falling into the new fuel handling area.

The following assumptions are made in evaluating criticality safety:

A. Under postulated conditions of complete flooding by unborated room temperature water, the storage array is treated as described in item D.

B. Under postulated conditions of envelopment by aqueous foam or mist, a range of foam or mist densities is examined to ensure that the maximum reactivity of the array is established. The foam or mist is assumed to be pure water.

C. For the analyses presented here, the poisoning effects of rack structure have been included in a conservative manner by assuming the box wall thickness to be less than the minimum wall thickness shown in figure 9.1-1. It is also assumed that no supplemental fixed poisons are utilized in the storage array.

D. Two concrete storage cavities are utilized for new fuel storage. Each cavity is approximately 8 feet by 23 feet and contains 45 fuel assemblies with an active fuel length of 150 inches. Three racks (figure 9.1-1) are installed in each cavity forming a 3 x 15 array of fuel assemblies.

   The 3 x 15 array is assumed to be surrounded on all six faces by a 1-foot thick close-fitting reflector of concrete with reflective boundary conditions applied to the outside of each the six faces. This assumption is conservative since the concrete walls are several inches away from the outer rows of fuel assemblies, the

floor is several inches below the bottom of the active fuel, and the materials above the active fuel provide a substantially poorer reflector than the assumed thick concrete reflector. Calculations indicate that the assumption of concrete reflectors is conservative relative to the assumption of thick water reflectors.

E. The rack is assumed to be filled to capacity with fuel assemblies.

F. No burnable poison shims or other supplemental neutron poisons (e.g., control element assemblies) are assumed to be present in the fuel assemblies.

Criticality safety margins are maintained by:

A. Limiting the size of the array to 90 assemblies.

B. Defining an overall array configuration as shown in figure 9.1-1.

C. Providing adequate mechanical separation of fuel assemblies in the array, even under postulated accident conditions.

The mechanical separation provided is discussed in paragraph 9.1.1.2.

In evaluating criticality safety, neutron cross-section data for representative fuel rod cells, and material between and around assemblies, is from the updated 44 group ENDF/B-5 neutron cross section library[1]. Spatial calculations are performed using the three-dimensional Monte Carlo code KENO-Va[1] to quantify the multiplication factor for the storage racks for the range of water densities from flooded to mist conditions

assuming thick concrete reflectors on all faces of the storage array.

Maximum K_{eff} values have been calculated for radially averaged enrichments up to 4.80 w/o U-235. For all conditions, i.e., normal and accident, the K_{eff} values are less than 0.95.

These k_{eff} values are substantially below the limiting values allowed by ANSI Standard N18.2 and provide adequate margin for calculation uncertainty.

The rack structure provides at least 10 inches between the top of the active fuel and the top of the rack to preclude criticality in the event a fuel assembly is dropped into a horizontal position on the top of the rack.

The new fuel storage area is protected from the effects of missiles or natural phenomena as discussed in section 3.5.

9.1.1.3.2 Compliance with Regulatory Guide 1.13

New fuel storage complies with Regulatory Guide 1.13.

9.1.1.3.3 Seismic Classification

New fuel storage racks and facilities are qualified as Seismic Category I.

9.1.1.3.4 Storage Capacity

Storage is provided for at least one-third of a core of new fuel.

9.1.2 SPENT FUEL STORAGE

9.1.2.1 Design Bases

9.1.2.1.1 Spent Fuel Pool

The following design bases are imposed on the storage of fuel within the spent fuel pool:

A. Accidental criticality shall be prevented by assuring the K_{eff} remains less than 1.0 with full density unborated water under normal conditions, and by assuring that K_{eff} remains less than or equal to 0.95 taking credit for 900 ppm soluble boron in the water under any normal or accident conditions. These K_{eff} limits include an allowance for biases and uncertainties, including methodology and temperature biases, and enrichment, stack density, steel thickness, storage cell pitch, assembly position, calculational, and 95/95 confidence level uncertainties.

B. The requirements of Regulatory Guide 1.13 shall be met.

C. The storage racks and facilities shall be Seismic Category I.

D. Storage shall be provided for up to 1329 fuel assemblies.

E. The storage racks and spent fuel pool facilities shall prevent extensive bulk boiling in the fuel racks and prevent fuel assembly peak clad temperatures from exceeding 650F.

F. Shielding of spent fuel shall be adequate to ensure that the radiation zone criteria of section 12.3 are met.

9.1.2.1.2 Independent Spent Fuel Storage Installation (ISFSI)

The principle design bases of the ISFSI are prescribed in the NAC-UMS® Certificate of Compliance (CoC) and FSAR (Docket no. 72-1015). Refer to the ISFSI 72.212 Evaluation Report for additional details regarding dry fuel storage system design bases.

9.1.2.2 Facility Description

9.1.2.2.1 Spent Fuel Pool

For the purpose of compliance with NAC-UMS Technical Specifications, the spent fuel pool consists of the spent fuel pool and/or the cask loading pit; however, the Seismic Category I boundary varies depending on configuration of the gates, PCN-V-118, and the quick closure device.

During normal operations, the spent fuel pool Seismic Category I physical boundary is defined as the inner gate located between the spent fuel pool and the cask loading pit and the quick operating closure device on the containment side of the transfer tube in combination with the spent fuel pool liner drain valves.

During scheduled refueling operation, the Seismic Category I physical boundary of the spent fuel pool is defined as the inner gate located between the spent fuel pool and the cask loading pit and the valve PCN-V-118 on the fuel building side

of the transfer tube in combination with the spent fuel pool liner and drain valves.

During transfer of spent fuel assemblies to support dry fuel storage loading operations, the Seismic Category I physical boundary of the spent fuel pool is defined as the outer gate located between the cask loading pit and the cask wash down area and the quick closure device on the containment side of the transfer tube in combination with the spent fuel pool liner and drain valves.

During movement of heavy loads with the cask handling crane, the spent fuel pool Seismic Category I physical boundary is the same as that defined for normal operations.

The fuel pool transfer canal, cask loading pit and cask washdown area gate seals are designed as Class Q, Seismic Category I. These seals are designed to remain functional during and after accident conditions.

9.1.2.2.2 Spent Fuel Pool Storage Racks

The spent fuel pool storage racks are made up of individual modules. A module is an array of fuel storage cells similar to that shown in figure 9.1-3. The storage racks are comprised of 17 modules: twelve 8 by 9 and four 8 by 12 arrays, and one 9 by 9 array. The storage racks are stainless steel honeycomb structures with rectangular fuel storage cells. The stainless steel construction of the racks is compatible with fuel assembly materials and the spent fuel borated water environment. The fuel assembly spacings of a nominal 9.5 inches center-to-center distance between adjacent storage

cell locations are minimum values after allowances are made for rack fabrication tolerances and predicted deflections resulting from a safe shutdown earthquake (SSE)

The spent fuel pool was originally designed and approved by the NRC to store up to 1329 new or spent fuel assemblies in a borated fuel storage mode, up to 665 assemblies in a checkerboard storage mode, or between 665 and 1329 assemblies in a mixed mode.

In September 1994, the NRC approved Technical Specification amendments 82, 69, and 54 for Units 1, 2, and 3, respectively, to allow credit to be taken for burnup of spent fuel assemblies in establishing storage locations within the spent fuel pool in three distinct storage regions.

In March 2000, the NRC approved Technical Specification amendment 125 for Units 1, 2, and 3 to increase the storage capacity of the spent fuel pools by taking credit for burnup, decay time, and soluble boron in establishing storage locations with the spent fuel pool in four storage regions. These storage regions are shown in Figures 9.1-7 and 9.1-7A. Fuel is placed in the appropriate region based on the initial enrichment, actual burnup, and actual decay time as designated in Table 9.1-1. Core operating conditions, such as temperature and boron concentration, influence plutonium production and may increase the discharged fuel reactivity which could impact those numbers. Curves corresponding to the data in Table 9.1-1 are shown in Technical Specification LCO 3.7.17, and Regions 1, 2, 3, and 4 are described in Sections 9.1.2.2.2.1 through 9.1.2.2.2.4.

The spent fuel pool criticality analysis of record allows 1209 fuel assemblies to be stored in the four region configuration. However, since the design basis for the spent fuel cooling system assures adequate cooling for only 1205 fuel assemblies (Section 9.1.3), four additional cells are required to be blocked to satisfy both the criticality analysis and the spent fuel cooling system design basis. As shown in Figures 9.1-7 and 9.1-7A, cells A-22, A-23, A-24, and HH-26 have been specified as the additional four cells required to be blocked.

The spent fuel pool incorporates L-inserts as shown in Figure 9.1-4 in every other storage rack location. The change to the spent fuel pool made as a result of the September 1994 Technical Specification changes did not install L-inserts in the available storage cells where L-inserts were not previously installed. The safety analysis submitted for that Technical Specification change justified not installing the additional L-inserts.

TABLE 9.1-1

REQUIRED ASSEMBLY BURNUP FOR STORAGE IN REGIONS 2, 3, AND 4 (NOTES 1 & 2)

INITIAL RADIALLY AVERAGED ENRICHMENT (weight percent)	MINIMUM ASSEMBLY BURNUP (MWD/MTU) FOR DECAY TIME	MINIMUM ASSEMBLY BURNUP (MWD/MTU) FOR DECAY TIME	MINIMUM ASSEMBLY BURNUP (MWD/MTU) FOR DECAY TIME	MINIMUM ASSEMBLY BURNUP (MWD/MTU) FOR DECAY TIME	MINIMUM ASSEMBLY BURNUP (MWD/MTU) FOR DECAY TIME
REGION 2	0 YEARS	NOTE 3	NOTE 3	NOTE 3	NOTE 3
1.50	0.00	---	---	---	---
2.00	7048.00	---	---	---	---
2.50	14574.00	---	---	---	---
2.54	15085.90	---	---	---	---
3.00	15085.90	---	---	---	---
3.50	15085.90	---	---	---	---
4.00	15085.90	---	---	---	---
4.50	15085.90	---	---	---	---
4.80	15085.90	---	---	---	---
REGION 3	0 YEARS	5 YEARS	10 YEARS	15 YEARS	20 YEARS
1.50	0.00	0.00	0.00	0.00	0.00
2.00	7048.00	6778.00	6691.00	6586.00	6609.00
2.50	14574.00	13699.00	13372.00	13011.00	12838.00
2.54	15085.90	14185.00	13833.00	13457.00	13271.00
3.00	21238.00	20024.00	19379.00	18818.00	18475.00
3.50	27335.00	25854.00	24879.00	24264.00	23888.00
4.00	33095.00	31344.00	30083.00	29517.00	29206.00
4.50	38706.00	36703.00	35248.00	34672.00	34320.00
4.80	42059.00	39998.00	38505.00	37706.00	37057.00
REGION 4	0 YEARS	5 YEARS	10 YEARS	15 YEARS	20 YEARS
1.50	3591.00	3379.05	3257.46	3177.47	3121.75
2.00	12982.17	12215.92	11766.36	11487.17	11285.74
2.50	20567.63	19220.67	18789.89	18039.66	17674.13
2.54	21083.89	19702.97	19265.59	18491.64	18116.96
3.00	27288.35	25499.37	24982.61	23923.65	23438.98
3.50	33710.97	31650.14	30790.07	29732.01	29113.79
4.00	40026.64	37807.83	36461.14	35557.17	34665.51
4.50	46053.67	43643.61	41963.39	41081.69	39521.11
4.80	49160.90	46479.19	45040.87	43703.55	41334.54

NOTE 1: Minimum assembly burnup for fuel with initial radially averaged enrichment other than the weight percents shown should be linearly interpolated.
NOTE 2: Minimum assembly burnup for fuel with actual decay time other than the values shown should be linearly interpolated.
NOTE 3: Credit for decay time greater than 0 years does not apply to Region 2.

9.1.2.2.2.1 Region 1. Fresh fuel assemblies with a maximum radially averaged enrichment equal to 4.80 weight percent U-235 will be stored in a checkerboard (two-out-of-four) storage pattern. Fuel assembly blocking devices are used in rack cells that are not within the acceptable checkerboard storage pattern (see figures 9.1-5, 9.1-7, and 9.1-7A). This prevents accidental insertion of a fuel assembly into an interstitial position so as to preclude criticality. Fuel that qualifies to be stored in Regions 1, 2, 3, or 4 may be stored in Region 1. Fresh fuel assemblies may only be stored in Region 1. Storage for up to 119 fuel assemblies can be provided in Region 1.

9.1.2.2.2.2 Region 2. Fuel will be stored in a repeating three-by-four storage pattern in which Region 2 (two-out-of-twelve) and Region 4 (ten-out-of-twelve) locations are mixed as shown in Figures 9.1-7 and 9.1-7A. Fuel that qualifies to be stored in Regions 2, 3, or 4 may be stored in Region 2. Fuel that only qualifies to be stored in Region 1 may not be stored in Region 2. Storage for up to 131 fuel assemblies can be provided in Region 2 in Units 2 and 3. Storage for up to 119 fuel assemblies can be provided in Region 2 in Unit 1.

9.1.2.2.2.3 Region 3. Fuel will be stored in a four-out-of-four storage pattern. Fuel that qualifies to be stored in Regions 3 or 4 may be stored in Region 3. Fuel that only qualifies to be stored in Regions 1 or 2 may not be stored in Region 3. Storage for up to 297 fuel assemblies can be provided in Region 3 in Units 2 and 3. Storage for up to 369 fuel assemblies can be provided in Region 3 in Unit 1.

9.1.2.2.2.4 Region 4. Fuel will be stored in a repeating three-by-four storage pattern in which Region 2 (two-out-of-twelve) and Region 4 (ten-out-of-twelve) locations are mixed as shown in Figures 9.1-7 and 9.1-7A. Only fuel that qualifies to be stored in Region 4 will be stored in Region 4. Storage for up to 658 fuel assemblies can be provided in Region 4 in units 2 and 3. Storage for up to 598 fuel assemblies can be provided in Region 4 in Unit 1.

9.1.2.2.3 Independent Spent Fuel Storage Installation (ISFSI)

The ISFSI is a 20-acre facility located Northeast of the Palo Verde 525 kV switchyard. The ISFSI provides a location for interim dry storage of spent nuclear fuel prior to shipment off-site for permanent storage. The ISFSI consists of 12 Seismic Category IX reinforced concrete pads arranged in a 3 x 4 array. Each pad is 285′ x 35′ x 30″ and is capable of storing 28 vertical concrete casks arranged in a 2 x 14 array. The 2 rows of each array are 15′ center to center with individual casks in each row spaced a minimum of 15′ center to center. This spacing provides sufficient room for maneuvering of the cask transporter and also assures the casks will be stored in a subcritical array. Each cask is loaded with up to 24 spent fuel assemblies. The 336 total casks that the ISFSI is designed to store are sufficient to contain all anticipated spent fuel assemblies that will be generated by PVNGS for the duration of its current license.

While on the storage pad, the VCC outlet temperatures are monitored and compared to ambient temperature using the temperature monitoring system (TMS). The temperature

monitoring system relays data form each VCC to the Unit 1 control room for performance of NAC-UMS® Technical Specification Surveillances. Performance of these Surveillances provides assurance that the VCC heat removal system remains Operable (i.e., air inlets and outlets are not blocked).

The ISFSI is secured in a protected area that is separate from the 10CFR50 reactor facility protected area. Refer to the PVNGS security plan for additional details.

The ISFSI is surrounded on three sides by an earthen berm. The earthen berm is designed to provide radiation shielding to maintain personnel dose ALARA and to meet the requirements of 10CFR72.104 and 10CFR72.106. There is no active radiation monitoring or alarm system at the ISFSI. Radiation is monitored by use of strategically located TLD's.

9.1.2.3 Safety Evaluation

The spent fuel pool storage rack design and location, discussed in paragraph 9.1.2.2, provides assurance that design bases of paragraph 9.1.2.1 are met as noted in the following sections.

9.1.2.3.1 Criticality Safety

The following postulated accidents were considered in the design of the spent fuel pool storage racks.

A. A fuel assembly dropped from a height of 2 feet above the rack onto the rack with the assembly then falling horizontally across the top of the rack or falling

between the rack and surrounding spent fuel pool walls or falling into a blocked-off fuel storage cavity.

B. Tensile load on the rack of 5000 pounds.

Although the above accident conditions have been postulated, the fuel handling equipment, fuel racks, and building arrangement are designed to minimize the possibility of these accidents or the effects resulting from these accidents by:

A. Providing positive mechanical travel hoist limits and interlocks to ensure proper equipment operation and sequence.

B. Limiting the crane loads when installing fuel into or removing fuel from the fuel rack.

C. Designing the fuel racks for SSE conditions and dropped fuel bundle conditions.

D. Designing the fuel handling machine as Seismic Category I to preclude the fuel handling machine, or any part thereof, from falling into the spent fuel pool.

The following assumptions are made in evaluating criticality safety:

A. No control element assemblies (CEAs) are assumed to be present in the fuel assemblies.

B. The rack is assumed to be filled to capacity (as defined by Section 9.1.2.2.2) with fuel assemblies of the type whose criticality safety was evaluated with the pool filled with water.

C. For normal operation, no credit is assumed for the soluble boron contained in the spent fuel pool water (K_{eff} < 1.0). For operation with the most limiting single fuel misloading, credit is taken for 900 ppm of the soluble boron contained in the spent fuel pool water (which is normally at $\geq$ 2150 ppm) to assure that K_{eff} remains less than or equal to 0.95 at all times. For the flooded spent fuel pool criticality analysis, a conservative temperature is assumed for the water moderator.

D. Intentionally left blank.

E. Only one fuel assembly is assumed to be dropped in a fuel handling accident, and only one fuel assembly is assumed to misloaded in a fuel misloading event.

Criticality safety margins are assured by:

A. Not crediting the neutron absorption effects associated with the soluble boron concentration in excess of 900 ppm contained in the spent fuel pool water.

B. Qualifying a fuel assembly to be stored in Regions 1, 2, 3, or 4 based upon the initial enrichment, burnup, and decay time of the fuel assembly.

In evaluating criticality safety, neutron cross-section data for representative fuel rod cells, and material between and around assemblies, is from the updated 44 group ENDF/B-5 neutron cross section library[1]. Spatial calculations are performed using the three-dimensional Monte Carlo code KENO-Va[1] to quantify the multiplication factor for the storage rack as a

whole as well as the sub-region infinite multiplication factors.

Maximum K_{eff} values have been calculated for radially averaged enrichments up to 4.80 w/o U-235.

For all conditions, i.e., normal and accident, K_{eff} is less than 0.95 given partial credit for soluble boron contained in the spent fuel pool water. The K_{eff} values are less than or equal to the values allowed by 10CFR50, Appendix A, Criterion 62, "Prevention of Criticality in Fuel Storage and Handling".

The spent fuel storage area is protected from the effects of missiles or natural phenomena as discussed in section 3.5.

9.1.2.3.2 Deleted

9.1.2.3.3 Seismic Classification

The PVNGS spent fuel pool storage racks and facilities are Seismic Category I.

9.1.2.3.4 Storage Capacity

Storage is provided for up to 1329 fuel assemblies.

9.1.2.3.5 Fuel Assembly Cooling

The PVNGS spent fuel pool storage racks are designed to prevent extensive bulk boiling in the racks as well as maintain fuel cladding temperatures well below 650F for the following collective conditions:

A. Natural convection water circulation within the spent fuel pool

B. Maximum pool water temperature of 180F at the fuel rack inlet flow passages

C. Maximum fuel pool heat load as described in subsection 9.1.3.

9.1.2.3.6 Shielding

Concrete and water shielding are provided as shown in engineering drawings 13-P-OOB-003 through –005, 13-P-OOB-007 and 13-P-OOB-010. This shielding attenuates radiation from the maximum design loading of stored fuel assemblies such that the radiation zone criteria of section 12.3 are met.

9.1.2.4 Design Bases for Containment Fuel Storage Racks

The following design bases are imposed on the storage of fuel within the containment fuel rack:

A. Accident criticality shall be prevented for the most reactive arrangement of fuel stored in unborated water by designing to a k_{eff} less than 0.95. This design basis shall be met under any normal or accident conditions.

B. The requirements of Regulatory Guide 1.13 shall be met as described in Section 1.8.

C. The storage racks and facilities shall be Seismic Category 1.

D. Storage shall be provided for up to four fuel assemblies having a maximum radially averaged U-235 enrichment of 4.80 weight percent.

E. The refueling canal facilities shall prevent extensive bulk boiling in the fuel racks and prevent fuel assembly peak clad temperatures from exceeding 650F.

F. Shielding of spent fuel shall be adequate to ensure that the radiation zone criteria of section 12.3 are met.

9.1.2.4.1 Description of Containment Fuel Storage Racks

The four-cavity containment fuel storage rack is designed as an intermediate storage location for fuel bundles during a refueling.

The rack consists of four cavities for storage of fuel. Each cavity is a stainless steel can 8.69 inches on a side. The cavities are separated by a minimum fuel edge-to-edge distance of 9.4 inches. Each of the cavities is open at the bottom to provide thermal cooling for a worst case fuel bundle. The rack's structure is designed to maintain k_{eff} of less than 0.95 by assuring that under all normal and accident conditions, which includes SSE, the minimum edge distance is not violated and also that a fuel bundle cannot violate the 12-inch minimum stand-off distance around the cavities. The rack is located adjacent to the core support barrel laydown area, which provides access to the refueling machine for insertion and removal of fuel bundles.

9.1.2.4.2 Safety Evaluation

The containment fuel storage rack design and location, discussed in paragraph 9.1.2.4.1, provides assurance that design bases of paragraph 9.1.2.4 are met as noted in the following paragraphs.

9.1.2.4.2.1 Criticality Safety. The following assumptions are made in evaluating criticality safety:

A. No CEAs are assumed to be present in the fuel assemblies.

B. The rack is assumed to be filled to capacity with fuel assemblies of the type whose criticality safety is being evaluated.

C. For normal operation, no credit is assumed for the boron normally found in the refueling pool water.

D. An infinitely long fuel assembly is assumed.

Criticality safety margins are assured by:

A. Neglecting the neutron absorption effects associated with the boron normally in the refueling pool water during refueling operations.

B. When fuel is stored in the rack, no credit is taken for the neutron absorption affects of the rack structure.

C. No credit is taken for burnable shims or other supplemental neutron poisons (e.g., CEAs).

In evaluating criticality safety, neutron cross-section data for representative fuel rod cells, and material between and around assemblies, is from the updated 44 group ENDF/B-5

neutron cross section library[1]. Spatial calculations are performed using the three-dimensional Monte Carlo code KENO-Va[1] to quantify the multiplication factor for the storage racks.

Maximum K_{eff} values have been calculated for radially averaged enrichments up to 4.80 w/o U-235.

For all conditions, i.e., normal and accident, K_{eff} is less than 0.95. The K_{eff} values are substantially below the limiting values allowed by ANSI Standard N18.2 and provide adequate margin for calculation uncertainty.

9.1.3 SPENT FUEL POOL COOLING AND CLEANUP SYSTEM

9.1.3.1 Design Basis

9.1.3.1.1 Fuel Pool Cooling Design Bases

The following design bases are imposed on spent fuel pool cooling:

A. Two independent, 100% capacity spent pool cooling systems are provided to cool the spent fuel pool and prevent damage to spent fuel assemblies stored therein under normal plant operation. Spent fuel pool cooling system capacity requirement vary significantly during refueling and accident conditions. During these modes of operation, the shutdown cooling system may be used to augment pool cooling. The combination of these systems provide the flexibility required to maintain spent fuel cooled while maintenance tasks are performed during refueling outages. The simultaneous operation of two PC pumps and one LPSI or one CS pump is administratively prohibited due to the

potential for air entrainment into the suction line. Table 9.1-2 and sections 9.1.3.2.1.1 and 9.1.3.3.1.1 provide a minimum number of systems required to be available based on maximum decay heat generated from the spent fuel assemblies. However, minimum systems in operation could be less if bulk water temperature in the spent fuel pool can be maintained to values stated in section 9.1.3.3.1.1. Also, these requirements are only applicable if decay heat is present in the spent fuel pool and decay heat loads are comparable to values listed in table 9.1-2. System requirements are usually less restrictive and are time dependent due to reduction of decay heat as a function of time.

B. Each of the spent fuel pool cooling system trains must reject heat to an ultimate heat sink qualified under the provisions of Regulatory Guide 1.27.

C. Two makeup water sources, one of which is Seismic Category I, shall be available for use.

D. All equipment and instrumentation necessary to meet the design bases of this section shall be provided with reliable power source and capability of being loaded on Class 1E electrical power if needed.

E. Spent fuel pool cooling systems, in conjunction with shutdown cooling systems when needed, shall provide adequate cooling to the spent fuel during all operating conditions for up to 1205 spent fuel assemblies.

9.1.3.1.2 Spent Fuel Pool Cleanup Design Bases

The following design bases are imposed on spent fuel pool cleanup:

A. Fuel pool water clarity shall be maintained.

B. A level of decontamination of the spent fuel pool water during normal operation and refueling shall be maintained such that dose rates above the pool at the refueling machine platform are maintained less than 2.5 mrem/h event when considering direct shine due to fuel assemblies.

C. The fuel pool cleanup system shall be designed to tolerate the following water chemistry:

1.	pH (at 77F)	3.8 to 10.2
2.	Boric acid, max weight percent	2.5
3.	Ammonia, maximum ppm	50
4.	Lithium, maximum ppm	0.5
5.	Dissolved air, maximum	Saturated
6.	Chloride, maximum ppm	0.15
7.	Fluoride, maximum ppm	0.1

9.1.3.2 System Description

9.1.3.2.1 Spent Fuel Pool Cooling and Cleanup System

Engineering drawings 01, 02, 03-M-PCP-001 is a piping and instrumentation diagram of the spent fuel pool cooling and cleanup system. As this system has two different functions, the system description is in two parts. Refer to

paragraph 9.1.3.2.1.1 for the spent fuel pool cooling subsystem and to paragraph 9.1.3.2.1.2 for the spent fuel pool cleanup subsystem.

9.1.3.2.1.1 Spent Fuel Pool Cooling. The spent fuel pool cooling system is manually operated from a local control panel. The pool high temperature alarm, the water level alarms, and local control panel trouble alarm are annunciated in the main control room via a common trouble alarm.

The spent fuel pool cooling system consists of two spent fuel pool cooling pumps, each powered from the Class 1E electrical system, and two fuel pool heat exchangers. The fuel pool cooling pumps are connected to a common suction header and return header. The system is also provided with appropriate valves, piping, and instrumentation. Spent fuel pool water is circulated by the fuel pool pumps through the fuel pool heat exchangers, where it is cooled by the nuclear cooling water system or by the essential cooling water system and ultimate heat sink. The following is a summary of analyzed plant condition (also refer to sections 9.1.3.1.1 and 9.1.3.3.1).

1- Normal plant condition: One or two trains of the spent fuel pool cooling system provide cooling of the spent fuel pool. During this mode of operation, heat exchangers are cooled by the nuclear cooling water system. If the nuclear cooling water system is unavailable, the essential cooling water system can be used.

2- Emergency plant condition: The spent fuel pool cooling system can be aligned manually with the essential cooling water system and ultimate heat sink system during any event

described in chapter 15 which would result in loss of offsite power. See section 9.2 for details of these auxiliary systems.

3- Scheduled normal refueling condition (includes full core off load/reload, fuel off load initiated 100 hours after shutdown): The spent fuel pool cooling system is normally cooled by one or two trains of the pool cooling system and the nuclear cooling water system. If the nuclear cooling water system is unavailable, the essential cooling water system can be used. The shutdown cooling system (using either the LPSI or containment spray pump) can also be used to augment spent fuel pool cooling as needed. The system description for the shutdown cooling system is presented in section 5.4.7.

4- Emergency condition during a scheduled normal refueling (loss of offsite power): One train of the spent fuel pool cooling system augmented by one train of the shutdown cooling system (using either the LPSI or containment spray pump). These systems are cooled by essential cooling water in conjunction with the ultimate heat sink (spray pond).

5- Emergency condition during fuel transition mode (loss of offsite power); During this mode of operation when the core is being off loaded or re-loaded, the spent fuel pool cooling system may be augmented by one train of shutdown cooling (using either the LPSI or containment spray pump) and associated auxiliaries. The shutdown cooling train in service is aligned such that it would provide cooling to both the reactor core and the spent fuel pool.

6- Emergency core off load condition: When the core is fully off loaded, during an unscheduled outage for emergency maintenance, the spent fuel pool can be cooled by one train of the fuel pool cooling system cooled by the nuclear cooling water system, augmented by one train of the shutdown cooling system cooled by the essential cooling water system.

Instrumentation is provided which monitors the temperature of both the refueling and spent fuel pools and the water level in both pools. Spent fuel pool alarms are annunciated locally and in the main control room via a common trouble alarm. Refueling pool computer alarms are annunciated in the main control room only. Additional instrumentation and a thermowell on the heat exchanger inlet, monitored locally, is provided to check inlet and outlet temperatures on the heat exchangers, and to determine the pressure of the cooling pump discharge. Sight gauges are provided on the heat exchangers and the cooling pump drain lines.

Table 9.1-2 provides the principal design parameters of the cooling loop.

9.1.3.2.1.2 Spent Fuel Pool Cleanup. The spent fuel pool cleanup system consists of two trains, each having a strainer, a pump, a filter, and an ion exchanger. Either one or both trains may be aligned to clean the water in the spent fuel pool or the refueling water tank continuously (if required). During refueling, this system can be aligned with the refueling pool if all fuel assemblies are in the reactor vessel or in the spent fuel pool and valve PCN-V-118 is closed, or

administrative procedures are in place to ensure timely identification and isolation of a breach of spent fuel pool cleanup system boundary as result of a seismic event or pipe break. The spent fuel pool clean up system is aligned with the pool drain system only for a short duration of time during the refueling operation for fill and drain operation. The system is under procedural control during these evolutions.

The cleanup loops are normally run from a local panel when required by the water conditions from the various sources. It is possible to operate each loop independently and with either the ion exchanger or filter bypassed by means of manually operated valves. Local samples permit analysis of ion exchanger and filter efficiency. A small fraction of the purification flow is drawn through the surface skimmers.

The spent fuel pool and refueling pools are continuously monitored by detectors XJ-SQA-RU-31 and XJ-SQA-RU-33 (refer to table 11.5-1). Additionally, sampling is provided by a batch method as shown in engineering drawing 13-N-997-184.

The fuel pool cleanup system has differential pressure transducers on the cleanup filters, the ion exchangers, and the cleanup strainers. Sight gauges are provided on the cleanup pumps and filters.

The principal design parameters of the cleanup loop are listed in table 9.1-3.

9.1.3.3 Safety Evaluation

9.1.3.3.1 Fuel Pool Cooling

Each unit has continuous, independent, ESF grade, fuel pool cooling systems designed to ensure safe spent fuel handling and storage as described below.

9.1.3.3.1.1 Safety Design Bases. There are four provisions for cooling discharged fuel:

- Spent fuel pool cooling train A
- Spent fuel pool cooling train B
- Shutdown cooling system train A (LPSI or Containment spray pump)
- Shutdown cooling system train B (LPSI or Containment spray pump)

Each cooling system can itself be cooled by the essential cooling water (ECW) system. However, spent fuel pool cooling is normally cooled by the nuclear cooling water system (reference sections 1.2.10.3.3.1, 1.2.10.3.3.6, 9.2.2.1 and 9.2.2.2). The ECW system heat exchangers are serviced by the ultimate heat sink (spray pond). In the event that the spent fuel pool temperature rises above 125F, alarms are annunciated locally and in the main control room. If the nuclear cooling water system is out of service, the cooling water for the PC heat exchangers can be switched to the ECW system. The following summarizes different plant conditions

Table 9.1-2
COOLING SYSTEM DESIGN PARAMETERS (Sheet 1 of 4)

Parameter	Value
Minimum Analyzed Heat Removal Capability, Btu/hr	
1 - Normal plant condition 2 trains of PC cooled by NC	9.9E+6/train or 19.8E+6 total
2 - Emergency plant condition 1 train of PC cooled by EW	12.6E+6
3 - Scheduled Normal refueling plant condition 1 train of PC cooled by NC augmented by 1 train of SDC	 9.9E+6 37.6E+6
Total	47.5E+6
4 - Emergency plant condition during a scheduled refueling. 1 train of PC cooled by EW augmented by 1 train of SDC	 16.4E+6 63.6E+6
Total	80.0E+6
5 - Emergency plant condition during fuel transition mode (off load/ reload). 1 trains of PC cooled by EW augmented by 1 train of SDC	 16.4E+6 32.6E+6
Total	49.0E+6
6 - Emergency core off load during an unscheduled outage. 1 train of PC cooled by NC augmented by 1 train of SDC	 9.9E+6 45.0E+6
Total	54.9E+6
Spent Fuel Decay Heat[1], Btu/Hr	
1 - Design heat load power operation	12.6E+6 Administrative limit conservatively based on the SFP cooling capability given in Condition 2.
2 - Design heat load during emergency plant condition (accident)	12.6E+6 Administrative limit based on maximum heat removal capability of 1 train of PC cooled by EW (plant condition 2 above) following a design basis accident, concurrent with a LOP.
3, 4, and 5 - Design normal/emergency refueling heat load	47.0E+6 Full core offload beginning at 100 hours after shutdown plus 964 assemblies from the 12 previous annual refuelings.

1. Decay heat assumptions
   Method of calculation: Branch Technical Position 9-2, 1975
   Maximum duration of fuel cycle: 13,200 hr/cycle, irradiated 3 full cycles
   Plant capacity factor: 100%/cycle
   Plant power level: 3990 MWt
   For Cases 3, 4, 5, and 6: Fuel management practices limit total number of fuel assemblies in spent fuel pool as a function of time following reactor trip to maintain margin to spent fuel pool cooling system design capacity.

Table 9.1-2
COOLING SYSTEM DESIGN PARAMETERS (Sheet 2 of 4)

Parameter	Value
6 - Design Maximum heat load during emergency core offload	47.0E+06 Full core offload beginning at 100 hours after shutdown plus 1/3 core offload 90 days before the full core offload plus 884 assemblies from the 12 previous annual refuelings.
Normal spent fuel pool temperature, degrees F	125
Maximum spent fuel pool temperature(2), degrees F	167
Spent fuel pool boron concentration, ppm	0 to 4400
Fuel Pool Cooling Pumps	
Quantity	2
Type	Centrifugal, mechanical seals
Design pressure, psig	150
Design temperature, °F	250
Design head, ft	100
Design flow, gal/min	2000
NPSH required, ft at gal/min	13 at 2000
Normal operating temperature, °F	125
Fluid, boric acid solution, wt%	2-1/2
Materials in contact with fluid	Stainless steel
Bhp	72.8
Driver:	
Type	Electric motor
HP	100
Speed, r/min	1180
Power supply	480V Class 1E power system, 3 phase, 60Hz
Fuel Pool Cooling Heat Exchangers	
Quantity	2
Type	Shell and tube, horizontal
Configuration	TEMA CEM
Tube Side	
Code	ASME III, Class 3, TEMA R
Design fluid, boric acid solution, wt%	2-1/2

2. Maximum fuel pool temperature reached during a chapter 15 accident plant condition (loss of offsite power and single failure). Spent fuel pool cooling is manually aligned with EW within 8 hours after the initiating event.

Table 9.1-2
COOLING SYSTEM DESIGN PARAMETERS (Sheet 3 of 4)

Parameter	Value
Design pressure, psig	150
Design temperature, °F	250
Design flow, gal/min	2000
Pressure loss, psi at gal/min	4.2 at 2000
Material	Stainless steel
Shell side	
Code	ASME III, Class 3, TEMA R
Design fluid	Nuclear cooling water or Essential Cooling Water System
Design pressure, psig	150
Design temperature, °F	250
Design flow, gal/min	2500
Pressure loss, psi at gal/min	8 at 2500
Material	Carbon steel
Tube side, fuel pool water:	
Flow per heat exchanger, gal/min	2000
Nominal Inlet temperature, °F	125
Nominal Outlet temperature, °F	115

Table 9.1-2

COOLING SYSTEM DESIGN PARAMETERS (Sheet 4 of 4)

Parameter	Value	
Shell side, nuclear cooling water (NCW) / essential cooling water (ECW)	NCW	ECW
Flow per heat exchanger, gal/min	2500	1340
Nominal Inlet temperature, °F	105	105
Nominal Outlet temperature, °F	113	117

1- Normal plant condition: Two trains of the spent fuel pool cooling system are available. One or two spent fuel pool cooling pumps would be in operation to keep the pool temperature below 125F. In the event of failure of one train of spent fuel pool cooling, a single train is sufficient to maintain the spent fuel pool temperature below 145F. The heat removal capability of the spent fuel pool cooling system with two pool cooling trains available (PC cooled by NC) is 9.9E+6 Btu /hr/train, and the maximum decay heat generated in the spent fuel pool is administratively controlled to 12.6E+6 Btu/hr. (Refer to sections 9.1.3.1.1 and 9.1.3.2.1.1 for design bases and system descriptions.)

2- Emergency plant condition: The spent fuel pool cooling system would be available within 8 hours from the initiating event by manually aligning it with the essential cooling water system and ultimate heat sink system (this scenario is applicable to any event described in chapter 15 which would result in loss of offsite power). During this scenario, spent fuel pool temperature would be limited to 167F. The heat removal capability of one train of the spent fuel cooling system under this condition is 12.6E+6 Btu /hr, and the maximum decay heat generated in the spent fuel pool is administratively controlled to 12.6E+6 Btu/hr. (Refer to sections 9.1.3.1.1 and 9.1.3.2.1.1 for design bases and system descriptions.)

3- Scheduled normal refueling condition (includes full core off load/reload, beginning at 100 hours after shutdown with fuel management practices limiting total number of fuel

assemblies in spent fuel pool as a function of time following reactor trip to maintain margin to spent fuel pool cooling system design capacity): The spent fuel pool cooling system is normally cooled by one or two trains of the spent fuel pool cooling system (PC cooled by NC). The shutdown cooling system (LPSI or containment spray pump) can also be used to augment spent fuel pool cooling as needed. The spent fuel pool temperature during this mode of operation is maintained below 125F. The combined heat removal capability of the spent fuel cooling system and shutdown cooling system under this condition (1 train of PC/NC augmented by 1 train SDC) is 47.5E+6 Btu /hr, and the maximum calculated decay heat generated in the spent fuel pool is 47.0E+6 Btu/hr for a core power of 3990 MWt. (Refer to sections 9.1.3.1.1 and 9.1.3.2.1.1 for design bases and system descriptions.)

4- Emergency condition during a scheduled normal refueling (loss of offsite power and mechanical single failure): One train of the spent fuel pool cooling system augmented by one train of the shutdown cooling system (LPSI or containment spray pump). These systems are cooled by essential cooling water in conjunction with the ultimate heat sink (spray pond). During this scenario, the spent fuel pool temperature would be limited to 145F. The combined heat removal capability of one train of the spent fuel cooling system and one train of the shutdown cooling system under this condition is 80.0E+6 Btu/hr, and the maximum calculated decay heat generated in the spent fuel pool is 47.0E+6 Btu/hr for a core power of 3990 MWt.

(Refer to sections 9.1.3.1.1 and 9.1.3.2.1.1 for design bases and system descriptions.)

5- Emergency condition during fuel transition mode (loss of offsite power and a mechanical single failure): During this mode of operation when the core is being off loaded or re-loaded one train of the fuel pool cooling system could be augmented by one train of the shutdown cooling (LPSI or containment spray pump) and associated auxiliaries. The shutdown cooling train in service is aligned such that it would provide cooling to both the reactor core and spent fuel pool. The maximum pool temperature during this condition would be limited to 145F. The combined heat removal capability of one train of the spent fuel cooling system and one train of the shutdown cooling system under this condition is 49.0E+6 Btu/hr, and the maximum calculated decay heat generated in the spent fuel pool is 47.0E+6 Btu/hr for a core power of 3990 MWt. (Refer to sections 9.1.3.1.1 and 9.1.3.2.1.1 for design bases and system descriptions.)

6- Emergency core off load condition: One train of fuel pool cooling and one train of shutdown cooling can maintain and limit the maximum spent fuel pool temperature to less than 125F. Fuel pool decay heat for this event is a full core off load (beginning at 100 hours after shutdown with fuel management practices limiting total number of fuel assemblies in spent fuel pool as a function of time following reactor trip to maintain margin to spent fuel pool cooling system design capacity) plus 1/3 core offload 90 days before the full core offload plus 884 assemblies

from the 12 previous annual refuelings. This same temperature limit will apply even with a mechanical single failure, as there is a spare train available for each system. The combined heat removal capability of one train of the spent fuel cooling system and one train of the shutdown cooling system under these conditions is 54.9E+6 Btu/hr, and the maximum calculated decay heat generated in the spent fuel pool is 47.0E+6 Btu/hr for core power of 3990 MWt. (Refer to sections 9.1.3.1.1 and 9.1.3.2.1.1 for design bases and system descriptions.)

9.1.3.3.1.1.1 Minimum Water Level Requirement. If the spent fuel pool levels fall below a setpoint of 137 feet 6 inches an alarm is sounded locally and in the control room. The low level alarm is provided to ensure that assumptions made in chapter 15.7.4 would be maintained during movement of spent fuel or a heavy load over the pool area. The spent fuel pool cooling system includes inherently safe design features which would prohibit loss of pool cooling during event such as:

- Pipe break in the non-quality portion of cooling/cleanup loops by providing siphon holes.
- Component failure - such as pump seals by providing redundant make-up capabilities.
- Loss of source water - by providing sufficient reserved inventory and makeup capabilities.

If a pipe break were to occur in the Seismic Category I/quality portion of the system, pool cooling could be lost. However,

the event would be self-limiting as all pipe penetrations through the pool wall are at or above the minimum required water levels for spent fuel shielding of 10 ft as required by Regulatory Guide 1.13. All pipes extending down into the pool have siphon breaker holes at or above the minimum required water level. Under these conditions, sufficient time (longer than 30 minutes) is available to isolate the break and recover the minimum level required for start of the pool cooling system. If the spent fuel pool clean up system is aligned with the refueling pool (drain valves), administrative procedures are in place to identify, locate and isolate a pipe break within the containment in a timely manner.

9.1.3.3.1.2 Ultimate Heat Sink. The spray ponds (refer to subsection 9.2.5) qualify as the ultimate heat sink for spent fuel cooling under the provisions of Regulatory Guide 1.27. During normal operation, the fuel pool heat exchangers are supplied with cooling water by the nuclear cooling water system which is in turn supplied by plant cooling water. During abnormal operation (e.g., loss of offsite power), the fuel pool heat exchangers are supplied with cooling water from the essential cooling water system. (Refer to section 1.2.10.3.3, Cooling Water Systems)

Table 9.1-3
CLEANUP SYSTEM DESIGN PARAMETERS (Sheet 1 of 4)

Parameter	Value
General system data	
Normal cooling flowrate, gal/min	4000
Normal purification flowrate, °F gal/min	300
Normal fuel pool temperature, °F	125
Fuel loading	1329 assemblies
Pool boron concentration, ppm	zero to 4400
Fuel pool cleanup strainers	
Quantity	2
Type	Basket
Screen size, perforated, in	1/8
Design pressure, psig	200
Design temperature, °F	250
Flow, gal/min	150
Clean pressure drop, psi at gal/min	0.5 at 150
Fluid, boric acid solution, wt%	2-1/2
Materials in contact with fluid	Stainless steel
Maximum WP across element, psi	30
Fuel pool cleanup pumps	
Quantity	2
Type	Centrifugal, mechanical seals

Table 9.1-3
CLEANUP SYSTEM DESIGN PARAMETERS (Sheet 2 of 4)

Parameter	Value
Design pressure, psig	200
Design temperature, °F	250
Design head	170
Design flow, gal/min	150
NPSH required, ft at gal/min	9.5 at 150
Normal operating temperature, °F	125
Fluid, boric acid solution, wt%	2-1/2
Materials in contact with fluid	Stainless steel
Bhp	11.5
Driver:	
Type	Electric motor
HP	15
Speed, r/min	3600
Power supply	480V Non-Class 1E power system, 3 phase, 60 Hz
Fuel pool cleanup filters	
Quantity	2
Particle retention size, micron - %	5 – 98 or better
Code	ASME VIII
Design pressure, psig	200
Design temperature, °F	250
Flow, gal/min	150

Table 9.1-3
CLEANUP SYSTEM DESIGN PARAMETERS (Sheet 3 of 4)

Parameter	Value
Pressure loss, clean, psi at gal/min	Value will vary depending on filter micron size. For example, the value is 5 psi at 150 gpm for a 5μm - 98% filter.
Fluid, boric acid solution, wt%	2-1/2
Materials in contact with fluid	Stainless steel
Type of elements	Replaceable cartridge, depth type, synthetic fiber
Fuel pool cleanup ion exchanger	
Quantity	2
Resin type	Mixed bed, disposable
Code	ASME VIII
Design pressure, psig	200
Design temperature, °F	250
Flow, gal/min	150
Resin volume, useful, ft^3	50
Bed depth, ft	4
Retention screen, type and size	Johnson Weldscreen 0.006-in. slot
Pressure loss, clean, psi at gal/min	7 at 150
Material	Stainless steel
Fluid, boric acid solution, wt%	2-1/2
Fuel pool cleanup ion exchanger strainer	
Quantity	2

Table 9.1-3
CLEANUP SYSTEM DESIGN PARAMETERS (Sheet 4 of 4)

Parameter	Value
Type	Wye
Screen size	100 U.S. mesh
Design pressure, psig	200
Design temperature, °F	250
Flow, gal/min	150
Pressure loss, clean, psi at gal/min	1.1 at 150
Maximum ΔP across element, psi	100
Materials in contact with fluid	Stainless steel
Fluid, boric acid solution, wt%	2-1/2

9.1.3.3.1.3 Makeup Water. Normal makeup water for the pool is drawn from the refueling water tank (Seismic Category I source including lines). The RWT makeup water is the only Borated water source. Backup makeup water can be obtained from the liquid radwaste system (LRS) recycle monitor tank or the condensate tank. If makeup is the result of evaporation losses, then the LRS makeup water source is used in order to minimize waste and maintain proper spent fuel boron concentration. A minimum of 9 feet 5 inches of water is maintained over the active portion of the fuel assemblies during fuel movement (reference UFSAR sections 9.1.4.3.4, 9.1.4.6 and 9.1.4.7). Technical Specifications require at least 23 feet of water over the top of irradiated fuel assemblies seated in the storage racks.

9.1.3.3.1.4 Electrical Power. Normal and Class 1E electrical power is supplied to necessary components of the spent fuel cooling system.

9.1.3.3.1.5 Storage Capacity. Storage and cooling for 1329 spent fuel elements (5-1/3 cores) is provided as described in subsection 9.1.2 and paragraph 9.1.3.2.

9.1.3.3.2 Fuel Pool Cleanup

None of the design bases listed in paragraph 9.1.3.1.2 is safety-related. However, the design bases are met as follows:

A. The fuel pool cleanup system will maintain fuel pool water clarity.

B. Dose rates above the surface of the spent pool are less than 2.5 mrem/h.

C. The fuel pool cleanup system will accommodate the water chemistry limits of paragraph 9.1.3.1.2, listing C.

9.1.3.4 Inspection and Testing Requirements

Fuel pool cooling lines and components will be inspected in accordance with ASME Section XI, Subsection IWD. Fuel pool cleanup lines are ANSI class lines and do not require inservice inspection.

Instrumentation will be recalibrated at regular intervals as part of normal plant maintenance in accordance with the PVNGS preventive maintenance program. Chemical analysis downstream of the filters and ion exchangers is done via batch sampling only. These samples, as a minimum, are to be taken at 1 week intervals.

Decontamination factors or radiation levels are the criteria used to determine replacement of the resin bed for the ion exchangers. The cleanup filters are provided with pressure differential indicator switches which gave local indication of pressure drop across the filters and alarm to the local panel on high pressure drop.

The fuel pool cleanup filter cartridges will be replaced when the pressure drop across the filters exceeds 25 psid during operation of the system or the gamma radiation reading on the outside of the filter housing exceeds a reading to be determined when normal system radiation levels have been measured in order to maintain radiation exposures ALARA.

Fuel pool cleanup ion exchanger performance will be monitored by determining a decontamination factor from ion exchange inlet to outlet samples for gross activity and gross iodine. Ion exchanger resin will be replaced when the decontamination factor drops below a minimum efficiency level, as determined by examining initial operating decontamination factors, for three consecutive samples taken 2 hours apart or when the gamma radiation readings on the outside of the filter housing exceed a reading to be determined when normal system radiation levels have been measured in order to maintain radiation exposures ALARA. Water chemistry will be sampled and analyzed as necessary.

9.1.4 FUEL HANDLING SYSTEM

9.1.4.1 Design Bases

9.1.4.1.1 System

The fuel handling system is designed for the handling and storage of fuel assemblies and control element assemblies (CEAs). Associated with the fuel handling system is the equipment used for assembly, disassembly and storage of the reactor closure head and internals. As appropriate, the fuel handling equipment included interlocks, travel limiting features, and other protective devices to minimize the possibility of mishandling or equipment malfunction that could result in inadvertent damage to a fuel assembly and potential fission product release.

The refueling water provides the coolant medium during spent fuel transfer. The spent fuel pool is provided with a pool cooling and purification system.

All spent fuel transfer and storage operations except dry cask storage operations are designed to be conducted underwater to insure adequate shielding. Dry cask storage canisters and casks contain integral shielding.

The primary function of the cask load pit is to support dry cask storage operations. The cask load pit may remain filled with borated water since it has a liner plate leak detection system. Long-term borated water storage in the cask load pit is permitted to support dry cask storage, refueling outages or other normal operational maneuvers.

The arrangement of the fuel handling system is shown in engineering drawings 13-P-OOB-0003 through –0005, 13-P-OOB-0007 and 13-P-OOB-0010. Also refer to figure 9.1-2 for crane travel limits in the fuel building.

9.1.4.1.2 Fuel Handling Equipment

The principle design criteria for the dry fuel storage system fuel handling equipment is discussed in the NAC-UMS® CoC and FSAR.

The principle design criteria for the fuel and CEA handling equipment (refueling machine, fuel transfer equipment, spent fuel handling machine, CEA change platform and new fuel and CEA elevators) are as follows:

A. For non-seismic operating conditions, the bridges, trolleys, hoist units, hoisting cable, grapples and hooks conform to the requirements of Crane Manufacturing Association of America Specification #70.

B. For seismic design, the combined dead loads, live loads and seismic loads do not cause any portion of the equipment to disengage from its supports and fall into the pool.

C. Grapples and mechanical latches that carry fuel assemblies or CEAs are mechanically interlocked against inadvertent opening.

D. Equipment is provided with locking devices or restraints to prevent parts, fasteners, or limit switch actuators from becoming loose. In those cases where loosened parts or fasteners can drop into, or are not separated by a barrier from, or whose rotary motion will propel it into the water of the refueling pool or spent fuel pool, these parts and fasteners are lockwired or otherwise positively captured.

E. A positive mechanical stop is provided to prevent the fuel from being lifted above the minimum safe water cover depth and shall not cause damage or distortion to the fuel or the refueling machine when engaged at full operating hoist speed.

F. The fuel hoists are provided with load measuring devices and interlocks to interrupt hoisting if the load increases above the overload set point and interrupts lowering if the load decreases below the underload set point. The PLC will generate the normal operational load weighing interlocks.

G. In the event of loss of power, the equipment, and its load remain in a safe condition.

H. Equipment remaining within the containment is capable of withstanding, without damage, the internal building test pressure.

Electrical interlocks are provided to ensure the reliability of system components, to simplify the performance of sequential operations, and to limit travel and loads such that design conditions will not be exceeded. In no case will they be utilized to prevent inadvertent criticality or the reduction of the minimum water coverage for personnel protection. In addition to electrical interlocks, visual load indication is provided at the controls such that the operator can monitor the load. In the event an interlock fails to stop the hoist, the operator can take action to stop hoist movement. Load indications exceeding interlock setpoints would subsequently necessitate evaluation of the fuel handling equipment and fuel assemblies involved.

In addition, the new fuel handling crane design bases are described as follows:

A. Design Basis A

The new fuel handling crane shall be designed to prevent operation over the spent fuel pool except by the use of a key-operated interlock override.

B. Design Basis B

Hoisting load lift force shall be restricted to 5000 pounds when fuel assemblies are being lifted.

C. Design Basis C

The new fuel handling crane shall be restrained and supported such that it does not become a hazard, in the event of an SSE, to safety grade components, systems, or structures.

9.1.4.1.3 Cask Handling Crane and Containment Polar Crane

The design bases for the cask handling crane and the containment polar crane are as follows:

A. Design Basis A

The cask handling crane shall be designed to meet the guidelines of NUREG-0612, Section 5.1.6 (Single Failure – Proof Handling Systems).

B. Design Basis B

The cask handling crane shall be designed to restrict operation over the main body of the spent fuel pool.

C. Design Basis C

The cask handling crane shall be restrained and supported such that in an OBE or SSE event, it does not become a hazard to safety grade components, systems, or structures.

D. Design Basis D

The containment polar crane shall be designed not to lift any object higher than 40 feet above the reactor vessel flange, while the crane hook is over the reactor vessel flange, except through the use of an administratively controlled key-operated bypass switch.

E. Design Basis E

The containment polar crane shall be equipped with an interlock designed to prevent the trolley from carrying loads over the reactor vessel. The interlock is designed to prevent the trolley from moving within the 15 foot exclusion zone when the reactor vessel contains fuel. This interlock can be bypassed by an administratively controlled key-operated bypass switch to allow for removal and replacement of the Upper Guide Structure and Reactor Vessel Head and for movement of loads located in the area above the reactor vessel.

9.1.4.1.4 Codes and Standards

Codes and standards that apply wholly or in part to the design of the fuel handling system include:

- General Design Criteria 61 and 62 of 10CFR50, Appendix A, as discussed in section 3.1
- Regulatory Guides 1.13, 1.29, and 1.65 as discussed in section 1.8
- 29CFR1910
- 10CFR71

- NUREG-0612, Control of Heavy Loads at Nuclear Power Plants
- NUREG-0554, Single-Failure-Proof Cranes for Nuclear Power Plants
- ASME NOG-1, Rules for Construction of Overhead and Gantry Cranes
- CMAA Specification #70, Specifications for Top Running Bridge and Gantry Type Multiple Girder Electric Overhead Traveling Cranes

9.1.4.2 System Description

9.1.4.2.1 System

The fuel handling system is an integrated system of equipment, tools and procedures for refueling the reactor. The system provides for handling and storage of fuel assemblies from receipt of new fuel to shipment of spent fuel. The equipment is designed to handle the spent fuel underwater from the time it leaves the reactor until it is placed in a canister for storage at the ISFSI or cask for shipment from the site. Underwater transfer of spent fuel provides a transparent radiation shield, as well as a cooling medium for removal of decay heat. Boric acid is added to the water in the quantity required to assure subcritical conditions during refueling. The dry cask storage system provides passive cooling, shielding and criticality control. See the NAC-UMS® Certificate of Compliance (CoC) and FSAR for details.

The major components of the system are the refueling machine, the CEA change platform, the fuel transfer system, the spent fuel handling machine, the cask handling crane, the transfer cask, and the new fuel elevator and new fuel handling crane. The refueling machine moves fuel assemblies into and out of the core and between the core and the transfer system. The CEA change platform is used to move the CEAs within the Upper Guide Structure or between the UGS and the CEA elevator and new fuel handling crane. The CEA elevator is used to introduce new CEAs into the refueling pool and may be used to hold the spent CEAs while they are being disassembled for disposal. The fuel transfer system moves the fuel between the containment building to the fuel building through the transfer tube. The spent fuel handling machine handles fuel between the transfer system, the spent fuel storage racks, the new fuel elevator and the NAC-UMS® transportable storage canister in the cask loading pit. The new fuel elevator and new fuel handling crane are used to introduce new fuel into the spent fuel pool so that it can be moved to the transfer system by the spent fuel-handling machine. The NAC-UMS® transfer cask provides shielding and a means of transferring the transportable storage canister to and from the vertical concrete cask. The cask handling crane is used to move the transfer cask, transportable storage canister and other heavy loads.

Special tools and lifting rigs are also used for disassembly of reactor components.

In the design of this equipment, mechanical stops and positive locks have been provided to prevent damage to or dropping of

the fuel assemblies. In the design of the refueling machine, positive locking between the grapple and the fuel assemblies is provided by the engagement of the actuator arm in vertical channels in the hoist assembly so that relative rotational movement and uncoupling is not possible, even with inadvertent initiation of an uncoupling signal to the actuator assembly. Therefore, failure of an electrical interlock will not result in the dropping of a fuel assembly.

The following list identifies and defines the function of the interlocks contained in the fuel handling equipment. Typically, no method has been provided to directly inform the operator that an interlock is inoperative. However, in most cases a redundant device has been provided to perform the same function as the interlock or to present information to the operator allowing him to deduce that an interlock has malfunctioned.

The fuel handling and CEA machines do not fully fall within the framework of an overhead or gantry crane as described in OSHA subpart N, Materials Handling and Storage, of 29 CFR 1910.179. However, it has been used for guidance. More than 95% of the fuel-handling machine does conform to the OSHA regulations. In each case, additional features to protect the safety of the operator and facility have been installed and are part of appropriate operational procedures.

9.1.4.2.1.1 Refueling Machine. The following identifies and describes the functions of the interlocks that are contained in the refueling machine. The PLC will generate the normal operational load weighing interlocks. The load cell output

will be fed to the control system and displayed on the control console. This allows monitoring of overloads, underloads, and slack cable.

A. Refueling Machine Hoist Interlock (Overload)

Interrupts hoisting of a fuel assembly if the load increases above the overload set point. The hoisting load is visually displayed so that the operator can manually terminate the withdrawal operation if an overload occurs and the hoist continues to operate. In the event load indications exceed the setpoint, evaluation of the fuel handling equipment and fuel assemblies involved would be performed.

B. Refueling Machine Hoist Interlock (Up Limit)

Interrupt hoisting of a fuel assembly when the correct (full up) vertical elevation is reached. A mechanical up stop has also been provided to physically restrain the hoisting of a fuel assembly above the elevation which would result in less than the minimum shielding water coverage.

C. Refueling Machine Hoist Interlock (Underload)

Interrupts insertion of a fuel assembly if the load decreases below the underload setpoint. The load is visually displayed so that the operator can manually terminate the insertion operation if an underload occurs and the hoist continues to operate. In the event load indications exceed the setpoint value, evaluation of the fuel handling equipment and fuel assemblies involved would be performed.

D. Refueling Machine Hoist Interlock (Cable Slack)

Interrupts lowering of the hoist under a no-load condition. An independent slack cable switch that also terminates lowering under a no-load condition backs up the weighing system interlock.

E. Refueling Machine Translation Interlock

Denies translation of the bridge and trolley while the fuel hoist is operating.

F. Refueling Machine Hoist Interlock (Bridge/Trolley Interlock - BTI)

Hoisting is denied during translation of the bridge and/or trolley. No backup or additional circuitry is provided for this interlock.

G. Refueling Machine Translation Interlock (Spreader Extended)

Denies translation of the bridge and/or trolley with the spreader extended. An underwater TV system can be used by the operator to determine whether the spreader has been raised, and icons on the control console indicate whether it is withdrawn or extended.

H. Refueling Machine Mast Anti-collision Interlock

Stops translation of the bridge and/or trolley when the collision ring on the mast is contacted and deflected.

Redundant switches are provided to minimize the possibility of this interlock becoming inoperative. Slow bridge speeds are provided for movement of the

refueling machine in areas other than its normal travel route that might contain obstructions. Travel limits are also provided to prevent machine contact with obstructions within the pool area.

I. Refueling Machine Hoist Speed Interlock

Provides restriction on maximum hoisting speed when the fuel is within the core. During insertion and withdrawal the change in hoist speed can be monitored by observation of the hoist vertical position indicator.

J. Refueling Machine Hoist Interlock (Maximum Overload)

Interrupts hoisting of a fuel assembly if the load increases above the maximum overload set point.

9.1.4.2.1.2 Transfer System. The following identifies and describes the functions of the interlocks that will be contained in the transfer system.

A. Transfer System Winch Interlock

Terminates movement of the fuel carriage through the transfer tube if the load increases above the overload setpoint.

An overload is indicated by a light on the control panel and by an audible alarm.

B. Transfer System Winch Interlock

Prevents the winch from attempting to pull the fuel carriage through the transfer tube with an upender in a vertical position. If this interlock fails and a transfer signal is initiated, winching will be

terminated when the load increases above the overload setpoint.

C. Transfer System Upender Interlock

Rotation of the upender is denied while the refueling machine and SFHM are at their upender stations and the hoist is not at full up. Failure of this interlock while the machines are at the upending station will allow the transfer equipment operator to initiate rotation of the fuel carrier.

D. Transfer System Upender Interlock

Rotation of the upender is denied unless the fuel carrier is correctly located for upending. Failure of this interlock will: (1) with the fuel carrier in the transfer tube allow the upender to rotate with no effect on the carrier or fuel bundle, and (2) with the fuel carrier partially in the upender, attempt to but not be successful in, rotating the carrier since a mechanical lock prevents premature carrier rotation.

9.1.4.2.1.3 Spent Fuel Handling Machine. The following identifies and describes the functions of the interlocks that will be a part of the spent fuel handling machine:

A. Spent Fuel Handling Machine Hoist Interlock (Overload)

Interrupts hoisting if the load increases above the overload setpoint.

Since the operator manually controls the tool, failure of the tool to move or reduction in tool speed as a

result of an overload can be sensed by the operator if the interlock becomes inoperative. The hoist load is displayed on the control console so that the operator can manually terminate the withdrawal operation if an overload occurs and the hoist continues to operate. In the event load exceeds the setpoint, evaluation of the fuel handling equipment and fuel assemblies involved would be performed.

B. Spent Fuel Handling Machine Hoist Interlock (Underload)

Interrupts lowering if the load decreases below the underload setpoint. Since the operator manually controls the tool, failure of the tool to move downward or reduction in cable tension as a result of an underload can be sensed by the operator if the underload interlock becomes inoperative. The hoist load is displayed on the control console so that the operator can manually terminate the withdrawal operation if and overload occurs and the hoist continues to operate. In the event load exceeds the setpoint, evaluation of the fuel handling equipment and fuel assemblies involved would be performed.

C. Spent Fuel Handling Machine Hoist Interlock (Cable Slack)

Interrupts hoisting if the load decreases to cable slack.

Since the tool is manually controlled, a slack cable condition can be visually determined by the operator and hoisting terminated.

D. Spent Fuel Handling Machine Translation Interlock

Provides speed restriction on bridge and trolley translation unless the load is in the full up position, at which time fast speed is allowed.

If this interlock fails, the mandatory slow speed restriction is removed. However, since the translation speed controls are infinitely variable, the operator can run at slow speed when the interlock malfunction is recognized.

E. Spent Fuel Handling Machine Translation Interlock

A dual redundant encoder positioning system protects against running the load into walls or the gate of the storage area. The operator has direct vision of the tool and the attached load so that translation can be terminated if an interlock fails to operate.

F. Spent Fuel Handling Machine Hoist Interlock (Maximum Overload)

Interrupts Hoisting of a Fuel Assembly if the load increases above the maximum overload set point.

9.1.4.2.1.4 New Fuel Elevator. The following identifies and describes the functions of the interlocks that are part of the new fuel elevator.

A. New Fuel Elevator Hoist Interlock

Stops the elevator motor should the cable become slack.

If this interlock fails, the operator can stop the elevator motion from the spent fuel handling machine console.

B. New Fuel Elevator Hoist Interlock

Prevents raising of the elevator with a fuel assembly in the elevator box. This interlock is a backup for the administrative control, which precludes the placement of a spent fuel assembly in the new fuel elevator. A key operated bypass switch is provided to allow raising of dummy or new fuel assemblies should it become necessary.

9.1.4.2.2 Components

9.1.4.2.2.1 Refueling Machine. The refueling machine is a traveling bridge and trolley which is located above the refueling pool and rides on rails set in the concrete on each side of the refueling pool. Motors on the bridge and trolley position the machine over each fuel assembly location within the reactor core or fuel transfer carrier. The controls for the refueling machine are mounted on a console that is located on the refueling machine trolley. Coordinate location of the bridge and trolley is indicated at the console by digital readout devices that are driven by encoders coupled to the guide rails through rack and pinion gears. During withdrawal or insertion of a fuel assembly, the load on the hoist cable is monitored at the console to assure that movement is not being restricted. Limits are such that damage to the assembly is prevented.

Locking between the grapple and the fuel assembly is provided by the engagement of the grapple actuator arm in axial channels running the length of the fuel hoist assembly. Therefore, it is not possible to uncouple even with inadvertent initiation of an uncoupling signal to the actuator assembly. The drives for both the bridge and the trolley provide close control for accurate positioning, and brakes are provided to maintain the position once achieved. In addition, interlocks are installed so that movement of the refueling machine is not possible when the hoist is withdrawing or inserting an assembly. PLC interlocks are provided that deny translation of the bridge and trolley while the fuel hoist is in operation and translation of the hoist while the bridge and trolley are in operation.

For operations above the core, the bottom of the hoist assembly is equipped with a spreading device to align the surrounding fuel assemblies to their normal core spacing to assure clearance for fuel assemblies being installed or removed. An anti-collision device at the bottom of the mast assembly prevents damage should the mast be inadvertently driven into an obstruction. A positive mechanical up stop is provided to prevent the fuel from being lifted above the minimum safe water cover depth. A system of pointers and scales serves as a backup for the remote positioning readout equipment.

Manually operated handwheels are provided for bridge, trolley and winch motions in the event of a power loss. Manual operation of the grappling device is also possible in the event that air pressure is lost.

The refueling machine hoist box is equipped with the necessary manifolds, tubing, and fittings to allow for wet sipping of fuel assemblies. See Sections 9.1.4.2.2.23 and 9.1.4.2.3.4 for a description of the wet sipping system components and operation.

9.1.4.2.2.2 Transfer System. The major components of the transfer system are one carriage with carrier, two upenders, and two hydraulic power packages as described below.

A. Transfer Carriage

A transfer carriage conveys the fuel assemblies through the transfer tube. Two fuel assembly cavities are provided in the fuel carriage. Fuel assemblies are placed on the transfer carriage in a vertical position, lowered to the horizontal position, moved through the fuel transfer tube on the transfer carriage, and then restored to the vertical position. Only one irradiated fuel assembly is permitted to be transferred through the transfer tube at a time.

Wheels support the carriage and allow it to roll on tracks within the transfer tube. The track sections at both ends of the transfer tube are mounted on the upending machines to permit the carriage to be properly positioned at the limits of its travel. The carriage is driven by steel cables connected to the carriage and through sheaves to its driving winch mounted on the operating floor.

The load in the transfer cables is displayed at the master control console. An overload will interrupt the transfer operation. Manual override of the overload cutout allows completion of the transfer. The supports for the replaceable rails on which the transfer carriage rides are welded to the 36-inch diameter transfer tube. The rail assemblies are fabricated to a length that will allow them to be lowered for installation in the transfer tube. No rails need be installed in the valve on the spent fuel pool side of the transfer tube.

B. Upending Machine

An upending machine is provided at each end of the transfer tube. Each machine consists of a structural support base from which is pivoted an upending straddle frame that engages the two-pocket fuel carrier. When the carriage with its fuel carrier is in position within the upending frame, the pivots for the fuel carrier and the upending frame are coincident. Hydraulic cylinders, attached to both the upending frame and the support base, rotate the fuel carrier between the vertical and horizontal position as required by the fuel transfer procedure. Each hydraulic cylinder can perform the upending operation alone and can be isolated in the event of its failure. A long tool is also provided to allow manual rotation of the fuel carrier in the event that both cylinders fail or hydraulic power is lost.

C. Hydraulic Power Unit

The hydraulic power unit provides the motive force for raising and lowering the upender with the fuel carrier. It consists of a stand containing a motor coupled to a hydraulic pump, a pump reservoir, valves and the necessary hoses to connect the power package to the hydraulic cylinders on the upender. The valves can be aligned to actuate either or both upender cylinders. The hydraulic fluid is distilled water.

9.1.4.2.2.3 Fuel Transfer Tube and Valve. A fuel transfer tube extends through the containment wall. During reactor operation, the transfer tube is sealed by means of a remotely operated quick operating closure device (QOCD) located inside the containment. Prior to filling the refueling pool, the closure cover plate is removed. After a common water level is reached between the refueling pool and the spent fuel pool, the transfer tube valve is opened.

The procedure is reversed after refueling is completed.

The transfer tube arrangement consists of a 36-inch diameter transfer tube contained within a penetration which is sealed to the containment. The transfer tube and penetration sleeves are sealed to each other by welding rings and bellow-type expansion joints to allow for horizontal movement to the tube and valve. During reactor operation, the containment side of the fuel transfer tube is contained within a tube, one end of which is welded to the pool liner and the other end equipped with a quick operating closure device. The closure device reducing ring is permanently bolted to the tube and sealing is

accomplished through two sealing rings. The closure plate that attaches to the reducing ring is also sealed with two sealing rings. Both sets can be checked for adequacy by pressurizing the annulus between the seals. In this arrangement, the transfer tube never sees containment pressure during reactor operation. Other arrangements are acceptable provided containment integrity is maintained during reactor operation.

9.1.4.2.2.4 CEA Change Platform. The CEA change platform is positioned above the upper guide structure after it has been placed in the storage area and the UGS lifting rig removed. The platform is mounted on the same rails as is the refueling machine. The platform locates the operator over the CEA to be moved. The CEA handling tool, attached to an overhead crane, is then lowered, grappled to the CEA and the CEA relocated, as required. The platform is also utilized during the handling of ICIs and during trash can movements.

9.1.4.2.2.5 Fuel Handling Tools. Two fuel handling tools are used to move fuel assemblies in the spent fuel pool area. A new fuel tool is provided for dry transfer of new fuel, and a spent fuel tool is provided for underwater handling of both spent and new fuel in the spent fuel pool. The tools are operated manually from the new fuel handling crane and from the trolley on the spent fuel handling machine respectively. An additional fuel handling tool is used to move fuel assemblies, trash cans and dummy fuel assemblies within the refueling pool. The New Fuel Handling Crane is also used to support tools used to perform spent fuel reconstitution and recaging.

9.1.4.2.2.6 Reactor Vessel Head Lifting Rig. The reactor vessel head lifting rig consists of three (3) lifting legs which extend from the reactor vessel closure head lifting lugs to the ring girder elevation at the top of the simplified head assembly air cooling shroud. The legs are located external to the simplified head assembly lower cooling shroud/radiation shield and upper shroud assembly.

9.1.4.2.2.7 Reactor Internals Handling Equipment. The reactor internals lift rig is a structure used to remove either the upper guide structure assembly or the core support structure from the reactor vessel.

The upper clevis assembly is a tripod-shaped structure connecting the lifting rig to the containment crane lifting hook. The lifting rig includes a spreader beam providing three attachment points that are bolted to the core support barrel flange. Correct positioning of the lifting rig is assured by attached guide bushings that mate to the reactor vessel guide pins. With the lift rig in the configuration provided for removal of the upper guide structure, the spreader beam supports three columns, providing attachment points to the upper guide structure assembly. Attachment to the upper guide structure assembly is accomplished manually from the working platform. Correct positioning is assured by attached bushings that mate to the reactor vessel guide pins.

The clevis assembly, tie rod assembly, and spreader beam assembly which are common to this and the core support structure lifting rig, are installed prior to lifting of the structure by the crane hook. The working platform also

incorporates the holding fixtures for the extension shafts and CEAs after the CEAs have been withdrawn into the upper guide structure. The holding fixtures that latch the extension shafts (with the CEAs) to the work platform are positive locking in that the extension shafts have to be raised before the fixtures can be disengaged.

9.1.4.2.2.8 Spent Fuel Handling Machine. The spent fuel handling machine is a traveling bridge and trolley which rides on rails over the spent fuel pool, refueling canal, and cask storage area. Motors on the bridge and trolley position the machine over the spent fuel assembly storage racks, the new fuel elevator and the upending machine. An auxiliary crane is used to transfer new fuel from the new fuel storage racks to the new fuel elevator.

The spent fuel handling machine hoist assembly supports a grappling tool which, when rotated by the operator, engages the fuel assembly to be moved. Once the fuel assembly is grappled, the hoist raises the fuel assembly and the machine then transports the fuel assembly from the new fuel elevator to the upending machine or spent fuel storage racks (new fuel), from the upender to the spent fuel storage racks or from the spent fuel storage racks, to the spent fuel cask.

The controls for the spent fuel handling machine are mounted on a console that is located on the spent fuel handling machine trolley.

Coordinate location of the bridge and trolley position is indicated by a pointer and target system. Dual encoders are

also installed and the location of the bridge and trolley will be displayed on the console.

During withdrawal or insertion of a fuel assembly, the load on the hoist cable is displayed on the console and is monitored to assure that movement is not being restricted. Set points are such that damage to the assembly is prevented.

Positive locking is provided between the grappling device and the fuel assembly to prevent inadvertent uncoupling. The drives for both the bridge and the trolley provide close control for accurate positioning, and brakes are provided to maintain the position once achieved. In addition, interlocks are installed so that movement of the spent fuel handling machine is not possible when the hoist is withdrawing or inserting an assembly.

Manually operated handwheels are provided for bridge, trolley and winch motions in the event of a power loss.

9.1.4.2.2.9 New Fuel Elevator. A fuel elevator is utilized to lower new fuel from the operating floor to the bottom of the pool where it is grappled by the spent fuel handling tool. The elevator is powered by a cable winch and fuel is contained in a simple support structure whose sliding pads are captured in two rails. New fuel is loaded into the elevator by means of the new fuel handling crane hoist and the new fuel handling tool.

A manually operated handwheel is provided for elevator operation in the event of a power loss.

9.1.4.2.2.10 Underwater Television. A closed circuit television system is available to monitor the fuel handling operations inside the containment. The camera is an operator aid and is not required for refueling machine operation.

9.1.4.2.2.11 Dry Sipping Equipment. Refer to FSAR paragraph 1.9.2.4.19.

9.1.4.2.2.12 Transport Container. The Transport Container is used to store and move cut up pieces of spent CEAs and In-core Instruments (ICIs). The container has the same nominal outside dimensions as a fuel bundle and is provided with top fitting to mate with the fuel grapple so it can be moved by the fuel handling equipment.

9.1.4.2.2.13 Refueling Pool Seal. The temporary refueling pool seal which was installed and removed for each refueling outage has been replaced by a Permanent Reactor Cavity/Refueling Pool Seal (PRCRPS). The PRCRPS is an annular ring approximately 23 feet OD, 6.5 inches high, and 3 feet wide. The PRCRPS is designed to perform two basic functions. First, the PRCRPS provides a seal for the reactor vessel cavity during refueling operations. Second, the PRCRPS is designed to allow the free flow of cooling air in the reactor vessel cavity during plant operation. The function is accomplished with access openings in the PRCRPS. These openings are covered and sealed during refueling operations. The covers may be removed and conveniently stored during plant operation. The covers can also be removed for access to excore nuclear instrumentation.

The PRCRPS is designed to accommodate the hydrostatic loads (nominally 26 ft.) of the refueling pool water and allow unrestricted reactor vessel thermal and seismic movement as per the original reactor coolant system design. These requirements are met by providing a flexible seal membrane and a separate rigid structure in the PRCRPS. The sealing function is accomplished with a thin, flexible membrane which is welded to the reactor vessel seal ledge, covers the support structure, and is also welded to the refueling pool embedment ring. The structural function is accomplished by a separate structure used to support hydrostatic loads which rests on the reactor vessel seal ledge and refueling pool embedment ring under the seal membrane.

9.1.4.2.2.14 In-Core Instrumentation and CEA Cutters. A portable underwater hydraulic cutter is provided to cut the expended CEAs into lengths necessary to permit transfer to the spent fuel building in the fuel carrier. A second cutter is used for disposal of the incore instrumentation leads.

9.1.4.2.2.15 Gripper Operating Tool. This tool is approximately seventeen feet long and consists of two concentric tubes with a funnel at the end to facilitate engagement with the CEA extension shafts. When installed, pins attached to the outer tube are engaged with the extension shaft. The inner tube of the tool is then lifted and rotated relative to the outer tube which compresses a spring allowing the gripper to release, thus separating the extension shaft from the control element assembly.

9.1.4.2.2.16 Cask Handling Crane. The cask handling crane is designed to transfer dry fuel storage system components and other heavy loads in the fuel building. The crane maximum critical load (MCL) and design rated load (DRL) are 150 tons. This capacity is sufficient to fulfill the design function of handling the SAFLIFT^{tm}, and a transfer cask containing a transportable storage canister loaded with 24 spent fuel assemblies and water in the canister.

The cask handling crane main hoist critical load bearing components are classified as Seismic Category I, Quality Class Q (Reg. Guide 1.13 and 1.29). All other components including the auxiliary hoist are classified as Seismic Category IX, Quality Augmented.

Since the crane handles spent fuel and also operates in the vicinity of spent fuel and safe shutdown equipment, it is designed to meet the guidelines of NUREG-0612, Section 5.1.6 (Single-Failure-Proof Handling Systems), NUREG-0612, Appendix C (Modification of Existing Cranes) and NUREG-0554 (Single-Failure-Proof Cranes for Nuclear Power Plants). Special lifting devices and other rigging used to handle heavy loads must meet the applicable guidelines of NUREG 0612 and ANSI N14.6. The cask handling crane has an auxiliary hoist with an MCL and DRL of 15 tons, which is designed to be single failure proof. Use of single failure proof hoisting systems makes it unnecessary to analyze the effects of postulated load drops because the probability of occurrence is extremely small.

For an item by item evaluation of NUREG-0554 compliance, refer to the single-failure-proof trolley final safety analysis report.

Mechanical antiderailment devices, mounted on the wheel axles of the overhead crane bridge and trolley, prevent the crane from being dislodged from the rail due to horizontal motion during an earthquake. The crane is designed so that vertical acceleration resulting from an earthquake is not large enough to overcome the downward load of gravity. The crane complies with the requirements of 29CFR1910, OSHA Subpart N, Section 1910.179.

Mechanical stops on the crane rails, shown on figure 9.1-2, prevent crane movement such that the crane hook cannot travel east of the cask pit centerline. The stops react on the crane bridge via buffers, and prevent crane movement over the main body of the spent fuel pool and the new fuel storage areas.

Limit switches on the crane rail normally interrupt the crane drives before the stop is contacted.

When handling spent fuel in dry fuel storage system transportable storage canisters (TSC), the cask handling crane uses the SAFLIFT^{tm}, which is an under the hook special lifting device designed to handle the TSC and the transfer cask (TFR). The SAFLIFT^{tm} incorporates a lifting beam with load hooks that support the TFR, and an underhung hoist and grapple that support the TSC. The MCL of the lifting beam and load hooks is 125 tons, while the MCL of the canister hoist and grapple is 50 tons. The SAFLIFT^{tm} weighs approximately 22 tons, so

lifting its MCL of 125 tons will not result in overloading the cask handling crane.

The SAFLIFT^{tm} critical load bearing components are classified as Seismic Category I, Quality Class Q (Reg. Guide 1.13 and 1.29). All other components are classified as Seismic Category IX, Quality Augmented.

Since the SAFLIFT^{tm} handles spent fuel and also handles heavy loads in the vicinity of safe shutdown equipment, it is designed to be used in single failure proof applications in accordance with NUREG-0612, NUREG-0554, CMAA-70 and ANSI N14.6.

9.1.4.2.2.17 New Fuel Handling Crane. The new fuel handling crane transfers new fuel assemblies between the transportation carrier, new fuel inspection station, new fuel storage facility, and new fuel elevator. This crane is a 10-ton bridge crane. The New Fuel Handling Crane is also used to perform activities associated with spent fuel reconstitution and recaging.

Drives for the crane provide close control for accurate positioning and brakes to maintain the position once achieved.

During withdrawal (or insertion) of a new fuel assembly in the new fuel storage facility, the hoisting load is limited to 5000 pounds and monitored by load cell readout to ensure that vertical movement of the fuel assembly is not being obstructed. The load cell operates an electrical trip circuit at the 5000-pound load. This interrupts the hoist drive. If loads larger than 5000 pounds need to be lifted in areas other than

over the spent fuel pool, the load interlock can be overridden by utilization of a key under administrative control.

Electrical interlocks on the crane long travel and cross travel motions prevent the crane hook from being traversed over the spent fuel pool. A key-operated interlock override is used to allow crane operation over the spent fuel. The key is under administrative control. In addition, electrical interlocks are provided to prevent movement of the crane when the hoist is withdrawing (or inserting) a new fuel assembly in its storage position. However, those interlocks may be bypassed using an administratively-controlled key, allowing crane long and cross travel with the hook below its upper travel limit. In the event of a power loss, the hand release feature of the spring set brake provides maneuverability to move the bridge, and the self-excited, eddy-current brake alternator generates adequate power to allow a controlled, safe lowering of the load. The new fuel handling crane and its rails are designed to withstand a safe shutdown earthquake without becoming dislodged and causing the loss of function of component systems or structures that must remain functional.

The new fuel handling crane is the only crane that can traverse the spent fuel pool.

9.1.4.2.2.18 Containment Polar Crane. Refer to Section 9.1.4.3.3 for the handling of the reactor vessel closure head.

The containment polar crane is used during the construction phase for installation of the heavy equipment items inside the containment. Thereafter it is used during refueling operations. It also may be used for maintenance operations for

the lifting and removal of major items of equipment if required. An administratively controlled key-operated limit switch prevents the crane from lifting the reactor closure head more than 40 feet above the reactor vessel flange while over the reactor vessel.

Reference to the reactor vessel closure head assembly raised height of 18 feet in CESSAR Interface Evaluation section 9.1.4.7 is no longer applicable to PVNGS. Refer to section 9.1.4.3.5 for closure head lift height evaluation.

9.1.4.2.2.19 Intermediate Storage Rack. The intermediate storage rack is used for the temporary storage of new fuel assemblies, spent fuel assemblies, and CEAs. It is located in the containment building on the refueling canal wall adjacent to the core support barrel laydown area and has four storage cavities (refer to paragraph 9.1.2.4).

9.1.4.2.2.20 Transportable Storage Container (TSC) The TSC is a component of the NAC-UMS dry cask storage system as described in the NAC-UMS Certificate of Compliance (CoC) and FSAR (Docket no. 72-1015). The TSC is designed for storage of 24 spent fuel assemblies. The TSC contains a fuel basket, which is a stainless steel lattice that provides criticality control by maintaining the fuel in a sub-critical array. The fuel basket contains BORAL sheets between the cells to assure the array remains subcritical with full density moderator intrusion. Once the TSC is loaded, confinement of the fuel is achieved by sealing the canister with a shield lid and structural lid, both of which are welded in place. The loaded

TSC is backfilled with helium to facilitate heat transfer and protect against corrosion.

9.1.4.2.2.21 Transfer Cask (TFR) The TFR is a component of the NAC-UMS dry cask storage system as described in the NAC-UMS Certificate of Compliance (CoC) and FSAR (Docket no. 72-1015). The TFR provides shielding during loading operations until the TSC is placed in the VCC. The TFR is fabricated primarily from lead for gamma shielding, NS-4-FR for neutron shielding, and low alloy steel for structural support. The transfer cask is a special lifting device designed in accordance with NUREG-0612 and ANSI N14.6 for use in single failure proof applications.

9.1.4.2.2.22 Vertical Concrete Cask (VCC) The VCC is a component of the NAC-UMS dry cask storage system as described in the NAC-UMS Certificate of Compliance (CoC) and FSAR (Docket no. 72-1015). The VCC is the storage overpack for the TSC. The VCC is a reinforced concrete structure with a structural steel inner liner. The VCC provides structural support, shielding, protection from environmental conditions, and natural convection cooling of the canister during storage. The lifting lugs on the VCC are designed to meet the guidelines of NUREG-0612 for single failure proof handling systems.

9.1.4.2.2.23 Telescope Fuel Sipping Equipment. The Telescope fuel sipping equipment is used when wet sipping is implemented during fuel handling evolutions to identify cladding failures by detection of leaking gaseous and water soluble fission products. The Telescope fuel sipping equipment is skid mounted and portable, and it is only in place on the refueling machine

bridge when being used. After Telescope fuel sipping is completed, the skid-mounted equipment is disconnected and removed. Refer to paragraph 9.1.4.2.3.4 for a description of the fuel sipping system operation.

9.1.4.2.2.24 Rod Storage Basket (RSB) and Rod Capture Tube (RCT). The RSB is used to store and move fuel rods with identified cladding defects or rods removed from fuel assemblies. The storage basket has the same nominal outside dimensions as a fuel assembly and is provided with a removable top fitting to mate with the fuel grapple so it can be moved by the fueling handling equipment. The RCT is used to capture fuel rods or pieces of fuel rods that may have separated during reconstitution or appear to have a high potential for separation. The RCT's are sized to be stored within the RSB.

9.1.4.2.3 System Operation

9.1.4.2.3.1 New Fuel Transfer. After arrival of the new fuel shipping containers, the container covers are removed and the fuel assembly strongback raised to the vertical position and locked. The new fuel handling tool, attached to the overhead crane, is then locked to the fuel assembly, the fuel assembly clamping fixtures are removed and the fuel assembly is removed from the shipping container. Next, the fuel assembly is moved over to the new fuel storage racks where it is placed into its designated cavity. (The fuel may also be moved directly to the new fuel elevator and placed in its designated spent fuel storage rack location.) The tool is unlocked from

the assembly and the operation repeated until all assemblies have been placed in the racks.

Prior to or during reactor refueling operations, the new fuel is removed from the new fuel storage racks and transferred to the new fuel elevator by using the overhead crane and the short fuel handling tool.

The new fuel elevator lowers the fuel assembly into the pool to allow the spent fuel handling machine to transfer the fuel assembly to the upending mechanism or storage location.

9.1.4.2.3.2 Dry Fuel Storage Refer to the NAC-UMS® FSAR for detailed description of the fuel basket, transportable storage container (TSC), vertical concrete cask (VCC), and the handling of these components. Refer to ISFSI 72.212 Evaluation Report for additional details regarding system operation. The principle design bases of the ISFSI are prescribed in the NAC-UMS Certificate of Compliance (CoC) and FSAR (Docket no. 72-1015).

With the spent fuel pool (SFP) gate installed, a transfer cask (TFR) containing a TSC is placed on the alignment stand in the cask loading pit (CLP). The single failure proof cask handling crane and the SAFLIFT are used to handle this heavy load. The CLP water level is equalized with the SFP level by transferring borated water from the RWT. When CLP and SFP water levels are equalized, the gate is removed. Spent fuel is loaded into the TSC using the spent fuel handling machine.

When fuel loading is complete, the SFP gate is reinstalled, and the shield lid is installed on the TSC using the cask handling

crane and the shield lid lift rig (SLLR). Once the shield lid is in position, the water level in the CLP can be lowered. The shield lid is welded, then the canister is drained, dried, and backfilled with helium. The water and air removed from the TSC using a vacuum drying skid is discharged into the SFP via temporary spargers. This process is necessary to assure there is no moisture remaining in the canister that could cause corrosion during storage. The helium is also necessary to maintain the heat transfer properties assumed in the NAC accident analyses. The canister is pneumatically tested and helium leak tested as part of the loading process to verify integrity of the confinement boundary. The structural lid is then installed and welded in place.

There are two temporary modifications that, when installed, support the dry cask loading process; 1) the Annulus Flush System (AFS) and 2) spargers connected to a vacuum drying skid. The temporary AFS provides positive pressure of filtered CLP water to the annulus between the TSC and the TFR. The AFS provides supplemental CLP water cleanup to reduce contamination levels on the TSC. Supply water comes from the CLP that it is processed through an ion exchange vessel and discharged into the TFR annulus. When installed, the ion exchangers are located on the 140’ elevation of the Fuel Building. A chiller and heat exchanger are provided for use if necessary to reduce CLP temperature during loading operations.

The TSC is then placed in the VCC using the cask handling crane, the SAFLIFT, and the TFR. The loaded VCC is then transported to the ISFSI along specifically designated transportation paths. The VCC is transported to the ISFSI

using a specially designed railcar and railcar mover. Once at the ISFSI, the VCC is removed from the railcar at the unloading pad and placed on its designated location on the storage pads. Transportation of the VCC at the ISFSI is performed using a hydraulic mobile lifting frame.

Once on the storage pad, the VCC air inlet and outlet temperatures are monitored by the temperature monitoring system. The temperature differential is surveilled as a means of determining OPERABILITY of the concrete cask heat removal system. This information is routed to the Unit 1 control room through the ISFSI interface shed. The interface shed provides a controlled environment to house the ISFSI security and environmental monitoring components.

9.1.4.2.3.3 Refueling Procedure. The following information provides a general description of the refueling activities. It is not intended to be totally inclusive of all activities, nor is it intended to be utilized as a procedure. Some of the evolutions described below may be performed in parallel with other refueling operations.

During cooldown of the reactor coolant system, preparations are begun for the refueling operation. The control element drive mechanisms (CEDMs) are disengaged from the control element assemblies extension shafts by de-energizing the CEDM electromagnets. The CEDM cabling is then disconnected in preparation for removal of the reactor vessel head. Refueling operations are initiated when the missile shield is removed from over the reactor vessel. The cable support structure, reactor vessel head vent line, nuclear cooling line, CEDM

ventilation ducts and reactor vessel head insulation are removed and stored in the appropriate laydown areas. The multiple stud tensioner (MST) is then set into place around the reactor vessel head. The MST then tensions the reactor vessel head studs such that the nuts may be removed. Once the nuts are removed, the MST stud handling vehicles are then utilized to remove the studs. Plugs and two guide pins are installed into the stud holes to prevent water from filling the stud holes once the reactor cavity is flooded for fuel movement. Openings in the reactor cavity pool seal are closed and leak tested. The ICI detectors are disconnected and withdrawn from the core region to allow the fuel assemblies to be moved. The Quick Operating Closure Device (QOCD) is removed to allow the fuel assemblies to be transported to and from the fuel building. The reactor vessel head delta beam is then installed on the reactor vessel head assembly. The reactor vessel head assembly is then lifted by the polar crane and transported to the head laydown stand. The refueling pool is partially filled while the head assembly is being transported to the head stand.

The upper guide structure (UGS) lift rig is installed on, and bolted to, the upper guide structure. The CEA extension shafts are then latched to the UGS lift rig working platform. The working platform is raised, withdrawing the CEAs from the reactor core into the UGS. As the working platform is raised, refueling pool water level is also increased until the normal water level for fuel movement is achieved. The UGS is then removed from the reactor vessel and transported to the UGS laydown area in the refueling pool. If CEAs are to be replaced or inspected, the extension shafts are uncoupled from the CEAs

and the UGS lift rig, with the CEA extension shafts, is moved to the UGS lift rig storage stand.

After correct water level in the refueling pool has been established and the UGS has been stored, the spent fuel pool to transfer canal gate is removed and the transfer tube gate valve is opened. These actions allow fuel assemblies to be moved between the reactor vessel and the spent fuel pool.

Refueling the reactor vessel now takes place. The reactor core may be entirely off-loaded to the spent fuel pool, or a fuel shuffle may take place. If the reactor core is to be off-loaded, each fuel assembly is removed from the reactor vessel by the refueling machine and placed into the transfer machine. The transfer machine transfers the fuel assembly to the fuel building, where it is removed from the transfer machine by the spent fuel handling machine. The spent fuel handling machine then places the fuel assembly into a storage location within the spent fuel pool. If a core shuffle is performed, approximately one-third of the fuel assemblies are removed from the reactor vessel and stored in the spent fuel pool. The remaining fuel assemblies are shuffled to accommodate the new core design as new fuel is transported and loaded into the reactor vessel. The fuel handling sequence is briefly described in the following paragraphs.

Once conditions for fuel movement are established, the refueling machine (RFM) is positioned over the desired core location. Alignment of the RFM to the desired fuel assembly is accomplished by verifying correct bridge and trolley position via a digital positioning readout system. After the hoist

grapple is positioned on the fuel assembly, the operator actuates the grapple actuator which rotates the hoist grapple such that it engages the fuel assembly. The fuel assembly is then hoisted into the RFM hoist box which protects the fuel assembly during transportation.

Once the fuel assembly has been hoisted to the correct elevation, the fuel assembly may then be transported to a different core location, the fuel transfer machine baskets or to a temporary storage rack. If the assembly is transported to a different core location or to a temporary storage rack, then the RFM is positioned over the desired location and the RFM position is verified via the digital positioning readout. The fuel assembly is then lowered into position. When correct positioning of the fuel assembly has been verified, the RFM operator will actuate the grapple actuator to disengage the grapple from the fuel assembly. The RFM hoist is then raised to allow safe movement of the RFM.

If it is desired to transfer the fuel assembly to the spent fuel pool, the RFM operator will position the RFM over the fuel transfer machine carriage baskets. The fuel assembly is then lowered into an empty basket and ungrappled from the RFM. If a core shuffle is in progress, the other basket may contain a replacement fuel assembly. The RFM operator will reposition the RFM over the replacement fuel assembly and remove it from the basket. The replacement fuel assembly will be inserted into the reactor vessel while the spent fuel assembly is transported to the fuel building by the fuel transfer system.

The fuel transfer system moves the fuel baskets to the horizontal position. Once the baskets are horizontal, the carriage drive actuates to transport the transfer carriage on tracks through the transfer tube to the fuel building. The fuel transfer baskets are then upended to the vertical position. If a core shuffle is in progress, the spent fuel handling machine (SFHM) may place a replacement fuel assembly in an empty fuel transfer basket. The spent fuel assembly is removed from the other fuel transfer basket by the SFHM and placed in an appropriate spent fuel pool storage location.

Removal and cutup of spent ICI detectors may take place during the refueling operation. This activity is not performed during each refueling outage - ICI detector replacement is dictated by the life of the ICI detectors.

If necessary, CEAs may be relocated or replaced within the UGS. This activity may occur simultaneously with fuel movement operations. The CEAs are moved using specialized tooling and the CEA change platform. Expanded CEAs are moved to the CEA elevator or other disposal location where the CEA fingers are cut and placed into a transport container. Remnant pieces of the CEA fingers, locking nuts and spiders are then removed from the refueling pool, disassembled and loaded into a disposal container. The transport container, with the cut CEA fingers in it, is transferred to the spent fuel pool using the fuel handling system where they will be stored or disposed of. New CEA fingers, spiders and locking nuts are assembled outside of the refueling pool and placed in the CEA elevator or are assembled in the CEA elevator. The new CEA assembly is then re-installed in the UGS.

Inspection of the fuel assemblies for leaks may be performed during fuel handling evolutions. The lower end of the fuel assembly is placed into the ultrasonic test, or other inspection, machine. The fuel assembly is then scanned to determine if any of the fuel pins are leaking. When the scan is complete, the fuel is removed from the machine and placed into the appropriate fuel location.

At the completion of fuel handling activities, the spent fuel pool to transfer canal gate is reinstalled and the transfer tube gate valve is closed. The UGS is reinserted into the reactor vessel. The refueling pool level is lowered and the CEAs are lowered into position. The reactor vessel head assembly is then placed on the reactor vessel and bolted into place. The remaining water in the deep ends of the refueling pool is drained and the QOCD is reinstalled. The refueling cavity pool seal hatches are opened. The ICI detectors are reinserted into the core region and reconnected. The cable support structure, reactor vessel head vent line, nuclear cooling line, CEDM ventilation ducts and reactor head insulation are installed. Placing the missile shield into position concludes the refueling operations.

References to the temporary pool seal in the section of the CESSAR are no longer applicable to PVNGS. Refer to PVNGS UFSAR Section 9.1.4.2.2.13 for a description of the permanent reactor cavity/refueling pool seal (PRCRPS) now used.

References to installing the pool seal and air testing for leak tightness in the CESSAR shall now be interpreted to mean the

closure and air testing of the access/air flow hatches on the PRCRPS.

References in the CESSAR to the removal of the refueling pool seal following fuel reload shall now be interpreted to mean the opening of the PRCRPS access/air flow hatches if desired at that time. (All six hatches must be removed prior to plant heat up.)

9.1.4.2.3.4 Telescope Fuel Sipping. Telescope fuel sipping may be implemented during fuel handling evolutions to identify cladding failures by detection of leaking gaseous and water soluble fission products. Sipping of fuel assemblies is performed during the initial de-fueling process in the refueling outage while the assemblies are being moved via the refueling machine between the reactor core and the transfer system. As the fuel assembly is raised from the reactor by the grapple, a reduced pressure condition is created in the water around the fuel assembly, resulting in a release of fission product gases into the water in the hoist box. A skid-mounted portable fuel sipping station located on the refueling machine bridge is connected to the hoist box fittings and draws water from a position close to the top of the fuel bundle. The sipping station separates the fission gases from the water and then circulates the fission gases through a sensitive Beta detector that measures the activity level as an indicator of cladding failure. The sampled water and gas are discharged back to the refueling pool.

9.1.4.3 Safety Evaluation

9.1.4.3.1 Cask Handling Crane

The cask handling crane is designed to transfer dry cask storage system components in the fuel building. The capacity of the crane is based on lifting the SAFLIFT^{tm}, and a transfer cask containing a fully loaded transportable storage canister including water.

The cask-handling crane is upgraded to meet the guidelines for single failure proof hoisting systems contained in NUREG-0612 Section 5.1.6, NUREG-0612 Appendix C, and NUREG 0554. The maximum critical load (MCL) and design rated load (DRL) of the main hoist on the upgraded crane are both 150 tons. The MCL and DRL of the auxiliary hoist are 15 tons.

The SAFLIFT^{tm} is designed to handle the dry fuel storage system transfer cask (TFR) with a transportable storage canister (TSC) containing 24 spent fuel assemblies. The SAFLIFT^{tm} is designed to meet the applicable guidelines for single failure proof special hoisting systems contained in NUREG-0612 Section 5.1.6, ANSI N14.6, and NUREG 0554. The MCL of the SAFLIFT^{tm} lift beam is 125-ton including the 50-ton MCL of the canister hoist and grapple.

The crane and lifting devices are designed such that a single failure of a critical component will not result in the loss of the capability to safely retain the load. Where redundant features are not practical the design safety factor has been doubled as recommended in NUREG-0612, ANSI-N14.6, and NUREG-0554 in order to provide enhanced safety. By designing

the crane and lifting devices to be single failure proof, it is not necessary to analyze the effects of postulated events involving loss of the load, which in turn cause a direct or indirect release of radioactivity. Similarly, it is also not necessary to analyze the effects of postulated events in which the loss of the load adversely affects the ability to mitigate the consequences of an accident.

The design of the fuel building structure, the runway and the crane bridge is not affected by the new single failure proof trolley since the existing bridge analysis bounds the new trolley weight. Therefore, there is no need to re-perform the structural analysis of the crane bridge girders, end ties, trolley rails, end trucks, crane runway, runway rails, and rail clips. As a result, seismic analyses are only performed for the new single failure proof trolley.

Since the existing bridges will not be modified, critical welds on the bridges are identified, nondestructively examined and repaired if required in accordance with UFSAR section 17.2 and AWS D1.1.

Components that are subject to wear are designed to carry a load approximately 15% higher than the MCL. This provides a margin in the crane’s load handling ability before it drops below its MCL capacity. See the single failure proof cask handling crane safety analysis report for details of the affected components and the specific design load.

The trolley is designed to operate at temperatures between 40 °F and 104 °F; however, the operating temperature of the

crane is limited to the fuel building licensing basis temperatures between 50 °F and 104 °F (Ref. UFSAR table 9.4-2).

The occurrence of a bridge girder brittle fracture failure is not credible. Brittle fracture is typically a concern with members whose thickness exceeds 5/8”, areas in tension with a stress riser present, and a relatively low temperature of structural steel member. The only primary load-carrying member of the existing bridge box girders whose thickness exceeds 5/8” is the top flange, which is 7/8” thick. Under normal operating loads, the top flange of the girder will be in compression only. Therefore, brittle fracture is not a concern for the existing bridge box girders.

The bridge, trolley and hoist motions are controlled by flux vector variable frequency drives that provide for smooth slow speed positioning and gradual acceleration and deceleration. These drives also provide dynamic braking.

Electrical controls are incorporated in the design to mitigate design basis events due to inadvertent operator action, component or sub-component malfunction, and/or site conditions that may occur during load handling. Design features on the main and auxiliary hoists include, overspeed and uncommanded motion detection, weight overload protection, redundant upper and lower limits, two-block protection, wire rope level wind limits, and unbalanced load detection. The bridge and trolley motions are provided with end of travel limit switches. There are emergency stop buttons located both in the cab and on the radio control transmitter.

Should the crane become immobilized with a critical load suspended, repairs, replacement or adjustment of failed or malfunctioning components may be made without affecting the ability of the crane to hold the load. The crane also has provisions for manual operation in the event of loss of electrical power. These provisions allow a suspended load to be transferred to a specific laydown area and safely lowered.

Both the main and auxiliary hoists are dual rope reeved with the load balanced between head and load blocks through the configuration of the ropes and rope equalizers. The design of the reeving limits the load experienced by the wire rope with the MCL attached to less than 10% of the manufacturer's published breaking strength. In the case of a broken rope, the design of the equalizer system limits the load on the intact reeving system to less than 40% of the breaking strength of the rope, including the dynamic effects of load transfer caused by the broken rope condition.

The main hoist sister hook and the auxiliary hook have been designed with a 10:1 safety factor to compensate for a single attaching point. NUREG-0612, Appendix C allows the use of a single attachment point for existing cranes if the hook height is limited by building height. If a single attachment point is employed, NUREG-0612 states that increasing the safety factor to 10:1 compensates for the loss of the single failure proof feature, and equals the total safety factor of the wire rope.

Two diverse limit switches are supplied to prevent two blocking. The lower limit switch is a geared type that counts drum rotations. The upper limit switch is a paddle type that

is actuated by contact of the lower block with the actuating arm if the low limit fails. Should both limits fail, protection against two blocking is provided by a mechanical slip clutch located between the gearbox and the motor, and by sizing of mechanical and structural components with the required strength to maintain integrity.

The wire rope is protected from side loads by limit switches that detect excessive unbalanced loading of the equalizer. The rope is also protected against jumping grooves on the drum by photoelectric sensors that are focused across the outside diameter of wire rope laying in the grooves. Should the rope jump grooves, it will break the beam during drum rotation and activate the switch.

Dynamic braking of both the main and auxiliary hoists is provided by the flux vector drive. Both hoists have primary and secondary holding brakes, which are single failure proof. On the main hoist, the gearbox is not of dual design since the secondary holding break system is mounted on the hoisting drum which provides single failure proof design. The auxiliary hoist has dual gearboxes to account for single failure proof design since they are mounted between the drum and the secondary holding brakes. The brakes are all sized with sufficient capacity to stop the full load of the respective hoist. Each of the breaking systems are designed for fail safe operation.

Trolley and bridge dynamic braking is provided by the flux vector variable frequency drive system. This system also provides overspeed protection and torque limiting. Both the

dynamic brakes and the holding brakes are rated at greater than 100% of the maximum driving torque at the point of application. The holding brakes for both the trolley and bridge are fail safe with manual release provided. They are electrically actuated during normal operation and cannot be used as slow-down brakes.

The crane can be operated from the cab or by radio control. Selecting one mode of operation disables the other.

Critical load bearing components of the crane (main hoist, trolley frame, and bridge girders) and SAFLIFT^{tm} (Lift Beam, Cask hooks, 50-ton hoist, 50-ton Grapper, and Canister Ring) are classified as Seismic Category I, Quality Class Q since the crane and SAFLIFT^{tm} will be handling TSCs containing irradiated nuclear fuel. Critical load bearing components are designed to remain functional during and after SSE or OBE events.

9.1.4.3.2 New Fuel Handling Crane

The new fuel handling crane is designed so that through the use of interlock and operating procedures the hoisting load is limited to 5000 pounds and a key-operated interlock override is used to allow crane operation over the spent fuel pool. Additional design details are discussed in paragraph 9.1.4.2.2.17.

9.1.4.3.3 Containment Polar Crane

The operation of the containment polar crane during lifting and lowering the reactor vessel closure head is described as follows:

In preparation for refueling, the crane lifts the closure head, transports it to the laydown area of the refueling floor where the closure head is temporarily stored. The crane is then used for other lifting functions during the refueling operation. The main hoist raise circuit limit switch is equipped with an administratively controlled key operated bypass switch that enables override of the 40 ft limit. The bypass switch is used for lifts other than the reactor vessel closure head under administrative controls.

The trolley travel exclusion zone interlock circuit is also administratively controlled by a key operated switch that can be bypassed when fuel is present for removal and replacement of the Reactor Vessel Head and the Upper Guide Structure and for movement of loads located in the area above the reactor vessel.

9.1.4.3.4 Fuel Handling

A failure mode analysis is described in Table 9.1-4.

Direct communication between the control room and the refueling machine console is available whenever changes in core geometry are taking place. This provision allows the control room operator to inform the refueling machine operator of any impending unsafe condition detected from the main control board indicators during fuel movement.

Functionality of the fuel handling equipment including the bridge and trolley, the lifting mechanisms, the upending machines, the transfer carriage, and the associated instrumentation and controls is assured through the implementation of pre-operational tests and routines. In

addition to the interlocks described in section 9.1.4.2.1, the equipment has the following special features:

A. The major systems of the fuel handling system are electrically interlocked with each other to assist the operator in properly conducting the fuel handling operation. Failure of any of these interlocks in the event of operator error will not result in damage to more than one fuel assembly.

B. Miscellaneous special design features which facilitate handling operations include: backup hand operation of the refueling machine hoist and transverse drives in the event of power failure; backup hand operation of the CEA change platform traverse drives in the event of power failure. A two speed transmission is installed on the transfer machine winch skid to permit applying an increased pull on the transfer carriage in the event it becomes stuck; a viewing port in the refueling machine trolley deck to provide visual access to the reactor for the operator; electronic and visual indication of the refueling machine position over the core; a protective shroud into which the fuel assembly is drawn by the refueling machine; transfer system upenders manual operation by a special tool in the event that the hydraulic system becomes inoperative.

C. The fuel transfer tube is sufficiently large to provide natural circulation cooling of one irradiated fuel assembly in the unlikely event that the transfer carriage should be stopped in the tube.

D. The manual operator for the fuel transfer tube valve extends from the valve to the operating deck. Also, the valve operator has enough flexibility to allow for operation of the valve even with thermal expansion of the fuel transfer tube.

E. Travel stops in both the refueling and spent fuel handling machines restrict withdrawal of the spent fuel assemblies. This results in the maintenance of a minimum water cover of 9 feet 5 inches over the active portion of the fuel assembly resulting in a radiation level of 2.5 mr/hr or less at the surface of the water. The depth of water surrounding the fuel transfer canal, transfer tube and spent fuel storage pool is sufficient to limit the maximum continuous radiation levels in working areas to 2.5 mr/hr.

9.1.4.3.5 Reactor Vessel Closure Head Handling

The reactor vessel closure head is a heavy load that by necessity must be transported above irradiated fuel in the vessel in order to perform core off-load and reactor reassembly operations. Since the containment polar crane is not single-failure proof, a reactor head drop is a credible event that may damage fuel resulting in significant offsite exposures. Per the guidance in NUREG-0612 and NEI 08-05, the effects of a postulated load drop event have been analyzed using realistic calculation to demonstrate that the potential consequences are acceptable.

Operating experience shows that special lifting devices such as the head lift rig are extremely reliable, and problems tend to

be self-revealing at an early stage in the lift sequence. Consequently, malfunction of the polar crane or operator error are the only credible failure mechanisms that may result in a dropped head. To analyze this event, the assumed drop weight accounts for the reactor head, the lifting rig, and the remainder of the head assembly. The weight of the crane hook or load block need not be included because they cannot impact simultaneously with the head if dropped. Failures in the handling system are postulated to occur directly above the head’s center of gravity and so impart no significant rotational movement to the head. The result is a flat drop which conservatively transfers more load to vessel internal components than the case where the head rotates as impact. Because drops beyond the outer radius of the vessel flange would likely transfer substantial energy to structures other than the reactor vessel, a concentric orientation is more limiting than an offset drop. Load drops form locations prohibited by interlock or procedures were not considered credible because they would require either an interlock malfunction or a human error in combination with an additional crane failure, which would exceed the single failure criterion.

The analysis considers the flat, concentric drop of a head assembly weighing 400,000 pounds from a height of 40 feet. Since the refueling pool may or may not contain water during head movement, the head is assumed to fall through air; no credit is taken for water to slow the head descent or otherwise dissipate the impact energy. The head is conservatively assumed to be perfectly rigid because plastic deformation of the head would reduce the energy deposited in the system. The

head drop calculations utilize a hybrid approach involving both classical lumped mass-spring models of assemblies and also three-dimensional finite element modeling of critical components. Static and dynamic, non-linear, elastic-plastic analyses were performed using codes approved for safety related applications in accordance with the methodology provided in NEI 08-05 with minor exceptions as described below.

The reactor coolant system evaluation used a lumped mass and stick model similar to that shown in Figure 3.7-9B. This model, developed previously for seismic and LOCA blowdown analysis, is suitable for an impact transient but was modified to account for the locally high, non-linear, elastic-plastic effects. All major system components, including supports and a simplified representation of the reactor internals and fuel, were incorporated to more accurately model the distribution of vibration energy in a coupled system. The effective spring stiffnesses of the reactor of the reactor vessel support columns were computed based on an elastic-plastic analysis of the columns and a static finite element analysis of the primary biological shield structure using ANSYS (refer to Section 3.9.1.2.1.8). Piping branch connections with negligible contribution to the dynamic response were omitted. The transient analysis is initiated when the head weight is allowed to dynamically impact the reactor vessel with the velocity determined from the kinetic energy of the fall. Time-varying stress intensities were calculated using ANSYS and compared to the Level D services limits in Appendix F of ASME Boiler and Pressure Vessel Code. The 1983 code year was selected over the original construction code because it

provided more appropriate criteria for the analysis. The initial results showed that the bolts that anchor the reactor vessel support column base plates to the biological shield structure fail during rebound. The event was re-analyzed assuming that the bolts break at the moment of peak tensile stress, and thereafter the vessel support columns were modeled as only proving compressive restraint (no upward vertical stiffness). With the bolts either intact or failed, the structural integrity of the vessel and main loop piping was sufficient to maintain shutdown cooling.

The effect of the head drop impact on the primary bioshield structure supporting the reactor vessel was also considered. The relevant portions of the reactor vessel support structure and the containment base mat were represented in a simplified 3-D finite element model using ANSYS that included all openings that could significantly influence the overall structural response. Property data were taken from project design specifications and the construction codes as applicable. Credit was taken for the increase in compressive strength of concrete due to aging based on actual 91-day test results, and an additional increase for dynamic loads events was also considered. Although 28-day data were not used for aging as described in NEI 08-05, the 91-day data are representative of the installed properties and thus consistent with a realistic evaluation of the transient. The primary shield concrete structural dynamic response was analyzed with ANSYS using the interface force and moment time-histories developed from the reactor coolant system analysis for cases where the vessel support column anchor bolts failed or remained intact.

Resultant stresses in critical areas were compared to the inelastic limits in ACI 349-06 for concrete (with amendments per Regulatory Guide 1.142) and AISC N690 for steel. Use of the 2006 edition of ACI 349 instead of the 1997 edition described in NEI 08-05 has negligible impact on the analysis. The impact load response of the primary shield structure region that bridges over the in-core instrument chase lies in the inelastic range. Energy balance methods were used to determine the inelastic response ductilities for comparison with code allowables. The structural response to the impact attenuates rapidly away from the vessel support column base plate region where the maximum loading occurs. Although some crushing of concrete may occur immediately below the base plates, this minor and localized damage has a negligible effect on the overall structural integrity of the vessel support system.

The reactor vessel internals were modeled using a lumped mass and stick model considering vertical displacements only. A stick representation similar to the seismic model shown in Figure 3.7.40-8 was expanded to include the effects of the vessel supports, and non-linear spring elements were added to account for energy dissipation due to plastic deformation, friction, and hydrodynamic interaction. Initial displacements due to the deadweight of the internal components were determined using STATIC. Then they dynamic response and peak forces in the elements resulting form the impact were calculated by CESHOCK (refer to Section 3.9.1.2.3.5). The upper guide structure (UGS) flange is indirectly supported by the vessel flange via the holdown ring and the core support barrel. In a postulated head drop, the head first contacts the

UGS, which would be transmitted to the reactor vessel flange, forcing the vessel downward, compressing the vessel supports, and rebounding. The peak loads experienced during the transient analysis were compared to Level D service limits in Appendix F of the 1974 ASME Code with no addenda. For critical members subject to bending, elastic-plastic finite element static analyses with solid 3-D elements were performed using ANSYS to determine the load-deflection behavior. The results indicate the fuel is not damaged, and the vessel and internals experience limited deformation that does not prevent adequate core cooling.

As a heavy load, the reactor head is moved using the administrative controls described in NUREG-0612 and Regulatory Guide 1.160, Revision 3, which serve to reduce the probability of a dropped load. The analyses above demonstrate that the postulated drop of the reactor vessel head will not result in damage to irradiated fuel directly due to the impact or indirectly through loss of core cooling capability. Minor deviations from the guidance in NEI 08-05 had minor effects on the results that were small in comparison with the overall uncertainty of the analysis. Additionally, head removal and installation with fuel in the vessel are performed with “containment closure” as defined in the Technical Specification Bases to provide further defense in depth for the reduction of potential radioactive release consequences. These programmatic controls ensure that the overall risk from reactor head movement remains at an acceptably low level.

9.1.4.4 Testing and Inspection Requirements

During manufacture of the fuel and CEA Handling Equipment at the vendor's plant, various in-process inspections and checks are required including certification of materials and heat treating, and liquid-penetrate or magnetic-particle inspection of critical welds. Following completion of manufacture, compliance with design and specification requirements is determined by assembling and testing the equipment in the vendor's shop. Utilizing a dummy fuel assembly having the same weight, center of gravity, exterior size and end geometry as an actual assembly, all equipment is run through several complete operational cycles. All traversing mechanisms are tested for speed and positioning accuracy. All hoisting equipment is tested for vertical functions and controls, rotation, and load misalignment.

Hoisting equipment is also tested to 125 percent of specified hoist capacity. Set points are determined and adjusted and the adjustment limits are verified. Equipment interlock functions, and backup systems operations are checked.

Those functions having manual operation capability are exercised manually. During these tests, the various operating parameters such as motor speed, voltage, and current, hydraulic system pressures and load measuring accuracy and set points are recorded. At the completion of these tests the equipment is checked for cleanliness and the locking of fasteners by lockwire or other means is verified.

Equipment installation and testing at the plant site is controlled by approved installation procedures and

pre-operational test procedures designed to verify conformance with procurement specifications. Each component is inspected and cleaned prior to installation into the system. Recommended maintenance, including any necessary adjustments and calibration, is performed prior to equipment operation. Preoperational tests also include checks of all control circuits including interlocks and alarm functions.

9.1.4.5 Instrumentation Requirements

The refueling system instrumentation and controls are described in Paragraph 9.1.4.2. No credit is taken for instrumentation or interlocks on components of the fuel handling equipment to either prevent or mitigate the consequences of the postulated accident. Thus, safety-related interlocks are not provided.

9.1.4.6 CESSAR Interface Requirements

Below are detailed the interface requirements that reactor vessel closure head lifting and the fuel handling system places on certain aspects of the BOP, listed by categories. Additionally, refer to subsection 4.2.1 for additional containment polar crane interface requirements.

A. Power

   1. At least 24.0 kVA shall be provided to power the fuel handling system.

   2. Instrument air and power shall be provided for the refueling equipment.

B. Protection from Natural Phenomena

1. Protection shall be provided in accordance with Criterion 2 of 10CFR50, Appendix A.

C. Protection from Pipe Failure

Not Applicable

D. Missiles

Not Applicable

E. Separation

Not Applicable

F. Independence

Not Applicable

G. Thermal Limitations

Not Applicable

H. Monitoring

Not Applicable

I. Operational/Controls

1. If a single failure can cause the reactor vessel closure head assembly to drop on the reactor vessel flange, the reactor vessel closure head assembly shall not be raised to a height greater than 17 feet while above the reactor vessel flange.

2. Equipment design and building arrangement shall be such that during all phases of expended fuel handling and storage minimum water coverage of

9 feet above the active portion of the fuel assembly shall be maintained to provide adequate shielding for the protection of operating personnel. A nominal 2-foot pool freeboard should be employed.

Equipment shall be provided for moving reactor vessel surveillance specimens, neutron sources, expended CEAs and expended ICIs through the transfer tube and to allow handling or storage of these items in the fuel storage building.

J. Inspection and Testing

Not Applicable

K. Chemistry/Sampling

Not Applicable

L. Materials

Not Applicable

M. System/Component Arrangement

1. The depth of the spent fuel pool shall be such that a fuel rod assembly lying horizontally on the top of the fuel racks shall be covered by a water depth of at least 23 feet.

N. Radiological Waste

Not Applicable

O. Overpressure Protection

Not Applicable

P. Related Services

1. Refueling Pool

   a. Within the pool, embedment and foundation supports shall be designed to accommodate the design loads from the equipment installed for refueling.

   b. Adequate underwater areas shall be provided for storage of the internals and tools without interfering with the refueling operation.

2. Spent Fuel Pool

   a. Within the pool, embedment and foundation supports shall be designed to accommodate the design loads from the equipment installed for refueling.

   b. Adequate underwater areas shall be provided for storage of tools and equipment without interfering with the refueling operation.

   c. Drains, permanently connected systems, and other features of the spent fuel pool shall be designed so that neither maloperation nor failure can result in loss of coolant that would uncover the stored fuel.

   d. Spent fuel pool cooling shall be capable of removing the decay heat generated from all spent fuel placed in the pool.

3. During reactor operation, the tools and equipment on Table 9.1-1 shall be stored in such a manner as to maintain the tools in a safe condition and to prevent them from damaging safety class equipment during a seismic excursion.

4. Motion between the fuel transfer tube support points shall be limited to 3/4 inch.

   a. Supports for the transfer tube shall be provided to allow for thermal expansion and for seismic loadings.

5. A fire protection system shall be provided to protect the fuel handling system consistent with the requirements of GDC 3, and shall include, as a minimum, the following features:

   a. Facilities for fire detection and alarming.

   b. Facilities or methods to minimize the probability of fire and its associated effects.

   c. Facilities for fire extinguishment.

   d. Methods of fire prevention such as use of fire resistant and noncombustible materials whenever practical, and minimizing exposure of combustible materials to fire hazards.

   e. Assurance that fire protection systems do not adversely affect the functional and structural integrity of safety related structures, systems, and components.

f. Care should be exercised to ensure fire protection systems are designed to assure that their rupture or inadvertent operation does not significantly impair the capability of safety-related structures, systems, and components.

Q. Environmental

1. Containment Ventilation Requirements

a. During refueling operations, the containment ventilation system must be capable of maintaining the ambient temperature within the range of 60F - 120F.

9.1.4.7 CESSAR Interface Evaluation

CESSAR interface requirements listed in paragraph 9.1.4.6 are met by PVNGS design as follows and, in addition, refer to subsection 4.2.6 for the evaluation of additional containment polar crane interface requirements.

A. Power

1. At least 24 kVA is provided to power the fuel handling system.

2. Instrument air and power are provided for the refueling equipment.

Table 9.1-4
(Sheet 1 of 2)
FAILURE MODE ANALYSIS OF FUEL HANDLING EQUIPMENT

Component Identification	Failure Mode	Detrimental Effect on System	Corrective Action	Remarks
R. M. Fuel Hoist weight system	Electrical Overload Trip fails	None	Continue refueling, repair on non-interfering basis	Use visual presentation load on meter.
Fuel carrier	Wheels lock in transfer Tube	Transfer Operation can be completed	Move carriage in opposite direction. If carriage does not move, then use handwheel at lower gear ratio to move carriage in both directions.	Power Sufficient to move fuel carrier with all wheels locked.
Hydraulic Power supply for upender	Line to cylinder on upender ruptures	None	Valve off defective line	Upender has two cylinders, each of which is capable of raising upender.
	Loss of hydraulic power	Process can continue on slower basis	Upend manually	Use tool provided.
Brake on R.M. fuel hoist	Does not provide required brake load	None	Continue, repair on noninterfering basis	Redundant brake system provided
Fuel Carrier Cable	Cable parts	Delays refueling	Move fuel carrier to safe position with manual tool	Remove fuel prior to repair
R. M. Hoist Motor	Power Failure	Delays refueling	Repair	Hoist using manual handwheel

Table 9.1-4
(Sheet 2 of 2)
FAILURE MODE ANALYSIS OF FUEL HANDLING EQUIPMENT

Component Identification	Failure Mode	Detrimental Effect on System	Corrective Action	Remarks
Bridge Drive Motor	Power Failure	Delays refueling	Repair	Drive using manual hand-wheel
RFM electronic hoist position indication	Electrical Failure	None	Repair	Redundant indicators are provided
Fuel Carrier Position Sensing System	Electrical Failure	None	Repair	
Refueling Machine	Loss of air pressure	None	Repair	Continue, using manual mode
Refueling Machine TV Camera	Electrical Failure	None	Repair on noninterfering basis	Non-mandatory for fuel handling
Refueling Machine Electronic hoist position indication	Electrical Failure	None	Repair on noninterfering basis	Redundant mechanical counter provided
Reactor Vessel Closure Head Assembly Lift Rig	Mechanical Failure	Possible local damage to vessel head assembly and internals.	Repair	Core maintained in a coolable array

B. Protection from Natural Phenomena

1. All safety-related pumps and components are located in Seismic Category I structures. The protection of Seismic Category I structures against natural phenomena is presented in subsections 3.3.4 and 3.4.4.

C. Protection from Pipe Failure

Not Applicable

D. Missiles

Not Applicable

E. Separation

Not Applicable

F. Independence

Not Applicable

G. Thermal Limitations

Not Applicable

H. Monitoring

Not Applicable

I. Operational/Controls

1. The reactor vessel closure head assembly will not be raised to a height greater than 18 feet above the reactor vessel flange while over the reactor vessel.

References to the reactor vessel closure head assembly raised height of 18 feet are no longer

applicable to PVNGS. Refer to section 9.1.4.3.5 for closure head lift height evaluation.

2. Water shielding in excess of 9 feet can be obtained with 27 inches of freeboard. Equipment is provided to move reactor vessel surveillance specimens, neutron sources, and expended ICIs through the transfer tube and to allow handling or storage in the fuel building.

J. Inspection and Testing

Not Applicable

K. Chemistry/Sampling

Not Applicable

L. Materials

Not Applicable

M. System/Component Arrangement

1. The depth of the spent fuel pool will be such that a fuel rod assembly lying horizontally on top of the fuel racks will be covered by a water depth of at least 22 feet and 6 inches. Refer to sections 1.9 and 15.7.4.1.3.C.

N. Radiological Waste

Not Applicable

O. Overpressure Protection

Not Applicable

P. Related Services

1. Refueling Pool

   a. Within the pool, embedment, and foundation supports are designed to accommodate the design loads from the equipment installed for refueling.

   b. Adequate underwater areas are provided for storage of the internals and tools without interfering with the refueling operation.

2. Spent Fuel Pool

   a. Within the pool, embedment and foundation supports are designed to accommodate the design loads from the equipment installed for refueling.

   b. Adequate underwater areas are provided for storage of tools and equipment without interfering with the refueling operation.

   c. Drains, permanently connected systems, and other features of spent fuel pool have been designed so that neither malfunction nor failure can result in loss of coolant that would uncover the stored fuel.

   d. Spent fuel pool cooling capability is sufficient to remove the decay heat generated from all spent fuel placed in the pools.

3. During reactor operation, the tools and equipment noted on CESSAR Table 9.1-1 are stored in such a manner as to maintain the tools in a safe condition and to prevent them from damaging safety class equipment during a seismic excursion.

4. Motion of fuel transfer tube supports due to seismic building movements will be less than ¾ inch. The transfer tube supports are designed to accommodate seismic and thermal expansion movements and loads.

5. Fire protection for the fuel handling system is discussed in subsection 9.5.1.

Q. Environmental

The containment ventilation system is capable of maintaining the ambient temperature within the range of 70 to 100F.

9.1.5 OVERHEAD HEAVY LOAD HANDLING SYSTEMS (OHLHS)

9.1.5.1 Program Requirements

A Heavy Loads Program is established to implement the guidelines of NUREG-0612 (Control of Heavy Loads at Nuclear Power Plants). These guidelines provide defense in depth against load handling accidents that could result in the release of radioactivity in excess of 10CFR100 limits.

A heavy load is defined as a load whose weight is greater than the combined weight of a single spent fuel assembly, CEA, and

its associated handling tool. The handling of a single spent fuel assembly has been reviewed in the original licensing review or in the Generic Issue “Fuel Handling Accident Inside Containment.” The heavy load for PVNGS is 1480 pounds for the spent fuel assembly and 760 pounds for the handling tool, for a combined weight of 2240 pounds. For convenience and conservatism, PVNGS considers loads in excess of 2000 pounds as heavy loads.

The NRC has established seven general guidelines in NUREG-0612 that must be met in order to provide the defense-in-depth approach for the handling of heavy loads. These seven guidelines should be satisfied for all overhead handling systems that handle heavy loads in the vicinity of the reactor vessel, near spent fuel in the spent-fuel pool, or in other areas where a load drop may damage safe shutdown systems. The following guidelines from Section 5.1.1 (Phase 1) of NUREG-0612 should be satisfied for all heavy load handling unless other alternative measures are taken:

1. Safe load paths
2. Procedures
3. Crane operators
4. Special lifting devices
5. Lifting devices that are not specially designed
6. Crane (inspection, testing and maintenance)
7. Crane (design)

Alternative measures may be taken to compensate for deficiencies in safe load paths, mechanical stops, or

electrical interlocks. These alternative measures can include: increasing crane reliability; restricting crane operations over the spent fuel pool until fuel has decayed sufficiently to limit offsite doses to acceptable levels; or, analyzing the effects of postulated load drops to show that the consequences are within acceptable limits. These alternative guidelines are described in detail in Section 5.1.2 through 5.1.6 (Phase II) of NUREG-0612.

NUREG-0612 Phase II guidelines have been implemented as an alternative means of compensating for deficiencies in safe load paths associated with: spent fuel in the transportable storage canister (TSC); handling of the loaded canister; and, handling of heavy loads in the vicinity of the fuel building essential air filtration units. The Phase II guidelines have been met for the cask handling crane and associated lifting devices by implementation of NUREG-0612, Section 5.1.6 (Single-Failure-Proof Handling Systems).

9.1.5.2 References

All references regarding Heavy Loads, NUREG 0612, and the Reactor Vessel Closure Head (RVCH) drop analysis, including the licensing correspondence previously contained in the section, have been consolidated in Section 9.1.6.

9.1.5.3 Applicability

The cranes and special lifting devices that are used to handle heavy loads in accordance with the heavy loads program are identified in table 9.1.5-1.

9.1.5.4 Compliance with Guidelines

9.1.5.4.1 Safe Load Paths

NUREG-0612 requires that the safe load path be painted on the floor. APS instead identifies the safe load paths in procedures and work documents. In certain cases, exclusion zones may be established in lieu of safe load paths to prevent heavy loads from encroaching on either spent fuel or safe shutdown equipment. In this case, handling of heavy loads may take place in areas outside the exclusion zone, but safe load paths or other compensatory measures must be established if carrying a heavy load within the exclusion zone. A signal person is required to verify the safe load path prior to lifting the load.

General guidelines for establishing safe load paths are contained in the rigging control procedure. Deviations from approved safe load paths require an approved engineering evaluation and changes to the appropriate procedures. Plant Safety Review Board approval is not required as detailed in NUREG-0612 guideline 5.1.1(1).

The fuel building cask handling cranes are single failure proof in accordance with NUREG-0612 Appendix C, and NUREG-0554. Heavy loads handled with this crane may deviate from established safe load paths/exclusion zones only when necessary. Approval for deviations from safe load paths/exclusion zones may be justified based upon the fact that the increased reliability of the crane and associated lifting devices makes the probability of a load handling accident extremely small.

9.1.5.4.2 Procedures

Procedures are established to cover load-handling operations for heavy loads that are or could be handled over or in proximity to irradiated fuel or safe shutdown equipment. These procedures should include:

- identification required plant conditions and equipment that are prerequisites for performing these lifts
- inspection, tests, and acceptance criteria required before movement of loads
- verifications and oversight required for movement of loads
- qualifications and training of riggers and crane operators
- the steps and proper sequence to be followed in handling the load
- defining the safe load paths
- maintenance requirements for rigging and cranes, and
- other special precautions

These controls may be contained in either administrative or technical procedures as appropriate.

Heavy load lifts during outages are controlled by the appropriate procedures. Heavy load lifts are evaluated as maintenance activities using the maintenance rule risk assessment procedures in compliance with Regulatory Guide 1.160 as described in Section 1.8.

Heavy load lifts by both the polar crane and pedestal crane are allowed to occur simultaneously through defense-in-depth

approach. Crane design and administrative controls that mitigate common cause failure are:

- different crane designs
- both cranes are designed to maintain structural integrity with load during an SSE
- both cranes are designed to not drop a load on loss of power
- rigging meets the appropriate standard design requirements
- rigging used for heavy loads is engineered with at least a 15% safety margin
- independent rigging crews and operators are used for the cranes
- rigging crews and operators must attend a high risk evolution briefing for heavy loads lifts
- safe load path verification is performed prior to lift
- rigging is checked by different qualified individual prior to lift

9.1.5.4.3 Crane Operators

Procedures are established to assure that individuals operating OHLHS are trained and qualified in accordance with applicable sections of ANSI B30.2, Overhead and Gantry Cranes. These procedures provide assurance that individuals certified as crane operators have the necessary knowledge level, proficiency level and physical capabilities commensurate with the importance to safety of the duties they perform.

9.1.5.4.4 Special Lifting Devices

Special lifting devices are listed in Table 9.1.5-1.

NUREG-0612 states that special lifting devices should satisfy the guidelines of ANSI N14.6, Standard for Special Lifting Devices for shipping Containers Weighing 10000 Pounds (4500kg) or More for Nuclear Materials with the exception that the stress design factor should be based on the combined maximum static and dynamic loads that could be imparted on the handling device based on the characteristics of the crane that will be used.

Special lifting devices used in single failure proof applications meet the augmented requirements of NUREG-0612, Section 5.1.6(1)(a). These devices either employ dual load paths or are designed with twice the design safety factor as is required for special lifting devices.

The special lifting devices that are designated for use with the containment polar crane were designed to ANSI N14.6 unless otherwise noted in Table 9.1.5-1. The special lifting devices designed by C-E or Westinghouse have been analyzed for potential load drops and the effects have been found acceptable. Administrative controls require all new special lifting devices to be designed in accordance with NUREG-0612 Section 5.1.1 or 5.1.6 as applicable.

The special lifting devices designed by CE that are designated for use with the containment polar crane are subject to different testing and inspection criteria than recommended in ANSI N14.6. These devices are subject to the following testing and inspection:

a) Performance of a visual inspection on the special lifting devices at the beginning of each refueling outage, prior to the returning the device to service. Dimensional testing shall be performed if indications from the visual inspections warrant it. Every third refueling outage ($\pm$ one refueling outage) the inspections shall be performed, in accordance with item b) or c).

b) Performance of a complete visual inspection with applicable NDE tests (magnetic particle testing and liquid penetrant testing) at all major load-carrying welds and critical areas defined in EER 87-ZC-072. NDE of the Reactor Vessel Head Lift Rig may be performed with the lift rig removed from the Containment Building during the operating cycle. Dimensional testing shall be performed if indications from either the visual inspections or NDE testing warrant further inspection, or

c) Performance of a 125% minimum load test followed by a complete visual inspection. Perform dimensional testing, if required, as a result of the load test or visual inspection.

Testing and inspection of all other special lifting devices shall be performed in accordance with applicable guidelines of ANSI N14.6.

9.1.5.4.5 Lifting Devices That Are Not Specially Designed

These devices include slings, shackles, rigging eyes, and other “off the shelf” type devices. NUREG-0612 requires these devices to be sized in accordance with ASME B30.9, Slings,

except that the load used in selecting the device must be based on the combined maximum static and dynamic loads that could be imparted on the device based on the characteristics of the crane that will be used.

Devices used in single failure proof applications meet the augmented requirements of NUREG-0612, Section 5.1.6(1)(b). The devices either employ dual load paths or are selected based on twice the load as is required for other devices used to handle heavy loads.

The lifting device designed by Bechtel (SLD 4 of Table 9.1.5-1) is maintained, tested and inspected in accordance with 9.1.5.4.4 a) through 9.1.5.4.4 b). All other lifting devices that are not specifically designed are tested and inspected in accordance with ASME B30.9 – slings.

9.1.5.4.6 Crane Inspection, Testing, and Maintenance

Administrative controls are established to perform inspection, testing, and maintenance of OHLHS overhead cranes in accordance with chapter 2-2 of ASME B30.2.

9.1.5.4.7 Crane Design

OHLHS cranes and hoists are designed and fabricated in accordance with applicable sections of ASME B30.2, CMAA Specification 70, and CMAA Specification 74.

9.1.5.4.7.1 Single Failure Proof Crane Design

OHLHS Cranes that are required to handle heavy loads in the vicinity of spent fuel or safe shutdown equipment, are either

analyzed for postulated load drops, or are designed with increased reliability to make the probability of postulated load handling accidents extremely small. NUREG-0612, Section 5.1.6 and Appendix C, and NUREG-0554 contain guidelines for crane design to provide increased reliability through the use of dual load paths or increased design stress factors. It is not necessary to analyze the effects of postulated load drops for single failure proof cranes, since the probability of occurrence is extremely small.

The cask handling cranes are upgraded to meet the guidelines of NUREG-0612, Section 5.1.6. The trolleys on the upgraded cranes meet the guidelines of NUREG-0554 (Single-Failure-Proof Cranes) and NUREG-0612, Appendix C (Modification of Existing Cranes). To comply with guidelines for prevention of brittle fracture of the girders, operation of the cask handling cranes are restricted to temperatures between 50°F and 104°F, inclusive (ref. UFSAR Table 9.4-2).

Table 9.1.5-1
CRANES AND ASSOCIATED SPECIAL LIFTING DEVICES

Crane	**Special Lifting Devices**	**Special Lifting Device Design Standard**
1. Containment Polar Crane	1. Reactor Vessel Head Lift Rig 2. Upper Guide Structure Lift Rig 3. Air Handling Unit/Reactor Vessel Missile Shield Lifting Frame 4. CEDM Cable Support Structure Lifting Assembly 5. East Riser duct Lifting Assembly	1. NUREG-0612 (5.1.6) ANSI N14.6 2. ASME Section III, Appendix 17 3. NUREG-0612 (5.1.3) ANSI N14.6 4. AISC, ASME B30.9 5. NUREG-0612 (5.1.3) ANSI N14.6
2. Containment Pedestal Crane	None	N/A
3. Fuel Building Cask Handling Crane(1)	1. NAC UMS Transfer Cask(1) 2. SAFLIFT Strongback Canister hoist lifting beam(1) 3. Shield Lid Lift Rig(1)	1. NUREG-0612 (5.1.6), ANSI N14.6, 2. NUREG-0612 (5.1.6), ANSI N14.6, NUREG-0554 3. NUREG-0612 (5.1.6), ANSI N14.6,
4. Fuel Building New Fuel Crane	None	N/A
5. Fuel Building SFP Cooling Pumps and HXs Monorail Hoist(2)	None	N/A
6. Main Steam Support Structure (MSSS) Hoists	None	N/A

(1) Single Failure Proof
(2) Hoist removed from monorail

9.1.6 REFERENCES

<u>Regulatory</u>

1. NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” July 1980.

2. NEI 08-05, “Industry Initiative on Heavy Load Lifts,” July 2008

3. NRC Letter September 5, 2008, “Safety Evaluation Report for NEI 08-05.”

4. NRC Regulatory Issue Summary RIS 2008-28, “Endorsement of Nuclear Energy Institute Guidance for Reactor Vessel Head Heavy Loads Lifts,” December 2008.

5. Generic Letter 80-113, Control of Heavy Loads, dated December 22, 1980.

6. Generic Letter 81-07, Control of Heavy Loads, dated February 3, 1981.

7. Generic Letter 85-11, Completion of Phase II of “Control of Heavy Loads at Nuclear Power Plants, NUREG-0612, dated June 28, 1985.

8. NRC Enforcement Guidance Memorandum EGM 07-006, “Enforcement Discretion for Heavy Load Handling Activities,” 9/28/2007.

9. NEI Letter, “Industry Initiative on Heavy Load Lifts,” 9/25/2007.

Industry Standards

10. Crane Manufacturers Association of America CMAA Specification 70, 1971.

11. ANSI B30.2-1976, "Overhead Gantry Cranes."

12. ANSI B30.9-1971, "Slings."

13. ANSI N14.6-1978, "Standard for Special Lifting Devices for Shipping Containers Weighing 10,000 pounds or More for Nuclear Materials."

Correspondence

14. Letter ANPP-18281-JMA/WFQ, dated June 25, 1981;

15. Letter ANPP-18686-JMA/WFQ, dated August 18, 1981;

16. Letter ANPP-19200-JMA/KEJ, dated October 20, 1981;

17. Letter ANPP-22328-WFQ/KEJ, dated November 18, 1982;

18. Letter ANPP-22704-WFQ/KEJ, dated January 12, 1983;

19. Letter ANPP-23062 WFQ/KEJ, dated February 23, 1983;

20. Letter ANPP-32958-EEVB/JKO, dated July 5, 1985; and,

21. Letter 161-03811-WFC/JRP, dated March 15, 1991.

9.1.7 COMPLIANCE WITH 10CFR50.68 "CRITICALITY ACCIDENT REQUIREMENTS"

Controls of Special Nuclear Material and plant equipment comply with 10CFR50.68. Reference RCTSAI 2149.

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9.2 WATER SYSTEMS

9.2.1 STATION SERVICE WATER SYSTEM (ESPS)

The station service water system, referred to as the essential spray pond system (ESPS), removes heat from engineered safety features (ESF) and safety-related components and dissipates it to the atmosphere via the essential spray ponds (ultimate heat sink).

The ESF and safety-related components served by the ESPS are:

- Standby diesel generator cooling systems
- Essential cooling water system (ECWS) heat exchangers

The ESPS includes safety-related components and components used for ESPS water cleanup and chemistry control. It is operated in an emergency situation and in conjunction with a normal reactor shutdown. During normal plant operation, the ESPS may be operated in support of several auxiliary systems including emergency diesel generators, shutdown cooling, essential chillers, fuel pool cooling, and nuclear cooling water priority loads, as well as for chemistry control, and testing. The system is also actuated each time the standby diesel generators are started and on loss of offsite power.

Each generating unit is provided with two redundant, safety-related ESPS trains. There are no interconnections or cross connections with any other PVNGS unit's ESPS.

The ESPS provides the cooling water needed for those components that must operate following a loss-of-coolant accident (LOCA) and that are essential to a safe reactor shutdown.

The ESPS is shown in engineering drawings 01, 02, 03-M-SPP-001. Table 9.2-1 lists the safety-related component heat loads and associated water requirements for the ESPS and the ECWS.

In addition, table 9.2-1 cross-references the sections covering the related systems that include the safety-related components listed.

The ESPS will be operated in accordance with Technical Specifications.

9.2.1.1 Safety Design Bases

Safety design bases pertinent to the ESPS are as follows:

A. Safety Design Basis One

The ESPS, in conjunction with the ultimate heat sink and the ECWS, shall be capable of removing sufficient heat to ensure a safe reactor shutdown coincident with a loss of offsite power.

B. Safety Design Basis Two

The ESPS, in conjunction with the ultimate heat sink, shall be capable of maintaining the ECWS temperature to the essential chiller at 135°F or less following the design basis LOCA under the most adverse historical meteorological conditions consistent with the requirements of Regulatory Guide 1.27.

C. Safety Design Basis Three

A single failure of any component in the ESPS will not impair the ability of the ESPS to meet its design

requirements because two 100% redundant trains are provided.

D. Safety Design Basis Four

Adverse environmental occurrences will not impair the ability of the ESPS to meet its functional requirements.

E. Safety Design Basis Five

The ESPS shall be designed to detect leakage of pond water from the ESPS.

F. Safety Design Basis Six

The ESPS shall be designed to minimize the effects of long-term corrosion and organic fouling.

G. Safety Design Basis Seven

The ESPS shall be designed to withstand the effects of a safe shutdown earthquake (SSE).

H. Safety Design Basis Eight

All components of the ESPS shall be capable of being fully tested during normal plant operation. In addition, all parts and components shall be accessible for inspection at any time.

I. Safety Design Basis Nine

The ESPS, in conjunction with the ultimate heat sink and the ECWS, provides cooling capability for the spent fuel pool when the spent fuel pool normal cooling system is not available.

Table 9.2-1
TABULATION--HEAT LOADS AND WATER REQUIREMENTS
ESSENTIAL SPRAY POND SYSTEM AND ESSENTIAL COOLING WATER SYSTEMS (Sheet 1 of 2)

Component	Related System	FSAR Section Reference	Heat Load (10^6 Btu/h) Note 11			Water Flow (gal/min)		
			3.5 h After Shutdown	27.5 h After Shutdown	LOCA	Normal	LOCA	Basis
ESPS								
Diesel generator cooling system train A	Diesel generator cooling water system	9.5.5	12.4	12.4	12.4	--	1,500	Note 1 & 10
	Diesel generator lubrication system	9.5.7						
	Diesel generator combustion air system	9.5.8						
Diesel generator cooling system train B	Diesel generator cooling water system	9.5.5	12.4	12.4	12.4	--	1,500	Note 1 & 10
	Diesel generator lubrication system	9.5.7						
	Diesel generator combustion air system	9.5.8						
Essential cooling water system heat exchanger (tube side) train A	ECWS	9.2.2.1	247.5	88.4	Note 6	14,420	14,000	Note 2 & 9
Essential cooling water system heat exchanger (tube side) train B	ECWS	9.2.2.1	247.5	88.4	Note 6	14,420	14,000	Note 2 & 9

Notes:

1. Actual heat to be rejected by a 5500 kW diesel generator Unit.
2. Summation of individual heat loads on train for a single train cooldown.
3. Also see subsection 9.2.7 for heat loads and flowrates.
4. Condenser heat rejection for 100% air conditioning load on levels 100 and 140 feet of the control building.
5. During normal operation cooling is provided from the NCWS.
6. Heat load is variable and is discussed in subsection 6.2.1.
7. Heat load and water flow requirements are placed on the ECWS when the NCWS is not available, but not during post-LOCA operation. Only one train of the ECWS services these components at any given time.
8. Heat load is variable. The "LOCA" spent fuel heat load to be rejected is a combination of the maximum decay heat in the pool at the end of a cycle (constant equal to 4.0E+6 Btu/h) and the sensible heat of the pool at the time of manual alignment to ECWS.
9. The LOCA flow rates shown in the Table are those chosen for and are specific to the Design Bases scenario evaluated for the Ultimate Heat Sink (UHS) thermal performance analyses. The “Normal” flow rates represent values that are selected for use in analyses of other assumed events that require a normal unit shutdown.

Table 9.2-1
TABULATION--HEAT LOADS AND WATER REQUIREMENTS
ESSENTIAL SPRAY POND SYSTEM AND ESSENTIAL COOLING WATER SYSTEMS (Sheet 2 of 2)

Component	Related System	FSAR Section Reference	Heat Load (10^6 Btu/h) Note 11			Water Flow (gal/min)		
			3.5 h After Shutdown	27.5 h After Shutdown	LOCA	Normal Shutdown	LOCA	Basis
ECWS								
Shutdown heat exchangers, one per train (SDHX)	Shutdown cooling system	5.4.7	247	87.6	Note 6	14,000	12,600	Note 2, 3, 9 & 12
	Habitability systems chilled water systems	6.4 9.2.9			4.20	--	720	Note 4
Essential chiller train A	Air conditioning, heating, cooling, and ventilation system	9.4						
Essential chiller train B	Air conditioning, heating, cooling, and ventilation system	9.4	--	--	4.20	--	720	Note 4
Fuel pool heat exchanger train A (FPHX)	Spent fuel pool cooling and cleanup system	9.1.3	12.6	12.6	Note 8	--	1,206	Note 2 & 5
Fuel pool heat exchanger train B	Spent fuel pool cooling and cleanup system	9.1.3	12.6	12.6	Note 8	--	1,206	Note 2 & 5
Normal chiller	Normal chilled water system	9.2.9	12.9	12.9	--	--	2,500	Note 7
Reactor coolant pumps (seals and motor)	Reactor coolant system	5.1	12.4	--	--	2,044	2,044	Note 7
CEDM air coolers	Reactor	9.4	5.0	--	--	400	400	Note 7

Notes (continued):

10. The minimum cooling water flow rate required for each diesel generator is based on the maximum spray pond water temperature and permissible plugging in the heat exchangers. The diesel generator fuel oil cooler is not required for diesel engine operation. (Note 13) Therefore, the fuel oil coolers of all six emergency diesel generators have been functionally abandoned.
11. Heat Loads are bounding for core power up to 3990 MWt.
12. See Table 6.2.1-7 for EW flow ranges used and evaluated in the Containment Peak Pressure Analysis.
13. In units where DEC-00649 has been implemented, the diesel generator fuel oil coolers cooling function has been permanently retired.

J. Safety Design Basis Ten

Design and arrangement of the ESPS is such that its functional operation is unaffected by any missile effects.

9.2.1.2 Power Generation Design Bases

Pertinent power generation design bases are as follows:

A. Power Generation Design Basis One

The ESPS, in conjunction with the ultimate heat sink and the ECWS, is designed to cool the reactor from 350F to 125F within 27-1/2 hours during normal shutdown utilizing two trains of ESPS and ECWS. The cooling rate of the reactor coolant does not exceed 75F per hour.

B. Power Generation Design Basis Two

The ESPS, in conjunction with the ultimate heat sink and the ECWS, is designed to provide a maximum cooling water temperature of 105F to the shutdown cooling heat exchanger 27-1/2 hours after normal shutdown utilizing two trains of ESPS and ECWS.

9.2.1.3 Codes and Standards

The ESPS and associated components are designed in accordance with codes and standards described in section 3.2 and specified in table 3.2-1.

9.2.1.4 System Description

The ESPS consists of two separate, redundant trains, each train comprised of an ESPS pump (rated at 16,300 gpm, at 120 ft. TDH, 600 hp), pump structure, piping, valves, instrumentation, and controls required to provide cooling water to the nuclear safety-related components listed in table 9.2-1, in conjunction with the ultimate heat sink. The rated flow and head are the conditions for which the pumps were originally purchased. The performance requirements (as validated by surveillance tests) are established by the system hydraulic and thermal performance analyses. The ultimate heat sink (essential spray ponds) is discussed in subsection 9.2.5.

Each ESPS train, in conjunction with the ultimate heat sink, is capable of supporting alone 100% of the cooling functions required for a safe reactor shutdown or following a LOCA.

The ESPS operates at a higher pressure than the ECWS as protection against leakage into the ESPS from the ECWS in case of tube leakage in the ECWS heat exchanger. Analysis of postulated cracks in moderate-energy piping is discussed in section 3.6.

9.2.1.5 ESPS Components

9.2.1.5.1 Essential Spray Pond Pump Intake Structures and Sumps

The ESP pump intake structures and sumps are Seismic Category I structures, 6 feet deeper than the ponds to satisfy NPSH requirements.

9.2.1.5.2 Essential Spray Pond System Pumps

Each of the redundant ESPS trains includes a water pump (ESPS pump). Each pump is sized for full emergency load capacity and provides the flow needed to remove the heat following a LOCA from the components listed in table 9.2-1. These pumps are Seismic Category I and are furnished with onsite power when offsite power is not available. Each pump is powered from a separate ESF bus. The pump arrangement as shown in figure 9.2-1 (sheet 1 of 2) is such that pump performance is not affected by high and low pond water levels. Refer to section 3.9 for a discussion of qualification testing of these pumps.

9.2.1.5.3 Essential Spray Pond System Valves

Valves are used for control of the ESPS and for isolation of components in the ESPS. These valves are furnished in conformance with ASME Code, Section III, Class 3. These valves are operated manually.

9.2.1.5.4 Essential Spray Pond System Piping

Essential spray pond system water service piping inside the spray ponds is made of 316L austenitic stainless steel. Epoxy-lined carbon steel is used for water service piping outside the spray ponds. Piping external to the pond is installed underground.

Piping is corrosion protected or of corrosion-resistant material.

The supply and return piping to and from system components in a train are separated physically from the supply and return lines in the redundant train, except for a short section of piping within the instrumentation vault. Physical separation of the trains is designed to mitigate the consequences of a fire or pipe rupture. The probability of a fire inside the vault is considered to be insignificant. A calculation on the section of piping within the vault showed that a moderate energy line break is not a credible accident. Therefore, physical separation inside the vault is not required. Holes are provided in selected risers in the spray piping of each spray pond to drain standing water, in the exposed piping, to preclude freezing.

9.2.1.5.5 Instrumentation and Controls

Refer to paragraph 7.4.1.1.4 for the ESPS pump control logic. (Refer to paragraph 9.2.1.9 for instrumentation and control applications to the ESPS.)

9.2.1.5.6 Chemical Control Equipment

Chemical Control equipment is indicated in Table 9.2-2. Other equipment in addition to the listed equipment may be installed as needed (such as equipment needed for the addition of corrosion inhibitors and biocides).

9.2.1.6 System Operation

During emergency operations, the ESPS provides cooling water directly to the cooling systems of the diesel generators and to the ECWS indirectly through the ECWS heat exchangers. Cooling

water for the ESPS is supplied from the ultimate heat sink as described in subsection 9.2.5. Return flow from components serviced by the ESPS is returned to the ESPS spray cooling subsystem and to the ultimate heat sink for reuse.

The ESPS will operate for 26 days following a postulated LOCA without requiring any makeup water to the ultimate heat sink and without requiring any blowdown from the spray ponds for dissolved solids control. Provisions for makeup water and spray pond blowdown for the time period following 26 days are discussed in subsection 9.2.5. The combined water inventory of both essential spray ponds is needed for a 26-day operation without makeup.

The ESPS has two redundant and separate trains. During the early stages of a LOCA, when heat removal demands are highest, spray pond flow rate is controlled by a combination of a flow orifice and bypass valve in the spray pond return line. Later into the accident, when heat removal demands are lower, the bypass valve will be closed. This increases thermal performance margin while maintaining the 26 day inventory requirement described in Section 9.2.5. In Unit 1 and 3 Train B installations, DMWO 3304346 has not been fully implemented on the spray pond return piping, and therefore, the spray pond bypass valves remain in the closed position during a postulated LOCA event until completion of DMWO 3304346.[1] Each train alone, in conjunction with the ultimate heat sink, has a full 100% heat dissipation capacity for a safe shutdown. Although

(1) DMWO 3304346 adds the capability to vary SP flow rates. This note applies to units and trains where this DMWO has been installed.

an emergency reactor shutdown is accomplished by initial (first 24 hours) operation of both ESPS trains, shutdown and cooldown over an extended period of time is possible with the use of a single train.

The ESPS operational logic and the associated initiation and actuation controls and instrumentation are summarized in the following paragraphs.

Both trains of the ESPS and the ECWS (see paragraph 9.2.2.1) are operationally actuated by any single or any combination of the following signals or operations:

- Safety injection actuation signal (SIAS)
- Containment spray actuation signal (CSAS)
- Control room ventilation and isolation actuation signal (CRVIAS)
- Control room essential filtration actuation signal (CREFAS)
- Auxiliary feedwater actuation signal (AFAS-1 or AFAS-2)Diesel generator start signal (DGSS)
- Loss of offsite power signal (LOP)
- Manual start by control room operator

Manual start and stop actuation from the control room overrides the automatic mode. Manual start and stop controls are also provided for each of the two ESPS trains and two ECWS trains. This individual control feature permits the removal of a train from operation after the automatic operation actuation if it is not required.

The only components that are actuated in any of the trains, either automatically or by manual control room operator initiation in lieu of automatic actuation, are the ESPS pumps. Essential spray pond system and ECWS valves are manually and locally operated. Valves in the supply lines from the pumps and in the return lines to the essential spray ponds or to the ECWS and diesel generator heat exchangers are locked open. In Unit 1 and 3 Train B installations of the spray pond return line, DMWO 3304346 has not been fully implemented, and therefore, the spray pond margin bypass valves remain in the locked closed position.

9.2.1.7 Safety Evaluations

Safety evaluations, numbered to conform to the safety design bases, are as follows:

A. Safety Evaluation One

The ESPS, in conjunction with the ultimate heat sink, has the capability to dissipate within the safe reactor shutdown time frame all imposed heat loads.

Loss of offsite power results in the shutdown and restarting of the ESPS in accordance with the diesel generator load sequencing. The diesel generator load capacity and sequencing times, as described in section 8.3, are commensurate with ESPS requirements. Thus, safe reactor shutdown is supported by the ESPS.

B. Safety Evaluation Two

The ESPS, in conjunction with the ultimate heat sink, maintains the ECW heat exchanger outlet temperature at or below 135F for the design basis LOCA.

C. Safety Evaluation Three

The ESPS is comprised of two physically separate, independent, full capacity trains, each of which is powered from a separate ESF bus and a separate diesel generator. This ensures that a single failure does not impair system effectiveness. Refer to table 9.2-3 for the single failure analysis. A short section of ESPS piping within the instrumentation vault does not have physical separation. Separation of trains is designed to mitigate the consequences of a fire or pipe rupture. The probability of a fire inside the vault is considered to be insignificant. A calculation on the section of piping within the vault showed that a moderate energy line break is not a credible accident.

Table 9.2-2
EQUIPMENT LIST ESSENTIAL SPRAY POND CHEMICAL CONTROL (PER UNIT)

Component Description	Quantity	Type	Design Flow (gal/min)
Sulfuric Acid Metering Pump	2	Positive Displacement	0 - 0.1
Hypochlorite Metering	2	Flow Orifice	0.25
Hypochlorite Metering	2	Flow Orifice	0.5
Hypochlorite Metering	2	Flow Orifice	10
Dispersant Metering Pump	2	Positive Displacement	$\geq$ 0.25

Table 9.2-3
ESSENTIAL SPRAY POND SYSTEM SINGLE FAILURE ANALYSIS

Components	Failure Mode/Cause	Effect on System	Method of Detection	Inherent Compensating Provision
ESP pumps	One pump inoperable/ mechanical or electrical failure	None--Redundant loop is available	Motor status and flow indicated in the control room	Two redundant loops are provided. Either loop is capable of providing 100% of heat removal require-ments under normal or accident condition.
ESP spray nozzle header	Spray nozzle header loss	None--Redundant spray nozzle header is available	Temperature indication in the control room	Two redundant spray loops are available. Each loop is capable of 100% heat removal.
Check valve in pump discharge	Check valve stays closed	None—Redundant loop is available	Pressure is indicated locally and in the control room	Two redundant loops are provided.
Piping	Loss of pump discharge header	None--Redundant loop is available	Flow and pressure indications are indicated in the control room	Two redundant loops are provided.
	Loss of return header	None--Redundant loop is available	Flow and pressure are indicated in the control room	Each loop will be capable of satisfying the heat requirements.
ESP return line flow orifice bypass valve (1)	Valve stays open Valve remains locked closed - Unit 1B & 3B	None--Redundant loop is available	Valve position indication locally at MCC	Two redundant loops are provided.

(1) DMWO 3304346 adds the capability to vary SP flow rates. This note applies to units and trains where this DMWO has been installed.

Therefore, physical separation inside the vault is not required.

D. Safety Evaluation Four

The ESPS pumps are located in Seismic Category I pump structures that protect the pumps against the adverse environmental occurrences outlined in chapters 2 and 3. Other required portions of the ESPS are either installed underground or are located in buildings that also protect against adverse environmental conditions described in chapters 2 and 3. Holes are provided in selected risers in the spray piping of each spray pond to drain standing water, in the exposed piping, to preclude freezing.

E. Safety Evaluation Five

Flow differential is monitored between ESPS pump discharges and the return lines to the essential spray ponds for detecting large system leaks/pipe breaks. Since the ESPS operates at a higher pressure than the ECWS, leakage of potentially radioactive water from the ECWS into the ESPS is precluded.

F. Safety Evaluation Six

Wetted surfaces in the ESPS are of materials compatible with the cooling water chemistry. Organic fouling and inorganic buildups are controlled by proper water treatment. (Refer to subsection 9.2.5).

G. Safety Evaluation Seven

The ESPS is Seismic Category I in accordance with requirements presented in chapter 3.

H. Safety Evaluation Eight

During normal plant operation, the ESPS may be operated in support of several auxiliary systems including emergency diesel generators, shutdown cooling, essential chillers, fuel pool cooling, and nuclear cooling water priority loads, as well as for chemistry control, and testing. The redundant features of the ESPS allow testing of one train without violation of technical specifications.

I. Safety Evaluation Nine

The capacity of the ESPS, in conjunction with the ultimate heat sink and the ECWS, is sufficient to dissipate the heat loads of the fuel pool in the event the normal fuel pool cooling system is unavailable.

J. Safety Evaluation Ten

Components of the ESPS outside of buildings or structures, except for spray pond nozzles, are located below grade such that missiles from any source would not prevent the system performing its design function. Each ESPS train is separated from the other ESPS train. For additional information on the effect of tornado missiles on the spray nozzles see section 3.5.1.4 and 9.2.5.4(B).

9.2.1.8 Tests and Inspections

Preoperational testing is performed in accordance with the test descriptions of section 14.2. Periodic surveillance testing is described in the Technical Specifications.

9.2.1.9 Instrument Application

The ESPS instrumentation facilitates automatic operation, remote control, and continuous indication of system parameters (ESP water temperature, ESPS pump flow, ESP inlet flow, ESP water level) both locally and in the control room.

Controls and instrumentation necessary for operation of the ESPS pumps are located in the control room. Local instrumentation and controls also are provided at ESPS pumps and ECWS heat exchangers for maintenance, testing, and performance evaluation.

Specifically, control room process indication and alarm is provided to enable the operator to evaluate the ESPS performance and to detect malfunctions. Essential spray pond system pump discharge pressure is displayed and alarmed to detect an abnormally low pressure (pump failure, piping break) or abnormally high pressure (piping blockage, closed valves). Spray pond levels and temperatures are indicated to show a low or high level condition or a high temperature condition in a spray pond.

Control conditions of level and temperatures are also alarmed in the control room. The ESPS water discharge temperatures from the ECWS heat exchangers are indicated in the control room. A high temperature condition is alarmed to indicate either a reduced water flow to the exchanger or an abnormal heat input to the exchanger from the ECWS. ESPS chemistry is monitored by grab samples (table 9.3-3). Out-of-specification chemistry readings may indicate a buildup of dissolved solids level in the water and a need for pond blowdown with makeup to maintain the safe water inventory of the pond.

Differential flow between the ESPS pump discharge and the spray header is indicated in the control room to identify a significant line break or a large system leak. Local pressure or temperature indicators are provided on the cooling water discharge lines of various heat exchangers or cooling systems served by the ESPS.

9.2.2 COOLING SYSTEMS FOR REACTOR AUXILIARIES

Two separate, independent cooling systems for reactor auxiliaries are provided. Each of the systems provides for the indirect cooling, through heat exchangers, of those reactor auxiliaries that carry radioactive or potentially radioactive fluids. The ECWS serves the safety-related and normal shutdown components. The nuclear cooling water system (NCWS) serves the nonsafety-related (normal operating) components.

Paragraph 9.2.2.1 discusses the ECWS and paragraph 9.2.2.2 discusses the NCWS. Equipment locations for the ECWS are shown in engineering drawings 13-P-OOB-002 through -004.

9.2.2.1 Essential Cooling Water System

The ECWS is shown in engineering drawings 01, 02, 03-M-EWP-001. Table 9.2-1 lists the safety-related nuclear component heat loads and associated water requirements for the ECWS. Cross-references to sections covering the related systems also are included in table 9.2-1. Table 9.2-4 lists the ECWS major equipment items and their design specifications.

9.2.2.1.1 Safety Design Bases

Safety design bases applicable to the ECWS are:

A. Safety Design Basis One

The ECWS, in conjunction with the ESPS (including the ultimate heat sink), shall be capable of removing sufficient heat to ensure a safe reactor shutdown coincident with a loss of offsite power.

B. Safety Design Basis Two

The ECWS, in conjunction with the ESPS, shall be capable of maintaining the outlet temperature of the ECWS heat exchanger from exceeding 135F during a postulated LOCA with loss of offsite power.

C. Safety Design Basis Three

A single failure of any component in the ECWS will not impair the ability of the ECWS to meet its functional requirements.

D. Safety Design Basis Four

Adverse environmental occurrences will not impair the ability of the ECWS to meet its functional requirements.

E. Safety Design Basis Five

The ECWS shall be designed to detect leakage of radioactive water into the ECWS, and to detect leakage from the ECWS.

F. Safety Design Basis Six

The ECWS shall be designed to minimize the effects of long-term corrosion.

Table 9.2-4

EQUIPMENT LIST ESSENTIAL COOLING WATER SYSTEM

Component Description	Quantity	Type	Rated Head (ft)	Rated Flow (gal/min)	Motor (hp)	Design Pressure (psig)	Water Capacity (gal)	Material	Service Side
ECWS pump	2	Centrifugal	138	16,650	800	150	--	Carbon steel	--
Surge Tank	2	Vertical Cylindrical	--	--	--	15	1,000	Carbon steel	--
Chemical addition tank	2	Ball feeder	--	--	--	200	11.3	Carbon steel	--
ECWS heat exchanger	2	Shell & tube; Refer to Table 9.2-1	--	--	--	150	--	--	ESPS

G. Safety Design Basis Seven

The ECWS shall be designed to withstand the effects of an SSE.

H. Safety Design Basis Eight

Components of the ECWS shall be capable of being fully tested during normal plant operation. In addition, parts and components shall be accessible for inspection at any time.

I. Safety Design Basis Nine

The ECWS, in conjunction with the ESPS, shall provide cooling capability for the fuel pool when the fuel pool normal cooling system is not available.

J. Safety Design Basis Ten

The design and arrangement of the ECWS shall be such that its functional operation is unaffected by any missiles.

9.2.2.1.2 Power Generation Design Bases

Power generation design bases pertinent to the ECWS are as follows:

A. Power Generation Design Basis One

The ECWS, in conjunction with the ESPS, is designed to cool the reactor coolant from 350F to 125F within 27-1/2 hours during normal shutdown utilizing two trains of ECWS and ESPS. The cooling rate of the reactor coolant does not exceed 75F per hour.

B. Power Generation Design Basis Two

The ECWS, in conjunction with the ESPS, is designed to provide a maximum cooling water temperature of 105F to the shutdown heat exchanger 27-1/2 hours after normal shutdown utilizing two trains of ESPS and ECWS.

C. Power Generation Design Basis Three

The ECWS, in conjunction with the ESPS, is designed to provide cooling water to the reactor coolant pumps, control element drive mechanism (CEDM) coolers, nuclear sample coolers, and normal chillers by manual valve realignment in the event of a loss of offsite power.

9.2.2.1.3 Codes and Standards

The ECWS and associated components are designed in accordance with codes and standards described in section 3.2 and specified in table 3.2-1.

9.2.2.1.4 System Description

The ECWS consists of two separate, independent, redundant, closed loop, safety-related trains. Either train of the ECWS is capable of supporting 100% of the cooling functions required for a safe reactor shutdown or following a LOCA.

The ECWS operates at a lower pressure than the ESPS as protection against leakage into the ESPS from the ECWS in case of tube leakage in the ECWS heat exchanger.

Each train of the ECWS includes a heat exchanger, surge tank, pump, chemical addition tank, piping, valves, controls, and instrumentation.

The ECWS provides cooling water to the safety-related components listed in paragraph 9.2.2.1.6.

The makeup water line to the ECWS is connected to the demineralized water system. A backup makeup water line of Seismic Category I construction is provided from the condensate tank. A makeup line is also provided from the cooling water holdup tank. Additionally a connection is provided to hook up a fire hose to the makeup line. Normal makeup is supplied from the demineralized water system. When the normal makeup is not available, the other sources listed may be used as necessary, if available. For details on makeup from the condensate storage facility, refer to Section 9.2.6.

In case of a major leak in one of the ECWS trains, that train is removed from service and the other train is used.

The ECWS equipment is located in the auxiliary building and control building.

The chemistry control program applicable to the ECWS is established in accordance with the EPRI Closed Cooling Water Chemistry Guideline. The ECWS chemistry control program is an objective based program and the water quality control parameters are designed to minimize corrosion, organic and inorganic fouling and microbiological growth. Table 9.2-6 lists Seismic Category I valves in the ECWS.

9.2.2.1.5 Component Description

Table 9.2-4 lists the major ECWS components and their design specifications.

Table 9.2-5
Deleted

Table 9.2-6

ESSENTIAL COOLING WATER SYSTEM PROCESS VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-NCP-001, -002 and -003) (Sheet 1 of 2)

Valve Tag Number	Location	Valve Type	Line Size Inches	Actuator Type[a]
EWA-HCV-41	Shutdown heat exchanger inlet valve - train A	Butterfly	20	Hand
EWA-HCV-53	Shutdown heat exchanger outlet valve - train A	Butterfly	20	Hand
EWA-HCV-71	ECWS heat exchanger inlet valve - train A	Butterfly	20	Hand
EWA-HCV-5	ECWS pump inlet valve - train A	Butterfly	20	Hand
EWA-HCV-135	ECWS pump discharge valve - train A	Butterfly	20	Hand
EWA-V-005	ECWS chemical addition tank inlet valve - train A	Globe	1	Hand
EWA-V-051	ECWS chemical addition tank outlet valve - train A	Globe	1	Hand
EWA-V-021	Essential chiller inlet valve - train A	Gate	6	Hand
EWA-PCV-173	Essential Chiller Flow Control outlet valve - train A	Globe	4	Pilot (self activated)[b]
EWA-V-348	Essential Chiller Flow Control outlet valve bypass - train A	Gate	4	Hand
EWA-V-022	Essential chiller outlet valve - train A	Globe	6	Hand
EWA-HCV-133	Fuel pool heat exchanger supply valve - train A	Butterfly	10	Hand[b]
EWA-HCV-67	Fuel pool heat exchanger return valve - train A	Butterfly	10	Hand[b]
EWB-V-039	ECWS chemical addition tank inlet valve - train B	Globe	1	Hand

a. All valves are nonactive, except for those with Note (b), as discussed in section 3.9.

b. Valves are active

Table 9.2-6

ESSENTIAL COOLING WATER SYSTEM PROCESS VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-NCP-001, -002 and -003) (Sheet 2 of 2)

Valve Tag Number	Location	Valve Type	Line Size Inches	Actuator Type[a]
EWB-V-031	ECWS chemical addition tank outlet valve – train B	Globe	1	Hand
EWB-HCV-6	ECWS pump inlet valve - train B	Butterfly	20	Hand
EWB-HCV-136	ECWS pump discharge vavle - train B	Butterfly	20	Hand
EWB-HCV-42	Shutdown heat exchanger inlet valve - train B	Butterfly	20	Hand
EWB-HCV-54	Shutdown heat exchanger outlet valve train B	Butterfly	20	Hand
EWB-HCV-72	ECWS heat exchanger inlet valve - train B	Butterfly	20	Hand
EWB-V-043	Essential chiller inlet valve - train B	Gate	6	Hand
EWB-PCV-174	Essential Chiller Flow Control outlet valve - train B	Globe	4	Pilot (self activated)[b]
EWB-V349	Essential Chiller Flow Control outlet valve bypass - train B	Gate	4	Hand
EWB-V-044	Essential chiller outlet valve - train B	Globe	6	Hand
EWB-HCV-134	Fuel pool heat exchanger supply valve - train B	Butterfly	10	Hand[b]
EWB-HCV-68	Fuel pool heat exchanger return valve - train B	Butterfly	10	Hand[b]
EWA-UV-145	Train A - train B isolation, supply	Butterfly	14	Motor[b]
EWA-UV-65	Train A - train B isolation, return	Butterfly	14	Motor[b]
EWB-HCV-146	Train B - train A isolation, supply	Butterfly	14	Hand
EWB-HCV-66	Train B - train A isolation, return	Butterfly	14	Hand

9.2.2.1.5.1 ECWS Heat Exchangers. The ECWS heat exchanger in each train has a 100% heat dissipation capacity. The heat exchangers are of the shell and tube type. The tube side is furnished with cooling water from the ESPS at a higher operating pressure than the shell side as noted in paragraph 9.2.2.1.4.

The shell side carries the ECWS cooling water. This closed-loop, shell-side water is initially supplied with demineralized water from the demineralized water system as discussed in subsection 9.2.3.

9.2.2.1.5.2 ECWS Pumps. One ECWS pump is provided for each ECWS train. Each pump has the flow capacity to move sufficient flow to remove 100% of the heat dissipated. The pumps are of the horizontal centrifugal type and are installed at an elevation below the ECWS surge tank to ensure flooded suction and maintain a constant pressure at the suction side of the pump. Pump motors are connected to separate Class 1E buses. Each motor can be supplied by its related emergency diesel generator (standby) power supply. In the event offsite (preferred) power is lost, the pumps are stopped and restarted in accordance with the emergency diesel generator load sequencing. Refer to section 3.9 for a detailed discussion of ECWS pump qualification testing.

9.2.2.1.5.3 ECWS Surge Tanks. One surge tank is provided in each ECWS train to automatically accommodate the closed loop water expansion and contraction due to thermal changes in the system. Level controls in each tank signal a demineralized

water makeup line control valve that then actuates to maintain the water required in the ECWS. The surge tanks are installed on the suction side of the ECWS pumps.

9.2.2.1.5.4 Safety-Related Equipment Heat Exchangers. Table 9.2-1 lists the safety-related equipment, associated heat loads, and their water requirements. Descriptions of these items are included in the applicable sections as noted on the table.

9.2.2.1.5.5 Piping, Valves, and Fittings. Piping from and to the ECWS heat exchangers is of carbon steel. Piping, valves, and fittings are supplied in accordance with ASME Code, Section III, Class 3.

Piping is corrosion protected. The supply and return piping to and from system components in a train is physically separated from the supply and return lines in the redundant train.

9.2.2.1.5.6 Instrumentation and Controls. The discussion of the operational logic and the associated initiation and actuation controls and instrumentation of the ECWS and the ESPS is covered jointly in paragraph 9.2.1.6.

Refer to paragraph 9.2.2.1.9 for instrumentation and control applications to the ECWS.

9.2.2.1.6 System Operation

The ECWS has two redundant and separate trains. Each train is connected to its corresponding ESPS train through the ECWS heat

exchanger that serves as a pressure-thermal barrier between the ESPS and the ECWS.

Although either train has a 100% heat dissipation capacity (through heat transfer from the shell side to the tube side of the ECWS heat exchanger and the dissipation of the transferred heat load by the ESPS to the atmosphere), an emergency reactor shutdown is normally accomplished by initial operation of both trains of the ECWS and ESPS.

Shutdown and cooldown by only one train over an extended period of time is possible. The discussion of operations of the ECWS and ESPS are given in paragraph 9.2.1.6.

Each train of the ECWS provides cooling for the following redundant safety-related components:

- Shutdown cooling heat exchangers (one per train)
- Essential chillers (one per train)
- Fuel pool heat exchangers (one per train) if NCWS is not available

Each train can also provide cooling for the following non-safety-related components:

- Reactor coolant pump assemblies (four pumps on one train at a time) if NCWS is not available
- Control element drive mechanism coolers (one on one train at a time) if NCWS is not available
- Normal chillers (one on one train at a time) if NCWS is not available

- Nuclear sample coolers if NCWS is not available

In the event the NCWS becomes inoperable the operator has the option of valving in either train A or train B of the ECWS (never both) to the above nonsafety-related components.

In the event of an LOP, the operator can open the train A NCWS crosstie valves from the control room, permitting the ECWS train A to supply cooling water to the reactor coolant pump assemblies, CEDM coolers, normal chillers, and nuclear sample coolers. If train A fails, the operator must manually open the train B NCWS crosstie valves and shut the train A crosstie valves to permit the same function.

9.2.2.1.7 Safety Evaluations

Safety evaluations are numbered to conform to the safety design bases and are as follows:

A. Safety Evaluation One

   The ECWS has the capability to dissipate within the safe reactor shutdown time frame the imposed heat loads.

   Loss of offsite power results in the shutdown and restarting of the ECWS in accordance with the diesel generator load sequencing. The diesel generator load capacity and sequencing times, as described in section 8.3, are commensurate with ECWS requirements. Thus, safe reactor shutdown is supported by the ECWS.

B. Safety Evaluation Two

   The required cooling water flow is listed in table 9.2-1. This flow and associated heat transfer

capability are compatible with providing the required ESF system cooling water from exceeding 135F during a postulated LOCA.

C. Safety Evaluation Three

The ECWS is comprised of two physically separate, independent, full-capacity trains, each of which is powered from a separate ESF bus and a separate diesel generator. This ensures that a single failure does not impair system effectiveness. Refer to table 9.2-7 for the single failure analysis.

D. Safety Evaluation Four

Components of the ECWS are installed in buildings that protect against adverse environmental conditions described in chapters 2 and 3.

E. Safety Evaluation Five

To detect leakage into or out of the ECWS, high and low level signals at the surge tank will alarm in the control room. Radiation monitors indicate leakage of radioactive fluids into the ECWS. Finally, each system being served by the ECWS is monitored for inleakage.

F. Safety Evaluation Six

Wetted surfaces in the ECWS are of materials compatible with the cooling water chemistry. Organic fouling and inorganic buildups are controlled by proper water treatment. The use of demineralized water and corrosion inhibitors for this system minimizes this problem.

The water in the loop is sampled for quality on a scheduled basis and the pH is adjusted if required by the addition of treatment chemicals.

G. Safety Evaluation Seven

The ECWS is Seismic Category I in accordance with requirements presented in chapter 3.

H. Safety Evaluation Eight

During normal plant operation, the ECWS is not operating. The redundant features of the ECWS allow testing of one train without violation of technical specifications.

I. Safety Evaluation Nine

The capacity of the ECWS, in conjunction with the ESPS, is sufficient to dissipate the heat loads from the fuel pool in the event that the normal fuel pool cooling system is unavailable. In the event that the NCWS becomes inoperable, the fuel pool heat exchangers must be supplied cooling water by the ECWS. Each fuel pool heat exchanger is supplied water separately by each train of the ECWS; i.e., one heat exchanger by train A and the other heat exchanger by train B.

Valves associated with switching service from the NCWS to the ECWS are manually operated, Seismic I, and Safety Class 3. These valves are also used to isolate the ECWS from the NCWS. They are located in the auxiliary building.

Table 9.2-7

ESSENTIAL COOLING WATER SYSTEM SINGLE FAILURE ANALYSIS

Components	Failure Mode/Cause	Effect on System	Method of Detection	Inherent Compensating Provision
ECWS pumps	One pump inoperable/ mechanical or electrical failure	Loss of flow in one loop None--redundant loop is available	Motor status and flow indication in the control room	Redundant loops are provided. One operable loop is capable of providing 100% of heat removal requirements under normal and accident conditions.
ECWS heat exchangers	One heat exchanger malfunction Leaking tubes or blockage	Loss of heat sink None--redundant loop is available	Temperature indication in the control room	Heat exchanger in redundant loop will provide 100% of heat removal
ECWS surge tank	One surge tank malfunction Tank leaking	Loss of water level None--redundant loop is available	Low level alarm in the control room	Redundant loops are provided.
Butterfly valves	Butterfly valve in the pump suction stays closed/operator error	None--redundant loop is available	Flow indication and pressure alarm in the control room	Redundant loops are provided.
Piping (pipe breaks)	Loss of pump discharge header/ linebreak or mechanical damage Loss of return header/linebreak or mechanical damage	None--redundant loop is available	Flow indication and pressure alarm in the control room	Redundant loops are provided.

Sufficient time would be available for the operator to access the auxiliary building to manually actuate these valves since the fuel pool does not require continuous cooling.

J. Safety Evaluation Ten

Components of the ECWS are located such that missiles from any source would not impair the system's functional requirements. The two trains of the ECWS are physically separated and are routed such as to be protected from missiles that could be potentially generated from other sources. Refer to section 3.5 for a discussion of missile protection.

9.2.2.1.8 Tests and Inspections

Preoperational testing is performed in accordance with the test descriptions of section 14.2. Periodic surveillance testing is described in the Technical Specifications.

In response to Generic Letter 89-13, Palo Verde will conduct heat exchanger thermal performance testing on the Essential Cooling Water (EW) heat exchangers in accordance with site Heat Exchanger Program Procedure developed in accordance with Electric Power Research Institute (EPRI) guidelines.

9.2.2.1.9 Instrument Application

Refer to paragraph 9.2.1.9 for a presentation of the ECWS interfaces to the ESPS.

The ECWS instrumentation facilitates automatic operation, remote control, and continuous indication of system parameters

locally and in the control room. Controls and instrumentation necessary for operation of the ECWS pumps are located in the control room. Local instrumentation and controls also are provided at the ECWS pumps and at the various safety-related nuclear component heat exchangers for maintenance, testing, and performance evaluation.

Specifically, control room process indication and alarm is provided to enable the operator to evaluate the ECWS performance and to detect malfunctions. Essential cooling water system pump discharge pressures and temperatures at the inlets and outlets of the ECWS heat exchangers are locally displayed. Essential cooling water system pump discharge pressures are alarmed to detect a pump failure, return piping blockage, or pipe breaks. Essential cooling water system pump discharge temperature is indicated and alarmed in the control room for detection of ECWS heat exchanger malfunction.

Surge tank is provided with level gauge glass to show low or high level condition in the closed loop. Critical conditions of tank level and pressure are alarmed in the control room for leak detection.

As discussed in paragraph 9.2.1.9, the ESPS water discharge temperature from the ECWS heat exchangers are indicated in the control room. A high temperature condition of ESPS water discharge is alarmed to indicate either a reduced ESPS flow to the exchanger or an abnormal heat input to the exchanger from a component in the ECWS closed loop.

Relief valves are provided, as required, for personnel and equipment protection.

9.2.2.2 Nuclear Cooling Water System

The NCWS is shown in engineering drawings 01, 02, 03-M-NCP-001, -002 and -003. Table 9.2-8 lists the components served by the NCWS, their required heat load cooling requirements and their associated cooling water flows.

9.2.2.2.1 Safety Design Bases

The safety design basis applicable to the NCWS is that the dose consequences resulting from an interfacing system component failure (i.e. heat exchanger tube rupture) shall be maintained below 10CFR20.1-20.601 and 10CFR100 limits.

9.2.2.2.2 Power Generation Design Bases

The power generation design basis pertinent to the NCWS is as follows:

A. Power Generation Design Basis One

   The NCWS, in conjunction with the plant cooling water system (PCWS), is designed to provide an adequate supply of cooling water to the nonsafety-related components listed in table 9.2-8.

9.2.2.2.3 Codes and Standards

The NCWS and associated components are designed in accordance with codes and standards described in table 3.2-1.

Table 9.2-8

HEAT LOADS AND WATER REQUIREMENTS NUCLEAR

COOLING WATER SYSTEM (Sheet 1 of 3)

Component	Related System	FSAR Section Reference	Heat Load (ea) (10^6 Btu/h)	Cooling Water Requirement (ea) (gal/min)
Boric acid concentrator package	Chemical and volume control system (CVCS)	9.3	13.00 (Max)	700 (Max)
Radwaste evaporator package	Radwaste	11.2	21.11	993
Waste gas compressor (2 ea)	Radwaste	11.3	0.025	5
Reactor coolant sample cooler	Sampling	9.3.2	0.24	16
Safety injection system sample coolers (2 ea)	Sampling	9.3.2	0.13	7
Pressurizer vapor space sample cooler	Sampling	9.3.2	0.26	26
Pressurizer surge sample cooler	Sampling	9.3.2	0.26	17
Gas stripper	CVCS	9.3	6.0	500

a. Allowable heat load is Administratively controlled prior to unit startup (see Table 9.1-2)

Table 9.2-8

HEAT LOADS AND WATER REQUIREMENTS NUCLEAR

COOLING WATER SYSTEM (Sheet 2 of 3)

Component	Related System	FSAR Section Reference	Heat Load (ea) (10^6 Btu/h)	Cooling Water Requirement (ea) (gal/min)
Normal chillers (3 ea.) (one standby)	HVAC	9.4	12.9 (max)	2,500
Normal chiller (1 ea.)	HVAC	9.2.9 9.4	3.73 (max)	500
Letdown heat exchanger	Reactor coolant system (RCS) and connected systems	5.1	21.60 (max)	1,500 (max)
Reactor coolant pumps (4 ea.)	RCS and connected systems	5.1		
Seal cooler and hp cooler			1.29	163
Motor air cooler and oil coolers			1.81	348
Fuel pool heat exchangers (2 ea; one standby)	Fuel pool cooling and cleanup system	9.1.3	12.6[(a)]	2,500
CEDM air coolers (2 ea) (one standby)	HVAC	9.4	5.0	400

Table 9.2-8
HEAT LOADS AND WATER REQUIREMENTS NUCLEAR
COOLING WATER SYSTEM (Sheet 3 of 3)

Component	Related System	FSAR Section Reference	Heat Load (ea) (10^6 Btu/h)	Cooling Water Requirement (ea) (gal/min)
Auxiliary steam vent condenser	Auxiliary steam system	---	4.38	500
Nonnuclear sampling coolers	Sampling	9.3.2	3.0 (Total, Max.)	60-90 (Total)
Auxiliary Steam Rad Monitor Cooler	Auxiliary steam system	--	0.02	5

9.2.2.2.4 System Description

The NCWS equipment required for the cooling of nonsafety-related components includes heat exchangers, surge tank, chemical water treatment components, pumps, piping, valves, controls, and instrumentation. The NCWS equipment items are located in the auxiliary building, the radwaste building, the turbine building, the containment building, the fuel building, and outside areas.

The NCWS consists of one closed loop flow train of full unit capacity. This loop includes redundant 100% capacity pumps and redundant 100% heat exchangers. The tube sides of the heat exchangers are furnished with cooling water from the plant cooling towers via the PCWS. The shell side of the heat exchangers is part of the closed cooling loop that includes the pumps, surge tank, and nonsafety-related reactor auxiliaries listed in table 9.2-8.

The water quality parameters applicable to the NCWS are the same as those itemized for the ECWS in paragraph 9.2.2.1.4. Makeup water for the closed loop is supplied to the surge tank from the demineralized water system as discussed in subsection 9.2.3.

Because of the possible radioactive contamination of the NCWS through heat exchanger tubes connected to the reactor coolant or radwaste systems, the design pressure of the PCWS is higher than the design pressures for the NCWS. This ensures against contamination of the PCWS and the outside environment. Additionally, safety relief valves are provided to protect the containment isolation valves from overpressurization in the

event of a reactor coolant pump high pressure seal cooler tube rupture. The NCWS is required to function during normal power generation and during a normal reactor shutdown. The maximum water temperature at the outlets of the NCWS using a wet bulb temperature of 78F (0.1% summer high) during normal power generation does not exceed 105F.

Coolant flow of approximately 17,500 gallons per minute is maintained in the closed loop during normal power generation operation.

9.2.2.2.5 Component Description

Major components of the NCWS are shown in table 9.2-9 and are discussed in the following sections.

9.2.2.2.5.1 NCWS Heat Exchangers. Each of the redundant NCWS heat exchangers has a 100% load carrying capacity. The heat exchangers are of the counter flow horizontal shell and straight tube type.

Each heat exchanger is rated at 110.7 x 10^6 Btu/h, the shell side flow is 17,500 gallons per minute, and the tube side flow is 14,500 gallons per minute.

9.2.2.2.5.2 NCWS Pumps. Each of the redundant NCWS pumps has a 100% load carrying capacity. Only one pump is used and the other pump is on standby. The NCWS pumps are of the horizontal, centrifugal, single-stage, double-suction type. Each pump is rated at 17,500 gallons per minute, 180-foot design head.

Table 9.2-9

EQUIPMENT LIST NUCLEAR COOLING WATER SYSTEM

Component Description	Quantity	Type	Design Head (ft)	Design Flow (gal/min)	Motor (hp)	Design Pressure (psig)	Water Capacity (gal)	Material	Service Side
NCWS pump	2	Centrifugal	180	17,500	1000	--	--	--	--
Surge tank	1	--	--	--	--	15	1000	Carbon steel	--
Chemical addition tank	1	--	--	--	--	200	11	Carbon steel	--
NCWS heat exchanger	2	Shell and tube	--	--	--	--	--	--	Plant cooling water system

9.2.2.2.5.3 NCWS Surge Tank. A surge tank is provided in the train to automatically accommodate the closed loop water expansion and contraction due to thermal changes in the system. Level controls in the tank control a demineralized water makeup control valve to maintain the water level required in the NCWS.

The surge tank is installed on the suction side of the NCWS pump to ensure flooded suctions and NPSH requirement.

9.2.2.2.5.4 Nuclear Nonsafety-Related Equipment Heat Exchangers. Table 9.2-8 lists the nuclear nonsafety-related equipment, associated heat loads, and their water requirements. Description of these items are included in the applicable sections as noted on the table.

9.2.2.2.5.5 Piping, Valves, and Fittings. Piping to and from the NCWS heat exchangers is of carbon steel. Piping, valves, and fittings are supplied in accordance with table 3.2-1. Seismic Category I valves, which are a part of the NCWS, are listed in table 9.2-10.

Table 9.2-10
NUCLEAR COOLING WATER SYSTEM
SEISMIC CATEGORY I PROCESS VALVE LIST

Valve Tag Number	Location	Valve Type	Line Size Inches	Actuator Type[b]	Valve Classification[a]
NCA-UV-402	To NCWS - outside containment	Butterfly	10	Motor	A
NCB-UV-403	To NCWS - inside containment	Butterfly	10	Motor	A
NCB-UV-401	From NCWS - outside containment	Butterfly	10	Motor	A
NCE-V-118	From NCWS - inside containment	Check	10	None	N
NCA-HCV-244	ECWS - NCWS isolation fuel pool heat exchanger train A	Butterfly	10	None	A
NCA-HCV-262	Fuel pool heat exchanger inlet valve train A	Butterfly	10	Hand	N
NCA-HCV-264	Fuel pool heat exchanger outlet valve train A	Butterfly	10	Hand	N
NCA-HCV-258	ECWS - NCWS isolation fuel pool heat exchanger train A	Butterfly	10	Hand	A
HCB-HCV-245	ECWS - NCWS isolation fuel pool heat exchanger train B	Butterfly	10	Hand	A
NCB-HCV-263	Fuel pool heat exchanger inlet valve train B	Butterfly	10	Hand	N
NCB-HCV-265	Fuel pool heat exchanger outlet valve train B	Butterfly	10	Hand	N
NCB-HCV-259	ECWS - NCWS isolation fuel pool heat exchanger train B	Butterfly	10	Hand	A
NCE-PSV- 614	Inside containment	Safety Relief	6 x 8	None	A
NCE-PSV-615	Inside containment	Safety Relief	6 x 8	None	A
NCE-PSV-617	Inside containment	Pressure Relief	¾ x 1	None	A

a. An "A" indicates an active valve, an "N" a nonactive valve, as discussed in section 3.9.

9.2.2.2.6 System Operation

The NCWS, in conjunction with the PCWS, operates during all modes of normal power generation. Only one of the two NCWS pumps and only one of the two NCWS heat exchangers are in normal operation and the redundant pump and heat exchanger are on standby. The operator preselects the pump and heat exchangers for operation. In the event of an operating pump malfunction, the standby pump is placed in service by automatic actuation. In the event of an operating heat exchanger malfunction or a requirement for maintenance of a heat exchanger, the operator manually places the standby heat exchanger into service by operating the valves involved.

During Refueling Outages, the heat sink to the NCWS is provided by a temporary cooling water system installed on the Plant Cooling Water side of one NCWS heat exchanger. This temporary cooling water system is described in UFSAR section 9.2.10.2.3.

9.2.2.2.7 Tests and Inspections

Tests and inspections are divided into preoperational and operational phases. These are described in the following paragraphs.

9.2.2.2.7.1 Preoperational Testing. Acceptance testing of this system is performed to demonstrate proper system and equipment functioning.

9.2.2.2.7.2 Operational Tests and Inspections. Instrumentation provided for the NCWS permits continuous surveillance of the proper operation of each component in the

system, as well as a check on system performance. Adjustments are made in the operating conditions as required during operation. No tests are required during operation because of this inspection and adjustment availability.

9.2.2.2.8 Instrumentation Applications

The NCWS instrumentation facilitates automatic operation, remote control, and indication of system parameters locally and in the control room. Controls and instrumentation necessary for operation of the NCWS pumps are located in the control room. Local instrumentation and controls also are provided at the NCWS pumps and at various heat exchangers for maintenance, testing, and performance evaluation.

Instrumentation, including audible alarms and visual status indicators, are provided to indicate loss of cooling water flow to the reactor coolant pumps. This instrumentation for audible alarms are of high quality and meet the single failure criterion.

9.2.2.2.9 Safety Evaluations

Failure of a reactor coolant pump high pressure seal cooler tube may result in overpressurization and failure of the NCWS surge tank located on the auxiliary building roof. In such an event, the plant operator has sufficient event indication and time to remote manually close the NCWS containment isolation valves from the control room. Redundant safety-relief valves are provided on the NCWS piping inside containment to protect and prevent overpressurization of the NCWS containment isolation valves following their closure in such an event. NCWS containment

isolation valve closure and resultant safety relief valve actuation and discharge to the containment atmosphere result in the event scenario being bounded by the LOCA scenarios discussed in section 6.3. The dose consequences resulting from this event are bounded by the letdown line break scenario discussed in section 15.6.2. The redundant safety relief valves satisfy the single failure criteria.

9.2.3 DEMINERALIZED WATER SYSTEM

The demineralized water system (DWS) processes product water from the reverse osmosis units of the domestic water system (DS) to remove dissolved gas and solids, stores the demineralized water, and transfers it to each PVNGS unit and to common facilities in the chemical production system (CPS).

9.2.3.1 Design Bases

9.2.3.1.1 Safety Design Bases

Except where needed to provide containment isolation via containment penetrations, the DWS serves no safety function and has no safety design bases.

9.2.3.1.2 Power Generation Design Bases

A. Simultaneously supply the normal operational demands for makeup demineralized water at each PVNGS unit, for its own regeneration, and for the CPS. The design capacity of the DWS is 600 gallons per minute.

B. Provide 125,000 gallons of storage capacity in a surge-rinse tank within each DWS common facility and 125,000 gallons of storage capacity at each PVNGS unit.

C. Provide makeup demineralized water for the following systems:

- Condensate system
- Reactor makeup water system
- Nuclear cooling water system
- Essential cooling water system
- Radwaste system
- Essential chilled water system
- Chilled water system
- Stator cooling system
- Turbine cooling water system
- Diesel generator cooling water system
- Miscellaneous services

D. The design and subsequent upgrades of the demineralized water system is such that demineralized water of the following specifications can be produced:

Total dissolved solids, ppm	0.1 max
Dissolved oxygen, ppm	0.1 max
Chloride, as Cl, ppb	<0.50 max
Fluoride, as F, ppm	<0.01 max
Total silica, as $Si0_2$, ppm	<0.005 max
Sodium, as Na, ppb	<0.10 max
Conductivity, µmhos/cm	0.08 max
pH	6.0 to 8.0

Gaseous	Nondeaerated/ deaerated

Except where needed to provide containment isolation via containment penetrations, the DWS is designed to nonnuclear safety codes and standards as defined in table 3.2-1.

9.2.3.2 System Description

The DWS, as shown in engineering drawings AO-M-DWP-001 and 01, 02, 03-M-DWP-002, consists of a degasifier subsystem, a demineralizer subsystem, a regeneration subsystem, a demineralized water storage and transfer subsystem, and a sulfuric acid storage and transfer subsystem. Waste water from DWS operations is directed to a spent regenerant sump, is treated in accordance with Water Reclamation Facility operating procedures, and is pumped to the Water Reclamation Facility clarifier feed sump or the trickling filter sump emergency overflow. During Water Reclamation Facility (WRF) outages or emergencies, this wastewater can bypass the WRF clarifier feed sump or the trickling filter sump emergency overflow and be fed directly into the wet dry sump which feeds the 45 acre/or 85 acre reservoirs.

9.2.3.2.1 Component Description

9.2.3.2.1.1 Degasifier Subsystem. The degasifier subsystem includes the following components:

A. Vacuum Degasifier

The vacuum degasifier consists of a three-stage packed tower over a 6000-gallon catch tank. The tower and

tank are designed for full vacuum and 75 psig pressure. An ejector on each stage of the tower maintains the desired operating vacuum. Reverse osmosis product water enters the top of the tower and is progressively degasified to a carbon dioxide content of 5 ppm or less and an oxygen content of 0.1 ppm or less. The tower is designed to process up to 600 gallons per minute of water.

B. Vacuum Pumps

Two rotary ring vacuum pumps, one redundant, pull vacuum on the stage ejectors. The vacuum pumps are water sealed. Seal water is provided from a package cooling tower subsystem in the CPS, is discharged to an air-water separator, and is returned to the cooling tower by seal water pumps.

C. Air-Water Separator

The air-water separator receives seal water discharge from the vacuum pumps and vents the gases to atmosphere.

D. Seal Water Pumps

Two seal water pumps (one redundant) take suction from the air-water separator and return the seal water to the CPS cooling tower.

9.2.3.2.1.2 Demineralizer Subsystem. The demineralizer subsystem includes the following components:

A. Demineralizer Feed Pumps

Three centrifugal pumps take suction from the degasifier catch tank and deliver water to the mixed bed demineralizers.

B. Mixed-Bed Demineralizers

Three mixed-bed demineralizers operate two-in-series, with one bed in regeneration or standby. Each vessel contains mixed strong acid cation and strong base anion resins. The beds are designed to process a minimum of 864,000 gallons in the primary working bed position. The beds will process 200 gallons per minute up to 600 gallons per minute (maximum) forward flow.

9.2.3.2.1.3 Regeneration Subsystem. The regeneration subsystem includes the following components:

A. Regenerant Day Tank

A day tank for acid is provided which holds sufficient chemical for one regeneration. The acid day tank holds 66°Be' sulfuric acid.

B. Regenerant Feed Pumps

Two metering pumps (one redundant) are provided for acid. The chemical is metered automatically and is diluted at a mixing tee with demineralized water. Caustic is metered directly to a mixing tee with a control valve.

C. Hot Water Storage Tanks

Two storage tanks provide hot water for bed warmup and anion resin regeneration. The tanks are equipped with two electric immersion heaters per tank.

D. Surge-Rinse Tank

The surge-rinse tank is a 125,000-gallon capacity, diaphragm-sealed, stainless steel tank that provides temporary storage for regeneration rinse water and to prevent the reverse osmosis system supplying makeup to the demineralizer from cycling excessively.

E. Rinse Water Booster Pumps

Two centrifugal pumps (one redundant) supply regenerant dilution water and rinse water for bed regeneration.

The regeneration subsystem has an automatic, computerized control system for the regeneration steps, with manual override to stop, start, or repeat steps as desired by the operator to assure adequate resin regeneration and rinsing.

9.2.3.2.1.4 Demineralized Water Storage and Transfer Subsystem. The storage and transfer subsystem includes the following components:

A. Demineralized Water Booster Pumps

Three centrifugal pumps supply demineralized water to the storage tank at each PVNGS unit.

B. Demineralized Water Storage Tank

Each PVNGS unit has a 125,000-gallon capacity, nitrogen blanketed, stainless steel storage tank for makeup demineralized water.

C. Demineralized Water Transfer Pumps

Each PVNGS unit has two centrifugal pumps (one redundant) to supply makeup demineralized water on demand of the using systems.

9.2.3.2.1.5 Sulfuric Acid Storage and Transfer Subsystems. The acid storage and transfer subsystem includes the following components:

A. Sulfuric Acid Storage Tanks

Two tanks provide acid storage for the DWS and the DS. The tanks receive acid from trucks through an unloading boom. The acid is transferred to the tanks by instrument air pressurization of the tank truck.

B. Sulfuric Acid Transfer Pumps

Two pumps (one redundant) supply acid from the storage tanks to day tanks in the DWS and DS. These pumps also supply acid to the spent regenerant sump as required for neutralization of the waste water.

9.2.3.2.1.6 Pipe Materials. Piping materials in the DWS include the following:

A. Demineralized Water

The degasifier, demineralizer, and regeneration subsystems have polypropylene-lined carbon steel piping. The surge-rinse tank and the storage and transfer system have 304 stainless steel piping. PVNGS unit piping carrying makeup demineralized water is 304 stainless steel.

B. Dilute Caustic

Dilute caustic supply piping is chlorinated polyvinyl chloride (CPVC) underground and polypropylene-lined carbon steel aboveground.

C. Sulfuric Acid

The diluted regenerant acid piping is polypropylene-lined carbon steel.

9.2.3.2.1.7 Spent Regenerant Sump. The spent regenerant sump is an outdoor, underground concrete structure which collects water treatment area drains, including the DWS regenerant waste. The sump has a normal usable capacity of 60,588 gallons of waste water. Two vertical, wet pit centrifugal pumps (one redundant) are located in the sump. The sump is equipped with level controls, automatic outflow control valves, and a pH indicator-controller. Acid and caustic are supplied to the spent regenerant sump for neutralization of the waste water.

9.2.3.2.2 System Operation

9.2.3.2.2.1 Degasifier Subsystem. Water is supplied to the vacuum degasifier at 200 to 600 gallons per minute from the DS reverse osmosis units. The flow is controlled by operator diverting of reverse osmosis unit(s) and setting the reverse osmosis unit(s) product flow controllers. The tank volume provides a surge time of 10 to 15 minutes.

Vacuum is maintained continuously in the three-stage tower by one of the vacuum pumps. Vacuum seal water flows through the operating pump at 20 gallons per minute to the air-water separator, and is returned to the CPS package cooling tower for recirculation.

9.2.3.2.2.2 Demineralizer Subsystem. The demineralizer feed pumps take suction from the degasifier catch tank and provide flow through two mixed beds in series to the surge rinse tank or the suction of the demineralized water booster pumps, if in manual operation. The feed pumps are controlled manually based on demineralized water usage rates and reverse osmosis influent rate to the DW system.

Two demineralizer beds are rotated through positions of regeneration, standby, and working bed. The third demineralizer bed is used as a dedicated polisher. The working bed and polishing bed are connected in series flow between the feed pumps and the surge-rinse tank. Water is continuously recirculated through the operating beds and vacuum degasifier during standby.

Conductivity, silica, sodium and oxygen analyzer-controllers monitor water quality entering the system effluent header. High conductivity, silica, sodium or oxygen causes water to recycle back through the degasifier. The quality analyzers trip alarms to alert operators of the bed breakthrough or of an off-specification water quality condition. Flow totalizers on each bed are used to track throughout and determine when to preservice rinse the standby bed, and take the primary bed out of service for regeneration.

9.2.3.2.2.3 Regeneration Subsystem. When the working bed has reached "end of run" condition and has been removed from service, it is ready for regeneration. The operator manually initiates the regeneration process. Steps in the regeneration are automatically controlled thereafter, with stop, start, or repeat of steps optional to the operator.

The bed is backwashed to clean and separate the resin in-place, with the anion resin above the cation resin. The anion bed is prewarmed with 120F water, then simultaneously injected with dilute acid (upflow through cation bed) and dilute, 120F caustic (downflow through anion bed). The spent regenerant intermixes at the resin interface and flows to the spent regenerant sump. The regenerants are displaced from the bed by slow rinse, followed by a fast rinse step. The bed water level is reduced by blowing down, then air is introduced to remix the resins. The bed is refilled with rinse water, expelling the air, and is given a final rinse to expel air-containing rinse water. The bed is then placed on standby.

9.2.3.2.2.4 Demineralized Water Storage and Transfer Subsystem. The degasified and demineralized water is supplied from the common surge-rinse tank to unit storage tanks at each PVNGS unit. One of the three common booster pumps, taking suction from the surge-rinse tank, or mixed bed demineralizers (in manual operation only). Is operated continuously to pressurize the common pipeline to the PVNGS units. The second and third booster pumps operate as required by demand.

At each PVNGS unit, the makeup storage tank is automatically filled through a fill valve controlled by a liquid level controller on the tank. One of two transfer pumps, taking suction from the makeup tank, is operated continuously to pressurize the PVNGS unit makeup demineralized water piping. The second transfer pump operates as required by demand. PVNGS unit demands are normally met by the two transfer pumps. Check valves in the demineralized water supply headers are provided to preclude (1) siphoning from the decontamination sump in event of a loss of offsite power, or (2) cross-contamination from temporary connections with decontamination facility (Unit 1), radwaste building decontamination stations, RV head decontamination stations, and fuel cask decontamination washdown station. In addition, the condensate storage tank can be manually filled directly from the common pipeline by opening two (normally closed) isolation valves.

9.2.3.2.2.5 Sulfuric Acid Storage and Transfer Subsystem. Commercial grade 66°Be' sulfuric acid is supplied from one of two DWS storage tanks to the day tank in the DWS system. One of two transfer pumps, taking suction from the storage tanks,

is manually started by the operator on indication of low acid level in the day tank. The day tank fill is automatically stopped by closing of a fill valve controlled by a high level switch on the day tank. The transfer pump is also automatically stopped at the same time.

9.2.3.2.2.6 Waste Water. The spent regenerant sump receives waste water from the demineralizer regeneration process, the chemical production area wastes, the fire pump house oily waste sump, the water treatment building sump, and various filter backwashes.

This waste water is treated in accordance with Water Reclamation Facility operating procedures and then pumped to the Water Reclamation Facility clarifier feed sump or the trickling filter sump emergency overflow. During Water Reclamation Facility (WRF) outages or emergencies, this wastewater can bypass the WRF clarifier feed sump or the trickling filter sump emergency overflow and be fed directly into the wet dry sump which feeds the 45 acre/or 85 acre reservoirs.

9.2.3.3 Safety Evaluation

The DWS has no safety function except where needed to provide containment isolation via the containment penetrations. The malfunction or failure of a component has no adverse effect on any safety-related system or component.

9.2.3.4 Tests and Inspections

Acceptance testing of this system is performed to demonstrate proper system and equipment functioning. The system continues to be proved functional through normal plant operations.

The regular sampling of demineralized water tank contents ensures that the limits for radioactive concentrations are not exceeded.

9.2.3.5 Instrumentation Applications

Local instrumentation, controls, and alarms are provided for monitoring and partial automatic control of the system process and for protection of system components. Pressure, level, flow, temperature, conductivity, silica, sodium, oxygen, and pH monitors, recorders, and alarms are provided for each applicable point in the various subsystems.

The system production rate is automatically paced to demand of the PVNGS units by feedback of supply line header pressure to transfer pumps and surge tank levels to processing equipment.

Pumps are protected by low level switches on the suction side and minimum flow piping or pressure relief valves on discharge lines. Effluent water quality and quantity is monitored and recorded with off-specification water returned for reprocessing and the condition alarmed. The regeneration process is automatically controlled, after manual initiation, and is fully monitored by pressure, flow, conductivity, and temperature alarms. High and low level alarms are installed on the regenerant day tank, on demineralized water surge and storage tanks and on the spent regenerant sump.

Individual alarms are annunciated on a local demineralizer control panel for shared portions of the system. A common trouble alarm is provided in the water reclamation plant control room. Alarms for the PVNGS unit storage and transfer subsystem are annunciated in the unit control room.

9.2.4 DOMESTIC WATER SYSTEM

The DS processes local onsite well water to remove suspended solids and part of the dissolved solids, chlorinates and neutralizes the processed water, stores and transfers the domestic water to each PVNGS unit and to common facilities in the plant.

9.2.4.1 Design Bases

9.2.4.1.1 Safety Design Bases

The DS serves no safety function and has no safety design bases.

9.2.4.1.2 Power Generation Design Bases

A. Prevent contamination due to potential radioactivity or due to backflow from cross-connected systems using water unfit for human consumption.

B. Provide a quantity of 50 gallons per person per day for the largest number of persons expected to be at the station during a 24-hour period of plant refueling and maintenance operations.

C. Provide potable water storage to provide surge control for the DS system and allow maintenance on the well water treatment subsystem without disrupting distribution.

D. Supply water for plant uses except makeup to the circulating water systems.

E. Provide potable water quality conforming to the requirements of the regulations of the Arizona Department of Environmental Quality and the U.S. Environmental Protection Agency.

The DS is designed to nonnuclear safety codes and standards as defined in table 3.2-1. In addition, the DS outlets are provided in compliance with the intent of Title 29, Chapter XVII, Part 1910, Occupational Safety and Health Standards of the Code of Federal Regulations. Backflow preventers are provided in conformance with state regulations.

9.2.4.2 System Description

The DS, as shown in engineering drawings AO-M-DSP-001 and 01, 02, 03-M-DSP-002, consists of a well water supply subsystem, a water treatment subsystem, and a storage and transfer subsystem which are shared facilities. Each PVNGS unit has a hot and cold water distribution system. Domestic water is also distributed to facilities in the water reclamation plant and the water treatment area. Waste water from operation of the treatment subsystem is directed to the water reclamation plant for recovery. During Water reclamation Facility (WRF) outages or emergencies, this wastewater can bypass the WRF clarifier feed sump or the trickling filter sump emergency overflow and be fed directly into the wet dry sump which feeds the 45 acre/or 85 acre reservoirs.

Major component equipment data for the DS is provided in table 9.2-13.

The DS system provides hot water to the main toilet and shower areas and other locations where needed. The storage capacity for water heaters used is based on providing an adequate supply of hot water for the anticipated maximum drawdown, which occurs during the plant personnel shift change during maintenance and refueling operations. Use of only 75% of the stored capacity of each unit is assumed, due to the addition of cold makeup during this drawdown. The recovery sections are capable of reheating the total design water storage capacity to design temperature within 6 hours.

9.2.4.2.1 Component Description

9.2.4.2.1.1 Well Water Supply Subsystem. The well water supply subsystem consists of the following components:

A. Deep Well Pumps

Two onsite deep wells are equipped with five-stage vertical turbine pumps. The wells are equipped with sanitary collars and air vent valves.

B. Well Water Transfer and Storage

The well pumps transfer water to two 500,000-gallon fire water storage tanks and to two 27,000-gallon well water storage tanks. The two well water storage tanks provide water to the domestic water system. The well pumps are connected by a common pipeline to the tanks. Branch piping from each well contains a double check backflow

preventer to stop cross-flow between the wells or backflow from the tanks and pipeline.

C. Well Water Booster Pumps

Three horizontal centrifugal pumps (one redundant) provide flow from well water storage to the treatment subsystem.

Table 9.2-13

DOMESTIC WATER SYSTEM EQUIPMENT DATA (Sheet 1 of 2)

Tanks Description	Number Required	Design Pressure (psig)	Size (gals)	Material
Well water storate tanks	2	atm	27,000	Fiberglass reinforced plastic
Domestic water storage tanks	2	atm	120,000	Carbon steel
Domestic water hypochlorite tank	1	atm	30	Fiberglass reinforced plastic
Sulfuric acid day tank	1	atm	65	Carbon steel
Flush tank	1	atm	500	Fiberglass reinforced plastic

Pumps Description	Number Required	Design Flow (gal/min)	Design Head (ft)	HP	Type
Well water booster pumps	3	750	255	75	Horizontal, centrifugal
Domestic water transfer pumps	3	500	290	60	Horizontal, centrifugal

Table 9.2-13

DOMESTIC WATER SYSTEM EQUIPMENT DATA (Sheet 2 of 2)

Pumps Description	Number Required	Design Flow (gal/min)	Design Head (ft)	HP	Type
Domestic water hypochlorite metering pumps	2	0.037	57	0.25	Positive displacement, proportioning
Deep well pumps	2	1400	412	200	Vertical turbine
Sulfuric acid injection pumps	2	0.092	150	0.25	Positive displacement, proportioning
Reverse osmosis feed pumps	5	250	1,608	200	Horizontal centrifugal
Flush pump	1	200	85	7.50	Horizontal centrifugal

Neutralizing Filters Description	Number Required	Design Flow (gal/min)	Design Pressure (psig)	Material
Domestic water	3	200	75	Carbon steel, epoxy lined shell; neutralite fill

9.2.4.2.1.2 Water Treatment Subsystem. The water treatment subsystem consists of the following components:

A. Prefilters

Two cartridge type pressure filters (one redundant) provide suspended solids removal from the well water. Sand filtration will also be provided.

B. Sulfuric Acid Day Tank

The acid day tank has a 65-gallon capacity. 66° Be' sulfuric acid is delivered from storage by pumped-flow pipeline.

C. Sulfuric Acid Injection Pumps

Two diaphragm type metering pumps (one redundant) inject acid for pH control of the well water. The acid is injected into a mixing tee upstream of the safety prefilters.

D. Reverse Osmosis Feed Pumps

Five two-stage horizontal centrifugal pumps (one redundant) provide high-pressure feed to the reverse osmosis (RO) modules. The pumps are manifolded at suction and discharge.

E. Reverse Osmosis Modules

Four RO modules, rated at 250 gallons per minute product output each at a maximum of 80% recovery, process the well water. The modules are skid-mounted and consist of 8-inch pressure tubes manifolded in a 10-into-5 staging array. The pressure tubes contain spiral-wound membrane

elements of cellulose acetate in two stages. Product water from both stages is manifolded into a header and the brine is similarly collected in a brine header. The four skids are manifolded together at inlet, product and brine headers. Each skid has its own controls and instrumentation, with remote readout and control from a common local panel.

F. Flow-Direction Valves

The common product water header has three automatic flow-direction valves, with one valve located between each pair of RO module inlet headers. These valves direct flow to the DWS and the DS.

G. Hypochlorite Day Tank

The hypochlorite day tank has a 30-gallon capacity. Sodium hypochlorite of 8% strength is manufactured onsite and delivered by pumped-flow pipeline.

H. Hypochlorite Injection Pumps

Two diaphragm type metering pumps (one redundant) inject hypochlorite into the RO product water directed to the DS. (Water directed to the DWS is not chlorinated.)

I. Domestic Water Filters

Three pressure filters loaded with pelletized calcium carbonate (neutralite) receive RO product water and neutralize free carbon dioxide or other acidity by reaction with the neutralite. The filters are designed for 200 gallons per minute flow.

J. Flush Tank

A 500-gallon capacity tank is used for mixing and recirculating chemical solutions as required for periodic cleaning and flushing of the RO membrane modules.

K. Mixer

A propeller type mixer is mounted on the flush tank.

L. Flush Pump

One horizontal centrifugal pump is provided to recirculate the cleaning and flushing solutions through the RO membrane modules and back to the flushing tank.

9.2.4.2.1.3 Storage and Transfer Subsystem. The storage and transfer subsystem consists of the following components:

A. Domestic Water Storage Tanks

Two tanks, of 120,000-gallon capacity each, receive water from the filters for storage.

B. Domestic Water Transfer Pumps

Three horizontal centrifugal pumps (one redundant) provide flow from the domestic water tanks to the distribution system.

C. Backflow Preventers

The distribution system includes a common header from the water treatment area to a loop main around the PVNGS units. Branch mains to the PVNGS units are equipped with state regulatory approved backflow preventer assemblies

(BPA) which are installed as close as practical to potential sources of contamination.

9.2.4.2.1.4 Distribution Subsystem. The distribution subsystem consists of the following components:

A. Strainers

Pressure control valves on branch mains leading to all buildings are equipped with permanent Y-strainers and blowoff valves on the upstream side.

B. Hot Water Tanks and Heaters

Hot water tanks equipped with electric immersion heaters, thermal controls, and pressure relief valves are located in each building which requires hot water service. The PVNGS unit buildings are serviced as follows:

- Auxiliary building - one approximately 120-gallon tank plus one 200-gallon tank minimum
- Control building - one 200 to 225-gallon tank
- Service building - two 125-gallon tanks
- Administration building - one 85-gallon tank
- Main guardhouse - one 30-gallon tank
- Outage Support Facility – one 80-gallon tank

9.2.4.2.1.5 Piping Materials. Piping materials used in the DS prevent the introduction of objectionable tastes, odors, discoloration, and toxic substances into the system, and

conform to the plumbing code adopted by the Maricopa County Planning and Developing Department. Copper piping is used in the buildings for hot and cold water distribution. Underground mains and outdoor service piping are constructed of epoxy-lined carbon steel. Replacement piping or system extensions used in underground mains and outdoor service piping after January 1, 1993, will be National Sanitation Foundation (NSF) certified or will be an alternative as provided by Arizona State Laws. Process piping utilizes 316L stainless steel to the suction of the RO feed pumps and 316L stainless steel for high-pressure pipe and RO headers. Low-pressure manifolding for RO product water is done with PVC.

9.2.4.2.2 System Operation

9.2.4.2.2.1 Well Water Supply Subsystem. In normal operation, one of the two deep well pumps automatically fills the fire water/well water reserve tanks and the well water storage tanks in response to tank level control signals. These signals also open and close flow control valves on the common pipeline from the two wells. Both well pumps start on low-low level signals and both pumps continue to operate until the tanks are full.

One of the three booster pumps operates continuously to supply water to the treatment subsystem. The second and third pump operate as required by demand.

9.2.4.2.2.2 Water Treatment Subsystem. The RO feedwater is supplied by the well water booster pumps. One pump supplies

the requirements of two RO modules. A second pump is automatically started when demand requires three or four RO tank of the DWS starts the RO system in the 400-gallon per minute mode to the DWS, a low level signal from the domestic water storage tank starts the RO system in a 400-gallon per minute mode to the DS. Low-low level in either the domestic water tanks or the surge-rinse tank will start the RO in a 600-gallon per minute to the system which requires it. However, internal logic in the RO gives priority to the DWS. Flows can also be manually adjusted.

The RO feedwater is filtered in cartridge filters and acidified with sulfuric acid. High-pressure feed pumps supply the RO modules through a common header.

Reverse osmosis product to the DS system is chlorinated using sodium hypochlorite. The dissolved carbon dioxide in the RO product which results from acid pretreatment of the feedwater reacts with the neutralite in the domestic water filters to produce noncorrosive water with a pH of approximately 7.2. Continuous sampling of the chlorinated water is performed entering and leaving the filters. The controls adjust the hypochlorination rate for approximately 1 ppm of residual chlorine.

The RO system is supplied with a flushing pump and tank for periodic cleaning or flushing of the membranes. One module can be cleaned at any time without affecting operation of the remaining modules. Cleaning is a manual operation.

9.2.4.2.2.3 Storage and Transfer Subsystem. Water from the domestic water filters flows to the domestic water storage tanks.

The domestic water transfer pumps take suction from the storage tanks and deliver water to the distribution subsystem.

9.2.4.2.2.4 Distribution Subsystem. State regulatory approved backflow preventers are installed on each branch line off the domestic water loop, except lines where backflow is not possible, to prevent contamination of the distribution header. Pressure control valves reduce the distribution loop pressure to the points of use where a constant pressure is required.

9.2.4.3 Safety Evaluation

The domestic water system has no safety functions. The malfunction or failure of a component has no adverse effect on any safety-related system or component.

9.2.4.4 Tests and Inspections

Acceptance testing of this system is performed to demonstrate proper system and equipment functioning.

Periodic testing of the backflow preventers will be performed per the requirements of the state of Arizona. Other system components will be used during normal operation. No inservice inspections are required.

9.2.4.5 Instrument Applications

Local instrumentation, controls, and alarms are provided for monitoring and automatic control of the system process and for protection of system components. Pressure, level, flow and chlorine analysis monitors, recorders, and alarms are provided for each applicable point in the various subsystems.

The RO system production rate is automatically paced by the demands from the DS storage tanks and DW surge-rinse tank. Pumps are protected by minimum flow piping or pressure relief valves on discharge lines. Analyzers measure the chlorine residual. High or low residuals are alarmed and, at the filters, result in shutdown of the RO and hypochlorite pumps. High and low level alarms are installed on the domestic water storage tanks and the hypochlorite day tank.

9.2.5 ULTIMATE HEAT SINK

The ultimate heat sink for each PVNGS unit consists of two independent Seismic Category I essential spray ponds (ESPs) which provide cooling water for the ESPS described in subsection 9.2.1.

Each unit is provided with a separate individual ultimate heat sink. There is no sharing of ultimate heat sinks between units.

The function of the ultimate heat sink is to provide cooling of the ESPS during a normal shutdown or during accident conditions, with no other water source available.

Each pond serves one train of the ESPS. Redundant manually operated seismically qualified butterfly valves are provided to equalize the water level between ponds, if required, and to provide the combined inventory of both ponds to the operating ESPS for a 26 day period following a postulated LOCA.

The ultimate heat sink meets the requirements of Regulatory Guide 1.27.

The ultimate heat sink will be operated in accordance with the Technical Specifications.

9.2.5.1 Design Bases

9.2.5.1.1 Safety Design Bases

Safety design bases pertinent to the ultimate heat sink are as follows:

A. Safety Design Basis One

In the unlikely event of a LOCA, the ESP in conjunction with the ESPS provides sufficient cooling for a period of 26 days without water makeup to cool down the unit and maintain it in a safe condition under the most adverse historical meteorological conditions consistent with the guidelines of Regulatory Guide 1.27 without exceeding the design basis temperature of the ESPS.

B. Safety Design Basis Two

The function of the ESP is not impaired during or after any one of the following events:

1. The most severe natural phenomena including SSE, tornado, flood, or drought taken individually
2. Nonconcurrent site-related events including transportation accidents, oil spills, and fires
3. Credible single failures of man-made structures

C. Safety Design Basis Three

Procedures for assuring continued cooling capability beyond the 26 days specified within Safety Design Basis One are available.

D. Safety Design Basis Four

The ESP in conjunction with the ESPS provides sufficient cooling for the safe shutdown and cooldown of the unit and to maintain it in a safe shutdown condition during a normal reactor shutdown.

9.2.5.1.2 Codes and Standards

Applicable codes and standards for the ultimate heat sink are as follows:

A. The ESP and associated components are Seismic Category I.

B. Codes and standards applicable to the ESP and associated components are listed in section 3.2.

C. The ESP conforms to the requirements of Regulatory Guide 1.27.

9.2.5.2 System Description

The ultimate heat sink consists of two ESPs that are adjacent to each other, and interconnected by two redundant normally closed butterfly valves. The location of the ESP with respect to the site is shown in engineering drawings 13-C-ZVA-005 and 13-P-OOB-001. The process and instrument diagram for the ESPS is shown in engineering drawings 01, 02, 03-M-SPP-001.

A detailed description of the ESPS is provided in subsection 9.2.1.

The water inventory in the ultimate heat sink is sufficient to provide 26 days of cooling capacity, using the combined water

capacity of both ESPs, without water makeup. However, separate makeup water lines are provided to each ESP from the following independent water supply sources:

- Domestic water system
- Station makeup water reservoirs via cooling tower makeup and blowdown system

The ESPs are Seismic Category I and are of concrete, watertight, vertical wall construction. The ESP Structures are made “watertight” by the quality of the concrete construction, the 2-foot minimum concrete thickness of the walls and base mat, and the use of waterstops in construction joints. The likelihood of significant seepage through the ESP concrete structure is small given the quality of the concrete, its thickness, the proven performance of the waterstop material, and the autogenous healing nature of concrete (small cracks fill with calcium carbonate that leeches form concrete exposed to water).

Spray heads over the ESPs are arranged to minimize interference between sprays. The spray heads provided are designed to develop the optimum spray drop spectrum to maximize cooling and to minimize drift losses.

Spray head piping is sized to provide approximately equal flow through each spray nozzle. Discharge from the spray pond system is directed through the spray nozzles during operation of the sprays.

Each ESP is 345 feet by 172 feet with a depth of 15 feet 6 inches. The depth of the pond includes the allowances in

table 9.2-14. The dimensions and arrangement of the ponds are shown in figure 9.2-1.

The essential spray ponds are reinforced concrete structures with vertical walls extending 3.5 feet above backfill. The maximum static water level is 1.1 feet below the top of the vertical walls as shown in figure 9.2-1. The resulting free-board is adequate to assure minimum water inventory is available during seismic or high wind conditions. The ponds are designed as Category I structures in accordance with section 3.8, including static and dynamic lateral earth pressures specified in PVNGS 1, 2, and 3 PSAR, Appendix 2T. Excessive leakage from the ponds is precluded by the thickness of the reinforced concrete walls and base slab, and by waterstops at construction joints.

Table 9.2-14

ESP DEPTH ALLOWANCES

Purpose of Allowance	Depth (ft)
Minimum Water Inventory for evaporation and drift[1]	12.0
Pump NPSH requirement	1.5
Water margin for operating range instrument uncertainty, and wind wave action	2.0
Total depth	15.5

[1]The minimum water inventory allowance contains the volume of water between elevations 94’ and 106’. This volume satisfies the minimum water inventory requirement of 26 days as discussed in Section 9.2.5.4.A and is the volume that would be lost following a LOCA due to evaporation and drift. The thermal performance analysis utilizes the entire inventory of the pond(s) since the entire volume is always available as a heat sink.

The two ESPs are interconnected with redundant valves installed in their common wall in order to permit equalization of the water levels between ESPs of the same unit. These valves are normally closed during plant operation to maintain the ESPs independent of one another. For post-LOCA cooling, at least one of the two redundant valves will need to be opened to provide combined water inventory as discussed in paragraph 9.2.5.4.A. As these valves are part of the UHS, which falls under UHS Technical Specification, and are not required for ESPS redundancy, they are not subject to the ESPS Technical Specification.

In order to prevent dissolved solids buildup due to solar evaporative losses, a blowdown line from each ESP to the circulating water system is provided.

In order to maintain the ESP water quality requirements, each ESP is provided with a closed loop water filtering recirculation system and hypochlorite injection system. Hypochlorite solution is normally injected into the ESP system from the hypochlorite header. Periodic analysis of pond water is taken to maintain the desired chemistry in the pond.

Since the water makeup lines, hypochlorite injection system, and pond filtering system are not safety-related, they are of non-Category I construction. The makeup water discharge lines are routed over the pond wall and terminate above the minimum Tech. Spec. required level in the spray pond(s). The pond filter pump suction lines, which extend below the pond surface are provided with siphon breakers to prevent drainage of water

from the pond(s) below the minimum Tech. Spec. required level in the event of a piping failure.

Table 9.2-15 lists Seismic Category I valves.

9.2.5.3 System Design

The design of the ESP is in accordance with Regulatory Guide 1.27 as discussed in the following paragraphs.

9.2.5.3.1 Meteorology

The determination of the meteorological parameters is in accordance with Regulatory Guide 1.27 for the design of the ESP.

9.2.5.3.1.1 Historical Meteorological Data. Data for the time span from 1948 through 1973 were obtained from the Sky Harbor Meteorology Station at Phoenix, Arizona, and screened to determine the worst 1 day and worst 29 consecutive days during the time span for use in establishing the thermal design of the ESP and in establishing the ESP water mass. The worst day for the thermal design of the ESP per Regulatory Guide 1.27 was August 14, 1955, and the worst 29 consecutive days were from July 30, 1955, to August 27, 1955. The worst day for the ESP design water mass was August 23, 1969, and the worst 29 consecutive days were from July 12, 1971, to August 9, 1971.

The wet bulb, dry bulb, and dewpoint temperatures and the wind speed data for these time periods are tabulated in tables 9.2-16 and 9.2-17, respectively.

The average wind speed for these two periods was 4.7 miles per hour and 10.8 miles per hour, respectively. These data were used to determine the drift loss and nozzle efficiency from the experimental data taken at the Rancho Seco Nuclear Power Station spray pond tests.(1) The average drift loss and nozzle efficiency for the meteorology in tables 9.2-16 and 9.2-17, respectively, are 0.188% and 32.86%, and 0.551% and 44.6%.

9.2.5.3.1.2 Meteorology Data Screening Methodology. For the thermal design of the ESP, Regulatory Guide 1.27 defines the use of that 30-day period for which the difference between the dry bulb temperature and the dewpoint temperature is a minimum. Since the thermal efficiency of the sprays is less at high temperatures than at low temperatures and also is less for still air than for high wind speeds, compliance with the intent of the guide requires including these two additional factors in the screening methodology. For the design of the water mass of the ESP, the guide defines the use of that 30-day period for which the difference between the dry bulb temperature and dewpoint temperature is a maximum concurrent with the highest wind speeds. Since the rate of evaporation is higher and the thermal efficiency of the nozzles is lower at high air temperatures than at lower air temperatures, compliance with the intent of the guide requires including these factors in the screening methodology.

Table 9.2-15

ESSENTIAL SPRAY POND SYSTEM SEISMIC CATEGORY 1 VALVE LIST (Sheet 1 of 2)

(Refer to engineering drawings 01, 02, 03-M-SPP-001)

Valve Tag Number	Location	Valve Type	Line Size Inches	Actuator Type[b]	Valve Classification[a]
SPA-V041	ESP pump discharge, train A	Check	24	None	A
SPA-HCV045	Inlet to ECW heat exchanger, train A	Butterfly	20	Hand	N
SPB-HCV047	Discharge from ECW heat exchanger, train A	Butterfly	20	Hand	N
SPA-HV49A	ESP pump to spray headers, train A	Butterfly	24	Hand (c)	N
SPA-HV49B	ESP pump to spray headers, bypass train A	Butterfly	18	Hand (c)	N
SPA-HV0075[1]	ESP Flow Control Valve, Train A	Butterfly	14	Motor	A
SPA-V087[d]	Fuel oil cooler inlet, train A	Globe	1	Hand	N
SPA-V088[d]	Fuel oil cooler outlet, train A	Globe	1	Hand	N
SPA-HCV125	Jacket water cooler inlet, train A	Butterfly	8	Hand	N
SPA-HCV127	Jacket water cooler outlet, train A	Butterfly	8	Hand	N
SPA-HCV129	Aftercooler inlet, train A	Butterfly	6	Hand	N
SPA-HCV131	Aftercooler outlet, train A	Butterfly	6	Hand	N
SPA-HCV133	Lube oil cooler inlet, train A	Butterfly	6	Hand	N
SPA-HCV135	Lube oil cooler outlet, train A	Butterfly	6	Hand	N
SPB-V012	ESP pump discharge, train B	Check	24	None	A
SPB-HCV046	ECW heat exchanger inlet, train B	Butterfly	20	Hand	N
SPB-HCV048	ECW heat exchanger discharge, train B	Butterfly	20	Hand	N
SPB-HV050A	ESP pond pump to spray headers; train B	Butterfly	24	Hand (c)	N
SPB-HV0076[1]	ESP Flow Control Valve, Train B	Butterfly	14	Motor	A

(1) DMWO 3304346 adds the capability to vary SP flow rates. This not applies to units and trains where this DMWO has been installed.

Table 9.2-15

ESSENTIAL SPRAY POND SYSTEM SEISMIC CATEGORY 1 VALVE LIST (Sheet 2 of 2)

(Refer to engineering drawings 01, 02, 03-M-SPP-001)

Valve Tag Number	Location	Valve Type	Line Size Inches	Actuator Type[b]	Valve Classification[a]
SPB-HV050B	ESP pond pump to spray headers bypass, train B	Butterfly	18	Hand (c)	N
SPB-V093[d]	Fuel oil cooler inlet, train B	Glove	1	Hand	N
SPB-V094[d]	Fuel oil cooler outlet, train B	Globe	1	Hand	N
SPB-HCV134	Jacket water cooler inlet, train B	Butterfly	8	Hand	N
SPB-HCV136	Jacket water cooler outlet, train B	Butterfly	8	Hand	N
SPB-HCV130	Aftercooler inlet, train B	Butterfly	6	Hand	N
SPB-HCV132	Aftercooler outlet, train B	Butterfly	6	Hand	N
SPB-HCV126	Lube oil cooler inlet, train B	Butterfly	6	Hand	N
SPB-HCV128	Lube oil cooler outlet, train B	Butterfly	6	Hand	N
SPE-HCV-207	ESP cross-connect valve [b]	Butterfly	10	Hand	A
SPE-HCV-208	ESP cross-connect valve [b]	Butterfly	10	Hand	A

a. An "A" indicates an active valve and "N" a nonactive valve, as discussed in section 3.9.

b. The ESP cross-connect valves are part of the ESP (UHS) as described in section 9.2.5.

c. Operation of these valves requires using the manual de-clutching lever and hand wheel on the existing motor operator. The power source to these motors are de-terminated and spared.

d. In units where DEC-00649 has been implemented, this valve has been removed.

Table 9.2-16
HISTORICAL WEATHER DATA
WORST RECORDED MINIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
JULY 30, 1955, THROUGH AUGUST 27, 1955 (Sheet 1 of 8)

	7-30-55				7-31-55				8-1-55				8-2-55			
Time (hrs)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
0	3.5	82	72	67	4.6	82	73	70	5.8	79	70	66	0.0	88	75	70
1	4.6	81	72	68	4.9	81	74	72	0.0	80	71	67	0.0	86	75	70
2	4.6	81	72	68	2.3	80	74	72	0.0	79	71	67	6.9	85	74	70
3	2.3	80	72	68	2.3	79	74	72	0.0	79	71	68	15.0	87	75	70
4	0.0	80	72	68	8.1	79	73	71	0.0	80	72	68	30.0	79	71	68
5	4.6	80	72	69	6.9	78	73	71	0.0	79	72	69	11.5	81	70	65
6	0.0	79	73	70	4.9	78	73	71	0.0	79	72	70	9.2	76	72	70
7	4.6	82	72	68	4.6	80	73	70	0.0	81	72	69	8.1	77	72	70
8	4.6	84	73	68	2.3	83	73	69	3.5	84	73	69	3.5	81	73	70
9	5.8	85	73	67	0.0	85	74	70	5.8	88	75	70	5.8	83	74	71
10	4.6	87	73	67	4.6	88	75	70	0.0	90	75	69	2.3	87	75	70
11	6.9	89	74	68	2.3	89	75	70	0.0	93	75	68	3.5	92	77	72
12	2.3	91	75	68	5.8	92	76	70	0.0	94	76	68	0.0	94	77	70
13	5.8	93	75	67	5.8	93	76	69	4.6	96	76	67	2.3	96	76	69
14	5.8	94	75	66	4.6	95	77	70	9.2	97	77	69	8.1	98	77	69
15	9.2	95	75	66	9.2	95	77	69	8.1	98	77	69	8.1	98	77	68
16	5.8	95	74	65	3.5	96	77	70	8.1	98	77	70	8.1	97	76	67
17	11.5	94	76	69	11.5	94	75	67	8.1	98	76	68	5.8	96	75	66
18	8.1	88	75	69	13.8	89	74	67	4.6	97	76	68	0.0	95	76	68
19	3.5	88	76	71	15.0	80	73	70	5.8	95	76	68	3.5	90	76	70
20	6.9	88	74	69	5.8	81	72	68	4.6	93	75	68	3.5	87	74	68
21	10.4	86	75	70	3.5	80	72	68	0.0	90	76	70	4.6	87	73	68
22	8.1	84	74	71	0.0	79	71	67	2.3	90	75	69	5.8	86	73	67
23	6.9	82	74	70	6.9	79	71	67	0.0	89	75	70	4.6	85	74	69

Table 9.2-16
HISTORICAL WEATHER DATA
WORST RECORDED MINIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
JULY 30, 1955, THROUGH AUGUST 27, 1955 (Sheet 2 of 8)

	8-3-55				8-4-55				8-5-55				8-6-55			
Time (hrs)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
0	6.9	84	72	67	0.0	76	73	72	3.5	82	75	72	4.6	85	75	71
1	9.2	83	72	67	0.0	76	72	71	0.0	80	74	71	3.5	84	74	70
2	4.6	81	72	68	4.6	76	72	71	0.0	79	74	71	2.3	84	75	71
3	3.5	80	71	68	3.5	75	72	70	4.6	79	73	71	2.3	81	73	70
4	5.8	78	72	69	4.6	75	72	71	3.5	78	73	71	5.8	81	73	70
5	8.1	79	72	69	3.5	75	73	72	3.5	78	73	71	6.9	80	73	70
6	5.8	79	72	68	2.3	75	72	71	3.5	78	74	72	8.1	80	73	71
7	4.6	82	72	68	0.0	77	73	72	5.8	81	74	72	5.8	81	74	72
8	4.6	85	74	69	0.0	80	74	71	4.6	85	75	71	20.7	84	74	69
9	3.5	87	74	68	0.0	81	73	70	0.0	86	74	70	18.4	89	75	69
10	8.1	89	74	68	0.0	83	74	70	0.0	89	75	70	4.6	90	74	67
11	11.5	90	74	68	0.0	85	74	69	5.8	91	76	70	0.0	92	75	67
12	10.4	91	74	67	2.3	87	74	69	4.6	93	76	69	8.1	93	76	69
13	9.2	93	75	67	8.1	88	74	69	8.1	94	76	69	3.5	92	75	68
14	11.5	94	75	66	5.8	90	74	67	2.3	95	76	68	0.0	94	76	69
15	8.1	95	75	66	5.8	90	75	69	4.6	96	75	67	5.8	95	75	67
16	10.4	96	75	65	5.8	92	74	67	2.3	97	75	65	6.0	96	76	67
17	11.5	96	75	65	4.6	90	74	67	9.2	98	76	67	4.6	97	76	68
18	9.2	96	74	65	0.0	90	74	66	8.1	97	76	68	6.9	97	76	67
19	20.7	91	74	68	5.8	90	74	67	0.0	95	76	69	5.8	94	77	70
20	19.6	81	72	68	5.8	87	75	70	0.0	93	76	69	9.2	91	77	71
21	5.8	78	73	71	0.0	86	75	71	2.3	91	77	71	19.6	82	73	70
22	9.2	76	73	72	0.0	85	74	70	0.0	90	77	72	13.8	76	72	70
23	4.6	76	73	72	0.0	84	74	70	0.0	88	76	71	5.8	74	72	72

Table 9.2-16
HISTORICAL WEATHER DATA
WORST RECORDED MINIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
JULY 30, 1955, THROUGH AUGUST 27, 1955 (Sheet 3 of 8)

	8-7-55				8-8-55				8-9-55				8-10-55			
Time (hrs)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
0	4.6	74	72	72	3.5	82	76	74	4.6	84	74	69	5.8	84	76	72
1	5.8	74	72	71	4.6	81	75	73	23.0	75	71	69	0.0	84	75	72
2	4.6	74	72	71	4.6	80	75	73	9.2	80	69	64	0.0	83	76	73
3	6.9	74	72	71	5.8	79	74	72	2.3	79	71	67	5.8	82	75	73
4	0.0	75	72	71	0.0	78	74	72	4.6	78	70	67	4.6	81	75	73
5	0.0	74	72	71	0.0	78	74	72	4.6	76	70	67	3.5	80	75	72
6	5.8	76	73	72	0.0	78	74	72	6.9	75	70	68	4.6	80	75	73
7	0.0	77	73	71	0.0	79	74	72	9.2	78	71	67	6.9	83	75	73
8	0.0	79	72	69	3.5	81	75	72	6.9	80	70	66	3.5	87	76	72
9	2.3	80	73	70	2.3	84	75	71	2.3	84	72	67	0.0	89	74	67
10	4.6	82	74	70	0.0	87	75	70	3.5	87	73	66	0.0	91	75	69
11	2.3	85	76	71	0.0	89	75	69	2.3	89	73	66	3.5	93	75	68
12	0.0	85	74	70	5.8	91	76	70	9.2	91	74	66	0.0	95	75	66
13	3.5	87	76	71	2.3	92	76	70	2.3	93	75	68	8.1	96	75	66
14	2.3	89	75	70	5.8	94	76	69	8.1	95	74	65	2.3	98	76	66
15	4.6	89	76	70	2.3	93	75	67	5.8	97	75	66	4.6	99	76	67
16	4.6	90	75	70	4.6	94	75	67	6.9	97	76	67	10.4	99	76	66
17	6.9	90	74	67	5.8	94	77	70	6.9	96	75	65	4.6	100	76	65
18	4.6	89	74	68	0.0	94	75	67	4.6	96	74	65	4.6	99	76	66
19	0.0	88	73	67	0.0	92	74	67	0.0	95	74	65	3.5	96	75	66
20	0.0	86	76	72	0.0	91	75	69	8.1	90	76	71	13.8	90	75	68
21	0.0	85	76	73	2.3	90	76	71	5.8	88	77	73	5.8	86	74	69
22	0.0	84	76	73	0.0	88	73	67	4.6	86	77	73	6.9	85	73	67
23	4.6	83	76	73	3.5	85	74	69	4.6	85	76	73	4.6	85	72	67

Table 9.2-16
HISTORICAL WEATHER DATA
WORST RECORDED MINIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
JULY 30, 1955, THROUGH AUGUST 27, 1955 (Sheet 4 of 8)

Time (hrs)	8-11-55				8-12-55				8-13-55				8-14-55[a]			
	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
0	5.8	83	73	68	0.0	89	75	69	4.6	74	72	72	4.6	82	75	72
1	8.1	80	72	68	0.0	87	75	70	13.8	74	72	70	5.8	81	76	74
2	5.8	78	71	68	0.0	85	75	71	6.9	75	71	70	0.0	80	76	75
3	0.0	78	71	68	3.5	84	75	72	9.2	75	70	67	5.8	79	75	73
4	4.6	78	71	68	3.5	84	75	72	5.8	75	71	69	0.0	78	74	72
5	4.6	78	71	69	4.6	83	75	71	2.3	74	71	69	0.0	78	75	74
6	5.8	77	72	69	0.0	83	73	69	6.9	75	71	69	0.0	78	75	74
7	0.0	78	72	69	4.6	87	75	70	5.8	78	71	68	0.0	80	75	73
8	0.0	82	73	70	8.1	91	75	68	0.0	80	71	67	6.9	82	76	73
9	0.0	86	74	69	4.6	92	74	66	2.3	83	73	69	0.0	84	76	73
10	0.0	89	75	69	4.6	95	76	68	4.6	86	74	68	4.6	86	77	73
11	0.0	93	75	68	2.3	96	75	67	2.3	87	74	69	2.3	88	77	73
12	3.5	95	74	65	13.3	98	76	67	0.0	89	75	69	3.5	90	77	72
13	5.8	96	75	66	9.2	99	75	64	2.3	90	74	68	8.1	92	77	72
14	8.1	98	75	66	8.1	101	76	65	2.3	93	75	68	4.6	93	77	70
15	4.6	99	75	66	5.8	101	75	64	2.3	94	76	68	4.6	95	77	70
16	5.8	99	76	66	2.3	101	75	64	3.5	94	75	68	2.3	95	76	69
17	3.5	100	76	65	0.0	102	76	66	4.6	94	75	67	0.0	96	77	70
18	8.1	99	76	66	23.0	92	75	67	0.0	92	75	68	0.0	95	76	68
19	5.8	96	75	67	11.5	85	73	69	4.6	91	77	71	0.0	92	78	72
20	3.5	93	76	69	17.3	85	71	65	4.6	88	78	74	3.5	89	77	72
21	0.0	91	77	71	5.8	84	70	64	0.0	87	78	75	3.5	88	75	69
22	2.3	90	76	71	13.8	79	72	69	0.0	85	78	75	5.8	86	74	69
23	0.0	89	75	70	11.5	84	72	71	5.8	83	77	75	0.0	85	74	69

a. Worst day for thermal design used as day 1 and day 17.

Table 9.2-16
HISTORICAL WEATHER DATA
WORST RECORDED MINIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
JULY 30, 1955, THROUGH AUGUST 27, 1955 (Sheet 5 of 8)

Time (hrs)	8-15-55				8-16-55				8-17-55				8-18-55			
	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
0	4.6	82	73	70	3.5	84	71	64	0.0	81	73	70	3.5	83	74	71
1	5.8	82	73	69	3.5	81	71	66	3.5	82	73	70	4.6	82	74	71
2	5.8	81	73	69	10.4	82	71	66	3.5	81	73	70	0.0	81	74	71
3	2.3	80	73	69	5.8	84	71	66	3.5	80	73	71	0.0	80	74	72
4	0.0	79	73	70	6.9	81	71	67	5.8	80	73	78	3.5	80	74	72
5	0.0	79	73	70	2.3	80	71	66	3.5	80	73	71	0.0	79	74	72
6	4.6	78	72	70	2.3	79	71	68	2.3	79	73	70	0.0	79	74	72
7	3.5	80	73	70	5.8	81	72	68	0.0	81	74	71	0.0	81	74	71
8	0.0	86	74	68	6.9	85	73	68	0.0	86	75	70	8.1	83	74	71
9	2.3	88	74	69	2.3	89	73	66	8.1	87	75	70	9.2	85	75	71
10	0.0	90	74	67	4.6	90	74	67	5.8	87	74	69	6.9	87	76	71
11	2.3	92	75	67	4.6	92	75	68	9.2	88	75	70	8.1	88	76	71
12	2.3	94	75	67	2.3	94	76	68	6.9	90	75	69	5.8	90	76	70
13	2.3	96	75	67	3.5	95	75	66	6.9	91	75	68	10.4	92	76	70
14	0.0	97	76	67	5.8	96	75	65	6.9	91	75	68	11.5	93	76	69
15	4.6	98	75	65	5.8	97	76	67	4.6	92	75	68	5.8	94	76	69
16	3.5	99	76	67	2.3	97	76	67	8.1	93	76	70	6.9	95	76	68
17	4.6	99	76	67	5.8	97	76	67	3.5	93	76	70	9.2	94	75	66
18	5.8	98	74	63	17.5	90	76	70	5.8	92	75	68	5.8	93	75	67
19	0.0	95	75	67	13.8	86	74	70	10.4	90	76	71	10.4	90	75	70
20	4.6	92	75	67	12.7	84	73	69	5.8	88	75	70	10.4	87	74	68
21	2.3	90	76	70	10.4	83	73	69	2.3	85	75	71	8.1	87	75	70
22	13.8	86	74	69	6.9	83	73	69	8.1	85	75	71	4.6	86	74	70
23	15.0	85	72	66	8.1	83	73	69	3.5	84	74	71	4.6	85	74	70

Table 9.2-16
HISTORICAL WEATHER DATA
WORST RECORDED MINIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
JULY 30, 1955, THROUGH AUGUST 27, 1955 (Sheet 6 of 8)

	8-19-55				8-20-55				8-21-55				8-22-55			
Time (hrs)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
0	5.8	85	74	70	6.9	77	73	71	0.0	83	75	72	0.0	83	71	66
1	0.0	84	74	70	5.8	77	73	71	8.1	82	75	73	6.9	82	71	65
2	2.3	83	74	71	0.0	76	72	70	12.7	77	72	69	3.5	81	71	66
3	0.0	81	74	71	3.5	75	72	71	5.8	78	72	69	0.0	81	71	66
4	2.3	81	74	71	0.0	75	72	71	9.2	76	71	69	2.3	82	71	65
5	0.0	80	74	71	5.8	75	72	71	6.9	76	71	70	2.3	80	71	67
6	0.0	81	75	72	4.6	75	72	71	9.2	75	71	70	5.8	79	70	66
7	0.0	82	74	71	4.6	76	72	70	6.9	77	72	70	3.5	81	70	66
8	0.0	85	75	72	9.2	77	73	71	4.6	79	73	70	0.0	83	72	67
9	8.1	87	76	71	8.1	78	73	70	2.3	84	75	71	3.5	86	72	66
10	8.1	89	75	70	5.8	79	73	70	0.0	86	74	69	0.0	90	75	68
11	3.5	91	76	70	0.0	82	73	69	0.0	88	75	70	2.3	92	76	70
12	6.9	93	76	69	5.8	86	74	69	8.1	89	75	70	3.5	95	77	70
13	10.4	94	75	68	0.0	86	74	69	9.2	90	76	70	3.5	96	76	67
14	8.1	96	75	67	5.8	88	74	69	5.8	92	76	70	3.5	97	76	67
15	10.4	96	76	67	4.6	90	75	68	3.5	93	77	71	4.6	99	75	64
16	8.1	96	75	66	8.1	92	76	69	0.0	92	77	71	2.3	99	75	65
17	20.7	85	72	66	4.6	92	76	69	0.0	93	77	71	0.0	100	76	66
18	5.8	83	71	66	4.6	91	75	69	4.6	91	77	71	3.5	97	75	66
19	17.3	78	74	72	4.6	91	76	70	0.0	90	77	72	2.3	95	74	65
20	2.3	78	72	69	0.0	89	76	71	0.0	89	76	71	3.5	93	76	68
21	8.1	78	72	70	6.9	86	76	72	3.5	88	77	72	4.6	91	75	69
22	15.0	78	73	71	9.2	84	75	72	4.6	88	76	71	5.8	90	75	68
23	6.9	77	73	72	8.1	83	75	72	0.0	87	74	69	15.0	85	74	69

Table 9.2-16
HISTORICAL WEATHER DATA
WORST RECORDED MINIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
JULY 30, 1955, THROUGH AUGUST 27, 1955 (Sheet 7 of 8)

Time (hrs)	8-23-55				8-24-55				8-25-55				8-26-55			
	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
0	15.0	83	73	70	3.5	76	73	73	4.6	78	73	71	5.8	81	73	69
1	15.0	81	72	69	0.0	76	73	71	6.9	77	73	71	0.0	79	72	69
2	3.5	79	71	68	0.0	75	72	71	4.6	77	73	71	0.0	79	72	69
3	6.9	79	71	68	2.3	74	71	71	4.6	76	72	71	0.0	79	72	69
4	4.6	78	71	68	0.0	74	72	71	3.5	76	73	71	0.0	78	72	69
5	9.2	78	71	68	0.0	75	72	71	0.0	75	72	71	0.0	78	72	69
6	0.0	78	71	68	2.3	74	72	71	4.6	75	72	71	0.0	77	71	69
7	3.5	80	72	69	0.0	75	73	72	0.0	78	73	71	0.0	79	72	68
8	0.0	82	73	69	0.0	77	74	72	6.9	84	74	70	0.0	84	73	69
9	4.6	81	73	70	4.6	81	74	71	6.9	86	75	71	0.0	89	74	68
10	5.8	82	73	70	5.8	84	75	71	9.2	87	74	69	2.3	91	75	68
11	4.6	84	73	69	3.5	85	75	71	6.9	89	75	78	0.0	93	75	68
12	3.5	88	74	69	6.9	88	77	73	6.9	91	74	68	6.9	95	75	67
13	5.8	90	76	70	6.9	88	76	71	5.8	92	75	67	3.5	96	74	64
14	3.5	91	76	70	6.9	89	76	70	9.2	94	75	68	4.6	96	73	63
15	5.8	92	76	69	8.1	88	75	70	2.3	94	75	67	0.0	97	74	63
16	5.8	93	76	69	9.2	87	75	71	3.5	94	76	68	8.1	98	74	63
17	9.2	92	77	71	10.4	87	74	69	0.0	94	75	67	6.9	98	74	63
18	5.8	91	76	71	9.2	85	75	71	6.9	92	75	67	6.9	96	75	65
19	11.5	85	73	67	6.9	84	75	71	6.9	91	74	66	0.0	94	74	65
20	6.9	81	73	70	6.9	84	74	70	2.3	89	74	67	0.0	91	74	67
21	4.6	78	74	72	5.8	83	75	71	3.5	87	74	68	0.0	89	73	67
22	3.5	77	75	74	3.5	82	74	70	0.0	85	73	68	3.5	87	73	67
23	2.3	77	74	73	5.8	80	73	69	0.0	85	73	69	10.4	84	73	69

Table 9.2-16
HISTORICAL WEATHER DATA
WORST RECORDED MINIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
JULY 30, 1955, THROUGH AUGUST 27, 1955 (Sheet 8 of 8)

Time (hrs)	8-27-55 Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
0	5.8	84	74	69
1	6.9	83	73	69
2	4.6	81	72	69
3	6.9	79	72	70
4	8.1	78	71	69
5	9.2	77	71	69
6	4.6	77	72	69
7	5.8	81	73	69
8	6.9	83	72	69
9	6.9	86	74	66
10	5.8	89	75	68
11	5.8	92	75	69
12	9.2	94	75	68
13	6.9	96	74	66
14	6.9	97	75	63
15	4.6	99	75	64
16	3.5	100	75	64
17	5.8	99	75	64
18	5.8	98	74	64
19	3.5	96	74	64
20	0.0	92	73	65
21	4.6	89	71	63
22	4.6	85	72	66
23	5.8	83	72	67

Table 9.2-17
HISTORICAL WEATHER DATA
WORST RECORDED MAXIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES, AUGUST 23, 1969, AND JULY 12, 1971, THROUGH AUGUST 9, 1971 (Sheet 1 of 4)

Time (hrs)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
Date	8-23-69				7-12-71				7-13-71				7-14-71			
0	16.1	87	73	67	5.8	91	63	42	3.5	91	70	58	6.9	94	70	56
3	13.8	90	70	59	8.1	87	68	39	6.9	87	68	58	9.2	87	67	56
6	13.8	95	71	58	9.2	90	66	51	6.9	92	70	59	8.1	93	69	55
9	9.2	104	74	59	9.2	102	70	50	11.5	101	72	55	11.5	100	71	55
12	6.9	110	75	57	11.5	108	72	50	10.4	107	72	51	15.0	105	74	57
15	24.2	99	73	61	13.8	111	72	50	13.8	110	73	52	13.8	107	74	57
18	16.1	95	72	61	9.2	107	71	50	5.8	108	73	53	11.5	104	72	55
21	15.0	88	72	64	11.5	98	70	55	12.7	101	69	49	8.1	96	70	56
Date	7-15-71				7-16-71				7-17-71				7-18-71			
0	15.0	93	70	58	6.9	91	70	59	9.2	79	72	69	6.9	91	71	60
3	9.2	86	68	58	10.4	87	69	60	8.1	80	71	67	3.5	86	70	61
6	10.4	90	71	62	11.5	92	71	60	5.8	86	71	64	4.6	91	71	61
9	9.2	96	71	57	15.0	98	72	59	8.1	95	73	62	9.2	100	73	59
12	12.7	103	74	58	13.8	103	73	57	11.5	102	73	58	15.0	106	74	57
15	13.8	105	73	56	13.8	105	73	55	15.0	103	75	61	15.0	108	74	55
18	15.0	101	73	57	21.5	85	72	66	10.4	99	73	61	12.7	105	72	53
21	15.0	95	71	58	4.6	85	73	67	9.2	94	72	60	9.2	98	70	55

Table 9.2-17
HISTORICAL WEATHER DATA
WORST RECORDED MAXIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
AUGUST 23, 1969, AND JULY 12, 1971, THROUGH AUGUST 9, 1971 (Sheet 2 of 4)

Time (hrs)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
Date	7-19-71				7-20-71				7-21-71				7-22-71			
0	11.5	89	69	57	13.8	79	72	68	3.5	89	71	62	12.7	87	72	65
3	10.4	84	68	59	5.8	79	72	69	5.8	84	71	64	5.8	84	72	67
6	8.1	90	69	57	8.1	86	71	64	8.1	90	71	61	6.9	88	72	65
9	10.4	100	72	57	12.7	94	73	63	8.1	99	73	60	4.6	94	74	64
12	11.5	106	73	55	13.8	103	74	58	13.8	107	74	57	13.8	102	75	61
15	12.7	108	74	55	12.7	105	72	54	13.8	107	74	56	13.8	105	74	57
18	9.2	103	72	54	8.1	102	72	55	13.8	105	73	56	13.8	100	75	58
21	12.7	81	72	68	4.6	92	70	58	12.7	97	73	62	12.7	94	71	59
Date	7-23-71				7-24-71				7-25-71				7-26-71			
0	5.8	90	72	63	8.1	91	69	57	10.4	90	72	63	8.1	93	69	56
3	8.1	88	71	62	6.9	86	70	62	5.8	88	71	62	4.6	91	69	57
6	6.9	90	72	63	6.9	89	72	63	5.8	88	70	61	9.2	90	69	57
9	10.4	98	73	61	13.8	98	72	58	9.2	96	64	54	4.6	100	71	55
12	9.2	105	75	60	9.2	104	72	54	12.7	104	73	56	11.5	106	72	53
15	23.0	100	71	55	11.5	107	72	51	15.0	106	73	54	9.2	108	72	50
18	4.6	96	69	54	8.1	103	72	55	11.5	103	71	53	0.0	106	71	49
21	8.1	93	70	57	10.4	98	71	56	10.4	97	70	55	5.8	97	69	52

Table 9.2-17
HISTORICAL WEATHER DATA
WORST RECORDED MAXIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
AUGUST 23, 1969 AND JULY 12, 1971, THROUGH AUGUST 9, 1971 (Sheet 3 of 4)

	8-7-55				8-8-55				8-9-55				8-10-55			
Time (hrs)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
Date	7-27-71				7-28-79				7-29-71				7-30-71			
0	9.2	92	69	57	12.7	93	68	55	11.5	92	73	63	4.6	93	73	63
3	11.5	90	69	57	10.4	90	69	57	6.9	88	71	63	5.8	91	71	60
6	9.2	93	71	59	5.8	91	70	59	10.4	91	72	63	13.8	91	72	63
9	5.8	101	71	54	11.15	98	74	62	6.9	97	74	63	8.1	94	73	62
12	9.2	106	73	54	12.7	104	74	58	13.8	104	75	61	11.5	102	74	60
15	10.4	108	72	52	11.5	106	74	58	13.8	106	76	61	10.4	103	75	61
18	25.3	102	69	48	10.4	103	73	57	10.4	102	74	59	13.8	99	73	60
21	9.2	97	68	50	13.8	97	73	62	10.4	98	74	62	5.8	92	70	59
Date	7-31-71				8-1-71				8-2-71				8-3-71			
0	21.9	82	70	64	8.1	86	70	62	17.3	89	68	56	9.2	88	69	59
3	13.8	79	70	65	23.0	87	71	62	15.0	82	68	61	15.0	85	68	59
6	6.9	83	70	63	16.1	87	71	62	6.9	89	68	56	8.1	88	70	61
9	8.1	92	70	59	11.15	96	72	60	8.1	96	71	57	13.8	97	73	62
12	8.1	101	73	59	6.9	103	74	58	10.4	103	73	56	13.8	102	75	62
15	6.9	103	72	55	6.9	105	74	57	6.9	106	73	56	11.5	104	74	59
18	9.2	103	73	56	6.9	100	73	58	5.8	102	72	56	17.3	101	74	61
21	17.3	96	73	61	8.1	93	71	60	12.7	94	71	59	10.4	76	71	69

Table 9.2-17
HISTORICAL WEATHER DATA
WORST RECORDED MAXIMUM DIFFERENCE BETWEEN DRY BULB AND DEWPOINT TEMPERATURES,
AUGUST 23, 1969, AND JULY 12, 1971, THROUGH AUGUST 9, 1971 (Sheet 4 of 4)

Time (hrs)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)	Wind Speed (mph)	Dry Bulb (°F)	Wet Bulb (°F)	Dew-Point (°F)
Date	8-4-71				8-5-71				8-6-71				8-7-71			
0	5.8	75	70	68	3.5	88	71	63	18.4	77	72	69	6.9	85	75	70
3	8.1	74	70	68	3.5	83	70	64	5.8	78	72	70	7.2	82	74	70
6	5.8	80	72	69	3.5	89	72	63	10.4	81	72	68	9.2	87	73	67
9	4.6	89	71	61	5.8	98	72	54	10.4	90	73	65	9.2	97	72	59
12	10.4	96	74	63	5.8	103	72	54	6.9	97	72	60	5.8	101	70	52
15	9.2	97	72	60	9.2	102	74	60	9.2	99	73	60	10.4	100	71	55
18	8.1	93	71	59	8.1	100	72	57	6.9	95	74	64	0.0	95	71	59
21	9.2	90	71	62	15.0	96	72	59	6.9	90	74	67	8.1	91	69	57
Date	8-8-71				8-9-71											
0	12.7	85	72	66	15.0	87	73	66								
3	0.0	82	71	66	6.9	82	70	64								
6	0.0	87	71	63	9.2	87	71	63								
9	9.2	96	72	59	6.9	93	73	63								
12	9.8	101	73	59	10.4	101	76	64								
15	12.7	103	74	58	13.8	103	74	60								
18	8.1	99	72	59	11.5	100	72	57								
21	4.6	96	71	57	20.7	92	72	62								

In the evaluation of the minimum and maximum difference between the dry bulb and dewpoint temperatures, the moisture content of the air and the mass of water required to saturate the air at each time-dependent meteorology data point was calculated. The relative humidity of the air was determined from a correlation of dry bulb and wet bulb temperatures, wet bulb temperature depression, and relative humidity. The partial pressure of saturated steam at the dry bulb temperature was obtained from the ASME steam tables. The specific humidity of the saturated air was calculated using Dalton's Law by the equation:

$$W = \frac{Pv \quad Mw}{(P_t - P_v)\ M_a} \qquad (9.2\text{-}1)$$

where P_v is the partial pressure of the moisture M_w and M_a are respectively the mole weight of steam and air and P_t is the sum of the moisture and air partial pressures. The moisture in the air is the product of the values for the relative and specific humidities. The moisture required to saturate the air is the difference between the specific humidity and the moisture in the air.

The effect of the wind on the evaporation rate of water was evaluated by determining the effect of the wind speed on the equilibrium temperature of a pond in accord with methodology of Brady, Graves, and Geyer.[2]

The mass of water leaving the pond due to the surface heat exchange was combined on a weighted basis with the mass of water required to saturate the air and used to screen the data for the maximum and minimum effects. This combined effect was not evaluated against the effect due to drift loss,

recirculation rate, time the sprays are operating, and wind speed. The detailed analysis indicates that the combined effect selected for the evaluation results in satisfying the intent of the guide.

9.2.5.3.2 ESP Design Methodology

The equations derived by Merkel[3] for the passage of heat from the water to the air are applicable to the calculation of the thermal performance of a spray pond. However, insufficient information concerning the flow of air, the amount of surface area per unit volume for heat exchange, and the variation of wet bulb temperature across the sprayed area prohibit the evaluation of the equations. Hence, the performance of a spray pond is calculated by the equation:

$$\varepsilon = \frac{T_{in} - T_{out}}{T_{in} - T_{wb}} \qquad (9.2\text{-}2)$$

where the efficiency, ε, is an experimentally determined function of windspeed and:

T_{wb} is the average ambient wet bulb temperature

T_{in} is the water temperature leaving the spray nozzles

T_{out} is the sprayed water temperature just before impacting the pond surface

The sprayed water evaporation loss, L_o, is calculated by the equation:

$$L_o = (T_{in} - T_{out})\ L\ C/h_{fg} \qquad (9.2\text{-}3)$$

where the latent heat of evaporation, h_{fg}, is evaluated from the ASME steam tables at the average value of T_{in} and T_{out} and

L is the recirculation rate of the spray pond water

C is the specific heat of water

The spray pond water drift loss is calculated from the product of the drift loss fraction and the spray flowrate where the drift loss fraction is an experimentally determined function of windspeed.

The spray nozzle efficiency and drift loss fraction correlations used for the PVNGS ESP design are those generated by testing of the Rancho Seco Nuclear Power Station spray pond(1). The PVNGS design uses the same nozzle and nozzle flowrate, spacing, and height used in the Rancho Seco design; in addition, pond boundary extensions beyond the spray pattern envelope are similar.

Convective heat transfer between ambient air and the sprayed water is included in the spray nozzle efficiency. When the sprayed water temperature exceeds the ambient air temperature (dry bulb) convective heat transfer provides a cooling effect without a corresponding evaporative mass loss. Equation 9.2-3, which attributes all spray cooling to evaporation, is conservative under these conditions which are generally prevalent for most spray pond applications. However, at the Palo Verde site there are times during the warm part of the year, specifically during the design basis meteorological conditions, when the average ambient air temperature will exceed the sprayed water temperature. Under these conditions, convective heat transfer will occur from the air to the sprayed

water causing additional evaporative water losses not computed by equation 9.2-3. The design basis water consumption analysis for PVNGS include: an added evaporative water loss term, L_s, due to sensible heat transfer calculated from:

$$L_s = hA_d \overline{\Delta T}_{aw}/h_{fg} \qquad (9.2\text{-}3A)$$

where:

- h is the air-to-water droplet convective heat transfer coefficient
- A_d is the droplet surface area of the total spray field
- $\overline{\Delta T}_{aw}$ is the average air-to-water droplet temperature difference
- h_{fg} is the latent heat of vaporization as used in equation 9.2-3

Net air-to-sprayed water sensible heat transfer does not begin until several days post-LOCA when the forced heat load on the spray pond has declined to a level where the spray water temperature is less than the average air temperature.

The equilibrium temperature of the pond both initially and throughout the transient is calculated by the equations:[2]

$$T_a = (T_s + T_{dp})/2 \qquad (9.2\text{-}4)$$

$$\beta = 0.255 - 0.0085T_a + 0.000204T_a^2 \qquad (9.2\text{-}5)$$

$$f(U) = 70 + 0.7U^2 \qquad (9.2\text{-}6)$$

$$K = 15.7 + (\beta + 0.26)\, f(U) \qquad (9.2\text{-}7)$$

$$E = T_{dp} + H_s/K \qquad (9.2\text{-}8)$$

where:

T_a is an average water temperature for use in equation 9.2-5

T_s is the water surface temperature

T_{dp} is the dewpoint temperature

β is the slope of the saturated vapor pressure curve

U is the windspeed

K is the surface heat exchange coefficient

E is the equilibrium temperature

H_s is the solar radiation

The equations are solved by an iterative procedure to obtain a value for T_s which is approximately equal to the equilibrium temperature, E. The heat exchange with the environment for the maintenance of the equilibrium temperature is calculated by the equation:

$$H_e = \frac{(K - 15.7)\,\beta\,(E - T_{dp})}{24(0.26 + \beta)} \qquad (9.2\text{-}9)$$

The mass evaporated from the pond for the maintenance of the equilibrium temperature is calculated by the equation:

$$M_e = H_e A/h_{fg} \qquad (9.2\text{-}10)$$

where the latent heat of vaporization, h_{fg}, is evaluated from the ASME steam tables at the dewpoint temperature and A is the surface area of the pond. The heat exchange with the environment due to the temperature excess resulting from the thermal load is calculated by the equation:

$$H_x = \frac{(K - 15.7)\ \beta\ (T_p - E)}{24(0.26 + \beta)} \qquad (9.2\text{-}11)$$

where:

T_p is the pond temperature

The mass evaporated from the pond due to the thermal load heat exchange is calculated by the equation:

$$M_x = H_x A/h_{fg} \qquad (9.2\text{-}12)$$

where the latent heat of vaporization, h_{fg}, is evaluated from the ASME steam tables at the pond temperature, T_p, and A is the surface area of the pond.

During the time that the sprays are operating, the thermal load is dissipated to the air by the sprays and the surface heat exchange of the unsprayed area. During the time when the sprays are not operating, a part of the thermal load is dissipated to the atmosphere by the surface heat exchange of the total pond area, whereas the remainder goes into raising the spray pond temperature.

9.2.5.4 Safety Evaluation

Safety evaluations are as follows:

A. Safety Evaluation One

The combined available water inventory of the two essential spray ponds is a minimum of 87.734 x 10^6 pounds which is equivalent to a water depth of 12.0 feet. This water capacity would be depleted following a design basis LOCA in 26 days without water makeup under the

worst historical meteorological condition listed in table 9.2-17, assuming both spray pond trains operate for the first 24hours post-LOCA followed by single train operation for the remaining 25 days. Continuous spraying of the warm return water is assumed at all times that a spray pond is in operation. The water requirements for 30 days operation under the meteorological conditions of table 9.2-17 for each ESP is given in table 9.2-18. Credit is taken for the ability to utilize water from one ESP in the other of the same unit. Establishment of makeup capability within 26 days vs. 30 days meets the intent of Regulatory Guide 1.27 (see paragraph 9.2.5.4, listing C).

Table 9.2-18

WATER CONSUMPTION FOR 30 DAYS

Meteorology	Train A lb x 10^6	Train B lb x 10^6	Total lb x 10^6
Table 9.2-17	92.3	4.8	97.1

The total sprayed area of each essential spray pond is approximately 32,500 square feet which is sufficient to maintain the ECWS temperature into the SDC heat exchanger at 135F or less, following the design basis LOCA under the worst historical meteorological conditions listed in table 9.2-16.

In determining the maximum heat load from a postulated LOCA required to be dissipated by the ESP, it is assumed

that both diesels are operating and that all safety trains are operating for the first 24 hours post-LOCA. For the remaining 29 days, it is assumed that only one ESPS train and one safety train are operating, with the exception of two HPSI pumps, and that both spray ponds are cross-connected for maximum usable mass inventory. This mode of operation ensures maximum heat removal from the core and maximum heat load on one ESPS train.

The postulated LOCA is the double-ended discharge leg slot break with maximum safety injection which is shown in subsection 6.2.1 to impose the design energy load on the ESPS. The constant heat loads on train A and train B of the ESPS are those due to equipment cooling and pump operation and are given in table 9.2-19. The blowdown energy from the design basis LOCA that is dissipated by the ESPS is given in subsection 6.2.1. For the double-ended suction leg slot break, the total energy discharged to the pond in the 30-day period is the same.

The decay heat is computed from the equations given in Branch Technical Position ASB 9-2, Residual Decay Energy for Light-Water Reactors for Long-Term Cooling. Assumptions for the decay heat calculation include 100% reactor power, and fission product uncertainty factors of +20% for decay times less than or equal to 1000 seconds and +10% for decay times greater than 1000 seconds. The assumed operating cycle is 13,200 hours of full power operation per cycle, with 110 assemblies irradiated 3 full cycles, 110 assemblies

irradiated 2 full cycles, and 21 assemblies irradiated 1 full cycle.

The total energy released to the spray ponds following the DBA for the 0 to 30-day design basis water consumption analysis is given in table 9.2-19. Table 9.2-20 gives maximum daily temperatures for this analysis for an analyzed core power of 4070 MWt.

B. Safety Evaluation Two

1. The ESP is a Seismic Category I structure. A discussion of the seismic analysis used in the design of the ESP is given in section 3.8.

   It is highly improbable that a tornado and DBA would occur simultaneously and, therefore, no water allowance or protection of the spray headers is provided. For the more probable case of a tornado occurring simultaneously with a normal shutdown, the ESP pumps and lines are protected against a tornado.

   Since the makeup water lines to the ESP are underground and two independent onsite sources of water are available, a tornado would not impair the essential function of the ESP.

   Flood design considerations for the ESP are discussed in subsection 2.4.10. Freezing design considerations for the ESP are discussed in subsection 2.4.7.

Table 9.2-19

ENERGY RELEASED TO PONDS FROM 0 TO 30 DAYS (Sheet 1 of 3)

Parameter	Energy (10^6 Btu)
Initial containment Energy inventory (avg. temp = 120F)	
Primary coolant	407.0
Safety injection tank water	42.4
Fuel	13.2
Vessel shell	93.5
Vessel internals	32.0
RCS Loop metal	130.5
Steam generator secondary coolant	237.5
Steam generator tube metal	39.0
Steam generator secondary walls	69.8
Main steam line inventory to MSIV's	4.9
Containment vapor region	0.6
Refueling water tank	199.6
Total	1,270.0
Residual containment energy inventory, 30-day post-accident	
Sump	265.4
Vapor	4.5
Reactor coolant below primary nozzles	20.1
RCS sensible energy	325.8[a]
Containment structure (avg. temp. < 120F)	-720.8
Total	-105.0

(a) Includes SG sensible energy release.

Table 9.2-19

ENERGY RELEASED TO PONDS FROM 0 TO 30 DAYS (Sheet 2 of 3)

Parameter	Energy (10^6 Btu)
Sensible and decay heat[(b)] transferred to ESP train A (0 to 720 hours)	28,332.0
Train A auxiliary equipment heat loads (0 to 720 hours)	18,831
Total heat transferred to ESP train A (0 to 720 hours)	47,163
Sensible and decay heat[(b)] transferred to ESP train B (0 to 24 hours)	1,546
Train B auxiliary equipment heat loads (0 to 24 hours)	575
Total heat transferred to ESP train B (0 to 24 hours)	2,121

(b) Including spent fuel pool decay heat.

Table 9.2-19

ENERGY RELEASED TO PONDS FROM 0 TO 30 DAYS (Sheet 3 of 3)

Notes:

1. Train A operated for 30 days; train B operated only first 24 hours post-LOCA.

2. Auxiliary heat loads (10^6 Btu/hr):

	Train A	Train B
0 to 1403 seconds	27.08	27.08
1403 sec to 1 day	25.95	25.95
1 day to 30 days	30.23	0

3. Auxiliary heat loads include (10^6 Btu/hr/train):

High-pressure SI pump	2.28
Low-pressure SI pump	1.13[(a)]
Containment spray pump	1.60
Spent fuel pool pump	0.19
Spent fuel pool decay heat	4.00[(b)]
ECWS pump	1.84
ESPS pump	1.48
Essential chiller	4.16
Diesel generator cooling system	12.40

a. Low-pressure safety injection pump off after containment sump recirculation at 1438 (1403) seconds.

b. Spent fuel pool in 4 out of 4 configuration and filled to capacity except for 241 spaces for fuel assemblies just loaded in reactor (just after last refueling outage prior to exceeding the spent fuel pool capacity). Value represents a bounding end-of-cycle spent fuel decay heat load. Also, see note for Table 9.2-1.

Table 9.2-20

30-DAY MAXIMUM DAILY TEMPERATURE (F)[a]
ANALYZED CORE POWER OF 4070 MWt (SHEET 1 OF 2)

Day	Leaving ECWS Hx	Sprayed Water	Water Entering Spray Pond	Water Leaving Spray Pond
1[b]	103	103	90	92
2	94	94	84	82
3	95	95	87	84
4	94	94	85	84
5	91	91	83	82
6	89	90	82	80
7	89	89	83	81
8	89	90	83	82
9	87	88	81	80
10	87	88	82	81
11	88	89	82	82
12	88	89	81	81
13	87	88	82	81
14	86	87	81	80
15	86	87	81	80
16	86	86	81	79
17	85	86	80	79
18	84	85	79	78
19	86	87	81	80

a. Daily maxima not necessarily coincident.
b. Two ponds operating during day 1; single pond operation days 2 through 30.

Table 9.2-20

30-DAY MAXIMUM DAILY TEMPERATURE (F)[a]
ANALYZED CORE POWER OF 4070 MWt (SHEET 2 OF 2)

Day	Leaving ECWS Hx	Sprayed Water	Water Entering Spray Pond	Water Leaving Spray Pond
20	87	88	82	81
21	85	86	79	79
22	84	85	78	78
23	83	84	80	78
24	83	84	78	78
25	85	86	81	80
26	87	88	82	82
27	85	86	82	80
28	87	88	82	82
29	86	88	82	82
30	86	87	82	81

No credit is taken for possible rainfall in the design of the ESP minimum water inventory. The water level available at the intake of the makeup lines from the plant water wells during severe drought conditions is discussed in subsection 2.4.11. Under these drought conditions, submergence of the intake ensures an uninterrupted supply of makeup, notwithstanding that there is sufficient water available in the two ESPs for heat dissipation for a minimum of 26 days.

2. The probability that an aircraft will impact PVNGS is discussed in section 2.2. The existing rail spur is not considered a credible origin for an ESP incapacitating accident since it is used infrequently and is removed from the vicinity of the ESP. The physical remoteness of the ESP to the avenues of bulk petroleum transportation makes massive fouling of the ESP surface by an oil spill incredible.

   Inasmuch as the ESP and related equipment are largely heat resistant or noncombustible, a fire would have minimal impact upon safe shutdown cooling. Fire protection for the ESPS intake structures is provided as discussed in subsection 9.5.1.

3. The possible failure of a single structure cannot result in the loss of the ESP safety function. The redundant valves between the two ESPs provide the

capability to supply cooling water flow in the event of the failure of one intake.

4. The ESP integrity is not impaired by missile accident as discussed in section 3.5.

C. Safety Evaluation Three

Provisions for assuring the continued cooling capability beyond the nominal 30-day requirement of Safety Design Basis One have been included.

1. Two separate makeup water lines are provided to each ESP from the following independent water sources:

   - Domestic water system
   - Station makeup water reservoir via cooling tower makeup and blowdown system

   The domestic water system is supplied with water from onsite wells. The cooling tower makeup and blowdown system is supplied with water from the station makeup water reservoirs. The reservoirs are 45-acre (normal operating level capacity – 1023 acre – feet) and 85-acre (normal operating level capacity – 2191 acre-feet) and are excavated impoundments (below grade); reservoir water will be available even if the retaining walls fail.

2. Procedures for ensuring the continuing capability of the ESPs by specifying detailed steps needed to replenish the ESPs from primary and backup water sources, as recommended by the regulatory position

of Regulatory Guide 1.27, is available onsite for NRC review.

D. Safety Evaluation Four

The heat rejection capability of the ESP in conjunction with the ESPS is sufficient to provide for the safe shutdown and cooldown of the unit and to maintain it in a safe shutdown condition during and following a normal plant shutdown. Two separate and redundant ESPS trains are provided, along with two essential spray ponds, and each train alone has a full 100% heat dissipation capacity for a safe shutdown.

9.2.5.5 Tests and Inspections

Refer to section 14.2 for a discussion of preoperational test procedures. Refer to the Technical Specifications for a description of periodic surveillance testing.

9.2.5.6 Instrumentation Applications

The water level in the ESP is monitored continuously so that there is always sufficient water to ensure the continuous capability of the ESP to perform its safety functions. The water temperatures of the ESP are also monitored.

9.2.6 CONDENSATE STORAGE FACILITY

The condensate storage facility is the primary source of demineralized water for the auxiliary feedwater system, which uses it for removal of reactor decay heat during a hot standby condition and for cooling the reactor to the point where the shutdown cooling system can assume the heat load. The facility

is a redundant source of demineralized water makeup for the essential cooling water system, essential chilled water system, diesel generator system, and the spent fuel pool. It also maintains proper feedwater inventory in the secondary system during startup, shutdown, hot standby, and normal power generation operations. The condensate storage facility may not be available for severe accident scenarios where condensate is depleted by the Auxiliary Feedwater system prior to a demand for makeup from the essential cooling water system, essential chilled water system, or the diesel generator system. The essential cooling water system, essential chilled water system, and the diesel generator system are designed to be capable of operating for a minimum period of 24 hours without makeup from the condensate storage facility. (Refer to appendix 5A, Question 5A.17, for additional discussion.)

9.2.6.1 Design Bases

9.2.6.1.1 Safety Design Bases

The safety design bases for the condensate storage facility are as follows:

A. Safety Design Basis One

   Those portions of the condensate storage system required for maintaining a hot standby condition and for an orderly reactor cooldown must remain functional during and after an SSE.

B. Safety Design Basis Two

   Adverse environmental occurrences shall not impair the ability of those portions of the condensate storage

facility required to maintain the reactor at a hot standby condition and to allow an orderly reactor cooldown.

C. Safety Design Basis Three

The condensate storage facility shall be designed to ensure a sufficient reserve of steam generator feedwater for use in maintaining a hot standby condition for 8 hours and for an orderly reactor cooldown in the event of main condenser unavailability.

9.2.6.1.2 Power Generation Design Basis

The applicable power generation design bases for the condensate storage facility are as follows:

A. Power Generation Design Basis One

The condensate storage facility will provide an initial fill for the condensate and feedwater system. It also will serve as a reservoir to supply or receive condensate as required by the main condenser hotwell level control system.

B. Power Generation Design Basis Two

The condensate storage tank shall be of sufficient capacity to supply the normal anticipated secondary system condensate demands for 3 days without replenishment from the demineralized water system or other source. This capacity is in addition to the maintained reserve of auxiliary feedwater inventory required for reactor shutdown and cooldown.

9.2.6.1.3 Codes and Standards

The condensate storage facility is constructed in accordance with applicable codes and standards identified in table 3.2-1. Those portions of the system required to satisfy the safety design bases are designated Seismic Category I.

Protection from wind and tornado effects is discussed in section 3.3. Flood design is discussed in 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with postulated systems of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

9.2.6.1.4 CESSAR Interface Requirements

Refer to subsection 5.1.4 and paragraph 9.3.4.1.

9.2.6.2 System Description

The condensate storage facility (engineering drawings 01, 02, 03-M-CTP-001) for each unit consists of one condensate storage tank, two parallel condensate transfer pumps, and associated piping, valves, instrumentation, and controls. A closed piping system is provided that collects overflow and drainage from the condensate tank and transfers it to the turbine building drainage system. The turbine building drains can be directed to the liquid radwaste system. The facility is located outdoors and is situated to permit gravity feed to the auxiliary feedwater pump suction and condenser hotwell.

The condensate storage tank is missile protected as it is a concrete tank with a steel liner provided to maintain water

quality. Since the tank liner is fabricated of ductile steel, fragmentation is unlikely. Piping penetrating the tank, whose failure could result in an insufficient supply of water, is protected from missiles by a concrete structure.

The portion of the stainless steel liner that is protected by the concrete wall could be damaged locally by a missile entering through the upper portion (roof) of the tank. In the event of local damage to the stainless steel liner below the top of the exterior concrete wall, significant water loss is not possible as the tank is designed as a Seismic Category I missile resistant barrier.

The concrete tank will ensure that a minimum of 300,000 gallons of water is available for a safe shutdown of the plant following 8 hours of hot standby.

Redundant, 100% capacity condensate transfer pumps provide demineralized water to their respective trains of the essential chilled water system, essential cooling water system, and diesel generator system. Either condensate transfer pump can be manually aligned to provide demineralized water to the spent fuel pool. Design data of the condensate storage facility are presented in table 9.2-21. The pumps are also powered by the onsite diesel generators.

The 520,000-gallon condensate tank is constructed with a stainless steel liner to minimize corrosion. The storage capacity provides a total of 300,000 gallons for 8 hours of reactor hot standby, followed by an orderly reactor cooldown to 350F, plus 220,000 gallons to satisfy the normal secondary system makeup demands. Prior to reactor startup, it provides

initial fill for the secondary system. Demineralized water is supplied to the condensate tank from the demineralized water system (refer to subsection 9.2.3) through an automatic control valve that maintains the water inventory in the tank within the capacities shown in table 9.2-21.

To maintain proper main condenser hotwell level, condensate is supplied from (or returned to) the condensate tank as required by the hotwell level control system.

The two condensate transfer pumps are each 100% capacity, with one operating as required and the second on standby.

Essential portions of the condensate storage facility are constructed in accordance with the ASME Code, Section III, Class 3, and are Seismic Category I.

Wherever practical, facility leakage is minimized by using welded connections. Leakage can be detected by visual inspections and by loss of tank inventory. Level detection drains are also located in the protective concrete structure housing the condensate transfer pumps. Tank penetrations at or below the 300,000-gallon level occur within this protective structure. Leakage from the pumps, piping, or tank penetrations will be detected and alarmed by the leak detection drains. Table 9.2-22 lists the Seismic Category I valves.

Table 9.2-21

CONDENSATE STORAGE SYSTEM DESIGN DATA

Condensate Tank	
Number of tanks per unit	1
Reserve capacity provided for hot standby and reactor cooldown, gal.	300,000
Storage capacity for condensate makeup, gal	220,000
Total capacity, gal. (Reserve capacity and condensate makeup)	520,000
Material	Concrete with stainless steel liner
Piping and Valves	
Material	Stainless steel
Design pressure, psig	150
Condensate Transfer Pumps	
Number of pumps per unit	2
Type of pumps	Horizontal centrifugal
Design flow/head	130 gal/min/61 ft
Material	Stainless steel

9.2.6.3 Safety Evaluation

Safety evaluations are numbered to correspond to the safety design bases.

A. Safety Evaluation One

As defined in section 3.2 and Table 3.2-1, the condensate tank, safety-related the piping to the auxiliary feedwater pump suctions and piping supporting other essential portions of the condensate facility are designed to Seismic Category I requirements.

B. Safety Evaluation Two

The condensate tank is a Seismic Category I structure and can withstand adverse environmental occurrences, including tornadoes, that could impair its ability to maintain the reactor at a hot standby condition and to allow an orderly reactor shutdown. The Seismic Category I piping is located below grade or within a protective concrete structure.

Should a seismic event occur when the nonseismic auxiliary feedwater pump is in service, the operator can take the necessary action to locally close one of the suction line valves should the line fail. This action will be taken in sufficient time to prevent a significant loss of water from the condensate storage tank.

Table 9.2-22

CONDENSATE STORAGE FACILITY SEISMIC CATEGORY I VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-CTP-001) (Sheet 1 of 3)

Valve Tag Number	Location	Valve Type	Line Size Inches	Actuator Type	Valve Classification[(a)]
CT-V009	Condensate tank drain line	Gate	6	Hand	N
CT-V013	Level controller root valve	Globe	2	Hand	N
CT-V014	Auxiliary feedwater pump isolation valve	Gate	8	Hand	N
CT-V015	Auxiliary feedwater pump isolation valve	Gate	8	Hand	N
CT-V016	Condensate transfer pump discharge for essential cooling water system	Check	3	None	N
CT-V017	Condensate transfer pump discharge to essential cooling water system	Gate	3	Hand	N

a. An “A” indicates an active valve, and an “N” a nonactive valve, as discussed in section 3.9.

Table 9.2-22

CONDENSATE STORAGE FACILITY SEISMIC CATEGORY I VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-CTP-001) (Sheet 2 of 3)

Valve Tag Number	Location	Valve Type	Line Size Inches	Actuator Type	Valve Classification[(a)]
CT-V018	Condensate transfer pump discharge to fuel pool	Gate	3	Hand	N
CT-V019	Condensate transfer pump discharge to fuel pool	Gate	3	Hand	N
CT-V020	Condensate transfer pump discharge to essential cooling water system	Check	3	None	N
CT-V021	Condensate transfer pump discharge to essential cooling water system	Gate	3	Hand	N
CT-V022	Condensate tank to transfer pump suction	Gate	3	Hand	N
CT-V023	Condensate tank to transfer pump suction	Gate	3	Hand	N
CT-V024	Tank enclosure drain line	Check	4	None	N
CT-V025	Level controller root valve	Gate	2	Hand	N
CT-V028	Transfer pumps to storage tank	Gate	1	Hand	N
CT-V029	Transfer pumps to storage tank	Gate	1	Hand	N

Table 9.2-22

CONDENSATE STORAGE FACILITY SEISMIC CATEGORY I VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-CTP-001) (Sheet 3 of 3)

Valve Tag Number	Location	Valve Type	Line Size Inches	Actuator Type	Valve Classification[a]
CT-V031	Tank sample line	Globe	1	Hand	N
CT-V033	Transfer pump to storage tank	Globe	1	Hand	N
CT-V034	Tank enclosure drain line	Gate	4	Hand	N
CT-V035	Level switch root valve	Globe	1	Hand	N
CT-V036	Level switch root valve	Globe	1	Hand	N
CT-V037	Transfer pump to fuel pool	Check	3	Hand	N
CT-V038	Transfer pump to fuel pool	Check	3	Hand	N
CT-V042	Transfer pump to condensate tank	Globe	3	Hand	N
CT-V055	Tank drain to condenser hotwell	Gate	6	Hand	N
CT-V056	CST Drain Isolation Valve	Gate	6	Hand	N
CT-V057	CST Drain Storz Riser Isolation	Gate	6	Hand	N
CT-HV-1	Auxiliary feedwater pump suction	Butterfly	10	Motor	A
CT-HV-4	Auxiliary feedwater pump suction	Butterfly	10	Motor	A

C. Safety Evaluation Three

A total of 300,000 gallons of condensate is provided for maintaining the plant at hot standby for 8 hours followed by cooling the reactor to 350F, at which point the shutdown cooling system assumes the heat load. The piping that supplies the secondary system enters the tank at an elevation such that 300,000 gallons of usable water is reserved. This ensures a sufficient supply to the auxiliary feedwater pumps. A separate line is connected to the tank at a lower elevation to supply the auxiliary feedwater pumps with the reserved water supply. A single active failure analysis for the condensate storage facility is provided in table 9.2-23.

9.2.6.4 CESSAR Interface Evaluation

Refer to subsection 5.1.5 and paragraph 9.3.4.2.

9.2.6.5 Tests and Inspections

Preoperational testing is performed in accordance with the test descriptions of section 14.2. Periodic surveillance testing is described in the Technical Specifications.

The regular sampling of condensate storage tank contents ensures that the limits for radioactive concentrations are not exceeded.

9.2.6.6 Instrumentation Applications

A flow transmitter with output to the computer is provided on the condensate tank fill line.

A level detection system is installed on the condensate tank with level signals transmitted to the automatic tank level controller. Level indication is provided locally, in the control room, and at the remote shutdown panel. Low and high level alarms are provided in the control room. The low level alarms will annunciate to inform the opertors prior to the tank contents dropping below the following conditions. The setpoint calculations for these alarms include Total Plant Uncertainties and additional margin:

- The minimum normal operating level as defined in Section 9.2.6.2
- The minimum level required to maintain a hot standby condition for 8 hours followed by an orderly reactor cooldown as defined in Section 9.2.6.3.C.
- The volume of water required to provide operators time (20 minutes) to anticipate the need to either make-up water or transfer to an alternate water supply. This is approximatley 34,400 gallons.

9.2.7 SHUTDOWN COOLING SYSTEM

Refer to subsection 5.4.7.

Table 9.2-23

CONDENSATE STORAGE FACILITY SINGLE FAILURE ANALYSIS

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Condensate transfer pump	Inoperable/ mechanical or electrical failure	Low level in essential cooling, essential chilled, and diesel generator cooling water surge tanks	Low level alarm in surge tank	Redundant pump running on standby diesel generator train	There are redundant systems
Transfer piping	Line break/ corrosion or mechanical damage	Low header pressure. Tank drained through break	Low tank level alarm. Leaking water collects in leak detection drains. Drain alarms	Leak isolated. Redundant train placed in operation	
Nitrogen regulator	Fails open/ material failure or binding	None	None	Redundant breather valves discharge excess pressure	
Nitrogen regulator	Fails closed/ material failure or binding	None	None	Redundant breather valves open to equalize the tank	
NQR Piping	Line Break/Seismic Event	Low header pressure. Tank drained through break	Low tank level alarm. Leaking water collects in leak detection drains. Drain alarms	Redundant breather valves open to equalize the tank	
Breather valve	Fails closed/material failure or binding	None	None	Redundant breather valve opens to equalize vacuum	Single breather valve has the capacity to mitigate a concurrent nitrogen regulator failure.
Makeup water valve	Fails closed/ material failure or binding	Low level in storage tank	Low level alarms	Tank inventory maintained at adequate level. Only emergency services penetrate tank below 300,000 gal level	
Level control in storage tank	Fails to function/ material failure or mechanical bind	High level in storage tank	High level alarms	Overflow line	

9.2.8 TURBINE COOLING WATER SYSTEM

The turbine cooling water system (TCWS) provides cooling for the nonnuclear-related components in the various turbine plant auxiliary systems. Cooling is effected through heat exchangers with heat rejected to the PCWS. This closed cooling water system is used in lieu of direct cooling by the PCWS because the quality of the water being circulated in the PCWS could result in a greater tendency for equipment fouling and corrosion.

9.2.8.1 Design Bases

9.2.8.1.1 Safety Design Bases

The TCWS has no safety design bases.

9.2.8.1.2 Power Generation Design Bases

The TCWS is designed to cool the nonnuclear-related auxiliary components of the steam and power conversion system over the full range of normal plant operation.

9.2.8.1.3 Codes and Standards

The TCWS is designed in accordance with codes and standards set forth in table 3.2-1.

9.2.8.2 System Description

The TCWS is a single, closed-loop cooling water system. The TCWS includes two heat exchangers, two pumps, one surge tank, one chemical addition tank, piping, valves, instrumentation and controls (table 9.2-24).

The following components are cooled by the TCWS:

- Main turbine lube oil coolers
- Circulating water pump motor lube oil coolers
- Heater drain pump lube oil coolers
- Electrohydraulic control fluid coolers
- Air compressor coolers
- Feedwater pump turbine lube oil coolers
- Condensate pump motor lube oil coolers
- Gland steam packing exhauster
- Isolated phase bus cooling coils
- Main generator hydrogen coolers
- Main generator stator coolers
- Various nonnuclear-related sample coolers

Table 9.2-25 lists the above components, their heat loads, and associated cooling water requirements. In addition, table 9.2-25 cross-references the related systems and the sections where they are discussed.

The TCWS utilizes treated demineralized water to remove waste heat from the various nonnuclear-related components in the turbine plant. Refer to subsection 9.2.3 for the discussion of the demineralized water system. Discharge from the TCWS pumps supplies cooling water to the system's component coolers and returns to the TCWS heat exchangers where heat is rejected to the PCWS. A process and instrumentation diagram of the TCWS is provided in engineering drawings 01, 02, 03-M-TCP-001, -002 and -003.

9.2.8.2.1 System Operation

The TCWS is required only for power generation operations. Normally, one TCWS pump and heat exchanger are operating with a second pump and heat exchanger on standby. The standby pump is automatically brought online whenever the pump discharge header pressure falls below a preselected value. The redundant TCWS heat exchanger is placed in service manually. The surge tank is provided with a level control that signals a demineralized water makeup line control valve, which then actuates to maintain the required water level.

Instrumentation is provided for automatic temperature control of some components and manual control is provided for the other components.

9.2.8.3 Safety Evaluation

The TCWS has no safety function.

9.2.8.4 Tests and Inspections

Acceptance testing of this system is performed to demonstrate proper system and equipment function.

Table 9.2-24

TURBINE COOLING WATER SYSTEM EQUIPMENT DATA

Surge tank	
Number required	1
Design pressure, psig	150
Size, gallons	500
Material	Carbon steel
Chemical addition tank	
Number required	1
Design pressure, psig	150
Size, gallons	11
Material	Carbon steel
Pumps	
Number required	2
Design flow, gal/min	18,000
Design head, ft	135
Horsepower	800
Type	Horizontal centrifugal
Heat exchangers	
Number required	2
Type	Shell and tube
Tubeside	Plant cooling water system

Table 9.2-25

TURBINE COOLING WATER SYSTEM COMPONENT HEAT EXCHANGERS

Heat Exchanger	Quantity	Heat Load (ea) (10^6 Btu/hr)	Cooling Water Requirement (ea) (gal/min)	Related System	Related FSAR Section
Main turbine lube oil cooler	2	13.5	5,370	Turbine and auxiliary lube oil systems	10.2
Circulating water pump motor lube oil cooler	4	0.025	20	Circulating water system	10.4.5
Heater drain pump lube oil cooler	2	0.03	10	Feedwater heater extraction steam and drain system	10.4.7
Electro-hydraulic control cooler	2	0.065	30	Turbine control oil system	10.2
Instrument air compressor coolers	3	0.38	39	Instrument air system	9.3.1
Feedwater pump turbine lube oil cooler	4	0.495	242	Turbine and auxiliary lube oil systems	--
Condensate pump motor lube oil cooler	3	0.267	18	Condensate system	10.4.7
Main turbine gland steam exhauster	1	14.5	1,728	Turbine steam seal and drain system	10.4.3
Isolated phase bus cooling coils	1	1.58	185	--	--
Main generator hydrogen cooler	2 (Duplex)	14.0	1,964	Generator hydrogen system	10.2
Main generator stator cooler	2	8.3	2,050	Stator cooling system	10.2
Nonnuclear related sample cooler	4	0.50	10	Nonnuclear process sampling system	--
Service air system compressor coolers	1	0.62	42	Service air system	9.3.1

9.2.8.5 Instrumentation Application

Local temperature gauges and pressure/test points are provided for temperature and pressure determination. Indication of the surge tank level is provided locally. An alarm also is provided in the control room for high and low TCWS pump discharge pressure and high and low surge tank water level and pressure. Makeup water flow to the surge tank is initiated automatically by low surge tank water level and is continued until the normal level is reestablished.

9.2.9 CHILLED WATER SYSTEMS

Individual closed loop chilled water systems are provided for those buildings or rooms that require chilled water for air conditioning. Separate chilled water systems are provided for essential and normal use. There is no interconnection between essential and normal chilled water systems. The chilled water circulating loops are provided to remove the heat from the various heating, ventilating, and air conditioning (HVAC) systems, which are discussed in sections 6.4 and 9.4. The normal air handling units, which require chilled water for normal plant operation and normal shutdown (nonsafety-related operations), are indicated in engineering drawings 01, 02, 03-M-WCP-001 and are discussed in paragraph 9.2.9.1. The essential cooling units, which are used during safety-related operations and require chilled water, are indicated in engineering drawings 01, 02, 03-M-PWP-001 and are discussed in paragraph 9.2.9.2.

9.2.9.1 Normal Chilled Water System

The normal chilled water system provides the required chilled water flow for the following systems:

- Control building normal cooling system
- Containment building normal cooling system
- Auxiliary building cooling system
- Radwaste building control room cooling system
- Turbine building (various sampling points)

9.2.9.1.1 Design Bases

9.2.9.1.1.1 Safety Design Bases. There are no safety design bases for the normal chilled water system.

9.2.9.1.1.2 Power Generation Design Bases. The power generation design basis for the normal chilled water system consist of the following:

A. Power Generation Design Basic One

The normal chilled water system supplies chilled water to the various buildings listed in paragraph 9.2.9.1 during normal plant operating conditions to provide personnel comfort and the operating environment for equipment specified in section 9.4.

B. Power Generation Design Basis Two

The normal chilled water system supplies chilled water to the containment building air cooling units and to the charging pump rooms air cooling units in case of a forced shutdown with loss of offsite power.

9.2.9.1.1.3 Codes and Standards. The chilled water system is designed in accordance with codes and standards set forth in table 3.2-1.

9.2.9.1.2 System Description

The normal chilled water system is of the closed-loop type. It consists of chilled water refrigeration units (consisting of a compressor, evaporator, condenser/receiver unit, controls, and instrumentation), chilled water circulation pumps, an expansion tank, control valves, instrumentation, and insulated piping.

The system is furnished with three units of 50% capacity each (two operating and one on standby) and one unit of 213-ton capacity operating continuously in support of the two operating units. The condensers of all normal chiller units normally reject heat to the nuclear cooling water system. When the nuclear cooling water system is unavailable, the condensers reject heat to the essential cooling water system as discussed in subsection 9.2.2. The normal chilled water system supplies the chilled water to the cooling coils in the normal operating air handling units in the containment building, control building, radwaste building, auxiliary building, and nonnuclear process sampling system, as shown in engineering drawings 01, 02, 03-M-WCP-001.

The normal chilled water system operates during normal plant operation, during hot standby, and during programmed refueling or maintenance shutdown periods. Chilled water is circulated by the chilled water pumps from the chillers to the air cooling coils of the individual normal air handling units. Makeup water supply to the closed chilled water circulating loops of

the various systems is provided from the demineralized water system to the expansion tank in the loop.

Chilled water is provided for the containment building normal air cooling units and the charging pump rooms air cooling units in case of a forced shutdown with loss of offsite power.

9.2.9.1.2.1 Component Description. Design data for major components of the normal chilled water system are presented in table 9.2-26. The major components of the system are described below:

A. Chillers

   The chiller is of the self-contained package refrigeration unit type, consisting of a compressor, evaporator-cooler, condenser, oil lubricating system, oil cooler system, and controls.

B. Chilled Water Pump

   The chilled water pump is of centrifugal type.

C. Expansion Tank

   The expansion tank is a nitrogen charged water accumulator.

D. Piping, Valves, and Fittings

   Piping, valves, and fittings are supplied in accordance with table 3.2-1. Seismic Category I valves which are a part of the normal chilled water system are listed in table 9.2-27.

Table 9.2-26

NORMAL CHILLED WATER SYSTEM TABULATION

Component	Number of Units	Unit Capacity	Units Required for Operation	Remarks
Chillers	3	9.6×10^6 Btu/h, 800 tons	2	105 to 120F maximum temperature cooling water
Chilled water pumps	3	50 hp, 1200 gal/min	2	
Expansion tank	1	270 gal	1	
Chiller	1	2.556×10^6 Btu/h, 213 tons	1	105 to 120F maximum temperature cooling water
Chilled water pump	1	20 hp, 320 gal/min	1	

9.2.9.1.3 Safety Evaluation

The normal chilled water system has no safety function.

9.2.9.1.4 Tests and Inspections

Acceptance testing of this system is performed to demonstrate the proper system and equipment function.

9.2.9.1.5 Instrumentation Applications

An individual internal temperature and capacity controller which maintains a constant chilled water supply temperature is provided with each chiller unit. Flow switches prevent the chiller unit from operating unless there is water flow through the evaporator and condenser.

Makeup water for the chilled water system is controlled automatically by regulating the level in the expansion tank. Temperature and pressure indicators and test points are provided throughout the system to monitor operation and efficiency. Monitors, controls, and displays for the chilled water system are located in the control room and additional local display instruments are placed in the equipment areas for periodic checkout of the system.

9.2.9.2 Essential Chilled Water Systems

The essential chilled water system provides the required chilled water flow for the following systems:

- Control room essential ventilation system
- Electrical penetration room cooling system
- High pressure safety injection pump room cooling system

- Containment spray pump room cooling system
- Low pressure safety injection pump room cooling system
- Engineered safety features switchgear room cooling system
- Engineered safety features equipment room cooling system
- Auxiliary feedwater pump room cooling system
- Essential cooling water pump room cooling system

9.2.9.2.1 Design Bases

9.2.9.2.1.1 Safety Design Bases. The safety design bases for the essential chilled water system consist of the following:

A. Safety Design Basis One

The essential chilled water system is designed to provide chilled water to the air handling units of the systems listed in paragraph 9.2.9.2.

B. Safety Design Basis Two

The essential chilled water system is designed to satisfy the single failure requirements of 10CFR50, Appendix A, General Design Criterion 21.

C. Safety Design Basis Three

The essential chilled water system is designed to withstand an SSE.

Table 9.2-27

NORMAL CHILLED WATER SYSTEM SEISMIC CATEGORY I PROCESS VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-WCP-001)

Valve Tag Number	Location	Valve Type	Line Size (in)	Actuator Type	Valve Classification
WC-UV-61	To normal chilled water system - inside containment	Gate	10	Motor	A
WC-UV-62	To normal chilled water system - outside containment	Gate	10	Motor	A
WC-UV-63	From normal chilled water system - outside containment	Gate	10	Motor	A
WC-V-039	From normal chilled water system - inside containment	Check	10	None	N

D. Safety Design Basis Four

The essential chilled water system is designed to permit inservice inspections in accordance with ASME Section XI, Inservice Inspection of ASME Code, Class 2 and 3, Nuclear Power Plant Components.

E. Safety Design Basis Five

The essential chilled water system is designed to meet the environmental and missile design requirements of 10CFR50, Appendix A, General Design Criterion 4.

9.2.9.2.1.2 Power Generation Design Bases. The essential chilled water system has no power generation design bases.

9.2.9.2.1.3 Codes and Standards. The essential chilled water system is designed to the codes and standards listed in table 3.2-1.

9.2.9.2.2 System Description

The essential chilled water system is of the closed-loop type. The chilled water system includes two independent 100% redundant systems, each consisting of a chilled water refrigeration unit, a circulating chilled water pump, control valves, instrumentation, and piping (refer to table 9.2-28). The refrigeration unit consists of a compressor, evaporator, refrigerant condenser/receiver unit, controls, and instrumentation. Cooling water from the essential cooling water system is supplied to the refrigerant condensers of the safety-related essential chilled water systems shown in engineering drawings 01, 02, 03-M-ECP-001. The cooling water

flow is regulated by the Refrigerant Head Pressure Control to ensure reliable chiller operation.

The essential chilled water system is automatically activated by the actuation signals shown in engineering drawings 01, 02, 03-M-ECP-001. Redundant chilled water units are connected to independent chilled water trains A and B which supply chilled water to the cooling coils of the essential trains A and B air conditioning units serving the control room, ESF switchgear, electrical penetration rooms, ESF equipment rooms, and ECW pump rooms in the auxiliary building and the auxiliary feedwater pump rooms in the main steam support structure. Since each train is capable of removing the total emergency heat load (100% redundancy), one of the redundant chilled water systems with its corresponding essential air conditioning units can be manually deactivated once the other train has demonstrated its capability to supply the required essential chilled water. Table 9.2-29 lists Seismic Category I valves that are installed in 1-1/2-inch and larger lines in the water side of the essential chilled water system.

The makeup water line to the essential chilled water system is connected to the demineralized water system. A backup makeup water line of Seismic Category I construction is provided from the condensate storage tank. Normally, makeup is supplied from the demineralized water system. In case of a loss of offsite power, makeup is supplied from the condensate storage tank. Additionally, a connection is provided to hook up a fire hose to the makeup line (see Section 9.2.6 for details).

In case of a major leak in one of the ECWS trains, that train is removed from service and the other train is used.

Table 9.2-28
ESSENTIAL CHILLED WATER SYSTEM

Component	Number of Units	Unit Capacity	Units Required for Operation	
Chillers	2	2.724×10^6 Btu/h. 227 tons	1	Cooling water temperature maximum of 132°F
Chilled water pumps	2	20 hp, 400 gal/ min	1	Centrifugal type
Expansion tanks	2	80 gal	1	Closed to atmosphere
Chemical addition tanks	2	11.3 gal	1	Ball feeder

Table 9.2-29

ESSENTIAL CHILLED WATER SYSTEM SEISMIC CATEGORY I, 1-1/2" AND LARGER VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-ECP-001) (Sheet 1 of 8)

Valve Tag Number	Location	Valve Type	Line Size (in)	Actuator Type[(a)]
ECA-HCV-71	Chiller to CS pump room essential ACU train A	Three-way	2	Hand
ECA-V005	Chiller to CS pump room essential ACU train A	Gate	2	Hand
ECA-V016	Chiller to CS pump room essential ACU train A	Gate	2	Hand
ECA-HCV-65	Chiller to HPSI pump room essential ACU train A	Three-way	2	Hand
ECA-V006	Chiller to HPSI pump room essential ACU train A	Gate	2	Hand
ECA-V017	Chiller to HPSI pump room essential ACU train A	Gate	2	Hand
ECA-HCV-59	Chiller to LPSI pump room essential ACU train A	Three-way	1-1/2	Hand
ECA-V007	Chiller to LPSI pump room essential ACU train A	Gate	1-1/2	Hand
ECA-V018	Chiller to LPSI pump room essential ACU train A	Gate	1-1/2	Hand
ECA-HCV-41	Chiller to electrical penetration room (west) essential ACU train A	Three-way	1-1/2	Hand
ECA-V001	Chiller to electrical penetration room (west) essential ACU train A	Gate	1-1/2	Hand
ECA-V013	Chiller to electrical penetration room (west) essential ACU train A	Gate	1-1/2	Hand

a. All valves are nonactive, except as discussed in section 3.9.

Table 9.2-29

ESSENTIAL CHILLED WATER SYSTEM SEISMIC CATEGORY I, 1-1/2" AND LARGER VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-ECP-001) (Sheet 2 of 8)

Valve Tag Number	Location	Valve Type	Line Size (in)	Actuator Type[a]
ECA-HCV-53	Chiller to ECW pump room essential ACU train A	Three-way	2	Hand
ECA-V004	Chiller to ECW pump room essential ACU train A	Gate	2	Hand
ECA-V015	Chiller to ECW pump room essential ACU train A	Gate	2	Hand
ECA-HCV-115	Chiller to Auxiliary feedwater pump room essential ACU train A	Three-way	3	Hand
ECA-V201	Chiller to Auxiliary feedwater pump room essential ACU train A	Gate	3	Hand
ECA-V202	Chiller to Auxiliary feedwater pump room essential ACU train A	Gate	3	Hand
ECA-TV-29	Chiller to control room essential AHU train A	Three-way	4	Electro-Hydraulic
ECA-V008	Chiller to control room essential AHU train A	Gate	4	Hand
ECA-V019	Chiller to control room essential AHU train A	Gate	4	Hand
ECA-V525	Chiller to control room essential AHU train A	Globe	3	Hand
ECA-V518	Chiller to control room essential AHU train A	Globe	3	Hand

Table 9.2-29

ESSENTIAL CHILLED WATER SYSTEM SEISMIC CATEGORY I, 1-1/2" AND LARGER VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-ECP-001) (Sheet 3 of 8)

Valve Tag Number	Location	Valve Type	Line Size (in)	Actuator Type[(a)]
ECA-HCV-119	Chiller to Channel A, DC equipment room essential ACU train A	Three-way	2	Hand
ECA-V209	Chiller to Channel A, DC equipment room essential ACU train A	Gate	2	Hand
ECA-V210	Chiller to Channel A, DC equipment room essential ACU train A	Gate	2	Hand
ECA-V230	Chiller to Channel A, DC equipment room essential ACU train A (Unit 1 only)	Globe	2	Hand
ECA-V231	Chiller to Channel A, DC equipment room essential ACU train A (Unit 1 only)	Globe	2	Hand
ECA-HCV-35	Chiller to ESF SWGR room essential AHU train A	Three-way	2	Hand
ECA-V009	Chiller to ESF SWGR room essential AHU train A	Gate	2	Hand
ECA-V020	Chiller to ESF SWGR room essential AHU train A	Gate	2	Hand
ECA-V002	Chiller pump inlet train A	Gate	6	Hand
ECA-V011	Chiller pump discharge train A	Gate	6	Hand
ECB-HCV-72	Chiller to CS pump room essential ACU train B	Three-way	2	Hand
ECB-V048	Chiller to CS pump room essential ACU train B	Gate	2	Hand
ECB-V049	Chiller to CS pump room essential ACU train B	Gate	2	Hand

Table 9.2-29

ESSENTIAL CHILLED WATER SYSTEM SEISMIC CATEGORY I, 1-1/2" AND LARGER VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-ECP-001) (Sheet 4 of 8)

Valve Tag Number	Location	Valve Type	Line Size (in)	Actuator Type[(a)]
ECB-HCV-66	Chiller to HPSI pump room essential ACU train B	Three-way	2	Hand
ECB-V051	Chiller to HPSI pump room essential ACU train B	Gate	2	Hand
ECB-V052	Chiller to HPSI pump room essential ACU train B	Gate	2	Hand
ECB-HCV-60	Chiller to LPSI pump room essential ACU train B	Three-way	1-1/2	Hand
ECB-V053	Chiller to LPSI pump room essential ACU train B	Gate	1-1/2	Hand
ECB-V054	Chiller to LPSI pump room essential AHU train B	Gate	1-1/2	Hand
ECB-HCV-048	Chiller to Auxiliary feedwater pump room essential ACU train B	Three-way	2-1/2	Hand
ECB-V045	Chiller to Auxiliary feedwater pump room essential ACU train B	Gate	2-1/2	
ECB-V046	Chiller to Auxiliary feedwater pump room essential ACU train B	Gate	2-1/2	Hand
ECB-HCV-42	Chiller to electrical penetration room (east) essential ACU train B	Three-way	1-1/2	Hand
ECB-V047	Chiller to electrical penetration room (east) essential ACU train B	Gate	1-1/2	Hand
ECB-V050	Chiller to electrical penetration room (east) essential ACU train B	Gate	1-1/2	Hand

Table 9.2-29

ESSENTIAL CHILLED WATER SYSTEM SEISMIC CATEGORY I, 1-1/2" AND LARGER VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-ECP-001) (Sheet 5 of 8)

Valve Tag Number	Location	Valve Type	Line Size (in)	Actuator Type[(a)]
ECB-HCV-54	Chiller to ECW pump room essential ACU train B	Three-way	2	Hand
ECB-V055	Chiller to ECW pump room essential ACU train B	Gate	2	Hand
ECB-V056	Chiller to ECW pump room essential ACU train B	Gate	2	Hand
ECB-TV-30	Chiller to control room essential AHU train B	Three-way	4	Electro-Hydraulic
ECB-V057	Chiller to control room essential AHU train B	Gate	4	Hand
ECB-V058	Chiller to control room essential AHU train B	Gate	4	Hand
ECB-V524	Chiller to control room essential AHU train B	Globe	3	Hand
ECB-V516	Chiller to control room essential AHU train B	Globe	3	Hand
ECB-HCV-118	Chiller to channel B, DC equipment room essential ACU train B	Three-way	2	Hand
ECB-V213	Chiller to channel B, DC equipment room essential ACU train B	Gate	2	Hand
ECB-V214	Chiller to channel B, DC equipment room essential ACU train B	Globe	2	Hand
ECB-V228	Chiller to channel B, DC equipment room essential ACU train B (Unit 1 only)	Globe	2	Hand
ECB-V229	Chiller to channel B, DC equipment room essential ACU train B (Unit 1 only)	Globe	2	Hand

Table 9.2-29

ESSENTIAL CHILLED WATER SYSTEM SEISMIC CATEGORY I, 1-1/2" AND LARGER VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-ECP-001) (Sheet 6 of 8)

Valve Tag Number	Location	Valve Type	Line Size (in)	Actuator Type[(a)]
ECB-HCV-36	Chiller to ESF SWGR room essential ACU train B	Three-way	2	Hand
ECB-V070	Chiller to ESF SWGR room essential ACU train B	Gate	2	Hand
ECB-V071	Chiller to ESF SWGR room essential ACU train B	Gate	2	Hand
ECB-V065	Chiller pump inlet train B	Gate	6	Hand
ECB-V068	Chiller pump discharge train B	Gate	6	Hand
ECA-V025	Essential chilled water tank instrument isolation train A	Gate	2	Hand
ECA-V026	Essential chilled water tank instrument isolation train A	Globe	2	Hand
ECB-V028	Essential chilled water tank instrument isolation train B	Globe	2	Hand
ECB-V029	Essential chilled water tank instrument isolation train B	Globe	2	Hand
ECA-PSV-75	Essential chilled water tank instrument relief valve train A	Safety	1-1/2	Self
ECB-PSV-76	Essential chilled water tank instrument relief valve train B	Safety	1-1/2	Self

Table 9.2-29

ESSENTIAL CHILLED WATER SYSTEM SEISMIC CATEGORY I, 1-1/2" AND LARGER VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-ECP-001) (Sheet 7 of 8)

Valve Tag Number	Location	Valve Type	Line Size (in)	Actuator Type[(a)]
ECB-V059	Essential chilled water tank demin. water check valve	Check	1-1/2	Self
ECB-V060	Essential chilled water tank demin. water check valve	Check	1-1/2	Self
ECB-V072	Essential chilled water tank condensate water check valve	Check	1-1/2	Self
ECB-V061	Essential chilled water tank supply isolation	Globe	1-1/2	Hand
ECB-V062	Essential chilled water tank supply isolation	Globe	1-1/2	Hand
ECA-V037	Essential chilled water tank demin. water check valve	Check	1-1/2	Self
ECA-V038	Essential chilled water tank demin. water check valve	Check	1-1/2	Self
ECA-V039	Essential chilled water tank supply isolation	Globe	1-1/2	Hand
ECA-V040	Essential chilled water tank supply isolation	Globe	1-1/2	Hand
ECA-V041	Essential chilled water tank condensate water check	Check	1-1/2	Self

Table 9.2-29

ESSENTIAL CHILLED WATER SYSTEM SEISMIC CATEGORY I, 1-1/2" AND LARGER VALVE LIST

(Refer to engineering drawings 01, 02, 03-M-ECP-001) (Sheet 8 of 8)

Valve Tag Number	Location	Valve Type	Line Size (in)	Actuator Type[(a)]
ECA-V240	Essential chilled water tank instrument isolation	Globe	2	Hand
ECA-V242	Essential chilled water tank instrument isolation	Globe	2	Hand
ECB-V235	Essential chilled water tank instrument isolation	Globe	2	Hand
ECB-V238	Essential chilled water tank instrument isolation	Globe	2	Hand
ECA-V532	Chiller to control room essential AHU train A flow point (unit 2 only)	Gate	1-1/2	Hand
ECB-V546	Chiller to control room essential AHU train B flowpoint (unit 2 only)	Gate	1-1/2	Hand

9.2.9.2.2.1 Component Description. Design data for major components of the essential chilled water system are presented in table 9.2-28. The major components of each train are the chiller, chilled water pump, closed expansion tank, piping, valves, instruments, and controls.

A. Chillers

The chiller is of the self-contained package type, consisting of compressor, evaporator-cooler, condenser, oil lubricating system, oil cooler system, and controls. The oil cooler is cooled by water from the essential chilled water loop.

B. Chilled Water Pump

The chilled water pump is of the centrifugal type.

C. Expansion Tank

The expansion tank is a nitrogen charged water accumulator sized to allow for thermal expansion and contraction.

9.2.9.2.3 Safety Evaluations

The following safety evaluations are numbered to correspond to the safety design bases:

A. Safety Evaluation One

The essential chilled water system is designed to provide the chilled water at the required temperature and flowrate.

Table 9.2-30

SINGLE FAILURE MODE ANALYSIS-ESSENTIAL CHILLED WATER SYSTEM

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Condenser cooling water isolation valve or control valve	Fails closed	No cooling water flow to condenser	Temperature indication and high temperature alarm in control room	Redundant 100% capacity chilled water train available	Valve normally open except for repair
	Fails open	None			
Chiller condenser	Loss of coolant water	Refrigerant does not condense	Temperature indication and high temperature alarm in control room	Redundant 100% capacity chilled water train available	Additional local display instrumentation
Chiller compressor	Fails to operate	No cooling provided for water	Temperature indication and high temperature alarm in control room	Redundant 100% capacity chilled water train available	Additional local display instrumentation
Chiller evaporator	Chilled water coil leakage	Loss of chilled water	Expansion tank low level alarm	Redundant 100% capacity chilled water train available	Additional local display instrumentation
Chilled water pump	Fails to operate	Loss of chilled water	Pressure differential indication and alarm in control room	Redundant 100% capacity chilled water train available	Additional local display instrumentation
Thermostat 3-way valve control room	Fails closed/ mechanical binding	No chilled water flow to cooling units	Local temperature indications	Redundant 100% capacity chilled water train available	Essential to control temperature in rooms during and following emergency
	Fails open/ mechanical binding	No regulation of chilled water to coolers	Local temperature indications	Redundant 100% capacity chilled water train available	

B. Safety Evaluation Two

The essential chilled water system is divided into two trains, each supplied from redundant power sources and redundant essential cooling water system trains. No single failure can impair the ability of the system to function. (For a single failure analysis of the essential chilled water system, see table 9.2-30.)

C. Safety Evaluation Three

The essential chilled water system is designed to Seismic Category I criteria.

D. Safety Evaluation Four

The essential chilled water system is provided with sufficient access and removable insulation to permit visual inspection of the piping and equipment surfaces.

E. Safety Evaluation Five

The essential chilled water system is protected from missiles by means of physical separation of redundant units and by use of adequate building structure where it is located. Refer to section 3.5.

9.2.9.2.4 Tests and Inspections

Preoperational testing is performed in accordance with the test descriptions of section 14.2. Periodic surveillance testing is described in the Technical Specifications.

9.2.9.2.5 Instrumentation Applications

The chiller units and chilled water pumps for the essential chilled water system are automatically actuated upon receiving any of the signals shown in engineering drawings 01, 02, 03-M-ECP-001.

After automatic startup of the two essential chilled water trains, train A and train B, the operator has manual override capability on the essential trains. The operator is able to determine which train he wishes to remain in operation, which train he wishes to deactivate, and can reactivate the standby train manually, as required.

A temperature and capacity controller is provided with each essential chiller unit and maintains a constant chilled water supply temperature when the unit is working. A flow switch prevents the chiller from operating unless there is chilled water flow in the evaporator. A trip of any chiller or pump causes an alarm in the control room. Essential chilled water system differential pressure indication and alarm and essential chiller outlet temperature indication and alarm are provided in the control room to monitor system operation and efficiency. Additional local display instrumentation and test points are placed in the equipment areas for periodic checkout of the system.

The essential chilled water expansion tank is provided with a local level indicator to show low or high level condition in the closed loop. Critical conditions of the tank level and pressure are alarmed in the control room for leak detection.

Relief valves are provided, as required, for personnel and equipment protection.

9.2.10 PLANT COOLING WATER SYSTEM

The PCWS removes heat from the TCWS, the NCWS, and the condenser vacuum pump seal coolers, and rejects the heat to the circulating water system (CWS).

9.2.10.1 Design Bases

9.2.10.1.1 Safety Design Bases

The PCWS has no safety design bases.

9.2.10.1.2 Power Generation Design Bases

The power generation design basis applicable to this system is as follows:

A. Power Generation Design Basis One

   The PCWS is designed to remove heat from the nonsafety-related, normally operating, closed cooling water systems over the full range of normal plant operation.

9.2.10.1.3 Codes and Standards

The PCWS is designed in accordance with applicable codes and standards set forth in table 3.2-1.

9.2.10.2 System Description

9.2.10.2.1 General Description

The PCWS uses a portion of the CWS flow from the plant cooling towers to remove heat from the NCWS, the TCWS, and the condenser vacuum pump seal coolers. Cooled circulating water, returned from the cooling towers, is pumped in parallel through the TCWS and NCWS heat exchangers and the condenser vacuum pump seal coolers, and is discharged back into the CWS at a point between the main condenser cooling water outlet and the cooling tower inlet. Circulating water quality is maintained as discussed in subsection 10.4.5.

Because of possible radioactive contamination of the NCWS through leaks in various nuclear-related components in the system, the design operating pressure of the PCWS is higher than the design operating or transient pressures of the NCWS. This pressure differential ensures against radioactive contamination of the PCWS and outside environment. Inleakage to the NCWS is detected and alarmed as described in subsections 9.2.2 and 9.2.8, respectively.

Piping and valves in the PCWS are carbon steel and are coated with a suitable corrosion-resistant material. The NCWS and TCWS heat exchangers are constructed of corrosion-resistant materials to minimize corrosion.

A diagram of the PCWS system is provided in engineering drawings 01, 02, 03-M-PWP-001.

9.2.10.2.2 Component Description

The PCWS consists of two, 100% capacity, vertical, wet pit pumps (one on standby) which are located at the PCWS intake structure. Design data for the PCWS equipment are given in table 9.2-31.

The PCWS serves the following components with their respective flows and heat loads given in table 9.2-31:

- Two TCWS heat exchangers (one normally in service and one on standby)
- Two NCWS heat exchangers (one normally in service and one on standby)
- Four condenser vacuum pump seal coolers

9.2.10.2.3 System Operation

Normally, one PCWS pump is started manually from the main control room and is operated continuously during normal plant operating conditions.

The standby PCWS pump is started automatically in the event the normally operating pump is tripped or the discharge header pressure drops below a preset limit.

The flow through and pressure in the tube side of the TCWS, NCWS heat exchangers, and the condenser vacuum pump seal coolers are regulated manually so that the PCWS operates at a continuous, steady-state during plant operating conditions. The redundant heat exchangers are placed in service manually as required.

During Refueling Outages, the Plant Cooling Water System is shutdown for maintenance. The continued operation of the NCWS for the Refueling Outage is warranted for Spent Fuel Pool cooling and other selected components. To support NCWS operation during a Refueling Outage, the PCWS allows for the installation of a temporary cooling water system to serve as a heat sink to one NCWS Heat Exchanger.

The temporary cooling water system is made up of two cooling towers, two recirculating pumps, two make-up pumps, several manual control valves, and temporary piping. Make-up to the temporary cooling system is provided by the Essential Spray Pond (SP) System and Domestic Service Water (DS) System. The temporary cooling system has a normal power supply provided by non-class 480VAC and a back-up power supply provided by a portable diesel generator capable of 480VAC, 500KW.

The mechanical and electrical portions of the temporary cooling water system are installed and removed each outage under Maintenance Procedures. The temporary cooling water system is operated in accordance with PVNGS operating procedures.

9.2.10.3 Safety Evaluation

The PCWS has no safety function.

9.2.10.4 Tests and Inspections

Acceptance testing of this system is performed to demonstrate proper system and equipment function.

9.2.10.5 Instrumentation Application

Local pressure and temperature indicators are provided at selected points in the system. Plant cooling water system pump discharge pressure indication is provided locally and in the main control room. Pressure switches are provided at the PCWS pump discharge for standby pump auto start and for low pressure alarm in the main control room.

Table 9.2-31

DESIGN DATA FOR PCWS EQUIPMENT

	Pumps
Plant cooling water pump	
Number required	2/100%
Design flow, gal/min	29,000
Design head, ft	110
Type	Vertical
Exchangers	
TCW exchanger	
Number required	2/100%
Type	Shell and straight tube
Heat load, Btu/h	80.4×10^6
NCW exchanger	
Number required	2/100%
Type	Shell and straight tube
Heat load, Btu/h (max)	110.7×10^6
Condenser vacuum pump	
Seal cooler	
Number required	4/100%
Heat load, Btu/h (ea)	1.0×10^6

9.2.11 REFERENCES

1. Schrock, V. E. and Trezek, G. J., Rancho Seco Nuclear Service Spray Ponds Performance Evaluation, unpublished report submitted to Sacramento Municipal Utility District, July 1, 1973.

2. Brady, D. K., Graves, W. L., and Geyer, J. C., "Cooling Water Studies for Edison Electric Institute," RR-49, Johns Hopkins University, November 1969.

3. Nottage, H. B., "Merkel's Cooling Diagram as a Performance Correlation for Air-Water Evaporative Cooling Systems", Presented at the Semi-Annual Meeting of the American Society of Heating and Ventilating Engineers, San Francisco, Calif., June 1941.

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9.3 PROCESS AUXILIARIES

9.3.1 COMPRESSED AIR SYSTEM

9.3.1.1 Design Bases

9.3.1.1.1 Safety Design Bases

The compressed air system has no safety design bases.

9.3.1.1.2 Power Generation Design Bases

Each generating unit is provided with its own independent compressed air system. The system is required for normal operation but is not required for safe shutdown.

The compressed air system is divided into two subsystems, the instrument air system and the service air system.

9.3.1.1.2.1 Instrument Air System. The instrument air system provides a continuous supply of filtered, dry, oil-free air at a pressure up to 125 psig for pneumatic instrument operation and the control of pneumatic actuators. This subsystem has three air compressors and three air receivers. Each air compressor operating alone has the capacity to provide all instrument requirements of the normally operating generating unit. The total air receiver storage capacity is adequate to supply instrument air requirements during the period required for the standby air compressor to come up to full pressure, in the event of an operating air compressor failure. Two air compressors are powered from one electrical bus while the other is powered from the redundant electrical bus. The system has nitrogen backup in the event the air compressors cannot maintain adequate instrument air header pressure.

9.3.1.1.2.2 Service Air System. The service air system supplies oil-free air at a pressure of 125 psig to service air stations located throughout the generating unit. Service air stations are provided for the operating of miscellaneous pneumatic tools, stud tensioners, and stud tension hoists, and for resin transfer, refueling machine manual operation, and other service requirements. A piping connection is provided to use a portable air compressor in the event the permanent air compressor is unavailable.

9.3.1.1.3 Codes and Standards

The compressed air system is designed to the codes and standards set forth in table 3.2-1. In addition, the compressed air system is designed to meet pertinent Occupational Safety and Health Administration (OSHA) requirements and the air compressors are supplied in conformance with noise limitations defined by the Walsh-Healy Act.

9.3.1.1.4 Protection

Protection of the compressed air system from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

9.3.1.1.5 CESSAR Interface Requirements

Refer to subsection 5.1.4 and paragraphs 6.3.1.3 and 9.3.4.1.

9.3.1.2 System Description

9.3.1.2.1 General Description

The compressed air system (as shown in engineering drawings 01, 02, 03-M-IAP-001, -002 and -003) is composed of two subsystems, the instrument air system and the service air system. The major component parameters are given in table 9.3-1.

9.3.1.2.1.1 Instrument Air System. The instrument air system is provided with three 100% capacity rotary screw air compressors. Each compressor is furnished with a filter, an aftercooler, a moisture separator, and an air receiver. Cooling water for the air compressor and aftercooler is supplied by the turbine cooling water system as discussed in subsection 9.2.8.

The three air receivers are connected on the discharge side by a header with nonsafety-related isolation valves. The discharge header conducts the instrument air supply through one of two coalescing prefilters, which removes liquid aerosols and particulate, then to a duplex heatless dessiccant dryer which lowers the dewpoint of the air to between minus 20F and minus 40F, depending on flowrate and inlet air temperature. The air next passes through one of two afterfilters which removes particles greater than 0.9 microns (absolute) in size. This instrument air is then distributed to the various pneumatic control systems.

Table 9.3-1
COMPRESSED AIR SYSTEM MAJOR COMPONENT PARAMETERS
(Sheet 1 of 2)

Equipment Parameters	Value
1. Instrument Air System	
Air compressors	
Quantity	3
Capacity, standard ft^3/min	571
Pressure, psig	125
Horsepower	125
Revolutions per minute	1775
Volts/Hz/phase	460/60/3
Air receivers	
Quantity	3
Size, ft^3	151
Pressure, psig	140
Instrument air dryers	
Quantity	2
Type	Duplex, heatless desiccant
Capacity, standard ft^3/min	1000
Pressure, psig/Temperature °F	110/125
Dew point, @ 500 SCFM, °F	-40
Dew point, @1000 SCFM, °F	-20
Instrument air afterfilters	
Quantity	2
Efficiency, %	100
Micron Size	0.9 absolute
Instrument air coalescing prefilters	
Quantity	2
Efficiency, % (D.O.P. test)	99.9
Micron size	0.3
Liquid aerosols, ppmw	0.013-0.0014

Table 9.3-1
COMPRESSED AIR SYSTEM MAJOR COMPONENT PARAMETERS
(Sheet 2 of 2)

Equipment Parameters	Value
2. Service Air System	
Air compressors	
Quantity	1
Capacity, standard ft^3/min	1,019
Pressure, psig	125
Horsepower	250
Revolutions per minute	1,780
Volts/Hz/phase	460/60/3
Air receivers	
Quantity	2
Size, ft^3	214
Pressure, psig	150
Air Dryer	
Quantity	1
Type	Refrigerated
Capacity, standard ft^3/min	1220
Pressure, psig	125
Dew Point Range, °F	35 to 45
Volts/Hz/Phase	460/60/3

Carbon steel piping and carbon steel valves are used in the air lines upstream of the instrument air dryers. Copper piping and bronze valves are used in the instrument air lines downstream of the air dryers.

Should the compressors fail to maintain the instrument air header pressure in the normal operating range of 105 to 125 psig, nitrogen backup is available to assure continued pneumatic instrument operation. If the header pressure should fall below 85 psig, a solenoid valve in a nitrogen crosstie automatically opens to allow 115 psig nitrogen to repressurize the instrument air system.

The instrument air system is not required to achieve a safe reactor shutdown or to mitigate the consequences of an accident. Pneumatically operated valves that have a safety function and may be required to operate to ensure safe shutdown of the plant following an accident or to mitigate the consequences of an accident use a safety-related check valve to isolate their safety-related pneumatic backup supply from the nonsafety-related instrument air system. All other pneumatically operated valves that have a safety function are designed to fail to a safe position upon loss of instrument air and do not require a continuous air supply under emergency or abnormal conditions. Both types of valves are listed in table 9.3-2.

9.3.1.2.1.2 Service Air System. The service air system is provided with a two-stage, rotary screw air compressor furnished with a filter-silencer, an intercooler, an aftercooler, and a moisture separator. Cooling water for the

air compressor package is supplied by the turbine cooling water system as discussed in subsection 9.2.8. A refrigerated air dryer, located downstream of the two air receivers, removes moisture to a dew point between 35 to 45 °F at 125 psig.

The air compressor discharges into two air receivers. A flanged connection on the discharge piping is furnished to accommodate a portable air compressor which will be used to provide service air when the permanent air compressor is not available. The air receivers have sufficient capacity to allow safe egress of maintenance personnel after service air quality or pressure is alarmed.

Excessive temperature of the compressed air entering the air receivers is alarmed for personnel safety.

The outlets of two air receivers are piped to a common service air header which distributes service air throughout the unit. This header is normally pressurized between 115 and 125 psig. The low pressure alarm setpoint is 100 psig.

9.3.1.2.1.3 Environmental Design Conditions. The major compressed air system components are located in the turbine building and are designed to operate under all specified environmental design conditions. Refer to section 9.4 for a discussion of environmental design conditions associated with the turbine building.

Table 9.3-2
PNEUMATICALLY OPERATED VALVES THAT HAVE A SAFETY FUNCTION[a] (Sheet 1 of 9)

System, Figure Numbers and Valve Number	Location	Design Function	Normal Position	Fail Position	Safe Position
Chemical and Volume Control (engineering drawings 01, 02, 03-M-CHP-001, -002, -003, -004 and -005)					
CHA-HV507	Containment	Isolation	Open	Open	Open
CHA-UV506	Containment	Isolation	Open	Closed	Closed
CHA-UV516	Containment	Isolation	Open	Closed	Closed
CHA-UV560	Containment	Isolation	Closed	Closed	Closed
CHA-UV580	Auxiliary Bldg.	Isolation	Closed	Closed	Closed
CHB-UV505	Auxiliary Bldg.	Isolation	Open	Closed	Closed
CHB-UV515	Containment	Isolation	Open	Closed	Closed
CHB-UV523	Containment	Isolation	Open	Closed	Closed
CHB-UV561	Auxiliary Bldg.	Isolation	Closed	Closed	Closed
CHE-FV204	Auxiliary Bldg.	Flow control	Modulating	Open	Open
CHE-FV241	Containment	Flow control	Open	Open	Open
CHE-FV242	Containment	Flow control	Open	Open	Open
CHE-FV243	Containment	Flow control	Open	Open	Open
CHE-FV244	Containment	Flow control	Open	Open	Open
CHE-HV239	Containment	Isolation	Open	Closed	Closed

a. A complete list of valves important to containment isolation is found in table 6.2.4-1.

Table 9.3-2

PNEUMATICALLY OPERATED VALVES THAT HAVE A SAFETY FUNCTION[(a)] (Sheet 2 of 9)

System, Figure Numbers and Valve Number	Location	Design Function	Normal Position	Fail Position	Safe Position
Chemical and Volume Control (engineering drawings 01, 02, 03-M-CHP-001, -002, -003, -004 and -005) (cont'd)					
CHE-HV532	Auxiliary Bldg.	Isolation	Open	Open	Open
CHE-LV110P	Auxiliary Bldg.	Flow control	Modulating	Closed	Closed
CHE-LV110Q	Auxiliary Bldg.	Flow control	Modulating	Closed	Closed
CHE-PDV240	Containment	Isolation	Open	Closed	Closed
CHE-PV201P	Auxiliary Bldg.	Pressure control	Modulating	Closed	Closed
CHE-PV201Q	Auxiliary Bldg.	Pressure control	Modulating	Closed	Closed
CHE-UV231P	Auxiliary Bldg.	Isolation	Open	Open	Open
CHE-UV500	Auxiliary Bldg.	Flow control	3-way	Open to VCT	Open to VCT
CHE-UV520	Auxiliary Bldg.	Flow control	3-way	Open to VCT	Open to VCT
CHE-UV521	Auxiliary Bldg.	Flow control	3-way	Open to VCT	Open to VCT
CHE-UV565	Auxiliary Bldg.	Selector (3-way)	3-way	Open to EDT	Open to EDT
CHE-UV566	Auxiliary Bldg.	Selector (3-way)	3-way	Open to EDT	Open to EDT

Table 9.3-2

PNEUMATICALLY OPERATED VALVES THAT HAVE A SAFETY FUNCTION[(a)] (Sheet 3 of 9)

System, Figure Numbers and Valve Number	Location	Design Function	Normal Position	Fail Position	Safe Position
Containment Purge (engineering drawings 01, 02, 03-M-HAP-001, -002, -003 and -004)					
CPA-UV004A	Auxiliary Bldg.	Containment power access purge exhaust isolation	Closed	Closed	Closed
CPA-UV004B	Containment	Containment power access purge exhaust isolation	Closed	Closed	Closed
CPB-UV005A	Containment	Containment power access purge exhaust isolation	Closed	Closed	Closed
CPB-UV005B	Auxiliary Bldg.	Containment power access purge exhaust isolation	Closed	Closed	Closed
Auxiliary Bldg. HVAC (engineering drawings 01, 02, 03-M-HAP-001, -002, -003 and -004)					
HAA-M01	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAA-M02	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAA-M03	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAA-M04	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAA-M05	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAA-M06	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAA-M214	MSSS	Isolation	Open	Closed	Closed
HAA-M216	MSSS	Isolation	Open	Closed	Closed

Table 9.3-2

PNEUMATICALLY OPERATED VALVES THAT HAVE A SAFETY FUNCTION[(a)] (Sheet 4 of 9)

System, Figure Numbers and Valve Number	Location	Design Function	Normal Position	Fail Position	Safe Position
Auxiliary Bldg. HVAC (engineering drawings 01, 02, 03-M-HAP-001, -002, -003 and -004) (cont'd)					
HAB-M01	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAB-M02	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAB-M03	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAB-M04	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAB-M05	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAB-M06	Auxiliary Bldg.	Isolation	Open	Closed	Closed
HAB-M215	MSSS	Isolation	Open	Closed	Closed
HAB-M217	MSSS	Isolation	Open	Closed	Closed
Fuel Bldg. HVAC (engineering drawings 01, 02, 03-M-HFP-001)					
HFA-M01	Fuel Bldg.	Isolation	Open	Closed	Closed
HFA-M02	Fuel Bldg.	Isolation	Open	Closed	Closed
HFA-M03	Fuel Bldg.	Isolation	Open	Closed	Closed
HFA-M04	Fuel Bldg.	Isolation	Open	Closed	Closed
HFB-M01	Fuel Bldg.	Isolation	Open	Closed	Closed
HFB-M02	Fuel Bldg.	Isolation	Open	Closed	Closed
HFB-M03	Fuel Bldg.	Isolation	Open	Closed	Closed
HFB-M04	Fuel Bldg.	Isolation	Open	Closed	Closed

Table 9.3-2
PNEUMATICALLY OPERATED VALVES THAT HAVE A SAFETY FUNCTION[(a)] (Sheet 5 of 9)

System, Figure Numbers and Valve Number	Location	Design Function	Normal Position	Fail Position	Safe Position
Control Bldg. HVAC (engineering drawings 01, 02, 03-M-HJP-001 and -002 and 02-M-HJP-003)					
HJA-M01	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M15	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M16	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M23	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M25	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M28	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M34	Control Bldg.	Isolation	Open	Open	Open
HJA-M36	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M51	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M52	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M53	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M54	Control Bldg.	Smoke exhaust	Open	Closed	Closed
HJA-M55	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M56	Control Bldg.	Smoke exhaust	Closed	Closed	Closed
HJA-M57	Control Bldg.	Smoke exhaust	Closed	Closed	Closed
HJA-M58	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M59	Control Bldg.	Isolation	Open	Closed	Closed
HJA-M62	Control Bldg.	Isolation	Closed	Open	Open
HJA-M66	Control Bldg.	Isolation	Open	Closed	Closed

Table 9.3-2
PNEUMATICALLY OPERATED VALVES THAT HAVE A SAFETY FUNCTION[a] (Sheet 6 of 9)

System, Figure Numbers and Valve Number	Location	Design Function	Normal Position	Fail Position	Safe Position
Control Bldg. HVAC (engineering drawings 01, 02, 03-M-HJP-001 and -002 and 02-M-HJP-003) (Cont'd)					
HJB-M01	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M10	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M13	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M23	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M24	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M28	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M31	Control Bldg.	System operation	Open	Open	Open
HJB-M32	Control Bldg.	System operation	Open	Open	Open
HJB-M34	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M38	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M52	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M55	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M56	Control Bldg.	Smoke exhaust	Closed	Closed	Closed
HJB-M57	Control Bldg.	Smoke exhaust	Closed	Closed	Closed
HJB-M58	Control Bldg.	Isolation	Closed	Open	Open
HJB-M66	Control Bldg.	Isolation	Open	Closed	Closed
HJB-M67	Control Bldg.	Isolation	Open	Open	Open

Table 9.3-2

PNEUMATICALLY OPERATED VALVES THAT HAVE A SAFETY FUNCTION[(a)] (Sheet 7 of 9)

System, Figure Numbers and Valve Number		Location	Design Function	Normal Position	Fail Position	Safe Position
Reactor Coolant (engineering drawings 01, 02, 03-M-RCP-001, -002 and -003)						
RCE-PV100E		Containment	Flow control	Closed	Closed	Closed
RCE-PV100F		Containment	Flow control	Closed	Closed	Closed
Radioactive Waste Drains (engineering drawings 01, 02, 03-M-RDP-003)						
RDB-UV24		Auxiliary Bldg.	Isolation	Open	Closed	Closed
Main Steam (engineering drawings 01, 02, 03-M-SGP-001 and -002)						
SGA-HV179	ADV	MSSS	Flow control	Closed	(b)	(c)
SGA-HV184	ADV	MSSS	Flow control	Closed	(b)	(c)
SGA-UV174	FWIV	MSSS	Isolation	Open	(b)	(c)
SGA-UV177	FWIV	MSSS	Isolation	Open	(b)	(c)
SGB-HV178	ADV	MSSS	Flow control	Closed	(b)	(c)
SGB-HV185	ADV	MSSS	Flow control	Closed	(b)	(c)
SGB-UV132	FWIV	MSSS	Isolation	Open	(b)	(c)
SGB-UV137	FWIV	MSSS	Isolation	Open	(b)	(c)
SGE-UV170	MSIV	MSSS	Isolation	Open	(b)	(c)
SGE-UV171	MSIV	MSSS	Isolation	Open	(b)	(c)
SGE-UV180	MSIV	MSSS	Isolation	Open	(b)	(c)
SGE-UV181	MSIV	MSSS	Isolation	Open	(b)	(c)

b. Backup safety-related pneumatic supply will permit valve operation on failure of the instrument air system.

c. Not applicable. See note (b).

Table 9.3-2
PNEUMATICALLY OPERATED VALVES THAT HAVE A SAFETY FUNCTION[a] (Sheet 8 of 9)

System, Figure Numbers and Valve Number	Location	Design Function	Normal Position	Fail Position	Safe Position
Main Steam (engineering drawings 01, 02, 03-M-SGP-001 and -002)(Cont'd)					
SGA-UV172	MSSS	Isolation	Open	Closed	Closed
SGA-UV175	MSSS	Isolation	Open	Closed	Closed
SGA-UV1133	MSSS	Isolation	Open	Closed	Closed
SGA-UV1134	MSSS	Isolation	Open	Closed	Closed
SGB-UV1135A/B	MSSS	Isolation	Open	Closed	Closed
SGB-UV1136A/B	MSSS	Isolation	Open	Closed	Closed
SGA-UV500P	Containment	Isolation	Open	Closed	Closed
SGA-UV500S	MSSS	Isolation	Open	Closed	Closed
SGB-UV130	MSSS	Isolation	Open	Closed	Closed
SGB-UV135	MSSS	Isolation	Open	Closed	Closed
SGB-UV500Q	MSSS	Isolation	Open	Closed	Closed
SGB-UV500R	Containment	Isolation	Open	Closed	Closed
SGE-UV169	MSSS	Bypass	Closed	Closed	Closed
SGE-UV183	MSSS	Bypass	Closed	Closed	Closed
Shutdown Cooling (engineering drawings 01, 02, 03-M-SIP-001, -002 and -003)					
SIA-HV619	Containment	SIT isolation	Closed	Closed	Closed
SIA-HV629	Containment	SIT isolation	Closed	Closed	Closed
SIA-HV639	Containment	SIT isolation	Closed	Closed	Closed

Table 9.3-2

PNEUMATICALLY OPERATED VALVES THAT HAVE A SAFETY FUNCTION[a] (Sheet 9 of 9)

System, Figure Numbers and Valve Number	Location	Design Function	Normal Position	Fail Position	Safe Position
Shutdown Cooling (engineering drawings 01, 02, 03-M-SIP-001, -002 and -003) (Cont'd)					
SIA-HV649	Containment	SIT isolation	Closed	Closed	Closed
SIA-HV682	Containment	SIT isolation	Closed	Closed	Closed
SIB-HV612	Containment	SIT isolation	Closed	Closed	Closed
SIB-HV622	Containment	SIT isolation	Closed	Closed	Closed
SIB-HV632	Containment	SIT isolation	Closed	Closed	Closed
SIB-HV642	Containment	SIT isolation	Closed	Closed	Closed
SIB-UV322	Containment	Isolation	Closed	Closed	Closed
SIB-UV332	Containment	Isolation	Closed	Closed	Closed
SIB-UV611	Containment	SIT isolation	Closed	Closed	Closed
SIB-UV618	Containment	SIT isolation	Closed	Closed	Closed
SIB-UV621	Containment	SIT isolation	Closed	Closed	Closed
SIB-UV628	Containment	SIT isolation	Closed	Closed	Closed
SIB-UV631	Containment	SIT isolation	Closed	Closed	Closed
SIB-UV638	Containment	SIT isolation	Closed	Closed	Closed
SIB-UV641	Containment	SIT isolation	Closed	Closed	Closed
SIB-UV648	Containment	SIT isolation	Closed	Closed	Closed
SIE-HV661	Containment	SIT isolation	Closed	Closed	Closed

9.3.1.2.1.4 Safe Shutdown. The necessary protective measures are taken to ensure that the equipment essential for a safe and maintained reactor shutdown is not jeopardized by the generation of missiles or high pressure air leakage from the compressed air system. This is accomplished by separation of the compressed air system from the engineered safety features (ESF) systems, or by use of barriers between systems. Safety valves are provided in the system to prevent or mitigate a high-pressure rupture incident.

9.3.1.2.1.5 Containment Isolation. A normally open instrument air line and a normally closed service air line penetrate the containment (two separated penetrations), as shown in engineering drawings 01, 02, 03-M-IAP-001 and -002. The instrument air line penetrating the containment serves the normally operating valves of the pressurizer spray system and the normally operating valve of the nitrogen supply to the safety injection tanks (used to maintain pressure on top of the liquid in the tanks). The penetrating instrument air line is provided with a check valve inside the containment and a solenoid-operated valve on the outside of the containment. This solenoid-operated valve closes automatically upon a containment spray actuation signal (CSAS) or in case of an electrical (train A) failure. It can also be closed manually from the control room. Should the line rupture inside the containment, airflow is limited to a flow of 10 actual ft^3/min by a restriction orifice upstream of the solenoid-operated valve.

The service air line penetrating the containment is used to support refueling operations and required maintenance. This line is provided with a check valve inside the containment and a manual block valve at the point of service connection in the containment. The line is provided with a locked closed manual isolation valve outside the containment.

9.3.1.2.2 System Operation

9.3.1.2.2.1 Instrument Air System. One compressor is normally in operation with the other two on standby. Normally, the capacity of one compressor is adequate for base load operation. The other compressors cycle on and off as required to meet increased plant demands as evidenced by a drop in the instrument air header pressure. In order to equalize wear on each compressor, the compressors are periodically rotated for base load operation.

In the event that the one operating compressor fails to supply the full air demand, or an electrical trip of an operating compressor occurs, the resulting continuous low pressure in the supply line initiates an automatic start of the standby compressors.

Instrument air is filtered and dehumidified prior to its introduction into the instrument air distribution piping. This is accomplished by two trains of prefilters, regenerative duplex air driers, and afterfilters.

If plugging of a filter occurs, a high differential pressure alarm is provided to warn the operator who may then divert the air stream to the other train through manually operated valves.

Normally, filter elements are replaced on a regular basis to prevent plugging during operation.

The duplex (two tower) drier is operated in such a manner that one tower regenerates while the other tower is in service. The two towers interchange automatically based on the moisture load on the desiccant bed of the in-service tower. A standard timed cycle operating mode is also available.

9.3.1.2.2.2 Service Air System. Normally the service air compressor will maintain the header pressure in the 115 to 125 psig range. If the compressor runs unloaded for 30 minutes the drive motor is tripped.

The moisture collected downstream of the compressor intercooler and aftercooler and in the air receivers is automatically drained. Manual bypasses are to be used when the drain traps or automatic drain valves are out of service.

Letdown lines are provided for each air receiver to perform necessary maintenance with the receiver depressurized.

A refrigerated air dryer, located downstream of the air receivers, cools the air for removal of moisture, which is automatically drained.

9.3.1.2.3 CESSAR Interface Evaluation

Refer to subsections 5.1.5 and 6.3.3 and paragraph 9.3.4.2.

9.3.1.3 Safety Evaluation

Because the compressed air system has no safety design basis, no safety evaluation is provided. Paragraph 9.3.1.2 provides

an assessment of the compressed air system design and operation.

9.3.1.4 Tests and Inspections

The compressors, aftercoolers, receivers, filters, air dryers, and control panel are shop inspected, or tested, prior to installation. The complete, installed compressed air system is inspected, tested, and then operated to verify its performance requirements including operational sequences and alarm functions.

The containment isolation valves, and piping between isolation valves, are tested in accordance with paragraph 6.2.6.3.

9.3.1.5 Instrumentation Requirements

9.3.1.5.1 Instrument Air

Local indication is provided for the following changes in instrument air quality:

1. High differential pressure across the prefilter
2. High differential pressure across the dryer
3. High differential pressure across the afterfilter
4. Loss of power
5. Dryer bed is too wet (high alarm)
6. Dryer bed is too dry (low alarm)
7. Probe cable disconnected
8. Inlet valve malfunction
9. Exhaust valve malfunction

Items 1 through 9 have a common trouble alarm in the control room.

APS utilizes ISA-S7.3 (1975), "Quality Standard for Instrument Air" as guidance for controlling air quality. This instrumentation is adequate for monitoring air quality to this standard. The afterfilter removes particulate matter in excess of 0.9 microns absolute. These specifications meet air supply requirements for safety-related valves. All valves fail in their safe position upon loss of instrument air.

An instrumentation package accompanies each of the air compressors and air dryer packages. Each package consists of locally mounted temperature and pressure switches, indicators, and automatic protection devices. The temperature and pressure instruments support the automatic control modes of compressor and dryer operation. A manual or hand mode of operation is also provided for each control room. The instrument air system also includes additional local instrumentation and controls necessary to ensure the ability of the system to perform its design functions.

9.3.1.5.2 Service Air

An instrumentation package accompanies the air compressor. The package consists of locally mounted temperature and pressure switches, indicators, and automatic protection devices. The temperature and pressure switches support the automatic control mode of compressor operation. A manual or hand mode of operation is also provided from the control room. The service air system also includes additional local instrumentation and

controls necessary to ensure the ability of the system to perform its design functions.

9.3.2 PROCESS SAMPLING SYSTEM

9.3.2.1 Design Bases

The process sampling system design bases are as follows:

A. General

The normal sampling system is designed to collect samples from the reactor coolant and auxiliary systems for analysis. It permits sampling during reactor operation and cooldown without requiring access to the containment. As a secondary function of the normal sampling system, the pressurizer team space sample line is capable of degassing the RCS by recirculating the pressurizer steam space to the VCT via the sample line. Remote samples of fluids in high radiation areas can be taken without requiring access to these areas. Neither sampling system performs a safety function. The radiological (shielding) evaluation for normal operation of the process sampling system is provided in section 12.2. The sample analyses may be performed:

1. Under normal conditions by drawing samples at a sample sink and conducting the analysis in the hot laboratory

2. Under post-accident conditions by obtaining grab samples and performing the required analyses in an appropriate laboratory facility.

B. Reactor Coolant System Samples

Samples are taken from one hot leg, the pressurizer surge line, and the pressurizer steam space. Sampling lines are connected to the reactor coolant system (RCS) piping downstream of a passive flow restriction device. Provisions can be made to permit sampling of the RCS during startup.

The sample line from the RCS hot leg is delayed in transit to the secondary shield wall to allow sufficient time for the decay of N^{16} to less than 10% of the total activity in the line.

C. Sample Temperature and Pressure

The high-pressure, high-temperature reactor coolant samples and intermediate pressure and temperature samples are cooled to 120F or less and depressurized. This permits analysis by standard sampling methods.

D. Verification of Boron Concentration

To verify the boron concentration of the water recirculated via the safety injection and shutdown cooling system, provisions for extracting, processing, and analyzing samples from the following points are provided: each of the two shutdown cooling suction lines and the safety injection pump miniflow lines.

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 1 of 11)

(b) Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis(b)	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters: Pressure (psig)	Design Parameters: Temperature (°F)	Engineering Drawing
<u>Primary Sampling System</u>								
Hot Leg Loop 1	Rough	pH, O_2, H_2, Total Dissolved Gas, NH_3, Lithium, Boron, Radioactivity, Chloride, Fluoride	Yes	None	Remote Aux Bldg El-140'	2485	621	01, 02, 03-M-RCP-001, -002 and -003 01, 02, 03-N-SSP-001
Pressurizer Steam Space	Rough	H_2 Hydrogen, Radioactivity,	Yes	None	Remote Aux Bldg El-140'	2500	700	01, 02, 03-M-RCP-001, -002 and -003 01, 02, 03-N-SSP-001
Shutdown Cooling Suction Lines 1 & 2	Rough	Boron, Radio-activity, Chloride, Fluoride, Sulfate	No	None	Remote Aux Bldg El-140'	485	350	01, 02, 03-M-SIP-001, -002 and -003 01, 02, 03-N-SSP-001
ESF A&B Train Safety Injection Pump Mini Flow Line	Rough	Boron, Radio-activity, Chloride, Fluoride, Sulfate	No	None	Remote Aux Bldg El-140'	2050	350	01, 02, 03-M-SIP-001, -002 and -003 01, 02, 03-N-SSP-001
Purification Filter Inlet	None	pH, NH_3 Lithium, Boron, Radioactivity, Chloride, Fluoride, Suspended Solids	No	None	Remote Aux Bldg El-140'	60	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005 01, 02, 03-N-SSP-001
Purification Filter Outlet, Ion Exchanger Inlet	None	Suspended Solids, Radioactivity	No	Radio-activity(c)	Remote Aux Bldg El-140'	50	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005 01, 02, 03-N-SSP-001

a. Pressure value in psia.
b. Radioactivity samples can be analyzed for gross activity, isotopic composition, tritium or alpha activity.
c. Refer to section 11.5 for detailed descriptions of process and effluent radiation monitors.
d. Refer to section 11.3 for a description of the explosive mixtures monitoring.
e. Sample required to comply with NUREG-0737, Item II.B.3, and/or Reg. Guide 1.97, Rev. 2.
f. Sample not required - redundant or alternate sampling means.

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 2 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[(b)]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters: Pressure (psig)	Design Parameters: Temperature (°F)	Engineering Drawing
<u>Primary Sampling System (Cont'd)</u>								
Purification Ion Exchanger Outlet	None	pH, Lithium, Boron, , Radioactivity, Sulfate, Decon Factor Chloride, Fluoride	No	None	Remote Aux Bldg El-140'	50	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005 01, 02, 03-N-SSP-001
Pressurizer Surge Line	Rough	Boron	No	None	Remote Aux Bldg El-140'	2500	700	01, 02, 03-M-RCP-001, -002 and -003 01, 02, 03-N-SSP-001
Reactor Drain Pump Discharge Before Filter	None	Conductivity pH, Boron, Chloride	No	None	Local Aux Bldg El-120'	65	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Reactor Drain Pump Discharge After Filter	None	Conductivity pH, Boron, Chloride	No	None	Local Aux Bldg El-120'	65	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Pre-holdup Ion Exchanger Outlet	None	Conductivity pH	No	None	Local Aux Bldg El-120'	65	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Holdup Tank Inlet	None	Conductivity pH, Boron, Chloride	No	None	Local Aux Bldg El-120'	60	130	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Boric Acid Condensate Ion Exchanger Inlet	None	Conductivity pH, Boron	No	None	Local Aux Bldg El-120'	60	140	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Boric Acid Condensate Ion Exchanger Outlet	None	Conductivity pH, Boron	No	None	Local Aux Bldg El-120'	60	140	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Reactor Makeup Water Pump Discharge	None	Conductivity pH, Boron, Chloride	No	None	Local Aux Bldg El-120'	130	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 3 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[b]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters		Engineering Drawing
						Pressure (psig)	Temperature (^{o}F)	
<u>Primary Sampling System (Cont'd)</u>								
Reactor makeup Water Pump Recirculation	None	Conductivity pH, Boron	No	None	Local Aux Bldg El-120'	130	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Boric Acid Makeup Pump Recircula-tion	None	Boron	No	None	Local Aux Bldg El-120'	130	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Boric Acid Makeup Pump Discharge	None	Boron	No	None	Local Aux Bldg El - 120'	130	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Boric Acid Batching Tank	Portable	Boron	No	None	Local Aux Bldg El - 120'	5	160	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Reactor Makeup Water to Volume Control Tank	None	Conductivity pH, Boron, Chloride	No	None	Local Aux Bldg El - 120'	130	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Volume Control Tank Drain to Recycle Drain Header	None	Conductivity pH, Boron	No	None	Local Aux Bldg El - 120'	50	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
CVCS Letdown	None	Boron	No	Yes Boron, Radioactivity	Remote Aux Bldg El - 120'	50	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005
Shutdown Cooling Heat Exchanger Outlet	Portable	Boron, Radio-activity	No	None	Local Aux Bldg El - 120'	650	160	01, 02, 03-M-SIP-001, -002 and -003
Safety Injection Tanks 1, 2, 3, 4	None	Boron	No	None	Local Containment El - 80'	610	120	01, 02, 03-M-SIP-001, -002 and -003
<u>Secondary Sample Points</u>								
Hotwell 1A, 2A, 1B, 2B, 1C, and 2C	Fine	Yes Cation Conductivity Sodium	No	Yes Cation Conductivity Sodium	Remote Hotwell Analysis Station Turbine Bldg El 100'	2[a]	121	01, 02, 03-M-CDP-001, -002, -003 and -004 01, 02, 03-M-SCP-005, -006 and -007

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 4 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[b]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters: Pressure (psig)	Design Parameters: Temperature ($^{\circ}F$)	Engineering Drawing
Secondary Sample Points (Cont'd)								
S/G 1 and 2 Hotleg Blowdown	Rough & Fine	Yes Conductivity pH & Radio-activity	No	Yes, Specific Conductivity, pH, Radioactivity[c], Cation Conductivity & Sodium Concentration	Remote Cold Lab Aux Bldg El-140'	1179	554	01, 02, 03-M-SGP-001 and -002 01, 02, 03-M-SCP-005, -006 and -007
S/G 1 and 2 Downcomer	Rough & Fine	Yes Conductivity pH & Radio-activity	No	Yes, Specific Conductivity, pH, Radioactivity[c], Cation Conductivity & Sodium Concentration	Remote Cold Lab Aux Bldg El-140'	1179	554	01, 02, 03-M-SGP-001 and -002 01, 02, 03-M-SCP-005, -006 and -007
S/G 1 and 2 downcomer blowdown	Rough & Fine	Yes Conductivity Ph & Radio activity, pH	No	Yes, specific pH cconductivity, PH, radioactivity, cation conductivity & Sodium concentration	Remote cold Lab Aux Bldg El-140'	1179	554	01, 02, 03-M-SGP-001 01, 02, 03-M-SCP-006
Condensate LP Heater Train A, B, and C Outlet	Portable	Yes Conductivity	No	None	Local Turbine Bldg, El-140'	400	396	01, 02, 03-M-CDP-001, -002, -003 and -004
FW Pump A and B Suction	Portable	Yes Conductivity	No	None	Local Turbine Bldg, El-140'	400	396	01, 02, 03-M-FWP-001
HP Heater Train A and B Outlet	Portable	Yes Conductivity	No	None	Local Turbine Bldg, El-140'	1225	450	01, 02, 03-M-FWP-001
MSR A, B, C and D Drain	Portable	Yes Conductivity Iron, Copper	No	None	Local Turbine Bldg, El-140'	202[a]	383	01, 02, 03-M-EDP-001, -002, -003, -004 and -005
First Stage RHTR Drain Tank A, B, C and D	Portable	Yes Conductivity Iron, Copper	No	None	Local Turbine Bldg, El-140'	432[a]	452	01, 02, 03-M-EDP-001, -002, -003, -004 and -005
Second Stage RHTR Drain Tank A, B, C and D	Portable	Yes Conductivity Iron, Copper	No	None	Local Turbine Bldg, El-140'	985[a]	543	01, 02, 03-M-EDP-001, -002, -003, -004 and -005
Htr Drain Tank A and B Drain	Portable	Iron	No	None	Local Turb Bldg El - 100'	433[a]	371	01, 02, 03-M-EDP-001, -002, -003, -004 and -005

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 5 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[b]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters Pressure (psig)	Design Parameters Temperature (°F)	Engineering Drawing
Secondary Sample Points (Cont'd)								
Htr Drain Tank A and B Discharge	Portable	Iron	No	None	Local Turb Bldg El - 100'	202[a]	393	01, 02, 03-M-EDP-001, -002, -003, -004 and -005
Spray Pond Water	None	Hardness, Alkalinity, pH, chlorine, Conductivity	No	None	Remote Chemical Pump House Yard Area Local SP Inlet Piping to DG Cooler DG,EW piping	15	97	01, 02, 03-M-SPP-001 and -002
Circulating Water Outlets	Fine	Conductivity, pH	No	Yes Conductivity, pH, Chlorine	Remote Cold Lab Aux Bldg 140' Chlorine Analysis Sta Turbine Bldg 100'	30	108	01, 02, 03-M-CWP-001 01, 02, 03-M-SCP-005, -006 and -007
Condensate Tank Sample	None	Conductivity, pH, Chlorides, Silica	No	None	Local Yard Area	25	Ambient	01, 02, 03-M-CTP-001
Essential Chiller A and B Outlets	None	pH	No	None	Local Control Bldg El 74'	45	44	01, 02, 03-M-ECP-001
Essential Cooling Water Pumps A and B Discharge	None	pH	No	Radioactivity[c]	Local Aux Bldg El 70'	105	89	01, 02, 03-M-EWP-001
Normal Chillers A, B, and C Outlet Headers	None	pH	No	None	Local Aux Bldg El 140'	45	44	01, 02, 03-M-WCP-001
Nuclear Cooling Water Pump Discharge Header	None	pH	No	Radioactivity[c]	Local Aux Bldg El - 140'	80	105	01, 02, 03-M-NCP-001, -002 and -003
Shutdown Cooling Heat Exchanger Room A and B Drain Radwaste Building Sumps	None	pH	No	None	Local Radwaste Bldg El - 88'	Atmos.	120	01, 02, 03-M-RDP-004
LRS Hold-Up Tank Leak Drain	None	Radioactivity	No	None	Local LRS Hold-up Tank Area El - 100'	Atmos	120	01, 02, 03-M-RDP-004
LRS Recycle Monitor Tank Leak Drain	None	Radioactivity	No	None	Local LRS Hold-up Tank Area El - 100'	Atmos.	120	01, 02, 03-M-RDP-004
Main Turbine Lube Oil Conditioner Outlet	None	Suspended Solids	No	None	Local Turbine Bldg El - 100'	35	120	-01, 02, 03-M-OSP-001
FWPT Lube Oil Centrifuge Outlet	None	Suspended Solids	No	None	Local Turbine Bldg El - 100'	52	120	-01, 02, 03-M-OSP-001

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 6 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[b]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters		Engineering Drawing
						Pressure (psig)	Temperature (^{o}F)	
Secondary Sample Points (Cont'd)								
Cooling H_2O Hold-up Tank	None	Radioactivity pH	No	None	Local Aux Bldg El - 40'	10	75	01, 02, 03-M-CMP-001 and -002
Chemical Waste Neutralizer Tank (1 Sample Point at Each Tank)	None	Radioactivity pH	No	None	Local Yard Area El - 100' (V088 - V195)	10	75	01, 02, 03-M-CMP-001 and -002
Condensate Polishing Demineralizer (LO-TDS) Sump (2 Sample Points)	None	Radioactivity	No	None	Local Yard Area El - 100' (V028, V031)	60	100	01, 02, 03-M-CMP-001 and -002
Condensate Polishing Demineralizer (HI-TDS) Sump (2 Sample Points)	None	Radioactivity	No	None	Local Yard Area El - 100' (V034, V037)	60	100	01, 02, 03-M-CMP-001 and -002
Retention Tank (Holdup Prior to Evaporation Pond) (2 Sample Points)	None	pH, Hydrazine Radioactivity	No	None	South of Unit 3, El - 100' (V227, V229)	Atmos.	116	A0-M-OWP-004
Spent Regeneration Sump Water Reclamation Facility)	None	pH	No	Yes pH	Water Rec Facility	40	75	01, 02, 03-M-CMP-001 and -002 A0-M-CMP-003
Demineralizer Influent	Fine	Dissolved O_2	No	Cation and Specific Conductivities, pH, Sodium	Local and Remote Cold Lab Aux Bldg El - 140'	450	120	01, 02, 03-M-CDP-001, -002, -003 and -004 01, 02, 03-M-SCP-005, -006 and -007
Demineralizer Effluent	Fine	Conductivity, pH, Chlorides, Sodium	No	Cation and Specific Conductivities	Local/Remote Cold Lab Aux Bldg El - 140'	450	120	01, 02, 03-M-CDP-001, -002, -003 and -004 01, 02, 03-M-SCP-005, -006 and -007

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 7 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[b]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters		Engineering Drawing
						Pressure (psig)	Tempera-ture (^{o}F)	
Secondary Sample Points (Cont'd)								01, 02, 03-M-FWP-001
S/G 1 and 2 Feedwater	Rough Fine	Conductivity, pH, Dissolved O_2, Hydrazine, Sodium, Boron	No	Cation and Specific Conductivity, pH, Hydrazine, Sodium	Local/Remote Cold Lab Aux Bldg El - 140'	1300	450	01, 02, 03-M-SGP-001 and -002 01, 02, 03-M-SCP-005, -006 and -007
Main Steam S/G 1 and 2	Rough Fine	Chloride, Sodium, Si, Sulfate, Cation Conductivity Silica	No	Cation Conductivity	Local/Remote Cold Lab Aux Bldg El - 140'	1100	575	01, 02, 03-M-SGP-001 and -002 01, 02, 03-M-SCP-005, -006 and -007
Reverse Osmosis Outlet	None	Chlorine	Yes	Yes Chlorine	Local Water Treatment Bldg	30	90	01, 02, 03-M-CTP-001, A0-M-DSP-001
Domestic Water Filter Outlet	None	Chlorine	Yes	Yes Chlorine	Local Water Treatment Bldg	30	90	01, 02, 03-M-CTP-001 A0-M-DSP-001
Domestic Water Filter Outlet	None	Chlorine	Yes	Yes Chlorine	Local Water Treatment Bldg	125	90	01, 02, 03-M-CTP-001 A0-M-DSP-001
ESF Sump Pump A and B Discharge	None	pH	No	None	Local Aux Bldg El - 40'	50	120	01, 02, 03-M-RDP-002
ESF Sump Pump A and B Discharge	None	pH	No	None	Local Aux Bldg El - 40'	15	120	01, 02, 03-M-RDP-002
Blowdown Demineralizer Effluent (1)	Rough	Na, Si, Silica, Conductivity Radioactivity	Yes	Yes, Na, Cation Conductivity	Remote Yard Area	225	135	01, 02, 03-M-SCP-004, -002
Blowdown Demineralizer Effluent (2)	Rough	Na, Si, Silica Conductivity Radioactivity	Yes	Yes, Na, Cation Conductivity	Remote Yard Area	225	135	01, 02, 03-M-SCP-004, -002
Blowdown Demineralizer Strainer Influent (1)	None	Conductivity	Yes	Yes Conductivity	Remote Yard Area	225	135	01, 02, 03-M-SCP-004, -002
Blowdown Demineralizer Strainer Influent (2)	None	Conductivity	Yes	Yes Conductivity	Remote Yard Area	225	135	01, 02, 03-M-SCP-004, -002
Blowdown Demineralizer Waste (High TDS)	None	Conductivity Radioactivity	Yes	Yes Conductivity	Remote Yard Area (V182, V204)	225	135	01, 02, 03-M-SCP-002

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 8 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[b]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters: Pressure (psig)	Design Parameters: Temperature ($^{\circ}F$)	Engineering Drawing
Secondary Sample Points (Cont'd)								
Blowdown Demineralizer Waste (Low TDS)	None	Conductivity Radioactivity	Yes	Yes Conductivity	Remote Yard Area (V182, V204)	225	135	01, 02, 03-M-SCP-002
Diesel Fuel Oil Storage Tank A and B	None	API° Gravity, Viscosity, Water and Sediment	No	None	Local Outside by D.G. Bldg El - 100'	35	75	01, 02, 03-M-RDP-004
Condenser Sump (North and South) Pump Discharges	None	Radioactivity	No	None	Local Turb Bldg El - 100' (V075, V078)	20	75	01, 02, 03-M-OWP-001, -002 and -003 and A0-M-OWP-004
Turbine Building Sump	None	Radioactivity	No	None	Local Turb Bldg El - 100' (V076)	20	75	01, 02, 03-M-OWP-001, -002 and -003 and A0-M-OWP-004
TCW Pump A and B Discharge	None	pH, Chloride ions, Nitrite, Fluoride	No	None	Local Turb Bldg El - 105'	90	110	01, 02, 03-M-WCP-001
Auxiliary Steam Condensate Receiver Tank	Portable	pH, Conductivity Sodium, Chloride, Sulfate, Radioactivity	No	Radioactivity[c]	Local Aux Bldg El - 40'	15	212	13-M-ASP-001
Auxiliary Steam	Rough	pH, Conductivity Nitrogen	No	None	Local Yard Area	250	405	A0-M-ASP-002
Circulating Water Cooling Towers	None	Foam, pH, Conductivity Silica, Calcium	No	No	Local Cooling Tower Area	Atmos.	108	01, 02, 03-M-CWP-001
Demineralized Water Surge-Rinse Tank	None	Water Chemistry pH, Conductivity, Oxygen	Yes	Yes Silica, Oxygen, Conductivity	Wtr Treatment Area	20	Ambient	A0-M-DWP-001 and 01, 02, 03-M-DWP-002
Demineralized Water Storage Tank	None	Water Chemistry Conductivity, Silica, Radioactivity	No	None	Local Yard Area	288" H_2O	Ambient	A0-M-DWP-001 and 01, 02, 03-M-DWP-002

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 9 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[b]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters Pressure (psig)	Design Parameters Temperature (°F)	Engineering Drawing
Secondary Sample Points (Cont'd)								
Fuel Pool Clean-up Pump (1 & 2) Discharge (Spent Fuel Pool or Refueling Pool)	None	Boron, Sulfate, pH, Chloride ions, Fluoride ions, Boric Acid, Ammonia, Lithium, Radioactivity	No	None	Local Fuel Bldg El - 100'	90	125	01, 02, 03-M-PCP-001
Fuel Pool Clean-up Filter 1 & 2 Outlet (Spent Fuel Pool or Refueling Pool)	None	Conductivity, pH, Chloride ions, Sodium Radioactivity	No	None	Local Aux Bldg El - 120'	50	125	01, 02, 03-M-PCP-001
Fuel Pool Clean-up Demineralizer 1 & 2 Outlet (Spent Fuel Pool or Refueling Pool)	None	Conductivity, pH, Chloride ions, Sodium, Sulfate Radioactivity Decon Factor	No	None	Local Aux Bldg El - 130'	50	125	01, 02, 03-M-PCP-001
Radwaste Sampling Points								
Evaporator Feed from LRS Holdup Pumps	None	pH	No	Yes pH	Local Radwaste Bldg El - 100'	107 psia	60 to 120	01, 02, 03-N-LRP-001, -002 and -003
Chemical Drain Pump Discharge	None	pH, Conductivity	Yes	None	Local Radwaste Bldg El-140'	88 psia	60 to 120	01, 02, 03-N-LRP-001, -002 and -003
Hi-Lo TDS Holdup Pump Recycle	None	pH, Conduc-tivity Boric Acid Concentration	Yes	None	Local Radwaste Bldg El-100'	Hi-TDS 55 psia LO-TDS 42 psia	60-120	01, 02, 03-N-LRP-001, -002 and -003
Evaporator Concentrate Pumps Recycle to Vapor Body	Portable	Boric Acid Concentration, pH, Wt% Solids	Yes	None	Local Radwaste Bldg El-120'	34	224	01, 02, 03-N-LRP-001, -002 and -003
Gas Sampling System								
Gas Surge Tank	None	Radioactivity, O_2	No	O_2[d]	Remote Radwaste Bldg El-140''	380	200	01, 02, 03-N-LRP-001, -002 and -003 01, 02, 03-N-SSP-001 01, 02, 03-N-GRP-001

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 10 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[b]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters: Pressure (psig)	Design Parameters: Temperature (^{o}F)	Engineering Drawing
Gas Sampling System (Cont'd)								
Gas Decay Tank	None	Radioactivity, O_2	Yes	O_2[d]	Remote Rad-waste Bldg El-140'	380	200	01, 02, 03-N-GRP-001 01, 02, 03-N-SSP-001
Gas Stripper	None	Radioactivity, O_2	Yes	O_2[d], When Selected	Remote Rad-waste Bldg El-140'	200	120	01, 02, 03-N-GRP-001, 01, 02, 03-N-SSP-001
Volume Control Tank	None	Radioactivity, O_2	No	O_2[d], When Selected	Remote Rad-waste Bldg El-140'	50	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005 01, 02, 03-N-SSP-001
Equipment Drain Tank	None	Radioactivity, O_2	No	O_2[d], When Selected	Remote Rad-waste Bldg El-140'	3	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005 01, 02, 03-N-SSP-001
Reactor Drain Tank	None	Radioactivity, O_2	No	O_2[d], When Selected	Remote Rad-waste Bldg El-140'	3	120	01, 02, 03-N-GRP-001 01, 02, 03-N-SSP-001
Holdup Tank	None	H_2	No	None	Local Rad-waste Yard Area	Atmos	120	01, 02, 03-M-CHP-001, -002, -003, -004 and -005 01, 02, 03-N-SSP-001
Containment Atmosphere	None	Radioactivity	No	Radio-activ-ity[c]	Local Aux Bldg. 100' Level NE Quad	5	122	01, 02, 03-M-CPP-001 01, 02, 03-M-HCP-001
Containment Purge Exhaust	None	Radioactivity	No	Radio-activ-ity[c]	Local Aux Bldg. 100', 140' Level NE Quad	Atmos	120	01, 02, 03-M-CPP-001

Table 9.3-3
SAMPLING SYSTEM DESIGN PARAMETERS (Sheet 11 of 11)

Sample Origin	Type of Sample Cooler	Typical Discrete Sample Analysis[b]	Pressurized Sample Capability	Continuous On Line Analysis Provided	Mode of Sample Removal and Location	Design Parameters Pressure (psig)	Design Parameters Tempera-ture (°F)	Engineering Drawing
Gas Sampling System (Cont'd)								
Plant Vent	None	Radioactivity	No	Radio-activ-ity[c]	Local Turb Bldg. 176' Level	Atmos.	120	01, 02, 03-M-CPP-001
Containment Atmosphere	None	Moisture (4 points)	No	Yes Moisture (4 points)	Local 1 at El-104'-6" NW Quad; 1 at El 124'-9" NW Quad;	5	122	01, 02, 03-M-HCP-001
Control Building Outside Air Intake	None	Radioactivity Smoke, Cl_2 (2 points each)	No	Radio-activ-ity[c] Smoke, Cl_2 (2 points each)	Remote Control Bldg. 140' Level in Outside Air Chase	Atmos	113	01, 03-M-HJP-001 and 02-M-HJP-001 and -002

E. Chemical and Volume Control System Samples (Normal Sampling Only)

Both liquid and gas sampling provisions are required to monitor chemical and volume control system (CVCS) performance.

1. In order to monitor the overall purification effectiveness, liquid samples are taken from the purification filter inlet stream for filterable corrosion products, the outlet stream for soluble activity, and the purification ion exchanger outlet for soluble activity.

2. Deleted

F. Representative Samples

In order to ensure that representative samples are obtained, the sampling lines are purged prior to sampling. Purge flow shall be high enough (i.e., turbulent) to inhibit deposition of suspended solids and to remove crud from sampling lines.

G. Relief Protection

Relief protection is provided to limit the sample pressure to a value below the design rating of the sampling system.

H. The seismic design classification and quality group classification of sample lines and components conform to the classification of the system to which each sampling line and component is connected out to such a point where classification to lower seismic and quality group

classification is justified on the basis that adequate isolation valving or flow restriction is provided.

I. Sample lines penetrating the containment are provided with isolation valves in accordance with 10CFR50, Appendix A, General Design Criterion 55 or 56. Containment isolation is described in subsection 6.2.4.

J. The configuration of the process sampling system provides the sample points and capability outlined in table 9.3-3.

K. The process sampling system provides the capability to conduct the continuous analyses indicated in table 9.3-3.

L. The process sampling system shall provide the capability to conduct discrete analyses on samples as indicated in table 9.3-3.

M. For the process sampling system, the reactor coolant sample lines shall be sized to assure complete turbulent flow during purging (i.e., Reynolds Number ≥4.000). This ensures particle suspension.

N. The process sampling system shall be designed to direct most reactor coolant sample purge fluids to the volume control tank or the recycle drain header. Other radioactive samples that purge and overflow a sample collector are directed to the liquid radwaste system discussed in section 11.2.

O. Sample lines connected to ASME Section III code class lines or vessels shall be constructed in accordance with

ASME Section III code class up to and including the first normally closed manual, automatic isolation, or throttling valve.

P. Consistency with the recommendations of Regulatory Guide 1.21, Revision 1, and ANSI N13.1-1969 is discussed in section 11.5.

Q. Codes and standards applicable to the process sampling system are listed in table 3.2-1.

9.3.2.2 System Description

The normal process sampling system is illustrated in engineering drawings 01, 02, 03-N-SSP-001. The secondary sampling system and local sampling points are illustrated on the piping and instrumentation diagrams (P&IDs) referred to in table 9.3-3 and in engineering drawings 01, 02, 03-M-SCP-005, -006 and -007.

Locations of sample points are shown on the appropriate system P&IDs for the systems to be sampled. The process sampling system includes sampling lines, heat exchangers, sample vessels, sample sinks or racks, analysis equipment, and instrumentation.

The sampling points have been selected to provide the required chemical and radiological information while keeping the system simple for reliability and ease of maintenance. Separate lines from the various sampling points to the sample sink or sample vessel are provided to allow for simultaneous sampling. The normal process sampling system is operated from the cold or hot laboratory's sampling room, with the exception of the

containment isolation valves which are operated from the control room.

Chemical and radiochemical analyses are performed to determine boron concentration, fission and corrosion product activity, crud concentration, dissolved gas and corrosion product concentrations, chloride concentration, coolant pH, conductivity of the reactor coolant, and noncondensable gas concentration in the pressurizer. Analyses results from the normal process sampling system are used to regulate the boron concentration, monitor the fuel cladding integrity, evaluate ion exchanger and filter performance, specify chemical additions to the various systems, and maintain the proper hydrogen concentration in the reactor coolant systems.

9.3.2.2.1 Normal Operation

Reactor coolant system samples are taken from the hot leg piping of one reactor coolant loop, the pressurizer surge line, and the pressurizer steam space. These high-pressure, high-temperature samples are individually routed to the sampling room where they are first cooled in a sample heat exchanger to 120F or less, and then reduced in pressure by a throttling valve to approximately 25 psig. The reactor coolant flows to the volume control tank or to the equipment drain tank through a purge line until sufficient volume has passed to permit the collection of a representative sample. The purge flow is normally directed to the volume control tank in the CVCS to minimize waste generation.

The hot leg is sampled to check reactor coolant chemistry and radioactivity. Piping is arranged so that the overall transit

time from the loop to the containment wall is sufficient to permit decay of short-lived radioactivity. Two types of samples may be collected from the hot leg: a high-pressure, low-temperature sample may be collected in a sample vessel where amounts of oxygen, nitrogen, helium, hydrogen, and fission gases can be determined; or a low-pressure, low-temperature sample may be collected at the sampling sink where an analysis of the chloride and boron concentration can be made. The pressurizer surge line sample checks the boron concentration at the pressurizer surge line. This low-pressure, low-temperature sample is collected in the sampling sink only. Pressurizer steam space samples can be collected in a sample vessel at a high pressure and low temperature. These samples give a representation of fission products and noncondensable gases in the pressurizer steam space.

Liquid samples taken from the safety injection system are at intermediate temperature and pressure and are routed through a sample heat exchanger and a manually set throttling valve in the sampling room. Remote or local (dependent on RCS pressure) samples are taken separately from each of the two shutdown cooling suction lines. Remote samples are taken from the safety injection pump miniflow lines to check the boron concentration of the recirculated water. The safety injection pump sample points permit sampling during the recirculation period following a postulated loss-of-coolant accident (LOCA), while the shutdown cooling samples allow for the verification of the reactor coolant boron concentration prior to and during shutdown cooling.

Low-pressure, low-temperature samples from the CVCS and the secondary chemistry control system (SCCS) are routed directly to the hot laboratory and cold laboratory. The purification filter inlet and outlet samples from the CVCS verify filter performance for crud removal. The purification ion exchanger outlet sample, together with the purification filter outlet sample, verify ion exchange removal of soluble activity.

In order to assure that a representative sample is obtained, the sampling lines are purged prior to withdrawing the sample. The volume of the purge flow must be at least twice sampling line volume. This purge must be accomplished for two different sections of the sampling system. First, the lines are purged, usually to the volume control tank to minimize waste or to the equipment drain tank. Second, the lines to the sample sink are purged prior to withdrawing a hand sample. The pressure and flowrate of these purge flows are indicated in the sampling room.

The sample volume will vary according to the type of analysis to be performed. The hot leg and pressurizer steam space samples that will be collected as high-pressure, low-temperature samples within the sample vessel will have a volume of 1 liter. From this type of sample, corrosion product concentrations and activity levels, fission products and gases, or other noncondensable gases can be determined. However, these same samples can be collected at the sample sink as low-pressure, low-temperature samples. In this case, the sample volume required would be approximately 250 ml for a boron or chloride concentration analysis and could be as large as 5 liters for a crud concentration analysis. When testing for

coolant pH and conductivity at the various sample points, a sample volume of 250 ml will also be sufficient.

Samples can be collected at the sample sink located in a hooded, ventilated enclosure equipped with a fan exhausting to the plant vent system. A demineralized water line is routed to the sink for flushing purposes. The sink drains to the liquid radwaste system.

Relief protection is provided to limit the sample pressure to 140 psig. The relief valve discharge to the equipment drain tank located in the CVCS.

9.3.2.2.2 Post-Accident

Post accident, PVNGS will use the normal sampling system to secure samples. This will be performed in accordance with ALARA guidelines.

9.3.2.2.3 Secondary Systems Drain Sampling

There are eight sumps in or near turbine building structures with potential for transferring radioactivity to flow paths leading to the retention tanks/evaporation ponds.

In addition to the eight sumps, the Blowdown Flash Tank Overboard path and the Condensate Polishers Pre-Service Rinse Overboard path have the potential for transferring radioactivity to the retention tanks. These two paths discharge through a common line into the CWNT header. Prior to entering the CWNT header, the effluent is sampled by a continuous-acting radiation monitor, JSQN-RU0200. This monitor alarms in the control room and automatically closes the

discharge valve, JSCN-HV1283, when radioactivity in the liquid effluent exceeds predetermined limits. In the event of a radiation monitor failure or loss of power to the monitor or the isolation valve, the isolation valve will close and terminate this path. There are three drainage sumps in the turbine building: the north sump, the south sump, and the turbine building sump. Each sump has an analysis point on its discharge piping and can transfer fluids to the liquid radwaste system (LRS), either of two chemical waste neutralizing tanks (CWNTs), or to an oil/water separator. Each CWNT has separate analysis points and can be sampled prior to discharge. Each CWNT can discharge to the LRS or the retention tanks. The oil/water separator discharges to its sump (sump four), which in turn discharges to the retention tanks.

There is not a very great potential of introducing significant radioactivity to these sumps, and it is not likely that the sumps would be aligned to discharge radioactivity to the retention tanks. The following are the sources to these sumps:

<u>North Sump</u>

Battery room neutralizing pit (nonradioactive)

Floor drains (equipment leakage and cleaning liquids)

Feedwater heaters Heater drain tank and pump

Instrument air compressor drains (nonradioactive)

Air dryer/prefilter drains (nonradioactive)

Blowdown flash tank liquid drain

Turbine cooling water heat exchanger drain (nonradioactive)

Turbine cooling water surge tank drain (nonradioactive)

Heater blowdown stack Condensate storage tank

Condenser drains

Generator stator cooler drain (nonradioactive)

South Sump

Floor drains (equipment leakage and cleaning liquids)

Low-pressure heaters and condenser drains

Condenser evacuation drain

Steam seal exhauster drain

Isophase bus cooler drain (nonradioactive)

H_2 seal oil cooler (nonradioactive)

Condensate pump drainage

Turbine Building Sump

Feedwater pump lube oil reservoir drains (nonradioactive)

Feedwater pump drain

Turbine lube oil drains (nonradioactive)

Oil/Water Separator Sump

North, south, and turbine building sumps

Control building sumps (nonradioactive)

The only sources noted above that could contain any radioactivity are secondary system component sources -- condensate or blowdown. No regenerant chemicals are present. Thus, any radioactivity which is present must be at least as dilute as the secondary system.

The activity level in the secondary system is monitored at two points. Steam generator blowdown monitors 13-J-SQN-RU-4 and RU-5 will detect abnormal activity in the secondary as it is diverted to the blowdown processing equipment. The condenser gland seal exhauster monitor 13-J-SQN-RU-141 will detect abnormal activity in the condenser.

If abnormal activity levels are present, sump transfer paths will be aligned to transfer to the LRS or the CWNTs with subsequent alignment to the LRS. However, if it is determined during operating (by sampling or monitoring) that the sumps do not contain significant radioactivity, they may be realigned to discharge to the CWNTs (aligned to the retention tanks) or the oil water separator and thence to the retention tanks.

The remaining four sumps are the high and low total dissolved solids (TDS) sumps that receive regenerant wastes from the condensate polishing demineralizers or the blowdown demineralizers, respectively. Each sump has local drains that will be used for grab sampling. For either processing stream, initial regenerant effluent is fed to the resin and subsequently directed to the high TDS sumps. These discharge to the CWNTs. As noted previously, the CWNTs can discharge to the LRS or retention tanks and are sampled prior to discharge. Only after the TDS level of the regenerant has dropped (associated with activity levels), as measured by online conductivity cells, would flow be directed to the low TDS sumps or the circulating water system (and thence to the evaporation ponds via blowdown). Thus, the systems are designed to send radioactive waste to the LRS and yet recover clean liquid for recycle to the greatest extent practical.

To ensure that abnormal levels of activity are not sent to clean systems, design provisions for sampling have been clarified. Table 9.3-3 has been revised to show the sampling capabilities at these sumps. Operationally, when significant activity is present in the secondary (as detected by the steam generator or condenser gland seal exhaust monitors), the low TDS sumps will be aligned to discharge to the high TDS sumps. A grab sample analysis for radioactivity will be required prior to changing this alignment to allow discharge to the circulating water.

In summary, the secondary systems are continuously monitored for activity. If abnormal activity is present, this will lead to alignment of leakage and cleanup stream discharge to the LRS. If, after grab sampling, no abnormal activity is present in effluents, they can be directed to the circulating water or retention tanks.

9.3.2.2.4 Retention Tanks Sampling

The divided retention tank is located south of the Unit 3 spray ponds. It has approximately a 1-million gallon capacity and is divided into two identical compartments. The compartments are approximately 123 feet x 93 feet with a nominal depth of 8 feet which includes a 2 foot freeboard. To avoid ponding on the bottom of the tank during dewatering cycles, the tank is sloped 1/8 inch per foot from North to South.

The tanks act as storage in the event the effluent is not within the standards for pH, Hydrazine, and radioactivity prior to discharge to the evaporation pond. One retention tank can store the normal waste effluent of 800 gallons per minute for a

10-hour period. The offline tank is monitored, chemically treated (if necessary), and discharged to the evaporation pond. The waste effluent which meets the Offsite Dose Calculation Manual (ODCM) release limits will be pumped into evaporation ponds numbers 1 and/or 2.

Sampling can be conducted directly by dip grab sampling or by sampling the retention tank pump discharge (engineering drawing A0-M-OWP-004, valve V227 or V229.)

If a portable ion exchanger is used to purify the retention tank, expended resins will be disposed of in one of two ways. If resins are radioactive, they will be transferred by truck or drum to the solid radwaste system of either Unit 1, 2, or 3. If resins are not radioactive, they will be hauled to a licensed disposal site. Regeneration is not currently contemplated due to the low frequency projected for this operation.

9.3.2.3 Component Description

9.3.2.3.1 Sampling Lines

Sampling points are at locations where turbulence ensures representative sampling. Sampling nozzles are provided where deemed required as shown on the appropriate system P&ID. The sample line from the RCS hot leg has a delay that ensures adequate N-16 decay through a transit time of approximately 90 seconds to the secondary shield wall. Sampling lines from the primary coolant loop are provided with flow restriction orifices to limit coolant loss from a rupture of the sample line.

Fail-closed containment isolation valves are provided for sampling lines that penetrate the containment.

Relief valves provide protection to limit the pressure to a value below the design rating of the sampling system.

Waste handling is provided for purging the primary sample lines with sample fluid and flushing with demineralized water.

9.3.2.3.2 Sample Coolers

Rough and fine sample coolers are provided for remote sampling. These coolers are heat exchangers. Cooling is provided by the nuclear cooling water system for the primary sampling system and by the nuclear cooling water system, turbine cooling water system, and chilled water system for the secondary sampling system.

Where temperatures are above 140F, portable coolers are used for local grab sample points to prevent injury to sampling personnel.

The primary sampling heat exchangers are located in the hot laboratory in the auxiliary building.

The maximum sample temperature out of the heat exchangers is 120F for all operating modes.

Table 9.3-5 stipulates the primary sampling system design parameters.

Table 9.3-6 contains the operating parameters for the sample heat exchangers.

9.3.2.3.3 Sample Vessels

9.3.2.3.3.1 Normal. A capability is provided to take pressurized samples from the sources indicated in table 9.3-3. Each sample line from these sources is provided with connections for a sample pressure vessel to provide the capability to sample at the local RCS operating pressure. The vessel is sized to contain a sufficient volume to perform an analysis of reactor coolant for dissolved hydrogen or fission gas content. The vessel material is chemically compatible with reactor coolant.

Table 9.3-5 stipulates the sample vessel design parameters.

9.3.2.3.3.2 Post-Accident. The capability is provided to take depressurized samples from the RCS.

9.3.2.3.4 Primary Sample Sinks

The primary sample sinks are located in the hot laboratory along with the sample vessels and associated control panels. The sample sink is drained to the liquid radwaste system through a water trap. Demineralized water is provided at the sample sink to flush and clean the sink. The sampling room and sample hood are ventilated. Additional ventilation requirement

9.3.2.3.5 Gas Analyzers

Dual oxygen gas analysis equipment located in the radwaste building has the capability to analyze selected sample points.

Continuous sampling capability is provided for the gaseous radwaste system (GRS) surge tank and the waste gas header. The

surge tank sample provides a representative sample of a mixture of gases that accumulate in the surge tank while the GRS compressor is not in operation.

These analyzers provide a direct readout of oxygen concentration. The dual oxygen monitors have automatic control functions which preclude the formation of explosive hydrogen and oxygen mixtures. Alarms are provided in the radwaste panel and main control room to notify the operators of high oxygen. Samples may be collected in a sample vessel and taken to the hot laboratory for further analysis.

It is assumed that the waste gas holdup system contains greater than 4% hydrogen whenever the system is in service.

Automatic control functions are provided to stop compressor operation on high-high oxygen alarm at 3.75%. Analyses are provided on the suction side of the compressor (by sampling the surge tank and waste gas surge header).

The O_2 content of the sampled gas is indicated in the radwaste control room. Annunciating alarms are provided locally in the radwaste control room for each train of the gas analyzer, and a common radwaste trouble alarm is provided in the main control room via the plant computer. The O_2 high alarm is set at 2% and the high-high alarm is set at 3.75%.

Table 9.3-5
PRIMARY SAMPLING SYSTEM DESIGN PARAMETERS
(NORMAL) (Sheet 1 of 1)

Sample Heat Exchanger	
Quantity	5 (identical units)
Type	Shell and tube, vertical
Tube side (sample)	
Fluid	3.6 wt. % boric acid
Design pressure	2485 psig
Design temperature	700F
Pressure drop	55 psi at 0.5 gal/min
Material	Stainless steel
Shell side (component cooling water)	
Fluid	Nuclear cooling water
Design pressure	150 psig
Design temperature	200F
Pressure drop	3 psi at 3 gal/min
Material	Carbon steel
Safety class, tube/shell	NNS/NNS
Seismic class, tube/shell	None/None
Sample Vessel	
Quantity	2
Internal volume	1000 $cm^{(3)}$
Design pressure	2485 psig
Design temperature	200F
Normal operating pressure	2250 psia
Normal operating temperature	120F
Material	Stainless steel
Fluid	3.6 wt % boric acid
Safety class	NNS
Seismic class	None

Table 9.3-6
OPERATING PARAMETERS FOR THE SAMPLE HEAT EXCHANGERS

Sample Heat Exchanger	Tube Side (Sample)			Shell Side (Cooling Water)			Heat Transferred (Btu/h) (max)
	T In (F)	T Out (F)	Flow (gal/min) (max)	T In (F)	T Out (F)	Flow (gal/min) (max)	
Pressurizer steam space	653	120	1.0	105	125	30	5.1×10^5
Pressurizer surge line	653	120	1.0	105	135	30	5.1×10^5
Hot leg	621	120	1.0	105	135	30	5.1×10^5
Safety injection system	350	120	1.0	105	140	30	5.1×10^5
Safety injection sumps	350	120	1.0	105	140	30	5.1×10^5
Containment radwaste sumps	350	120	1.0	105	140	30	5.1×10^5

Table 9.3-7 provides sample points, alarms, and frequencies.

Table 9.3-7
SAMPLE POINTS, ALARMS, AND FREQUENCIES
FOR GAS ANALYZERS

Sample Point	Frequency	Alarm
Train A		
Gas surge tank	Continuous	Oxygen
Train B		
Waste gas Header	Continuous	Oxygen

9.3.2.3.6 Analysis Equipment and Instruments

Modern chemistry instrumentation including ion chromatographs, auto-titrators, atomic absorption spectrophotometers, analytical balances and other common laboratory equipment and glassware are maintained in the both hot and cold chemistry laboratories. Certain laboratory instrumentation is utilized inline (continuous monitoring of the sample stream). Many samples can be drawn in the laboratory, however certain samples must be taken locally. Some inline instrumentation is located outside of the laboratory such as the hotwell monitoring skids located in the turbine building. Instruments for monitoring flow and pressure on the purge discharge line downstream of the common purge header are provided. The pressurizer steam space sample line, which is not connected to the header, has its own pressure and flow instruments. Post-accident analysis will be performed by laboratory analysis in an appropriate laboratory facility.

9.3.2.4 System Operation (For normal sampling only unless noted)

Except as discussed in paragraph 9.3.2.3.6, all primary and secondary sampling points can be sampled in the auxiliary building cold and hot laboratories. Secondary sampling points inside the turbine building can also be sampled in the turbine building cold laboratory. Remotely operated valves are controlled from the main control room or from the sampling laboratories.

9.3.2.4.1 Sample Line Purging

Prior to discrete samples being taken, the sample line for the normal sampling system is purged with the fluid to be sampled so that a representative sample may be obtained. For RCS samples, initial purge of most of the sample line length can be directed to the equipment drain tank for normal sampling. Secondary sampling purge can be directed to the liquid radwaste system. Final purging for the RCS during normal sampling is directed to the sample sinks. Sampling lines that are used for continuous samples do not require additional purging prior to taking a sample.

9.3.2.4.2 Discrete Atmospheric Pressure Liquid Sampling (Normal sampling only)

Each sample container is rinsed with the liquid to be collected prior to sample collection. The container is then stoppered with a stopper previously rinsed with the sample water.

9.3.2.4.3 Discrete Pressurized Liquid or Gaseous Sampling (Normal sampling only)

After the sample vessel is purged, samples are collected by closing valves at each end of the sample vessel. Venting to achieve atmospheric pressure within the sample container is required prior to some analyses.

9.3.2.4.4 Continuous Sampling (Normal sampling only)

Liquids or gases that require constant monitoring are directed through pressure-reducing devices, sample coolers, and ion exchanger, as required, prior to flowing through the inline device.

9.3.2.4.5 Analysis of Samples (Normal sampling only)

A capability is provided to determine such reactor coolant parameters in discrete samples as boron concentration, fission and corrosion product activity, dissolved gas concentration, chloride concentration, pH and conductivity, fission gas content, and gas compositions in various vessels. Analytical results are used to regulate boron control adjustments, monitor fuel rod integrity, evaluate ion exchanger and filter performance, specify chemical additions to the various systems, maintain the proper hydrogen overpressure in the volume control tank, and establish conformance with applicable technical specifications. Water quality analyses are performed on discrete and/or continuous secondary system samples as appropriate to determine such parameters as pH specific and cation conductivity, dissolved oxygen, residual hydrazine, sodium ion concentrations, and radioactivity. Conductivity and

pH measurements in the circulating water system are used to control chemical addition and blowdown to maintain acceptable water chemistry. The remainder of the analyses are recorded to permit appropriate monitoring by the operating staff.

9.3.2.5 Post Accident Operation

The operation of the sampling system requires communication between the chemistry technician and operators in the control room. Prior to sampling a specific point, the chemistry technician verifies with the control room operator to ensure that the system isolation valves are in the appropriate position to allow for sampling. This may involve overriding a CIAS to reopen certain valves.

9.3.2.5.1 Post Accident Sampling

The chemistry technician will then operate the sampling system to obtain the desired sample. Once the sample arrives at the remote grab sampler, the chemistry technician will obtain a sample for laboratory analysis. The grab sample is then transported to the appropriate laboratory for analysis.

9.3.2.6 Design Evaluation

The normally closed containment isolation valves are designed to fail closed, in addition to closing on a containment isolation signal. These valves can only be operated from the main control room.

Connections made to ASME Section III code class systems are fitted with flow restriction devices to satisfy NRC General Design Criterion 33. Sample system piping, up to and including

the passive flow restrictors, is designed and fabricated in accordance with the same code class as the system to which it is connected. The piping and components near the sample sink are of low pressure design and are provided with pressure relief for protection of personnel.

The sampling room and the sample hood are ventilated to reduce the potential for airborne radioactivity exposure. Operating procedures specify the precautions to be observed when purging and drawing samples.

9.3.2.7 Testing, Inspection, and Training

The containment isolation valves associated with any sampling system will undergo inservice inspection as described in section 6.6.

9.3.2.8 Instrumentation Applications

For the normal sampling system, pressure, temperature, and flow indicators and/or flow switches are used where required to facilitate manual operation and to verify sample conditions before samples are drawn.

A radiation sensing element monitors the steam generator sample for primary-to-secondary tube leaks (applicable to normal sampling only). A data logger records radiation levels and a high-radiation alarm in the control room warns of out-of-specification radioactivity.

Continuous analyzers monitor for normal sampling specific water quality conditions in the secondary plant. Alarms are sounded

when these sensors detect parameters that are out-of-specification.

9.3.2.9 CESSAR Interface Requirements

Refer to paragraphs 5.4.7.1 and 6.3.1.3.

9.3.2.10 CESSAR Interface Evaluations

Refer to paragraphs 5.4.7.2 and 6.3.1.4.

9.3.3 EQUIPMENT AND FLOOR DRAINAGE SYSTEMS

The equipment and floor drainage system is divided into individual and segregated systems:

A. Radioactive waste drainage system

B. Chemical waste system -- This system consists of five subsystems as follows:

- The radioactive chemical waste subsystem
- The cooling water waste subsystem
- The condensate polishers regeneration waste subsystem
- The spent regenerant waste subsystem
- The chemical tank drains

C. Oily waste and nonradioactive waste system

D. Sanitary drainage and treatment system

9.3.3.1 Design Bases

9.3.3.1.1 Safety Design Bases

The safety design bases pertinent to equipment and floor drainage systems are as follows:

A. Safety Design Basis One

The equipment and floor drainage system provided for each ESF equipment compartment shall not be interconnected to any other ESF compartment's equipment and floor drainage system unless check valves are utilized to prevent cross-flow.

B. Safety Design Basis Two

The equipment and floor drainage system shall be capable of preventing a backflow of water that might exist from maximum flood levels resulting from external or system leakage to areas of the plant containing ESF equipment.

9.3.3.1.2 Power Generation Design Bases

Power generation design bases pertinent to equipment and floor drainage systems are as follows:

A. Power Generation Design Basis One

Radioactive or potentially radioactive contaminated waste materials are selectively collected by drainage and collection systems that are separated and isolated from the drainage and collection systems provided for handling of strictly nonradioactive waste materials.

B. Power Generation Design Basis Two

A leak detection system is provided in the containment radwaste sumps where the flowrate can be established and monitored during plant operation. The sumps are instrumented with level alarms and indicators capable of monitoring the rate of leakage.

C. Power Generation Design Basis Three

A leakage detection system is provided to determine cask load pit, refueling pool and fuel pool liner plate leakage.

D. Power Generation Design Basis Four

Conduit drains for safety channel excore detectors are separated and protected from overfill to enable operation of the nuclear instrumentation following a LOCA.

E. Power Generation Design Basis Five

Watertight rooms are equipped with level switches in floor drains and room walls. Should a line rupture in the room, the control room would be informed by an annunciator activated by these switches. Each water-tight room is designed to contain water from a flood in that room until plant conditions are such that it can be drained into the normal drainage system.

F. Power Generation Design Basis Six

With the exception of the containment building, fuel building, and holdup tanks area, the sumps of collection systems for potentially radioactive drainage

are vented to the respective area's HVAC exhaust system.

G. Power Generation Design Basis Seven

Drainage lines from areas that are required to maintain an air pressure differential but drain into the same collection sump are provided with a water seal at the sump. This is accomplished by running separate branch drains with all inlets to the sump turned down and terminated at least 12 inches below the level at which the sump pump stops in pumping down the sump.

H. Power Generation Design Basis Eight

Sump pumps are designed to discharge at a flowrate adequate for preventing sump overflow during normally anticipated drainage periods.

I. Power Generation Design Basis Nine

Sump capacities provide a live storage capacity consistent with an operating period of not less than 5 minutes with one pump operating. Where necessary, additional live storage capacity is provided to minimize the possibility of drainage backup through floor drains.

9.3.3.1.3 Codes and Standards

Generally, equipment and floor drainage collection piping from areas of potential radioactivity and nonradioactivity within the power block is constructed in accordance with ANSI B31.1.0. All other drainage systems comply with the plumbing code adopted by the Maricopa County Plumbing and Developing

Department regarding permits, materials of construction, installation, tests, inspections, and approval. All drainage systems comply with the intent of the following sections of Title 29, Chapter XVII, Part 1910 (OSHA) of the Code of Federal Regulations, as set forth in the Federal Register, Volume 37, Number 202, Sections 1910.96, 1910.106, 1910.141, 1910.151, 1910.156, and 1910.159 (c) (3), dated October 18, 1972.

9.3.3.2 System Description

9.3.3.2.1 General Description

9.3.3.2.1.1 Radioactive Waste Drainage System. The radioactive waste drain system collects and transports noncorrosive, radioactive, or potentially radioactive liquid wastes from equipment and floor drains of the containment building, the auxiliary building, the fuel building, the radwaste building, the holdup tank area, and the decontamination and laundry facilities. The wastes collected are pumped to the liquid radwaste system for processing.

9.3.3.2.1.1.1 Containment Building. The radioactive waste drain system within the containment building consists of floor and equipment drains, vertical drain risers, sloped horizontal drain pipes, two containment radwaste sumps interconnected by piping, each with one 100%-capacity sump pump, one reactor cavity sump with two 100%-capacity sump pumps, piping, valves, controls, and instrumentation serving the equipment and areas shown in engineering drawings 01, 02, 03-M-RDP-001.

The maximum normal leakage to the containment radwaste sumps is estimated to be 30 gallons per day. During refueling

operation, equipment decontamination is estimated to result in a total flow of 54 gallons per minute for 30 minutes directed to the containment radwaste sumps. The maximum reactor vessel seal ring leakage is estimated at 0.5 gallon per minute and is directed to the reactor cavity sump.

The reactor cavity sump pumps, operating automatically under control of level instrumentation in the sump, pump the collected waste from the sump to the containment radwaste sump east. The containment radwaste sumps (east and west) are interconnected with a 4-inch line. Each containment radwaste sump is provided with one sump pump. Both sump pumps, operating automatically under control of their own level instrumentation, pump the collected waste from the sumps to the liquid radwaste system holdup tanks.

Leak detection is done by time level measurements in the reactor cavity sump and in the containment radwaste east and west sumps. Flowrate changes, which exceed a preset rate limit, are readily detected by monitoring the changes in sump water level. In the event that the rate of fill of the sumps exceeds the preset rate limit, an alarm will annunciate in the control room.

A leak detection station is provided to monitor leakage through the refueling pool liner plate. The detection system is divided into six leak chase zones such that a leak in the liner plate can be isolated to a specific zone. The leak chases for each zone are manifolded into one detection test station having a normally closed valve. The test station for each leak chase zone is monitored periodically for leakage.

Excore detector drains are provided to remove condensate buildup within the excore detectors. The conduit drains for the safety channel excore detectors are separated and protected from overfill in the sump to enable operation of the nuclear instrumentation following a LOCA.

9.3.3.2.1.1.2 Auxiliary Building. The radioactive waste drain system within the auxiliary building consists of floor and equipment drains, vertical drain risers, sloped horizontal drain pipes, three sumps, each with two 100%-capacity sump pumps, piping, valves, controls, and instrumentation serving the equipment and areas as shown in engineering drawings 01, 02, 03-M-RDP-002 and -003.

The drainage system for the rooms containing redundant ESF equipment are provided with separate drainage subsystems, utilizing independent drain trains (train A and train B), so that flooding of the redundant ESF rooms of one train will not jeopardize the operation of the remaining train of redundant ESF equipment. The two drainage subsystems providing drainage for the ESF equipment rooms are separate from the drains serving the non-ESF equipment rooms.

The ESF drain headers empty into independent and segregated sumps. A separate drain header is provided for the non-ESF equipment which empties into a separate sump. Engineered safety features train A sump, ESF train B sump, and the non-ESF sump are each equipped with two 100%-capacity sump pumps. The sump pumps, operating automatically under control of level instrumentation in the sump, pump the collected waste from the sump to the liquid radwaste holdup tanks.

The maximum normal leakage to the non-ESF sump is estimated at 116 gallons per day. Maximum abnormal leakage to the non-ESF sump is estimated at 10 gallons per minute. The maximum normal leakage to each ESF sump is estimated to be 10 gallons per day. The maximum abnormal leakage to each ESF sump is estimated to be 50 gallons per minute.

The abnormal leakage of 50 gallons per minute conservatively bounds the total leakage from all ESF components, such as pumps, valves, etc. The auxiliary building is sized to accept 400,000 gallons of non-ESF leakage before any leakage would affect ESF components. For flooding considerations, all nonseismic piping was assumed to have failed. The water volume released will not exceed the design 400,000-gallon capacity. The auxiliary building rooms, including the ESF pump rooms on elevation 40, were analyzed for flooding due to rupture of the largest nonsafety-related piping for a duration of 30 minutes. Flooding was also analyzed based on operation of fire protection systems, such as hoses and sprinklers, for 15 minutes without operator action or without operation of the sump pumps.

To assure train separation of ESF equipment necessary for the safe shutdown of the plant, each train-oriented piece of equipment is placed in its own room. These rooms prevent excessive amounts of water, from a tank or pipe rupture, from flooding redundant train-oriented equipment in the building. These rooms are designed to handle a limited duration single failure of the heaviest flowing line in any compartment containing safety-related piping or equipment. A single

failure of any line in an equipment area will affect, at worst, only one train of operation.

Engineered safety features equipment rooms are equipped with Class 1E level switches in leak detecting floor drains. Should a line rupture in the room, the control room would be informed by an annunciator activated by these switches (refer to section 7.6). The auxiliary building drains are run so that leakage external to the ESF equipment room does not flow into the rooms. Each room is protected from backflow by a check valve located in the drain line.

9.3.3.2.1.1.3 Radwaste Building. The radioactive waste drain system within the radwaste building consists of floor and equipment drains, vertical drain risers, sloped horizontal drain pipes, one sump with two 100%-capacity sump pumps, piping, valves, controls, and instrumentation serving the equipment and areas as shown on engineering drawings 01, 02, 03-M-RDP-004.

The maximum normal leakage to the sealed sump is estimated at 12 gallons per day. Maximum abnormal leakage is estimated at 400 gallons per day.

The sump pumps, operating automatically under control of level instrumentation in the sump, pump the collected waste from the sump to the LRS holdup tanks.

The room containing the antifoam, caustic, and acid tanks and pumps has its floor and equipment drains routed to a neutralizer tank prior to draining to the building sump. The neutralizer tank is located in a concrete pit. Its

neutralization medium can either be lump limestone or marble chips with a high calcium carbonate equivalent content in excess of 85%. Since this area of the radwaste building has insignificant potential for radioactive contamination, a trap is installed in the drain line upstream of the neutralizer tank to prevent acidic or caustic fumes from entering the room.

The LRS holdup tanks and the LRS recycle monitor tanks are located outside in the yard adjacent to the radwaste building in concrete compartments that are open to the atmosphere. The floor drains for these compartments are isolated from the radwaste building sump by means of a normally closed valve to prevent rainwater from entering the sump. In the event of a rainstorm, a pipe and closed valve are provided to drain the contained water to ground surface, or the rainwater may be pumped to portable containers and disposed of in accordance with station procedures. A level switch is provided in each compartment which will alarm high level to the radwaste control panel in the event of a leaking or ruptured tank flooding the area. A local sample point is located upstream of the normally closed drain valve to provide an indication of whether the content of the compartment is either rainwater or radioactive waste.

An oil interceptor is provided to prevent the potential oily waste from the controlled machine shop and tool room from entering the LRS system via the building sump. The floor drains and sink are routed to the oil interceptor prior to draining to the sump. An isolation valve is located downstream of the oil interceptor in order to provide for oil removal and maintenance of the oil interceptor.

9.3.3.2.1.1.4 Fuel Building. The radioactive waste drain systems within the fuel building consist of floor and equipment drains, vertical drain risers, sloped horizontal drains, one sump with two 100%-capacity sump pumps, piping valves, controls, and instrumentation serving the equipment and areas as shown in engineering drawings 01, 02, 03-M-RDP-005.

The maximum normal leakage to the sump is estimated at 10 gallons per day. The decontamination washdown of the transfer cask and transportable storage canister is estimated to result in a flow of 200 gallons per minute for a 5-minute operation. The sump pumps, operating automatically under control of level instrumentation in the sump, pump the collected waste from the sump to the LRS holdup tanks.

A leak detection station is provided to monitor leakage through the fuel pool liner plate. The detection system is divided into ten leak chase zones such that a leak in the liner plate can be isolated to a specific zone. The leak chases for each zone are manifolded into one detection test station having a normally closed valve. Provisions are included upstream of the valve to provide helium leak testing of the liner plate in the event leakage is detected at the test station. The test station for each leak chase zone is monitored periodically for leakage.

A leak detection station is provided to monitor leakage through the cask load pit liner plate. The detection system consists of a wet-side leak chase over the floor of the CLP and use of the existing open W6 columns/horizontals behind the liner plate which are utilized to provide the main leak path for wall leakage. The leak chase system drains to one detection test

station having a normally closed valve. Provisions are included upstream of the valve to provide pressurized leak testing of the liner plate in the event leakage is detected at the test station. The test station is monitored periodically for leakage and is adjacent to the test station for the fuel pool.

9.3.3.2.1.1.5 Holdup Tank Area. The radioactive waste drain system within the holdup tank area consists of hardpipe overflow drains from the holdup tank, the reactor makeup tank, the refueling water tank, hardpipe equipment drains, floor drain from the holdup pumps and room, one sump with two 100%-capacity sump pumps, piping, valves, and control and instrumentation as shown in engineering drawings 01, 02, 03-M-RDP-005.

Maximum normal leakage to the sealed sump is estimated at 20 gallons per day. Maximum abnormal leakage is estimated at 200 gallons per minute.

The sump pumps, operating automatically under the control of level instrumentation in the sump, pump the collected waste from the sump to the LRS holdup tanks.

9.3.3.2.1.1.6 Decontamination and Laundry Facilities. The radioactive waste drain system within the decontamination and laundry facilities consists of floor, equipment and sink drains, sloped horizontal embedded drainage pipe, one sump with two 100%-capacity sump pumps, piping, controls, and instrumentation serving equipment and areas as shown in engineering drawing A0-M-RDP-006.

The sump pumps, operating automatically under control of level instrumentation in the sump, pump the collected waste from the sump to the chemical drain tanks of the LRS system.

9.3.3.2.1.1.7 Main Steam Support Structure. The radioactive waste drain system within the main steam support structure (MSSS) consists of floor and equipment drains, vertical drain risers, sloped horizontal drain pipes, valves, and leak detecting instrumentation as shown in engineering drawings 01, 02, 03-M-RDP-002.

Each auxiliary feedwater pump room is provided with a separate drain. Each drainage line to the auxiliary feedwater pump rooms is provided with a check valve so that the flooding of one room will not jeopardize the operation of the redundant train.

A common drain header carries the drainage from the MSSS to the non-ESF sump in the auxiliary building.

The maximum normal leakage from the MSSS drainage is estimated at 5 gallons per day. The maximum abnormal leakage is estimated at 10 gallons per minute.

9.3.3.2.1.2 Chemical Waste System. The chemical waste system consists of five subsystems as follows:

A. The radioactive chemical waste subsystem which collects by gravity the corrosive radioactive waste from the chemical laboratory and decontamination stations.

B. The cooling water waste subsystem which collects by gravity the chemically treated cooling water from the auxiliary and radwaste buildings for reuse or disposal.

C. The condensate polishers regeneration waste subsystem which collects and neutralizes the potentially radioactive waste for disposal. Those wastes exceeding the release limits stated in the Offsite Dose Calculation Manual (ODCM) will be sent to the liquid radwaste system for disposal.

D. The spent regenerant waste subsystem which collects and neutralizes the rinse wastes from the makeup demineralizers for disposal.

E. The chemical tank drains in the yard areas.

Engineering drawings 01, 02, 03-M-CMP-001 and -002 show a piping and instrumentation diagram for the chemical waste system.

9.3.3.2.1.2.1 Radioactive Chemical Waste Subsystem. The radioactive chemical waste subsystem is a gravity collection system and includes only drains and piping as shown in engineering drawings 01, 02, 03-M-CMP-001 and -002.

The subsystem transports the liquid waste and drainage by gravity flow to the chemical drain tanks.

9.3.3.2.1.2.2 Cooling Water Waste Subsystem. The cooling water waste subsystem consists of drains, one cooling water holdup tank, two 100%-capacity cooling water holdup tank pumps, piping, controls, and instrumentation.

Separation and isolation of the drain headers from the ESF rooms are provided along with a separate drain header from the non-ESF rooms.

The system drains into the cooling water holdup tank. Since the cooling water holdup tank is a common collection point, valving is provided to prevent backflooding into the ESF rooms. Two redundant holdup tank pumps take suction from this tank and discharge to the chemical waste neutralizer tanks. Branch lines are provided for diverting the pump discharge to the essential cooling water surge tanks or to the nuclear cooling water surge tanks.

9.3.3.2.1.2.3 Condensate Polishing Demineralizer Waste Subsystem. The condensate polishing demineralizer waste subsystem consists of drains, two condensate polishing demineralizer sumps, each provided with two 100%-capacity sump pumps, two chemical waste neutralizer tanks, each equipped with an agitator, two neutralizer transfer pumps, piping, valves, controls, and instrumentation.

The subsystem collects liquid waste and drainage in the condensate polisher demineralizer sumps. The condensate polisher regeneration waste can be divided into two types: high and low TDS. The high TDS waste is the acid and caustic rinses when chemically regenerating the spent resin. Low TDS results from two operations:

- The final rinsing of the regenerated resin to remove all traces of acid or caustic

- The overflow from the resin cleaning operation which removes particulates from the condensate polisher resins

High TDS waste is collected in one sump, and low TDS waste in the other. The high TDS waste is pumped to the neutralizer tanks. The low TDS waste is normally pumped to the circulating water return line for reuse unless there is radioactive contamination, in which case the water is discharged to the low TDS LRS holdup tanks. The low TDS waste can also be diverted to the neutralizer tanks. The neutralizer tanks also receive waste from the cooling water holdup tank and from the condenser area sumps.

Each neutralizer tank can receive the largest single batch of high and low TDS waste without processing so that a polisher may be regenerated without the necessity of operating the neutralizer transfer pumps.

The neutralizer tanks are provided with acid and caustic supply lines from the acid transfer pumps and the dilute caustic supply lines, respectively. Acid or caustic, as required, is added to the waste in the neutralizer tanks. The neutralized waste is then pumped to the retention tank by the neutralizer transfer pumps. The subsystem also has the capability for diverting the pump discharge to the liquid radwaste holdup tanks.

9.3.3.2.1.2.4 Spent Regenerant Waste Subsystem. The spent regenerant waste subsystem consists of drains, one spent regeneration sump provided with two 100%-capacity sump pumps, piping, valves, controls, and instrumentation.

The major discharge to the sump is the waste from the makeup demineralizers. The waste is treated in accordance with Water Reclamation Facility operating procedures and then pumped to the Water Reclamation Facility clarifier feed sump or the trickling filter sump emergency overflow. During Water Reclamation Facility (WRF) outages or emergencies, this wastewater can bypass the WRF clarifier feed sump or the trickling filter sump emergency overflow and be fed directly into the wet dry sump which feeds the 45 acre/or 85 acre reservoirs.

9.3.3.2.1.2.5 Yard Area Chemical Tank Drains Subsystem. The yard area chemical tanks and pumps, which are located outside, are installed on concrete slabs with retaining curbs. Small sumps are provided inside to collect equipment leakage. Portable pumps or disposal tankers are used to dispose of the effluent.

9.3.3.2.1.3 Oily Waste and Nonradioactive Waste System. The oily waste and nonradioactive waste (OW) system collects and transports liquid waste from equipment and floor drains of the turbine building, the control building, the diesel generator buildings, the fire pumphouse, and the yard area.

The system removes entrained oil from the wastewater for disposal and conveys the oil-free water to the evaporation pond.

Engineering drawings 01, 02, 03-M-OWP-001, -002, -003, A0-M-TBP-003 and A0-M-OWP-004 show piping and instrumentation diagrams for the oily waste and nonradioactive waste system.

9.3.3.2.1.3.1 Turbine Building. The OW system within the turbine building consists of floor drains, equipment drains, one turbine building sump with two sump pumps, two condenser area sumps with two sump pumps each, one turbine building oil/ water separator, one oil/water separator sump with two sump pumps, piping, valves, instrumentation, and controls.

The maximum normal leakage to each condenser sump is estimated at 380 gallons per day. The maximum normal leakage to the turbine building sump is estimated at 170 gallons per day.

Sump pumps, operating automatically under control of level instrumentation in each sump, pump the collected wastes from the sumps into a common discharge header. The discharge header normally conveys the wastes to the turbine building oil/water separator, but lines are provided for diverting the flow to either the chemical waste neutralizer tank or to the liquid radwaste system holdup tanks when required by the presence of chemicals or radioactivity greater than the Offsite Dose Calculation Manual (ODCM) release limits in the wastes.

The oil/water separator receives effluent from the turbine building and condenser area sump pumps, the control building sump pumps, and the diesel generator building sump pumps. The oil/water separator is a gravity and coalescing separator system for removing free dispersed, and mechanical emulsified oils from water.

The wastewater from the turbine building oil/water separator gravity flows into the oil/water separator sump.

Sump pumps, operating automatically under control of level instrumentation in the sump, pump the wastewater to the duplex

retention tank. A duplex retention tank is provided to act as a storage tank in the event the effluent is not within standards for pH, Hydrazine, and radioactivity prior to discharge to the evaporation pond. The radioactivity standard is the release limits in the ODCM. The retention tank also serves to retain the wastes in order to allow treatment to remove chromates when present.

In addition, the retention tank, along with the low TDS sumps and the chemical waste neutralizer tank, provide samples for radioactivity tests if online radiation monitors for the condenser air removal system or steam generator indicate primary-to-secondary leakage. If radioactivity greater than the release limits in the ODCM is present in the wastes, they will be sent to the liquid radwaste system for processing.

When the chemistry of the waste in one section of the retention tank is acceptable, or has been treated to make it acceptable, the pumps are manually started and discharge valves aligned to pump the waste from the retention tank to the evaporation ponds. The pumps are normally started manually, but stop automatically on low level signal from level instrumentation in the tank.

A connection for a temporary (portable) ion exchanger is provided in the unlikely event that radioactivity (i.e., activity greater than the ODCM release limits) is detected in one of the retention tanks: In this situation the effluent is pumped through a portable ion exchanger and returned to the other retention tank where it is eventually discharged to the evaporation pond.

9.3.3.2.1.3.2 Control Building. The OW system within the control building consists of floor drains, equipment drains, two control building sumps with two sump pumps each, piping, valves, instrumentation and controls serving the equipment and areas shown in engineering drawings 01, 02, 03-M-OWP-001, -002, -003 and A0-M-OWP-004.

Waste from the battery rooms flows through an acid neutralizer sump before flowing to the control building sumps.

The maximum normal leakage to the west sump is estimated at 1000 gallons per day. The maximum normal leakage to the east sump is estimated at 275 gallons per day.

Sump pumps, operating automatically under control of level instrumentation in the sumps, pump the collected wastes from the two sumps into a common discharge header, which conveys the wastes to the turbine building oil/water separator.

Wastes from the train A and train B cable spreading rooms do not flow to the control building sumps. These areas are each drained separately to the outside area.

9.3.3.2.1.3.3 Diesel Generator Building. The OW system within the diesel generator building consists of floor drains, equipment drains, the diesel generator west building sump with two sump pumps, piping, valves, instrumentation, and controls serving the equipment and areas as shown in engineering drawings 01, 02, 03-M-OWP-004 and A0-M-OWP-004.

The maximum normal leakage to each sump is estimated at 15 gallons per day.

Sump pumps, operating automatically under control of level instrumentation in the sump, pump the collected wastes from the sump to the oil/water separator via the discharge headers of the control building sump pumps.

9.3.3.2.1.3.4 Fire Pumphouse. The OW system for the fire pumphouse consists of floor drains, equipment drains, an oil/water separator, the fire pumphouse sump with two sump pumps, and piping, valves, controls, and instrumentation.

This subsystem is entirely separate from the other parts of the OW system.

The wastes from the floor and equipment drains flow to the fire pumphouse oil/water separator. The wastewater flows from the oil/water separator to the fire pumphouse sump.

The sump pumps, operating automatically under control of level instrumentation in the sump, pump the wastewater from the sump to the spent regenerant sump.

9.3.3.2.1.3.5 Yard Area. The OW system in the yard area consists of equipment drains, one sump with two sump pumps, piping, valves, instrumentation, and controls.

The yard area sump normally receives drainage and liquid waste from the following equipment and areas:

- Demineralized water storage tank and pumps
- The abandoned auxiliary boiler and deaerator area
- Turbine building normal air handling units at elevation 100’

The maximum normal input to the yard sump is approximately 30 gallons per minute of domestic water which is based upon a maximum continuous flow of 5 gallons per minute per normal air handling unit.

Sump pumps, operating automatically under control of level instrumentation in the sump, pump the collected effluent from the sump to the circulating water intake structure.

9.3.3.2.1.3.6 Roof Drainage. Except for turbine building roof drains, water resulting from precipitation is collected on all building roofs and open areaways within the buildings and is conveyed to the storm drainage. Turbine building roof drainage and Turbine building normal air handling units at elevation 176’ can be aligned to drain to the CW System intake canal or yard sump.

9.3.3.2.1.3.7 Storm Drainage. Except for the Turbine building roof drains rainwater from the roof drainage and surfaces outside the building is collected and conveyed to the natural site drainage. Turbine building roof drainage and Turbine building normal air handling units at elevation 176’ can be aligned to drain to the CW System intake canal or yard sump.

9.3.3.2.1.4 Sanitary Drainage and Treatment System. The sanitary drainage and treatment system consists of drains, drain piping, one wet well, one sewage lift station, one surge tank, three package sewage treatment plants, one chlorine contact chamber, one sanitary waste water sump with two sump

pumps, and piping, valves, controls, and instrumentation as shown in engineering drawing A0-M-STP-001.

The sanitary waste flows from facilities throughout the plant to the wet well at the sewage lift station. The wet well is equipped with bar screens and air bubblers. The bubbler level control system has been abandoned in place and their function has been replaced by a more advanced level control system.

Two vertical centrifugal dry pit type pumps, taking suction from the wet well, transfer the waste to the surge tank.

In the surge tank, the waste is again aerated by a bubbler system, and two submersible type surge pumps transfer the waste to a stilling well located in the surge tank. From the stilling well, three airlift pumps transfer the waste to the three package sewage treatment units.

In the sewage treatment unit, the waste is treated and clarified. The sludge is removed by air lifts, and the clarified wastewater overflows a weir into the discharge line which transports it to the chlorine contact chamber.

In the chlorine contact chamber, the wastewater is chlorinated (only when the effluent is pumped to the retention tanks) and overflows a weir into a discharge line which conveys it to the sanitary wastewater sump.

Two sump pumps, operating automatically under control of level instrumentation in the sump, pump the wastewater from the sanitary wastewater sump to the water reclamation plant for further treatment and reuse. If the water reclamation plant is not in service, the effluent is pumped to the retention tanks.

9.3.3.2.2 Component Description

9.3.3.2.2.1 Cleanouts. Cleanouts are provided, when practicable, where the change in direction in horizontal lines is 90 degrees, at offsets where the aggregate change is 135 degrees or greater, and at maximum intervals of 50 feet. Cleanouts are welded directly to the piping and are located with their access covers flush with the finished floor.

9.3.3.2.2.2 Floor Drains. All floor drains are installed with their rims flush with the low point elevation of the finished floor. Floor drains in areas of potential radioactivity are welded directly to the collection piping. Floor drains in areas not restricted, due to potential radioactivity, are provided with caulked or threaded connections.

9.3.3.2.2.3 Equipment Drains. Equipment vent and drain lines control valve station vent and drain lines handling radioactive fluids are welded directly to the collection piping. High point vents and low point drains of process piping handling radioactive fluids, when utilized, are routed to the collection piping with flexible hoses. Drain lines from equipment that may be pressurized during drainage, and where the flow is by a direct or indirect connection to the floor drain system, are equipped with valves that may be throttled, so that the equipment discharge flow will not exceed the gravity flow capacity of the drainage header at atmospheric pressure.

9.3.3.2.2.4 Traps. Inlets to chemical drainage systems, and sanitary sewage treatment systems, except those in areas of potential radioactivity and those in storm drainage, are provided with a water seal in the form of a vented P-trap to minimize entry into the building of vermin, foul odors, and toxic, corrosive, or flammable vapors. Air pressure vent lines to the outside atmosphere are provided downstream of the P-traps to prevent excessive backpressures that could cause blowout or siphonage of the water seal. Traps are not installed at inlets in areas of potential radioactivity in order to preclude either a potential for an accumulation of radioactivity in the trap or difficult maintenance of seal water level.

9.3.3.2.2.5 Collection Piping. In areas of potential radioactivity, the collection system piping for the liquid system is stainless steel. Potentially radioactive chemical waste and detergent waste collection system piping is stainless steel. Where necessary to vent potentially radioactive liquid waste collection systems, connections are provided to the gaseous radwaste system. Offsets in the piping are provided where necessary for radiation shielding. The fabrication and installation of the piping provides for a uniform slope that induces waste to flow in the piping at a velocity of not less than 2 feet per second. Equipment drainage piping is terminated not less than one and one-half nominal pipe diameters above the finished floor or drain receiver at each location where the discharge from equipment is to be collected, except in locations where hose manifolds are installed. The

final connections are made after the equipment is installed in its proper location.

Note: Drain manifolds 13MRDNM01 – 13MRDNM18 discharge into the floor drains below floor grade, a minimum of 1” above the highest level of the floor drain pipe (collection piping). Plant systems will be connected to the drain manifolds via hoses.

9.3.3.2.2.6 Pumps. Redundant sump pumps are provided in each sump. Individual pump capacities are determined by the expected normal maximum inflow from the associated drainage subsystem. Alternating dual pumps are employed to even wear and eliminate operator responsibility for manual alternating of pumps. Sump pumps are designed to discharge at a flowrate adequate for preventing sump overflow during normal anticipated drainage periods. Normal drainage is that drainage expected to occur from equipment maintenance, leakage, and washdown during normal plant operation. The sump pump operating conditions are tabulated in table 9.3-8.

9.3.3.2.2.7 Collection Sumps. Drains located at a higher elevation than the designated receiving tanks are conveyed by gravity directly to the receiving tanks. All other drainage is conveyed by gravity to sumps and then is pumped to the appropriate receiving station.

Sump capacities provide a minimum active storage volume equal to at least the volume required for the operation of one pump for 5 minutes.

The various sump dimensions and capacities are tabulated in table 9.3-9.

9.3.3.3 Systems Operation

9.3.3.3.1 Sump Pumps

Each sump is equipped with two duplex type sump pumps with the exception of the containment radwaste east and west sumps. However, the containment radwaste east and west sumps are interconnected with a 4-inch pipe that serves to treat both sumps as one.

The sump pumps are controlled by one control displacer type level switch per sump. When the sump level rises to a preset point, the pump selected by the alternator is started by the displacement action of the level switch. If the level continues to rise, a second displacer starts the second pump.

Failure of one pump to start will not prevent the second pump from starting. If the level continues to rise, a separate high-high level switch is incorporated in the design to activate an annunciator in the control room advising the operators that a flooding condition is imminent. After the pumps lower the level to a point just above the pump suction, a third displacer on the control level switch stops both pumps.

9.3.3.3.2 Radioactive Waste Drainage System

The radioactive waste is gravity drained directly to the respective sumps. Sump pumps are started automatically when a predetermined high level in the sump is reached. The waste

effluent is pumped to the LRS holdup tanks for processing and reuse.

9.3.3.3.3 Radioactive Chemical Waste Subsystem

The radioactive chemical waste subsystem is designed to gravity flow directly to the chemical drain tanks.

9.3.3.3.4 Cooling Water Waste Subsystem

The chemically treated cooling water waste is gravity drained directly to the cooling water holdup tank. When the liquid contents of the tank reach a preset level, a high level switch will alarm in the control room. A sample is taken of the tank contents to determine if radioactivity is present. The system is normally aligned to transfer the contents of the tank to the chemical waste neutralizer tanks. The pumps are manually started and will be automatically stopped by a low-low level signal from the holdup tank. The pumps can also be manually stopped.

In addition to collecting leakage, the system operates, during maintenance of plant equipment containing chemical treated cooling water, to accept drainage from such equipment. The holdup tank is sized to hold the capacity from the equipment item having the largest volume of cooling water. Piping is provided to the surge tanks of the essential cooling water system - train A and train B, and the nuclear cooling water system, for use only during maintenance, to return cooling water drained from equipment to the appropriate cooling water loop.

Table 9.3-8
SUMP PUMP OPERATING CONDITIONS (Sheet 1 of 2)

Sump Pump	Flow (gal/min)	Total Differential Head	Location Bldg	Location Elevation (ft)
Reactor cavity	30	45	Containment	55
Auxiliary building ESF (train A)	50	110	Auxiliary	40
Auxiliary building ESF (train B)	50	110	Auxiliary	40
Auxiliary building non-ESF	50	110	Auxiliary	40
Radwaste building	50	65	Radwaste	88
Fuel building	100	65	Fuel	100
Control building (west)	50	65	Control	74
Control building (east)	50	65	Control	74
Diesel gen (west)	30	35	Diesel gen	94
Diesel gen (east)	30	35	Diesel gen	94
Turbine building	50	60	Turbine	100
Condenser area (south)	100	70	Turbine	100
Condenser area (north)	100	70	Turbine	100
Spent regen waste	525	63	Outdoor	100
Decontamination facility	50	45	Decont facility	100
Oil/water separator				
Unit 1	200	70	Outdoor	N/A
Unit 2	200	60	Outdoor	N/A
Unit 3	200	50	Outdoor	N/A

Table 9.3-8
SUMP PUMP OPERATING CONDITIONS (Sheet 2 of 2)

Sump Pump	Flow (gal/min)	Total Differential Head	Location Bldg	Location Elevation (ft)
Fire pump house	30	25	Outdoor	N/A
Sanitary waste return	200	60	Outdoor	N/A
Retention tank	500	130	Outdoor	N/A
Containment radwaste (east)	50	75	Containment	80
Containment radwaste (east)	50	75	Containment	80
Yard	50	80	Maintenance	100
Holdup tank area	150	65	Outdoor	N/A

Table 9.3-9
DIMENSIONS AND CAPACITIES OF SUMPS (Sheet 1 of 2)

Sump	Quantity per Unit	Dimensions (feet)			Maximum Usable Capacity (gal)	Materials		
		Length	Width	Depth		Sump	Liner	Cover
Containment radwaste, east	1	4	3	6-1/4	530	Concrete	Stainless steel	Stainless steel
Containment radwaste, west	1	4	3	6-1/4	530	Concrete	Stainless steel	Stainless steel
Reactor cavity	1	5	4	5	710	Concrete	Stainless steel	Stainless steel
ESF Train A	1	6	6	7	1800	Concrete	Stainless steel	Stainless steel
ESF Train B	1	6	6	7	1800	Concrete	Stainless steel	Stainless steel
Non-ESF	1	6	4	7	1200	Concrete	Stainless steel	Stainless steel
Fuel building	1	6	6	12	3100	Concrete	Stainless steel	Stainless steel
Radwaste building	1	5	5	7	1250	Concrete	Stainless steel	Stainless steel
Decontamination facility	1	5	5	6	1250	Concrete	Stainless steel	Stainless steel
Holdup tank area	1	6-1/2	6-1/2	7-1/2	2300	Concrete	Stainless steel	Stainless steel

Table 9.3-9
DIMESIONS AND CAPACITIES OF SUMPS (Sheet 2 of 2)

Sump	Quantity per Unit	Dimensions (feet)			Maximum Usable Capacity (gal)	Materials		
		Length	Width	Depth		Sump	Liner	Cover
Condenser area, south	1	6	6	10	2600	Concrete	None	Carbon steel
Condenser area, north	1	6	6	10	2600	Concrete	None	Carbon steel
Turbine building	1	6	6	10	2600	Concrete	None	Carbon steel
Oil/water separator	1	5.5	5.5	10	2100	Concrete	None	Carbon steel
Control building, west	1	5	5	6	1070	Concrete	None	Carbon steel
Control building, east	1	5	5	6	1070	Concrete	None	Carbon steel
DG building, east	1	4	4	5	570	Concrete	None	Carbon steel
DG building, east	1	4	4	5	570	Concrete	None	Carbon steel
Fire pump house	1[a]	5 Dia.		9	1200	Concrete	None	Carbon steel
Yard	1	5.5	5.5	12	2716	Concrete	None	Carbon steel
Sanitary waste	1[a]	15	15	10	15,000	Concrete	None	Carbon steel
Spent regenerant	1[a]	30	30	12	60,000	Concrete	HDPE	Carbon steel

a. Common to all three units

9.3.3.3.5 Condensate Polishing Demineralizer Waste Subsystem

Rinse washes from the condensate polishing demineralizers are automatically sent to the high or low TDS sumps as determined by conductivity. The rinse water can also be sent directly to the retention tank by manually lining up the condensate polisher pre-service rinse overboard line. Low conductivity waste is routed to the low TDS sump and high conductivity waste is routed to the high TDS sump. Conductivity values to determine High and Low TDS are included in station operating procedures. Each sump is equipped with dual pumps and level instrumentation to actuate the lead pump upon high level. The level switch assembly will start (and stop) the pump alternately by a contact closure on rising level at a preset high level, and stop on opening of the same contact on decreasing level at a preset low level.

The low TDS waste is normally pumped to the circulating water return line.

In the event the low TDS waste becomes radioactive due to steam generator leakage, manually operated valves are provided to reroute the waste effluent to the low TDS LRS holdup tank or high TDS LRS holdup tank. Radioactivity in the secondary side is detected by monitoring the air condenser removal system or steam generator by use of online radiation monitors. When these monitors indicate a steam generator tube leakage, periodic samples of the low TDS sump are taken for analyses. Should the activity level exceed a predetermined level, the low TDS sump is manually diverted to the liquid radwaste system.

The high TDS waste is pumped directly to one of the two chemical waste neutralizing tanks. The pH of the waste and the radioactivity in the tanks are determined by analysis of samples taken manually from a sampling point valve on each tank. The high TDS waste is neutralized on a batch basis, by injection of concentrated acid or caustic solution into each tank.

After neutralization the waste can be gravity drained from the waste tanks to the retention tank, or the neutralizer transfer pump can be manually started to pump the waste to the retention tank. The pump discharge can be manually valved to divert the neutralized waste to the liquid radwaste system holdup tanks in the event the waste exceeds the release limits stated in the Offsite Dose Calculation Manual (ODCM).

The low-low level switch is interlocked with the pumps' suction crossover valve. When the crossover valve is closed, each pump shuts off automatically by its associated low-low level switch. When the crossover valve is open, a low level in either tank will automatically stop both pumps. Both pumps can also be manually shut off.

9.3.3.3.6 Spent Regenerant Waste Subsystem

Rinse washes from the makeup demineralizers are automatically sent to the spent regenerant sump. The sump is equipped with dual pumps and level instrumentation to actuate the lead pump upon high level. The level switch assembly will start (and stop) the pump alternately by a contact closure on rising level at a preset high level, and stop by opening the same contact on decreasing level at a preset low level.

The waste collected in the sump is treated in accordance with Water Reclamation Facility operating procedures and then pumped to the Water Reclamation Facility clarifier feed sump or the trickling filter sump emergency overflow. During Water Reclamation Facility (WRF) outages or emergencies, this wastewater can bypass the WRF clarifier feed sump or the trickling filter sump emergency overflow and be fed directly into the wet dry sump which feeds the 45 acre/or 85 acre reservoirs.

9.3.3.3.7 Yard Area Chemical Tank Drains Subsystem

The yard area chemical tanks and pumps are located outside on concrete slabs and surrounded by concrete curbs that function as secondary containments. Small sumps are provided inside the secondary containments to collect the equipment drainage. In the event of rain, equipment drainage, or chemical spills, the collected liquids will be removed from the secondary containment according to environmental requirements or procedures. The removal of the liquids may be through pumping or through an embedded drainpipe.

9.3.3.3.8 Oily Waste and Nonradioactive Waste System

The oily waste and nonradioactive waste system collects in sumps, via equipment drains and floor drains, nonradioactive waste from the diesel generator building, turbine building, and the control building and pumps the waste to an oil/water separator. Each turbine building sump is provided with valving for diverting the flow to either the chemical waste neutralizer tank or to the LRS holdup tanks when required by the presence

of chemicals or radioactivity in the waste. Waste is pumped to the LRS holdup tanks when activity levels are greater than the release limits in the Offsite Dose Calculation Manual (ODCM).

From the oily/water separator, after the oil is removed, the clarified effluent is pumped to the retention tanks. A divided retention tank is provided to act as a storage tank in the event the effluent is not within standards for pH, conductivity, and radioactivity prior to discharge to the evaporation pond. The standard for radioactivity is the release limit values in the Offsite Dose Calculation Manual (ODCM). The waste water in the first section is treated as required until its chemistry is acceptable for discharge to the evaporation pond. When the chemistry is acceptable, the waste water is pumped to the evaporation pond by manually starting the retention tank pump and aligning the discharge valves. A line is also provided for recirculating the waste from the pump to the supply end of the retention tank if required for mixing during treatment.

9.3.3.3.9 Sanitary Sewage and Treatment System

The liquid waste and entrained solids discharged by all plumbing fixtures located in areas not restricted due to potential radioactivity are conveyed by gravity to the onsite sewage treatment facility.

9.3.3.4 Safety Evaluations

The safety evaluations pertinent to the equipment and floor drainage systems are as follows:

A. Safety Design Basis One

   Equipment and floor drainage provided for each ESF equipment compartment are not interconnected to any other equipment or floor drainage unless check valves are utilized to prevent cross-flow.

B. Safety Design Basis Two

   Each ESF equipment room drainage system is equipped with backflow check valves.

9.3.3.5 Radiological Considerations

The radiological considerations for normal operation and accidents are discussed in sections 11.2, 11.3, and 12.3.

9.3.3.6 Tests and Inspections

9.3.3.6.1 Preoperational Testing

All waste collection systems from areas of no radioactivity potential are tested for 15 minutes at a hydrostatic test pressure equal to a 10-foot head of water. All collection systems from areas with a radioactivity potential are tested to 75 psig in accordance with ANSI B31.1.0, Power Piping, dated 1967.

9.3.3.6.2 Operational Testing Capability

The operability of equipment and floor drainage systems dependent on gravity flow can be checked by normal usage. Portions of these systems, dependent upon pumps to raise liquid waste to gravity drains, may be checked through instrumentation and alarms in the control room.

9.3.3.7 Instrumentation Application

Seismic Category I level alarms are provided for those safety feature sumps in the auxiliary building that serve safety feature pump rooms as described in paragraph 7.6.1.1.3.3. High temperature alarms and high level indication, in addition to the level-operated switch used for pump control, are provided for all sumps in the containment and the auxiliary building to provide backup indication of the presence of large leaks and to provide information as to the source. Level alarm is provided for all other sumps as well. Level alarms are displayed and monitored in the control room.

9.3.4 CHEMICAL AND VOLUME CONTROL SYSTEM

The following system description incorporates all of the critical licensing attributes of the Chemical and Volume Control System (CVCS) formally contained in CESSAR and CESSAR SER section 9.3.4. Since the following text now contains all of the current licensing commitments, the subject portions of the CESSAR and CESSAR SER are superseded and are no longer considered part of the active licensing basis.

9.3.4.1 Design Bases

9.3.4.1.1 Functional Requirements

The Chemical and Volume Control System (CVCS) is designed to perform the following functions:

A. Maintain the chemistry and purity of the reactor coolant during normal operation and during shutdowns;

B. Maintain the required volume of water in the Reactor Coolant System (RCS) compensating for reactor coolant contraction or expansion resulting from changes in reactor coolant temperature and for other coolant losses or additions;

C. Receive, store, separate, and process reactor grade, borated waste for reuse or discharge.

D. Control the boron concentration in the RCS to obtain optimum Control Element Assembly (CEA) positioning and compensate for reactivity changes associated with major changes in shutdown margin for maintenance and refueling operations;

E. Provide auxiliary pressurizer spray for operator control of pressurizer pressure whenever main sprays were not available and to provide a means for pressurizer cooling;

F. Provide a means for functionally testing the check valves that isolate the Safety Injection System (SIS) from the RCS;

G. Provide continuous measurement of reactor coolant fission product activity;

H. Provide seal injection water at the proper temperature, pressure, and purity for the reactor coolant pumps' seals and collect the controlled bleed-off;

I. Leak test the RCS;

J. Supply demineralized reactor makeup water to various auxiliary equipment;

K. Provide a means for sluicing ion exchanger resin to the Solid Radwaste System (SRS);

L. Provide a means for continuous removal of noble gases from the RCS;

M. Provide a source of borated water for engineered safety feature pump operation;

N. Provide makeup to the spent fuel pool;

O. Provide purification of shutdown cooling flow;

P. Provide makeup for losses from small leaks in RCS piping.

9.3.4.1.2 Design Criteria

The CVCS is designed in accordance with the following criteria:

A. The CVCS is designed to accept letdown and provide makeup in response to changes in reactor coolant volume resulting from normal plant heatup and cooldown. Rates of temperature change are administratively controlled within the CVCS capacity to maintain pressurizer level within Technical Specification limits.

B. The CVCS is designed to supply makeup water or accept letdown to support 10% step power increases between 15% and 90% of full power, 10% step power decreases between 100% and 25% of full power, and ramp changes of ±5% of full power per minute between 15 and 100% power.

C. The CVCS Volume Control Tank (VCT) is sized with sufficient capacity to accommodate the inventory change resulting from a 100% to 0% power decrease (reactor trip) with no makeup system operation, assuming that the VCT level is initially in the normal operating level band.

D. The CVCS provides a means for suitably controlling the concentration of radioactivity in the reactor coolant:

- The CVCS is operated as required to maintain the Technical Specification limits on RCS specific activity in order to ensure offsite dose consequences from postulated accidents are bounded by the analyses in Chapter 15. The operational limit for Dose Equivalent Iodine-131 corresponds to nominal ~0.2% failed fuel at steady-state, full power conditions.

- Nominal CVCS performance was credited in the calculation of expected RCS radionuclide concentrations used to evaluate the effectiveness of radwaste treatment systems and plant shielding design in Chapters 11 and 12, respectively. The analyses conservatively assume continuous full power operation with 1.0% failed fuel.

E. The CVCS is operated to maintain reactor coolant chemistry within the limits specified in the EPRI PWR Primary Water Chemistry Guidelines, as endorsed by NEI 97-06, Steam Generator Program Guidelines.

F. Letdown and charging portions of the CVCS are designed to withstand the design transients defined in Table 3.9-1 without any adverse effects.

G. The CVCS has the capacity to accommodate all liquid wastes generated due to the operations identified in Section 9.3.4.4.10.

H. The CVCS is designed to provide 30 GPM of filtered flow to the reactor coolant pump seal cavities and to accept a 22 GPM controlled bleed-off flow.

I. Components of the CVCS are designed in accordance with the requirements for the safety class and seismic class specified in Table 3.2-1. The applicable design codes are identified in that table as well.

J. The environmental design conditions of the CVCS components are given in Section 3.11.

K. The CVCS is designed to operate with no boric acid concentration above the point where precipitation could occur. The boric acid batching tank and the boric acid concentrator concentrate discharge line to the SRS are the only portions of the system requiring heat tracing to preclude boric acid precipitation. These portions of the system can contain fluid concentrated to 12 weight percent boric acid. The remaining portions of the system contain a lower boric acid concentration solution

(less than 4400 ppm) so heat tracing to prevent precipitation is not required.

L. The CVCS is configured as shown in engineering drawings 01, 02, 03-M-CHP-001, -002, -003, -004 and -005.

M. As described in UFSAR 9.3.4.4.11, the charging subsystem has a capacity sufficient to replace the flow lost to the containment due to breaks in small RCS lines, such as instrument and sample lines.

N. The CVCS is designed to receive discharges from drains and relief valves in the RCS, SIS and SCS.

O. The CVCS provides for boron concentration adjustment in the Reactor Coolant System by feed and bleed. The maximum possible rate of boron dilution is limited, such that the operator has sufficient time to identify and terminate a boron dilution incident prior to reaching criticality during any refueling operations.

P. The CVCS provides an emergency boration capability for recovery of lost shutdown margin (SDM). As described in the basis of the Technical Specifications, the CVCS can nominally add 1% $\Delta k/k$ of negative reactivity in less than 4 hours.

Q. The CVCS boric acid reserve is sufficient to make the reactor subcritical in the cold condition with the most reactive CEA withdrawn.

R. The CVCS is designed so that the minimum volume of borated water available in the Refueling Water Tank (RWT) is sufficient to support Emergency Core Cooling

System (ECCS) and Containment Spray System (CSS) operation as described in the Technical Specifications bases.

S. The CVCS has been designed with the appropriate vents, drains, connections and other provisions necessary to permit the performance of inservice testing and inspection of Safety Class components in accordance with ASME OM Code and Section XI programs described in Technical Specifications.

T. The CVCS design supports the plant capability for conducting a natural circulation cooldown in accordance with the requirements of Branch Technical Position (BTP) RSB 5-1 for a Class 2 plant.

9.3.4.2 System Description

The normal process flow paths through the CVCS may be traced on the Piping and Instrumentation Diagrams, 01, 02, 03-M-CHP-001, -002, -003, -004 and -005.

9.3.4.2.1 Process Overview

Letdown originates from the suction of reactor coolant pump 2B and passes through a letdown delay "coil," actually two parallel sections of large diameter pipe. The resulting reduction in flow velocity provides sufficient delay to ensure that N-16 gamma emissions have a negligible contribution to the external dose rate of letdown piping outside the containment. Letdown then flows through two inboard, air-operated isolation valves in series before entering the tube side of the

Regenerative Heat Exchanger. To enhance reliability, solenoids for the isolation valves receive control power from opposite trains of class 1E electrical service. The Regenerative Heat Exchanger provides the initial process temperature reduction before letdown flow reaches the containment penetration. Outside of containment, the fluid passes through an outboard, class-powered, air-operated isolation valve and goes to the letdown control valves.

There are two letdown control valves arranged in parallel, only one of which is normally in service during power operation. A warm-up bypass line around the control valves is provided for re-establishing letdown flow after its isolation and cooldown. The in-service letdown control valve adjusts flow rate based on input from the Pressurizer Level Control System (PLCS) to help keep pressurizer level at setpoint. In addition, flow through the valve also reduces process pressure within the operating range of the letdown heat exchanger. By rejecting heat to the Nuclear Cooling water system, the letdown heat exchanger provides a final reduction of temperature to that suitable for purification subsystem operation. Downstream of the letdown heat exchanger are two letdown backpressure control valves arranged in parallel. Normally, only one backpressure control valve is in service. It controls intermediate or "back" pressure to ensure that the piping between the letdown and backpressure control valves is adequately subcooled.

The properly conditioned flow then passes through a mechanical filter, one of three parallel ion exchangers, and an effluent strainer to remove resin fines. After filtration, but prior to demineralization, a portion of the flow also goes through the

Boronometer* (abandoned in-place) and by the Process Radiation Monitor. Flow valve CH-204 located in the main letdown line is automatically controlled to ensure that the minimum flow is provided to the process instruments. The processed letdown goes directly into the Volume Control Tank via the three-way valve CH-500. This valve is normally aligned to the VCT but will automatically divert letdown to the Holdup Tank upon high-high VCT level. The VCT inlet valve may also be manually repositioned to support reactor feed and bleed for adjustment of reactor coolant reactivity, inventory, and chemistry. In addition to letdown, the VCT also receives the reactor grade controlled bleed-off flow from the reactor coolant pump seals. The seal vendor has calculated that the design controlled bleed-off flow rate (total seal outflow) for all four pumps combined is 12.0 gpm at steady state and 13.6 gpm under transient conditions.

The VCT is maintained with a nominal 15-25 psig hydrogen overpressure to promote dissolution of hydrogen in letdown for the purpose of oxygen scavenging in the reactor coolant. The letdown flow enters the VCT via a spray nozzle to enhance mixing of the process fluid with the gas overpressure. The pressure of hydrogen (or nitrogen during shutdown conditions) is controlled by adjustment of a supply pressure regulation valve side or a discharge isolation valve, which allows venting of excess gas to the Gaseous Radwaste System (GRS) surge header.

Diverted letdown normally passes through the Pre-Holdup Ion Exchanger (PHIX) and the Gas Stripper prior to its direction to the Holdup Tank (HUT). Under normal conditions, the PHIX

inlet/bypass valve is positioned to bypass the PHIX. The PHIX is normally loaded with a mixed bed to remove ionic impurities, including radionuclides, prior to their concentration in the boric acid recovery subsystem. The resins are normally both lithiated and borated to prevent pH or reactivity changes in the coolant. Once the VCT inlet valve shifts to the divert position on high VCT level, letdown flow will be automatically directed through the PHIX. In addition, the PHIX may be manually aligned to process the contents of the Holdup Tank, Reactor Drain Tank, or Equipment Drain Tank, if necessary. The PHIX may also be bypassed if not required for chemistry control.

Flow through or around the PHIX may then pass through the Gas Stripper where hydrogen, gaseous fission products, and other non-condensable gases are removed with high efficiency. Stripping may be used to preclude the buildup of explosive gas mixtures in the Holdup Tank, minimize the release of radioactive fission product gases, and also to limit the concentrations of dissolved gases in the reactor coolant during startup and shutdown. Normally, the degassed liquid is automatically pumped from the Gas Stripper to the Holdup Tank. In the event that the Gas Stripper is not available, up to 20 minutes of full flow letdown may be directed into the Equipment Drain Tank. If gas stripping is not required, the Gas Stripper may be bypassed using a manual valve alignment. When continuous degasification of the RCS is desired, the letdown flow is diverted from the VCT to the Gas Stripper and then returned to the VCT. Sufficient hydrogen absorption

occurs via the Volume Control Tank hydrogen overpressure to replace the hydrogen removed during the gas stripping process.

The radioactive water processing subsystem also contains the Reactor Drain Tank (RDT) and Equipment Drain Tank (EDT). Reactor coolant quality water from equipment and valve (pressurizer spray control and bypass valve) leakoffs, drains, and reliefs within the containment are collected in the RDT. Recoverable reactor coolant quality water outside the containment from various equipment leakoffs, reliefs, and drains are collected in the EDT. The contents of the RDT and EDT are periodically pumped to the Holdup Tank using the Reactor Drain Pumps on a batch basis through the reactor drain filter, pre-holdup ion exchanger, and gas stripper, if necessary. Diverted letdown flow has priority over processing of the RDT, EDT, or the HUT. Once diversion occurs, the Reactor Drain Pumps and Holdup Pumps (only if CH-686 is open) are automatically secured.

When a sufficient volume accumulates in the Holdup Tank, the contents are pumped by one of two holdup pumps to the Boric Acid Concentrator in the boron recovery subsystem. If abnormal quantities of radionuclides or chemical impurities are present, the Holdup Tank contents may be recirculated back through the pre-holdup ion exchanger for further cleanup. Concentrator bottoms are continuously monitored for proper boron concentration and are normally pumped directly to the Refueling Water Tank when the bottoms reach 4000-4400 ppm boron. In the event that chemical impurity or radionuclide concentrations are too high, the bottoms may be processed further in the Liquid Radwaste System (LRS). If additional processing is not

economical, the bottoms are concentrated to 12 wt percent boric acid and discharged to the Solid Radwaste System (SRS) for disposal. The vapor from the boric acid concentrator is condensed and cooled into a distillate, which then passes through a boric acid condensate ion exchanger to remove boric acid carryover. The distillate is collected in the Reactor Makeup Water Tank for reuse in the plant. If recycle is not desired, concentrator vapor may be directed to the Plant Vent for discharge to the atmosphere, or the distillate may be diverted to the LRS.

The inventories stored in Refueling Water Tank (RWT) and Reactor Makeup Water Tank (RMWT) are reused as reactor coolant makeup. Boric acid solution in the RWT is supplied via the Boric Acid Makeup Pumps while the reactor makeup water in the RMWT is supplied via the Reactor Makeup Water Pumps. The normal makeup control system has four operational modes. Except for the automatic mode, the makeup water may be lined up to the VCT via CH-512 or directly to the charging pump suction via the VCT bypass valve CH-527. In the dilute mode, a preset quantity of reactor makeup water is introduced at a preset rate. In the borate mode, a preset quantity of boric acid is introduced at a preset rate. In the automatic mode, a preset blended boric acid solution from both tanks is automatically introduced into the Volume Control Tank upon demand from the VCT level controller. The preset solution concentration is adjusted periodically by the operator to match the existing boric acid concentration in the RCS so that makeup for lost RCS inventory produces no net reactivity effect on the reactor core. The manual mode is used as an alternate method for

accomplishing all of the makeup functions. In the manual mode, the flow rates of the reactor makeup water and the boric acid can be preset to give a blended boric acid solution with a concentration between zero and that in the RWT (4000-4400 ppm).

Boron may be added to the RWT using the boric acid batching tank (BABT). Reactor makeup water is first added to the BABT via the Reactor Makeup Water Pumps. After the fluid has been heated by electric immersion heaters, boric acid powder is added to the heated fluid while the solution is agitated by a mechanical mixer. Concentrations as high as 12 weight percent can be prepared. Immersion heaters and heat tracing of both the batching lines and the piping downstream of the eductor maintain the temperature of the batched solutions high enough to preclude precipitation. The level and/or boron concentration of the RWT is increased by drawing boric acid solution from the BABT into the RWT return flow by directing either the Boric Acid Makeup Pump or Reactor Makeup Water Pump discharge as motive flow through the boric acid batching eductor.

Of the three parallel charging pumps, two are normally in service taking suction from the Volume Control Tank and delivering that inventory to the RCS. With two pumps running, the design charging pump discharge rate or "total charging flow" is 88 gpm. With the pump controls in automatic, signals from the PLCS may automatically secure a running charging pump or start another (third) charging pump in order to maintain pressurizer level. Seal injection water is supplied to the Reactor Coolant Pump seal packages by diverting a portion of

the total charging flow upstream of the outboard containment isolation valve.

The seal injection flow is filtered and monitored for proper temperature prior to distribution to the Reactor Coolant Pump seals. The nominal flow rate is 6.6 gpm per RCP with the typical flow varying between 6.0 and 7.5 gpm. The combined nominal flow through the four RCPs is 26.4 gmp, and the design flow is 30 gpm. A Chemical Addition Tank and Chemical Addition Metering Pump are used to transfer chemical additives to charging downstream of the seal injection diversion. A separate connection is provided for the injection of hydrogen gas directly into the charging line. Isolation of the charging line containment penetration is provided by a class-powered, motor-operated outboard valve and by an inboard check valve. The motor-operated outboard valve is normally open and de-energized to ensure the functionality of charging following a transient.

The charging fluid (approximately 62 gpm) goes to the shell side of the regenerative heat exchanger to recover some heat from the letdown fluid before introduction into the RCS on the discharge side of Reactor Coolant Pump 2A. The nominal temperature of the heat exchanger charging side outlet is 455°F. Some portion of the return flow may also be manually directed to the auxiliary pressurizer spray. The charging line contains a differential pressure (backpressure) control valve in series with an isolation valve and in parallel with a spring-loaded check valve. In case the differential pressure control loop fails, the isolation valve can be closed forcing charging flow through the spring-loaded check valve. The

setpoints of the differential pressure controller and the spring-loaded check valve ensure that return backpressure is sufficient to maintain functionality of auxiliary pressurizer spray and seal injection.

The majority of the CVCS was designed to contain borated water solutions of 3.6% by weight. The exceptions include the BAC bottoms and the boric acid batching equipment, which are designed for 12% boric acid solutions, and the dilute makeup portions, which are designed for demineralized water. The latter would include the RMWT, the RMW pumps, and associated piping. The components and piping associated with the BAC distillate pathway are designed to accommodate 10 ppm boron solutions.

All of the major CVCS components in Table 9.3.4-2 are fabricated from austenitic stainless steel except the shell (NC) side of the letdown heat exchanger which is made of carbon steel. With respect to pumps, this description only applies to the wetted surface.

9.3.4.2.2 Components

The major components of the CVCS are described in this section. Supplemental component design data are provided in Table 9.3.4-2. Component seismic and safety classification as well as applicable design codes are discussed in Section 3.2.

The design transients used in the thermal fatigue analysis of Class 1 CVCS components are listed in Table 3.9.1-1, and design transients for Class 2 and 3 components are in Table 9.3.4-1.

A. Regenerative Heat Exchanger: The regenerative heat exchanger is a vertically mounted, shell and U-tube heat exchanger. The regenerative heat exchanger conserves RCS thermal energy by transferring heat from the letdown flow to the charging flow. Heating the charging flow serves to minimize thermal transients on the charging nozzle that penetrates the RCS cold leg. Reducing letdown temperature with both the regenerative and letdown heat exchangers allows proper operation of the purification ion exchangers and process instruments. The regen heat exchanger is designed to maintain letdown outlet temperature below 450°F under all normal operating conditions.

B. Letdown Heat Exchanger: The letdown heat exchanger is a horizontally mounted, shell and tube heat exchanger that transfers heat from letdown to the nuclear cooling water (NC) system. Nominal NC flow is 582 gpm. With NC at its design flow of 1500 gpm and the outlet temperature of the regenerative heat exchanger at its maximum of 450°F, the letdown heat exchanger is sized to cool the letdown flow down to the maximum allowable operating temperature of the ion exchange resins (140°F).

C. Purification Filters: Each of the two purification filters is designed to remove insoluble particulates from the letdown flow. Each filter is designed to pass the maximum letdown flow without exceeding the allowable differential pressure across the filter elements in the maximum fouled condition. Due to the high radiation

dose rates possible from the buildup of activity levels during filter operation, each filter is designed for efficient remote removal of the disposable cartridges.

D. Purification Ion Exchangers: The two purification ion exchangers are essentially identical, and each is designed to pass the maximum letdown flow. The ion exchange vessel normally contains mixed bed resins to remove radioactivity and corrosion products. The necessary connections are provided to replace resins by sluicing. Under normal conditions, one ion exchanger is usually in service continuously to control activity and impurity levels in the reactor coolant while the other is used intermittently to reduce the lithium concentration. The retention screen size is in the range from 80-300 mesh.

E. Deborating Ion Exchanger: The deborating ion exchanger is identical to the purification ion exchangers in mechanical design; however, the deborating ion exchanger is normally loaded with anion resin. The deborating ion exchanger is used to reduce the reactor coolant boron concentration at the end of core life when the low prevailing boron concentrations may make feed-and-bleed dilution impractical. The retention screen size is in the range from 80-300 mesh.

F. Volume Control Tank: The Volume Control Tank is designed to accumulate letdown and RCP controlled bleed-off water from the RCS, to adjust hydrogen concentration in the reactor coolant, and to provide a

reservoir of reactor coolant for the charging pumps. The tank has sufficient capacity below the normal operating level band to provide makeup for a swing from Hot Full Power (HFP) to Hot Zero Power (HZP) without automatic makeup operation. The minimum tank level also ensures that operation of all three charging pumps will not result in vortexing and gas entrainment into the charging pump suction. The normal operating level band is sized so that a normal makeup at a VCT pressure of 50 psig will not result in a lift of the associated safety relief valve. The volume above the minimum operating band is sufficient to receive the thermal expansion of the reactor coolant in a swing from HZP to HFP under nominal plant conditions without lifting the associated safety relief valve. The tank has hydrogen and nitrogen gas supplies and provisions that allow venting of hydrogen, nitrogen, gaseous fission products, and other non-condensable gases to the Gaseous Radwaste System (GRS).

G. Charging Pumps: The three charging pumps are positive displacement (triplex) pumps with both primary and secondary sets of packing. The primary packing is cooled primarily by process flow. In addition, each pump contains a cooling and lubricating system that recirculates reactor makeup water over the secondary packing and otherwise non-wetted portions of the primary packing. Each pump is provided with vent, drain, and flushing connections to minimize radiation levels during maintenance operations. The wetted surface is composed

of austenitic stainless steel. The design flow of each pump is 44 gpm. After the effects of pump inefficiencies are considered, the nominal flow rate is about 42 gpm. Each charging pump possesses an associated suction stabilizer and pulsation dampener in order to reduce the magnitude of pressure fluctuations and the resulting cyclic stresses common to reciprocating pump operation.

H. Boric Acid Batching Tank: The Boric Acid Batching Tank allows the operator to mix, store, and process concentrated boric acid solutions. The tank is insulated and has a reactor makeup water supply. The associated mechanical mixer, 45 kW electric immersion heaters, temperature controller, heat tracing, and sampling connections allow handling of boric acid solutions of up to 12 percent by weight without precipitation. The contents of the batching tank may be transferred to the Refueling Water Tank or the Spent Fuel Pool with an eductor using either the boric acid makeup pumps or the reactor makeup water pumps as the motive fluid.

I. Refueling Water Tank: The Refueling Water Tank is sized to allow total boric acid recycle, to support back-to-back cold shutdowns to five percent subcritical with the most reactive CEA withdrawn and subsequent startups at 90% core life, to fill the refueling pool and transfer canal, to provide sufficient volume for engineered safety features pump operation, and to provide sufficient volume above the high outlet nozzle

to support a natural circulation cooldown per the requirements of Branch Technical Position RSB 5-1.

J. Holdup Tank: The holdup tank is sized to store all recoverable reactor coolant generated by back-to-back cold shutdowns to five percent subcritical with the most reactive CEA withdrawn and subsequent startups at 90 percent core life. The minimum pump operating level is sufficient to provide adequate NPSH to either holdup pump.

K. Reactor Makeup Water Tank: The Reactor Makeup Water Tank capacity is based on providing dilution to allow total boric acid recycle. The low level alarm for the Reactor Makeup Water Tank warns the operator that the tank may not contain the volume needed as the backup supply to the essential auxiliary feedwater pumps (if the Condensate Storage Tank becomes inoperable).

L. Boric Acid Makeup Pumps: The two Boric Acid Makeup Pumps are single stage, centrifugal pumps with induction, squirrel-cage motors. The capacity of each boric acid makeup pump is greater than the combined capacity of two charging pumps. The pumps are arranged in parallel and interlocked so that only one pump operates at a time.

M. Reactor Makeup Water Pump: The two Reactor Makeup Water Pumps are single stage centrifugal pumps with induction, squirrel-cage motors. The capacity of each reactor makeup water pump is greater than the combined capacity of two charging pumps. The pumps are arranged in

parallel and interlocked so that only one pump operates at a time.

N. Holdup Pumps: The two Holdup Pumps are single stage, centrifugal pumps with induction, squirrel-cage motors.The pumps are arranged in parallel and interlocked so that only one pump operates at a time.

O. Chemical Addition Package: The chemical addition package consists of a Chemical Addition Tank, Chemical Addition Pump, and a strainer. The capacity of the Chemical Addition Tank is nominally sized so that the maximum anticipated amount of lithium (or hydrazine under cold conditions) could be added to the RCS in one batch. The Chemical Addition Pump is a positive displacement pump with a variable capacity.

P. Boric Acid Filter: The boric acid filter is designed to remove insoluble particulates from the normal borated makeup flow and may also be used for limited cleanup of the refueling water tank.

Q. Reactor Makeup Water Filter: The reactor makeup water filter is designed to remove insoluble particulates from the reactor makeup water supply to the resin sluice supply header, makeup header, and makeup system.

R. Reactor Drain Pumps: The two Reactor Drain Pumps are single stage, centrifugal pumps with induction, squirrel-cage motors. The pumps are arranged in parallel and interlocked so that only one pump operates at a time.

S. Reactor Drain Filter: The reactor drain filter is designed to remove insoluble particulates from the contents of the Reactor Drain Tank, Equipment Drain Tank, and Holdup Tank.

T. Reactor Drain Tank: This horizontal, cylindrical tank is designed to receive and quench the discharge from the pressurizer safety valves. The minimum tank level has sufficient inventory (and volume) to quench the relief expected during a loss of load event under nominal plant conditions without exceeding the rupture disc setpoint. This quench volume is also sufficient to receive the maximum expected thermal relief valve discharge from the Shutdown Cooling/Safety Injection System without blowing the tank rupture disc. The tank is intended to receive gravity drains and leakage of reactor grade quality water from components located within containment and to receive gravity drains from the RCS. To comply with the manufacturer's recommended limit on the frequency of reactor drain pump starts, the normal operating volume is sufficient to accommodate the maximum expected leakage from the RCS for 1 hour. This means the operating volume leaves sufficient room to accumulate the normally expected leakage from all sources for several days. The tank volume above the operating band is sufficient to receive reactor coolant pump (RCP) seal controlled bleed-off (CBO) flow for approximately 30 minutes without blowing the rupture disc. This is sufficient time for operator action in the event that the normal CBO pathway to the VCT becomes isolated. The

minimum tank level is also sufficient to prevent vortexing and provide adequate NPSH for the reactor drain pumps. The tank has a nitrogen blanket with a normal operating pressure of about 1 psig.

U. Equipment Drain Tank: This horizontal, cylindrical tank receives gravity drains from the Recycle Drain Header and the Ion Exchanger Drain Header. The normal operating band corresponds to the volume of resin sluice water produced during two sluice evolutions under nominal conditions. The tank also accepts discharge from miscellaneous relief valves via the Recycle Vent Header. The volume above the operating band is sufficient to accommodate either the discharge from the largest safety relief valve for 10 minutes or gas stripper bypass flow for 30 minutes. The minimum tank level is also sufficient to prevent vortexing and provide adequate NPSH for the reactor drain pumps. The tank has a nitrogen blanket with a normal operating pressure of about 3 psig.

V. Preholdup Ion Exchanger: The preholdup ion exchanger is identical to the purification ion exchangers in mechanical design. The component is used as required to provide additional removal of radioactivity and impurities in letdown/diversion flow before return to the VCT or direction to the Holdup Tank. The ion exchanger may be used to process the contents of the RDT and EDT as they are transferred to the Holdup Tank. Cleanup of the Holdup Tank or the Refueling Water Tank in a recirculation mode is also permissible. The vessel

normally contains mixed bed resin that is both borated and lithiated. It is designed to pass the maximum letdown flow.

W. Gas Stripper: The Gas Stripper achieves efficient gas stripping by heating the process fluid and passing it down through a packed tower. The stripping medium is steam produced by heating a portion of the degassed process fluid with auxiliary steam. Transfer pumps included on the gas stripper package take suction on the degassed process fluid and send it to the heat recovery heat exchanger and aftercooler. Once cooled, the fluid is then directed to the Holdup Tank or to the VCT during continuous degassing of letdown flow. Non-condensable gases, along with trace quantities of fission gases and water vapor, are directed to the Gaseous Radwaste System. The design decontamination factor (ratio of inlet to outlet gas concentration) is 1,000. When the unit operates at its design flow rate of 140 gpm, it requires about 13,500 lbm/hour of auxiliary steam at 50 psig and 500 gpm of nuclear cooling water flow.

X. Boric Acid Concentrator Package: The Boric Acid Concentrator concentrates the process flow boron concentration by means of evaporation. The process flow enters the concentrator and is recirculated through a steam heater. The vapor evolved from the heated recirculation flow is normally stripped of entrained liquid by demisters, condensed, demineralized, and pumped to the Reactor Makeup Water Tank. In order to facilitate water management or reduce primary tritium

concentrations, the BAC vapor may also be directed to the Plant Vent for offsite release. The concentrate (bottoms) is cooled and pumped to the Refueling Water Tank. The design decontamination factor (ratio of boron concentration in the bottoms to that in the distillate) is 10,000. The maximum distillate effluent boron concentration is less than 10 ppm. When the unit operates at its design flow rate of 20 gpm, it requires about 13,500 lbm/hour of auxiliary steam and 700 gpm of nuclear cooling water flow.

Y. Boric Acid Condensate Ion Exchanger: The boric acid condensate ion exchanger normally contains anion resin to remove boron carryover and ionic impurities from the boric acid concentrator distillate. It is designed to pass the maximum expected flow from a single distillate pump.

Z. Seal Injection Filters: These two redundant filters are designed to remove insoluble particles from the seal injection flow to the reactor coolant pumps. Each unit is designed to pass the maximum anticipated flow without exceeding the allowable differential pressure across the element in the defined maximum fouled condition. The media size is sufficiently small to meet the warranty requirements of the RCP seal vendor.

aa. Seal injection Heat Exchanger: The seal injection heat exchanger is a vertical heat exchanger that was intended to use auxiliary steam to heat the seal injection flow. Operational experience has shown that the heat exchanger

is not necessary to maintain seal injection water temperature stable in the desired range. Therefore, the auxiliary steam supply to the heat exchanger and its return have been capped off.

9.3.4.2.3 Process Instrumentation and Control

The notes in the following discussion are located at the end of this section. They refer to instruments and controls that are required for safe shutdown and/or are located at the Remote Shutdown Panel.

9.3.4.2.3.1 Temperature

A. Holdup Tank Temperature: The temperature of the tank contents is indicated in the main control room, and an alarm annunciates in the main control room to warn the operator of low temperature conditions.

B. Reactor Makeup Water Tank Temperature: The temperature of the tank contents is indicated in the main control room, and an alarm annunciates in the main control room on low temperature.

C. Refueling Water Tank Temperature: Two temperature channels are installed in the Refueling Water Tank. One provides temperature indication in the control room, and the other provides indication locally. Both instruments provide an alarm in the control room to warn the operator of low temperature conditions in the tank.

D. Boric Acid Batching Tank Temperature: The batching tank temperature measurement channel controls the tank

heaters. Local indication is provided to facilitate batching operations.

E. Letdown Line Temperature: The regenerative heat exchanger letdown outlet temperature is indicated in the control room and at the Remote Shutdown Panel (note 2). A high alarm is provided to alert the operator to degraded regen heat exchanger performance or abnormal charging/letdown temperatures or flows. The high regen heat exchanger letdown outlet temperature alarm has been specifically identified in UFSAR 15.6.2 as a potential indication of a letdown line break outside of containment. The instrument also provides a signal that automatically closes a letdown isolation valve at a setpoint above the high temperature alarm. The valve must be manually opened to restore letdown flow.

F. Letdown Heat Exchanger Outlet Temperature: This channel is used to control the Nuclear Cooling Water System (NC) flow through the letdown heat exchanger in order to maintain the proper letdown temperature for purification system operation. This temperature is indicated in the control room.

G. Ion Exchanger Inlet Temperature: This channel provides indication at the Remote Shutdown Panel (see note 2). It alarms in the control room if the letdown exiting the Letdown Heat Exchanger is above normal. On a high process temperature, the channel protects temperature sensitive equipment by terminating letdown with automatic closure of the outboard containment isolation

valve. When letdown flow is stopped, high temperature fluid may be trapped by the temperature sensor. Once proper letdown cooling has been re-established, the operator may override the temperature interlock at the isolation valve hand switch if restoration of letdown flow is needed to clear the high temperature condition. The channel also initiates a signal to bypass letdown flow around the purification and deborating ion exchangers, the boronometer and the process radiation monitor. Letdown flow through these components must be manually restored when the temperature decreases below the setpoint. On a high-high temperature, another control room alarm is generated. If the letdown backpressure controller is in automatic, purification flow is terminated by closure of the backpressure control valves.

H. Volume Control Tank Temperature: The Volume Control Tank is provided with temperature indication in the control room. An alarm is provided to alert the operator to abnormally high water temperature conditions in the tank.

I. Charging Line Temperature: The regenerative heat exchanger charging outlet temperature is indicated in the control room. This indication is used to evaluate heat exchanger performance and monitor the thermal condition of auxiliary spray.

J. Preholdup Ion Exchanger Inlet Temperature: This channel provides control room indication of the temperature of

influent to the Pre-Holdup Ion Exchanger (PHIX). A high temperature alarm is provided in the control room, and, on high inlet temperature, the flow is diverted to bypass the ion exchanger to preclude degraded resin performance.

K. Reactor Drain Tank Temperature: The Reactor Drain Tank is provided with temperature indication in the control room. A high temperature alarm is provided to alert the operator to possible relief valve discharge into the tank and the need for cooling the tank contents.

L. Seal Injection Temperature: This channel is used to monitor thermal conditions at the seal injection heat exchanger outlet. Indication is provided in the control room. Both high and low alarms are also provided in the control room to identify abnormal process conditions. High-high or low-low outlet temperature signals will automatically isolate the seal injection flow by closure of valve CH-231P if temperature falls beyond acceptable limits for the reactor coolant pump seals.

M. Equipment Drain Tank Temperature: The Equipment Drain Tank is provided with temperature indication in the control room. A high temperature alarm is provided to alert the operator to possible relief valve discharge into the tank and the need for cooling the tank contents.

9.3.4.2.3.2 Pressure and Differential Pressure

A. Letdown Backpressure Controller: This channel measures pressure between the letdown heat exchanger and the letdown backpressure control valves. The controller, located in the control room, adjusts the letdown backpressure control valve(s) to maintain proper intermediate pressure. Backpressure must be sufficiently high to ensure subcooled conditions throughout the intermediate letdown piping and sufficiently low to prevent unnecessary lifts of the associated pressure relief valve. This pressure is indicated in the control room, locally, and at the Remote Shutdown Panel (see note 2). Both high and low pressure alarms are provided in the control room. The low backpressure alarm may serve as the "low letdown pressure" alarm described in UFSAR 15.6.2 as a potential indication of a letdown line break outside of containment.

B. Purification Filter Differential Pressure: Pressure taps are provided to monitor the differential pressure across the purification filters. The differential pressure indicator has a local readout and a high differential pressure alarm in the control room. Periodic readings of the instrument will indicate any progressive particulate loading of the filter.

C. Purification Ion Exchanger and Letdown Strainer Differential Pressures: Pressure taps and valves are provided to monitor the pressure loss across the

purification ion exchangers (including the deborating ion exchanger) or across the purification ion exchangers and letdown strainer combination in series. The differential pressure channel provides a local indicator and a high differential pressure alarm in the control room. Periodic readings of the instrument will indicate any progressive loading of the components.

D. Boric Acid Makeup Pump Discharge Pressure: Discharge pressure of each pump is indicated in the control room and locally. Low pressure alarms provided in the control room may be indicative of a pump failure. In the event of a sustained low pressure condition, the affected pump is stopped automatically and the alternate pump is automatically started to prevent significant interruption of borated makeup flow.

E. Charging Line Pressure: This safety grade channel monitors the pressure immediately downstream of the charging pumps. Indication is provided in the control room and at the Remote Shutdown Panel (see note 1). The instrument at the Remote Shutdown Panel is used primarily to verify proper charging pump operation. A low pressure alarm is provided in the control room. Such an alarm during normal operation may indicate charging pump failure, safety relief valve lift, valve misalignment, or charging line break.

F. Reactor Coolant Pump Controlled Bleed-off (CBO) Header Pressure: Pressure is measured at the reactor coolant pump controlled bleed-off header in order to monitor the

status of CBO flow. Indication and high/high-high alarms are provided in the control room. The high alarm indicates that a valve in the normal flowpath to the Volume Control Tank has been closed, and CBO flow has been redirected to the Reactor Drain Tank via CH-507 and the CH-199 relief valve. The high-high alarm indicates that controlled bleed-off flow has stopped entirely.

G. Charging Pump Suction Pressure Switches: A pressure switch on the inlet to each charging pump suction trips the associated charging pump on low suction line pressure thus preventing damage due to cavitation.

H. Letdown Line Pressure: The letdown line pressure between the backpressure control valves and the purification filter is indicated in the control room, and both high and low pressure alarms are provided. The low backpressure alarm may be used as the "low letdown pressure" alarm described in UFSAR 15.6.2 as a potential indication of a letdown line break outside of containment.

I. Ion Exchanger Drain Header Strainer Differential Pressure: A local differential pressure indicator is provided with a local alarm. Periodic reading of this instrument will indicate any progressive loading of the strainer due to resin fines and other particulates.

J. Equipment Drain Tank Pressure: Indication of EDT pressure and a high pressure alarm are both provided in the main control room. On high-high pressure conditions, the channel automatically isolates the

equipment drain tank. Isolation occurs through closure of valves in lines to or from the gas analyzer in the gaseous radwaste system, the recycle drain header, and the reactor drain pumps.

K. Reactor Drain Pump Discharge Pressure: The pump discharge pressures are indicated locally and in the control room.

L. Reactor Drain Filter Differential Pressure: Pressure taps are provided to permit measurement of differential pressure across the filter. Periodic readings of this instrument will indicate any progressive loading of particulates. The differential pressure is indicated locally, and a high differential pressure alarm is provided in the control room.

M. Preholdup Ion Exchanger and Strainer Differential Pressures: A differential pressure channel and valves are provided to measure the pressure loss across the PHIX or across the PHIX and its outlet strainer in series. Periodic review of these readings will indicate any progressive loading of particulates on the components. Differential pressure is indicated locally, and a high differential pressure alarm is provided in the control room.

N. Reactor Drain Tank Pressure: The RDT possesses separate narrow and wide range pressure channels. Both instrument transmitters feed a dual indicator in the control room that displays both values simultaneously. The narrow range instrument monitors the nitrogen

blanket pressure and provides a control room alarm on high pressure. The wide range instrument is needed to monitor the pressure response during safety or relief valve discharges into the tank. On high-high pressure, the associated wide range switch will close the isolation valve on the vent to the GRS (CH-540) and the inboard containment isolation valve on the tank outlet (CH-560). The operator should then take action to control the situation causing safety or relief valve operation and restore the tank to normal operating conditions.

O. Holdup Pumps Discharge Pressure: The pump discharge pressures are indicated locally.

P. Boric Acid Condensate Ion Exchanger and Strainer Differential Pressure: Pressure taps and valves allow measurement of the pressure drop across either the ion exchanger itself or the ion exchanger in series with its outlet strainer. A local differential pressure indicator with a high alarm at a local panel is provided. Periodic reading of this instrument will indicate any progressive loading on the components.

Q. Seal Injection Filter Differential Pressure: Local differential pressure indication and high differential pressure annunciation in the control room are provided to monitor the pressure loss across the seal injection filters. Periodic readings of this instrument will indicate any progressive loading of the filters.

R. Reactor Makeup Water Pump Discharge Pressure: The reactor makeup water pump discharge pressure is indicated locally and in the control room. Low pressure alarms provided in the control room may be indicative of a pump failure. In the event of a sustained low pressure condition, the affected pump is stopped automatically, and the alternate pump is automatically started to prevent significant interruption of dilute makeup flow.

S. Volume Control Tank Gas Pressure: This channel provides Volume Control Tank pressure indication in the control room. High and low pressure conditions are annunciated in the control room as well. The low pressure alarm protects against loss of charging pump suction. The high alarm setpoint is established below the setpoint of the safety relief valve on the tank gas supply and so helps protect against tank overpressurization. Either alarm alerts the operator to the need to restore nominal pressure conditions in the tank by adjusting the inflow and outflow rate of cover gas and/or process liquid.

T. Charging Backpressure Control Valve Differential Pressure: Differential pressure across the charging isolation valve CH-239 and charging backpressure control and isolation valve CH-240 in series is indicated in the control room. This channel maintains sufficient backpressure upstream of the valves to ensure reactor coolant pump seal injection flow is adequate and the auxiliary spray subsystem remains functional. The range of permissible backpressure is defined by the channel

high and low alarms in the control room. The controller setpoint and the high alarm are less than the differential pressure needed to open the spring-loaded check valve CH-435.

U. Boric Acid Filter Differential Pressure: The channel contains a local differential pressure indicator to monitor the buildup of particulate matter on the boric 153

acid filter. A high differential pressure alarm in the control room indicates the need for filter replacement.

V. Reactor Makeup Water Filter Differential Pressure: The channel contains a local differential pressure indicator to monitor the buildup of particulate matter on the reactor makeup water filter. A high differential pressure alarm in the control room indicates the need for filter replacement.

9.3.4.2.3.3 Level

A. Holdup Tank Level: Level indication and alarms for this tank are provided in the control room. On low-low level in the Holdup Tank, the holdup pumps are automatically stopped. The high level alarm indicates that processing should be commenced, and the high-high level alarm indicates that filling of the tank should be secured.

B. Reactor Makeup Water Tank Level: Level indication and alarms for this tank are provided in the control room. The low level alarm for the Reactor Makeup Water Tank warns the operator that the tank may not contain the volume needed as the backup supply to the essential

auxiliary feedwater pumps (if the Condensate Storage Tank becomes inoperable). On low-low level in the tank, the reactor makeup water pumps are automatically stopped. The high level alarm in the Reactor Makeup Water Tank indicates that filling of the tank should be secured.

C. Volume Control Tank (VCT) Level: The VCT level is measured by two instrument channels utilizing the same high and low instrument taps. Although both are differential pressure type instruments, one has a dry reference leg and the other has a wet reference leg for enhanced reliability. A control room alarm is provided to alert the operators when the two channels differ by a significant amount.

- The dry reference leg instrument (CH-226) provides VCT level indication and associated alarms in the control room. This channel controls the starting and stopping of the automatic makeup system to maintain VCT level in its normal operating band. The high level alarm set above the level at which letdown diversion should have occurred. The low level alarm is established below the level at which automatic makeup should have occurred. An alarm is also provided whenever a VCT makeup demand signal is present.

- The wet reference leg instrument (CH-227) provides indication locally and at the Remote Shutdown Panel (see note 2). Associated switches actuate CVCS

components to keep VCT level within design limits. On high level, the channel automatically diverts letdown flow to the Holdup Tank. In addition, diversion will automatically send a stop signal to the reactor drain pumps and to the holdup pumps if CH-686 is open (that is, holdup pump discharge is aligned to the reactor drain filter). On a low-low level, CH-227 transfers charging pump suction from the VCT to the Refueling Water Tank by opening valve CH-514, closing VCT outlet valve CH-501, starting a boric acid makeup pump, and closing recirculation valve CH-510. If the low-low level occurs while CH-514 has no power, then CH-536 will open automatically to allow RWT inventory to gravity feed to the suction of the charging pumps.

D. Equipment Drain Tank Level: A differential pressure type instrument indicates EDT level and activates high and low-low level alarms in the control room. A low-low EDT level automatically stops the reactor drain pumps if the EDT outlet valve CH-563 is open.

E. Reactor Drain Tank Level: A differential pressure type instrument provides RDT level indication as well as high and low-low level alarms in the control room. A low-low RDT level will automatically stop the reactor drain pumps if both RDT outlet containment isolation valves, CH-560 and CH-561, are open.

F. Refueling Water Tank Level:

- Two high level band instruments are provided to monitor level above the high suction nozzle with indication in the control room. In addition, these two independent channels provide safety grade indication of borated water supply status at the Remote Shutdown Panel (see note 1). Both channels provide high and low level annunciation in the control room. The low level alarm warns the operator of entering the volume required for engineered safety features pump operation. A low-low level alarm secures the boric acid makeup pumps.

- There are four independent, safety grade level indicators provided on the Refueling Water Tank with readout in the main control room. On a low Refueling Water Tank level, these level channels initiate the recirculation actuation circuitry as described in UFSAR sections 7.3 and 6.3.3. Any two of four independent signals are required to initiate the signal thereby precluding spurious actions resulting from failure of one measurement channel. This arrangement results in a high degree of protective measurement channel reliability in terms of initiating safeguards action when required while avoiding unnecessary action.

9.3.4.2.3.4 Flow

A. Letdown Flow: An orifice-type flow meter indicates letdown flow locally, at the Remote Shutdown Panel (note 2), and in the control room. This channel actuates a high flow alarm in the control room. High flow conditions may result from improper letdown flow or backpressure control or from a line break downstream of the instrument.

B. Process Radiation Monitor Flow: A rotameter located downstream of the boronometer* (abandoned in-place) is used to control the flow rate through the unit by adjustment of flow control valve CH-204. Indication is provided locally and in the control room. High and low alarm annunciation is provided in the control room as well. The process instrument low flow alarm is described in UFSAR 15.6.2 as a potential indication of a letdown line break outside of containment.

C. Reactor Makeup Water Flow Switch: A flow switch located downstream of the makeup flow element FE-210X alarms in the control room if dilute makeup water flow occurs during refueling operations when dilute makeup should be secured. During normal operations, the flow switch is disabled.

D. Boric Acid Flow: A coriolis type sensor is provided to measure the flow rate of borated water to the blending tee. This associated control channel positions the borated makeup water flow control valve CH-FV-210Y to obtain a flow rate preset by the operator. When the

flow controller is in automatic, excessive deviation of borate flow rate from setpoint (Hi-Lo) produces a control room alarm to indicate improper control loop operation. When the makeup mode selector switch is in the AUTO mode, additional protection against unplanned changes in the reactor coolant boric acid concentration is provided by a trip signal on flow deviation from setpoint (Hi-Hi/Lo-Lo) which terminates both borate and dilute flow. To prevent unnecessary alarms and trips from expected setpoint deviations during initiation of flow, these signals are delayed to permit control action to establish the flow rate at setpoint. Since the maximum expected borate flow is less than the design flow of the boric acid filter, the high-high flow alarm and trip functions described in the CESSAR have been removed. A flow rate recorder and a borated water flow totalizer are provided in the main control room.

E. <u>Reactor Makeup Water Flow</u>: A coriolis type sensor is provided to measure the flow rate of dilute makeup water to the blending tee. The associated control channel positions the dilute makeup water flow control valve CH-FV-210X to obtain a flow rate preset by the operator. When the flow controller is in automatic excessive deviation of dilute flow rate from setpoint (Hi-Lo) produces a control room alarm to indicate improper control loop operation. When the makeup mode selector switch is in the AUTO mode, additional protection against unplanned changes in the reactor coolant boric acid concentration is provided by a trip signal on flow

deviation from setpoint (Hi-Hi/Lo-Lo) which terminates both borate and dilute flow. To prevent unnecessary alarms and trips from expected setpoint deviations during initiation of flow, these signals are delayed to permit control action to establish the flow rate at setpoint. Since the maximum expected dilute flow is less than the design flow of the reactor makeup water filter, the high-high flow alarm and trip functions described in the CESSAR have been removed. A flow rate recorder and a dilute water flow totalizer are provided in the main control room.

F. Charging Flow: A safety grade orifice-type flow meter is installed in the charging line just downstream of the pumps. Indication of combined charging pump discharge (total charging) flow rate is provided in the control room and at the Remote Shutdown Panel (see note 1). At the Remote Shutdown Panel, the instrument is used primarily to verify proper charging pump operation. The setpoint for the low alarm provided in the control room is set below the nominal flow rate of a single charging pump in order to identify degraded pump operation.

G. Ion Exchanger Drain Header Flow Switch: A flow switch is provided with a flow present/non-present indicating light on a local panel. The indicator light is on whenever draining is in progress and goes off when an ion exchanger draining operation is complete. When refilling an ion exchanger after charging new resin, the light indicates overflow from the vent line drain and therefore completion of the filling evolution.

H. Seal Injection Flow Rate: Orifice-type flow meters provide control room indication of seal injection supply flows to each reactor coolant pump. This channel controls the seal injection flow at a setpoint established by the operator in accordance with the recommendations of the pump seal vendor. Alarms for high, high-high, and low flow are provided in the control room to indicate abnormal seal flow conditions.

I. Boric Acid Batching Flow: This instrument indicates locally the flow of concentrated boric acid from the boric acid batching tank to the boric acid batching eductor. This instrument is used in combination with measurement of the motive fluid flow rate through the eductor from either FE-210X or Y to ensure the solution exiting the eductor is at the desired concentration.

J. Letdown Heat Exchanger Nuclear Cooling System Flow Switch: This instrument has been removed and its alarm and interlock functions have been moved to the Purification Ion Exchanger Inlet temperature channel described in Section 9.3.4.2.3.1.G.

K. Reactor Makeup Water Supply Header: This instrument provides local indication of reactor makeup water flow to the recycle drain header, equipment drain tank, and the reactor drain tank.

9.3.4.2.3.5 Boronometer (abandoned in-place)

A slip stream off the letdown flowpath flows through the abandoned boronometer. A throttling valve, CH-204, located in

the letdown line in parallel with the boronometer, is automatically controlled to ensure the proper slip stream flow rate through the instrument. A three-way valve located upstream of the boronometer bypasses flow around the instrument on high letdown heat exchanger outlet temperature.

The unit is provided with shielding as required to limit the maximum external radiation level from its neutron source to a low value. All wetted surfaces that contact reactor coolant are constructed of austenitic stainless steel for enhanced corrosion resistance. The unit's rated pressure and temperature of 200 psig and 200°F, respectively, are consistent with the design values of the letdown line.

9.3.4.2.3.6 Radiation Monitoring

9.3.4.2.3.6.1 Process Radiation Monitor. The Process Radiation Monitor provides a continuous reading in the control room of reactor coolant gross gamma radiation as a measure of fuel cladding integrity. The channel detector is an ion chamber mounted adjacent to the letdown piping, specifically the slip stream around CH-204. Since letdown piping external dose rate is roughly proportional to fuel defect, increasing trends in dose rate can be used as an indication of fuel element cladding failure. Verification of the Process Radiation Monitor reading is done by grab sample measurements.

Since the detector is located downstream of the Letdown Delay Coil, its response is not significantly affected by N-16 gamma radiation. Its process location upstream of the purification ion exchangers enhances sensitivity. However, it is positioned

downstream of the purification filters to reduce monitor response due to insoluble corrosion activation products, whose concentrations are not a function of fuel defect. The monitor is ranged to detect the radiation levels expected for 0.1% to 1% failed fuel.

The characteristic time of the detector is on the order of seconds; therefore, the overall response time of the monitor is limited by the sample transport time from the core. Since the transit time of the coolant from the reactor core to the detector is less than 6 minutes, the monitor can provide relatively rapid indications of degraded fuel cladding conditions.

The monitor is part of the Radiation Monitoring System (RMS) described in section UFSAR 11.5. All of the RMS capability for data acquisition, data storage, display, and trending are available. The monitor alert alarm setpoint is discretionary and is established high enough to prevent spurious actuation and low enough to identify significant changes in reactor coolant activity levels. The high alarm setpoint corresponds to a failed fuel fraction of 1% at steady state with the UFSAR Section 11.1 radionuclide distribution.

NOTE 1: These subject safety related instruments are identified in UFSAR 7.4.1.1.10, Emergency Shutdown Outside the Control Room, and are required to be operable per Technical Specifications.

NOTE 2: The subject instruments, although also identified in UFSAR 7.4.1.1.10, are non-safety related components located in a non-safety grade process instrument panel adjacent to

Train A/C of the class Remote Shutdown Panel. These instruments are supplementary devices used to enhance pressurizer level control during shutdowns where letdown remains in service. Letdown and the associated process instruments described above are neither required nor credited for either safe shutdown or remote shutdown outside the control room.

9.3.4.3 System Operation

The Chemical and Volume Control System is designed to be operated as follows:

9.3.4.3.1 Reactor Coolant Inventories

During normal power operations, the volume of water in the RCS is regulated automatically by the Pressurizer Level Control System (PLCS). To minimize the transfer of fluid between the RCS and CVCS during power changes, the pressurizer level setpoint or target RCS volume is programmed to vary as a function of the average RCS temperature. The relationship between the pressurizer level setpoint and Tavg is shown in Figure 5.4-2. The PLCS master controller generates a level error signal by comparing the programmed setpoint with the measured pressurizer water level. Based on the level error signal, the controller regulates the inservice letdown control valve(s) as needed to keep pressurizer level on program. Large changes in pressurizer level due to power changes or abnormal operations will also result in PLCS operation of the normally running and/or standby charging pumps if needed to supplement letdown control valve action. Under steady state conditions,

letdown flow rate will be the difference between the total charging flow rate and the controlled bleed-off flow.

The Volume Control Tank is provided to accommodate small and/or temporary mismatches between letdown and charging flow. The level in the Volume Control Tank is normally controlled by the makeup system in the automatic mode of operation. When the control band high level is reached, letdown flow is diverted to the holdup tanks via the preholdup ion exchanger and gas stripper. In the automatic mode, makeup flow of a preset blend of boric acid from the RWT and demineralized water from the Reactor Makeup Water Tank (RMWT) is initiated by the Volume Control Tank low level signal. A low-low level signal automatically closes the outlet valve on the Volume Control Tank (CH-501), opens the boric acid feed valve (CH-514), and starts the boric acid makeup pumps. This alignment of an alternate borated water supply prevents charging pump trip due to loss of net positive suction head or gas-binding.

The CVCS is also used to handle thermally induced volume changes of the reactor coolant during normal plant heatups and cooldowns. As coolant volume expands during plant heatup, letdown flow is increased to keep pressurizer level on program, and the surplus inventory is diverted to the Holdup Tank. Letdown may also be sent to the Equipment Drain Tank for small temperature changes. In a cooldown, the makeup system supplies the additional inventory needed to compensate for thermal contraction of the coolant and maintain pressurizer level. The makeup system can also replace reactor coolant inventory lost due to allowable system leakage. The overall RWT, RWMT, and HUT capacities are sufficient to support back-to-back shutdowns

as noted in the individual tank descriptions in section 9.3.4.2.2. The CVCS design supports nominal heatup and cooldown rates. Regardless of system capacity, the operator limits the rate of temperature change in order to maintain pressurizer operability as required in the Technical Specifications. Rates are also adjusted as required to comply with Technical Specification pressure/temperature limits.

9.3.4.3.2 Reactivity Control

The boron concentration of the reactor coolant is normally controlled using the feed and bleed method. To change RCS boron concentration, the makeup system supplies either dilute water from the Reactor Makeup Water Tank, boric acid solution from the Refueling Water Tank, or a blend of both. The makeup water goes to the Volume Control Tank or directly to the charging pump suction. Toward the end of a fuel cycle, with low boric acid concentration in the coolant, feed and bleed becomes inefficient, and the deborating ion exchanger is used to reduce the RCS boron concentration. The deborating ion exchanger contains an anion resin in the hydroxyl form initially and converts to a borate form as boron is removed from the reactor coolant.

9.3.4.3.3 Primary System Chemistry Control

The reactor coolant system chemistry is controlled to reduce corrosion that may result in subsequent system leakage/failure, degradation of heat transfer surfaces, or increase in radionuclide specific activity concentration. Operational limits for reactor coolant impurities are established in

accordance with the Technical Requirements Manual and the EPRI PWR Primary Water Chemistry Guidelines as endorsed by NEI 97-06, Steam Generator Program Guidelines. The EPRI guidelines and their bases represent the industry best practice, as developed from evaluation of the most recent experimental data and plant operating experience. Exceptions from that guidance required as a result of site specific circumstances are fully evaluated and documented prior to implementation.

The rate of both general and localized corrosion in carbon steel, 300 series stainless steel, and alloys used in the reactor coolant system increases with the concentration of dissolved oxygen in the coolant. In addition, if chlorides and fluorides are present concurrently, then localized stress corrosion cracking is possible. Dissolved oxygen is expected in the reactor coolant following refueling when the system is open and exposed to atmosphere. Once the system is closed, filled, and vented, then oxygen may be introduced into the system through makeup water (both the RMWT and RWT are exposed to atmosphere) and possibly by air intrusion via in-leakage through the charging pump suction, which may operate at sub-atmospheric conditions. During power operations, oxygen is also produced from the decomposition of water due to exposure of neutron and high-energy gamma flux in the core. During plant heatup and at power, the dissolved oxygen concentration is limited by maintaining a hydrogen overpressure on the Volume Control Tank. The partial pressure of the hydrogen overpressure creates an excess of dissolved hydrogen gas in the coolant that favors the recombination of dissolved hydrogen and

oxygen into water. Although not normally required, dissolved oxygen may be reduced by operation of the gas stripper during plant heatup if needed.

The pH of the reactor coolant is kept in the neutral and slightly basic region at system temperature in order to enhance passivation of system metals and to minimize the deposition of crud on core heat transfer surfaces. Operating experience has shown that the corrosion rates of Ni-Cr-Fe Alloy-600 and 300 series stainless steels decrease with time when exposed to normal reactor coolant chemistry conditions due to the development of passive oxide film on reactor coolant system surfaces. Most of the film is established within 7 days at hot, high pH conditions and approaches low steady state values within approximately 200 days. Elevated pH conditions within the reactor coolant at operating temperature have the added benefit of reducing corrosion product solubility. This both decreases the dissolved crud inventory circulating in the reactor coolant and promotes selective deposition of corrosion products on cooler surfaces of the steam generator, rather than on hotter surfaces in the core. Higher pH environments also form a more stable and tenacious passive oxide layer on out-of-core system surfaces.

At low temperature, high pH conditions may be maintained through the addition of hydrazine (and ammonia formed through its decomposition) which also acts as an oxygen scavenger. Thereafter, pH is adjusted by controlling RCS lithium concentration to values consistent with the concentration of boric acid maintained for reactivity control. For a given boron concentration, the coordinated boron-lithium program

described in the EPRI guidelines prescribes an allowable range for lithium concentration, nominally 1-3 ppm. The lower limit on lithium concentration ensures that sufficient lithium hydroxide is present during operation to achieve the target pH while the upper limit provides a wide margin to the threshold for the accelerated attack of zircalloy. Although zircalloy attack does not occur until lithium concentration approaches approximately 35 ppm lithium, a large margin is appropriate in the event that any concentrating phenomena exist in the system. During plant heatup and low power operation, lithium in the form of lithium hydroxide (LiOH) is added to the coolant to increase pH. The LiOH is enriched in the lithium-7 isotope to minimize tritium production via the Li-6(n,α)H-3 reaction. During power operation, lithium is normally produced by the activation and decay of Boron-10 through the B-10(n,2α)H-3 mechanism. As a result, periodic removal of lithium by ion exchange is required to keep lithium below the upper limit. Late in core life, when large dilutions are necessary to maintain coolant temperature on program, lithium additions may again be necessary to keep lithium within the control band. Lithium is not controlled during refueling operations, and no minimum concentration applies in that mode.

Particulates and other insoluble contaminants have the potential to increase reactor coolant specific activity by activation and to foul heat transfer surfaces. They are removed in part by the in-service purification filter located in the letdown line. In addition, the resin bed of the in-service ion exchanger provides some mechanical filtration of the process as well.

The presence of ionic impurities is associated with a variety of localized corrosion mechanisms. Of particular concern are halide induced stress corrosion cracking of sensitized austenitic stainless steels and Primary Water Stress Corrosion Cracking (PWSCC). The letdown line contains three ion exchange beds, and only one is usually in service at a time. The principal strategy for operation of the ion exchangers may be described as follows. Removal of ionic impurities is accomplished by the (essentially) continuous operation of a mixed bed whose cation resin is lithium saturated and whose anion resin is borated in order to prevent changes in either pH or reactivity. A second purification ion exchanger, a mixed bed whose cation/anion resins are in the hydroxide/borate form, is operated intermittently to reduce lithium concentration. The third ion exchanger is used to reduce the reactor coolant system boron concentration. This deborating bed is only used at the end of the core cycle when the quantities of waste water produced to adjust boron concentration through feed and bleed operations become excessive. The vessel contains an anion resin initially in the hydroxyl form that is converted to a borate form as boron is removed. While deviations from this strategy are not common, the design of both purification filters and ion exchangers provides a great deal of flexibility with respect to resin selection, process flowpath, and service times. Operations and Chemistry will operate the described purification equipment as needed to economically meet the requirements for reactor coolant water quality, water management, radwaste treatment, in-plant radiation exposure, and radioactive effluent release.

The reactor coolant also contains radioactive contaminants produced from fission, activation, and decay. The coolant specific activity may be limited by feed and bleed evolutions, radioactive decay, and operation of the purification filters and ion exchangers. The types and quantities of radioactive materials expected in the coolant and connecting systems are described in UFSAR Section 11.1.

9.3.4.3.4 Shutdown Purification

When the unit is on shutdown cooling, portions of the CVCS may be aligned as required to control reactor coolant chemistry and specific activity. In the process known as shutdown purification, a fraction of the Shutdown Cooling Heat Exchanger outlet flow or its bypass is directed to the CVCS by opening cross-connect valve CH-363 and either SIB-420 and/or SIA-421.

To simplify reactor coolant inventory control, normal letdown is secured by closure of one or more of the letdown containment isolation valves while shutdown purification is in service.

The diverted shutdown cooling flow enters the letdown line upstream of the letdown heat exchanger, which is used as needed to reduce temperature to levels suitable for proper operation of the process instruments and the purification ion exchangers. The fluid is mechanically filtered and ion exchanged to reduce impurity and radioactivity levels per station chemistry control requirements. The processed fluid is returned to the suction of the in-service shutdown cooling pump(s) via CH-397 and either SIB-418 and/or SIA-419.

The differential pressure created by the shutdown cooling pump(s) provides the motive force needed to circulate coolant through the CVCS purification equipment. Coarse flow adjustment may be accomplished through positioning of manual valves in the purification flowpath or through repositioning of the cold leg injection valves provided that minimum required shutdown core cooling flow is maintained. The CVCS backpressure control valves permit fine control of purification flow from the control room. The normal letdown flow rate instrument is configured so that it also measures shutdown purification flow if in service. The purification flow may also be monitored continuously for radioactivity using the normal letdown process instruments.

With shutdown cooling in service, the shutdown purification flowpath may be modified to permit resumption of reactor coolant pump seal injection if desired. In the modified flow path, the purification flow exiting the ion exchangers is lined up to the VCT, instead of the SDC pump suction. One or more charging pumps is then used to supply seal injection flow and RCS makeup. This configuration may also be used to control reactor coolant inventory and boron concentration by coordinated use of the backpressure control valves, the letdown diversion valve, and the normal makeup subsystem.

While shutdown cooling is in service, the total dissolved gas in the coolant is controlled to prevent gas binding and degraded performance of the shutdown cooling pumps. Total gas concentration is limited by proper filling and venting of the system and the use of chemical additives if necessary. With the system in the modified shutdown purification lineup, the

gas stripper may also be employed to reduce dissolved and otherwise entrained gases in solution.

When the reactor coolant system is in a drained condition (pressurizer level less than 10%), portions of the CVCS may be used to adjust level/inventory. Of the various methods for raising RCS level, the following utilize CVCS components: (1) the normal charging lineup, (2) the alternate charging discharge pathway through the hot leg injection path, (3) BAMP discharge through a SDC suction line, and (4) gravity drain of the RWT through a SDC suction line. RCS level can be lowered by diversions of shutdown purification flow to either the Holdup Tank (HUT) or Refueling Water Tank (RWT) via CH-500. When inventory is added during either drained operations or system fill evolutions, the boron concentration and temperature of the makeup water are checked to ensure that shutdown margin and pressure/temperature limits are maintained.

9.3.4.3.5 Plant Startup

Plant startup is the series of operations that bring the plant from a cold shutdown condition to a hot standby condition at normal operating pressure and zero power temperature with the reactor critical at a low power level.

Typically, shutdown purification or modified shutdown purification is used to control pressurizer level once recovered from drained conditions. Normal letdown may be placed in service as needed to support reactor coolant system fill and vent, including drawing a steam bubble in the pressurizer, reactor coolant pump sweeps, and subsequent depressurizations to enhance evolution of gas out of solution.

The objective of the fill and vent process is to establish a "loops filled" condition where sufficient inventory is available in the hot and cold legs to support heat transfer from the core to the steam generators via natural circulation. To help achieve this condition, the total gas concentration in the coolant may be controlled below that which may result in degraded natural circulation flow even if the system were depressurized to atmospheric conditions. Additional reduction of dissolved or entrained gas may be accomplished by further venting or by operation of the gas stripper. If the RCS is intact and the dissolved gas concentration is too high, then other administrative controls are required to establish the "loops filled" condition. This may include procedural restraints against lowering pressurizer pressure below that needed to support natural circulation or by maintaining a functional HPSI pump available to pressurize the system if forced circulation were lost.

The Volume Control Tank is initially purged with nitrogen. Under most circumstances, this sweep gas contains very low concentrations of radioactivity. Therefore, the gas is normally directed to the plant vent for release offsite under the normal effluent control procedures. If necessary, high activity sweep gas can be sent to the GRS for holdup and decay before release. Once the VCT is swept, the nitrogen sweep gas is replaced with a hydrogen overpressure to control dissolved oxygen in the coolant.

During the initial stages of heatup, both letdown control valves are in service. When pressurizer pressure reaches 1200 psia, the safety relief valve downstream of the letdown

control valves may not have sufficient capacity to relieve the flow through two letdown control valves. Therefore, one letdown control valve is closed by the operator when the RCS pressure exceeds 1200 psi.

Pressurizer water level can be controlled by manually adjusting the output of the pressurizer level master controller or by using the controller in local automatic mode. When using the latter, the operator must adjust the control setpoint to compensate for the fact that the pressurizer level instruments are calibrated for normal operating temperature and pressure. The heatup results in thermal expansion of the reactor coolant. Since the operators maintain pressurizer level in its normal operating band, the expansion volume and dilution water result in an increase in Volume Control Tank level. To accommodate the additional inventory, the operators may divert letdown manually; otherwise, letdown flow is automatically diverted to holdup tanks when the highest permissible level is reached in the Volume Control Tank.

The RCS boron concentration may be reduced during heatup in accordance with shutdown margin limitations. The makeup controller is operated in the dilute mode to inject a predetermined amount of reactor makeup water at a preset rate. Blended makeup is also permitted to control reactivity, but this method is less preferred because pure dilution generates smaller volumes of radwaste per ppm change in boron concentration. Compliance with the shutdown margin limitations is verified by sample analysis.

9.3.4.3.6 Normal Plant Shutdown

Plant shutdown is the series of operations that bring the reactor plant from a hot standby condition at normal operating pressure and zero power temperature to a cold shutdown condition for maintenance or refueling.

Prior to and during plant cooldown, the gas space of the Volume Control Tank is vented as needed to reduce fission gas activity and hydrogen concentration in the coolant. Degasification continues until station ALARA objectives are met and until RCS dissolved hydrogen concentration is low enough to provide reasonable protection against the formation of explosive pockets of gas when the system is finally depressurized. Degassing the reactor coolant is accomplished by sweeps of the Volume Control Tank (VCT), venting of the pressurizer steam space, and diverting letdown flow to the gas stripper and returning the process fluid to the VCT. During the cooldown, purification rate may be increased to accelerate the degasification, ion exchange, and filtration processes.

Although not required, chemicals (other than boric acid) may be added to the reactor coolant during a plant shutdown in order to reduce short and long term corrosion rates, control in-plant and offsite radiological exposure, and enhance radwaste system efficiency. Such chemicals are evaluated for material and system compatibility prior to use. The amount and timing of chemical additions are controlled by procedure or Chemical Control Instruction.

During a normal cooldown, the contraction of reactor coolant tends to decrease pressurizer level. In response the operators

will use charging pumps and letdown control valves to maintain pressurizer level in the normal range. The consequent mismatch between charging and letdown flow results in a low level in the Volume Control Tank. Borated makeup water may be manually or automatically aligned to the VCT or directly to the suction of the charging pumps for inventory and reactivity control. Since a refueling shutdown requires a greater concentration in the RCS than can easily be obtained by the feed and bleed method, the suction on the charging pumps is normally switched to the Refueling Water Tank using one of the gravity feed pathways. The concentration of boric acid in the makeup water is controlled so that temperature dependent shutdown margin requirements are met throughout the cooldown.

Charging flow may be used for auxiliary spray to reduce system pressure and to cool the pressurizer when main spray is not available.

After the reactor vessel head is removed, the Shutdown Cooling Pumps take the borated water from the Refueling Water Tank and inject the water into the reactor coolant loops via the normal flow paths thereby filling the refueling pool. The resulting concentration of the refueling pool and the RCS will be maintained above the minimum refueling concentration specified in Technical Specifications. However, the pool concentration may be lower than the minimum operating boron concentration for the RWT. Thus, when the refueling pool contents are returned to the RWT, use of the CVCS boric acid batching equipment may be required to return the tank to operability prior to entry into mode 6.

During refueling shutdown, the reactor makeup water supply piping is monitored and alarmed for flow to prevent dilution of the refueling pool.

9.3.4.3.7 Testing and Inspection

Pre-operational testing of the CVCS consisted of the following major elements:

- Each component was inspected and cleaned prior to installation into the CVCS.
- A high velocity flush using demineralized water was used to flush particulate material and other potential contamination from all lines in this system.
- Instruments were calibrated.
- Automatic controls were tested for actuation at the proper setpoints.
- Alarm functions were checked for functionality and proper setpoints.
- The relief valve settings were checked and adjusted as required.
- All sections of the CVCS were operated and tested initially with regard to flow paths, flow capacity and mechanical functionality.
- Pumps were tested to demonstrate head and capacity.

In addition, the CVCS was tested for integrated operation with the RCS during hot functional testing. This included the following elements:

- Heat exchanger performance was verified
- Proper control of letdown flow and charging pumps by the pressurizer level control system was tested.
- The charging line was checked to assure that the piping was free of excessive vibration.
- Response of the makeup portion of the CVCS in the automatic, dilute, and borate modes was verified.

Defects in operation that could have affected plant safety were corrected before fuel loading. During the operational phase of plant life, the CVCS will be checked and tested to a comparable level of detail following system modification or major maintenance. If these activities could affect the performance requirements of CVCS equipment important to safety, then proper system operation will be verified by post-modification or post-maintenance testing prior to return of the equipment to service.

As part of normal plant operation, tests, inspections, data collection, and instrument calibrations are made to evaluate the condition and performance of the CVCS equipment and instrumentation. Appropriate vents, drains, instruments, test connections, and sampling capabilities are provided to permit inservice testing of active safety components such as pumps and valves. Inservice inspection and testing of class components in the CVCS will be conducted in accordance with the provisions

of the ASME OM Code and Section XI. A listing of active valves in the CVCS is provided in Table 3.9.3-3.

In addition, sufficient instrumentation and sampling capabilities are provided to collect data on heat transfer capabilities and purification efficiency if required to evaluate system or component performance.

9.3.4.4 Design and Safety Evaluation

9.3.4.4.1 Availability and Reliability

A high degree of functional reliability is assured by providing standby components and by assuring fail-safe responses to the most probable modes of failure. Redundancy is provided as follows:

Component	**Redundancy**
Purification and Deborating Ion Exchangers	Three identical mechanical components
Charging Pumps	One standby, two operating pumps
Auxiliary Spray Valves	Two parallel valves
Letdown Control Valve	One parallel standby valve
Letdown Backpressure Control Valve	One parallel standby valve
Boric Acid Makeup Pump	One parallel standby pump
Reactor Makeup Water Pump	One parallel standby pump
Holdup Pump	One parallel standby pump
Reactor Drain Pump	One parallel standby pump
Gas Stripper	The gas stripper package includes redundant standby pumps
Boric Acid Concentrator Package	The concentrator package includes redundant standby pumps
Seal Injection Filter	One parallel standby filter
Purification Filter	One parallel standby filter

Component	Redundancy
Letdown Containment Isolation Valves	Three valves in series (two required for operability)
Controlled Bleed-Off Containment Isolation Valves	Two valves in series
Charging Containment Isolation Valves	One motor operated valve and one check valve in series
Seal Injection Containment Isolation Valves	One motor operated valve and one check valve in series

In addition to the normal makeup pathways, two independent, gravity-feed lines from the Refueling Water Tank to the charging pump suctions are provided to assure makeup, even during a loss of offsite power. In addition to the RWT, the charging pumps have an alternate source of borated water in the spent fuel pool, which is maintained above 4000 ppm boron concentration. While the normal charging path is through the regenerative heat exchanger, it is also possible to charge through the high pressure safety injection header, although seal injection and auxiliary spray would not be functional in this lineup.

In addition to the component redundancy, the CVCS may be operated in a manner such that some components are bypassed. Transfers boric acid to the charging pump suction header (bypassing the Volume Control Tank) are permissible. The letdown filter and purification and deborating ion exchangers can be bypassed. The pre-holdup ion exchanger (PHIX) and/or the gas stripper may be bypassed if not required to control chemistry or coolant activity. The contents of the Holdup Tank may be recirculated through the PHIX if the process chemistry is not suitable for feed to the boric acid concentrator. The

charging line backpressure control valve can be bypassed with the spring loaded check valve in the alternate pathway ensuring the functionality of auxiliary spray and seal injection (if required). Controlled bleed-off flow can be routed to the Reactor Drain Tank rather than Volume Control Tank.

Most of the valves in the system are air-operated and designed to fail in a safe condition. In the unlikely event of a loss of all three instrument air compressors, a backup nitrogen supply can be automatically or manually aligned in order to restore functionality of the CVCS air-operated valves.

9.3.4.4.2 Emergency Boration

The requirements for minimum shutdown margin are contained in the Technical Specifications and Core Operating Limits Report (COLR). When the reactor is critical (operational modes 1 and 2), shutdown margin requirements are met by maintaining control rods above the Power Dependent Insertion Limits (PDILs) presented in the COLR. In lower modes 3-5 and during refueling, shutdown margin is achieved by keeping the reactor coolant soluble boron concentration above the limits provided in the Core Data Book. If the minimum shutdown margin requirements are not maintained, then the reactor coolant system must be borated at a rate of approximately 26 gpm with a minimum 4000 ppm boric acid solution. This process of borating to recover shutdown margin is known as emergency boration. When required, it must be commenced within 15 minutes and continued until the margin is recovered. Emergency boration can be accomplished using components within either the Chemical and Volume Control System (CVCS) or the Safety Injection System

(SIS). The Technical Requirements Manual contains functionality requirements for borated water sources, gravity-feed boration flowpaths, and charging pumps within CVCS to ensure that the emergency boration capability exists if needed.

9.3.4.4.3 Accident Response

This section describes the response of CVCS components to Engineered Safety Features Actuation Signals (ESFAS) generated by challenges to the principal fission product barriers. Those that interface with CVCS include Safety Injection Actuation Signal (SIAS), Containment Isolation Actuation Signal (CIAS), Containment Spray Actuation Signal (CSAS), and Loss of Power (LOP). Detailed descriptions of the Reactor Protective System and ESFAS are presented in UFSAR Chapter 7.0.

Upon receipt of a SIAS the safety injection pumps take suction from the Refueling Water Tank. These pumps continue to drain the refueling water tank until a Recirculation Actuation Signal (RAS) occurs, at which point the ESF pumps switch suction to the containment sump. The operator then manually isolates the RWT by shutting CH-530 and CH-531. This action is time critical to prevent ingress of air in the ESF pump suction piping during switchover to recirculation.

Charging pump status may change in response to the SIAS, CSAS, and LOP ESFAS signals in accordance with the various modes of BOP ESFAS Sequencer operation. The LOP signal in this case refers to that generated by loss of power on the class 1E 4160 bus that energizes the pump. Response to the signal combinations may be summarized as follows:

- Upon receipt of a SIAS or CSAS without a LOP, any running charging pump will continue to run. Idle pumps will be locked out from any automatic start signals for 40 seconds. After 40 seconds, the pump can respond to start demands from the Pressurizer Level Control System (PLCS).

- If a SIAS or CSAS is received, and a LOP signal is present with the associated emergency diesel generator output breaker closed, then all charging pumps on the bus are load shed. Following a 40 second time delay, the pumps will automatically start as required by the PLCS.

- If a LOP occurs and the associated diesel generator output breaker is closed with no SIAS or CSAS, then idle charging pumps on the bus are unaffected while running pumps are tripped and placed in an "anti-pump" breaker configuration and can only be manually restarted.

Automatic operation of the charging pumps is not required for any analyzed accident or malfunction. The control logic design provides improved availability of the charging pumps for reactivity control, makeup, seal injection, and auxiliary spray without affecting the loading and sequencing requirements of the emergency diesel generators.

The charging line contains a motor-operated, outboard containment isolation valve in series with an inboard check valve. A handwheel is provided to allow local operation of the valve, if necessary. Because the availability of reactor coolant makeup, boration, and auxiliary spray enhances overall

plant safety, the motor-operated containment isolation valve CH-524 does not receive any automatic close signals. In addition, the valve is locked in the open position with power removed. This administrative control is established to prevent loss of safety functions due to inadvertent valve closure. Therefore, a CIAS, SIAS, CSAS, or LOP does not isolate the charging line. A sufficient volume of fluid exists in the VCT to provide sufficient time to manually align the gravity feed lines from the borated water sources to the charging pump suction header. Within the containment the charging line branches into two major pathways: direct charging flow to the reactor coolant loop or auxiliary spray to the pressurizer. Both of these lines are provided with check valves that preclude back flow from the reactor coolant loop.

The seal injection line branches from the main charging line outside of the containment. Similar to the charging line itself, the seal injection line also contains a motor-operated outboard containment isolation valve in series with an inboard check valve. The motor-operated valve CH-255 does not receive any automatic close signals and is provided with a handwheel for local operation of the valve, if required. The four seal injection flow control valves in the distribution header are normally open valves that fail open on loss of instrument air, solenoid power, or control power. Maintaining charging and seal injection flow following a CIAS reduces the potential for damage to the reactor coolant pump seals. Note that the seals may be further jeopardized following a CSAS due to the additional loss of nuclear cooling water.

The letdown line and the reactor coolant pump controlled bleed-off line penetrate the reactor containment with flow in the outward direction. The letdown line contains two air operated valves inside the containment and one air operated valve outside the containment. The two air-operated valves inside containment are automatically closed on a SIAS. One of the air-operated valves inside containment and the air operated valve outside containment are automatically closed on a CIAS.

The combined Controlled Bleed-Off (CBO) line from the reactor coolant pump seals to the Volume Control Tank contains two air-operated isolation valves (CH-506 and CH-505), which are located inboard and outboard of the containment penetration, respectively. These valves close automatically upon receipt of a CSAS, as do nuclear cooling water and instrument air containment isolation valves. On CSAS, the concurrent isolation of instrument air to containment will result in the CBO line relief isolation valve (CH-507) failing open and thus directing CBO flow through the relief valve to the reactor drain tank (inside containment). Isolation of these valves on CSAS instead of CIAS is an enhancement of the original CESSAR design that reduces operator actions needed to implement the "trip two/leave two" reactor coolant pump strategy when offsite power is still available. The modification allows use of reactor coolant pumps during steam generator tube ruptures, main steam line breaks, and other accident sequences where continued forced circulation is desired and the containment is not pressurized to the CSAS setpoint. The CH-507 valve is designed to fail open to prevent catastrophic damage to the RCP

seals should the combined CBO flow be inadvertently isolated with a pump running.

The inboard and outboard containment isolation valves on the Reactor Drain Tank (RDT) outlet as well as the makeup supply header and the post-accident sampling inputs to the tank all close automatically on a CIAS. DMWO 2529758 removes piping and valves (manual and/or solenoid) from selected portions of the PASS System piping that are connected to safety-related piping and/or components. In Units where DMWO 2529758 has been implemented for the appropriate isolation points, both the PASS System/Piping and PASS containment isolation valves have been removed and/or de-terminated with lines capped as appropriate.

9.3.4.4.4 Safe Shutdown

As described in UFSAR 7.4.1.1.9, the boron addition portions of the CVCS are required to achieve safe shutdown. Specifically, in the cooldown from normal operating temperature and pressure to shutdown cooling entry conditions, operation of the charging subsystem components is rquired to support three safety functions. The addition of borated water adds negative reactivity and thereby ensures that shutdown margin requirements are met as coolant temperature decreases. The makeup water volume is needed to maintain pressurizer level (RCS inventory control) as the coolant contracts during cooldown. Use of auxiliary pressurizer spray is required to reduce RCS pressure within the design limit of the shutdown cooling subsystem. The specific functionality requirements for borated water sources, boration flowpaths, charging pumps, and auxiliary pressurizer spray are contained in the Technical

Requirements Manual. The control logic for these safety related portions of CVCS are provided in Figure 9.3-1.

Letdown and controlled bleed-off portions of CVCS are in service during normal operations but are not required for safe shutdown. Because these reactor coolant losses may actually jeopardize the inventory control safety function, they are isolated during most design events. Closure of at least one containment isolation valve in both the letdown and the reactor coolant pump controlled bleed-off pathways is required for proper CVCS operation during safe shutdown. The operability of containment isolation valves in CVCS is controlled in the Technical Specifications. In events where reactor coolant pumps are idle and complete isolation of the controlled bleed-off (including closure of CH-507) cannot be assured, then increased RCS leakage due to reactor coolant pump seal damage must also be considered.

CVCS instruments required for safe shutdown are identified in UFSAR Table 7.4-1. Their associated indicators are provided both in the main control room and at the Remote Shutdown Panel (RSP). There are also five non-safety related CVCS instruments identified in UFSAR Table 7.4-1. These instruments, located in a non-safety grade panel adjacent to safety train A/C Remote Shutdown Panel, are supplementary devices used to enhance pressurizer level control during shutdowns where letdown remains in service. These non-safety instruments are neither required nor credited for either safe shutdown (UFSAR 7.4.1.1.9) or shutdown outside the control room (UFSAR 7.4.1.1.10).

CVCS controls and status indications required for safe shutdown include those listed in Table 7.4-1 plus the controls for the charging pumps and remotely operated valves in the gravity feed boration flowpaths. While all CVCS controls required for safe shutdown are available in the main control room, only the ones in Table 7.4-1 are also provided at the RSP. The rest (e.g., the charging pumps and remotely operated valves in the boration flowpaths), however, may be controlled locally from associated breakers or disconnect switches. This is consistent with SRP 7.4 and UFSAR SER 7.4, which state that limited local actions are acceptable for providing a remote shutdown capability as required in GDC 13 and 19.

Because of the CVCS role in achieving safe hot and cold shutdown, portions of CVCS are credited in the Appendix R fire protection analysis. The use of various safety related and non-safety related components within CVCS to mitigate the effects of postulated fires is described in UFSAR Appendix 9B and its supporting basis documents.

9.3.4.4.5 Natural Circulation Cooldown

Portions of the CVCS are utilized to achieve safe shutdown under the natural circulation cooldown conditions described in Branch Technical Position RSB 5-1. In a cooldown from normal operating temperature/pressure to shutdown cooling entry conditions, operation of the borated water sources, boration flowpaths, charging pumps, and the auxiliary pressurizer spray within the CVCS are required to support three safety functions. The addition of borated water adds negative reactivity and thereby ensures that shutdown margin requirements are met as

coolant temperature decreases. The makeup water volume is needed to maintain pressurizer level (RCS inventory control) as the coolant contracts during cooldown. Use of auxiliary pressurizer spray is required to reduce RCS pressure within the design limit of the shutdown cooling subsystem. The specific functionality requirements for these CVCS components are contained in the Technical Requirements Manual.

For Class 2 plants, the use of non-safety grade equipment to achieve safe shutdown may be acceptable if it can be shown that the effects of single failures may be corrected by manual actions outside the control room. Reliance on non-safety grade CVCS components at PVNGS has been conditionally accepted based on the implementation of the following engineering and administrative controls:

- The power supplies to CH-501 (VCT outlet valve) and CH-536 (RWT gravity feed to the charging pump suction valve) were upgraded to class 1E sources.
- An interlock was added to ensure that, in the event of a Lo-Lo VCT level with a concurrent loss of power to the non-class valve CH-514 in the alternate boration pathway, the class 1E powered valve CH-536 would automatically open to provide a gravity feed pathway from the RWT to the charging pump suction.
- A second VCT level instrument was installed, and an alarm was added to detect excessive deviation between the two readings. Use of separate dry and wet reference legs reduces the chance of level instrument failure leading to loss of the charging pumps on low pump

suction pressure. Note: low VCT level has the potential to allow dissolved hydrogen to come out of solution and gas bind the pumps.

- To ensure availability of the charging pumps, valves CH-532 (RWT to BAMP suction valve) and CH-524 (charging line outboard containment isolation valve) were locked open and their actuators de-energized.
- Procedures were developed for venting the charging pumps if they were to become gas-bound. Since the normal Auxiliary Building ventilation system above the 100' elevation is not available after a loss of offsite power, venting the hydrogen gas directly into the charging pump rooms is a fire and occupational safety hazard. Therefore, hardware provisions were made to vent the gas to the Essential Pipe Density Tunnel via an intermediate Vent Receiving Tank. This configuration also ensures that the gas would be monitored for radioactivity before discharge to atmosphere.
- Calculations were performed to verify that one train of the high pressure injection in combination with one train of the reactor head vent system were capable of cooling the reactor from Hot Standby to shutdown cooling entry conditions within the specified time. Thus, these subsystems provide a diverse, safety-grade backup method for natural circulation cooldown in the event CVCS was not functional.

While not all credited CVCS components are safety grade, these enhancements give the system an acceptable level of reliability

following a loss of offsite power, and only limited operation of system components outside the control room is required to mitigate the consequences of a single failure. As required by BTP RSB 5-1, the ability to perform a natural circulation cooldown using CVCS components was demonstrated by a test conducted at Unit 1 in January 1986. Therefore, the PVNGS design and operating limits provide reasonable assurance that a natural circulation cooldown could be conducted as described in Branch Technical Position RSB 5-1 for a Class 2 plant.

A complete summary of the RSB 5-1 Natural Circulation Cooldown Analysis is included at the end of Chapter 5 as Appendix 5C.

9.3.4.4.6 Overpressure Protection

In order to provide for safe operation of the CVCS, the following relief valve protection is provided.

A. Intermediate Pressure Letdown Relief Valve: The relief valve downstream of the letdown control valves protects the intermediate pressure letdown piping and letdown heat exchanger from overpressure. The valve capacity is equal to the flow expected through one letdown control valve in the full open position at normal operating system pressure. For a given valve position, letdown flow decreases with RCS pressure. When RCS pressure falls below 1200 psia, the relief valve will be capable of discharging the combined flow through two fully open letdown control valves. Consequently, operation of both letdown control valves in parallel is procedurally permitted only when RCS pressure is less than 1200 psia. Above that pressure, one letdown control valve must be

closed. The relief valve set pressure is equal to the design pressure of the intermediate letdown piping.

B. Low Pressure Letdown Relief Valve: The relief valve downstream of the letdown backpressure control valves protects the low pressure piping, purification filters, ion exchangers, letdown strainer, and associated letdown components from overpressure. The valve capacity is equal to the capacity of the intermediate pressure letdown relief valve. The set pressure is equal to the design pressure of the low pressure piping and components.

C. Charging Pump Discharge Relief Valves: The relief valves on the discharge side of the charging pumps are each sized to pass the maximum rated flow of the associated pump against maximum backpressure without exceeding the rated head of the pump. The valves are set to open when the discharge pressure exceeds the RCS design pressure by 10 percent.

D. Charging Pump Suction Relief Valves: A relief valve is located on the suction side of each charging pump. Each is sized to pass the maximum fluid thermal expansion rate that would occur if the associated pump were operated with the suction and discharge isolation valves closed. The set pressure is equal to the design pressure of the charging pump suction piping.

E. Volume Control Tank Relief Valve: The set pressure of the relief valve on the Volume Control Tank (liquid) is equal to the tank design pressure. The valve is sized to

pass a liquid flow rate equal to the sum of the following inputs with one charging pump in operation: (1) maximum operating reactor coolant pump controlled bleed-off flow, (2) letdown flow at the high letdown flow alarm setpoint, (3) design purge flow rate of the Sampling System (SS), and the maximum flow rate from a boric acid makeup pump with the VCT at its relief pressure setpoint.

F. Volume Control Tank Gas Supply Relief Valve: The relief valve is sized to exceed the combined maximum capacity of the nitrogen and hydrogen gas regulators. The set pressure is lower than the Volume Control Tank design pressure.

G. Reactor Coolant Pump Controlled Bleed-off Header Relief Valve: The relief valve located on the RCP controlled bleed-off header redirects flow to the Reactor Drain Tank in the event that the normal flowpath to the Volume Control Tank is isolated. It serves no overpressure protection function. The valve is sized to pass the flow rate from the failure of two seal stages in one reactor coolant pump plus the normal bleed-off from the other three reactor coolant pumps. The relief valve set pressure is greater than the normal operating pressure of the header (aligned to the VCT) and less than the controlled bleed-off high-high pressure alarm.

H. Heat Traced Piping Relief Valves: Relief valves are provided for those heat-traced portions of the boric acid system (e.g., boric acid batching and the Boric Acid Concentrator bottoms) that can be individually isolated.

The set pressure is equal to the design pressure of the corresponding portion of the system piping. Each valve is sized to relieve the fluid thermal expansion rate that would occur if maximum duplicate heat tracing power were inadvertently applied to the isolated line.

I. Equipment Drain Tank Relief Valve: The Equipment Drain Tank relief valve is sized to pass the liquid flow rate equivalent to the maximum expected tank input. The set pressure is equal to the design pressure of the Equipment Drain Tank.

J. Reactor Drain Tank Rupture Disc: An installed rupture disc, which vents to the containment atmosphere, provides overpressure protection for the Reactor Drain Tank if the discharge from pressurizer safety valves exceeds the quenching capacity of the tank. The rupture disc is designed to relieve at 120 psig tank pressure (with the containment at atmospheric pressure) and is sized to pass the rated flow from all four pressurizer safety valves.

K. Charging Line Spring-Loaded Check Valve: A spring-loaded check valve is arranged in parallel with the charging line differential pressure control valve and its associated isolation valve. In the event that flow through the normal pathway is blocked by closure of either the control or isolation valve, the check valve provides an alternate pathway for charging flow to enter the RCS. The differential set pressure and capacity of the spring-loaded check valve are established to ensure that (1) charging pressure remains below the charging

pump discharge relief valve setpoints, (2) auxiliary spray remains functional, and (3) minimum acceptable RCP seal injection flow is maintained.

9.3.4.4.7 Leakage Detection and Control

The components in the CVCS are provided with welded connections wherever possible to minimize leakage to the atmosphere. However, flanged connections are provided on all pump suction and discharge lines, on relief valve inlet and outlet connections, on the boric acid batching eductor, and on some flow meters to permit removal for maintenance.

All valves larger than 2 inches and all actuator-operated valves were provided with double-packing, lantern rings, and leakoff connections unless the valves are diaphragm (packless) valves. During original plant design, an evaluation determined that leakoffs piped to the equipment drain tank present a greater ALARA concern than capping the valve leakoff. The cap has been designed as part of the CVCS pressure boundary. Diaphragm valves are utilized around the Volume Control Tank gas space. Thus, activity release due to valve leakage is minimized.

The CVCS may also be used to monitor the total RCS water inventory. The system role in the detection and quantification of RCS leakage is described in UFSAR 5.2.5. During refueling shutdown, reactor makeup water flow is monitored to detect leakage past isolation valve CH-195 (locked shut during refueling shutdown). If leakage occurs, an alarm is annunciated in the control room.

9.3.4.4.8 Failure Mode and Effects Analysis

Table 9.3.4-3 shows a Failure Mode and Effects Analysis (FMEA) for the CVCS. At least one failure is postulated for each major component of the CVCS. Additionally, various line breaks throughout the system are also considered. In each case, the possible cause of such a failure is presented as well as the local effects, detection methods and compensating provisions.

9.3.4.4.9 Radiological Evaluation

Frequently used manually operated valves located in high radiation or inaccessible areas are provided with extension stem or "reach-rod" handwheels terminating in low radiation and accessible control areas. Manually operated valves are provided with locking provisions if unauthorized operation of the valve is considered a potential hazard to plant operation or personnel safety. A radiological evaluation of the CVCS is presented in Section 12.2.

9.3.4.4.10 Boron Recovery

To reduce the amount of radioactivity that must be discharged from the site as radioactive waste or effluent, the boron recovery subystem has been sized to process the nominal borated waste water generation rates. The annual volume of water directed to the Holdup Tank during normal operation has been estimated to be:

Plant Evolution	Volume (gal/yr)
Refueling, Startup and Shutdown	204,300
Cold Shutdowns and Startups (at 30%, 60% and 90% core life)	364,300
Hot Critical Shutdowns and Startups (at 55% and 65% core life)	115,400
Boron Dilution/Fuel Burnup Waste (out to approximately 97% core life)	240,800
Back to Back Cold Shutdowns to 5% subcritical and Startups (at 90% core life)	364,500
Average Leakage to Reactor Drain Tank and Equipment Drain Tank (250 gal/day)	91,250
Total	1,380,550

The capacities of CVCS tanks and the processing rate of the boric acid concentrator have been sized to allow complete boric acid recycle. However, full boron recovery may not be achievable under all operational conditions.

9.3.4.4.11 Small Line Break

General Design Criterion (GDC) 33 requires that the normal makeup system be able to supply sufficient reactor coolant makeup in the event of a small line break to assure that Specified Acceptable Fuel Design Limits (SAFDLs) are not exceeded. Small lines at PVNGS, such as those used for instrumentation and sample collection, are connected to the reactor coolant pressure boundary via appropriately sized flow restricting devices. These devices limit the potential break

flow within the capacity of the charging system, which provides reactor coolant makeup during normal plant operation.

The CVCS design incorporates a high degree of functional reliability by provision of redundant components. The charging subsystem contains three pumps when only two of charging pumps are required to be functional in modes 1-4. In addition, the CVCS will function with either onsite or offsite electric power available. The charging pumps and auxiliary pressurizer spray valves are powered from vital electrical buses fed either from offsite power or from the emergency diesel generators. The charging pump suction pathway is gravity fed from multiple pathways using manual valves or valves that can be energized from vital power sources.

During the transient, charging flow is needed to compensate for inventory lost out of the break, contraction of coolant volume during cooldown, as well as anticipated system losses from controlled bleed-off and leakage. The maximum flow through the orifice is initially estimated to be approximately 45 gpm, which is less than the nominal capacity of the minimum number of functional charging pumps. Once letdown is isolated, analysis shows that the nominal capacity of two charging pumps provides sufficient makeup to allow pressurizer pressure to be stabilized above the SIAS setpoint.

The operators are then assumed to initiate a cooldown to cold shutdown entry conditions. During the cooldown, the capacity of charging and auxiliary spray are sufficient to control pressurizer level and RCS subcooling margin within the limits prescribed by the emergency operating procedures. Since the

core remains covered and no bulk boiling occurs in the fuel region, the SAFDL on Departure of Nucleate Boiling Ratio (DNBR) cannot be exceeded. The event terminates with entry into cold shutdown, which is achieved using only the minumum inventory of borated water stored in the RWT above the high suction nozzle.

Thus, analysis demonstrates that a small line break can be mitigated without challenging the emergency core cooling systems. Note that, as an evaluation of normal makeup system performance, the effects of a single failure and instrument uncertainty were not considered. Based on the analysis summarized above, it is concluded that the CVCS normal makeup system meets the requirements of GDC 33.

TABLE 9.3.4-1
(Sheet 1 of 2)

DESIGN TRANSIENTS
CVCS Code Class 2* Components Which Are Part Of The Reactor Coolant Pressure Boundary

Event	Assumed number of occurrences during the 40-year design life of the plant	(1) Affected Component
1. Plant Startup	500	L,C
2. Step Power Change (90 Percent to 100 Percent)	2,000	L,C
3. Step Power Change (100 Percent to 90 Percent)	2,000	L,C
4. Ramp Power Change (15 Percent to 100 Percent at 5 Percent/Minute)	15,000	L,C
5. Ramp Power Change (100 Percent to 15 Percent at -5 Percent/Minute)	15,000	L,C
6. Turbine Trip	120	L,C
7. Loss of Flow to the Core	40	L
8. Loss of Secondary Pressure	1	L,C
9. Switch from Normal Purification to Maximum Purification	1,000	L,C
10. Low-Low Volume Control Tank Response	80	L,C,S
11. Charging cycles (on/off) during an Extended Loss of Letdown	800	L,C
12. Loss of Letdown Flow and Recovery	300	L,C
13. Loss of Charging Flow and Recovery	200	L,C

TABLE 9.3.4-1 (Cont'd.)
(Sheet 2 of 2)
DESIGN TRANSIENTS
CVCS Code Class 2* Components Which Are Part
Of The Reactor Coolant Pressure Boundary

Event	Assumed number of occurrences during the 40-year design life of the plant	(1) Affected Component
14. Plant Cooldown	500	L,C
15. Reactor-Turbine Trip	234	L,C
16. Inadvertent Actuation of Pressurizer Heaters	10	L,C
17. Inadvertent Initiation of Auxiliary Spray at Full Power	5	C
18. Depressurization due to Inadvertent Actuation of One Pressurizer Safety Valve	5	L,C
19. Opening One Steam Bypass Valve at Full Power	40	L,C
20. Excess Feedwater Flow Due to Control System Malfunction at Full Power	40	L,C
21. Loss of Feedwater Flow to the Steam Generators	85	L,C
22. Pressurizer Level Control Failure to Full Letdown	100	L
23. Initiation of Auxiliary Spray During Cooldown	500	C

NOTE (1): Code for symbols: L - Letdown line to and including CH-523
C - Charging line from and including CH-524
S - Seal injection line from and including CH-255

* Design transients for Code Class 1 components are listed in 3.9.1.1.

Table 9.3.4-2
PRINCIPLE COMPONENT DESIGN DATA SUMMARY
(Sheet 1 of 1)

Tanks	**Press** (internal/external)	**Temp**	**Minimum Volume**
Volume Control Tank	75 psig/15 psig	200°F	4,917 gal
Boric Acid Batching Tank	Atmospheric	200F	630 gal
Equipment Drain Tank	60 psig/15 psig	300F	10,500 gal
Reactor Drain Tank	130 psig/15 psig	350F	2,850 gal
Holdup Tank	1.5 psig	200F	435,000 gal
Reactor Makeup Water Tank	1.5 psig	200F	420,000 gal
Refueling Water Tank	1.5 psig	200F	620,000 gal
Chemical Addition Tank	Atmospheric	150F	8 gal

Pumps	**Press**	**Temp**	**NPSH Req.**	**Head (Rated)**	**Rated Flow**
Charging Pumps	2735 psig	200F	9.0 psia	2735 psig	44 gpm
Boric Acid Makeup Pumps	200 psig	200F	14 ft	300 ft	165 gpm
Reactor Makeup Water Pumps	200 psig	200F	14 ft	300 ft	165 gpm
Holdup Pumps	100 psig	200F	10 ft	145 ft	50 gpm
Reactor Drain Pumps	200 psig	200F	10 ft	145 ft	50 gpm
Chemical Addition Pump	2735 psig	250F	5 psia	2735 psig	25 gph

Ion Exchangers	**Press**	**Temp**
Purification Ion Exchangers	200 psig	200F
Deborating Ion Exchanger	200 psig	200F
Preholdup Ion Exchanger	200 psig	200F
Boric Acid Condensate Ion Exchanger	200 psig	200F

Filters	**Efficiency (Nom.)**	**Press**	**Temp**	**Flow**
Purification Filter	98% for ≥ 2 µ	200 psig	200F	150 gpm
Boric Acid Filter	98% for ≥ 2 µ	200 psig	200F	200 gpm
Reactor Makeup Water Filter	98% for ≥ 2 µ	200 psig	200F	200 gmp
Reactor Drain Filter	98% for ≥ 2 µ	200 psig	200F	100 gpm
Seal Injection Filter*	95% for ≥ 5 µ	2735 psig	200F	30 gpm

* See also Section 9.3.4.2.2.Z.

Heat Exchangers	**Tube**			**Shell**		
	Press	**Temp**	**Pressure Loss**	**Press**	**Temp**	**Pressure Loss**
Regenerative HX.	2485 psig	650F	60 psi @ 135gpm/565F	2735 psig	550F	7.5 psi @ 44 gpm/130F
Letdown HX.	650 psig	550F	10 psi @ 135 gpm/450F	150 psig	250F	15 psi @ 1500 gpm/105F
Seal Injection HX	2735 psig	200F	10 psi @ 30 gpm/120F	N/A	N/A	N/A

Table 9.3.4-3
(Sheet 1 of 71)
CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
1)	Letdown Stop Valve Inside Containment, CH-515	a) fails open	Mechanical binding	Failure to automatically terminate letdown flow on high temperature. Loss of double isolation for letdown line on SIAS.	Position indicator in control room; temperature indicator, TIC-221; flow indicator, FI-202.	Remote manual closure of redundant valve for Hi temp. condition: Series redundant valve automatically closes on SIAS	Temp. indicator/ controller TIC-223, will increase component cooling water (CCW) flow through letdown heat exchanger (LHX) to compensate for Hi. temp. letdown flow. Problem only if regenerative heat exchanger (RHX) discharge temp. exceeds 413°F
		b) fails closed	Loss of air or power supply, spurious signal, operator error	Loss of letdown flow, possible overcharging of RCS. Increase in pressurizer (PZR) level. Possible overpressurization of RCS during startup.	Letdown low pressure alarm (PIC 201), letdown flow indication (FI-202), PZR level alarms, position indication in control room, PZR pressure indicators T-229 indication FSHL-204 low flow alarm.	None	Letdown not required for Safe Shutdown
2)	Letdown Containment Isolation Valve Inside Containment, CH-516	a) fails open	Mechanical binding	Loss of redundance for letdown isolation on CIAS and/or SIAS.	Position indication in control room	Series redundant valve, CH-515, for SIAS; series redundant valve, CH-523 for CIAS.	
		b) fails closed	Same as 1b)	Same as 1b)	Same as 1b)	Same as 1b)	Same as 1b)
3)	Regenerative Heat Exchanger, RHX	a) plugged tubes	Corrosion buildup, boron buildup, foreign material in RCS	Reduced letdown flow	Flow indicator FI-202	None	Complete plugging of all tubes is unlikely. Flow deterioration would be detected long before complete plugging occurs
		b) insufficient heat transfer	Scale buildup, fouling	Letdown temperature may exceed 450°F. Possible thermal damage to downstream components.	Hi temp alarm and indication on TIC-221. Possible Hi temp alarm on TIC-224	TIC-223 will increase NC flow to LHX. TIC-221 will isolate letdown by closing CH-515 on Hi temp.	TIC-224 will isolate letdown by closure of CH-523 if TIC-223 cannot maintain LHX outlet temperature limits.

Table 9.3.4-3
(Sheet 2 of 71)
CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		c) external leakage	Casing crack, weld crack, seat leakage on vent valve CH-393	Possible reduction in charging/letdown flow, primary coolant released inside containment	Containment radiation monitor, local leak detectors, excessive make up rate. Possible high temp T-221.	None, except series redundant valve for seat leakage on CH-393	When leak is detected, the RHX can be isolated for repair by terminating letdown/charging
		d) cross leakage	Corrosion, vibration wear mfg defect	Reduced charging efficiency.	Disparity between letdown samples and RCS samples during boration or deboration	None	When leak is detected, letdown must be terminated to effect repair
4)	Temperature Indicator/ Controller, TIC-221	a) reads high	Electro-mechanical setpoint drift	Possible erroneous Hi letdown temp. alarms, possible termination of letdown flow by closure of CH-515	Hi temp. alarm from TIC-221 without corresponding changes in indications from TIC-223, TIC-224, or PIC-201	None	Letdown not required for safe shutdown
		b) false indication of low or normal temp	Electro-mechanical failure	Loss of ability to detect Hi letdown temp condition and terminate letdown flow. Possible thermal damage to downstream components	Hi temperature alarm on TIC-224, Hi temp. indication on TIC-223. Routine periodic test.	TIC-223 will increase CCW flow thru LHX to help compensate. TIC-224 will isolate letdown flow by closure of CH-523 on Hi temp.	Letdown flow can be terminated by remote manually closing of valves CH-515 or CH-516.
5)	Letdown Isolation Valve Outside Containment; CH-523	a) fails open	Mechanical binding	Loss of redundancy for letdown isolation on CIAS. Failure to secure letdown on Hi LHX outlet temp, with possible damage to downstream components.	Position indicator in control room. Possible high temperature alarm from TIC-224.	Series redundant isolation valve CH-516 on CIAS.	On Hi temp, TIC-224 will divert CH-521 and 520 to bypass PIX, PRM, and Boronometer.
		b) fails closed	Same as 1 b)	Same as 1 b)	Same as 1 b)	Spurious Hi temp signal may be manually overridden from HS-523.	Same as 1 b)

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
6)	Letdown Control Valve; CH-110P, CH-110Q	a) regulates low	Valve operator failure, mech. failure, false signal	Reduced letdown flow. PZR level increases, volume control tank (VCT) level decreases	PZR level indications, Lo flow indication from FI-202.	Parallel redundant control valve	One of the two (CH-110Q) control valves is normally isolated by manual isolation valves while the other valve controls flow. Flow control can be switched by opening the isolation valves for the “non operating” control valve and isolating the “operating” valve.
		b) regulates high	Valve operator failure, false signal	Increased letdown flow, PZR level decreases, VCT level increases. Possible increase in letdown temperature	PZR and VCT level indications, Hi flow indication from FI-202, Hi temp indication from TIC-221.	Parallel redundant control valve. Also, if RHX discharge temp. exceeds 413°F TIC-221 will close valve CH-515, thereby terminating letdown	
		c) fails closed	Air or power failure, spurious signal	Loss of letdown flow, possible overcharging of RCS, possible RCS over pressurization during shutdown, PZR level increase, VCT level decrease	Lo flow indication from FI-202, Lo press. indication from PIC-201, PZR and VCT level indications, valve position indicator in control room.	Parallel redundant control valve	Rapid pressure transient if failure occurs during shutdown if solid plant. Letdown not required for safe shutdown.
7)	Letdown Control Valve Isolation Valve; CH-340, CH-341, CH-342, CH-343	a) fails open	Mechanical failure	No impact on system operation, unable to isolate one valve for maintenance of standby condition	Operator	Two series redundant isolation valves for each control valve	One set of isolation valves normally closed, (for standby control valve), other set is normally open (for operating control valve).
		b) fails closed	Mechanical failure	Unable to transfer letdown flow control to standby control valve	Operator	None, if operating control valve has malfunctioned	
		c) seat leakage	Contamina-tion, mechan-ical damage	No impact on operation	None	None	
8)	Letdown Flow Control Bypass Valve; CH-526	a) fails closed	Mechanical failure, valve operator failure	Unable to warm up letdown line downstream of flow control valves prior to instituting letdown	Position indicator in control room (CR).	None	Operator can warm up letdown lines using letdown control valve under manual control

Table 9.3.4-3
(Sheet 4 of 71)
CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails open	Mechanical binding, spurious signal	No impact on operation	CH-526 position indication in control room	PZR level control will regulate letdown control valve to compensate for increased flow. Flow orifice will restrict flow to low level	
9)	Isolation Valve Inlet Line from Shutdown Cooling System (SDCS) CH-363	a) fails closed	Mechanical binding, mech. failure	Unable to divert shutdown cooling flow to IXs for purification	Operator	Purification during shutdown can be accomplished via letdown and charging	
		b) fails open	Mech. binding, mech. failure	No impact on operation.	Operator	Series redundant valve in SDCS	
		c) seat leakage	Contamination	No impact on operation.	None	Series redundant check valve in SDCS	
10)	Letdown Heat Exchanger LHX	a) tube leak	Corrosion, mfg defect	Contamination of CCW with primary coolant	CCW radiation monitors, CCW surge tank level increases, increased make up, possibly low flow indication from FI-202.	None	
		b) tubes plugged	Buildup of corrosion, boron, or RCS contaminants	PLCS will gradually open letdown control valve (LCV) to compensate for increased flow resistance. Degraded PZR level control once LCV is fully open.	Mismatch between letdown flow FI-202 and PLCS master controller output demand. Periodic Hx inspections.	PLCS will open LCV to control PZR level. TIC-223 will adjust NC flow to control LHX outlet temp.	Letdown not required for safe shutdown.
		c) insufficient heat transfer	Scale buildup, fouling	Hi temperature in LHX letdown outlet. Possible thermal damage to downstream components.	Hi temp alarm on TIC-224. Periodic Hx inspections.	TIC-223 will increase NC flow thru LHX to maintain letdown outlet temp.	TIC-224 will isolate letdown on Hi temperature.
		d) external leakage	Casing crack, seat leakage from vent valve CH-444	Primary coolant or CCW released outside containment.	Area radiation monitors, local leak detectors, Lo flow indication from FI-202, excessive makeup to VCT or CCW.	None	
		e) degraded cooling flow	Loss of NC flow, NC flow control valve malfunction, NC line break.	Hi temperature in LHX letdown outlet. Possible thermal damage to downstream components.	Hi temp alarm from TIC-224, Lo flow indication on NC-F208, Hi temp alarm and indication on NC-T207. Numerous alarms for complete loss of NC flow.	TIC-224 will isolate letdown on either Hi temperature or LOOP.	Once NC flow recovered, operator can over ride and open CH-523 to restore letdown if flow needed to clear high temp condition in stagnant piping.

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
11)	Temperature Indicator/ Controller, TIC-223	a) false low temperature	Electro-mechanical failure	TIC-223 will throttle back NC flow to LHX resulting in decreased LHX heat removal. Resulting high letdown outlet temp with possible damage to downstream components.	Hi temp alarm from TIC-224.	TIC-224 will isolate letdown flow on Hi temperature.	Letdown not required for safe shutdown.
		b) false high tempera-ture	Electro-mechanical failure	TIC-223 will increase CCW flow to LHX, increasing heat removal and resulting in lower letdown outlet temperature.	High flow indication on NC-F208, Low temp indication on NC-T207. Low VCT temperature indication on TIC-225.	None required. Low temp discharge from LHX not considered a problem.	Letdown temp cannot be lower than NC supply temp.
12)	NC Flow Sensor FSL-613 --Component Removed						
13)	Backpressure Indicator/ Controller, PIC-201	a) false low pressure indication	Electrical or mechanical malfunct.	Letdown backpressure control valve will start to close, reducing letdown flow. Letdown control valve will open to compensate, increasing pressure in LHX, may lift safety valve, CH-345	Possible Lo press. alarm from PIC-201, Lo press alarm from PI-220, Lo flow indication from FI-202	None	CH-345 will protect the letdown line from exceeding design pressure
		b) false high pressure indication	Electrical or mechanical malfunction	Letdown backpressure control valve will start to open, increasing letdown flow and decreasing backpressure on LHX. Flashing will occur downstream of letdown control valve. Possible water hammer with damage to instrument tap, valves and CVCS piping	High flow alarm from FI-202, possible Hi pressure alarm from PI-220, PZR and VCT level indication	None	This transient will continue until the operator terminates letdown, or takes manual control of PIC-201 possible loss of primary coolant outside containment if water hammer occurs and breaks an instrument line or small pipe
		c) reverts to manual control	Loss of power	The letdown backpressure control valve closes. When power is restored controller reverts to manual control.	Lo (No) flow indication from FI-202. Low pressure alarm and indication from CH-PI-220	None	Letdown can not be restored without operator intervention. When power is restored, PSV-345 & PSV-354[2] may relieve to the EDT depending on PIC-201 dial setting.

NOTE[2] PSV-345 and PSV-354 provide over-pressure protection for the intermediate and low pressure letdown SSCs, respectively. See UFSAR Section 9.3.4.4.6, Items A & B.

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
14)	Letdown Backpressure Control Valve; CH-201Q, CH-201P	a) fails to close properly on decreased upstream pressure	Valve operator malfunction, mechanical binding	Possible flashing between letdown control valve and backpressure control valve, possible water hammer in letdown piping. Increased letdown flow, with PZR level decrease and VCT level increase	Lo pressure alarm from PIC-201, Hi pres. alarm from PI-220, Hi flow alarm from FI-202, PZR & VCT level indications	Parallel redundant control valve	Two parallel backpressure control valves, one standby. Standby control valve is isolated by manual valves
		b) fails to open properly on increased upstream pressure	Valve operator malfunction, mech. binding	Pressure increase upstream, may lift safety valve, CH-345. Reduced letdown flow. Increase in PZR LVL and decrease in VCT level	Hi pressure alarm from PIC-201, Lo pres alarm from PI-220, Lo flow indication on FI-202, PZR and VCT level indications	Parallel redundant control valve	Same as 14a)
		c) fails closed	Air or power failure, spurious signal	Loss of letdown flow. Hi pres. upstream may lift safety valve CH-345. PZR level increase and VCT level decrease. Possible RCS overpress., especially during shutdown cooling or startup.	Hi press. alarm from PIC-201, Lo press. alarm from P-220 PZR and VCT level indications	Parallel redundant control valve. PZR level control to stop charging pumps (except the always running pump).	If letdown and charging in progress during startup or shutdown cooling, this failure will result in a rapid RCS over press. transient if the RCS is "solid". Letdown not required for safe shutdown.
15)	Temperature Indicator/ Controller; TIC-224	a) false low tempera- ture	Electro- mechanical failure	Loss of LHX outlet temp protection. If high letdown temp exists, possible damage to down-stream components.	CH-523 fails to close with high temp indication on TIC-223. Hi temp alarm/indication on NC-T207. Low flow indication on NC-F208.	TIC-223 will adjust NC flow to control temperature in response to letdown initiated transients.	Operator action required to isolate letdown for concurrent loss of NC flow to LHX.
		b) false high temperature .	Electro- mechanical failure	Letdown isolates by auto closure of CH-523. PIX, PRM, and boronometer are bypassed. Backpressure control valves CH-201P/Q go closed. Buildup of primary contaminants. Loss of process monitoring. Loss of letdown effects as described in 1b).	High alarm from TIC-224, low flow alarm on FI-204; Auto actuations occur with normal indication on TIC-223.	TIC-223 provides redundant temp reading. On partial actuation or high temp override, CH-523 will still close on CIAS.	Letdown not required for safe shutdown. If CH-201P/Q closes without auto or manual isolation of letdown, PSV-345 will lift and letdown flow will be diverted to the EDT.
16)	Letdown Pressure Control Valve Isolation Valves; CH-347, CH-348, CH-349, CH-350	a) fails open	Mechanical binding	No impact on system operation. Unable to isolate backpressure control valve for maintenance or standby status	Operator	Series redundant isolation valve	Two sets of isolation valves, one set normally closed (for standby backpressure control valve) and the other set is normally open (for operating backpressure control valve)

NOTE(1) The boronometer is abandoned in-place.

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails closed	Mechanical binding	Unable to transfer letdown backpressure control to standby valve	Operator	None if operating backpressure control valve has malfunctioned	
		c) seat leakage	Contamina-tion, mechan-ical damage	No impact on operation	None	Series redundant isolation valve	
17)	Pressure Indicator, PI-220	a) Spurious Hi pressure alarm	Electrical or mechanical malfunction	No direct impact on system operation	Hi pressure alarm from PI-220 with normal indications from FI-202, TIC-223 and TIC-224	None required	PI-220 serves no control function
		b) Spurious Lo pressure alarms	Electrical or mechanical malfunctions	No direct impact on system operation	Lo pressure alarm from PI-220 with normal indications from FI-202, TIC-223 and TIC-224	None required	
18)	Purification Filter; Filter 1, Filter 2	a) does not filer	"Punch through" of element	Particle and radiation level buildup in IXs. Eventually high differential pressure across IXs.	Lo differential pressure indication from PDI-202	Parallel redundant purification filter, can be valved in	Unlikely failure
		b) blocked	Element plugged with particles	Reduced letdown flow	Hi differential pressure indication from PDI-202, Hi pressure indication from PI-220	Parallel redundant filter can be valved in. Filters can be bypassed through valve CH-355 if both need maintenance.	
		c) external leakage	Casing crack, seat leakage from vent valve CH-359 or CH-366	Loss of primary coolant outside containment. Possible reduced letdown flow.	Local leak detectors, Lo flow indications from FI-202, Lo differential pressure indication from PDI-202	Parallel redundant filter can be valved in. Filters can be bypassed thru valve CH-355 if both need maintenance	
19)	Purification Filter Isolation Valves; CH-358, CH-360, CH-373, CH-376	a) fails open	Mech. binding	No direct impact on system operation. Unable to isolate filter for maint. or cartridge replacement	Operator	Series redundant isolation valve	Two sets of manual valves. One set normally open (for on-line purification filter) Other set normally closed (for standby filter)
		b) fails closed	Mech. binding	Unable to put standby filter on line	Operator	None	
		c) seat leakage	Contamina-tion, mech. damage	No impact on system operation	None	Series redundant isolation valve	

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
20)	Differential Pressure Indicator; PDI-202	a) spurious Hi differential pressure alarm	Electrical or mechanical malfunction	No direct impaction operation. Early replacement of a purif. filter cartridge	Hi differential pressure alarm from PDI-202 with normal indications from FI-202, PI-220, PI-225	None required	
		b) false Lo differential pressure indications	Electrical or mechanical malfunction	No direct impact on system operation	Lo differential pressure indication from PDI-202 with normal indications from FI-202, PI-220, and PI-225	None required	
21)	Differential Pressure Indicator Isolation Valves; CH-356 CH-357	a) fails open	Mech. binding	No direct impact on system operation. Unable to isolate PDI-202 for maint.	Operator	None	
		b) fails closed	Mech. binding	Unable to place PDI-202 back on line after maint.	Operator	None	
22)	Purification Filter Bypass Valve CH-355	a) fails closed	Mech. binding	Unable to divert letdown flow past purif. filters, during maint. or cartridge replacement	Operator	Two full capacity purif. filters; should never have to use bypass valve.	
		b) fails open	Mech. binding	Continued diversion of letdown flow past purif. filters when attempt to place filter back on line. Build-up of particles in IXs	Operator	Same as above	
		c) seat leakage	Contamination, mech damage, valve not seated properly	Minor diversion of letdown flow past purif. filters. Gradual particle buildup in IXs	In long term, IX diff. pres. indicator, PDI-203, otherwise, none.	None	IXs designed to remove particulate matter. Any diversion should be minor
23)	Flow Indicator FI-202	a) spurious Hi flow alarm	Electrical or mechanical malfunction	No direct impact on system operation	Hi flow alarm from FI-202 with normal indications from FIC-204, PI-220, PIC-201, and L-110X, Y (PZR level).	None	
		b) spurious Lo flow indication	Electrical or mechanical malfunction	No direct impact on system operation	Lo flow indication from FI-202 with normal indic. from PI-220, PIC-201, FIC-204, and L-110X, Y (PZR level).		
24)	Upstream Isolation Valve for Diversion Valve; CH-364	a) fails open	Mech. binding	No direct impact on system operation. Unable to isolate diversion valve, CH-521 for maint.	Operator	None	

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails closed	Mech. binding	Unable to reestablish flow thru boronometer(1) and past PRM after maint. on diversion valve, CH-521	Operator	None	
25)	Diversion Valve; CH-521	a) fails in the straight thru position	Mech binding, valve operator malfunction	Unable to divert Hi temp letdown flow around PRM and Boronometer(1).	Position indicator in control room. Flow indication from FI-204 during Hi temp condit.	High letdown temperature would cause CCW to the LHX to increase to maintain a normal temperature to the PRM	Letdown would have to be terminated to provide protection for PRM
		b) fails to the bypass position	Loss of air or power, spurious signal	Letdown flow diverted around PRM and boronometer. Loss of continuous radiation monitoring	No flow indication from FI-204, valve position indicator in control room	None	
26)	Isolation valve; CH-413	a) fails open	Mech. binding	Partial loss of isolation capability for diversion valve CH-521	Operator	Downstream isolation valve for FIC-204 can be used.	
		b) fails closed	Mech. binding	Unable to divert Hi temp letdown flow around PRM and Boronometer(1)	Operator	PRM not affected by process Temp changes	Flow past PRM and Boronometer(1) should not be re-established after maint on CH-521 unless this valve is open
27)	Isolation Valves; CH-409, CH-410	a) fails open	Mechanical binding	Unable to isolate PRM (CH-409) or Boronometer(1) (CH-410) after maint.	Operator	Entire PRM/boronometer(1) Loop can be isolated using valve CH-364	
		b) fails closed	Mech. binding	Unable to reestablish flow through PRM (CH-409) or Boronometer(1) (CH-410) after maint.	Operator	None	
28)	Process Radiation Monitor (PRM)	a) spurious Hi radiation alarms	Elect. malfunction	No direct impact on system operation	Comparison with grab sample iodine analysis	Sampling system backup	
		b) false Lo radiation level indi-cation	Elect. malfunction	No direct impact on system operation. May not detect fuel element failure if one occurs.	Iodine analysis of grab sample	Sampling system backup	
29)	Boronometer(1)						

NOTE(1) The boronometer is abandoned in-place

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
30)	DELETED						
31)	Throttle Isolation Valve CH-245	a) fails closed	Mech. binding, mech failure	Unable to establish flow through boronometer[1] after maint.	Operator	None required	
		b) fails open	Mechanical binding	Unable to isolate boronometer[1] or flow indicator/controller, FIC-204 (CH-245) for maintenance	Operator	boronometer[1] and flow indicator, FIT-204 can be isolated using valves CH-422, CH-410, and CH-413	
		c) won't throttle properly	Mechanical binding	Unable to obtain proper flow rates thru boronometer[1] CH-409, CH-245 for given back pressure.	Operator flow indicator/controller FIC-204 flow indicator, FI-202	Valve CH-410 and CH-409 can be used to throttle flow thru the boronometer[1]	
32)	Isolation Valve CH-422	a) fails open	Mech. binding	Unable to isolate flow indicator/controller FIC-204 (CH-422) for maint.	Operator	Boronometer[1] loop can be isolated using isolation valve CH-364, and check valve CH-449	
		b) fails closed	Mech. binding	Unable to reestablish flow through boronometer[1] and past PRM (CH-422) after maint. on flow indicator	Operator	None	
33)	DELETED						
34)	Flow Indicator/ Controller, FIC-204	a) false Indications of high flow rate	Elect. or mech. malfunction	FIC-204 will open valve CH-204 thereby reducing flow past PRM and boronometer[1]. This will reduce the accuracy of their indications	Lo flow alarm from FIC-204	None	Sampling system is backup for radioactivity concentration determination
		b) false Indication of low flow rate	Elect or mech. malfunction	FIC-204 will close valve CH-204 increasing flow thru PRM, thereby altering the accuracy of its indications	Hi flow alarm from FIC-204	None	Same as 34) a)
35)	Check Valve, CH-449	a) fails closed	Mech. binding	Unable to establish flow through boronometer[1] and past PRM	Lo flow alarms from FIC-204	None	Sampling system is backup for radioactivity concentration determination
		b) fails open	Mech. binding	No direct impact on system operation	None	None	

NOTE[1] The boronometer is abandoned in-place

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
36)	Diversion valve; CH-424	a) fails closed	Mech. binding	Unable to divert letdown flow around control valve CH-204 when maint. required on CH-204	Operator	None	Sampling system is backup for radioactivity concentration determination and iodine analysis
		b) fails open	Mech. binding	Letdown flow will be diverted around control valve CH-204, thereby eliminating ability to properly regulate flow thru boronometer[1].	Operator, Low flow indication/alarm from FIC-204	None	Same as 36) a)
37)	DELETED						
38)	Control Valve, CH-204	a) won't regulate back-pressure properly	Valve operator malfunction mech binding, loss of air power	Unable to maintain proper flow rates thru boronometer[1].	Flow Indicator/ controller, FIC-204	None	Proper flow required to ensure slip stream is representative of letdown process.
		b) fails to closed position	Sheared valve stem	Sudden diversion of full letdown flow thru boronometer[1]	Hi flow alarm from FI-204	None	
39)	Isolation Valves; CH-367, CH-368	a) fails open	Mech. binding	No direct impact on system operation. Unable to isolate control valve, CH-204 for maint.	Operator	None	
		b) fails closed	Mech. binding	Unable to re-establish flow thru valve, CH-204 after maint. Unable to properly regulate flow thru boronometer[1]	Operator	None	
40)	Ion Exchanger bypass Valve; CH-520	a) fails in "IX" position	Mech. binding valve operator failure	No direct impact on system operation. Unable to divert Hi temp letdown flow past IXs. Possible damage to IX resin	None until demand, then, Hi temp alarm from TIC-224 with no change in valve position indic. in control room or in the diff. press indic. from PDI-203	None	Alternate Bypass flow paths can be manually established
41)	Ion Exchanger Differential Pressure PDI-203	a) false Lo differential Pres indication	Elect. malfunct; mech malfunct	No direct impact on system operation. Unable to detect clogged ion exchangers	None	None	
		b) false Hi. diff. pres indication	Elect or mech malfunct.	No direct impact on system operation	No change in indic. when IXs are switched. Possible high ΔP alarm	None	

NOTE[1] The boronometer is abandoned in-place

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
42)	Isolation Valves; CH-407; CH-408	a) fails open	Mech. binding	No impact on system operation. Unable to isolate IX Diff. Pres Indic., PDI-203, for maint	Operator	None	
		b) fails closed	Mech. binding	Unable to put PDI-203 back on line after maint	Operator	None	
43)	Ion Exchangers Inlet Isolation Valves; CH-369, CH-383, CH-404	a) fails open	Mech. binding	Unable to isolate associated IX for maint or when capacity is not required	Operator	Valves, CH-374 and CH-392 for valves CH-383 and CH-404. For valve CH-369 letdown flow would have to be diverted past IXs until valve was repaired	
		b) fails closed	Mech. binding	Unable to place associated IX in service	Operator	None	
44)	Ion Exchangers Inlet Check Valves; CH-370, CH-384, CH-403	a) fails closed	Mech. binding	Same as 43 b)	Operator	None	
		b) fails open	Mech. binding	No impact on system operation. Possible release of gas to letdown line during flush and drain of associated IX	None	Inlet isolation valves CH-369, CH-383, and CH-404, respectively	
45)	Ion Exchanger Resin Addition Valves; CH-372, CH-387, CH-402	a) fails closed	Mech. binding	Unable to add new resin to associated IX	Operator	None	
		b) fails open	Mech. binding	No impact on system operation. Valve would be repaired before IX would be returned to service	Operator	None	
46)	Ion Exchanger Vent Valves; CH-377, CH-386, CH-401	a) fails closed	Mech binding	Unable to vent associated IX to gaseous waste management system (GWMs) during flush and drain. No impact on system operation	Operator	None	
		b) fails open	Mech binding	No impact on system operation. Valve would be repaired before IX returned to service	Operator	None	

Table 9.3.4-3
(Sheet 13 of 71)
CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
47)	Ion Exchanger Discharge Isolation Valves; CH-378, CH-389, CH-398	a) fails closed	Mech binding	Unable to place associated IX in service	Operator	None	CH-382 can be used to isolate PIX #1.
		b) fails open	Mech binding	Unable to isolate associated IX	Operator	None	
48)	Ion Exchanger Resin Drain Valves; CH-380, CH-391, CH-400	a) fails closed	Mech binding	No direct impact on system operation. Unable to flush resin from associated IX	Operator	None	
		b) fails open	Mech binding	No direct impact on system operation. Unable to refill associated IX with new resin until valve repaired	Operator	None	
49)	Ion Exchanger Drain and flush Valves; CH-379, CH-390, CH-399	a) fails closed	Mech binding	Unable to drain or flush associated IX	Operator	None	
		b) fails open	Mech binding	No impact on system operation. Valve would be repaired before returning IX to service	Operator	None	
50)	IX Drain and Flush Header to Drain Header Isolation Valve; CH-377	a) fails closed	Mech. binding	Unable to drain IXs to drain header. No impact on normal system operation	Operator	None	
		b) fails open	Mech. binding	No impact on system operation IX flush water diverted to drain header during resin sluicing	Operator	None	
51)	Purification Ion Exchanger (PIX) 1 and 2 Outlet Cross-connect, CH-382	a) fails open	Mech. failure	Unable to establish effective series flow through PIX's 1 and 2	Operator	PIX 2 can be used independently if lithium removal required	
		b) fails closed	Mech. failure	Unable to re-establish independent flow thru PIX 1	Operator	PIX 2 is capable of full spectrum ion removal	
52)	PIX 2 to Deborating Ion Exchanger (DIX) Outlet Cross-Connect Valve, CH-395	a) fails open	Mech. failure	Unable to establish series flow thru PIX(s) and DIX	Operator	None if lithium removal required. Otherwise, series flow can be established thru PIX 1 and DIX	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails closed	Mech. failure	Unable to re-establish independent flow thru PIX 1 and 2	Operator	None	
53)	PIX Series Flow Cross-over Valve CH-381	a) fails closed	Mech. failure	Unable to establish PIX 1/PIX 2 series flow	Operator	Can establish PIX 2/PIX 1 series flow using valve, CH-385	
		b) fails open	Mech. failure	Partial diversion of letdown flow if either PIX is being used independently	Operator	Other manual valves provide adequate isolation to prevent flow diversion	
54)	PIX Series Flow Crossover Valve, CH-385	a) fails closed	Mech. failure	Unable to establish PIX 2/PIX 1 series flow	Operator	PIX 1/PIX 2 series flow can be established using valve CH-381	
		b) fails open	Mech. failure	Letdown flow diverted past PIX's if PIX 1/PIX 2 series flow is in progress. Letdown flow diverted past PIX 1 if it is being used independently	Operator	Return to PIX 2/PIX 1 series flow or, for independent use of PIX 1, other isolation valves provide adequate isolation.	This failure could occur only when transferring from PIX 2/PIX 1 series flow to another flow configuration
55)	PIX 1, PIX 2 Inlet Crossover Isolation Valve, CH-374	a) fails closed	Mech. failure	Unable to establish independent flow through PIX 2 or DIX, or PIX 2/PIX 1 series flow configurations	Operator	PIX 1/PIX 2 series flow config. can be used unless PIX 1 plugged	
		b) fails open	Mech. failure	Unable to establish PIX 1/PIX 2 series flow	Operator	PIX 2/PIX 1 series flow can be established, or PIX 1 or 2 can be used independently (using PIX 1 independently requires additional manual value operation)	
56)	PIX 2, DIX Inlet Crossover Isolation Valve; CH-392	a) fails closed	Mech. failure	Unable to establish independent flow thru DIX	Operator	Alternate flow path can be manually aligned	
		b) fails open	Mech. failure	Unable to establish series configurations PIX 1/PIC 2/DIX, or PIX 2/DIX	Operator	None if lithium removal required, otherwise series flow can be established thru PIX 1 and DIX with additional manual valve operation	
57)	PIX 2 Outlet to DIX Inlet Cross-over Isolation Valve; CH-394	a) fails closed	Mech. failure	Unable to establish series flow thru PIX 2 and DIX	Operator	None if lithium removal required, otherwise series flow can be established thru PIX 1 and DIX	
		b) fails open	Mech. failure	Diversion of letdown flow if in any IX config. other than PIX/DIX series flow	Operator	Other manual valves provide adequate isolation capability	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
58)	Purification Ion Exchangers; PIX 1, PIX 2	fails to remove contamination	Resin exhausted	Buildup in RCS activity	PRM Hi activity alarm, sample analysis for radioactivity	Redundant IXs except for lithium removal. IXs can be bypassed for resin replacement	
59)	Deborating Ion Exchanger, DIX	fails to remove boron	Resin exhausted	Decreased boron removal capability at end of life. Unable to maintain power at end of core cycle	Sample analysis for boron, decrease in power.	Continue feed and bleed while restore DIX resin	
60)	Letdown Strainer	a) plugged	Contaminant buildup	Reduced letdown flow	Hi diff pres alarm from PDI-203	IXs and strainer can be bypassed while strainer element replaced	
		b) fails to strain properly	Element "punch through", wrong size element	Possible deposition of particles and resin in VCT. Possible contam. of charging pumps	Lo diff pres. indic from PDI-203, sample analysis	Same as above	
		c) external leakage	Mfg. defect, corrosion	Primary coolant released outside containment	Local leak detectors, radiation monitors	Same as above	
61)	Isolation Valve; CH-415	a) fails open	Mech. failure	Unable to isolate letdown strainer for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to restore letdown flow through IXs and letdown strainer after maint. on letdown strainer	Operator	None	
62)	Letdown Strainer Drain Valve, CH-419	a) fails closed	Mech. failure	No impact on system operation. Unable to drain letdown strainer for maint.	Operator	None	
		b) fails open	Mech. failure	Part of letdown flow diverted to SRS. VCT level decreases	VCT level indications, operator	None	
63)	Check Valve CH-396	a) fails open	Mech. failure	No impact on system operation	None	None	
		b) fails closed	Mech. failure	Unable to route shutdown cooling flow through IXs for purification	Lo flow indications from FI-202, and flow indicator in SDCS	Purification during shutdown cooling can be accomplished via normal letdown and charging	
64)	Discharge Valve to SDCS; CH-397	a) fails closed	Mech. failure	Same as 63 b)	Operator	Same as 63 B)	
		b) fails open	Mech. failure	Diversion of letdown flow to SDCS during normal operation. VCT level decrease	Operator, VCT level indications	Series redundant isolation valve in SDCS	
65)	Isolation Valve, CH-414	a) fails closed	Mech. failure	No impact on system operation. Unable to get a differential pressure reading across just the IXs	Operator	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails open	Mech. failure	Unable to transfer PDI-203 from reading diff. pres across IXs and letdown strainer	Operator	None	
66)	Letdown Line Sample Valves; CH-426, CH-353, CH-420	a) fails open	Mech failure	No impact on system operation. Unable to isolate affected sample line	Operator	Series redundant isolation valves in sampling system (SS)	
		b) fails closed	Mech. failure	Unable to obtain sample at specified point	Operator	None	Sample valves are normally open
67)	Letdown Line Safety Valves; CH-345, CH-354	a) fails closed	Mech. binding, blockage	No impact on system operation. Loss of over pres. protection for potentially closed line section	High pressure alarm from P-201 and P-220 respectively, on demand. Periodic tests	None	
		b) fails open	Broken spring, setpoint drift	Letdown flow diverted to equipment drain tank (EDT)	VCT and EDT level indications, Lo flow indication from FI-202 Lo pressure alarm P-201, P-220	None	
68)	Letdown Line Test Connection CH-853, CH-855	a) fails closed	Mech. failure	No impact on system operation. Unable to drain line section or test valves per ASME OM Code.	Operator	None	
		b) fails open	Mech. failure, seat leakage	Possible loss of primary coolant	None	These drain valves/test conn. blind flanged	
69)	VCT Bypass Valve Isolation Valve; CH-418	a) fails open	Mech. failure	Unable to isolate VCT bypass valve, CH-500, for maint. No impact on normal system operation	Operator	Valve CH-415 and CH-520 can be used	
		b) fails closed	Mech. failure, binding	Unable to reestablish letdown flow after maint. on CH-500	Operator	None	
70)	VCT Bypass Valve; CH-500	a) fails to VCT	Valve operator malfunct., Mech. failure, Loss of air or	Unable to divert letdown flow to pre-holdup ion exchangers (PHIX) during feed and bleed operations or for degassing of letdown flow	Hi VCT level indications/alarm from LIC-226 or LIC-227.	None. Letdown would have to be terminated to repair valve	Letdown not required for safe shutdown.
		b) fails to the PHIX position	Operator error, spurious signal	Decreasing VCT level during normal charging and letdown operations. Excessive amounts of primary coolant diverted for boron reclamation	Low VCT level alarms from LIC-227 and LIC-226 excessive use of boric acid make up	Makeup system will maintain VCT level. Letdown would have to be terminated to repair valve	Note: Normal letdown and charging could continue via the gas stripper
71)	VCT Inlet Check Valve, CH-101	a) fails open	Mech. binding	No impact on normal system operation. Unable to perform maintenance on CH-500 with pressure in VCT.	None	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails closed	Mech. binding, mech. failure blockage	Unable to establish normal letdown flow to VCT. PZR level increases, VCT level decreases	Low flow indication from FI-202, Hi pres indic from PI-220, VCT and PZR level alarms	Continuous bypass to the PHIX with return to VCT can be used, but letdown would have to be terminated and the valve repaired before normal letdown and charging could resume.	
72)	Gas Stripper (GS) to VCT Inlet Check Valve, CH-139	a) fails closed	Mech. binding blockage	Unable to establish return flow from GS to VCT. Loss of continuous degasification capability for letdown flow. VCT level decrease during continuous degasification. No impact on normal operation	VCT level alarms, possibly Lo flow indic from FI-202, and Hi pressure indic from PI-220	None	
		b) fails open	Mech. binding	Possible diversion of letdown flow to GS discharge line. Unable to perform maintenance on CH-567 with pressure in VCT.	VCT Lo Level indications	None	This failure mode is unlikely
73)	H_2 Supply Valve Isolation Valves CH-107, CH-108	a) fails open	Mech. binding	No impact on normal system operation. Unable to isolate VCT H_2 supply valve for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to re-establish H_2 supply to VCT. Loss of 0_2 control for primary coolant	Operator	O_2 control can be maintained by H_2 injection into the charging line	
74)	VCT H_2 Supply Valve, CH-502	a) regulates VCT pres. low	Mech. mal-funct. Elect. malfunct. mech. binding	Decreased H_2 pres. in VCT and RCS, partial loss of RCS 0_2 control	Low VCT pressure indication/alarm from PI-225	Same as above	
		b) regulates VCT pres Hi.	Elect. or mech. malfunct.	Increased H_2 pres. in VCT. possible overpressurization of VCT and increased H_2 concen-tration in RCS	Hi VCT pres. alarm from PI-225	Relief valve, CH-105 will keep H_2 addition header pres. down. VCT can be vented to GRS	CH-502 can be isolated and 0_2 control can be maintained by H_2 injection into the charging line.
75)	H_2 Flow indicator, FI-206	a) Erro-neously H_2 flow indications	Elect. or mech. malfunct.	No impact on system operation. Local readout only	Operator	None	
76)	VCT N_2 Supply Valve Isolation CH-109, CH-644	a) fails closed	Mech. binding	No impact on normal operation. Unable to purge VCT with N_2 during shutdown	Operator	None	
		b) fails open	Mech. binding	Unable to isolate N_2 supply purging VCT	Operator	Series redundant valve	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
77)	VCT N_2 Supply Valve, (CH-503)	a) regulates pressure low	Elect. or mech. malfunction	No impact on normal operation. Insufficient N_2 supply to VCT during purge. Incomplete VCT purge	Lo pres alarm from PI-225	None	
		b) regulates pressure high	Elect. or mech. malfunction	Possible overpressurization while purging VCT. No impact during normal operation	Hi pres alarm from PI-225	Vent control valve will open to maintain VCT pres. Valve CH-105 provides overpres. protection for gas supply header	
78)	N_2 Flow Rate Indicator, FI-215	erroneous flow indi-cations	Elect. or mech. malfunction	No impact on system operation. Local indication only	Operator	None	
79)	Gas Supply Header Safety Valve; CH-105	a) fails closed	Mech. binding, blockage	No impact on normal operation. Loss of overpressure protection for gas supply header	None	None	
		b) fails open	Mech. failure setpoint drift	H_2 or N_2 diverted to GRS. Possible decrease in H_2 concentrate, in RCS and increase in RCS 0_2 concentration	Possibly Hi pres alarms from GRS otherwise none.	High pressure H_2 injection into charging line is backup source	
80)	Gas Supply Header Check Valve; CH-112	a) fails closed	Mech. binding, blockage	Unable to add H_2 (or N_2) to VCT, H_2 concentration in RCS decreases and RCS O_2 concentration increases, possible VCT press. decrease	RCS sampling. Possibly, Lo pres alarm from PI-225	H_2 injection into charging line	
		b) fails open	Mech. binding mech. failure	No impact of normal operation. Possible diversion of radioactive gasses to GRS or H_2 supply	None	None	
81)	Gas Supply Header Isolation Valve; CH-645	a) fails open	Mech. binding	No impact on system operation. Unable to isolate gas supply header for maintenance	Operator	None	
		b) fails closed	Mech. failure, mech. binding	Unable to add H_2 (or N_2) to VCT. Decrease in RCS H_2 concentration and Increase in RCS 0_2 concentration	Operator	H_2 injection into charging lines	
82)	Gas Analyzer Isolation Valve, CH-104	a) fails open	Mech. binding	No impact on system operation. Unable to isolate gas analyzer for maintenance	Operator	None	
		b) fails closed	Mech. binding	No impact on system operation. Unable to sample VCT with gas analyzer.	Operator	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
83)	VCT Pressure Indicator, PI-225	a) spurious high pressure alarms	Elect. or mech. malfunct.	No Direct impact on system operation. Operator may vent VCT, resulting in Lo VCT pres and excessive use of H_2	Hi pressure alarms from PI-225 with normal H_2 flow indication from FI-206 (local readout only)	H_2 supply valve will maintain VCT pres.	
		b) spurious low pres alarms	Elect. or mech. malfunct.	No direct impact on system operation	Lo pres alarm from PI-225 with normal H_2 flow indic. from FI-206 (local readout only)	Same as above	
84)	VCT Vent Line Control Valve CH-513	a) fails closed	Mech. fail Loss of air or power	Unable to vent VCT to GRS during purge. Possible overpres. of VCT during purge. No impact on normal indication	Valve position indicator in control Rm. Hi pres. indic. from PI-225	N_2 supply valve should prevent overpres. of VCT by closing	
		b) fails open	Spurious signal mech. malfunct.	For spurious signal: unwanted venting of VCT, loss of VCT pres. decreased H_2 concen-tration in RCS with increased RCS O_2 concentrat. for mech. malfunct. Unable to terminate venting of VCT during purge	Lo pres. alarm from PI-225, valve position indicator in control room. Valve position indicator in control room	Manual isolation valve, HC can be closed. H_2 supply valve (or N_2 supply valve) will maintain VCT pressure	
85)	VCT Vent Line Pressure Regulator, CH-643	a) regulates pressure Hi	Elect. or mech. malfunct.	No impact on normal operation. Excessive use of N_2 during NCT purge	Lo pres. alarm from PI-225, Hi N_2 flow indic. from FI-215 (local readout only)	None	
		b) regulates pres. Lo	Elect. or mech. malfunct.	No impact on normal system operation. During VCT purge VCT pres. too high and the N_2 supply valve will close to counteract VCT pres. increase. Incomplete VCT purge	Hi pres alarm from PI-225, Lo N_2 flow indic. from FI-215 (local readout only)	None	
86)	Vent Line Isolation Valves CH-100	a) fails open	Mech. failure	No impact on normal operation. Unable to isolate vent line for maint.	Operator	None	
		b) fails closed	Mech. failure	No impact on normal operation. Unable to vent or purge VCT	Operator	None	
87)	Reactor Coolant Pump Controlled Bleedoff Excess Flow Check Valves, CH-301, CH-302, CH-303, CH-304	a) fails closed	Hi or Lo spring tension, plugged, mech. failure	Loss of controlled seal bleedoff for reactor coolant pump (RCP). Possible damage to RCP seals due to overpressurization of seals	Flow and pressure indicators on bleedoff lines	None	Associated RCP must be shut down

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
88)	Pressure Indicator, PI-215	a) erroneous high or high-high pressure alarms	Elect. or mech. failure, setpoint drift	No direct impact on system operation. Erroneous indication of loss of controlled bleedoff flow.	Hi pres alarms from PI-215 with normal readings from all other bleedoff line instruments	Redundant instruments on bleedoff lines inside containment	PI-215 is used to determine bleed-off throttle valve setting during startup. Once throttle valve is set it is rarely changed.
		b) false Lo pressure Indications	Elect. or mech. malfunction	No direct impact on system operations. Loss of bleedoff header pres. indication needed for setting throttle valve during startup	Bleedoff line instrumentation	None	
89)	RCP Controlled Bleedoff Line Containment Isolation Valves; CH-506, CH-505.	a) fails in open position	Mech. failure	No impact on normal operation. Loss of redundant isolation capability for bleedoff lines on CIAS	Valve position indicator in control room	Redundant isolation valve	
		b) fails to closed position	Loss of air or power, spurious signal, mech. failure	Sudden loss of normal RCP controlled bleedoff flowpath. Safety valve CH-199 will lift	Valve position indicator in control room, Hi pres alarm from bleedoff line instrumentation	CH-199 will lift, directing bleedoff flow to reactor drain tank (RDT).	
90)	RCP Controlled Bleedoff Relief Valve Stop Valve; CH-507	a) fails in open position	Loss of air or power, mech. failure	No impact on normal operation. Unable to isolate relief valve if relief valve starts to leak	Valve position indicator in control room on valve demand	None	
		b) fails closed	Spur signal, mech. failure	No impact on normal operation. Loss of backup controlled bleedoff flow path.	Valve position indicator in control room	Normal controlled bleedoff via CH-505, CH-506	
91)	RCP Controlled Bleedoff Header Relief Valve; CH-199	a) fails open	Mech. failure	Controlled bleedoff flow diverted to RDT	Lo pres indication from PI-215, temp. pres. and level indications on RDT	Valve CH-507 can be closed to isolate CH-199	
		b) fails closed	Mech. failure blockage	No impact on system operation. Loss of backup controlled bleedoff flow path	Periodic Test	Normal controlled bleedoff via CH-505, CH-506	
92)	Controlled Bleedoff Throttle Valve; CH-198	a) fails closed	Mech. failure	Unable to establish controlled bleedoff flow to VCT on startup	Operator	Backup controlled bleedoff flow path via CH-199	Startup delayed until valve repaired.
		b) fails open	Mech. binding	Unable to throttle controlled bleedoff flow properly	Operator	None	Throttle valve is set during startup, and is rarely changed during operation

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
93)	Controlled Bleedoff Line Check Valve; CH-646	a) fails closed	Mech. binding blockage	Unable to establish controlled bleedoff flow to VCT during startup	Hi pres alarm from PI-215	Backup controlled bleedoff flow path via CH-199	
		b) fails open	Mech. failure	No impact on normal operation. Possible reverse flow in bleedoff line during shutdown if VCT is at higher pressure than bleedoff lines	None	Excess flow check valves will be closed during shutdown	
94)	Controlled Bleedoff Line Test Connec-tions, CH-740, CH-741, CH-742, CH-743	a) fails closed	Mech. failure	No impact on normal operation. Unable to drain bleedoff line for one pump or inservice test CH-505 or 506	Operator	None	
		b) fails open	Seat leakage, mech. failure	Possible loss of primary coolant inside containment	Local leak detectors containment radiation monitors. Bleedoff line flow indicators	Valves are all blind flanged	
95)	Primary Sample Purge Check Valve; CH-197	a) fails closed	Mech. failure blockage	No impact on normal operation. Unable to purge primary sample system before obtaining primary sample	Operator	None	
96)	VCT Temperature Indicator, TI-225	a) spurious Hi temp alarms	Elect. or mech. failure, setpoint drift	No direct impact on system operation. False indication of Hi temp in VCT	Hi temp alarm from TI-225, with normal pressure and temp. Indication from letdown, charging, and controlled bleedoff instruments	None	
		b) false lo temp. indications	Elect. or mech. failure, setpoint drift	No impact on normal operation. Unable to detect Hi temp condition in VCT	Periodic test	None	
97)	VCT Level Indicator/ Controller LIC-226	a) spurious low level indication and alarm	Elect or mech failure setpoint drift	Possible overfilling of VCT due to actuation of automatic makeup. Letdown diverted to PHIX on High level in VCT	Excessive use of makeup. Diversion valve position indicator in control room, in combination with Lo level alarm from LIC-226	LIC-227 will alarm on Hi level and divert letdown flow to PHIX to prevent overfilling VCT	Excessive use of makeup and excessive generation of liquid waste
		b) spurious Hi level indication and alarm	Elect or mech failure, setpoint drift	Early termination of makeup flow, RCS losses not compensated for. Possible PZR level decrease. Gradual emptying of VCT	Hi level alarm from LIC-226 with diversion valve not changing position	On Lo-Lo VCT level, LIC-227 will switch charging pump suction to refueling water tank (RWT)	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
98)	VCT Level Controller, LC-227	a) spurious Lo level alarms	Elect. or mech. malfunction setpoint drift	VCT will be isolated and charging pump suction aligned to RWT. VCT will be overfilled because letdown will not be diverted	Lo Level alarm from LIC-227 with normal or Hi level indic. from LIC-226	CH-115 will relieve, if necessary	
		b) spurious Hi level alarms	Elect. or mech. malfunction setpoint drift	Letdown flow will be diverted to PHIX and holdup tank, VCT will start to empty	Hi level alarm from LIC-227 with normal or low level indications from LIC-226	LIC-226 will initiate automatic makeup on Lo level.	
99)	Volume Control Tank	a) breach	Weld failure, mfg defect	Loss of primary coolant outside containment	Low level alarms from LIC-226 and LIC-227. Local leak detectors	None	Operator action required to terminate this event. VCT not required for safe shutdown.
100)	VCT Discharge Relief Valve; CH-115	a) fails closed	Blockage. mech. failure	No impact on normal operation. Loss of overpressure protection for VCT and VCT discharge line	Periodic test	None	
		b) fails open	Mech. failure	Minor losses of primary coolant to equipment drain tank (EDT). Possible trip of charging pumps on low suction pressure	EDT level indications, possibly VCT level indicator LIC-226, possible charging pump trouble alarm.	Makeup system compensates for minor coolant losses. LIC-227 will switch charging pump suction to RWT via BAMP on low low level in the VCT	
101)	VCT Discharge Local Sample Valve, CH-116	a) fails closed	Mech. failure	No impact on normal operation. Unable to sample VCT contents	Operator	None	
		b) fails open	Seat leakage	Minor loss of primary coolant outside containment	Local leak detectors, radiation monitors	None	
102)	VCT Drain Valve CH-117	a) fails closed	Mech. failure mech. binding	No impact on normal operation. Unable to drain VCT	Operator	Other drain valves available downstream	
		b) seat leakage	Contamination mech. damage	Minor loss of primary coolant to drain header	Possibly low level indications from LIC-226	None	
103)	VCT Discharge Isolation Valve, CH-501	a) fails open	Mech. failure loss of power	Unable to isolate VCT on low level signal from LIC-227. Possible emptying of VCT. Possible charging pump trip on low suction pressure with loss of charging flow	Valve position indication in control room	LIC-227 will switch charging pump suction to RWT via boric acid makeup pumps (BAMP) on Lo-Lo level in the VCT	
		b) fails to closed position	Mech. failure, spur signal	Sudden loss of charging flow. PZR level decreases, loss of letdown due to high temp. trip (TIC-221) of CH-515	VCT and PZR level indicators, charging pump trip indications	None	Charging Pump Suction can be switched to RWT by opening valve CH-514 and starting BAMP

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		c) fails in closed position	Mech. failure, loss of power	Unable to switch charging pump suction back to VCT	Valve position indicator in control room	Charging pump can still be aligned to RWT	Valve normally aligned to VCT
104)	VCT Discharge Check Valve; CH-118	a) fails open	Mech. failure	No impact on normal operation. Possible leakage into VCT when charging pumps taking suction from RWT via BAMP	None	Valve CH-501 will be closed when charging pumps taking suction from RWT	
		b) fails closed	Mech. failure, mech. binding, blockage	Unable to switch charging pump suction back to VCT. Possible charging pump trip on Lo suction pres.	Charging pump trip, VCT level indications	Charging pumps can still be aligned to RWT	
105)	Charging Pump Isolation Valves, CH-316, CH-339, CH-319, CH-337, CH-322, CH-335	a) fails open	Mech. binding	Unable to isolate one charging pump for maint. No impact on normal operation	Operator	None	
		b) fails closed	Mech. binding, blockage	Unable to return charging pump to service after maint.	Operator	Redundant charging pumps	
106)	Charging Pump Drain Valves; CH-317, CH-329, CH-320, CH-332, CH-323, CH-336	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to drain pump for maint.	Operator	Some redundance between suction and discharge drain valves	
		b) seat leakage	Contamina-tion, Mech. damage	Minor loss of primary coolant to recycle drain header	Possibly Hi level indications from EDT, or low level indic. from VCT	Makeup system compensates for minor coolant losses	
107)	Charging Pump Discharge Check Valves; CH-328, CH-331, CH-334	a) fails open	Mech. failure	No impact on normal operation. Possible reverse flow into standby pump. Possible damage to pump	None	Charging pump discharge relief valves provide overpressure protection	
		b) fails closed	Mech binding blockage	Unable to use affected charging pump. Possible pump damage due to dead heading	Charging line flow indicator, Lo flow indication	Redundant charging pumps. Charging pump discharge relief valves provide recirculation for charging pumps	
108)	Charging Pump Discharge Relief Valves; CH-326, CH-325, CH-324	a) fails open	Mech. failure, setpoint drift	Charging pump discharge diverted to charging pump suction. Reduced charging flow from affected pump	Lo flow indication from charging line flow indicator, FI-212	Redundant charging pumps	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails closed	Mech. binding blockage	No impact on normal operation. Loss of discharge overpressure protection.	Periodic test	None	
109)	Charging Pump Suction Relief Valves; CH-315, CH-318, CH-321	a) fails closed	Mech. failure, blockage	No affect on normal system operation. Loss of overpressure protection for potentially closed suction line	Periodic test	None	
		b) fails open	Setpoint drift spring failure	Loss of primary coolant to EDT. Gradual VCT level reduction	EDT level indications, VCT level indications	Makeup System Compensates for minor coolant losses	
110)	Charging Pump, Suction Pressure Switches; PS-216, PS-217, PS-218	a) erron-eously senses Lo press.	Mech. failure, setpoint drift	Spurious charging pump trip	Charging pump trip indications. Low flow indication from FI-212, PZR and VCT level indic.	Redundant charging pumps	
		b) senses pressure too high	Mech. failure, setpoint drift point drift	No impact on normal system operation. Failure to sense Lo suction pressure. Possible cavitation damage to charging pump	Periodic test	None	
111)	Charging Pumps (CP) CP-1, CP-2, CP-3	a) operating pump stops	Loss of power, seizure, other mech. failure	Reduced charging flow, VCT level increase, PZR level decrease. Letdown temp. increases	Lo flow alarm from FI-212, VCT and PZR level indications, letdown temp indications	PZR level control will start standby CP	Normally two pumps are always running.
		b) standby pump fails to start	Loss of power mech. failure	Unable to deliver maximum charging flow when needed. PZR level drop. Possible SIAS if PZR empties	Lo PZR level alarm CP run indicator	Letdown Control Valves CH-110P, Q modulate letdown flow to maintain PZR level.	
		c) spurious startup of standby pump	Spurious signal, operator error	Excess charging flow, PZR level increase, possible overpres. of RCS	CP run indicator, Hi flow indication from FI-212, PZR level and pres. alarms	PZR level control could shut down one pump, or open letdown control valve further. PZR spray would come on to hold pres. down	
112)	Charging Pump to HPSI Header Isolation Valves; CH-796, CH-797, CH-798	a) fails closed	Mech. binding	Unable to test HPSI check valves or to establish alternate charging path using associated CP	Operator	Any one of the three CP's can be used through the associated valve	
		b) fails open	Seat leakage	Part of charging flow routed through HPSI header	Lo flow indication from FI-212, flow indications from HPSI indicators	Series redundant isolation valve in the SI System	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
113)	Charging Pump to HPSI Header Check Valve; CH-440	a) fails closed	Mech. failure blockage	No impact on normal operation. Unable to use charging pumps to test HPSI check valves or to establish alternate charging path.	No flow through HPSI check valves during test and subsequent check valve inspec.	None	
		b) fails open	Mech. failure	No impact on normal operation. Possible diversion of HPSI flow to charging pumps during safety injection	None	Series isolation valves are normally closed	
114)	Hydrostatic Test Connect. Isolation Valve; CH-314, CH-642	a) fails closed	Mech. failure	No impact on normal system operation	Operator	None	
		b) seat leakage	Contamination mech. damage	Minor loss of primary coolant outside containment	Local leak detectors	Test connections are blind flanged	For Units where DMWO 4304156 has been implemented, CH-314 is not a Hydrostatic Test Connect, Isolation Valve.
114A)	RC Alternate Suction Isolation Valve CH-1004 (Effective for Units where DMWO 4304156 has been implemented)	a) Fails closed	Mech. Failure blockage	No impact on normal system operation	Operator	Not required	
		b) Fails Open	Mech. failure	Loss of RWT fluid, possible charging pump performance reduction	Local leak detectors	Valve is normally closed	Multiple failures required to affect charging performance.
115)	Charging Pressure Indicator, PI-212	a) spurious Lo pres. alarm	Elect. or mech. failure	No direct impact on system operation. False indication of charging pump degradation or charging line break	Low pres. alarm from PI-212 with normal indications from FI-212, TI-229, and PDIC-240	None	
		b) erroneous Hi or normal pres. indication	Elect. or mech. failure	No impact on system operation failure to detect CP degradation or charging line break	Periodic test	FI-212 will provide indication of CP degradation or charging line break	
116)	Charging Flow Indicator FI-212	a) spurious Lo flow alarms	Elect. or mech. failure setpoint drift	No direct impact on system operation	Lo flow alarm with normal indication from PI-212, and stable PZR level	None	
		b) erroneous Hi or normal flow indications	Elect. or mech. failure setpoint drift	No impact on system operation. Failure to detect decreased charging flow	Periodic test, charging pump run indicator	None	
117)	H_2 Inject. Isolation Valves, CH-436, CH-828	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to inject H_2 directly into charging line	Operator	H_2 concentration normally maintained by H_2 blanket in VCT	
		b) fail open	Mech. failure	Unable to terminate H_2 injection directly into charging line	Operator	Redundant isolation valves	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
118)	H_2 Inject. Check Valve, CH-827	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to inject H_2 directly into charging line	Lo flow alarm from FI-207	Same as 117 a)	
		b) fails open	Mech. binding	No impact on normal operation. Possible diversion of charging flow to H_2 header	None	Manual isolation valves CH-436, CH-828	
119)	H_2 Inject. Flow Indicator, FI-207	a) spurious Hi flow alarms	Elect. or mech. malfunct. setpoint drift	No impact on normal operation. Incorrect indication of H_2 addition rate	Alarm and RCS sample analysis for H_2	None	H_2 blanket in VCT is preferred method of H_2 concentration control in RCS
		b) spurious Low flow alarms	Elect. or mech. malfunction, setpoint drift	Same as above	Same as above	Same as above	Same as above
120)	Charging Line Manual Isolation Valve; CH-429	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate charging line for maint. or for alternate path charging thru HPSI header	Operator	Valve, CH-524 can be closed	
		b) fails closed	Mech. binding	Unable to reestablish charging flow thru normal path	Operator	Alternate charging path thru HPSI header	
121)	Charging Line Isolation Valve; CH-524	a) fails open	Mech. binding, valve operator failure, loss of power	No impact on normal operation. Unable to isolate charging line for maint. or alternate path charging thru HPSI header	Valve position indicator in control room, flow indicator, FI-212	Manual isolation valve, CH-429	Handwheel on valve can be used to close valve if operator malfunction.
		b) fails closed	Mech. binding, valve operator failure	Unable to reestablish charging thru normal path; if this occurs during normal operation the chg. pump disch relief will lift.	Valve position indicator in control room, flow indicator, FI-212	Alternate path charging thru HPSI header	
122)	Test Connection CH-854	a) fails closed	Mech. binding	No impact on normal operation. Unable to test charging line isolation valves IAW ASME XI.	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Minor loss of primary coolant outside containment	Local leak detectors	Drain line is blind flanged	
123)	Temperature Indicator, TI-229	erroneous temperature indications	Elect. or mech. malfunct., setpoint drift	No impact on system operation TI-229 has no control function	Periodic test	None	
124)	Auxiliary Spray Valves; CH-203, CH-205	a) fails closed	Mech. binding, valve operator failure, loss of power	No impact on normal operation. Unable to use the charging pumps to provide aux. PZR spray for PZR pres. control during plant shutdown	Valve position indication in control room	Redundant valves from separate power supplies	Cold shutdown can be achieved without auxiliary spray.
		b) fails open	spurious signal, operator error	Excess PZR spray flow, resulting in reduction of RCS pres.	Valve position indicators in control room	None	PZR heaters will come on to maintain PZR pres

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
125)	Charging Line Pressure Control Valve, CH-240	a) fails closed	Mech. failure, spurious signal	Sudden loss of charging flow, VCT level increases, PZR level decreases. Pressure increases in charging line	VCT and PZR level indications, Lo flow alarms from FI-212, Hi pres indic. from PI-212	Alternate charging path through HPSI header. Spring check valve CH-435 will open to maintain charging flow	
		b) regulates back pressure too low	Valve operator malfunction, mech. binding	Short term decrease in RCP seal injection flow and increase in charging flow	Lo flow indications or alarms from seal injection flow indicators. Lo delta pres. indication or alarm from PDIC-240	Seal injection flow control valves will open to increase flow, thereby reestablishing flow balance	
		c) regulates back pressure too high	Valve operator malfunction, mech. binding partial blockage	Short term increase in RCP seal injection flow and decrease in charging flow. Increase in charging line pres.	Hi flow indications or alarm from seal injection flow indicators. Hi delta pres. indication or alarm from PDIC-240	Seal injection flow control valves will close to limit flow. Spring check valve CH-435 will open to maintain charging flow if necessary.	
126)	Auxiliary Spray Line Check Valve; CH-431	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to provide aux. PZR spray for PZR pressure control during plant shutdown	Lo flow indication from FI-212, PZR pres., not decreasing.	None	Plant can be brought to cold shutdown without auxiliary spray.
		b) fails open	Mech. failure	Diversion of PZR spray flow to charging line. Possible PZR pres. increase	PZR pres. indicators	Aux. spray valves CH-203 and CH-205 are closed during normal operation	
127)	Differential Pressure Indicator/ Controller; PDIC-240	a) spurious Lo diff. pres readings	Elect. or mech. malfunct., setpoint drift	PDIC-240 will drive CH-240 closed trying to maintain a DP of 30 lbs. seal injection flow will increase, charging line pressure will increase	Hi flow alarms from seal injection flow indicators, Hi pres indic. from PI-212, CH-240 position indicator	Seal injection flow control valves will maintain seal inject. flow. Spring check valve, CH-435 will open to maintain charging flow if necessary.	
		b) spurious Hi diff press. reading	Elect. or mech. malfunct., setpoint drift	PDIC-240 will drive CH-240 open trying to maintain proper DP. Charging flow will increase and seal injection flow will decrease	Low flow alarms from seal inject flow indic., Lo pres. indic. from PI-212, CH-240 position indic.	Seal inject flow control valves will open to maintain seal inject flow, thereby reestablish charging flow balance	
128)	PDIC-240 Isolation Valves; CH-405, CH-406	a) fails open	Mech. binding	No impact on system operation. Unable to isolate PDIC-240 for maint	Operator	None	
		b) fails closed	Mech. binding	Unable to place PDIC-240 back in service after maint	Operator	None	
129)	Spring Check Valve; CH-435	a) fails closed	Mech. failure, blockage	No impact on normal operation. Loss of pressure surge protection for charging line and CH-240	None	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails open	Mech. binding	Charging flow diverted past CH-240. Short term reduction in seal inject. flow	Low flow alarms from seal inject flow indic., Lo DP alarm from PDIC-240	Seal inject flow control valves will open to maintain seal inject. flow. CH-435 can be isolated using valve, CH-434	
130)	Isolation Valve, CH-434	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate spring check valve, CH-435	Operator	None	
		b) fails closed	Mech. failure	Same as 129 a)	Operator	None	
131)	Charging Line Check Valve; CH-433	a) fails closed	Mech. binding, blockage	Unable to establish charging flow via normal path	Lo flow indic. from FI-212, Lo DP alarm from PDIC-240	Alternate charging path through HPSI header	Unlikely event since valve is normally open.
		b) fails open	Mech. binding	No impact on normal operation	None	None	
132)	Seal Injection Isolation Valve; CH-231P	a) fails open	Mech. failure, valve operator malfunct., loss of air or power	No impact on normal operation. Unable to terminate seal injection on Hi-Hi or Lo-Lo seal injection flow temp. Possible damage to RCP seals	Periodic test, CH-231P position indication on Hi-Hi or Lo-Lo SIHX outlet temp.	RCP component cooling flow will provide protection for RCP seals	Steam supply to SIHX has been flanged off.
		b) fails closed	Mech. failure, spurious signal	Sudden loss of RCP seal injection flow. Possible damage to RCP seals	Lo flow alarms from RCP seal inject. flow indicators	RCP component cooling water flow will provide protection for RCP seals	
133)	Seal Injection HX Isolation Valves; CH-839, CH-836	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate seal injection heat exchanger (SIHX) for maint.	Operator	Valve CH-231P and CH-255 can be closed	
		b) fails closed	Mech. failure	Unable to reestablish seal inject. flow after maint on SIHX	Operator	None	
134)	Vent Valves; CH-612, CH-613	a) fails closed	Mech. failure	No impact on normal operation. Unable to vent SIHX during maint.	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Minor loss of primary coolant outside containment	Local leak detectors	Series redundant isolation valves	
135)	Seal Injection Heat Exchanger, SIHX	a) improper seal injection temp	VCT or RCS makeup temp variation	Seal injection temp changes, possible thermal damage to RCP seals.	Hi-Lo temp alarms from TSHL-231.	CH-231P auto closes on Hi-Hi or Lo-Lo seal inject. temp. NC flow to RCPs provides adequate seal cooling without seal inject.	Steam supply to SIHX has been flanged off. Letdown isolates before Hi-Hi seal inject temp occurs. RMWT and RWT have heaters to raise makeup temp.
		b) cross leakage	Tube corrosion, manufact. defect	Contamination of condensate with primary coolant.	Hi alarm on RU-7, chem analysis, RCS leak rate test, possible low seal injection flow alarms.	Aux steam condensate return from SIHX can be manually isolated.	If needed, closure of CH-231P will terminate leak without damage to RCP seals.

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
	Seal Injection Heat Exchanger, SIHX	c) external leakage	Weld failure, casing crack	Release of primary coolant outside CTMT.	RCS leak rate test, local leak indication, possible low seal injection flow indications	Manual closure of CH-231P will terminate leak without damage to RCP seals.	
136)	Relief Valve CH-865 (Component Removed)	N/A	N/A	N/A	N/A	Relief valves on CHG pumps' discharge provide adequate protection.	Steam supply to SIHX has been flanged off. Over-pressure due to high seal injection temp not credible.
137)	Temperature Indicator/ Controller; TIC-231	a) Spurious Hi-Lo indication	Elec/Mech malfunct., setpoint drift	CH-231P auto closes on Hi-Hi or Lo-Lo temp. The resulting termination of seal injection may possibly damage RCP seals.	Hi-Lo temp alarms from TSHL-231, valve CH-231P position indication, low flow alarms from seal inject. controllers.	NC flow to RCPs provides adequate seal cooling without seal injection.	Steam supply to SIHX has been flanged off. TIC-231, which regulates AS-TV231 in the steam return line, produces no control action.
		b) False indication of normal SIHX discharg e temp	Elect. or mech. malfunction	No impact on normal operation, but possible RCP seal thermal shock if SIHX discharge temp. is Hi or Low	Periodic tests	None	
138)	Seal Injection Filters, SIF 1, SIF 2	a) plugged	Normal contaminant buildup	Reduced seal injection flow. Possible RCP seal damage	Hi Delta P alarm from PDI-241, Lo flow alarms from seal inject. flow indicators	Parallel redundant full capacity filters	Seal inject flow normally comes from VCT which has relatively Lo particulate concentrations
		b) doesn't filter properly	Mfg. defect, wrong filter cartridge	Contamination of RCP seals, possible seal damage. Contaminant buildup in RCS	RCS chemistry analysis	Parallel redundant filter	Same as above
139)	SIF Isolation Valves; CH-816, CH-8I8, CH-819, CH-821	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate one SIF for element replacement	Operator	None	
		b) fails closed	Mech. failure	Unable to return filter to service after element replacement	Operator	None if other filter needs element replacement	
139A)	SIF fill and vent Valves; CH-1000, CH-1001	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate one SIF for element replacement	Operator	None	Valves are used for fill and vent only. Normally closed
		b) fails closed	Mech. failure	Unable to fill and vent per normal procedures	Operator	Utilize SIF isolation valves for fill and vent	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
140)	SIF Drain Valves; CH-822, CH-823	b) fails closed	Mech. failure	No impact on normal operation. Unable to drain filter for element replacement	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Seal injection flow diverted to recycle drain header	EDT Level indications, Lo flow indications from seal inject. flow indicators	Seal inject. flow control valves will open to maintain seal inject. flow rate. Makeup system will compensate for losses	
141)	Differential Pressure Indicator; PDI-241	a) false indications of Lo Delta pres.	Elect. or mech malfunct., setpoint drift	No impact on system operation	Periodic test	None	
		b) false Hi Delta P alarms	Elect. or mech. malfunct., setpoint drift.	No direct impact on system operation. Possible early replacement of filter element	Hi Delta P alarm	None	
142)	PDI-241 Isolation Valves; CH-825, CH-826	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate PDI-241 for maint	Operator	None	
		b) fails closed	Mech. failure	Unable to return PDI-241 to service after maint	Operator	None	
143)	Local Drain Valves; CH-833, CH-834, CH-848, CH-849, CH-859, CH-860	a) fails closed	Mech. binding	No impact on normal operation. Unable to drain affected line section or test isolation valves IAW ASME OM Code.	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	No impact on system operation	None	Drain lines are blind flanged	
144)	Seal Injection Line Isolation Valve; CH-255	a) fails closed	Spurious signal, mech failure	Same as 132 b)	Same as 132 b)	Same as 132 b)	Same as 132 b)
		b) fails open	Mech. binding, valve operator failure	No impact on normal operation. Loss of redundant seal injection line isolation capability	Periodic test	Check valve, CH-835. Isolation valve, CH-231P provide isolation	CH-255 can be closed via handwheel if problem is operator failure.
145)	Seal Injection Line Check Valve, CH-835	a) fails open	Mech. binding	No impact on normal operation. Partial loss of seal injection line isolation	None	Redundant check valves in individual seal injection lines	
		b) fails closed	Mech. binding, blockage	Unable to establish seal injection flow on startup	Lo flow alarms from seal injection flow indicators	None	Startup delayed until valve repaired

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
146)	Seal Injection Flow Indicator/ Controllers; FIC-241, FIC-242, FIC-243, FIC-244	a) false indication of Lo flow rate	Elect. or mech. malfunction, setpoint drift	Flow indicator/controller will drive associated control valve open, causing excess flow to associated RCP seal	Lo flow alarm, and valve position indicator in control room (if fully open).	None	
		b) false indication of Hi flow rate	Elect. or mech. malfunction, setpoint drift	Flow indicator/controller will drive associated control valve closed, resulting in a loss of seal injec. to one RCP. Possible seal damage	Hi flow alarm, and valve position indicator in control	RCP component cooling water flow provides protection for RCP seal on loss of seal injection	
147)	Seal Injection Flow Control Valves; CH-241, CH-242, CH-243, CH-244	a) fails open	Loss of air power	Seal injection flow to one RCP seal will increase	Hi flow alarm from associated flow indicator valve position indicator in control room	None	
		b) fails closed	Mech. failure, spurious signal	Loss of seal injection flow to one RCP seal. Possible seal damage	Lo flow alarm from associated flow indic., valve indic. in control room	RCP component cooling water flow provides protection for RCP seal	
		c) won't respond to control signal	Mech. binding, valve operator failure	Results are similar to a) or b), but less severe			
148)	Seal Injection Check Valves; CH-787, CH-866, CH-802, CH-867, CH-807, CH-868, CH-812, CH-869	a) fails open	Mech. binding	No impact on normal operation. Loss of isolation for seal injection line	None	Four pairs or series redundant check valves	
		b) fails closed	Mech. binding, blockage	Unable to establish seal injection flow to one RCP	Lo flow alarm from flow indicator/ controller on affected line	None	Startup delayed until valve repaired
149)	Refueling Water Tank, RWT	a) external leakage	Mfg. defect, mech. damage, corrosion	Boric acid solution lost. Reduced inventory for RCS makeup. Unable to fill refueling pool for refueling loss of inventory or for safety injection	Lo level alarms from RWT level indicators	None	Reactor would have to be shut down until RWT repaired and refilled. The fuel pool could be used to supply sufficient water for cooldown contraction and boration.

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
150)	Refueling Water Tank Level Indicators (Safety Ch.); LIC-203A, LIC-203B, LIC-203C, LIC-203D	a) spurious Lo level indication or spurious Hi level indication	Elect. or mech. malfunct., setpoint drift	No direct impact on normal CVCS operation. These indicators provide input to plant protection system to generate recirculation actuation signal during safety injection. Four redundant, independent channels with two of four logic, so a single failure will not affect the PPS	Redundant level detectors	4 redundant level indicator/controllers	
151)	Level Indicator, LI-201	a) spurious Hi level alarms	Elect. or mech. malfunct., setpoint drift	No impact on normal operation. LI-201 serves no control function	Hi level alarms from LI-201 with normal level indications from other RWT level indic.	Redundant level indicators	
		b) spurious Lo level alarms	Elect. or mech. malfunct., setpoint drift	No impact on normal operation	Lo level alarm LI-201 with normal indic. from other RWT level indicators	Redundant level indicators	
152)	RWT Level Indicator/ Controller LIC-200	a) spurious Hi level alarms or indications	Elect. or mech. malfunct., setpoint drift	No direct impact on normal operation. BAMPs will not auto stop on actual Lo-Lo RWT level. Operator may terminate boric acid batching to RWT.	Hi level alarms or indic. from LI-200, with normal or Lo level indic. from other RWT level indicators.	Redundant RWT level indication and alarms. Manual control of BAMPs	
		b) spurious Lo-Lo level indications	Elect. or mech. malfunct., setpoint drift	If makeup operations are in progress, BAMPs will be stopped. Possible decrease in VCT level. Possible deboration.	Lo-Lo level alarms from LALL-200 with normal indic. from other RWT level indicators	Redundant RWT level indicators. Safety related functions can be performed using gravity-fed boration pathways.	During makeup to the VCT or charging pumps, a BAMP trip will automatically secure the make-up evolution to prevent deboration
153)	RWT Isolation Valves; CH-530, CH-531	a) fails open	Loss of power, mech. binding, valve operator failure	No impact on CVCS operation. Unable to isolate RWT during recirculation phase of safety injection	Valve position indic. in control room	None required	
		b) fails closed	Loss of power, mech. binding, valve operator failure	No impact on normal operation. Loss of safety injection inventory. Unable to fill refueling pool for refueling. For CH-530 charging pumps unable to take direct suction from RWT through one gravity feed line.	Valve position indic. in control room	100% redundant paths. Alternate path for charging pump suction	These valves are normally locked open
		c) fails to close (manual action after RAS)	Electrical malfunction, mechanical failure	Degraded performance of one train of HPSI and CS (if air is entrained)	Valve position indicator; periodic testing	Parallel redundant path for HPSI and CS from sump	Timely operator action required to close
154)	RWT Isolation Check Valves; CH-305, CH-306	a) fails open	Mech. binding	No impact on CVCS operation. Possible flow to RWT during recirculation phase of safety injection	None	CH-305 and CH-306 are qualified as "active" to preclude this failure.	
		b) fails closed	Mech. binding, blockage	Same as 153 b)	Flow indic. on approp. flow paths	Same as 153 b)	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
155)	RWT Temperature Indicator, TI-200	a) spurious Low temp. alarms	Elect. or mech. malfunction, setpoint drift	No direct impact on system operation. TI-200 has no control function	Lo temp alarm from TI-200 without alarm from TI-201	Redundant temp sensor, TI-201	
		b) false Hi or normal temp. indications	Elect. or mech. malfunction, setpoint drift	Failure to detect Lo temp condit. in RWT, possible precipitation of boric acid	Periodic test	Redundant temp sensor TI-201	
156)	RWT Temperature Sensor, TI-201	a) spurious Low temp alarms	Elect. or mech. malfunction, setpoint drift	No impact on system operation. (Local read-out only)	Lo temp. alarm from TI-201 with normal temp indic. from TI-200	Redundant temp indicator, TI-200	
		b) fails to senses Lo temp. condition	Elect. or mech. malfunction, setpoint drift	Loss of redundant temp. indication for Lo temp in RWT. Possible boric acid precipitation if Lo temp. condition goes undetected	Periodic test	Redundant temp indicator, TI-200	
157)	RWT to Charging Pump Isolation Valve; CH-327	a) fails closed	Mech. failure	No impact on normal operation. Charging pumps unable to take direct suction from RWT via one gravity feed line for HPSI check valve test or other requirements	Operator	Alternate direct suction path available	
		b) seat leakage	Contamination, mech. damage	No impact on normal operation, minor diversion of RWT inventory	None	Isolation valves at charging pump suction	
158)	RWT to Charging Pump Line, CP Suction Isolation Valves; CH-755, CH-756, CH-757	a) fails closed	Mech. binding	Unable to align affected charging pump to RWT via one gravity feed line for test of HPSI check valves or other requirements	Operator	Redundant charging pump can be used/redundant feed feed line can be used	
		b) seat leakage	Contamination, mech. damage	Minor diversion of charging flow	None	Isolation valve CH-327	
159)	RWT Isolation Valve; CH-532	a) fails open	Mech. binding, valve operator, loss of air or power	No impact on normal system operation. Unable to isolate RWT in the event of a makeup line break	Valve position indicator in control room	None	
		b) fails closed	Mech. failure, spurious signal	Loss of makeup flow to VCT or RCS. Possible cavitation damage to BAMPs	Valve position indicator in control room, Lo flow alarm from FQRC-210Y, Lo discharge pres. alarm from PI-206, 207	BAMPs will trip on Lo discharge pres makeup can continue by aligning charging pumps to RWT via valve CH-327	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
160)	Boric Acid Makeup Pump Suction Isolation Valves; CH-143, CH-145	a) fails open	Mech. binding	No impact on normal system operation. Unable to isolate BAMP for maint.	Operator	None without terminating makeup	Makeup can continue using redundant pump
		b) fails closed	Mech. failure	Unable to return BAMP to service after maint.	Operator	None	
161)	Boric Acid Makeup Pumps; BAMP 1, BAMP 2	a) fails to start	Electrical malfunction, mech. binding	Unable to start makeup flow or to recirculate RWT contents	Pump run indicator, Lo discharge pres. alarm	Redundant pump or gravity feed	
		b) stops	Elect. malfunction mech. seizure	Loss of makeup flow. Possible deboration of RCS	Lo discharge pres. alarm, Lo flow from FQRC-210Y	Redundant pump or gravity feed	During makeup to the VCT or charging pumps, a BAMP trip will automatically secure the makeup evaluation to prevent deboration
		c) fails to deliver rated flow	Excess seal leakage, mech. malfunct.	Reduced makeup flow. Possible deboration of RCS	Low discharge pres indic., Lo flow indic from FQRC-210Y	Redundant pump	
162)	BAMP Discharge Pressure Indicators; PI-206, PI-207	a) spurious Lo pres. indications or alarms	Elect. or mech. malfunction, setpoint drift	BAMP will be tripped, causing loss of makeup flow	Lo pres. alarm followed by Lo flow alarm from FQRC-210Y	Redundant BAMP can be placed in service	Same as 161) b)
		b) false Hi or normal pres. indications	Elect. or mech. malfunction	No impact on normal operation, but unable to detect Lo discharge pres. Possible pump damage	Periodic test. Lo flow alarm from FQRC-210Y if Lo pres. condit develops.	Redundant BAMP can be placed in service	Same as 161) b)
163)	BAMP Discharge Check Valve; CH-154, CH-155	a) fails open	Mech. binding	No impact on normal operation possible reverse flow through standby BAMP	None	None	
		b) fails closed	Mech. failure, blockage	Unable to establish makeup flow with affected BAMP. Possible pump damage due to dead heading	Hi discharge pres indic., Lo flow alarm from FQRC-210Y	Redundant BAMP, gravity feed	
164)	BAMP Discharge Isolation Valves; CH-152, CH-153	a) fails open	Mech. binding	No impact on normal operation unable to isolate affected pump for maint	Operator	BAMP discharge check valve provides some isolation	
		b) fails closed	Mech. binding, blockage	Unable to return affected pump to service after maint	Operator	Redundant pump, gravity feed	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
165)	BAMP Recirculation Valves; CH-192, CH-130	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate recirculation line for maint. on BAMP	Operator	Valves CH-510 and CH-647 provide adequate isolation	
		b) fails closed	Mech. failure	Unable to establish recirculation flow path for one BAMP. Possible damage to pump if it is dead headed into a closed makeup line	Operator	Redundant BAMP available	This valve would be repaired before starting affected pump. Valves closed only for pump maint
166)	BAMP Suction to Pool Cooling and Purification System (PCPS) Isolation Valve; CH-144	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to obtain borated makeup water from PCPS Unable to supply boric acid solution from RWT via one gravity feed line and from the SFP via one gravity feed line to charging pump suction header.	Operator	RWT is normal source of borated makeup water Alternate gravity feed path to individual charging pump suction lines.	
		b) seat leakage	Contamina-tion, mech. damage	BAMP will draw suction on spent fuel pool, gradually reducing its level. Reduced shielding and cooling for spent fuel	Spent fuel pool level indicators	Redundant isolation valve in PCPS	
167)	BAMP Discharge to PCPS Isolation Valve, CH-753	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to supply boric acid solution from RWT via one gravity feed line and from the SFP via one gravity feed line to charging pump suction header.	Operator	Alternate gravity feed path to individual charging pump suction ilnes.	
		b) seat leakage	Contamina-tion, mech. damage	Minor diversion of makeup flow to spent fuel pool (SFP). Gradual SFP level increase	SFP Level indicators. Possibly Lo flow indic. from FQRC-210Y	None	
168)	RWT Gravity Feed to Charging Pump Suction Isolation Valve; CH-536	a) fails closed	Mech. failure, blockage, loss of power	No impact on normal operation. Unable to supply boric acid solution from RWT via one gravity feed line to charging pump suction header	Valve position indication in control room.	Alternate gravity feed path to individual charging pump suction lines	
		b) seat leakage	Contamination mech. damage	Diversion of boric acid solution from RWT to RCS via charging pumps. Possible over boration of RCS	Sample analysis. Decreasing reactor power	None	
		c) fails open	Mech. failure	Diversion of boric acid solution from RWT to RCS via charging pumps. Possible over boration of RCS.	Sample analysis. Decreasing reactor power	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
169)	RWT Gravity Feed to Charging Pump Suction Header Check Valve, CH-190	a) fails closed	Mech. failure, blockage	Same as 168 a)	None	Same as 168 a)	
		b) fails open	Mech. failure, seat leakage	No impact on normal operation	None	Isolation valve, CH-536	
170)	Boric Acid Filter (BAF) Isolation Valves; CH-161, CH-166	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate BAF for element replacement	Operator	None	
		b) fails closed	Mech binding	Unable to place BAF back in service after maint.	Operator	Boric acid makeup can continue through diversion valve CH-164	
171)	BAF Diversion Valve, CH-164	a) fails closed	Mechanical binding, blockage	No impact on normal operation. Unable to divert boric acid makeup flow past BAF when BAF element replacement needed	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Minor diversion of boric acid makeup flow past BAF. Possible buildup of contaminants in RCS and VCT	Possibly low diff. pres. indic. from PDI-260	None	
172)	BAF Differential Pressure Indicator, PDI-260	a) spurious Hi Delta P alarms	Elect. or mech. malfunction, setpoint drift	No impact on normal operation. Possible early replacement of BAF element	Hi Delta P alarm from PDI-260, with normal indic. from FQRC-210Y, PI-206, or PI-207	None	
		b) false Lo or normal Delta P indications	Elect. or mech. malfunction	No impact on normal operation. Possible failure to detect plugged BAF element	Periodic test	FQRC-210Y and BAMP discharge pres. indic should indicate plugged element	
173)	Boric Acid Filter	a) plugged	Normal contaminant buildup	Reduced boric acid makeup flow	Hi Delta P alarm from PDI-260, Lo flow alarm from FQRC-210Y	Boric acid makeup flow can be diverted past BAF and element replaced	
		b) does not filter	Element "punch through", wrong element	Contaminant buildup in RCS and VCT	Possibly Lo Delta P indication from PDI-260	Boric acid makeup flow can be diverted past BAF and element replaced	
174)	BAF Drain Valve; CH-134	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to drain BAF for element replacement	Operator	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) seat leakage	Contamina-tion, mech. damage	Minor diversion of boric acid makeup flow to recycle drain header	EDT level indic., possibly Lo flow indic. from FQRC-210Y, or Lo Delta P indic. from PDI-260	None	
175)	BAF Vent Valve; CH-132	a) fails closed	Mech. failure	No impact on normal operation. Unable to vent BAF for element replacement	Operator	None	
		b) seat leakage	Contamination mech. damage	Loss of boric acid solution, slight reduction in boric acid makeup flow	Local leak detectors possibly Lo flow indic. from FQRC-210Y	None	
176)	RWT Recircula-tion Valve; CH-510	a) fails closed	Mech. binding, valve operator malfunction, loss of air or power	No impact on normal operation. Unable to recirculate RWT contents through BAF for clean up	Valve position indic. in control room, Hi pres indic from PI-207 or PI-206	None	
		b) fails open	Mech. binding valve operator malfunct.	Boric acid makeup flow diverted back to RWT during makeup operations. Insufficient makeup flow to maintain RCS inventory also, possible deboration	Low flow alarm from FQRC-210Y, PZR LVL alarms, valve position indic. in control room	Gravity feed boric acid makeup can be instituted	A low flow alarm from FQRC-210Y will terminate automatic makeup to prevent dilution.
177)	RWT Recirculation Line Check Valve: CH-647	a) fails closed	Mech. failure blockage	Same as 176 a)	Hi pres. indic from PI-207 or PI-206	None	
		b) fails open	Mech. binding	No impact on normal operation	Operator	None	
178)	Isolation Valve Boric Acid Make-up to Holdup Tank; CH-330	a) fails closed	Mech. binding	No impact on normal operation. Unable to transfer RWT contents to hold up tank for processing or during maint. operation	Operator	None	Transfer would be made only when reactor shutdown
		b) seat leakage	Contamination mech. damage	Minor diversion of boric acid makeup flow to holdup tank during makeup operations. Possible deboration, PZR LVL decrease or VCT level decrease	Possible PZR or VCT level indic., Lo flow indic. from FQRC-210Y holdup tank level indic	None	Same as 176) b)
179)	Boric Acid Makeup Bypass Control Valve, CH-514	a) fails closed	Mech. failure, loss of power, valve operator failure	Unable to provide direct boric acid makeup to RCS on Lo-Lo VCT level. Decrease in PZR levels. Possible reactor trip on Lo PZR level	Valve posit. indic. in control room, Lo flow indic. from F-212, Lo PZR level alarms charging pump trips	Gravity feed boric acid makeup can be instituted by opening CH-536	A low-low VCT level condition is an uncommon situation during normal operation

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails open	Mech. fail, spurious signal, loss of power when open	Boric acid makeup flow to VCT diverted to charging pump suction. Decrease in VCT level. Possible overboration of RCS	Lo flow indic. from FQRC-210Y, Lo VCT level indic., valve position indic. in control room. Reactor power decrease	None	A low flow alarm from FQRC-210Y will terminate automatic makeup to prevent overboration
180)	Boric Acid Makeup Flow Controller Isolation Valves; CH-653, CH-172	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate FQRC-210Y for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to restore FQRC-210Y to service. Loss of controlled boric acid makeup capability	Operator	Other boric acid makeup paths available	Valves normally open.
181)	Boric Acid Makeup Flow Controller, FQRC-210Y	a) false indication of high flow	Elect. or mech. malfunction, setpoint drift	FQRC-210Y will drive CH-210Y, closed trying to establish proper flow rate. Possible deboration of RCS	Hi flow alarms from FQRC-210Y, valve CH-210Y position indic., VCT level indic., reactor power increase	No other controlled boric acid makeup paths available, but can provide boric acid makeup via direct flow to charging pump suction.	
		b) false indication of low flow	Elect or mech. malfunction, setpoint drift	FQRC-210Y will drive CH-210Y open to maintain flow. Overboration of RCS	Lo flow alarm from FQRC-210Y, valve, CH-210Y posit. indic. VCT level indic reactor power decrease	Same as above	
182)	Boric Acid Flow Controller Outlet to Direct Boration Line Isolation Valve, CH-174	a) fails closed	Mech. binding	No impact on system operation. Unable to use FQRC-210Y as flow indicator for one direct boration flow path.	Operator	Normal direct boration path or bypass of VCT via CH-527	
		b) seat leakage	Contamina-tion, mech. damage	Minor diversion of boric acid makeup flow to VCT to charging pump suction. No change in overall boric acid concentration in RCS, but possible decrease in VCT boric acid concentration	None	None	
183)	Direct Boration Line Check Valve, CH-177	a) fails closed	Mech. binding, blockage	Same as 179 a)	Lo flow indic. from FI-212, Lo PZR level alarms, charging pump trips	Same as 179 a)	Same as 179 a)
		b) fails open	Mech. binding	Diversion of charging flow to direct boration line	None	Line isolated by valve CH-514	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
184)	Boric Acid Makeup Flow Control Valve, CH-210Y	a) fails closed	Mech. binding, valve operator failure, loss of air or power	Unable to provide controlled boric acid makeup flow to VCT or to charging pump suction, possible deboration of RCS	Valve position indicator, Lo flow alarms from FQRC-210Y reactor power increase	Same as 181 a)	Same as 176 b)
		b) fails open	Valve operator malfunction, spurious signal, mech. failure	Excess boric acid makeup flow rate to VCT or charging pump suction. Possible overboration of RCS	Hi flow alarms from FQRC-210Y, valve position indicator, VCT level indic. reactor power decrease	Same as 181 a)	A high flow alarm from FQRC-210Y will terminate automatic makeup to prevent overboration.
		c) does not respond to control signal properly	Mech. binding, valve operator	Results similar to but less dramatic than a) or b) above			
185)	Boric Acid Makeup Line Check Valve, CH-668	a) fails closed	Mech. failure, blockage	Same as 184 a)	Lo flow alarms from FQRC-210Y, reactor power increase	Same as 181 a)	
		b) fails open	Mech. binding	No impact on normal operation. Diversion of reactor makeup water to boric acid makeup line	None	Valve CH-210Y provides isolation	
186)	Reactor Makeup Water Flow Controller Isolation Valves; CH-195, CH-183	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate reactor makeup water flow controller for maint.	Operator	None	
		b) fails closed	Mech. binding	Unable to restore reactor makeup water flow controller to service. Unable to provide reactor makeup water for controlled makeup to RCS or VCT	Operator	None	No reactor makeup could take place until valve repaired
187)	Reactor Makeup Water (RMW) Flow Controller, FQRC-210X	a) senses flow rate high	Elect or mech. malfunction	FQRC-210X would drive valve CH-210X closed, reducing RMW flow. Possible overboration of RCS due to improper mix of RMW and boric acid in makeup flow	Hi flow alarms from FQRC-210X, posit. indic., decrease in VCT level, decrease in reactor power.	None	Makeup would have to be terminated until controller repaired. A high flow alarm from FQRC-210X will terminate automatic makeup to prevent over-boration.

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) senses flow rate low	Elect. or mech. malfunction	FQRC-210X will drive valve CH-210X open, increasing RMW flow rate. Deboration of RCS due to excess RMW in makeup flow	Lo flow alarms from FQRC-210X, valve, CH-210X position indic., increase in reactor power.	None	Same as above for over-dilution
188)	RMW Flow Sensor FSL-250	a) fails to sense flow	Elect. or mech. malfunction, operator error	No impact on normal operation. Failure to detect RMW flow during reactor cold shutdown. Possible undetected deboration of RCS during shutdown	Periodic test	None	Flow sensor activated only when reactor is shut down
		b) spurious flow indications	Elect. or mech. malfunction	No impact on normal operation. False indication of RMW flow during reactor shutdown	Periodic test	None	
189)	RMW Makeup Flow Control Valve; CH-210X	a) fails closed	Loss of air or power, valve operator failure, spurious signal	Loss of RMW makeup flow to VCT or charging pump suction, possible over boration of RCS	Lo flow alarm from FQRC-210X, valve position indic. in control room, reactor power decrease	None	Makeup would have to be terminated until valve repaired. A low flow from FQRC-210X will terminate automatic makeup to prevent overboration.
		b) fails open	Valve operator malfunction, spurious signal, mech. binding when open	Excess RMW makeup flow to VCT or charging pump suction, possible deboration of RCS	Hi or Hi-Hi flow alarm from FQRC-210X, valve position indicator in control room, reactor power increase	None	Same as above
		c) fails to respond properly to control signal	Valve operator malfunction	Results similar to but less dramatic than a) and b) above			
190)	RMW Makeup Line Check Valve, CH-184	a) fails closed	Mech. binding, blockage	Unable to supply RMW makeup flow to VCT or charging pump suction. Possible over boration of RCS	Lo flow alarm from FQRC-210X, VCT level decrease, reactor power decrease.	None	Same as 189) a)
		b) fails open	Mech. binding	No impact on normal operation. Possible diversion of boric acid solution to RMW lines	None	Valve CH-210X provides line isolation	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
191)	Makeup Valve; CH-512	a) fails closed	Mech. binding, loss of air or power, valve operator malfunction	Unable to provide makeup to VCT. Unable to compensate for minor RCS losses, unable to conduct feed and bleed operations using normal makeup flow path.	Lo flow alarms from FQRC-210X and FQRC-210Y, VCT level indications	Makeup can be supplied directly to charging pump suction via valve CH-527	
		b) fails open	Spurious signal, valve operator malfunction mech. binding when open	Possible draining of VCT contents to makeup lines. Possible over filling and or dilution of VCT	Valve Position indic. in control level indicators	CH-210X and CH-210Y close automatically when makeup is completed except when “manual" is selected on the makeup controllers. Then CH-210X and CH-210Y provide isolation when manually closed	
192)	Makeup Line Check Valve; CH-188	a) fails closed	Mech. binding blockage	Same as 191 a)			
		b) fails open	Mech. binding	No impact on normal operation. Possible draining of VCT to makeup lines	VCT level detectors	Makeup line isolated by valve CH-512	
193)	Direct Makeup Valve; CH-527	a) fails closed	Mech. binding, valve operator malfunction, loss of air or power	Unable to supply blended makeup directly to charging pump suction. Loss of blended makeup capability if VCT isolated	Valve position indic. in control room, Lo flow alarms from FQRC-210X. FQRC-210Y. Lo PZR level alarms Lo flow indic. from FI-212	Normal makeup path is to VCT. None if VCT is isolated	
		b) fails open	Valve operator malfunction, spurious signal, mech. binding when open	Makeup flow to VCT diverted to charging pump suction	None	None	CH-527 can be closed with a handwheel for operator failures
194)	Direct Makeup Line Check Valve, CH-179	a) fails closed	Mech. binding blockage	Same as 193 a)	Lo flow alarms from FQRC-210X, and FQRC-210Y	Same as 193 a)	
		b) fails open	Mech. binding	No impact on normal operation. Minor diversion of charging suction flow to makeup lines	None	Direct makeup line isolated by CH-527	
195)	BAMP to Boric Acid Eductor Isolation Valve, CH-649	a) fails closed	Mech. binding	No impact on normal operation. Unable to initiate flow of RWT water through eductor to draw batched concentrated boric acid solution into RWT	Operator	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) seat leakage	Contamina-tion, mech. damage	Minor diversion of makeup flow into the boric acid batching lines	None	Isolation valves CH-124 or CH-126	
196)	Boric Acid Batching Eductor	a) eductor doesn't draw sufficient vacuum on boric acid batching tank	nozzle plugged, wrong nozzle	Concentrated boric acid drawn from boric acid batching tank at too slow a rate. Flow to RWT has too slow a rate. Flow to RWT has too low a concentration	Lo flow indic. from FI-213	Valve CH-122 can be opened to get desired flow	Final boric acid concentration in RWT depends on total amount of boric acid added, not addition rate
		b) draws too much vacuum on BABT	Nozzle too large	Concentrated boric acid drawn into recirculation flow at too high a rate. Flow to RWT has greater than desired boron concentration. Possible precip of boric acid	Hi flow indic. from FI-213	Valve CH-122 can be closed to get desired flow rate	Same as above
197)	Boric Acid Batching Line Isolation Valve, CH-126	a) fails closed	Mech. binding, blockage	Same as 195 a)			
		b) seat leakage	Contamina-tion, mech. damage	No impact on normal operation. Minor diversion of flow from boric acid concentrator (BAC) or PHIX to boric acid batching tank or makeup lines	None	Valves CH-122, and CH-649 provide isolation	
198)	Isolation Valve CH-124	a) fails closed	Mech. binding	Same as 195 a)			
		b) seat leakage	Contamina-tion, mech. damage	No impact on normal operation. Possible unwanted flow from BAC or PHIX to RWT	RWT level indicators	Redundant isolation valves for BAC and PHIX	
199)	BAC to RWT Check Valve, CH-127	a) fails closed	Mech. binding, blockage	Unable to deliver concentrated boric acid bottoms from BAC to RWT. No impact on normal operation	Lo flow rate indic. from FR-295	None	
		b) fails open	Mech. binding	No impact on normal operation. Possible diversion of boric acid batching flow to BAC	None	Check valves in BAC package prevent backflow into BAC	
200)	Makeup Supply Header Isolation Valve to the BABT CH-119	a) fails closed	Mech. binding	No impact on normal operation. Unable to supply makeup water for a batch of concentrated boric acid solution	Operator	None	
		b) seat leakage	Mech. damage contamination	Possible overfilling of BABT during makeup, RMW spill	Local leak detectors	None	Causes no problem other than minor loss of RMW

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
201)	Boric Acid Batching Tank BABT	a) leak	Manufacturing defect, mech. damage	No impact on normal operation. Loss of RMW when preparing a batch of concentrated boric acid	Operator, local leak detectors	None	BABT is empty during normal operation. Leak would be detected during batching operation
202)	Boric Acid Mixer	a) does not mix	Motor failure, mech. failure	Unable to properly mix concentrated boric acid batch. Possible precip. of boric acid	Operator	Manual mixing	
203)	BABT Heater	a) fails full on	Elect malfunction	Concentrated boric acid solution overheated. Possible boiling with increase in boric acid concentration	High temp. indic. from TIC-213, operator	Heater can be turned off manually	Operator is present for batching evolution.
		b) fails off	Elect or mech. malfunction	Concentrated boric acid solution not heated properly. Possible precipitation of boric acid	Lo temp. indic. from TIC-213, operator	None	BABT fluid is heated prior to adding boric acid to the tank
204)	BABT Temperature Indicator/ Controller, TIC-213	a) spurious Hi temp. readings	Elect or mech. malfunction	TIC-213 will turn off the BABT heater. Insuff. heat to boric acid solution, possible precipitation	Operator	Heater can be controlled manually	
		b) spurious Lo temp. readings	Elect. or mech. malfunction	TIC-213 will turn on the BABT heater. Boric acid solution will be overheated. Possible boiling	Operator	Heater can be manually turned off	
205)	Boric Acid Batching Drain Valves, CH-767, CH-121	a) fails closed	Mech. failure, blockage	Unable to flush and drain BABT or BAB lines after making up a batch or concentrated boric acid. No impact on normal operation	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	No impact on normal operation. Minor diversion of concentrated boric acid solution to recycle drain header during batching operations	Operator	None	
206)	Boric Acid Batching Valve; CH-122	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to add concentrated boric acid solution to RWT	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	No impact on normal operation. Diversion of RMW or boric acid solution to RWT while preparing batch of concentrated boric acid	Flow indic. from FI-213	Isolation valves CH-126 CH-649	
207)	Relief Valve CH-123	a) fails closed	Mech. binding, blockage	No impact on normal operation. Loss of overpres. protection for potentially closed line section	Periodic test	None	
		b) fails open	Spring failure, setpoint drift	No impact on operations	None	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
208)	Flow Indicator, FI-213	a) false Hi flow indicator	Elect. or mech. malfunction	CH-122 will be set too low, resulting in reduced boric acid mixing in RWT recirculation flow	Periodic test	None	Same as 196) a)
		b) false Lo flow indicator	Elec. or mech. malfunction	CH-122 will be set too Hi, resulting in Hi boric acid concentration in recirculation/ educting flow. Possible boric acid precipitation	Period test	None	Same as 196) a)
209)	Boric Acid Strainer	a) plugged	Normal contaminant buildup	No impact on normal operation. Unable to establish desired concentrated boric acid flow rate	Lo flow indic. from FI-213	Element can be removed and replaced before continuing boric acid addition.	
		b) doesn't strain out particles	Element "punch through," wrong element	No impact on normal operation. Possible contamination of RWT during boric acid addition	None	Makeup filters should remove contaminants before RWT inventory reaches RCS	
210)	BABT Local Sample Valve, CH-120	a) fails closed	Mech. failure, blockage	Unable to obtain sample of BABT contents for boron analysis	Operator	Sample can be obtained from top of tank	
		b) seat leakage	Contamina-tion, mech. damage	No impact on normal operation. Local spill of boric acid solution during batch operations	Operator, local leak detectors	None	
211)	Boric Acid Lines Heat Tracing	a) fails off	Elect malfunction	No impact on normal operation. Insufficient (no) heating for lines carrying concentrated boric acid. Possible boric acid precipitation	Heat tracing status indicator	Concentrated Boric Acid solution is generally not allowed to stagnate, even in the heat traced lines. Fluid movement should prevent precip.	
212)	Makeup Supply Header to Chemical Addition Tank (CAT) Isolation Valve, CH-312	a) fails closed	Mech. failure	No impact on normal operation. Unable to supply RMW to CAT. Unable to batch chemicals for RCS 0_2 concentration and pH control.	Operator	Makeup water could be carried to tank from another source.	Normal RCS O_2 control is via H_2 blanket in VCT.
		b) seat leakage	Contamina-tion, mech. damage	No impact on normal operations. Possible overfilling of CAT with RMW during makeup operations	Local leak detectors	None	
213)	Chemical Addition Tank	leak	Mfg. defect, mech. damage	No impact on normal operation. Loss of chemical solution when preparing a batch for addition to RCS	Operator, local leak detector	None	
214)	CAT Isolation Valve, CH-171	a) fails closed	Mech. binding	No impact on normal operation. Unable to add chemical solution to RCS	Operator	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) seat leakage	Contamina-tion, mech. damage	No impact	None	CAT normally empty, other isolation valves downstream	
215)	Chemical Addition Strainer	a) plugged	Normal contaminant buildup	No impact on normal operation. Unable to add chemical solution to RCS	CAT not empty	Isolate strainer and replace element	
		b) fails to remove impurities	Element "punch thru", wrong element	No impact on normal operation. Potential addition of contaminants to RCS	None	Contaminants removed from primary coolant by letdown filters	
216)	CAT and Strainer Drain Valve, CH-309	a) fails closed	Mech. failure	No impact on normal operation. Unable to flush & drain CAT after adding chemical solution to RCS. Unable to drain strainer for maint.	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	No impact on normal operation. Chemical solution diverted to waste management system. Possible increase in RCS 0_2 concentration	None	None	
217)	Chemical Metering Pump	a) fails to start	Loss of Power mech. failure	No impact on normal operation. Unable to add chemical solution to RCS	Pump run indicator	None	
		b) spurious start up	Elect. Malfunc. spurious sig. operator error	Pump damaged	Pump run indicator operator	None	Pump can only turned on by operator via hand switch, therefore this is a highly improbable incident.
218)	Chemical Addition Valve; CH-768	a) fails closed	Mech. failure	Same as 214 a)			
		b) seat leakage	Mech. damage contamination	No impact	None	Isolation valve CH-171, and CH-863.	
219)							
220)	Makeup Line Local Sample Valves; CH-648, CH-176, CH-185	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to obtain local sample at approp. locations in boric acid make up system	Operator	None	
		b) seat leakage	Contamination mech. damage	Loss of boric acid solution outside containment	Local leak detectors	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
221)	Resin Sluice Supply Header to Reactor Drain Tank Isolation Valve; CH-580	a) fails closed	Mech. binding, loss of air or power, valve operator malfunction	No impact on normal operation. Unable to provide RMW to fill RDT	Valve posit. indic. in control room, low flow indic. (F-249)	Alternate path via valve CH-862	
		b) fails open	Spurious signal, mech. binding or valve operator malfunc. when open	Loss of redundant containment ISOL capability for line on CIAS, possible unwanted RMW flow to RDT	Valve posit. indic. in control room, RDT level indic.	Check valve, CH-494 provides containment isolation. None for unwanted RMW flow.	
222)	Resin Sluice Supply Header Check Valve, CH-494	a) fails closed	Mech. binding, blockage	Same as 221 a)	Lo flow indic. from FI-249	Same as 221 a)	
		b) fails open	Mech. binding	Loss of redundant containment isolation capability for line. Possible drain flow to resin sluice supply header	None	Isolation valve CH-580	
223)	Resin Sluice Supply Header to RDT Manual Isolation Valve, CH-857	a) fails open	Mech. binding	No impact on normal operation, unable to isolate line for maint.	Operator	None	
		b) fails closed	Mech. failure	Same as 221 a)	Operator	Same as 221 a)	Valve is normally open
224)	PCPS to RDT Isolation Valve, CH-456	a) fails closed	Mech. failure	No impact on normal operation	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	No impact on normal operation. Possible diversion of drain flow to PCPS	None	None	
225)	Reactor Drain Tank; RDT	leakage	Mfg. defect, corrosion, mech. damage	Loss of primary coolant inside containment	Local leak detectors and radiation monitors, RDT level indicator LIC-268	None	
226)	RDT Level Indicator/ Controller, LIC-268	a) spurious high level alarms	Elect. or mech. malfunction, setpoint drift	No direct impact on operation. Operator may drain tank, losing steam quenching capability for PZR reliefs	Hi level alarms from LIC-268 with normal pres. indic. from PIC-268	None	
		b) spurious Lo level alarms	Same as above	No direct impact on operation. Reactor drain pumps (RDP) will be stopped. Possible level and pres. increase in RDT	Lo level indic. from LIC-268 with Hi or normal indic from PIC-268	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
227)	RDT Pressure Indicator/ Controller; PIC-268	a) spurious high pres. alarms	Same as above	PIC-268 will close valves CH-560 and CH-540, isolating the RDT outlet lines. Possible overfilling of RDT with a pres. increase	Hi pres. alarm from PIC-268	None	
		b) false Lo pres. indications	Elect or mech. malfunction	No impact on normal operation. Failure to detect pres. increase in RDT. Possible overpres. of gaseous waste management system (GRS) or RDPs	Periodic test	None	
228)	RDT Temp. Indicator, TI-268	Erroneous temp. indic. or alarms	Elect. or mech. malfunct. setpoint drift	No impact on operation. TI-268 has no control function	Periodic test or alarms	None	
229)	N_2 Supply Line Isolation Valve, CH-483	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate N_2 line for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to reestablish N_2 blanket in RDT. Possible combustible gas buildup in RDT	Operator	None	
230)	N_2 Control Valve; CH-484	a) fails closed	Mech. malfunct.	Loss of N_2 blanket for RDT. Possible buildup of combustible gas in RDT	N_2 usage drops, possible Lo pres indic. from PIC-268	RDT can be vented to GRS	
		b) fails open	Mech. malfunct.	Over pressurization of RDT with N_2	HI pres alarm from PIC-268	None	Rupture disc on RDT prevents rupture of tank.
231)	RDT to GRS Vent Valve, CH-540	a) fails closed	Mech. failure, loss of air or power valve operator malfunct.	No impact on normal operation. Unable to vent RDT to GRS	Valve position indic. in control room		None
		b) fails open	Spurious signal mech. binding or valve operator malfunct. when open	Unwanted venting of RDT to GRS. Possible over pres. of GRS.	Valve posit indic. in control room. Lo pres indic. from PIC-268, excess N_2 usage	None	CH-484 is set to maintain 3 psig in RDT, therefore GRS should not be overpressurized.
232)	RDT Outlet Line Containment Isolation Valves; CH-560, CH-561	a) fails open	Mech. binding, valve operator malfunct.	No impact on normal operation. Loss of redundant line isolation on CIAS. For CH-560, possible overpres. to RDP suction on Hi RDT pres	Valve posit. indic. in control room	Redundant valve for CIAS, None for Hi RDT pres. except high pressure alarm from PIC-268	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails closed	Mech. failure, Loss of air or power, valve operator malfunct.	No impact on normal operation. Unable to drain RDT	Valve posit. indic. in control room	None	
233)	RCP Leakoff Line Check Valve, CH-487	a) fails closed	Mech. binding, blockage	Loss of flow path for leakoff from RCP vapor seals. Buildup of primary coolant on "Top" of vapor seals. Coolant may spill out over the RCP into containment.	Containment sump level alarms	None	Flow rate is approx. 1.2 GPM total
		b) fails open	Mech. binding	Possible diversion of RDT contents to RCP seal leakoff lines. Coolant may spill out over the RCP into containment.	None	None	
234)	RMWT Supply to RDT, Isolation Valve; CH-862	a) fails closed	Mech. failure	No impact on normal operation. Unable to supply RMW to RDT or to RDP suction to aid in pump down of RDT after high temp. relief valve discharge.	Operator	Alternate path via valve CH-580	
		b) seat leakage	Contamina-tion, mechan-ical damage	Unwanted RWM flow to RDT or RDP suction. RDT level increase. Possible flow of RDT contents to resin supply header	Hi level indic. from LIC-268 for flow to RDT. Lo level indic. for flow from RDT	None	
235)	Reactor Drain Pump (RDP) Isolation Valves; CH-465, CH-472, CH-466, CH-473	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate affected RDP for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to put affected RDP back in service after maint.	Operator	Redundant RDPs	
236)	RDP Discharge Pressure Indicators; PI-256, PI-255	Erroneous pressure indic.	Electrical or mech. malfunction	No direct impact on operation. PI-256 and PI-255 have no control function. Possible early maint. on RDP	Periodic test	None	
237)	Reactor Drain Pumps; RDP 1 RDP 2	a) fails to start	Electrical malfunct., mech. binding or failure	Unable to drain RDT or EDT. to PHIX, gas stripper and holdup tank	RDT or EDT level indic. pump "run" indic. pump discharge pres. indic.	Redundant pump	
		b) Running pump stops	same as above				

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		c) Pump starts	Electrical malfunct., spurious signal	Unwanted draining of RDT or EDT	RDT or EDT level indic. pump "run" indic. pump discharge pres. indic	EDT or RDT isolation valves can be closed; pump power can be manually interrupted	Pumps are only started manually, therefore this is a highly improbable event.
238)	RDT Discharge Check Valves; CH-470, CH-471	a) fails closed	Mech. failure blockage	Unable to drain EDT or RDT. Possible damage to RDP due to dead heading	Hi discharge pres. indic. for RDP	Redundant RDP	
		b) fails open	Mech. binding	No impact on operation	Pressure indicator P-255 (P-256) when other RDP is running.	None	
239)	Reactor Drain Filter Isolation Valves: CH-477, CH-478	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate filter for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to return reactor drain filter to operation after maint.	Operator	Reactor drain filter can be bypassed via valve, CH-474	
240)	Reactor Drain Filter, RDF	a) plugged	Normal contaminant buildup	Unable to drain EDT or RDT through filter.	Hi Delta P alarm from PDI-258	Drain flow can be diverted by the filter while the element is replaced	
		b) doesn't filter	Element "punch thru", wrong element	Contaminants not removed from drain flow. Contam. buildup in PHIX, gas stripper or holdup tank	Low pressure indication from PDI-258.	Same as 240 a)	
241)	RDF Differential Pressure Indicator; PDI-258	a) spurious Hi Delta pressure alarm	Elect. or mech. malfunction, setpoint drift	No direct impact on operation. Possible early replacement of filter element	Hi Delta P alarms from PDI-258 with normal indic. from PI-255 or PI-256	None	
		b) erroneous Lo or normal Delta P indic.	Elect or mech. malfunct.	No impact on normal operation. Unable to detect plugged filter element	Periodic test	None	
242)	RDF Bypass Valve; CH-474	a) fails closed	Mech. failure	No impact on normal operation. Unable to bypass RDF for element replacement	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Diversion of drain flow past RDF. Contaminant buildup in PHIX, gas stripper, or holdup tank	Same as 240 b)	None	
243)	RDF Drain Valve; CH-475	a) fails closed	Mech. failure	No impact on normal operation. Unable to drain RDF for element replacement	Operator	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) seat leakage	Contamina-tion, mech. damage	No impact on normal operation. Portion of drain flow from RDT or EDT diverted back to EDT	EDT level indic.	None	
244)	RDF Vent Valve, CH-663	a) fails closed	Mech. failure	No impact on normal operation. Unable to vent RDF when replacing element	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Minor loss of primary coolant outside containment	Local leak detectors local radiation monitor	None	
245)	Letdown Diversion Line Isolation Valve; CH-721	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate letdown diversion valve for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to return letdown diversion line to service after maint., loss of letdown diversion capability for feed and bleed or gas stripping operations	Operator	None	
246)	Letdown Diversion Line Check Valve, CH-722	a) fails closed	Mech. binding	Loss of letdown diversion capability for feed and bleed or gas stripping operations	Lo flow indic. from FI-202	Normal letdown flow path can be maintained until valve is repaired	
		b) fails open	Mech. binding	RDT and EDT drain flow diverted to letdown diversion line	None	Letdown diversion line is closed by valve CH-500	
247)	Temperature Indicator/ Controller; TIC-264	a) spurious Hi temp. indic. and alarm	Elect. or mech. malfunction setpoint drift	EDT/RDT drain flow, or letdown diversion flow diverted from PHIX to gas stripper and/or holdup tank	Hi temp. alarm from TIC-264 with normal indic. from TI-268, TI-269, and TIC-223	None	
		b) erroneous Lo or normal temp. indic.	Elect. or mech. malfunction	No impact on normal operation. Failure to detect Hi temp flow to PHIX. Possible damage to PHIX	Periodic test	None	
248)	PHIX Flow Diversion Valve CH-565	a) fails to gas stripper	Loss of air or power, spurious signal valve operator malfunct., mech. failure	RDT/EDT drain flow or letdown flow diverted from PHIX to gas stripper. Contaminant buildup in gas stripper	Valve posit. indic. in control room, Lo Delta P indic. from PDI-265	None, except that flow will be diverted to EDT on trouble conditions in gas stripper	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails to PHIX	Spurious signal, mech. binding, valve operator malfunct.	Unable to divert Hi temp. flow past PHIX. Possible damage to PHIX. Unable to route letdown flow directly to gas stripper for continuous gas stripping	Periodic test, valve not change posit. on demand	None	
249)	PHIX Isolation Valves; CH-724, CH-490	a) fails open	Mech. failure	No impact on normal operation. Unable to isolate PHIX for maint. or resin change	Operator	None	
		b) fails closed	Mech. failure	Unable to restore PHIX to service after maint., possible contaminant buildup in gas stripper, holdup tank and/or VCT	Operator	Flow can be diverted past PHIX until valve repaired	
250)	PHIX Inlet Check Valve: CH-725	a) fails closed	Mech. binding, blockage	Unable to establish flow through PHIX. Possible contaminant buildup in gas stripper, holdup tank and/or VCT	Lo Delta P indic. from PDI-265, Lo flow indic. from FI-202 or High pres. indic. from PI-255, or PI-256	Same as 249 b)	
		b) fails open	Mech. binding	No impact on operation	None	None	
251)	PHIX Resin Fill Valve, CH-726	a) fails closed	Mech. failure	No impact on operation. Unable to add new resin to PHIX	Operator	None	
		b) seat leakage	Contamina-tion, mech damage.	Possible release of radioactive gas outside containment	Radiation monitors	Flow can be diverted past PHIX until valve is repaired	
252)	PHIX Differential Pressure Indicator; PDI-265	a) spurious Hi Delta P indic. and alarm	Elect. or mech. malfunction setpoint drift	No direct impact on operation. Possible early change out of PHIX resin	Hi Delta P alarm not clear when flow diverted to gas stripper	None	
		b) false Lo or normal Delta P indic.	Elect. or mech. malfunction	Unable to detect degradation of PHIX resin	Periodic test	None	
253)	PDI-265 Isolation Valves; CH-727, CH-492	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate PDI-265 for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to place PDI-265 back in service after maint.	Operator	For CH-727 - None for CH-492, valve CH-488 can be opened to take pres. diff. across just the PHIX	
254)	PDI-265 Isolation Valve, CH-488	a) fails closed	Mech. failure	No impact on system operation. Unable to place PDI-265 across just the PHIX rather than across PHIX and strainer	Operator	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) seat leakage	Mech. damage contamination	PDI-265 will be measuring Delta P across just the PHIX when it should be measuring Delta P across PHIX and strainer. Possible failure to detect PHIX degradation or strainer degradation	None	None	
255)							
256)	PHIX Vent Valve; CH-728	a) fails closed	Mechanical failure, blockage	No impact on normal operation. Unable to vent PHIX during drain and flush operations	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Diversion of radioactive gases to GRS. No impact on operation	None	None	
257)	PHIX and PHIX Strainer Flush Valves to SRS; CH-730, CH-489	a) fails closed	Mech. binding, blockage	No impact on normal operation. Spent resin in PHIX or resin in PHIX or resin trapped in strainer, cannot be flushed to the SRS	Operator	None	
		b) seat leakage	Mech. damage, contamination	Part of flow through PHIX will be diverted to SRS	Level indicators in SRS	Isolation valves in SRS	
258)	PHIX Sluice Valve; CH-485	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to flush PHIX with RMW during resin replacement	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Part of flow through PHIX will be diverted to the sluice supply header. Possible contamination of RMW supply	None	Check valve and isolation valve on RMW supply line to sluice supply header	
259)	PHIX Drain Valve; CH-486	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to drain PHIX after flushing spent resin	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Portion of flow through PHIX diverted to EDT	Level indications, or high level alarms from LIC-251	Isolation valve CH-457 on DIDH	
260)	Pre-Holdup Ion Exchanger; PHIX	a) fails to remove contami-nation	Spent resin	Buildup of activity in holdup tank	High ΔP alarm from PDI-265	Bypass PHIX and replace resin	
		b) restricts flow	Plugged	Unable to divert letdown flow during feed and bleed operations	High Delta P alarm from PDI-265	Bypass PHIX and replace resin	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		c) external leakage	Corrosion, mfg. defect, mech. damage	Local spill of primary coolant outside containment	Local leak detectors	PHIX can be bypassed and isolated for repair	
261)	PHIX Strainer	a) fails to remove particulate matter	Element "punch through" wrong element	Buildup of contamination in holdup tank, gas stripper, or VCT	Local sample analysis.	PHIX and strainer can be bypassed and isolated for strainer repair	
		b) plugged	Normal buildup of contaminants	Reduced flow through PHIX. Reduced letdown flow during feed and bleed operations.	Hi Delta P alarm from PDI-265, Low flow indic. F-202 if diverting letdown	Same as above	
262)	PHIX Strainer Isolation Valve; CH-491	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate strainer for maint.	Operator	None	
		b) fails closed	Mech. failure, blockage	Unable to restore PHIX to service after maint. on strainer. Possible buildup of activity in holdup tank if feed and bleed or other operations requiring PHIX are in progress	Operator	PHIX can remain bypassed until valve repaired, or operations can be interrupted for valve repair	
263)	PHIX to Holdup Tank Isolation Valve; CH-655	a) fails closed	Mech failures; blockage	Unable to route letdown or RCS drain flow through PHIX directly to holdup tank. Possible forced termination of feed and bleed	Operator	Flow can be routed to HT thru gas stripper, or flow can be routed to RWT	
		b) fails open	Mech. binding when open, or seat leakage	Portion of flow to the gas stripper (GS) will be diverted to HT. Possible buildup of gases in HT	Operator (for stuck open). None for seat leakage	HT is vented to GRS	
264)	PHIX to RWT Isolation Valve; CH-495	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to route letdown or RCS drain flow to RWT after it passes through PHIX	Operator	Flow can be routed to HT, and from there to the RWT	
		b) fails open	Mech. binding when open, or seat leakage	Portion of flow to GS will be diverted to RWT. Possible buildup of gasses in RWT	Operator, RWT level indicator	Series redundant isolation valve, CH-124	
265)	PHIX to Gas Stripper Isolation Valve; CH-496	a) fails open	Mech. binding	No impact on normal operation. Portion flow from PHIX to RWT or holdup tank will be diverted to GS	Operator	Series redundant isolation valve, CH-660, can be closed	

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails closed	Mech. binding	Unable to establish continuous degasification of letdown flow. Unable to degassify PHIX discharge flow. Possible gas buildup in RWT, HT, or VCT	Operator	HT and RWT are continuously vented to GRS VCT already has H_2 blanket.	
266)	Diversion Valve, CH-566	a) fails to gas stripper	Mech. binding valve operator malfunction	No impact on normal operation. Unable to divert flow to EDT on GS trouble condition. GS efficiency reduced. Possible damage to GS	Periodic test	None	
		b) fails to EDT	Loss of air or power, spurious signal, valve operator failure	Flow to GS diverted to EDT. Loss of degasification capability. Possible overfilling of EDT	EDT level alarms, valve position indication in control room	Flow to gas stripper can be interrupted until valve repaired	
267)	Makeup supply Header to Gas Stripper, Isolation Valve; CH-654	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to flush GS with RMW prior to maint.	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Primary coolant flow to gas stripper (during degasification) diverted to makeup supply header. Possible contamination of RMW supply	None	Isolation and check valves on makeup supply header	
				RMW diverted to gas stripper during makeup operations. Possible subsequent dilution of boric acid concentration in HT or VCT	None except boronmeter if dilution is significant	None	Dilution would be very minor unless continuous letdown degasification is in process, seat leakage is significant and makeup pumps are in operation
268)	Gas Stripper Isolation Valve, CH-660	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate gas stripper for maintenance.	Operator	Isolation valve CH-496 can be closed	
		b) fails closed	Mech. failure	Same as 265 b)			
269)	Gas Stripper to EDT Drain Valve, CH-662	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate GS for maint.	Operator	None	
		b) fails closed	Mech. failure	No direct impact on normal operation. Possible minor spill of primary coolant if gas stripper components have excess leakage	Operator, local leak detectors and radiation monitors	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
270)	Gas Stripper Sample Valve to Gas Analyzer; CH-467	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate GS for maint	Operator	None	
		b) fails closed	Mech. failure	Unable to sample GS with Gas Analyzer	Operator	None	
271)	Gas Stripper, GS	a) fails to remove gases	Loss of aux steam, loss of cooling water, mech. malfunction	Buildup of gasses in primary coolant, HT or VCT.	Local sample analysis, gas analysis	HT is vented to GRS. VCT already has H_2 blanket.	
272)	Diversion Valve CH-567	a) fails to VCT position	Mech. failure, valve operator failure	Unable to divert letdown flow to holdup tank during feed and bleed or on Hi VCT level. Possible overfilling of VCT	Hi VCT level alarms. Valve position indicator in control room	None	
		b) fails to holdup tank position	Loss of air or power, spurious signal, mech. failure, valve operator fail	Letdown flow diverted to hold-up tank during degasification of primary coolant. Decrease in VCT inventory	VCT level alarms. Hi level alarms, valve position indicator in control room	Makeup system will maintain VCT inventory	
273)	Isolation Valves; CH-656, CH-651	a) fails open	Mechanical binding	No impact on normal operation. Unable to isolate radiation monitor, or HT for maintenance	Operator	None	
		b) fails closed	Mech. failure	Unable to reestablish flow path to HT after maint. Unable to empty drain tanks to HT. Unable to conduct feed and bleed operations	Operator	None	
274)	Deleted						
275)	Hold Up Tank Level Indicator Controller, LIC-208	a) spurious low level alarms or indications	Elect. or mech. malfunct., setpoint drift	Transfer of holdup tank contents to BAC will be terminated. Possible overfilling of HT due to undetected HI level in HT	Low level alarm from LIC-208, and inspection	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) spurious Hi level indications or alarms	Same as above	No direct impact on normal operation. Possible undetected low level conditions in HT. Possible damage to holdup pumps if HT is drained	Hi level alarm from LIC-208, and test	None	
276)	Holdup Tank Temperature Indicator, TI-208	a) spurious low temp alarm	Elect malfunct., setpoint drift	No impact on system operation	Lo temp. alarm from TI-208 and test	None	
		b) false Hi or normal temp indications	Elect. malfunct.	No impact on normal operation. Unable to detect decreasing temp. in HT. Possible boron precipitation if temp. drops	Periodic test	None	
277)	Holdup Pump to Holdup Tank Isolation Valves CH-650	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate HT for maint	Operator	None	
		b) fails closed	Mech. failure	Unable to transfer HT contents to BAC for processing	Operator	None	
278)	Holdup Tank HT	leaks	mfg defect, mech. damage, corrosion	Loss of primary coolant quality water outside containment	HT level indicator	None	
279)	Ion Exchanger Drain Header (DIDH) Strainer Isolation Valves, CH-451, CH-454	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate DIDH strainer for maint	Operator	None	
		b) fails closed	Mech. failure	Unable to return DIDH strainer to service after maint. Unable to drain ion exchangers during resin replacement operations	Operator	None	
280)	DIDH Strainer	a) fails to remove contam-inants	Element "punch through", wrong element	Buildup of contaminants in EDT	Local sample analysis, possibly low differential pressure indication from PDI-250	None	
		b) plugged	Normal contaminant buildup	Unable to drain ion exchangers during resin replacement operations	High Delta P alarm from PDI-250	Isolate and clean strainer	
281)	DIDH Strainer Drain Valve, CH-455	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to drain and clean strainer	Operator	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) seat leakage	Contamina-tion, mech. damage	Minor diversion of ion exchanger drain flow to solid waste management system	None	None	
282)	DIDH Strainer Differential Pressure Indicator, PDI-250	a) spurious Hi Delta P alarm	Elect. or mech. malfunction, setpoint drift	No adverse impact on operation. Early maint. on strainer	Hi Delta P alarm from PDI-250 and test	None	
		b) false low or normal Delta P readings	Elect. or mech. malfunction	No impact on normal operation. Failure to detect plugged strainer	Periodic test	None	
283)	DIDH Flow Sensor, F-251	Erroneous flow indications	Elect. or mech. malfunction	No impact on normal operation. Flow sensor has only local readout and has no control function	Periodic test	None	
284)	DIDH Isolation Valve; CH-457	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to drain ion exchangers during resin replacement	Operator	None	
		b) fails open	Mech. binding when open, seat leakage	Possible diversion of primary coolant from ion exchangers to EDT	Operator for mech. binding when open, otherwise none	Isolation Valves for the ion exchangers	
285)	DIDH Check Valve, CH-480	a) fails closed	Mech. failure, blockage	Same as 284 a)	No flow indic. from F-250 when CH-457 opened	None	
		b) fails open	Mech. binding, seat leakage	No impact operation	None	Isolation valve, CH-457	
286)	Equipment Drain Tank (EDT) Level Indicator/ Controller; LIC-251	a) spurious high level indications	Elect. or mech malfunct., setpoint drift	No impact on normal operation. Failure to detect Lo EDT level and stop drain pumps during EDT draining. Possible damage to drain pumps	Hi level alarm LIC-251 and test	None	
		b) spurious Lo level indication or alarm	Elect. or mech. malfunction	Unable to detect Hi level in EDT. Possible overfilling of EDT. Possible trip of RDP's when pumping down EDT	Lo level alarm from LIC-251 and test	None	
287)	EDT Temperature Indicator, TI-269	a) spurious Hi temp. indications or alarms	Elect. or mech. malfunct., setpoint drift	No impact on operation. TI-269 has no control funct.	Hi temp. alarm from TI-269 and test. Normal pres indic. from PIC-251	None	
		b) erroneous Lo or normal temp indic.	Elect. or mech. malfunct.	No impact on normal operation. Unable to detect Hi temp condition in EDT	Periodic test	PIC-251 may indic. Hi pres if EDT temp went up	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
288)	EDT Pressure Indicator/ Controller, PIC-251	a) spurious Hi press indic. or alarm	Elect. or mech malfunct.	PIC-251 will close valves CH-563, CH-564, CH-562, effectively isolating EDT. Loss of recycle drain capability. Unable to drain EDT	Hi pres alarm from test PIC-251, and test	None	
		b) erroneous Lo or normal pres. indic.	Elect. or mech. malfunct	No impact on normal operation. Failure to isolate EDT on high pres. condition. Possible over-pressurization of GRS line and/or reactor drain pumps	Periodic test	None	
289)	EDT to GRS Isolation Valve; CH-564	a) fails open	Mech. binding, valve operator failure	No impact on normal operation. Unable to isolate lines to GRS on Hi. pres. in EDT. Possible overpres. of GRS lines	Valve posit. indic. in control room	None	
		b) fails closed	Loss of air or power, mech. failure, valve operator failure, spurious signal	Loss of ability to vent EDT to GRS. Possible pres increase in EDT.	Valve posit. indic. in control room. Pres indic. from PIC-251	None	
290)	Gas Analyzer Manual Isolation Valve, CH-458	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate Gas Analyzer for maint	Operator	CH-564 can be closed	
		b) fails closed	Mech. failure	Unable to restore one line to Gas Analyzer to service after maint	Operator	Alternate data via CH-568	
291)	EDT to GRS Line Pressure Control Valve; CH-568	a) controls back-pressure too low	Mech. malfunct., setpoint drift	Possible overpressurization of GRS lines. Decrease in EDT pres. Increased N_2 use	Lo pres. indic. from PIC-251. Increase in N_2 usage	N_2 regulator will adjust to maintain proper EDT pres.	Valve can be isolated and repaired
		b) controls back-pressure too high	Mech. malfunction, setpoint drift	Decreased venting of gases in EDT. Possible pres. increase in EDT. Decreased N_2 use	Hi press. indic from PIC-251. Decrease in N_2 in N_2 usage	N_2 Regulator will adjust to maintain proper EDT pres.	
292)	Recycle Drain Header Isolation Valve CH-562	a) fails open	Mech. binding valve operator failure	No impact on normal operation. Failure to isolate drain header from EDT on Hi pressure in EDT. Possible overpressure in drain header	Valve position indicator in control room	Check valve CH-450 will provide some protection	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails closed	Mech. failure, valve operator failure, loss of air, or power, spurious signal	Loss of drain capability for various leakoff lines	Valve position indication in control room	None	
293)	Recycle Drain Header Check Valve, CH-450	a) fails closed	Mech. failure, blockage	Same as 292 b)	None	None	
		b) fails open	Mech. binding	No impact on normal operation. Partial loss of isolation capability for drain header	None	Valve CH-562, will provide isolation	
294)	N_2 Supply Line Isolation Valve; CH-830	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate N_2 pres. control valve for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to restore N_2 supply after maint. Loss of proper pres. control and vent/purge capability for EDT	Operator	None	
295)	EDT N_2 Pressure Control Valve; CH-831	a) controls pressure too low	Mech. failure, setpoint drift	Decrease in EDT Vent/Purge rate. Decreased EDT pressure	Lo pres. indic from PIC-251	Vent pres. control valve will close to maintain EDT press	
		b) controls pressure too high	Mech. failure, setpoint drift	Possible overpressurization of EDT, excess N_2 usage	Hi pres. indic. from PIC-251	Vent pres. control valve will attempt to maintain EDT press. Relief valve CH-657	
296)	EDT Relief Valve, CH-657	a) fails closed	Mech. binding, blockage, setpoint drift	No impact on normal operation. Loss of overpres. protection for EDT	Periodic test	None	
		b) fails open	Spring failure, setpoint drift	Primary coolant diverted from EDT to misc radioactive sump	EDT level indic. sump level indic. Local radiation monitor	None	
297)	RSSH to EDT Check Valve; CH-858	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to cooldown EDT with this line and pump down EDT after high temperature relief discharge due to flashing in RDP suction	EDT level indic, Lo RMW flow indic. from F-249	Alternate flow path via, valve CH-562	
298)	Equipment Drain Tank, EDT	Leakage	Mfg. defect, mech. damage, corrosion	Loss of primary coolant outside containment	Lo level alarm from LIC-251, local leak detector, radiation monitor	Isolate and drain EDT for maint.	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
299)	EDT Drain Line Isolation Valve, CH-563	a) fails open	Mech. binding valve operator failure	Possible unwanted draining of EDT during draining of RDT. Possible overpressization of drain pump suction lines on high pressure in EDT	Valve position indic. in control level indic./controller LIC-251, pres. indic./controller, PIC-251	For emptying EDT, LIC-251 will stop drain pumps. Otherwise, none	
		b) fails closed	Mech. failure, valve operator malfunct. loss of air or power spurious signal	No impact on normal operation. Unable to drain EDT	Valve position indicator in control room	None	
300)	EDT Drain Line Check Valve, CH-464	a) fails closed	Mech. failure, blockage	Same as 299 b)	EDT level not decrease when attempt to pump out EDT	None	
		b) fails open	Mech. binding	No impact on normal operation. Possible flow diversion to EDT when draining RDT	None unless EDT level increases	Valve CH-563 will be closed	
301)	Local Sample Valves: CH-665, CH-723, CH-493, CH-652	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to obtain local sample	Operator	None	
		b) seat leakage	Contamination mech. damage	Local spill of primary coolant	Local leak detectors, or radiation detectors	None	
302)	EDT Local Drain Valve; CH-462	a) fails closed	Mech. binding	No impact on operations. Unable to drain EDT for maintenance	Operator	None	
		b) seat leakage	Contamination mech. damage	Possible leakage of primary coolant outside containment	Local leak detectors or radiation monitors	Drain line is blind flanged	
303)	Holdup Pump Suction Isolation Valves, CH-720, CH-734	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate one holdup pump for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to restore one holdup pump (HP) to service after maint	Operator	Redundant holdup pump	
304)	Holdup Pump; HP 1, HP 2	a) won't start	Elec. failure mech. failure	Unable to transfer contents of HT to BAC for processing. Unable to recycle contents of HT for additional cleanup	Operator, discharge pressure indicator	Redundant holdup pump	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) spurious startup	Elect. malfunction, spurious signal	High transfer rate if pumping HT contents to BAC. Possible unwanted transfer of HT contents to BAC, pump damage if isolated	HT level indicators BAC instrumentation pump run indicators	Power can be manually interrupted	Since pumps can only be started via a local HS, this is a highly improbable incident
305)	Holdup Pump Discharge Pressure Indicators; PI-270, PI-271	a) spurious High or Low pres. indic.	Elect. or mech. malfunction	No impact on normal operation. Pressure indicators have no control function. Possible unneeded maintenance on holdup pump	Periodic test	Redundant holdup pump	
306)	Holdup Pump Discharge Check Valves; CH-759, CH-735	a) fails closed	Mech. failure, blockage	Unable to transfer contents of HT to BAC, or to recirculate HT contents	High pres. indic. from HP discharge pres. indicator	Redundant holdup pump	
		b) fails open	Mech. binding	No impact on normal operation. Possible reverse flow thru standby HP	None	Suction isolation valve for standby HP is closed	
307)	Holdup Pump Discharge Isolation Valve; CH-658, CH-737	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate line to BAC for maint. or recirculation of HT contents	Operator	None for maint. Redundant HP for HT recirc.	
		b) fails closed	Mech. failure	Unable to transfer HT contents to BAC for processing after maintenance	Operator	Redundant HP can be used	
308)	Holdup Pump Recirculation Valves; CH-430, CH-446	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate holdup pump for maint.	Operator	Redundant HP can be used	
		b) fails closed	Mech. failure	Unable to restore HP recirculation line after pump maint. Possible damage to pump due to dead heading	Operator	Redundant HP can be used	
309)	HT to Reactor Drain Filter Line Check Valve, CH-685	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to recycle HT contents through reactor drain filter, PHIX or GS for additional clean up	High pres. indic. from HP discharge pres. indic.	None	
		b) fails open	Mech. binding	No impact on normal operation. Possible diversion of reactor drain tank flow directly to BAC	None	Valve CH-686 is normally closed	
310)	HT to Reactor Drain Filter (RDF) Isolation Valve, CH-686	a) fails closed	Mech. binding, blockage	Same as 309 a)	Operator	None	
		b) fails open	Mech. binding	Same as 309 b)	Operator	Check Valve CH-685	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
311)	HT to Liquid Radwaste System Isolation Valve, CH-684	a) fails closed	Mech. failure blockage	No impact on operations. Unable to transfer fluid to LRS	Operator	None	
		b) seat leakage	Contamina-tion, mech damage	Possible spill of primary coolant grade water	Local leak detectors	Line is blank flanged	
312)	BAC Bypass Line to BACIX, Isolation Valve, CH-683	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to divert HP flow to BACIX if reactor makeup water is needed when BAC out of service	Operator	None if BAC in service	
		b) seat leakage	Contamina-tion, mech. damage	Portion of HP flow diverted past BAC. Increased depletion of BACIX resin. Possibly eventual boron carry over to reactor makeup water tank (RMWT)	None	None	
313)	BAC Bypass Line to BACIX, Check Valve; CH-682	a) fails closed	Mech. failure blockage	Same as 312 a)	Hi pres. reading from HP discharge pres. indic. when CH-683 open	None if BAC in service	
		b) fails open	Mech. binding	Possible diversion of BAC purified water output back to HP discharge line	None	Isolation Valve CH-683	
314)	BAC Bypass to RWT, Isolation Valve, CH-752	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to divert HP flow to RWT if RWT inventory must be increased when BAC out of service	Operator	Operator can make up a batch of concentrated boric acid solution in BABT and add to RWT	
		b) seat leakage	Contamina-tion, mech. damage	Portion of HP flow diverted past BAC to RWT or LRS. Possible dilution of RWT	None unless RWT is diluted, then, local sample analysis	RWT concentration can be increased by adding concentrated boric acid solution from BABT	
315)	BAC Bypass Line to RWT, Check Valve, CH-718	a) fails closed	Mech. binding, blockage	Same as 314 a)	Hi pres. indication on HP discharge pres. indic. when CH-752 open	None	
		b) fails open	Mech. binding	Possible diversion of concentrated boric acid bottoms from BAC output back to HP discharge line	None	Isolation valve CH-752	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
316)	Boric Acid Concentrator BAC	a) fails to concen-trate boric acid enough	Electrical or mech. malfunction control malfunct. insufficient steam supply	Concentration of boric acid bottoms released to RWT too low. Dilution of RWT. Possible boron carryover to RMWT	Various BAC indic. and alarms, local sampling of RWT and RMWT	BACIX for boron carryover. Boric acid batching for low boron concentrate in RWT	
		b) concen-trates boric acid too much	Same as above	Concentration of boric acid bottoms released to RWT too high. RWT boron concentration increase, possible over boration of RCS	Local sampling of RWT, reactor power decrease	No safety problem	
		c) leakage	Mfg defect, corrosion, mech. damage	Release of primary coolant quality water, or concentrated boric acid solution outside containment	Local leak detectors or radiation monitors	None	
317)	BAC Isolation Valves; CH-708, CH-611, CH-732	a) fails open	Mech. failure	No impact on normal operation. Unable to isolate BAC for maint	Operator	Isolation valves on. BAC skid, and downstream	
		b) fails closed	Mech. failure, blockage	For CH-708, CH-611, unable to return BAC to service after maint. For CH-732, unable to provide RMW to flush BAC	Operator	None	
318)	BAC to RWT Isolation Valve; CH-709	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate line to RWT when transferring highly concentrated, activated bottoms to LRS	Operator	Series redundant isolation valve downstream	
		b) fails closed	Mech. failure, blockage	Unable to transfer concentrated boric acid bottoms from BAC to RWT. Unable to make up RWT inventory losses	Operator	Alternate sources for RWT inventory, including boric acid batching and spent fuel pool	
319)	BAC to LRS Isolation Valve; CH-499	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to transfer highly concentrated activated boric acid bottoms from BAC to LRS for processing	Operator	None	
		b) fails open	Mech. binding when open, seat leakage	Diversion of refueling shutdown concentration boric acid bottoms being transferred to RWT. Excess waste generation. Reduced RWT inventory makeup ability	Operator for binding, none for seat leakage	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
320)	Relief Valve CH-689	a) fails closed	Mech. binding, blockage, setpoint drift	No impact on normal operation. Loss of overpressure protection for potentially closed line section	Periodic test	None	
		b) fails open	Spring failure, setpoint drift	Same as 319 b)	Periodic test	None	
321)	BAC Concen-trator Concen-trate Line Heat Tracing	fails off	Electo failure	Possible precipitation of boric acid in lines, causing blockage	Heat tracing status indicator	Redundant heat tracing circuit	
322)	BACIX Bypass Line Isolation Valve; CH-619	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to bypass BACIX when BACIX needs maint.	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Portion of BAC distillate bypasses BACIX. Possible boron carryover to RMWT	Local sample of RMWT	None	
323)	BACIX Isolation Valves; CH-699 CH-670	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate BACIX for maint. or resin replacement	Operator	Redundant isolation valves upstream and downstream	
		b) fails closed	Mech. failure, blockage	Unable to restore BACIX to service after maint.	Operator	BACIX can be bypassed while valve is repaired	
324)	BACIX Inlet Check Valve; CH-696	a) fails closed	Mech. binding blockage	Unable to pass BAC distillate thru BACIX to remove carryover boron	Lo flow indic. from BAC distillate flow indicator	BACIX can be bypassed while valve is repaired	
		b) fails open	Mech. binding	No impact on operation	None	None	
325)	BMWT recirc to BACIX Line Isolation Valve, CH-690	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to recirc the RMWT through the BACIX	Operator	None	Infrequent operation
		b) seat leakage	Mech. defect or damage, contamination	Minor diversion of BAC distillate to RMW header. Possible minor contamination of resin sluice supply water	None	Redundant isolation valves downstream	
326)	BACIX Resin Fill Valve, CH-679	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to add new resin to BACIX	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	No impact on operation	None	Resin fill line is blind flanged	
327)	BACIX Differential Pressure Indicator, PDI-274	a) spurious Hi Delta pres. alarm	Elect. or mech. failure, setpoint drift	Early replacement of BACIX resin	High ΔP, P-274 alarm	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) false low or normal Delta P indic.	Elect. or mech. malfunct.	No impact on normal operation. Failure to detect plugged BACIX	Periodic test	None	
328)	BACIX Differential Pressure Indicator Isolation Valves; CH-693, CH-677	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate PDI-274 for maint	Operator	None	
		b) fails closed	Mech. failure	Unable to restore PDI-274 to service after maint	Operator	None for CH-693, for CH-677, valve CH-678 can be opened to obtain Delta P indic. across just the BACIX	
329)	BACIX Differential Pressure Indicator Isolation Valve, CH-678	a) fails closed	Mech. failure	No impact on normal operation. Unable to set PDI-274 to indic. Delta P across just the BACIX	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	PDI-274 will read Delta P across just the BACIX. Possible failure to detect plugged BACIX strainer	None	None	
330)	BACIX Vent Isolation Valve, CH-680	a) fails closed	Mech. binding	No impact on normal operation. Unable to vent BACIX during resin replacement operations	Operator	None	
		b) seat leakage	Contamination mech. damage	Minor releases of gases to GRS during normal operation	None	None	
331)	BACIX/BACIX Strainer Sluice Valves; CH-676, CH-675	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to sluice resin and contaminants out of BACIX or the BACIX strainer	Operator	None	
		b) seat leakage	Contamina-tion mech. damage	Minor diversion of BAC distillate flow (and resin for CH-676) to LRS	None	None	
332)	BACIX Flush Valve; CH-687	a) fails closed	Mech. binding	No impact on normal operation. Unable to provide RMW to flush BACIX during resin replacement	Operator	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) seat leakage	Contamina-tion, mech. damage	Minor diversion of BAC distillate to resin sluice supply header or diversion of RMW from resin sluice supply header back to RMWT	None	Normally closed upstream valves	
333)	BACIX Drain Valve, CH-688	a) fails closed	Mech. binding	No impact on normal operation. Unable to drain BACIX for resin sluicing	Operator	None	
		b) seat leakage	Contamina-tion, mech damage	Minor diversion of BAC distillate flow to EDT	None	Normally closed downstream valve	
334)	Boric Acid Condensate Ion Exchanger, BACIX	a) fails to remove boron	Resin depleted	Possible boron carryover from BAC to RMWT	Local sample analysis	Bypass BACIX and replace resin	
		b) plugged	Buildup of contaminants	Loss of BAC distillate flow to RMWT	Hi Delta P indic from PDI-274	Same as above	
		c) external leakage	Mfg. defect. corrosion, mech. damage	Local spill of BAC distillate and resin	Local leak detectors and radiation monitors	Bypass BACIX and repair	
335)	BACIX Strainer	a) fails to remove contami-nants	Element "punch thru", wrong element	Possible buildup of contaminants in RMWT	Local sample analysis	Bypass BACIX and repair strainer	
		b) plugged	Normal contaminant buildup	Same as 334 b)	Same as 334 b)	Bypass BACIX and clean strainer	
336)	BACIX Strainer Downstream Isolation Valve: CH-671	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate BACIX strainer for maint.	Operator	Redundant isolation valve downstream	
		b) fails closed	Mech. failure	Unable to restore BACIX to service after maint. on strainer	Operator	BACIX remains bypassed until valve repaired	
337)	BACIX to LRS Isolation Valve; CH-673	a) fails closed	Mech. failure	No impact on normal operation. Unable to dump BAC distillate to LRS when BACIX is out of service	Operator	None	
		b) seat leakage	Mech. damage	Minor diversions of BAC distillate to LRS	None	None	

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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
338)	Isolation Valves CH-672, CH-729	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate RMWT and BACIX when dumping BAC distillate to LRS. Possible contamination of RMWT	Operator	None	
		b) fails closed	Mech. failure	Unable to restore BAC distillate flow thru BACIX to RMWT	Operator	None	
339)	RMWT Level Indicator/ Controller LIC-210	a) spurious Low-Low level indication or alarms	Elect or mech. malfunct., setpoint drift	LIC-210 will stop reactor makeup water pumps (RMWP), thereby terminating RMW flow. Possible over boration of RCS. Failure to detect overfilling of RMWT	Lo-Lo level alarms from LIC-210, periodic test	None	Makeup operations to the VCT or charging pumps will be seemed on loss of RMW pumps.
		b) spurious Hi level indications or alarms	Elect. or mech. malfunction setpoint drift	No impact on normal operation. Possible early termination of holdup tank processing through BAC. Failure to detect Lo-Lo level in RMWT and stop RMWPs. Possible cavitation damage to pumps	Hi level alarms from LIC-210, periodic test	None	
340)	RMWT Temperature Indicator TI-210	a) spurious Low temp. indic. or alarm	Elect. or mech. malfunction, setpoint drift	No direct impact on operation.	Lo temp. alarms from TI-210 and test	None	
		b) spurious Hi or normal temp. indic.	Elect. or mech. malfunction	No direct impact on operation. Unable to detect Low temp. condition in RMWT. Possible undetected freezing of RMWT	Periodic test	None	
341)	Reactor Makeup Water Tank, RMWT	a) external leakage	Mfg. defect, mech. damage	Loss of RMW inventory loss of makeup capability	Lo-Lo level alarms from LIC-210	Isolate RMWT and repair	Reactor shutdown might be required
342)	RMWT Isolation Valve; CH-771	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate RMWT for maint.	Operator	RMWP isolation valves can be closed	
		b) fails closed	Mech. failure	Unable to provide RMWT flow after maintenance	Operator	None	
343)	RMWP Isolation Valves; CH-772, CH-776, CH-773, CH-778	a) fails open	Mech. failure	No impact on normal operation. Unable to isolate RMWP for maint.	Operator	Check valves CH-775 for valve CH-776, and check valve CH-777 for valve CH-778	Two sets of isolation valves, suction and discharge, for the two RMWPs
		b) fails closed	Mech. failure	Unable to restore RMWP to service after maint	Operator	Redundant RMWP	

Table 9.3.4-3
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CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
344)	Reactor Makeup Water Pumps; RMWP 1, RMWP 2	a) fails to start	Loss of power, elect. failure, mech. failure	Unable to provide makeup water to VCT or to makeup water headers	Low pres. alarms from pump discharge pres. indic.	Redundant RMWP	A low flow downstream FQRC-210X will stop automatic makeup operations.
		b) operating pump stops	Same as above	Loss of RMW flow to VCT or makeup water headers	Same as above	Redundant RMWP	
		c) standby pump starts up	Spurious signal, elect. malfunct.	Sudden increase (or start) of RMW flow. Excess usage of RMW, possible deboration of RCS	Hi pres indic. from pump discharge pres. indic Hi flow indic. from RMW flow indic. Possible high VCT level alarm.	FQRC-210X will modulate valve CH-210X to maintain proper flow to VCT or RCS, operator can manually stop pump	Normally this failure in the makeup controller would cause both RMWP & BAMP's to start which would maintain proper boron concentration in VCT
345)	RMWP Discharge Pressure Indicators; PI-208, PI-209	a) spurious Lo pres. indic. or alarm	Elect. or mech. malfunct. setpoint drift	RMWP will be stopped on spurious Lo discharge pres. loss of RMW flow. Possible over boration of RCS	Lo pres alarm from pres. indic.	Redundant RMWP	Same as 339 a)
		b) false normal pres indic.	Elect. or mech.	No impact on normal operation. Failure to detect pump degradation and trip pump	Periodic test. Lo flow indic. from FQRC-210X	Operator can manually trip pump and start redundant pump	
346)	RMWP Discharge Check valves CH-775, CH-777	a) fails closed	Mech. failure blockage	Unable to initiate RMW flow. Possible damage to RMWP	High press. indic. from discharge pres. indic.	Redundant RMWP	
		b) fails open	Mech. binding	No direct impact on normal operation. Possible reverse flow thru standby pump	Possible low pressure indication/alarm from running pump	None	
347)	RMWP Recirculation Valves; CH-794, CH-140	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate RMWP for maint.	Operator	None	
		b) fails closed	Mech. failure	Loss of RMWP recirculation path. Possible pump damage if pump is deadheaded	Operator	None	
348)	Reactor Makeup Filter, RMWF	a) doesn't filter	Wrong element, "punch thru"	Possible buildup of contaminants in VCT, or makeup headers, or RCS	Local sampling, possible Lo Delta P indic. from PDI-261	Isolate and bypass filter for repair	
		b) plugged	Normal contaminant buildup	Loss of RMW flow. Possible over boration of RCS	High Delta P indic. from PDI-261. Low flow alarm FQRC-210X.	Isolate and bypass filter for maint	Automatic makeup operations will be secured on low flow from FQRC-210X

Table 9.3.4-3
(Sheet 69 of 71)
CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		c) external leakage	Cracked casing, seat leak on vent valve CH-783	Local spill of RMW	Local leak detectors	Isolate and bypass filter for maint.	
349)	RMWF Isolation Valves; CH-780, CH-792	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate filter for maint.	Operator	None	
		b) fails closed	Mech. failure	Unable to restore filter to service after maint	Operator	Filter can remain bypassed until valves repaired	
350)	RMWF Bypass Valve, CH-779	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to bypass filter for maint.	Operator	None	
		b) fails open	Mech. binding when open, seat leakage	Portion of RMW flow bypasses filter. Possible buildup of contaminants in VCT or RCS	Operator for mech. binding, otherwise none	None	
351)	RMWF Differen-tial Pressure Indicator; PDI-261	a) spurious Hi Delta P alarms	Elect. or mech. malfunction setpoint drift	Early maint. on RMW filter	Hi Delta P alarm not clear when bypass filter	None	
		b) false normal Delta P indications	Elect. or mech. malfunction	No impact on normal operation. Failure to detect filter degradation	Periodic test	Filter degradation can be detected by grad increase in RMWP discharge pres. indic.	
352)	RMWF Drain Valve, CH-791	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to drain filter for maint.	Operator	None	
		b) seat leakage	Contamina-tion, mech. damage	Minor diversion of RMW to EDT	EDT level increases	None	
353)	RMWT Recirculation Valve, CH-511	a) fails closed	Mech. binding, loss of air or power, valve operator failure	No impact on normal operation. Unable to recirculate RMWT contents	Valve position indic. in control room	RMWP recirculation lines can be used	
		b) fails open	Mech. binding, valve operator failure	Major diversion of RMW flow while providing makeup to VCT. Possible overboration of RCS	Valve position indic. in control room. Lo flow alarms from FQRC-210X	None	Automatic makeup operations will be secured or low flow from FQRC-210X
354)	Makeup Supply Header Check Valve; CH-795	a) fails closed	Mech. binding blockage	Unable to provide RMW to makeup supply or resin sluice supply headers	Hi pres. indic. from RMWP discharge pres. indic., no flow in headers	None	
		b) fails open	Mech. binding	No impact on operation	None	None	

Table 9.3.4-3
(Sheet 70 of 71)
CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
355)	Resin Sluice Supply Header Isolation Valves; CH-790, CH-799	a) fails closed	Mech. binding, blockage	Unable to provide RMW to resin sluice supply header	Operator	None	
		b) seat leakage	Contamination, mech. damage	Minor diversion of RMW from makeup supply header to resin sluice supply header	None	Resin sluice Isol. valves at individ. equip. will prevent flow	
356)	Resin Sluice Supply Header Flow Indicator, FI-249	a) indicates flow too high	Elect. or mech. malfunction	Operator will set resin sluice supply throttle valve too low, resulting in reduced RMW to air mix ratio in resin sluice supply. Possible difficulties in flushing ion exchangers	Periodic test	None	
		b) indicates flow too low	Elect or mech. malfunction	Operator will increase throttle valve setting increasing RMW to air mix ratio in resin sluice supply. Excess use of RMW, excess waste generation	Periodic test	None	
357)	Resin Sluice Supply Isolation Valve, CH-691	a) fails closed	Mech. failure	Loss of RMW supply to resin sluice supply header	Lo flow indic from FI-249	None	
358)	Resin Sluice Supply Check Valve, CH-692	a) fails closed	Mech. binding, blockage	Same as 357 a)			
		b) fails open	Mech. binding	Possible air bubble formation in RMW supply header or lines	None	Isolation valves CH-790, CH-799	
359)	Resin Sluice Supply to EDT Isolation Valve CH-762, CH-861	a) fails closed	Mech. failure, blockage	Unable to supply RMW to EDT for flushing or initial inventory or pump down EDT after high temperature relief dischg. to tank with this line.	Operator	Redundant valve and flushing line	
		b) seat leakage	Contamination mech. damage	Diversion of resin sluice supply water to EDT. EDT level increase. Possible EDT pres increase	EDT level and pres. indicators	CH-790 & 799 normally closed.	
360)	Resin Sluice Air Supply Check Valve CH-695	a) fails closed	Mech. binding blockage	Unable to supply air to mix with RMW for resin sluice supply. Excessive use of RMW when flushing ion exchangers. Excess waste generation	No flow indic. from FI-248	None	
		b) fails open	Mech. binding	No impact on normal operation. Possible leakage of RMW to air supply lines	None	Isolation/throttle valve, CH-694	

Table 9.3.4-3
(Sheet 71 of 71)
CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)
FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
361)	Resin Sluice Air Supply Isolation/ Throttle Valve; CH-694	a) fails closed	Mech. failure	Same as 360 a)			
		b) fails to throttle properly	Mech. binding	Unable to obtain desired air supply to resin sluice supply header. Improper water to air mix ratio	Operator	RMW throttle valve can be adjusted to get proper mix ratio	
362)	Resin Sluice Air Supply Flow Indicator; FI-248	a) indicates flow too high	Elect. or mech. malfunct.	Air supply valve will be closed resulting in too little air in resin sluice supply. Excess RMW usage. Excess waste generation	Periodic test	None	
		b) indicates flow too low	Elect. or mech. malfunct	Air supply valve will be opened, resulting in high air content in resin sluice supply. Possible difficulties in flushing ion exchangers	Periodic test	None	
363)	Charging Line Check Valve (CH-639)	a) fails open	Mech. binding	No impact on normal operation. Possible diversion of High press. chemical addition flow	None	Charging pump discharge check valves will prevent signif. diversion of HI pres. chem addition flow.	
		b) fails closed	Mech. binding, blockage	Same as 120 b)	Same as 120 b)	Same as 120 b)	
364)	High Pressure Chemical Line Isolation Valves; CH-659, CH-863	a) fails open	Mech. binding, seat leakage	Possible diversion of part of charging flow to High pres. chemical addition system	None	Series redundant isolation valves	
		b) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to establish HI pres chemical addition flow to RCS	Operator	None	

9.3.4.5 CESSAR Interface Requirements

Provided below are interface requirements, repeated from CESSAR Section 9.3.4.6, with the exception of the emergency power supply requirement for valve CHA-HV-524, as described in Section 9.3.4.1.A.2.c.

Below are the interface requirements that the CVCS places on certain aspects of the BOP, listed by categories. In addition, applicable General Design Criteria (GDC) and Regulatory Guides which C-E utilizes in its design of the CVCS are presented. These GDC and Regulatory Guides are listed only to show what C-E considers to be relevant, and are not imposed as interface requirements, unless specifically called out as such in a particular interface requirement.

Relevant GDC	- 1, 2, 3, 4, 26, 27, 28, 29, 30, 31, 32, 33, 54
Relevant Reg. Guides	- 1.26, 1.28, 1.29, 1.31, 1.36, 1.37, 1.44, 1.48, 1.51, 1.64, 1.68

A. Power

1. Normal Power Requirements

    a. Two independent power sources shall be available to provide electric power to the Chemical and Volume Control System equipment. Power shall be capable of being supplied from the main generator. During startup or shutdown, power shall be available from offsite.

    b. Within the plant distribution system, redundant chemical and volume control system equipment loads shall be supplied by separate buses or

motor control centers to minimize the effect of outages.

c. In the event of a failure of a bus, standby equipment connected to other buses shall be capable of being placed in operation.

2. Emergency Power Requirements

a. Charging Pumps - Each emergency power bus shall supply one pump. Additionally, the third charging pump shall be capable of receiving power from either emergency power bus. The charging pumps shall not be automatically sequenced on the emergency power buses.

b. The following are emergency power supply requirements for CVCS instrumentation:

Instrument	Control[(1)] Location	Emergency Bus
L-200 (RWT level)	A/C	A
L-201 (RWT level)	A/C	B
F-212 (Charging flow)	A/C	B
P-212 (Charging pressure)	A/C	A
L-203A (RWT RAS level)	A	A
L-203B (RWT RAS level)	A	B
L-203C (RWT RAS level)	A	C
L-203D (RWT RAS level)	A	D

c. The following are emergency power supply requirements for CVCS valves:

Valve	Emergency Bus	Control Location[1]
CH-515 (receives SIAS)	B	A/C
CH-516 (receives SIAS & CIAS)	A	A/C
CH-560 (receives CIAS)	A	A
CH-561 (receives CIAS)	B	A
CH-580 (receives CIAS)	A	A
CH-506 (receives CSAS)	A	A/C
CH-505 (receives CSAS)	B	A/C
CH-523 (receives CIAS)	B	A
CH-507	A	A/C
CH-530	B	A
CH-531	A	A
CH-203	B	A/Ct
CH-205	A	A/C
CH-255	B	A
CH-501	A[2]	A
CH-524	A	A[3]
CH-536	A[2]	A

Notes (1) Location code is as follows;
A-Control Room, B-Local,
C-Remote Shutdown Panel,
D-Location outside Control Room.

(2) Receives emergency power under LOP condition

(3) The power supply for valve CHA-HV-524 is removed by locking open its breaker at MCC PHA-M3520. Restoration of the power supply requires local operator action at the MCC before control from the main control room can be restored for the valve.

B. Protection from Natural Phenomena

1. The location, arrangement, and installation of the RWT, charging pump gravity feed piping, charging pumps, charging pump discharge piping, the letdown line between the RCS and letdown containment isolation valves, and Safety Injection Systems (SIS) trains suction piping shall be such that floods (and tsunami and seiches for applicable sites) or the effects thereof will not prevent them from performing their functions. The severity of the above natural phenomena to be considered, as well as the combination of the effects of these natural phenomena with the design conditions of ANSI N18.2-1973, shall meet the requirements of Criterion 2 of 10CFR50, Appendix A.

2. The location, arrangement and installation of the RWT, charging pump gravity feed piping, charging pumps, charging pump discharge piping, and letdown line between the RCS and letdown containment isolation valves, and SIS trains suction piping shall be such that winds and tornadoes or the effects

thereof will not prevent them from performing their functions. The severity of the winds and tornadoes to be considered, as well as the combination of the effects of these natural phenomena with the design conditions of ANSI N18.2-1973, shall meet the requirements of Criterion 2 of 10CFR50, Appendix A.

3. The location, arrangement, and installation of the RWT, charging pump gravity feed piping, charging pumps, charging pump discharge piping, and letdown line between the RCS and letdown containment isolation valves, and SIS trains suction piping shall be such that they will withstand the effects of earthquakes without loss of the capability to perform their functions. The severity of the earthquakes considered, as well as the combination of these natural phenomena with the design conditions of ANSI N18.2-1973, shall meet the requirements of Appendix A of 10CRF50, Appendix A of 10CFR100, and NRC Regulatory Guide 1.48. Failure of non-seismic systems and structures shall not cause loss of either SIS train.

C. Protection from Pipe Failure

The letdown subsystem (from the RCS coolant system), charging system (from valve CH-118 through the charging pumps to RCS to CH523), auxiliary spray, high pressure safety injection header, and drain header isolation valves (CH-329, 332, 3367) and boric acid addition system (including both of the Refueling Water Tank gravity feed connections to the charging pump suction header) the

connections from the refueling water tank to the suction of the safety injection system pumps, and the Refueling Water Tank and spent fuel pool connections to the charging pump suction header via the Boric Acid Makeup Pumps and valve CH-514 shall be protected from loss of function from the effects of pipe rupture, such as pipe whip, jet impingement, jet reaction, pressurization, or flooding.

D. Missiles

The portion of the CVCS protected from pipe failure (see 9.3.4.6.C) shall also be protected from loss of function from the effects of missiles in accordance with the missile barrier design interface requirement of Section 3.5.3.1.

E. Separation

1. Adequate physical separation shall be maintained: (1) between the normal charging line and the alternate charging line through the safety injection header; (2) between the two alternate gravity feed suction lines from the RWT to the charging pump suction header; (3) between the RWT via the boric acid makeup pumps supply direct to the charging pump suction header and the gravity feed lines from the RWT to the charging pump suction header; (4) between the charging pump control circuits, and (5) between the power circuitry to the charging pumps. A single failure due to a missile, structural damage, pipe failure, or fire shall not result in functional

impairment of more than one of these independent paths or channels.

2. The CVCS circuits which are associated with the redundant channels pertaining to boron addition, charging and letdown functions shall be physically separated to preserve redundancy and prevent interactions between channels. Associated circuit cabling from redundant channels shall either be separated, provided with isolation devices, or analyzed or tested to demonstrate that no credible single failure could adversely affect redundant channels of these circuits.

F. Independence

See electric power independence requirements in A.1. above.

G. Thermal Limitations

The ventilation system shall provide suitable ambient conditions for equipment and instrumentation: Temperature and relative humidity ranges for equipment and instrumentation shall be limited to those in Section 3.11.

H. Monitoring

Not Applicable

I. Operational/Controls

Not Applicable

J. Inspection and Testing

1. Refer to CESSAR Section 9.3.4.4 for inspection and testing requirements for the CVCS with the exception of the boric acid concentrator pumps, as noted in section 1.9.2.4.20.

K. Chemistry/Sampling

Not Applicable

L. Materials

1. Controls shall be exercised to assure that contaminants do not significantly contribute to stress corrosion of the stainless steel and welds, including welds at the CVCS boundaries.

2. Piping and components in contact with the CVCS fluid shall be fabricated of austenitic stainless steel, with the exception that the charging pump cylinder block assembly may be fabricated of martensitic stainless steel.

3. Care shall be taken to prevent sensitization and to control the delta ferrite content of (a) welds which join any system fabricated of austenitic stainless steel to the CVCS, and (b) the field welds on the CVCS.

M. System/Component Arrangement

1. The Reactor Drain Tank rupture disc shall be located beneath a concrete ceiling or foundation to help shield other components from rupture disc fragments which may result from disc rupture.

2. The CVCS shall be installed to permit access for inservice inspection in accordance with Section XI of the ASME code and testing of ASME Class 2 and 3 components.

3. Charging pump suction and discharge lines shall be designed to accommodate the pulsating flow from the reciprocating pump. Pulsations from each charging pump will occur at approximately 600 and 1200 pulses per minute. Pump suction pressure can vary by as much as 40 psi peak to peak with approximately half the pressure pulse occurring above and below the main pressure line. The pump discharge pressure can vary as much as 850 psi peak to peak; approximately 350 psi will occur above the normal operating pressure of 2485 psig and 500 psi below.

    a. The discharge piping shall be provided with restraints to minimize vibrations resulting from these pressure surges. Provisions shall be made for the installation of pump inlet and outlet pulsation dampeners in the event they are required. Suction and discharge pulsation dampeners should be directly coupled to the charging pump, no further than 5 feet away. Any piping between the pump and dampener shall be straight.

    b. Suction and discharge piping should be as straight as possible with at least 10 feet of straight pipe directly connected to the suction and discharge of the charging pump. When bends

are necessary, 45 degree elbows or long radius elbows shall be used. A bend shall not be installed directly adjacent to the pump.

c. The suction and discharge piping shall be arranged to preclude the collection of vapor or gas and inleakage of air must be prevented.

4. The location, arrangement and installation of the charging pump gravity feed piping, charging pumps, charging pump discharge piping, the letdown line between the RCS and letdown containment isolation valves, and SIS trains suction piping shall be such that internal floods or the effects thereof will not prevent them from performing their safety functions.

N. Radiological Waste

1. Tables 11.1.1-1, 11.1.1-2 and 11.1.1-3 shall be utilized in determining waste management system input from the CVCS.

O. Overpressure Protection

1. The RWT vent shall be sized to prevent pressurization of the RWT during maximum filling rate operations and to prevent vacuum formation during maximum pumpdown rate operations.

P. Related Service

1. The Refueling Water Tank shall be sized to:

a. Accommodate maximum safety injection flow (see table 6.3.3.3-1) and maintain it for at least 20 minutes before switchover to

recirculation mode, which shall occur at the 10% level in the RWT.

b. Provide sufficient volume for boric acid recycle for back to back shutdown (to 5 percent subcritical) and startup at 90 percent core life without boric acid concentrator processing.

c. Provide sufficient volume to fill the refueling pool.

d. Provisions shall be made so that particles larger than 0.09 inch diameter do not enter the Engineered Safety Feature pump suction lines.

2. The spent fuel pool shall provide an alternate source of borated water to the CVCS.

   a. A volume of 33,500 gallons shall be available to achieve cold shutdown at the end of core life (5 percent subcriticality with rods) assuming 4000 ppm boron within the fuel pool. Draining 33,500 gallons from the spent fuel pool shall not reduce the pool water level below the volume needed for minimum shielding requirements.

   b. The boric acid makeup pumps shall be able to take suction from the spent fuel pool.

3. A fire protection system shall be provided to protect the CVCS. It shall include, as a minimum, the following features:

   a. Facilities for fire detection and alarming.

b. Facilities or methods to minimize the probability of fire and its associated effects.

c. Facilities for fire extinguishment.

d. Methods of fire prevention such as use of fire resistant and non-combustible materials whenever practical, and minimizing exposure of combustible materials to fire hazards.

e. Assurance that fire protection systems do not adversely affect the functional and structural integrity of safety related structures, systems, and components.

f. Care should be exercised to ensure fire protection systems are designed to assure that their rupture or inadvertent operation does not significantly impair the capability of safety related structures, systems, and components.

g. Assurance that a fire will not cause failure in systems, structures, and components to the extent that radioactive releases to the environment will exceed the guidelines values of 10CFR100.

4. Redundant means shall be provided to maintain the RWT contents, interconnecting piping to the safety injection pump trains, instrumentation lines, and loop seal above the minimum operating temperature of 60F and below the maximum operating temperature of 120F. Ensuring that the Auxiliary Building, Annulus Building, and Containment Building ambient

temperatures remain between 60F and 120F during all normal reactor operations may be done to meet this requirement. All other RWT interconnecting piping, including the vent line, which is located outside of the auxiliary building shall be maintained at a minimum temperature of 40F to prevent freezing. Electric heaters installed in the RWT for tank heating will be used to meet this requirement.

5. Air for all CVCS pneumatic valve operators shall be clean, dry, and oil-free.

Q. Environmental

1. The CVCS shall be provided with an environmental control system such that the safety related equipment operates within the environmental design limits specified in Section 3.11.

R. Mechanical Interaction Between Components

1. Those portions of the CVCS that are part of the reactor coolant pressure boundary shall be designed to tolerate the events described in CESSAR Table 9.3-2.

S. The reactor makeup water tank (RMWT) overflow is routed to the holdup tank sump and on to the liquid radwaste system. As noted in response to NRC Question 11A.4, no provision has been made to contain the tank's contents in case of RMWT failure. The failure of RMWT is considered a low probability occurrence, which, when taken into consideration with the low radioactive contamination of the tank's contents, the existing design is acceptable.

9.3.4.6 CESSAR Interface Evaluation

The interface requirements listed in paragraph 9.3.4.1 are met by the PVNGS design as follows:

A. Power

1. Normal Power Requirements

    a. During normal operation, startup, or shutdown, power is supplied from the offsite (preferred) power supply. In the event of loss of the offsite (preferred) power supply, the charging pumps can be manually connected to the emergency diesel generator (refer to section 8.3).

    b. Within the plant distribution system, the CVCS equipment loads are supplied by separate buses or motor control centers to minimize the effect of outages with the exception of the two RWT heaters.

    The RWT heaters are powered through separate circuit breakers in a single motor control center fed from a single 480V load center. The tank contents are normally above 60F and redundant low temperature annunciation is provided in the main control room. The thick concrete tank wall construction, relatively mild Palo Verde climate, and large tank inventory combine to allow only very slow tank content temperature changes. Adequate time is available to restore heater power following

distribution equipment malfunction without concern for precipitation of tank contents.

c. In the event of a failure of a bus, standby equipment connected to other buses is placed in operation.

2. Emergency Power Requirements

a. Charging pumps - Each emergency power bus supplies one pump. Additionally, the third charging pump can receive power from either emergency power bus. The charging pumps are not automatically sequenced on the emergency power buses. However, should a pressurizer low level signal exist upon restoration of power, the standby charging pump whose breaker is set in the Auto After Stop position (designated standby charging pump) only will automatically start. If an SIAS should exist upon restoration of power, however, the automatic start will be delayed 40 seconds by a sequencer permissive signal. The requirement to preclude potential pump damage due to inadequate NPSH is met by a pressure switch which trips the pump on low suction pressure.

b. The following are emergency power supply arrangements for the CVCS instrumentation:

Instrument	Control Location[a]	Emergency Bus
CHA-LI-200 (RWT level)	A/C	A
CHA-LI-200-1 (RWT level)	A/C	A
CHB-LI-201 (RWT level)	A/C	B
CHB-LI-201-1 (RWT level)	A/C	B
CHB-FI-212 (Charging flow)	A/C	B
CHB-FI-212-1 (Charging flow)	A/C	B
CHA-PI-212 (Charging pressure)	A/C	A
CHA-PI-212-1 (Charging pressure)	A/C	A
CHA-LI-203A (RWT RAS level)	A	A
CHB-LI-203B (RWT RAS level)	A	B
CHC-LI-203C (RWT RAS level)	A	C
CHD-LI-203D (RWT RAS level)	A	D

a. Location code is as follows: A-control room, B-local, C-remote shutdown panel, D-location outside control room.

c. The following are emergency power supply requirements for CVCS valves:

Valve	Emergency Bus	Control[a] Location
CHB-UV515 (receives SIAS)	B	A/C
CHA-UV516 (receives SIAS and CIAS)	A	A/C
CHA-UV560 (receives CIAS)	A	A
CHB-UV561 (receives CIAS)	B	A
CHA-UV580 (receives CIAS)	A	A
CHA-UV506 (receives CSAS)	A	A/C
CHB-UV505 (receives CSAS)	B	A/C
CHB-UV523 (receives CIAS)	B	A

Valve	Emergency Bus	Control[a] Location
CHA-HV507	A	A/C
CHB-HV530	B	A
CHA-HV531	A	A
CHB-HV203	B	A/C
CHA-HV205	A	A/C
CH-255	B	A
CH-501	A	A
CH-524	A	A[b]
CH-536	A	A

a. Location code is as follows: A-control room, B-local, C-remote shutdown panel, D-location outside control room.

b. The power supply for valve CHA-HV-524 is removed by locking open its breaker at MCC PHA-M3520. Restoration at the power supply requires local operator action at the MCC before control from the main control room can be restored for the valve.

B. Protection from Natural Phenomena

1. Design provisions for maintaining functional capability of the RWT, the boron addition, charging, and letdown portions of the CVCS during the maximum probable flood or phenomena defined by GDC 2 are discussed in subsection 3.1.2. All of the boron addition, charging, and letdown portions are located in Seismic Category I structures. The RWT is also a Seismic Category I structure. The protection of Seismic Category I structures against natural phenomena is presented in sections 3.3, 3.4, 3.5, and 3.8.

2. The RWT is a concrete structure, seismically qualified for the PVNGS. In addition, the tank is designed to withstand the design wind and tornado forces. The rest of the CVCS system piping, valves, and equipment is located inside the auxiliary and containment buildings which are designed to withstand the wind and tornado forces as required.

3. The RWT is a Seismic Category I concrete structure, lined with an austenitic stainless steel liner. The charging, letdown, and SIS suction piping, as well as associated valves and charging pumps, are Seismic Category I pressure vessels constructed in accordance with ASME Section III, Class 2, requirements.

C. Protection from Pipe Failure

The letdown subsystem (from the RCS coolant system to CHB-UV523), charging system (from valve CHN-V118 through

the charging pumps to RCS), auxiliary spray, high-pressure safety injection headers, and charging pumps drain header isolation valves (CHA-V329, CHB-V332, CHE-V336), the RWT gravity feed connections to the charging pump suction header, the connections from the RWT to the suction of the safety injection system pumps, and the RWT and spent fuel pool connections to the charging pump suction header via the boric acid makeup pumps and valve CHN-UV514 are protected from loss of function from the effects of pipe rupture, such as pipe whip, jet impingement, jet reaction, pressurization and flooding. Refer to section 3.6.

D. Missiles

The portion of the CVCS protected from pipe failure (see paragraph 9.3.4.2, listing C) is also protected from loss of function from the effects of missiles in accordance with the missile barrier design interface requirement of paragraph 3.5.4.1.

E. Separation

1. Adequate physical separation is provided and maintained between the normal charging line and the alternate charging line through the safety injection header, between the alternate gravity fed suction lines from the RWT to the charging pumps (suction lines from the RWT via the boric acid makeup pump and the gravity fed lines from the RWT to the charging pump suction), between the charging pump control circuits, and between the power channels provided to the charging pumps. A single failure due to a

missile, structural damage, pipe failure, or fire will not impair the function of more than one of these independent paths or channels. See paragraph 8.3.1.4 for a discussion on channel separation.

2. The CVCS circuits that are associated with redundant channels pertaining to boron addition, charging, and letdown functions are physically separated to preserve redundancy and to prevent a single event from causing multiple channel malfunctions or interactions between channels. Associated circuit cabling from redundant channels is either separated, provided with isolation devices, or analyzed and/or tested to demonstrate that no credible single failure could adversely affect redundant channels of these circuits as discussed in paragraph 8.3.1.4.

F. Independence

Two independent power sources are available to provide electric power to CVCS equipment (see sublisting A.1 above).

G. Thermal Limitations

1. The ventilation systems are designed in accordance with CESSAR Section 3.11 to maintain the ambient conditions in the auxiliary building between 50 and 104F, and in the containment building between 50 and 120F, under normal operating conditions (refer to section 9.4).

2. Following a loss-of-coolant accident, including the subsequent recirculation mode of operation, the ambient air conditions of the CVCS equipment located in the auxiliary building are controlled in accordance with the requirements of section 3.11.

H. Monitoring

Not applicable

I. Operational controls

Not applicable

J. Inspection and Testing

1. Inspection and testing requirements for the CVCS are given in the Technical Requirements Manual (TRM) and comply with CESSAR Chapter 16.

K. Chemistry/Sampling

Not applicable

L. Materials

1. The insulation used on austenitic stainless steel is discussed in subsection 5.2.3. Cleaning and contamination procedures are also discussed in subsection 5.2.3. Conformance to Regulatory Guides 1.36 and 1.37 is discussed in sections 6.1 and 1.8, respectively.

2. Piping and components in contact with the CVCS fluid are fabricated of austenitic stainless steel, with the exception that the charging pump cylinder block

assembly may be fabricated of martensitic stainless steel.

3. Using the guidance of Regulatory Guides 1.44 and 1.31 as discussed in section 1.8, care is taken in preventing sensitization and in controlling the delta ferrite content of: (a) welds that join any system fabricated of austenitic stainless steel in the CVCS, and (b) field welds on the CVCS (refer to subsection 5.2.3).

M. System/Component Arrangement

1. The reactor drain tank rupture disc is located about 3.5 feet underneath a concrete ceiling. This location helps to shield other components from rupture disc fragments, which may result from disc rupture.

2. The CVCS is installed to permit access for inservice inspection in accordance with Section XI of the ASME Code and testing of ASME Class 2 and 3 components.

3. Charging pump suction and discharge lines are designed to accommodate the pulsating flow from the reciprocating positive displacement pumps, with pulsations occurring at 600 and 1200 pulses per minute.

   a. The discharge piping is provided with restraints to minimize vibrations from the pump pulsation, and from pressure surges ±50 psi, which are the resultant pressure surges with installed pulsation dampeners. The suction and discharge

pulsation dampeners are installed in the immediate vicinity of the charging pumps, with only short, straight pieces of pipes enabling inservice inspection of the welds and facilitating pipe supports.

b. The suction and discharge piping is installed as straight as possible. The plant layout does not allow installation of 10 straight feet of suction and discharge pipes. To compensate for this, pipe bends in the suction piping are 5d bends and elbows in the discharge piping are long radius elbows.

c. Charging pump suction and discharge piping is arranged to preclude collection of vapor or gas in the piping. Should any air be present in the pump suction piping, it would collect in the suction pulsation dampener, from whence it can be periodically purged. In addition, all piping is provided with high-point vents to facilitate purging the system after prolonged shutdowns.

4. Protection is provided from internally generated flooding that could prevent performance of safety-related functions. Refer also to section 3.6 and subsection 9.3.3.

N. Radiological Waste

1. CESSAR Tables 11.1.1-1, 11.1.1-2, and 11.1.1-3 are utilized in determining waste management system input from the CVCS.

O. Overpressure Protection

1. The RWT vent is sized to prevent pressurization of the tank during maximum filling rate operations and to prevent vacuum formation during maximum pumpdown rate operations.

P. Related Services

1. The RWT is sized to:

   a. Ensure that a sufficient volume of borated water will be available to sustain two trains of ECCS and CSS pump flow for the duration of the injection period as assumed in the safety analyses.

   b. Provide sufficient volume for boric acid recycle for back-to-back shutdown (to 5% subcritical) and subsequent startup at 90% core life without boric acid concentrator processing.

   c. The RWT provides sufficient volume to fill the refueling pool.

   d. The engineered safety feature pump suction lines are provided with strainers that prevent particles larger than 0.09-inch diameter from entering the engineered safety feature pumps.

   e. The RWT suction is designed to prevent vortexing by the use of an appropriately designed suction strainer.

2. The spent fuel pool provides an alternate source of borated water to the CVCS.

    a. A minimum of 33,500 gallons is available. The associated reduction in spent fuel pool water level (less than 4 feet) will not appreciably reduce shielding of stored fuel.

    b. The boric acid makeup pump can be realigned to take suction from the spent fuel pool.

3. The fire protection system for the CVCS is discussed in subsection 9.5.1.

    a. Facilities for fire detection and alarming are provided in the auxiliary building where CVCS components are located.

    b. The probability of a disabling fire is minimized by compartmentation, which confines the fire and its associated effect to a limited area.

    c. The plant is equipped with multiple facilities for fire extinguishment. For details, refer to subsection 9.5.1.

    d. The probability of fire is minimized by selection of fire-resistant materials and by minimizing the quantities of combustibles.

    e. The fire protection system and piping have been designed to assure adequate separation from the safety-related components. The building/room draining capability assures that the flood water level, due to a single active failure of the

fire protection lines, would not impair the functioning of the safety-related components.

f. In addition to design features explained in sublisting P.3.e above, the drain systems are designed to mitigate the consequences of inadvertent activation of the fire protection systems.

g. A fire will not cause failure in systems, structures, and components to the extent that radioactive releases to the environment would exceed the guideline values of 10CFR100.

4. The RWT interconnecting piping to the safety injection pump trains, the gravity feed line to the charging pumps, instrumentation lines, and loop seal will be maintained at a minimum temperature of 60F by redundant heat tracing, powered from two redundant power sources. Redundant electric heaters installed inside the tank, powered from a common MCC, assure the minimum tank water temperature of 60F. As noted in the response to Question 6A.51, vent lines from the RWT are not heat-traced since the vent is located in the uppermost portion of the tank. The vent pipes are routed without piping pockets that could cause the accumulation of moisture. As the design winter ambient temperature at PVNGS is 25F for 24 hours, plugging of the RWT vent is considered very improbable.

Q. Environmental

1. The CVCS is provided with an environmental control system such that the safety-related equipment operates within the environmental qualification parameters specified in Appendix A of the Equipment Qualification Program Manual, as discussed in section 9.4.

R. Mechanical Interaction Between Components.

1. The portions of the CVCS that are part of the reactor coolant pressure boundary are designed to tolerate the events described in CESSAR Table 9.3-2.

9.3.5 STANDBY LIQUID CONTROL SYSTEM (BWRs)

This section is not applicable to PVNGS.

9.3.6 COMPRESSED GAS STORAGE SYSTEMS

Compressed gas storage is provided for nitrogen (N_2), hydrogen (H_2), carbon dioxide (CO_2), air, and Halon 1301. Refer to subsection 9.5.1 for the description, safety design bases, and safety evaluation of the CO_2 and Halon 1301 storage subsystems. Subsection 10.3.2 provides a description of the N_2 accumulators for the atmospheric dump valves and safety design bases and evaluations. Compressed air system descriptions, safety design basis, and safety evaluations are provided in subsections 9.3.1 and 9.5.6. Also refer to the PVNGS response to NRC Question 15A.55 contained within appendix 15A.

9.3.6.1 Safety Design Bases

The following safety design bases are applicable to the N_2 and H_2 storage:

A. Safety Design Basis One

The N_2 and H_2 storage subsystems shall be designed and located such that a tank rupture will not adversely affect any system, component, or structure required for safe shutdown.

9.3.6.2 Compressed Gas Storage System Description

9.3.6.2.1 Nitrogen Storage Subsystem

The nitrogen storage subsystem provides nitrogen for use as a pressurized gas blanket in various plant components and systems, as shown in the system P&IDs 01, 02, 03-M-GAP-001 and -002. Design parameters of the subsystem are provided in table 9.3-11.

9.3.6.2.2 Hydrogen Storage Subsystem

The hydrogen storage subsystem provides hydrogen for use as part of an oxygen-free gas blanket in various plant components and systems, as shown in engineering drawings 01, 02, 03-M-GAP-001, -002 and 01, 02, 03-M-GHP-001. Design parameters of the subsystem are provided in table 9.3-11.

The following protective measures are considered in the design to prevent fires and explosion during operation:

- The bulk storage system is located outdoors, away from any ignition sources. The distribution piping is of all-welded construction, and verified leaktight.

- To avoid producing an explosive mixture in the turbine-generator casing during the hydrogen fill or removal evaluation, carbon dioxide is used to purge air or hydrogen, respectively.

9.3.6.3 Safety Evaluation

The following safety evaluation is applicable to N_2 and H_2 storage:

A. Safety Evaluation One

The N_2 and H_2 storage subsystems are located north of the turbine building, outside of any plant structure.

Due to their location, the tank rupture energy release, noted in table 9.3-11, is not sufficient to adversely affect any system, component, or structure required for safe shutdown.

9.3.6.4 Tests and Inspections

No regularly scheduled periodic testing is done on this system. Containment penetration piping and isolation valves are examined for inservice inspection as described in section 6.6.

Table 9.3-11
COMPRESSED GAS STORAGE

Gas	Quantity of Vessels	Applicable Codes	Location in Plant	Pressures (psig)			Energy Release (Max) per vessel	Deviation From Codes
				Design	Operating	Maximum		
N_2	8 cylinders per unit, each 8350 std	ASME, OSHA, DOT	Outside	2450	2400	**2400**	$4.84 \times 10^7 \frac{\text{ft} - \text{lbf}}{\tan k}$	None
N_2	1 liquid N_2 tank, 3200 gal, per unit	ASME OSHA, DOT	Outside	245	245	**245**	$3.77 \times 10^7 \frac{\text{ft - lbf}}{\text{tank}}$	None
N_2[(a)]	6 cylinders per unit, each 1.7std ft^3	ASME, OSHA, DOT	Outside	2450	2400	**2400**	$1.13 \times 10^6 \frac{\text{ft - lbf}}{\text{tank}}$	None
H_2	14 vessels per unit 8932 std ft^3 vessels	ASME, OSHA, DOT,	Outside	2450	2400	**2400**	$4.72 \times 10^7 \frac{\text{ft - lbf}}{\text{tank}}$	None

Plant design can accommodate the failure of any of the above vessels or parts of vessels without jeopardizing nuclear safety.

(a) These nitrogen cylinders are now functionally retired because the ADV acculultor tanks capacity have been increased.

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9.4 AIR CONDITIONING, HEATING, COOLING AND VENTILATION SYSTEMS

Heating, ventilation, and air conditioning (HVAC) systems are provided as required throughout each unit for personnel comfort, personnel safety protection, and equipment functional protection.

The HVAC systems provided for each building or room are designed for the specific functional requirements of that individual building or room.

For those buildings and rooms required for functional use during all plant operating modes (normal, shutdown, emergency), two separate HVAC systems are provided (although some essential ducting is shared):

- Individual system for normal operation
- Individual system for emergency (essential) operation

For the essential system, redundant Seismic Category I trains are provided.

The meteorological conditions used as a basis for the design of the HVAC systems are listed in table 9.4-1 and in section 2.3. The design temperatures for each building, room, or area are provided in table 9.4-2. These temperatures are designated as "enveloping" because the maximum and minimum allowable temperatures are listed in the table. For areas serviced by normal and essential cooling systems, the enveloping temperatures cover the entire range of allowable temperatures with either cooling system in operation. For the containment building, the enveloping temperatures cover all modes of

operation with the normal cooling system in service. Essential containment cooling and heat removal are discussed in Section 6. In certain rooms, a transient temperature higher than the enveloping temperature is allowed for brief periods. A summary of the individual HVAC systems' equipment performance data and design details is tabulated in table 9.4-3.

This Section, 9.4, should be used in conjunction with Appendix A of the Equipment Qualification Program Manual. Appendix A of the Equipment Qualification Program Manual provides additional design information that must be considered when discussing HVAC performance and design parameters.

Table 9.4-1
OUTSIDE DESIGN CONDITIONS

Item	Parameter
Duration of design temperature, yearly percent	0.5% & 0.6%[a]
Summer design temperature[a] normal HVAC systems	113F (db) and 76F (wb)
Winter design temperature[a]	28F db
Winter minimum temperature	11F db
Elevation	950 ft msl
Average wind velocity	7 mi/h

a. Outside design temperatures are based on 0.5% summer design temperature (43.8 h/yr) and 0.6% winter design temperature (52.5 h/yr) for all HVAC systems, normal and essential. From ASHRAE Recommended Outdoor Design Temperatures for Buckeye, Arizona, 1972.

AIR CONDITIONING, HEATING, COOLING,
AND VENTILATION SYSTEMS

9.4.1 CONTROL BUILDING

The control building HVAC systems include an essential HVAC system and a normal HVAC system. Both HVAC systems, essential and normal, are provided for the following two areas:

- Control room, computer room, and associated rooms at elevation 140 feet
- Engineered safety features (ESF) switchgear, ESF equipment rooms, and battery rooms

Without ventilation, temperatures in the ESF air handling units' room will be less than 96F. Essential equipment in these areas is qualified to this limit.

The HVAC system for the upper and lower cable spreading rooms operates in the normal mode only, and is included as a part of the normal HVAC system of the ESF switchgear, ESF equipment rooms, and battery rooms. Without ventilation, temperatures in the upper and lower cable spreading rooms will be less than 105F. Essential equipment in these areas is qualified to this limit.

9.4.1.1 Essential HVAC System -- Control, Computer, and Associated Rooms

The essential (safety-related) HVAC system, as well as the habitability systems for the control room, are discussed in section 6.4.

Table 9.4-2
ENVELOPING DESIGN TEMPERATURES[c]

HVAC System	Interior Temperatures Maximum (F)	Interior Temperatures Minimum (F)
Control room	80[a][d]	70
Computer area	80[a][d]	70
ESF switchgear	104	40
ESF equipment rooms	104	60
Battery rooms	85	60
Cable spreading	122	40
Auxiliary building (excluding ESF equipment room and access control area)	104[b]	50
Access control area	80	70
ESF pump rooms	104	50
Containment building	120	50
Fuel building	104	50
Radwaste building	104	50
Turbine building		
Below operating deck	122	50
Above operating deck	122	40
Diesel generator building		
Diesel generator room	140	50
Diesel generator control room	122	39
Essential spray pond pump house	122	32

a. Relative humidity 40% to 60%

b. During a normal plant shutdown, the shutdown heat exchanger rooms and adjacent valve galleries shall be maintained at a maximum temperature of 122F

c. Refer to Appendix A of the Equipment Qualification Program Manual for additional information regarding the areas, rooms and buildings that are listed in this Table. Some of the HVAC systems that are listed, such as the ESF pump rooms and ESF equipment rooms, may have specific areas within that particular system's boundary that have design values which are more restrictive than the design values that are listed in this Table.

d. Maximum temperature for Rooms J-307, J-308, J-313/314, J-315/J-316, and J-318 (non-essential occupancy rooms within Control Room envelope) is 90°F

Table 9.4-3
HVAC SYSTEMS -- SUMMARY OF EQUIPMENT PERFORMANCE
DATA AND DESIGN DETAILS (Sheet 1 of 6)

Equipment Tag No.	Area or Location	Operational Mode: Normal	Operational Mode: Essential	Type Systems	Heat Load(a) (Btu/h)	Flowrate/Unit (a): Air (ft^3/min)	Flowrate/Unit (a): Cooling Water (gal/min)	No. Units % Capacity	Power Supply	Equipment Listing	Water Source	Water Makeup
AO-M-HPN-F01	Containment - essential		X	Hydrogen purge	N/A	50	N/A	1/100	Emergency trains	Demister, HEPA charcoal filters: (backup for recombiner)	-	-
HCN-A01-A, B, C, & D	Containment - normal	X		Cooling	10.2×10^6	80,000	690	4/50	Normal 120V & 460V	Cooling coil, fan, heater	Normal chilled water	-
HCN-F01-A&B		X		Power access filter	-	15,000	-	2/50	Normal 120V & 460V	HEF, HEPA, charcoal, fan	-	-
CPN-A01	Containment purge	X		Purge-supply refueling	1.28×10^6	30,000	171	1/100	Normal 120V & 460V	OIF, cooling coil, fans (2), heater	Normal chilled water	-
CPN-A02	Containment power purge			power access	6.07×10^6	2,000	8.1	1/100	Normal 120V & 460V	MEF, HEF, cooling coil, heater, fan	-	-
CPN-J01-A&B	Containment refueling exhaust	X		Purge-exhaust refueling fan	-	30,000	-	2/100	Normal 120V & 460V	Fans (2)		
CPN-J02	Containment power purge exhaust			power access filter fan	-	2,000	-	1/100	Normal 120V & 460V	Heating coil, fan, MEF, HEPA, and charcoal filters		
HCN-A02-A&B	CEDM	X		CEDM cooling	3.1×10^6	94,200	400	2/100	Normal 120V & 460V	Cooling coil, fan	NCWS	-
HCN-A03-A,B,C,&D	Containment reactor cavity	X		Cavity cooling	-	23,000	-	4/50	Normal 120V & 460V	Fan	-	-
HCN-A04	Tendon gallery (supply)	X		Outside air supply	-	5,000	-	1/100	Normal 120V & 460V	Fan	-	-
HCN-J01	Tendon gallery exhaust			exhaust	-	5,500	-	1/100	Normal 120V & 460V	Fan	-	-
HCN-A05-A&B	MSSS MSSS and containment main steam and feedwater penetrations	X		Outside air supply	-	32,400	-	2/100	Normal 120V & 460V	OIF, Fan	-	-

Legend: MEF – Moderate efficiency filter
HEF – High efficiency filter
OIF – Oil impingement filter

Table 9.4-3
HVAC SYSTEMS -- SUMMARY OF EQUIPMENT PERFORMANCE
DATA AND DESIGN DETAILS (Sheet 2 of 6)

Equipment Tag No.	Area or Location	Operational Mode		Type Systems	Heat Load[a] (Btu/h)	Flowrate/Unit [a]		No. Units % Capacity	Power Supply	Equipment Listing	Water Source	Water Makeup
		Normal	Essential			Air (ft^3/min)	Cooling Water (gal/min)					
HCN-J02 HCN-J03	Main steam and feedwater penetrations to the turbine building	X		Exhaust	-	6,400	-	1/100 per side	Normal 120V & 460V	Fan	-	-
HAN-A01-A&B	Auxiliary building - normal ventilation ESF equipment, access control facility, and mechanical and electrical room	X		Outside air supply	-	29,200	-	2/50	Normal 120V & 460V	Dust filter, air washer, fan	Domestic water	
HAN-J01-A&B		X		Exhaust	-	30,000		2/50	Normal 120V & 460V	HEF, HEPA, HEPA & fan charcoal filters	-	
HAN-Z02-A&B	Aux. bldg. CEDM controller rooms elev. 120'	X		Recirculating ACU	531,562[b]	10,000	70	2/100	Normal 120V & 460V	Cooling coil, fan	Normal chilled water	-
HAN-A02	Aux. bldg. access control area elev. 140'	X		Multizone air handling	374,800[b]	17,250	70	1/100	Normal 120V & 460V	Cooling coil, heating coil, fan	Normal chilled water	-
HAA(B)-Z01	Aux bldg. HPSI pump room		X[b]	Recirculating ACU	260,260[b]	5,500[b]	45[b]	2/100	Emergency Trains: A&B	Cooling coil, fan	Essential chilled water	-
HAA(B)-Z02	LPSI pump room		X[b]	Recirculating ACU	148,949[b]	3,100[b]	25[b]	2/100	A&B	Cooling coil, fan	Essential chilled water	-
HAA(B)-Z03	CS pump room		X[b]	Recirculating ACU	221,978[b]	4,600[b]	40[b]	2/100	A&B	Cooling coil, fan	Essential chilled water	-
HAA(B)-Z05	ECW pump room		X[b]	Recirculating ACU	212,326[b]	4,400[b]	35[b]	2/100	A&B	Cooling coil, fan	Essential chilled water	-
HAA-Z04	Turbine driven aux. feedwater pump room		X[b]	Recirculating ACU	246,064[b]	5,200[b]	45[b]	1/100	A	Cooling coil, fan	Essential chilled water	-
HAA-Z06	ESF electrical penetration room west, elev. 120'		X[b]	Recirculating ACU	111,946[b]	2,300[b]	20[b]	1/100	A	Cooling coil, fan	Essential chilled water	-
HAN-Z01-A, B, &C	Charging pump rooms elev. 100'	X		Recirculating ACU	54,450	1,100	10	3/100	Normal 120V & 460V	Cooling coil, fan	Normal chilled water	-

Table 9.4-3
HVAC SYSTEMS -- SUMMARY OF EQUIPMENT PERFORMANCE
DATA AND DESIGN DETAILS (Sheet 3 of 6)

Equipment Tag No.	Area or Location	Operational Mode		Type Systems	Heat Load(a) (Btu/h)	Flowrate/Unit (a)		No. Units % Capacity	Power Supply	Equipment Listing	Water Source	Water Makeup
		Normal	Essential			Air (ft^3/min)	Cooling Water (gal/min)					
HAB-Z06	ESF electrical penetration room east, elev. 100’		X(b)	Recirculating ACU	92,900 (b)	1,900(b)	16(b)	1/100	Emergency Train B	Cooling coil, fan	Essential chilled water	-
HAB-Z04	Motor driven aux feedwater pump room elev. 70'		X(b)	Recirculating ACU	246,064 (b)	5,200(b)	45(b)	1/100	Emergency Train B	Cooling coil, fan	Essential chilled water	-
	Elevation 140' except access control area	X			181,023	4,406			Normal 120V & 460V	Supplied from normal auxiliary building ventilation system		
	Elevation 120'	X			893,927	10,700			Normal 120V & 460V	Supplied from normal auxiliary building ventilation system		
	Elevation 100' except charging pump rooms	X			295,753	10,000				Supplied from normal auxiliary building ventilation system		
	Elevation 88'	X			189,248	4,350				Supplied from normal auxiliary building ventilation system		
	ECW chemical addition tank and pump room elev. 70'	X			10,230	800				Supplied from normal auxiliary building ventilation system		
	Elevation 70'	X			248,707	7,300				Supplied from normal auxiliary building ventilation system		
	Elevation 51' -6” and 40'	X			142,776	5,050				Supplied from normal auxiliary building ventilation system		
HAN-J02-A, B, & C	Laboratory fume hood exhaust fans	X		Exhaust fan		1,565		3/100	Normal 120V & 460V	Fan		

Table 9.4-3
HVAC SYSTEMS -- SUMMARY OF EQUIPMENT PERFORMANCE
DATA AND DESIGN DETAILS (Sheet 4 of 6)

Equipment Tag No.	Area or Location	Operational Mode		Type Systems	Heat Load[a] (Btu/h)	Flowrate/Unit [a]		No. Units % Capacity	Power Supply	Equipment Listing	Water Source	Water Makeup
		Normal	Essential			Air (ft^3/min)	Cooling Water (gal/min)					
HAN-J03	Laboratory spectrophotometer exhaust fan	X		Exhaust fan		1,250		1/100	Normal 120V & 460V	Exhaust fan		
HRN-A01-A&B	Radwaste building	X		Outside air supply		23,800	-	2/50	Normal 120V & 460V	filter, evaporative cooling pad, pump, and, fan	Domestic water	5 gal/m/ washer
HRN-E01-A&B		X		Heating	1,706,450		-	2/50	Normal 120V & 460V	Electric heater	-	-
HRN-J01-A&B		X		Exhaust filter	-	25,500	-	2/50	Normal 120V & 460V	HEF, HEPA filters, fan	-	-
HRN-A02		X		Control room	78,000	3,350	15	1/100	Normal 120V & 460V	MEF, cooling coil fan, duct heater	Normal chilled water	
HFN-A01-A&B	Fuel building	X		Outside air supply		39,600	-	2/50	Normal 120V & 460V[1]	Oil impingement filter, air washer, and fan[2]	Domestic water	5 gal/m/ cooler[3]
HFN-E01-A&B		X		Heating	720,122		-	2/50	Normal 120V & 460V	Electric heater	-	-
HFN-J01-A&B		X		Normal exhaust	-	23,000	-	2/50	Normal 120V & 460V	Fan	-	-
HFA(B)-J01			X	Exhaust filter	-	6,000		2/100	Emergency trains A & B	Heater, HEF, HEPA filter, charcoal adsorber, HEPA filter, fan	-	-
HJA(B)-F04	Control building Control room – essential		X	Cooling & filtration	1,027,686	28,600	107	2/100	Emergency trains A & B	HEF, HEPA, charcoal filters, HEPA, cooling coil, fan	Essential chilled water	-
HJN-A02	Control room – normal	X		Air handling	999,662	29,900	127	1/100	Normal 120V & 460V	HEF filters, cooling coil, fan (2/100)	Normal chilled water	-

(1) 120V only for trains where DMWO 3144423 has been implemented.

(2) The oil impingement filter has been removed for trains where DMWO 3144423 has been implemented.

(3) 6 gal/m/cooler for trains where DMWO 3144423 has been implemented.

Table 9.4-3
HVAC SYSTEMS -- SUMMARY OF EQUIPMENT PERFORMANCE DATA AND DESIGN DETAILS (Sheet 5 of 6)

Equipment Tag No.	Area or Location	Operational Mode		Type Systems	Heat Load(a) (Btu/h)	Flowrate/Unit (a)		No. Units % Capacity	Power Supply	Equipment Listing	Water Source	Water Makeup
		Normal	Essential			Air (ft^3/min)	Cooling Water (gal/min)					
	Control room - normal (continued)	X		Heating	15 kW	-	-	1/100	Normal 120V & 460V	Electric heater (1/100)		-
HJN-A04	Outside air air	X		Outside air supply	-	4,800		1/100	Normal 120V & 460V	Air washer	Domestic water	2/gal/m
HJN-J03	Control building exhaust	X		Smoke exhaust	-	21,000		1/100	Normal 120V & 460V	Fan	-	-
HJN-J04		X		Kitchen exhaust	-	600	-	1/100	Normal 120V & 460V	Fan	-	-
HJN-J02		X		Toilet exhaust	-	400	-	1/100	Normal 120V & 460V	Fan	-	-
HJN-A03	Control building ESF switchgear	X		Air handling unit	600,000	18,000	80	1/100	Normal 120V & 460V	Cooling coil, fan	Normal chilled water	-
HJN-A01	ESF equip- ment, battery, & upper &	X		Air handling unit	1,271,504	27,000	160	1/100	Normal 120V & 460V	HEF, cooling coil, fans (2/50)	Normal chilled water	
HJN-J01-A,B, C,&D	lower cable spreading rooms - normal	X		Battery room exhaust	-	700	-	4/100	Normal 120V & 460V	Fans (one per room)	-	-
HJA-Z03	Control building Essential ESF switchgear,		X	Air handling	131,558	4,005	35	1/100	Emergency trains A & B	Cooling coil, fan	Essential chilled water	-
HJB-Z03	ESF equipment, & battery rooms		X	Air handling	128,494	3,980	35	1/100	Emergency trains A & B	Cooling coil, fan	Essential chilled water	
HJA(B)-Z04			X	Air handling	263,581	5,750	39	2/100	Emergency trains A& B	HEF, cooling coil, fan	Essential chilled water	-
HJA(B)-J01 A&B			X	Battery room exhaust	-	700	-	4/100	Emergency trains A & B	Fans (one per room)	-	-
HTN-A01-A, B, &C	Turbine building	X		Outside air supply	12×10^6	82,000		6/17	Normal 120V & 460V	Oil impingement filter, air washers, fan	Domestic water	10 gal/m/ washer
HTN-A02-A, B, &C		X				-	-	-	Normal 120V & 460V		-	-
HTN-J01-A, B,C,&D		X		Exhaust fan		95,500		4/25	Normal 120V & 460V	Fan		

Table 9.4-3
HVAC SYSTEMS -- SUMMARY OF EQUIPMENT PERFORMANCE
DATA AND DESIGN DETAILS (Sheet 6 of 6)

Equipment Tag No.	Area or Location	Operational Mode		Type Systems	Heat Load(a) (Btu/h)	Flowrate/Unit (a)		No. Units % Capacity	Power Supply	Equipment Listing	Water Source	Water Makeup
		Normal	Essential			Air (ft^3/min)	Cooling Water (gal/min)					
HTN-J02-A&B	Turbine building (continued)	X		Battery room exhaust	-	8,300	-	2/100	Normal 120V & 460V	Fan		
HTN-J03-A&B		X		Lube oil area normal exhaust	-	5,000	-	2/100	Normal 120V & 460V	Fan		
HTN-J04		X		Demineralizer	-	3,000	-	1/100	Normal 120V & 460V	Fan		
	Diesel generator building											
HDA(B)-J01	Diesel generator room		X	Vent fan	$2.29x10^6$/ unit	105,000	-	2/100	Emergency trains A & B	Fans (1 per diesel generator)		
HDN-A02-A&2C		X		Heating	15.0 kW	750	-	2/50	Normal 120V & 460V	Unit heater	-	-
HDN-J01-A&B		X		Vent fan	18,866	4,000		1/100	Normal 120V & 460V			
HDN-J03-A&B	Air compressor room	X		Exhaust fan	39,000	4,200	-	2/100	Normal 460V	Exhaust fan		
HDN-J02-A, B,C,& D	Day tank room	X		Exhaust fan	-	400	-	4/100	Normal 460V	Exhaust fan	-	-
HDA(B) -A01	Diesel generator control room		X	Supply fan	80,975	13,700		2/100	Emergency trains A & B	Fan & high efficiency filter (one per diesel generator control room)	-	-
HDN-J03-A&B		X		Supply fan	17,240	1,900		2/100	Normal 460V	Fan & high efficiency filter (one per diesel generator control room)	-	-
HSA(B)-J01	ESF pump house		X	Exhaust fan	$1.15x10^5$/ unit	20,000	-	2/100	Emergency trains A & B	Exhaust fan	-	-

a. The equipment performance data listed in this table is kept for historical purpose. For latest values, see applicable HVAC calculations.

b. These values are equipment manufacturer's rated performance. The equipment capacity of the essential cooling units is capable of maintaining the temperature in the ECW, LPSI, CS, HPSI, AFW pump rooms and the ESF electrical penetration rooms within their design basis temperature values.

9.4.1.2 Normal HVAC System -- Control, Computer, and Associated Rooms

The control room complex is located on elevation 140 feet 0 inch. The normal HVAC system provided for the control and computer room includes cooling by an air washer (evaporative) for the outside air supply which is common for the total control building and by a recirculating air conditioning system with cooling coils served by the normal chilled water system described in section 9.2.

Heating is provided by the use of electric zone heaters located in the supply air ducts.

9.4.1.2.1 Design Bases

9.4.1.2.1.1 Safety Design Bases. The normal HVAC system provided for the control and computer room has no safety design bases. Protection of the operator from radioactivity and poisonous gases is described in section 6.4. The isolation is treated as a part of the essential control room HVAC system.

The vital area in the control building is the control room (elevation 140 feet). This is the only area subject to ESF grade charcoal/HEPA filtration. Contamination of this area is prevented by pressurization (using filtered makeup air) to ¼-inch water gauge.

Dose rates due to noble gases in other areas of the control building will be approximately the same as in the control room, ignoring local shielding effects. Accordingly, access by operators into other areas of the control building will not be

unduly restricted by airborne dose, provided respiratory and facial protection is used. (Whole-body exposure to operators due to iodine is 1.3 rem over 30 days.)

Equipment qualification design bases considered the radiation dose from airborne activity in the building, as well as direct dose from the outside cloud and adjacent buildings.

Accordingly, a proper environment for operation of essential equipment has been provided.

9.4.1.2.1.2 Power Generation Design Bases. The normal HVAC system provided for the control and computer room complex has one power generation design basis:

A. Power Generation Design Basis One

The normal HVAC system shall supply conditioned air to the control and computer room during normal plant operating conditions to provide personnel comfort and to maintain a suitable operating environment for equipment.

9.4.1.2.1.3 Codes and Standards. The normal HVAC system provided for the control and computer room is designed in accordance with codes and standards set forth in table 3.2-1.

9.4.1.2.2 System Description

The control room normal HVAC system is shown schematically in engineering drawings 01, 02, 03-M-HJP-001,-002 and 02-M-HJP-003. Major components of the system include one air

conditioning unit, ductwork with associated controls, and dampers for supply, return, and outside air, one smoke exhaust fan, one kitchen exhaust, and one toilet exhaust fan.

The outside air preconditioning unit is shared with the normal air conditioning system for the remaining parts of the control building.

There are two outside air intakes located at opposite ends of the control building. The outside air passes through an air washer, which cools the air adiabatically and cleans it. The preconditioned outside air flows into the mixing box of the draw-through type air conditioning unit where it mixes with the return air from the control and computer room. This air conditioning unit contains a high efficiency filter, chilled water cooling coil, and fan which discharge the conditioned air into the supply air ductwork connecting the unit with the control and computer room air distribution system. Part of the supply air is returned from the control and computer room while the balance is exhausted to the atmosphere by the kitchen and toilet rooms exhaust fans.

In case of a local fire incident, smoke can be removed by use of portable smoke removal equipment. The existing smoke removal system in the control room building can be used to remove the smoke. Only portable equipment, however, is relied on for smoke removal capability.

9.4.1.2.2.1 System Components. The normal HVAC system is comprised of the following components:

A. Air Washer

The air washer utilizes finely sprayed water to provide for the adiabatic cooling of the outside air being supplied to the building. The air washer consists of a metal enclosure, banks of spray nozzles, moisture eliminators, sump, and pump. A moisture eliminator downstream of the spray chamber is used to remove entrained moisture particles from the air. Water for the air washer is supplied from the domestic water system as discussed in subsection 9.2.4.

B. High Efficiency Filter

High efficiency filter elements precede the chilled water cooling coils of the air handling unit to maintain a clean cooling coil surface for the air being processed. The filters measure 24 by 24 inches and the fiberglass filter medium is encased in stainless steel or coated carbon steel. The airflow capacity is 500 cubic feet per minute per filter element.

C. Water Cooling Coil

The cooling coils are of nonferrous construction with aluminum plate fins mechanically bonded to seamless copper tubing. Coils are arranged for counterflow, using chilled water. The tube bundle is enclosed in a steel frame. Coils are arranged for horizontal airflow

and include vent and drain connections. The chilled water system is discussed in subsection 9.2.9.

D. Fans

Fans are capable of delivering the design flowrate with all filters at their maximum anticipated pressure drop. Fans were chosen with a steeply rising pressure-flow characteristic to maintain a reasonably constant airflow over the full filter train life.

E. Kitchen and Toilet Exhaust Fans

Exhaust fans are axial type.

F. Heaters

Electric heating elements (installed in the ducts) are used to heat the room supply air.

9.4.1.2.2.2 System Operation. The normal air conditioning system operates during normal modes of operation. Outside air is mixed with recirculating air and filtered through a high efficiency filter, cooled to the required design temperature, and discharged into a duct system which distributes the air to the computer rooms, control room, cabinet areas, offices, conference room, instrument repair room, kitchen, and halls.

Zone electric duct heaters, controlled by zone thermostats, regulate the temperature of each zone.

Outside air is supplied to make up for air exhausted from the kitchen and toilet areas. In case of a major fire in the control or computer room, the operation will be transferred to

the remote shutdown panel from where the reactor may be shut down. Firefighting will be initiated and the portable smoke removal equipment will be used to remove the products of combustion and noxious fumes produced and exhaust them to the outside once the fire is under control. The existing smoke removal system can also be used to exhaust smoke. Only portable equipment, however, is relied on for smoke removal capability.

In the event of a fire in the computer room, the smoke detectors close the ventilating ducts to isolate the computer room and contain the smoke. Also, an alarm sounds in the main control room.

The exhaust air from the kitchen, men's and women's toilets, and janitor's room is exhausted through normal exhaust fans to the atmosphere.

The system is started manually and can be stopped manually. In case of emergency conditions, the normal HVAC system is automatically stopped and isolated at the same time that the essential HVAC system is activated.

9.4.1.2.3 Safety Evaluation

Since the control and computer room normal HVAC system has no safety design bases, no safety evaluation is provided.

9.4.1.2.4 Inspection and Testing Requirements

Acceptance testing of this system is performed to demonstrate proper system and equipment functioning.

9.4.1.3 Essential HVAC System -- ESF Switchgear, ESF Equipment Rooms, and Battery Rooms

9.4.1.3.1 Design Bases

9.4.1.3.1.1 Safety Design Bases. Safety design bases pertinent to the essential HVAC system supplying the ESF switchgear, ESF equipment rooms, and battery rooms are as follows:

A. Safety Design Basis One

The essential HVAC system, consisting of a separate HVAC train for each redundant train of the ESF switch-gear, ESF equipment rooms, and the battery rooms shall be designed to maintain the room temperature requirements listed in table 9.4-2, and to provide for the required ventilation and exhaust for the ESF battery rooms when operating during accident conditions.

B. Safety Design Basis Two

Failure of an active component of the essential HVAC system serving one train of the ESF switchgear, ESF equipment rooms, and battery rooms, simultaneously with a loss of offsite power, shall not result in the complete loss of any ESF system function.

C. Safety Design Basis Three

The essential HVAC system for the ESF switchgear, ESF equipment rooms, and battery rooms shall be designed to operate during and after a safe shutdown earthquake (SSE).

9.4.1.3.1.2 Power Generation Design Bases. The essential HVAC system for the ESF switchgear, ESF equipment rooms, and battery rooms has no power generation design bases.

9.4.1.3.1.3 Codes and Standards. The essential HVAC system for the ESF switchgear, ESF equipment rooms, and battery rooms is designed to the codes and standards identified in table 3.2-1.

9.4.1.3.2 System Description

The ESF switchgear rooms and battery rooms are located at elevation 100 feet 0 inch. The essential HVAC units are located on the 74-foot 0 inch and 100-foot 0 inch elevations of the control building.

The essential HVAC system for the ESF switchgear, ESF equipment rooms, and battery rooms is shown in engineering drawings 01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003.

Two redundant, physically separated, air conditioning systems are provided, one for each ESF equipment train.

Each train includes two air handling units. One unit is composed of a high efficiency filter, a chilled water cooling coil, fans, supply and return air ductwork, and the other unit is composed of a chilled water cooling coil, fans, and supply air duct work. All units will start with either a safety injection actuation signal (SIAS) or loss of offsite power.

The outside air supplied during emergency operation may carry airborne dust. The outside air intake filters are designed for

an average dust loading of 1.78 mg/m^3 with an average maximum dust concentration period of 30 days. This dust loading is based on reference 2.

The essential HVAC system is inactive during normal operation and thus is not exposed to the atmospheric dust.

Separate 100% capacity exhaust fans are provided for each battery room. The fans exhaust to the atmosphere in order to prevent any hydrogen buildup in the battery room.

There are four battery rooms and one essential exhaust fan for each room. There is a backdraft damper in each exhaust duct.

The battery room air is supplied through a transfer grille with a fire damper. The exhaust fans exhaust the air directly to the atmosphere.

9.4.1.3.2.1 Component Description. System components are described briefly as follows:

A. Air Handling Unit Housings

   The air handling unit housings are Seismic Category I and are of all-welded carbon steel construction.

B. High Efficiency Filters

   High efficiency filter elements precede the chilled water cooling coils in one unit in order to maintain the cooling efficiency of the coils. Filters are 24 by 24 by 12 inches in size, and the filter medium is encased in a fire-retardant frame. The airflow velocity is 250 feet per minute, nominal. The minimum

average efficiency is 85% based on the ASHRAE 52-68 test method.

C. Cooling Coil

The cooling coils are of seamless copper tubing with copper plate fins mechanically bonded to them. Coils are arranged for counterflow using chilled water. The tube bundle is enclosed in a steel frame. Coils are arranged for horizontal airflow and include vent and drain connections. The chilled water cooling coils are served by the essential chilled water system discussed in subsection 9.2.9.

D. Fans

Fans are Seismic Category I and are capable of delivering the design flowrate with all filters at their maximum anticipated pressure drop. Fans are chosen with a steeply rising pressure-flow characteristic to maintain a reasonably constant airflow over the full filter train life. Fan and motor materials are suitable for operation under the environmental conditions associated with the postulated design basis loss-of-coolant accident.

E. Ductwork

The system ductwork and dampers are Seismic Category I. Accessibility and adequate working space for maintenance and testing operations are provided in the design and layout of the system equipment.

F. Battery Room Essential Exhaust Fans

The battery room exhaust fans are of nonsparking, explosion-proof construction and are designed for the specific service intended. The fans are designed to Seismic Category I requirements.

9.4.1.3.2.2 System Operation. Upon receipt of an ESF system actuation signal, the essential ESF switchgear, ESF equipment, and battery room HVAC system is automatically put into operation. The normal HVAC system is isolated and ceases operation.

Transfer to the essential system may also be initiated manually from the control room. The following actions take place automatically when transferring to the essential system:

- Closing the isolation dampers
- Stopping the normal air handling unit
- Stopping each battery room's normal exhaust fan
- Stopping the normal outside air supply air washer
- Stopping the normal chilled water system
- Activation of both essential HVAC trains and their associated essential chilled water systems
- Starting the essential exhaust fans in the battery rooms

After automatic activation of both safety trains, one train may be taken out of service manually, if the ESF equipment train which it serves is not required to remain functional.

The recirculation fans draw air through prefilters, high efficiency filters, and the chilled water coils and discharge the air into the ESF switchgear rooms and the battery rooms. The essential exhaust fans exhaust the battery room air to the atmosphere.

The ESF equipment room air (obtained by circulation from the ESF switchgear rooms) is recirculated through the essential cooling trains. Outside air is brought in to make up for the battery room air exhausted to the atmosphere.

9.4.1.3.3 Safety Evaluations

Safety evaluations are numbered to correspond to the safety design bases in paragraph 9.4.1.3.1.1.

A. Safety Evaluation One

   The essential HVAC system for the ESF switchgear, ESF equipment rooms, and battery rooms is capable of filtering and cooling the air supplied to the rooms under accident conditions, of maintaining the room air temperatures within the specified limits, and of providing ventilation and exhaust for the ESF battery rooms.

B. Safety Evaluation Two

A single active failure in one train of the essential HVAC system or in its supporting systems, including a loss of offsite power, does not cause a complete loss of ESF system function. The system single failure analysis is presented in table 9.4-4.

C. Safety Evaluation Three

The essential HVAC system for the ESF switchgear, ESF equipment rooms, and battery room is designed to Seismic Category I requirements.

9.4.1.3.4 Inspection and Testing Requirements

The systems and components used in the ESF switchgear, ESF equipment, and battery room essential HVAC system are designed to permit testing and inspection to assure the integrity and capability of the system. Such tests and inspections can be made during normal plant operation.

9.4.1.4 Normal HVAC System -- ESF Switchgear, ESF Equipment Rooms, Battery Rooms, Upper and Lower Cable Spreading Rooms

9.4.1.4.1 Design Bases

9.4.1.4.1.1 Safety Design Bases. The normal HVAC system provided for the ESF switchgear, ESF equipment rooms, battery rooms, and upper and lower cable spreading rooms has no safety design bases.

Table 9.4-4
ESSENTIAL HVAC SYSTEM SINGLE FAILURE ANALYSIS ESF SWITCHGEAR, ESF EQUIPMENT AND BATTERY ROOMS

Component	Failure Mode/ Cause	Effects on System	Method of Detection	Inherent Compensating Provision
Outside air damper	Fails closed makeup air side/ corrosion	Loss of makeup air to rooms	Position indicating lights in control rooms	Each of the two redundant ESF equipment and battery rooms is conditioned by separate air conditioning systems
Air handling unit	Fails to operate/ mechanical or electrical failure	Loss of cooling to one ESF train	Low fan differential pressure alarm in control room	Each of the two redundant ESF equipment and battery rooms is conditioned by separate air conditioning systems
Battery room exhaust fan	Fails to operate/ mechanical or electrical failure	Hydrogen level rises in battery room	Low fan differential pressure alarm in control room	Each of the two redundant ESF equipment and battery rooms is conditioned by separate air conditioning systems
ESF switchgear and battery room supply damper	Fails to operate/ mechanical or electrical failure	Loss of cooling to one ESF train or battery room	Position indicating lights in control rooms	Each of the two redundant ESF equipment and battery rooms is conditioned by separate air conditioning systems
Non-ESF dampers and ducts	Fails to operate/ mechanical or electrical failure	None	Operator patrol	Two independent ESF HVAC systems provided

9.4.1.4.1.2 Power Generation Design Bases. The normal HVAC system provided for the ESF switchgear, ESF equipment rooms, battery rooms, and upper and lower cable spreading rooms has the following power generation design bases:

A. Power Generation Design Basis One

The normal HVAC system provided for the ESF switchgear, ESF equipment rooms, battery rooms, and upper and lower cable spreading rooms shall supply conditioned air to the rooms and areas served during normal plant operating conditions to maintain the required temperatures for equipment, and to provide the required ventilation and exhaust for the battery rooms.

B. Power Generation Design Basis Two

Portable smoke removal equipment shall be provided to remove smoke from the control building.

9.4.1.4.1.3 Codes and Standards. The normal HVAC system provided for the ESF switchgear, ESF equipment rooms, battery rooms, and upper and lower cable spreading rooms is designed in accordance with codes and standards set forth in table 3.2-1.

9.4.1.4.2 System Description

The normal HVAC system provided for the ESF switchgear, ESF equipment rooms, battery rooms, and upper and lower cable spreading rooms is shown in engineering drawings 01, 02,

03-M-HJP-001, -002 and 02-M-HJP-003. This system is located on elevation 74 feet 0 inch. Major components are two air handling units, supply and return ductwork, and exhaust fans. The outside air preconditioning unit is shared with the normal control room system, shown in engineering drawings 01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003. The treated outside air flows into the mixing box at the entrance of the draw-through type air handling unit where it is mixed with air returning from the ESF switchgear, ESF equipment, and the cable spreading rooms. The mixed air is drawn through a high efficiency filter before it is cooled by the chilled water coil. The chilled water coil is supplied with chilled water from the chilled water system discussed in subsection 9.2.9. The fan discharges the air into the supply ductwork through which it flows to the ESF switchgear rooms, and, from there, to the ESF equipment and battery rooms. The supply ductwork also furnishes air to the upper and lower cable spreading rooms.

The battery room ventilation system is designed to maintain the combustible gas concentration in the battery rooms below the lower flammability limit of hydrogen. To accomplish this, air in the battery rooms is exhausted to the outside atmosphere in order to continuously sweep combustible gases out of the battery rooms. After receipt of an alarm indicating that the normal exhaust fan is not operating, the operator may remote manually start the emergency exhaust fan. Failure of the emergency exhaust fan to either start or continue to run will be detected by either a light on the control room panel, failure of the alarm to clear, or by the reactivation of the

alarm. The battery room essential exhaust fan will automatically start upon loss of offsite power or SIAS with simultaneous shutoff of the normal exhaust fan.

Air from the ESF equipment rooms and the cable spreading rooms is recirculated by returning the air through the return duct to the air handling unit where it is mixed with outside air and circulated into the system.

The system is started manually and can be stopped manually. It is automatically stopped and isolated in case conditions require operation of the essential HVAC system.

In the event of fire, area fire detectors will sound an alarm in the control room and the supply fan may be deactivated manually, if required. Smoke removal is then manually initiated by use of portable smoke removal equipment. The existing smoke removal system can also be used to remove smoke. Only portable equipment, however, is relied on for smoke removal capability.

9.4.1.4.2.1 System Components. System components are described as follows:

A. Air Washer

The air washer is shared with the control room HVAC system, and is described in paragraph 9.4.1.2.2.1.

B. Air Handling Unit

The high efficiency filter, cooling coil, and fan are identical to those described in paragraph 9.4.1.2.2.1.

C. Exhaust Fan

The battery room exhaust fans (one fan per room) are of nonsparking, explosion-proof construction.

D. Smoke Exhaust Fan

The smoke exhaust fan is a centrifugal fan capable of providing 300 cubic feet per minute exhaust per 200 square feet of floor space for any given floor at one time. Portable smoke removal equipment will be used to remove smoke from the control building. Only portable equipment, however, is relied on for smoke removal capability.

9.4.1.4.3 System Operation

During normal plant operation, recirculated air from upper and lower cable spreading rooms, ESF switchgear, and ESF equipment rooms is mixed with outside air and is distributed through the rooms. Outside air is used to make up for the air exhausted from the battery rooms.

9.4.1.4.4 Safety Evaluation

Since the normal HVAC system for the ESF switchgear, ESF equipment rooms, and battery rooms has no safety design bases, no safety evaluation is provided.

9.4.1.4.5 Inspection and Testing Requirements

Acceptance testing of this system is performed to demonstrate proper system and equipment functioning.

9.4.2 AUXILIARY BUILDING

Both essential and normal HVAC systems are provided for the auxiliary building. The equipment rooms, access control areas, the mechanical and electrical penetration areas, areas below the 100-foot 0 inch elevation of the main steam support structure (MSSS), and the remainder of the auxiliary building are served by a normal HVAC system. The ESF equipment rooms and the safety-related auxiliary feedwater pump rooms are served by an essential HVAC system during emergency operation. The essential system in the auxiliary building consists of individual essential cooling units for each ESF equipment room.

9.4.2.1 Normal HVAC System -- Equipment Rooms, Access Control Area, Penetration Area, and ESF Pump Rooms

The auxiliary building normal HVAC system is designed to maintain an environmental condition suitable for personnel comfort and safety and for performance of the equipment.

9.4.2.1.1 Design Bases

9.4.2.1.1.1 Safety Design Bases.

A. Safety Design Basis One

   The ductwork at all levels of the auxiliary building below level 140 feet 0 inch shall be designed to retain structural integrity, but is not required to function during and after a safe shutdown earthquake.

9.4.2.1.1.2 Power Generation Design Bases.

A. Power Generation Basis One

The normal auxiliary building HVAC system shall be designed to maintain the required temperatures and ventilation for the various areas of the building.

B. Power Generation Basis Two

The normal auxiliary building HVAC system shall be designed to prevent uncontrolled release of airborne radioactivity. This shall be accomplished by exhausting more air than is supplied and by exhausting through charcoal filtration trains.

9.4.2.1.1.3 Codes and Standards. The normal auxiliary building HVAC system is designed to conform to the applicable codes and standards listed in table 3.2-1.

9.4.2.1.2 System Description

The auxiliary building HVAC system, shown schematically in engineering drawings 01, 02, 03-M-HAP-001, -002, -003 and -004 consists of two outside air supply units, multizone air handling units for the access control area, a local recirculating air handling unit for the control element drive mechanism (CEDM) control system, motor generator set rooms, and, for the charging pump rooms, two exhaust filter units, exhaust fans for the laboratories, and associated ductwork, dampers, registers, and control.

9.4.2.1.2.1 Component Description. System components are described as follows:

A. Outside Air Handling Units

Each air handling unit consists of a dust filter, a cooling coil, and a supply fan. Electric duct heaters are installed downstream of each air handling unit.

B. Multizone Air Handling Unit

The air handling unit consists of a cooling coil, an electric heating coil, control dampers, and a fan.

C. Recirculating Air Handling Unit

Each recirculating air handling unit consists of a cooling coil and a fan.

D. Exhaust Filter Units

Each set of exhaust filters consists of a high efficiency filter, high efficiency particulate air (HEPA) filter, carbon adsorber, downstream HEPA filter, and an exhaust fan.

E. Laboratory Exhaust Fans

The fans exhaust from the fume hoods in the laboratories to the exhaust system upstream of the exhaust filter units.

9.4.2.1.2.2 System Operation. During normal plant operation, treated outside air is distributed through the building on a once-through basis. Only the air in the CEDM control system area, the motor generator set rooms, and the

charging pump rooms is recirculated through a local handling unit. The air flows from corridors to rooms to prevent spread of potential airborne radioactivity, and, from there, it is exhausted continuously through the exhaust filter units to the plant vent.

Air supplied to the access control area is cooled or heated to provide the closer temperature control required for personnel comfort.

Air supplied to radiation protection and locker rooms is taken from the outside air supply unit, then heated or cooled in a double duct system with zone mixing boxes, which distribute the air.

The air supplied to the radio-chemical laboratory and sampling room is exhausted through fume hoods by transfer fans to the continuous exhaust system.

Exhaust air from the decontamination room, storage area, counting room, and men's and women's toilets is discharged to the continuous exhaust system.

In the event of fire in the auxiliary building, fire and smoke detectors will alarm in the control room.

Smoke removal will be accomplished as follows:

The firefighters will remove the smoke from the fire area to the outside by means of portable smoke removal equipment. If normal HVAC system is available, smoke may be exhausted to outside by use of portable smoke removal equipment and existing exhaust filtration units.

In case the portable smoke removal equipment in conjunction with exhaust filtration units is used, the two HEPA filters in each of the two banks of the two exhaust filtration units will be removed and the exhaust system will be restarted. The HEPA filters would be removed to prevent HEPA clogging by the smoke particles.

The auxiliary building exhaust air system is continuously monitored for radiation levels. Isolation of this system from the ESF pump rooms during emergency conditions is discussed in paragraph 9.4.2.2.

The two 50% capacity air filtration units located on the roof of the auxiliary building exhaust to the plant vent stack.

The auxiliary building is kept under a slight negative pressure, except when any of the access doors are open, to ensure that leakage is into the building.

9.4.2.1.3 Safety Evaluation

The ducts below elevation 140 feet 0 inch are supported by Seismic Category I supports, and the ducts are designed to retain their structural integrity during and after an SSE.

9.4.2.1.4 Inspections and Testing Requirements

Acceptance testing of this system is performed to demonstrate proper system and equipment functioning.

9.4.2.2 Essential HVAC System -- ESF Equipment Rooms and Essential Exhaust

The auxiliary building HVAC system described in this section includes those systems that function post-LOCA within the ESF pump room, and the exhaust system, that maintains the auxiliary building below elevation 100 feet 0 inch at a negative pressure post-LOCA to prevent unfiltered release of possible airborne radioactivity to the surroundings.

9.4.2.2.1 Design Bases

9.4.2.2.1.1 Safety Design Bases. Safety design bases pertinent to the ESF equipment room essential cooling system and essential exhaust system are as follows:

A. Safety Design Basis One

The ESF pump room and safety-related auxiliary feedwater pump room coolers shall be designed to maintain the required room temperatures to ensure the operability of the ESF pumps and motors during accident conditions.

B. Safety Design Basis Two

The ESF essential cooling and exhaust system shall be designed to withstand the effects of an SSE.

C. Safety Design Basis Three

Following a LOCA, the ESF equipment and safety-related auxiliary feedwater pump rooms are automatically isolated (at approximately the 100-foot elevation) from

the auxiliary building normal HVAC system on receipt of an SIAS signal.

D. Safety Design Basis Four

Areas with safety injection piping and equipment shall be kept under measurable negative pressure in relation to ambient during emergency conditions by exhausting through ESF filtration systems.

E. Safety Design Basis Five

The auxiliary building essential HVAC system shall be designed so that a single failure of any active component, assuming loss of offsite power, cannot result in complete loss of an ESF system function.

Protection of the auxiliary building essential HVAC system from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

9.4.2.2.1.2 Power Generation Design Basis. The essential HVAC system has no power generation design basis.

9.4.2.2.1.3 Codes and Standards. The essential HVAC system is designed to conform to the applicable codes and standards listed in table 3.2-1.

9.4.2.2.2 System Description

The ESF equipment room essential air coolers, shown schematically in engineering drawings 01, 02, 03-M-HAP-001, -002, -003 and -004, consist of a recirculating air handling unit, including a cooling coil, in each pump room. There are no outside air connections.

The essential exhaust filtration system consists of two essential exhaust filtration units shared with the fuel building, and a connecting tunnel and plenum.

9.4.2.2.2.1 Component Description. Each ESF equipment room air handling unit consists of a fan and a cooling coil.

Electric and chilled water service for the unit is provided by the same trains which provide these services to the pump in the room. Water is distributed to the ESF equipment room cooling coils from the essential chilled water system as described in section 9.2.

The essential filtration units are described in paragraph 9.4.5.2.2.

9.4.2.2.2.2 System Operation. Following a LOCA, the ESF equipment and safety-related auxiliary feedwater pump rooms are automatically isolated (at approximately the 100-foot elevation) from the auxiliary building normal HVAC system on receipt of an SIAS signal. The building pressure is reduced to a measurable negative pressure relative to below ambient by the fuel building essential exhaust fans for the space below

elevation 100 feet 0 inch in the auxiliary building. Air exhausted from the ESF equipment rooms is filtered by the fuel building essential filter units. The essential exhaust filter units are automatically actuated by starting the fans and opening the dampers to the units in response to ESF pump start signal.

The essential air coolers are automatically started to maintain the equipment room design temperature. Each equipment room has its own air cooling unit.

High room temperature conditions in each ESF pump room are alarmed remotely in the control room.

9.4.2.2.3 Safety Evaluation

Safety evaluations pertinent to the ESF pump room essential cooling system are numbered to correspond to the safety design bases and are as follows:

A. Safety Evaluation One

   The essential cooling system is designed to maintain the temperature inside the ESF equipment rooms within the temperature range listed in table 9.4-2.

B. Safety Evaluation Two

   The fan, coils, piping, and valves associated with the ESF equipment room coolers are designed in accordance with Seismic Category I criteria.

C. Safety Evaluation Three

Two Seismic Category I isolation dampers and fire dampers are provided in the supply and return ducts penetrating the 100-foot elevation to isolate the normal exhaust and supply system.

D. Safety Evaluation Four

Two independent essential exhaust filter units are connected to the auxiliary building through Seismic Category I plenum and tunnel to the fuel building essential exhaust trains to provide exhaust filtration of the ESF equipment rooms, and maintain the pressure of the space below the 100-foot 0 inch elevation at a measurable negative pressure relative to the outside.

E. Safety Evaluation Five

The equipment for the auxiliary building essential HVAC system is provided with redundant trains A and B powered by separate buses A and B such that a failure of a single active component of the HVAC system cannot result in a complete loss of any ESF system function.

An ESF equipment and safety-related auxiliary feedwater pump room essential cooling system single failure analysis is presented in table 9.4-5.

9.4.2.2.4 Inspection and Testing Requirements

Preoperational testing is performed as described in section 14.2.

Table 9.4-5
ENGINEERED SAFETY FEATURES EQUIPMENT AND SAFETY-RELATED AUXILIARY FEEDWATER PUMP ROOM ESSENTIAL COOLING SYSTEM SINGLE FAILURE ANALYSIS (Sheet 1 of 2)

Component	Failure Mode/ Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Valves to essential chilled water supply	Fails closed/ operator failure	ESF equipment or safety-related auxiliary feedwater pump room overheats	High temperature alarm in control room	Redundant ESF and safety-related auxiliary feedwater pump and associated HVAC train available	
	Fails open/ operator failure	None	Position indicator in control room	None	Valve normally open
Air cooling unit	Cooling water coil leakage	ESF equipment or safety-related auxiliary feedwater pump room overheats	High temperature alarm in control room	Redundant ESF and safety-related auxiliary feedwater pump and associated HVAC train available	

Table 9.4-5
ENGINEERED SAFETY FEATURES EQUIPMENT AND SAFETY-RELATED AUXILIARY FEEDWATER PUMP ROOM ESSENTIAL COOLING SYSTEM SINGLE FAILURE ANALYSIS (Sheet 2 of 2)

Component	Failure Mode/ Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
	Fan motor fails/ mechanical or electrical failure	ESF equipment or safety-related auxiliary feedwater pump room overheats	High room temperature alarm in control room	Redundant ESF and safety-related auxiliary feedwater pump and associated HVAC train available	
Isolation damper	Fails open	None	Position indicator in control room	Redundant damper in duct available which also receives closing signal	

9.4.3 RADWASTE BUILDING

The function of the radwaste building HVAC system is to maintain ventilation in the process equipment areas, to provide personnel safety in access areas, and to restrict the spreading of airborne radioactivity. The radwaste building HVAC system is required to function during normal plant operation. This system is a once-through air system. There is no recirculation of air in the building, except in the control room where there is no source of potential airborne radiation.

9.4.3.1 Design Bases

9.4.3.1.1 Safety Design Bases

The radwaste building HVAC system has no safety design basis.

9.4.3.1.2 Power Generation Design Bases

The radwaste building HVAC system is designed to maintain the required temperatures to ensure the operability of the radwaste building equipment, to maintain suitable personnel working conditions, and to prevent exfiltration of untreated air containing airborne radioactivity. Airflow is from low activity to higher radioactivity areas.

9.4.3.1.3 Codes and Standards

The radwaste building HVAC system is designed to the applicable codes and standards listed in table 3.2-1.

9.4.3.2 System Description

The radwaste building HVAC system, shown schematically in engineering drawings 01, 02, 03-M-HRP-001, consists of a supply air system, exhaust filter system, and associated ductwork, dampers, registers, and controls.

9.4.3.2.1 Component Description

System components are described as follows:

A. Supply Air Handling Units

The two 50% air handling units each consist of an intake louver, a filter, evaporative cooling pad, pump, and a supply fan. Duct heaters are installed downstream of the supply air handling unit.

B. Exhaust Filter Unit

The two 50% exhaust filter units each consist of a high efficiency filter, a HEPA filter, and an exhaust fan.

C. Radwaste Building Control Room Air Handling Unit

The recirculating air handling unit consists of a moderate efficiency filter, a cooling coil, and a fan. The cooling coil is serviced from the normal chilled water system described in section 9.2. A duct heater is installed downstream of the air handling unit.

9.4.3.2.2 System Operation

The outside air supply is cooled adiabatically by the air handling units and is distributed to the radwaste building. The

air flows to the various rooms and from corridors to rooms to prevent uncontrolled flow of potential airborne radioactivity. The air is exhausted through the radwaste building exhaust filter unit to the plant vent. The radwaste building is maintained at a negative pressure to ensure that leakage is into the radwaste building. The negative pressure is maintained by exhausting more air from the building than is being supplied.

The system includes two 50% air supply units and two 50% exhaust filter units, to preclude total system loss in case of a fan (or exhaust filter) failure.

A recirculating local air handling unit is provided in the radwaste equipment control room, where there is a high local heat load but no source of potential airborne radioactivity. In order to provide fresh air and pressurization, the recirculated air is mixed with air from the radwaste building removal supply unit at the inlet to the local unit.

9.4.3.3 Inspection and Testing Requirements

Acceptance testing of this system is performed to demonstrate proper system and equipment functioning.

9.4.4 TURBINE BUILDING

The turbine building HVAC system described in this section operates during normal plant operation and during the shutdown period, depending upon heat removal requirements. The turbine building HVAC system includes the following subsystems: turbine building general area ventilation subsystem, switchgear room and

battery room ventilation subsystem, and lube oil room ventilation subsystem. The condenser air removal system is discussed in section 10.4.

9.4.4.1 Design Bases

9.4.4.1.1 Safety Design Bases

The turbine building HVAC system has no safety design bases.

9.4.4.1.2 Power Generation Design Bases

A. Power Generation Design Basis One

   The turbine building HVAC system shall be designed to maintain the required temperatures specified in table 9.4-2 to ensure equipment operation.

B. Power Generation Design Basis Two

   The system shall prevent combustible concentration of hydrogen gas from accumulating within the battery room.

C. Power Generation Design Basis Three

   The system shall provide adequate ventilation by exhaust for the lube oil room.

D. Power Generation Design Basis Four

   The system shall provide adequate ventilation by exhaust for the demineralizer area.

9.4.4.1.3 Codes and Standards

The turbine building HVAC system is designed to conform to the applicable codes and standards listed in table 3.2-1.

9.4.4.2 System Description

The turbine building HVAC system shown schematically in engineering drawings 01, 02, 03-M-HTP-001 consists of supply air handling units, duct heating coils associated ductwork, dampers, registers, controls, and exhaust fans. The air is supplied at all levels, transferred to the higher levels. Approximately 80% is exhausted through the roof exhaust fans, and the remaining 20% is exfiltered through wall openings and other exhaust fans.

9.4.4.2.1 Component Description

A. Supply Air Handling Units

Six air handling units, are provided. Three of the units are located at elevation 100 feet 0 inch (ground level) outside the building and on one side. The other three are located at elevation 176 feet 0 inch (turbine deck level) outside and on the opposite side of the building.

B. Roof Exhaust Fans

Four roof exhaust fans are provided. These are axial fans with vertical axes and weather heads.

C. Exhaust Fans

Four axial fans of the nonsparking explosion-proof type are provided for special exhaust from the battery room and from the lube oil room.

D. One vane-axial fan is provided for special exhaust from the demineralizer area.

E. One centrifugal fan is provided to exhaust the fumes from the secondary chemistry chemical addition tanks.

9.4.4.2.2 System Operation

The outside air is cooled adiabatically by the air handling units. From the supply fans, the air is ducted to the three levels along both sides of the building. In the summer and during power operation, all the air is exhausted via the exhaust fans and exfiltration.

During winter plant shutdown, part of the air is recirculated.

The supply air is distributed through ducts to the building.

The ventilation supply air unit distributes the air through ducts to the switchgear room and the battery room. During winter operation, the battery room space thermostat controls the electric duct heater located in the supply air duct and maintains 75F space temperature. The electric duct heater is turned off automatically to prevent burnout if the airflow switch, located in the battery room supply air duct, detects no airflow.

The switchgear room air is exhausted to atmosphere through backdraft dampers. Battery room air is exhausted to the atmosphere through an exhaust fan.

Ventilation supply air from the turbine building is distributed through the lube oil room. The air is exhausted to atmosphere by duct-mounted exhaust fans.

The exhaust ducts of the chemical addition tanks are maintained at a negative pressure within the turbine building. This minimizes any leakage of the tank fumes within the turbine building.

9.4.4.3 Safety Evaluation

Since the turbine building HVAC system has no safety design bases, no safety evaluation is provided.

9.4.4.4 Inspection and Testing Requirements

The turbine building HVAC system is designed to permit periodic inspection of system components to assure the capability of the system.

9.4.5 FUEL BUILDING

Two separate HVAC systems are provided for the fuel building. The normal system functions during normal plant operation only. The essential system functions only in the event of a fuel handling accident or LOCA. The fuel handling accident is evaluated in section 15.7. The LOCA is discussed in

section 15.6. The normal HVAC system is a once-through air system. The essential system is a filtered exhaust system.

9.4.5.1 Normal Fuel Building HVAC System

9.4.5.1.1 Design Bases

9.4.5.1.1.1 Safety Design Bases. The fuel building normal HVAC system has no safety design bases.

9.4.5.1.1.2 Power Generation Design Bases.

A. Power Generation Design Basis One

The fuel building HVAC system shall be designed to maintain the required temperature to ensure the operability of fuel building equipment, and to provide the required ventilation to maintain the level of airborne radioactivity below permissible limits.

9.4.5.1.1.2 Codes and Standards. The fuel building HVAC system is designed to conform to the applicable codes and standards listed in table 3.2-1.

9.4.5.1.2 System Description

The normal fuel building HVAC system, shown schematically in engineering drawings 01, 02, 03-M-HFP-001, consists of two 50% capacity supply air handling units, two 50% normal exhaust units, associated ductwork, dampers, registers, and controls. The equipment performance data of the fuel building HVAC systems are listed in table 9.4-3. Figure 9.4-1 shows the

ventilation flow distribution and general physical layout of the HVAC systems over the spent fuel pool. The ventilation rate for each set of units, one supply and one exhaust, is sufficient to meet the requirements of 10CFR20.1-20.601 for 40 hours per week of occupational exposure when operating alone.

The normal units are located on the roof of the building, and are arranged for ease of access, control, and monitoring. The exhaust fan removes more air than is supplied. The extra air is made up by infiltration from the outside and from adjoining areas of the auxiliary building, thus minimizing the possibility of exfiltration.

The fuel handling building doors are provided with self-closers to prevent an open door from disrupting fuel handling building ventilation.

9.4.5.1.2.1 Component Description. System components are described briefly as follows:

A. Supply Air Handling Unit

Each air handling unit consists of an oil impingement dust filter (not currently used)(1), evaporative cooler, and a supply fan.

B. Normal Exhaust Unit

Each exhaust unit consists of an exhaust fan.

(1) The oil impingement filter has been removed for trains where DMWO 3144423 has been implemented.

C. Heating Coil

Electrical heating coils are located in the ductwork to maintain the minimum design temperature.

9.4.5.1.2.2 System Operation. During normal operation, the fuel building is ventilated by distributing tempered, outside air throughout the building. The air is cooled adiabatically by the evaporative cooler which uses domestic water. The air is exhausted continuously to the fuel building vent. The fuel building is maintained under a negative pressure to ensure that all leakage is into the building.

Design temperatures for the fuel building are listed in table 9.4-2.

9.4.5.1.3 Safety Evaluation

Since the fuel building normal HVAC system has no safety design bases, no safety evaluation is provided.

9.4.5.1.4 Inspection and Testing Requirements

Acceptance testing of the system is performed to demonstrate proper system and equipment functioning.

9.4.5.2 Fuel Building Essential HVAC System

9.4.5.2.1 Design Bases

9.4.5.2.1.1 Safety Design Bases.

A. Safety Design Basis One

The fuel building essential HVAC system is designed to limit the potential release of radioactive iodine in the event of a fuel handling accident or a design basis LOCA (refer to paragraph 9.4.2.2).

B. Safety Design Basis Two

The fuel building essential HVAC system is designed to function during and after an SSE.

C. Safety Design Basis Three

Any single failure in the fuel building essential HVAC system will not impair the system's ability to comply with safety design bases one and two.

9.4.5.2.1.2 Power Generation Design Bases. The fuel building essential HVAC system has no power generation design bases.

9.4.5.2.1.3 Codes and Standards. Applicable codes and standards for the fuel building essential HVAC system are given in table 3.2-1.

9.4.5.2.2 System Description

The fuel building essential HVAC system consists of two 100% capacity exhaust charcoal filtration units. Each unit exhausts air from the fuel building to the fuel building vent to prevent release of airborne radioactivity to the surroundings in case of a fuel handling accident.

The essential exhaust trains are also connected through a Seismic Category I plenum and tunnel to the auxiliary building ESF equipment rooms. Separate dampers are provided for this service. These units would be utilized to create low pressure in the auxiliary building and thus prevent release of unfiltered air from the auxiliary building due to ESF system leakages post-LOCA. Refer to paragraph 9.4.2.2.

9.4.5.2.2.1 System Components. System components are described as follows:

A. Filter Unit Housings

The filter unit housings are Seismic Category I and are made of carbon steel. Each housing is provided with a service access door, explosion-proof light, filter test connections, connections for pressure gauges, and floor drains. The housings are of all welded construction. Filter unit housings are designed in accordance with Regulatory Guide 1.52 as noted in section 1.8.

B. High Efficiency Filters

The high efficiency elements are of pleated, fine fiber sheet media with a separator. The elements measure 24 by 24 by 12 inches and are capable of handling a nominal flowrate of 1000 cubic feet per minute each. The filter element is sealed in a fire-retardant frame. The minimum average efficiency of the filter, using atmospheric dust, is 85% by ASHRAE Standard 52 test methods. Prefilters are designed and qualified in accordance with Regulatory Guide 1.52 as noted in section 1.8.

C. High Efficiency Particulate Air Filters

Filter elements of the HEPA filters are pleated fiberglass with asbestos insert design, measure 24 by 24 by 11.5 inches, and are capable of handling a nominal flowrate of 1000 cubic feet per minute each. The filter medium is encased in stainless steel, is equipped with face guards on both sides, and is water- and fire-resistant. The filter element minimum acceptance criterion is removal of 99.97% of 0.3 micron thermally generated monodisperse DOP particles. These filter elements are designed and qualified in accordance with Regulatory Guide 1.52.

D. Carbon Adsorber

The adsorber sections contain impregnated activated carbon that meets the requirements of Regulatory Guide 1.52, with the exception taken in section 1.8,

with an assigned decontamination efficiency of 95% for elemental iodide and organic iodide. Each adsorber is designed for a maximum loading of radioiodine well below the recommendations of Regulatory Guide 1.52.

E. Fans

Essential air filtration unit fans are capable of delivering the design flowrate with all filters at their maximum anticipated pressure drop. Fans are chosen with a steeply rising pressure-flow characteristic to maintain a reasonably constant airflow over the full filter train life. Fan and motor materials are suitable for operation under the environmental conditions associated with the postulated design basis accident (DBA), in conformance with Position C.3.1 of Regulatory Guide 1.52, as noted in section 1.8. Essential air filtration unit fans are Seismic Category I.

F. Ductwork

The essential system ductwork is Seismic Category I, designed in accordance with Position C.3.m of Regulatory Guide 1.52. Ductwork is redundant where required to provide functional support to active components in meeting the single active failure criteria. Leaktight ductwork and isolation dampers are provided where required to prevent release of unfiltered air to the surroundings. In general conformance with Position C.4 of Regulatory Guide 1.52,

accessibility and adequate working space for maintenance and testing operations are provided in the design and layout of the air purification system equipment.

G. Isolation Dampers

Eight isolation dampers are provided in the normal ventilation supply and exhaust subsystem at the following locations:

- Two pairs of isolation dampers are located in the normal ventilation supply air duct at elevation 140 feet 0 inch of the fuel building. Each pair of dampers is in series. The two separate pairs of dampers are located in parallel with one another.
- Two pairs of isolation dampers in series are located in the normal ventilation exhaust air subsystem at elevation 140 feet 0 inch of the fuel building. Each pair of dampers is in series. The two separate pairs of dampers are located in parallel with one another.

Four isolation dampers are provided in each essential air filtration unit to control the appropriate service, either for the fuel building in case of a fuel handling accident, or for the auxiliary building post-LOCA.

H. Instrumentation

Details of the radiation monitors used to provide the signal placing the fuel building essential HVAC system in operation are given in section 11.5. Information, including detector locations, type of radiation, detector type, range, and sensitivity, is given in table 11.5-1.

Differential pressure indication is provided across filters and carbon adsorbers.

The instrumentation is designed to Seismic Category I requirements. A description of initiating circuits, logic, interlocks, and redundancy of instrumentation relating to fuel building essential HVAC system is discussed in section 7.3.

9.4.5.2.2.2 System Operation. In the event of a fuel handling accident, the fuel building is isolated automatically by the closure of the isolation dampers in the normal ductwork upon sensing a high level radiation signal either from the radiation monitor in the normal exhaust ductwork or from the fuel pool area monitor. There are eight Seismic Category I dampers, four in the normal supply and four in the normal exhaust ducts. At the same time the two exhaust filter units are actuated by the same high level radiation signal. Air infiltration into the fuel building is used for makeup in this mode of cleanup operation. A negative pressure in the fuel

building is maintained by exhausting of this filtered air to the atmosphere.

Refer to paragraph 9.4.2.2 for a discussion of the essential filtration operation following a LOCA.

The isolation and initiation of the units can be done manually from the control room. Also, refer to paragraph 9.4.2.2.2.2 for a discussion of the operation of the ESF equipment room exhaust to the fuel building essential HVAC system.

9.4.5.2.3 Safety Evaluation

Safety evaluations are numbered to correspond to the safety design bases.

A. Safety Evaluation One

   The fuel building essential HVAC system is designed to limit the offsite dose following a fuel handling accident or LOCA within the guidelines of 10CFR100. Radiological consequences of a LOCA are discussed in section 15.6. Radiological consequences of a fuel handling accident are discussed in section 15.7.

B. Safety Evaluation Two

   The fuel building essential HVAC system is designed to Seismic Category I requirements.

C. Safety Evaluation Three

   A single failure in any component of the fuel building essential HVAC system will not impair the system's ability

to fulfill the requirements of safety design bases one and two. A single failure analysis is given in table 9.4-6.

9.4.5.2.4 Testing and Inspection

Preoperational testing is performed as described in section 14.2.

9.4.6 CONTAINMENT BUILDING

The containment building HVAC systems described in this section include those systems that function during normal plant operation, containment preaccess period, or during extended shutdown. These systems are not required to operate during any design basis accident.

The containment hydrogen control system is discussed in subsection 6.2.5.

The normal operation systems shown in engineering drawings 01, 02, 03-M-HCP-001, -002, -003 and 01, 02, 03-M-CPP-001 are described in this section and include:

- Normal cooling system
- Normal cleanup system
- Normal purge system
- Control element drive mechanism cooling system
- Cavity cooling system
- Tendon gallery system

Table 9.4-6
SINGLE FAILURE ANALYSIS FUEL BUILDING ESSENTIAL HVAC SYSTEM
FUEL HANDLING ACCIDENT MODE (Sheet 1 of 2)

Component	Failure Mode	Effect	Comment
Fan	Failure	Loss of one exhaust filter	Redundant exhaust filter provided
Filter	Plugged	Loss of one exhaust filter	Redundant exhaust filter provided
Fuel building inlet damper	Fails to open	Loss of one exhaust filter	Redundant exhaust filter provided
Auxiliary building inlet damper	Fails to close	Degraded performance of one exhaust filter	Redundant exhaust filter provided
Fuel building normal ventilation isolation damper	Failure to close	None	Redundant isolation damper provided in series
Radiation monitor	Failure	None	Redundant monitor provided

Table 9.4-6
SINGLE FAILURE ANALYSIS FUEL BUILDING ESSENTIAL HVAC SYSTEM
LOCA MODE (Sheet 2 of 2)

Component	Failure Mode	Effect	Comment
Fan	Failure	Loss of one exhaust filter	Redundant exhaust filter provided
Filter	Plugged	Loss of one exhaust filter	Redundant exhaust filter provided
Auxiliary building inlet damper	Fails to open	Loss of one exhaust filter	Redundant exhaust filter provided
Fuel building inlet damper	Fails to close	Degraded performance of one exhaust filter	Redundant exhaust filter provided
Auxiliary building normal ventilation isolation damper	Failure to close	None	Redundant isolation damper provided in series

The containment requires normal air conditioning, heating, and ventilating to maintain the required temperature to ensure equipment operability, and to provide the required ventilation and control of airborne radioactivity for personnel access.

9.4.6.1 Design Bases

9.4.6.1.1 Safety Design Bases

A. Safety Design Basis One

   The HVAC equipment and ductwork within the containment and the MSSS shall be designed to retain the structural integrity, but is not required to function during and after a safe shutdown earthquake.

B. Safety Design Basis Two

   Those portions of containment HVAC systems that penetrate the containment boundary shall be designed as Seismic Category I insofar as they are required to function to maintain containment isolation capability.

9.4.6.1.2 Power Generation Design Bases

A. Power Generation Design Basis One

   The containment HVAC systems are designed to maintain a containment ambient air temperature between 50F and 120F during normal plant operation to permit continuous operation of all equipment within the containment. The system is also designed to prevent concrete structures within the containment from exceeding the maximum design temperature of 150F except for the concrete

under the reactor vessel column baseplates which have a maximum design temperature of 200F.

B. Power Generation Design Basis Two

The containment normal cooling system is designed to provide adequate internal recirculation to ensure thorough mixing of air throughout the containment, with the containment closed to the outside atmosphere and pressurized to design pressure, so that periodic containment integrated leakage rate tests can be conducted in accordance with 10CFR50, Appendix A, General Design Criterion 52 and 10CFR50, Appendix J.

C. Power Generation Design Basis Three

The containment purge system is designed to purge the containment atmosphere to the plant vent stack while introducing filtered and treated makeup air from the outside to provide adequate ventilation for personnel comfort when the plant is shut down during refueling operations and maintenance, and for limited periods during power operation to allow operator access.

D. Power Generation Design Basis Four

The recirculation cleanup units are designed to reduce the concentration of airborne radioactivity in the containment atmosphere prior to routine personnel access during operation, or in advance of a scheduled plant shutdown.

E. Power Generation Design Basis Five

Cooling air is provided to the CEDMs under normal plant operation with one air handling unit (AHU) and two vane-axial fans which produce a minimum flow rate of 700 standard cubic feet per minute (scfm) per CEDM at a temperature range of 80F to 120F. However, the cooling system can also operate with one single fan, when the other fan is inoperable and its discharge is closed with the backdraft damper, at a reduced flow rate such that it can satisfy the environmental conditions for the operation of the CEDMs. The environmental temperature conditions of the CEDM coils, RSPTs and cable under the reduced flow rate were evaluated in reference 3 and found to be acceptable. This change increases availability of the operating system without having to rely on the redundant standby AHU with its respective two fans in the CEDM cooling system.

F. Power Generation Design Basis Six

The reactor cavity cooling system is designed to maintain an average air temperature of 120F or below inside the reactor cavity. The region below the permanent reactor cavity/refueling pool seal and above the neutron shield plug in the annulus may reach a maximum of 150F.

G. Power Generation Design Basis Seven

The MSSS HVAC system is designed to provide cooling above the 100-foot 0 inch elevation and in the main steam and feedwater line penetration areas.

H. Power Generation Design Basis Eight

Nonsafety-related containment HVAC systems are designed to withstand the DBE to the extent that they will not collapse during the seismic event and damage safety-related systems and components.

9.4.6.1.3 Codes and Standards

The containment building HVAC system is designed to conform to the applicable codes and standards listed in table 3.2-1.

9.4.6.2 System Description

The containment HVAC systems are shown in engineering drawings 01, 02, 03-M-HCP-001, -002, -003 and 01, 02, 03-M-CPP-001. Data pertinent to the containment normal HVAC system are as follows:

A. The normal cooling system for the containment building consists of four air cooling units of 50% capacity each located at elevation 120 feet 0 inch that are cooled by chilled water. Electrical heating coils are provided in the discharge ducts.

B. The normal cleanup system for the containment building consists of two filtering units of 50% capacity located

at elevation 140 feet 0 inch that clean the containment atmosphere prior to personnel access.

C. The normal purge system for the containment consists of a refueling purge and a power access purge. The refueling purge train is used for high flowrate purge during refueling and is closed during normal power generation. It consists of a supply air handling unit and an exhaust fan.

   The power access purge is used for low flowrate purge prior to and during power access periods. It consists of a supply air handling unit and charcoal exhaust filtration unit. The purge supply and exhaust units are located on the roof of the auxiliary building.

   Containment supply and exhaust penetrations and isolation valves for refueling purge are 42-inch diameter, and for power access purge they are 8-inch diameter.

D. Two 100% capacity air handling units located on the missile shield above the reactor constitute the cooling system for the control element drive mechanisms.

E. Four 50% capacity fan assemblies located at elevation 80 feet 0 inch are used to ventilate the containment cavity.

F. The containment tendon gallery is ventilated by supply and exhaust fans.

G. The normal ventilation system for the MSSS consists of two 100% capacity supply air units. These units are located at elevation 166 feet 11 inches and provide cooling for the MSSS and main steam and feedwater containment penetration areas. One 100% capacity normal exhaust fan for each side of the MSSS, located at elevation 139 feet 0 inch, provides ventilation air for the main steam and feedwater penetration areas to the turbine building.

9.4.6.2.1 System Components

The system components are described as follows:

A. Each normal containment air cooling unit consists of a steel housing, chilled water cooling coils on three sides, a vane-axial fan, associated ductwork, and damper. Heating coils are installed in the ductwork downstream of the air cooling unit.

B. Each normal cleanup filtration unit consists of a housing with a prefilter (high efficiency filter), a HEPA filter, a charcoal adsorber with activated charcoal followed by a HEPA filter and a fan.

C. The supply unit for the containment refueling purge consists of a steel housing with a dust separator (oil impingement filter), a cooling coil, and two fans at 15,000 cubic feet per minute each. Heating coils are installed in the ductwork downstream of the supply air unit.

The supply unit for containment power access purge consists of a housing, a moderate efficiency filter, a high efficiency filter, a cooling coil, a heating coil, and a fan of 2000 cubic feet per minute capacity.

The exhaust for the refueling purge consists of two 16,500 cubic feet per minute fans in parallel. For the power access purge, the exhaust consists of a filtration unit with prefilter, a HEPA filter, a charcoal adsorber, a HEPA filter, and a 2200 cubic feet per minute fan.

D. Each one of the two control element drive mechanism cooling units consists of a steel housing with a cooling coil served by component cooling water and two, two-stage, vane-axial fans.

E. The units for the cavity cooling system each consist of a vane-axial fan and a two-position motorized damper on the discharge side of the fan.

F. The units for the tendon gallery system consist of a vane-axial supply fan and a vane-axial exhaust fan.

G. Each supply air unit for the MSSS consists of an oil impingement filtration unit and a vane-axial fan.

9.4.6.2.2 System Operation

The containment HVAC system normal mode of operation is described as follows:

A. The normal cooling system for the containment is designed to maintain the temperature and reduce the humidity below 90% within the limits specified in table 9.4-2. The containment air cooling can be maintained by two of the four units. The units are controlled from the control room. In the event of a loss of offsite power, the containment air cooling can be maintained. All four units are connected to the ESF buses. They are not energized post-LOCA. Temperature indicators for each level in the containment building are provided in the control room.

B. The normal cleanup system, together with the normal purge system discussed below, is designed to control the airborne radioactivity below the level required for personnel access for inspection, maintenance, and refueling operations. The recirculation cleanup system will clean up the internal air without providing new air makeup.

C. The refueling purge is designed to maintain the airborne radioactivity below the level that permits sustained personnel occupancy during refueling. The power access purge is designed to maintain the airborne radioactivity below the level that permits short-term personnel occupancy during reactor power operation. This system and the normal cleanup system reduce airborne radioactivity concentrations during the entire period of containment building occupancy.

The purging operation is initiated manually from the control room prior to personnel entry to the containment building. The containment is maintained at a negative pressure relative to the atmosphere during the purge cycle.

In the event that the concentration in the containment of either airborne particulates or iodine activity is higher than desired levels, air cleaning is accomplished by activating the recirculation filtration unit. This unit is equipped with charcoal and HEPA filters to reduce containment airborne radioactivity to acceptable levels. The operation of this unit is initiated from the control room by manually energizing the fan.

The containment penetrations of the refueling purge supply and exhaust are equipped with motor-operated isolation valves inside the containment and motor-operated isolation valves outside the containment. The refueling purge penetrations may be isolated using blind flanges in plant operating modes 1-4 as described in section 6.2.4. The containment penetrations of the power access purge supply and exhaust are provided with air-operated isolation valves inside and outside containment. The containment penetrations, including the isolation valves and appropriate seismic restraints, are designed in accordance with Seismic Category I, Quality Class Q, requirements as defined in section 3.2. The valves are controlled automatically by the containment

isolation system (discussed in subsection 6.2.4 and section 7.3), which overrides all manual signals.

D. The cooling system for the CEDM is designed to satisfy the environmental conditions for equipment operation. Both cooling units are connected to the ESF buses, but not energized post-LOCA, so that air cooling can be maintained in the event of a loss of offsite power. The system functions by induction of containment air through the control element drive mechanism. The air pulled through is returned to the containment atmosphere at a temperature less than or equal to 125°F.

The CEDM cooling units function continuously during normal plant operation and may be running during plant shutdown periods, depending upon the heat loads. The units are manually operated from the control room. Normally, one cooling unit is operating and the other unit is on standby. The operating cooling unit, under normal plant operation, provides cooling air to the CEDMs with two 50% capacity vane-axial fans; however, the cooling system can also operate with a single fan running when the other fan is inoperable and its discharge is closed to prevent short circuit of the air. Manual backdraft dampers are installed in the discharge side of the fans to stop air flow from containment on the fan unit that is not operating. The standby cooling unit is automatically energized when the power to the operating unit is lost. A low-differential pressure switch detects the loss of operation of any cooling unit, and transmits

an alarm signal for annunciation in the control room. Motorized dampers are located in the ductwork leading from the CEDM shroud to the units. These dampers are interlocked with the fans. These units are powered by a bus energized by the diesel generator upon loss of offsite power but not energized post-LOCA.

The containment air enters from below the CEDMs and hot air is exhausted from the top of the CEDM shroud. CEDM shroud access and shield doors are locked and administratively controlled in their required positions to support the CEDM cooling functions. Component cooling water is supplied to the cooling coils of these units when the fan is energized.

E. The reactor cavity cooling system operates in conjunction with the containment normal cooling units and provides cooling of the primary shield and reactor cavity to maintain the concrete temperature limit of 150F maximum. The system functions continuously during normal plant operation. Portions of the system may be running during plant shutdown periods, depending on the heat loads.

The system includes four 50% capacity fan units. Normally, two units are operating and the other two units are on standby. The units are manually operated from the control room. The two standby units can be manually energized when the reactor cavity temperature reaches the allowable maximum. Four cavity high-temperature alarm channels are annunciated in the control room.

Motorized dampers, which are located in the discharge of the fans, are electrically interlocked with the fan drive motors. The dampers will close upon fan shutdown. These units are powered from a bus energized by the diesel generator upon loss of offsite power, but not post-LOCA.

F. Tendon Gallery Ventilation System

The system provides ventilation with 100% outside air by one supply fan and one exhaust fan and provides a habitable environment in the tendon gallery area.

The fans are operated manually from local switches and activated during the preaccess period.

G. MSSS Normal Ventilation System

The MSSS normal ventilation system provides once-through ventilation with 100% filtered outside air for the MSSS. The supply air units are activated from a local control panel located in the MSSS. The main steam and feedwater penetration areas to the turbine building are cooled by exhaust air from the MSSS and turbine building. The air is exhausted to the atmosphere by 100% capacity fans for each side of the MSSS. The exhaust fans are activated from a local control panel in the MSSS.

9.4.6.3 Safety Evaluation

A. Safety Evaluation One

The ducts are supported by Seismic Category I supports and HVAC equipment and ducts in the containment are designed to preclude their damaging Seismic Category I components or structures.

B. Safety Evaluation Two

Those portions of containment HVAC systems which penetrate the containment boundary have been designed to Seismic Category I requirements as detailed in section 3.2 and subsection 6.2.4.

9.4.6.4 Inspections and Testing Requirements

Acceptance testing for this system is described in section 14.2.

9.4.7 DIESEL GENERATOR BUILDING -- HVAC SYSTEM

The diesel generator building HVAC system is designed to remove heat during diesel operation and to maintain the temperature within the required limits for personnel occupancy to perform maintenance and repair.

9.4.7.1 Design Bases

9.4.7.1.1 Safety Design Bases

Safety design bases pertinent to the diesel generator building HVAC system are as follows:

A. Safety Design Basis One

The diesel generator building HVAC system shall be designed to maintain the temperatures within the limits required to ensure the operability of the equipment during emergency conditions.

B. Safety Design Basis Two

A single failure in the diesel generator building HVAC system shall not cause the complete loss of both diesel generators.

C. Safety Design Basis Three

The diesel generator building HVAC system is designed to function during and after an SSE.

9.4.7.1.2 Power Generation Design Bases

The diesel generator building HVAC system maintains the temperatures suitable for personnel performing maintenance and repair, and for the starting of the diesel engines, if required, within the diesel startup time frame.

9.4.7.1.3 Codes and Standards

The HVAC system for the diesel generator building is designed to conform to the applicable codes and standards listed in table 3.2-1.

9.4.7.2 System Description

The diesel generator HVAC system is designed to ventilate the diesel generator and the diesel generator control rooms. A separate HVAC system is provided for each compartment. Each system is powered from its respective ESF bus. The diesel generator HVAC system is shown schematically in engineering drawings 01, 02, 03-M-HDP-001.

The diesel generator room is ventilated using one 100% essential exhaust fan to maintain the temperature within the specified limits during operation of the diesel engine. When the exhaust fan is in operation, air is drawn from the outside ventilation air intake located at the opposite end of the diesel compartment from the fan.

During normal plant operation, the room is ventilated by a normal exhaust fan.

Two 50% capacity unit heaters are provided to heat the diesel generator room during normal plant operation during cold weather to maintain a minimum room temperature of 50F. The heaters are controlled by room thermostats.

During essential operation of the diesel generators the diesel generator equipment control room is ventilated by essential air handling unit and during normal plant operation by the normal air handling unit. The air is exhausted from the control room into the diesel generator room.

Each diesel fuel oil day tank room is ventilated by two redundant 100% capacity normal exhaust fans. One fan normally

operates, while the other is in standby. Air is supplied from the diesel generator room.

9.4.7.2.1 Component Description

Components of the diesel generator HVAC system are as follows:

A. Essential Exhaust Fans

   The exhaust fans are heavy duty, direct-driven, vane-axial fans.

B. Outside Air Intake

   The outside air intake is through a building opening.

C. Normal Ventilation Fans

   The normal exhaust fan is a vane-axial fan.

D. Spray Nozzles

   Spray nozzles are no longer in use; abandoned in place.

E. Unit Heaters

   The unit heaters consist of an electric resistance heater element and a fan combined in a metal housing.

F. Diesel Generator Equipment Control Room Essential Air Handling Unit

   The essential outside air supply unit for the diesel generator control room consists of a high efficiency filter and a supply fan.

G. Diesel Generator Equipment Control Room Normal Air Handling Unit

The normal air handling unit consists of a high efficiency filter and a supply fan.

9.4.7.2.2 System Operation

During essential operation, the exhaust fan will induce the flow of outside air through the outside air intake over the heat-producing equipment to pick up the heat load, and exhaust the heated air to the atmosphere. A room thermostat controls operation of the exhaust fan which limits the room air temperature to 140F maximum.

During normal plant operation, the room is ventilated by the normal ventilation fans to limit the air temperature to 122F.

The unit heater pulls air over electric resistance heater elements to heat the room air during cold weather. Room thermostats control the input to the heaters to maintain a minimum air temperature of 50F. The unit heater fan is used to provide circulation of air during maintenance and repair operations, if required.

The essential outside air supply unit will provide ventilation to the diesel generator control room to limit the temperature of this room to 122F. The filters for this unit have a dust holding capacity which exceeds the required design basis capacity.

The outside air supplied during emergency operation may carry airborne dust. The filters for the essential air handling

units are designed for an average dust loading of 1.78 mg/m^3 with an average maximum dust concentration period of 30 days. This dust loading is based on reference 2. The filter in this unit has the capacity to hold the amount of dust that is anticipated for the period of essential operation. The air will flow from the diesel generator control room to the diesel generator room.

9.4.7.3 Safety Evaluation

Safety evaluations pertinent to the heating and ventilation system are numbered to correspond to the safety design bases and are as follows:

A. Safety Evaluation One

The diesel generator building is provided with an HVAC system designed to distribute air over the diesel generator, its components, and the control equipment to maintain the maximum air temperature at or below the maximum design temperature specified in table 9.4-2. A normal unit heating system, designed to distribute tempered air in the diesel generator building, maintains the minimum temperature at or above the minimum design temperature and the maximum temperature at or below the maximum design temperature specified in table 9.4-2.

B. Safety Evaluation Two

No single failure of any component in the diesel generator building HVAC system can prevent the system from complying

with safety design basis one. A single failure analysis is provided in table 9.4-7.

C. Safety Evaluation Three

The diesel generator HVAC system fans and dampers are designed to Seismic Category I criteria.

9.4.7.4 Inspection and Testing Requirements

Preoperational testing is performed as described in section 14.2.

9.4.8 ESSENTIAL SPRAY POND PUMPHOUSE

The essential spray pond (ESP) pumphouse HVAC subsystem consists of two essential safety exhaust fans, one each for train A and train B. The function of this subsystem is to provide ventilation in the two ESP pumphouses.

Outside air (20,000 cubic feet per minute for each train) is drawn through existing missileproof entrance openings by exhaust fans HSA-J01 and HSB-J01 and exhausted through missileproof grating. Ventilation air will maintain the room design temperature of 120F based on an outside air temperature of 113F. The room temperature will also be maintained at or below the pump qualification temperature, which is 122F, based on an outdoor temperature excursion to 116F. The exhaust fan is interlocked with the pump motor so that the fan and pump run simultaneously. The fan motors are Class 1E-powered from independent Class 1E power supplies.

Table 9.4-7

HVAC SYSTEM SINGLE FAILURE ANALYSIS FOR DIESEL GENERATOR BUILDING

Component	Failure Mode/ Cause	Effects on System	Method of Detection	Inherent Compensating Provision
Diesel generator room ventilation exhaust fan	Fails to operate/ mechanical or electrical failure	Partial loss of ventilation	Temperature rise in room	Redundant diesel generator available
Room thermostat	Fails to operate	Partial loss of ventilation	Temperature rise in room	Redundant diesel generator available
Diesel generator control equipment room ventilation supply fan	Fails to operate/ mechanical or electrical failure	Loss of ventilation	Temperature rise in room	Redundant diesel generator available

9.4.8.1 Design Bases

9.4.8.1.1 Safety Design Bases

Safety design bases applicable to the ESP pumphouse HVAC subsystem are as follows:

A. Safety Design Basis One

   The essential spray pond pumphouse HVAC subsystem is designed to assure ventilation of the ESP pumphouses with outside air to maintain the temperatures within the limits required to ensure the operability of the equipment within the pumphouses during emergency or post-accident operation of the essential spray pond system (ESPS).

B. Safety Design Basis Two

   The exhaust fans are Quality Class Q, are provided with missile protection, and are designed to function during and after an SSE.

9.4.8.1.2 Power Generation Design Basis

The ESP pumphouse HVAC subsystem is designed to ventilate the pumphouses with outside air to maintain the temperatures within the limits required to ensure operability of the equipment within the pumphouses during normal plant shutdown ESPS operation.

9.4.8.1.3 Codes and Standards

The essential spray pond pumphouse HVAC subsystem is designed to conform to the applicable codes and standards listed in table 3.2-1.

9.4.8.2 System Description

The ESP pumphouse HVAC subsystem ventilates each ESP pumphouse using a single fan for each pumphouse. The A and B train pumphouses are each provided with corresponding train-related fans. The subsystem also includes necessary ductwork.

9.4.8.2.1 Component Description

The ESP pumphouses each contain one essential Quality Class Q, missile-protected exhaust fan and ductwork as described in tables 9.4-3 and 3.2-1.

9.4.8.2.2 System Operation

The essential ventilation fans for the ESP pumphouses operate whenever the ESP pumps are running. The exhaust fans induce a flow of outside air over the ESP pump motors and exhaust the heated air to the outside atmosphere. Conditions inside the pumphouses will approach outside air temperatures and normally be within the range identified in table 9.4-2.

9.4.8.3 Safety Evaluation

Safety evaluations applicable to the ESP pumphouse HVAC subsystem are numbered to correspond to the safety design bases and are as follows:

A. Safety Evaluation One

   The ESP pumphouses are provided with an HVAC subsystem designed to circulate and exhaust outside air through each pumphouse to maintain air temperatures within operability limits for the equipment within the pumphouses.

B. Safety Evaluation Two

   The ESP pumphouse HVAC essential exhaust fans and structural supports are missile-protected and designed to Seismic Category I criteria. The exhaust fans are Quality Class C.

9 4.8.4 Inspection and Testing Requirements

Preoperational testing is performed as described in section 14.2.

9.4.9 REFERENCES

1. "Particulate Characteristics of Dust Storms at the Palo Verde Nuclear Generating Station," Final Report, Arizona Public Service Company, 1978.

2. "Dust Concentration Evaluation for Palo Verde Nuclear Generating Station Units 1, 2, and 3," Study No. 13-MS-A44, Revision 0, April 23, 1990.

3. CRDR 9-3-0787, Evaluation of Lower Air Cooling Rates on the RSPTs and Cable and the Effect on Their Operating Design Service Temperature; DCP 13-FM-HC-052, Installation of Manual Backdraft Dampers on the Discharge Side of the CEDM Fans to Enable Operation on Any of the Fans Without Causing Recirculation Air Flow From the Containment Atmosphere; supplier document MN742-A00197 Palo Verde Units 1, 2, and 3 Simplified Head Assembly (SHA) CEDM Cooling System Evaluation.

9.5 OTHER AUXILIARY SYSTEMS

9.5.1 FIRE PROTECTION SYSTEM

The fire protection system (FPS) is designed to detect, contain, and extinguish fires in the plant.

The fire protection water supply and pumping equipment is shared by all units. Other fire protection equipment described below is provided for each unit individually.

Where referred to in this section, the FPS includes fire detection and extinguishing systems and equipment. It is exclusive of such design elements as physical separation, barrier separation, and burning characteristics of combustibles, which limit the propagation of fire, but do not actively extinguish it.

Appendix 9B, Fire Protection Evaluation Report, describes and discusses the effects that various postulated fires may have on areas of the plant which contain safety-related structures, systems, and components.

Carpeting or resilient floor covering is utilized in the PVNGS control room for noise and dust control, to reduce operator fatigue, and to enhance the man-machine interface. The floor covering is listed by a nationally recognized testing laboratory as having a critical radiant flux minimum of 0.45 watts per square centimeter as determined by the NFPA 253 or ASTM E 648 test method.

9.5.1.1 Design Bases

9.5.1.1.1 Safety Design Bases

Safety design bases pertinent to the FPS are as follows:

A. Safety Design Basis One

The fire protection system shall be designed to minimize, consistent with other safety requirements, the effects of fires on structures, systems, and components important to safety, in accordance with 10CFR50, Appendix A, General Design Criterion 3, Fire Protection, Appendix R, Part III, Sections G, J, and 0, and Appendix A to BTP APCSB 9.5-1.

B. Safety Design Basis Two

Fire protection systems shall be designed so that their rupture or inadvertent operation does not significantly impair the function of plant structures, systems, and components important to safety, in compliance with 10CFR50, Appendix A, General Design Criterion 3, Fire Protection.

C. Safety Design Basis Three

Fire protection system components shall be designed to preclude their structure failure due to seismic loading which could cause loss of function to safety-related systems or components, in compliance with 10CFR50, General Design Criterion 3, Fire Protection.

D. Safety Design Basis Four

American Nuclear Insurer's (ANI) recommendations shall be used as guidance such that fire hazards and potentials are reduced during construction of multiple-unit plants when one or more units are in operation.

E. Safety Design Basis Five

Structures, systems, and components important to safety shall be designed and located to minimize the fire hazards consistent with other plant safety requirements. This requirement is in compliance with 10CFR50 General Design Criterion 3, Fire Protection. Noncombustible and heat-resistant materials shall be used wherever practicable throughout the plant.

The basis fire protection for engineered safety features (ESF) shall be achieved through separation of systems serving the same safety function, by fire barriers between such installations or by providing alternate means of assuring safe shutdown. Plant fire barriers, walls, and enclosures shall be rated and located as set forth in appendix 9B.

F. Safety Design Basis Six

The fire protection system shall be designed to minimize the effects of fires and to provide the capability to control and extinguish fires encountered in the plant. Areas housing equipment necessary to achieve safe shutdown that are protected by manual fire protection shall be accessible with respect to heat, smoke, toxic combustion products, and radiation.

The firefighting component shall be located as close as practical to the area it is to serve.

G. Safety Design Basis Seven

The plant fire protection water supply system shall be capable of supplying the required flow with any one of the three fire pumps out of service. The fire protection water supply system shall be rated to supply the hydraulically calculated demand for the largest fire sprinkler or deluge system plus 500 gallons per minute for manual hose stream.

To minimize cycling of the main fire pumps, a fire water jockey pump shall be provided to maintain system pressure.

The fire water/well water reserve tanks shall be separated by a distance so as to preclude washout of one tank by failure of the other.

H. Safety Design Basis Eight

Only one of the three fire pumps shall be motor-driven, with the remaining two pumps driven by diesel engines. The motor-driven pump shall have two sources of power.

I. Safety Design Basis Nine

The fire protection water supply yard main shall be arranged so that each branch line from the yard main to the various areas in each unit's facilities may be supplied with water by alternate flow paths. Two-way supplied fire hydrants, controlled by individual curb box valves, shall be installed at approximately 250-foot

intervals within the power block area, and as required near other hazards and near other remote buildings.

J. Safety Design Basis Ten

Hydraulically balanced automatic preaction and wet pipe sprinkler systems and hydraulically designed automatic water spray systems shall be installed in areas with a high fire potential. Criteria for determining the need for these systems shall be in substantial compliance with the following guidelines:

- ANI guidelines, Basic Fire Protection for Nuclear Power Plants, April 1976.
- Appendix A to Branch Technical Position APCSB 9.5-1, Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976 (revised February 24, 1977).

K. Safety Design Basis Eleven

Automatic low-pressure carbon dioxide flooding systems shall be provided for normally unoccupied electrical equipment and battery rooms that are safety-related. Hand hose lines supplied with low-pressure carbon dioxide from a central storage unit shall be provided for use in areas near nonsafety-related switchgear and motor starter panels.

L. Safety Design Basis Twelve

For equipment located in the remote shutdown rooms, computer room, the inverter room, and the communications equipment room, Halon 1301 flooding systems shall be

provided. In the occupied areas of the control room complex, portable water and carbon dioxide fire extinguishers shall be installed. Portable CO_2 extinguishers in the control room for manual firefighting shall not result in an uninhabitable condition within the room if the extinguishers are discharged since adequate ventilation is provided.

M. Safety Design Basis Thirteen

Fire hose stations shall be provided for all buildings and all floors, and spacing shall be such that normally accessible areas can be covered by 75- or 100-foot hoses where practical. Isolated cases may allow the use of 125- or 150-foot hose lengths if necessary.

N. Safety Design Basis Fourteen

Portable fire extinguishers shall be provided throughout normally accessible areas of the plant using the guidelines of NFPA 10 (1975) as referenced in table 9B.3-1.

O. Safety Design Basis Fifteen

Alarms shall be provided in the control room to function upon activation of automatic fire protection systems. Fire detection systems shall be installed in areas where a potential for fire exists. These detection systems shall alarm locally and in the control room.

P. Safety Design Basis Sixteen

Fire protective clothing and respiratory apparatus for use by plant firefighting personnel shall be provided

for use in fires which could produce an adverse environment and thus preclude manual fire suppression or could inhibit manual firefighting operations.

Q. Safety Design Basis Seventeen

Fire dampers shall be provided in those ventilation ducts penetrating rated fire barriers and penetration seals shall be provided for pipe, electrical raceways, or similar openings and shall provide fire protection equal to or greater than the rating of the fire barrier penetrated. Fire doors or the equivalent shall be installed in door openings through rated barriers.

R. Safety Design Basis Eighteen

Emergency lighting systems shall be provided in accordance with the guidance provided in Appendix A to NRC Branch Technical Position APCSB 9.5-1 (revised February 24, 1977) and 10CFR50, Appendix R, Section III.J (issued September 1, 1982), in areas needed for the local manual operation of safe shutdown equipment and in access and egress routes thereto in the event of a fire.

The emergency lighting fixtures shall be selected to be applicable to the areas in which they are installed and shall not necessarily include or exclude sealed beam units. Selection of fixtures and bulbs shall allow normal movement during emergency conditions.

Batteries for emergency lighting shall be rated for a minimum of 8 hours in areas needed for the operation of

safe shutdown equipment and in access and egress routes to these areas

The emergency lighting fixtures may or may not normally be lighted but shall automatically energize upon loss of essential ac, in areas where essential lighting is provided, or upon loss of normal ac, in areas where essential lighting is not provided.

The emergency lighting system is described in subsection 9.5.3.

Applicable codes and regulations of the State of Arizona, the National Fire Codes of the National Fire Protection Association (NFPA), and applicable sections of Title 29, Chapter XVII, Part 1910, Occupational Safety and Health Standards of the Code of Federal Regulations, as set forth in the Federal Register, Volume 37, Number 202, dated October 18, 1972, have been used as guidance in developing the plant fire protection system design.

9.5.1.2 System Description

The water and gaseous portions of the fire protection systems are shown schematically in engineering drawings 01, 02, 03-M-FPP-002, -003, -004, -006, A0-M-FPP-001 and A0-M-FFP-005.

Table 9.5-1 provides a tabulation of the types of fire protection and fire detection and actuating devices provided for each specific area in the plant.

Each unit's fire protection system is comprised of diversified monitoring, detection, alarm, suppression, and extinguishment

facilities particularly selected to protect the area or equipment from damage by fire. The system includes the following major features:

- Fire protection water supplies, yard mains, and hydrants
- Wet pipe sprinkler systems (hydraulically designed)
- Deluge water spray systems (hydraulically designed)
- Automatic preaction systems (hydraulically designed)
- Low-pressure carbon dioxide systems
- Halon 1301 systems
- Standpipes and fire hose stations
- Portable CO_2 and dry chemical (ABC powder) fire extinguishers
- Fire and smoke monitoring, detection, and alarm systems
- Fire walls and barriers

9.5.1.2.1 Component Description

Components of the plant fire protection system are selected to provide comprehensive protection against fire hazards throughout the plant.

A. Fire Protection Water Supplies

The primary water source for the fire water system is two 500,000 gallon carbon steel tanks located near the water reclamation facility boundary. These tanks are designated as the fire water/well water reserve tanks. Of the 500,000 gallons stored within each tank,

300,000 gallons are dedicated for fire protection. The remaining 200,000 gallons are available for fire protection and other uses by means of suction piping that penetrates each tank above the 300,000-gallon level. Makeup water for the fire water/well water reserve tanks is supplied by either of two site wells known as (B-1-6) 34abb and (B-1-6) 27dd (Arizona well numbering system).

Table 9.5-1
FIRE PROTECTION FOR AREAS AND EQUIPMENT[a] (Sheet 1 of 9)

Areas of Equipment	Primary Fire Protection	Backup Fire Protection	Detection Device for Primary Fire Protection	Safety-Related Area	Accessibility Restrictions		
					Heat	Radiation	Toxic Combustion Products
Outside Areas							
Exterior coverage of buildings	OH	None	V	No	P	O	P
Main transformers and isophase Bus	WS	OH	HAD	No	P	O	P
ESF service transformers	WS	OH	HAD	No	P	O	P
Auxiliary transformer	WS	OH	HAD	No	P	O	P
Normal service transformers	WS	OH	HAD	No	P	O	P
Startup transformers	WS	OH	HAD	No	P	O	P
Auxiliary boilers (Abandoned)	OH	NONE	V	No	P	O	P
Lube oil storage tanks	WS	OH	HAD	No	P	O	P
Diesel-driven fire pump areas	W	OH,PX	S	No	P	O	P
Condensate storage tank, transfer pumps and tunnel	OH	NONE	V	Yes	P	O	P
Diesel generator fuel oil storage tank and transfer pumps	OH	NONE	V	Yes	P	O	P
Refueling water storage tank	OH	NONE	V	Yes	P	O	P
Essential spray pond and spray pond pumps	OH	NONE	V	Yes	P	O	P
Station Blackout Generators	CD	OH	HAD, I	No	P	O	P
Turbine Building							
Turbine building areas, 100 ft. El.	W	WHS,PX	S,L	No	P	O	P
Turbine building areas, 140 ft. El.	W	WHS,PX	S	No	P	O	P
Turbine bearings	PA	WHS,PX	HAD	No	P	O	P
Oil piping and reservoir for steam generator feedwater pumps	WS	WHS,PX	HAD	No	P	O	P
Conditioner area and piping for turbine lubricating oil	WS	WHS,PX	HAD	No	P	O	P
Hydrogen seal oil unit	WS	WHS,PX	HAD	No	P	O	P
Reservoir area for turbine lubricating oil	WS	WHS,PX	HAD	No	P	O	P

Table 9.5-1
FIRE PROTECTION FOR AREAS AND EQUIPMENT[(a)] (Sheet 2 of 9)

Areas of Equipment	Primary Fire Protection	Backup Fire Protection	Detection Device for Primary Fire Protection	Safety-Related Area	Accessibility Restrictions		
					Heat	Radiation	Toxic Combustion Products
Non-ESF Switchgear Building	CDH	PX	V	No	P	O	P
Service Building	W	WHS, PX	S	No	P	O	P
Laundry Area (Unit 1 only)	PX	OH	V	No	P	O	P
Administration Complex Building "B"							
• Computer room	W	PX	I	No	P	O	P
• Record vault	W	PX	I	No	P	O	P
• Plant simulator control board room	W	PX	I	No	P	O	P
• Test Panel Area	W	PX	I	No	P	O	P
• All other areas of Administration building	W	WHS,PX	I,S	No	P	O	P
Control Building-El. 74 ft.							
• Chiller room, train B	WHS	PX	I	Yes	P	O	P
• Chiller room, train A	WHS	PX	I	Yes	P	O	P
• Cable shaft, train A	WHS	PX	I	Yes	P	O	P
• Cable shaft, train B	WHS	PX	I	Yes	P	O	P

Table 9.5-1
FIRE PROTECTION FOR AREAS AND EQUIPMENT[a] (Sheet 3 of 9)

Areas of Equipment	Primary Fire Protection	Backup Fire Protection	Detection Device for Primary Fire Protection	Safety-Related Area	Accessibility Restrictions		
					Heat	Radiation	Toxic Combustion Products
Control Building - El. 100 ft							
• ESF switchgear room, trains A and B	CD	WHS,PX	I,HAD	Yes	P	O	P
• Remote shutdown rooms	H	WHS,PX	I,HAD	Yes	P	O	P
• Battery room, CH C	CD	WHS,PX	I,HAD	Yes	P	O	P
• DC equip. room, CH C	WHS	PX	I	Yes	P	O	P
• Battery room, CH D	CD	WHS,PX	I,HAD	Yes	P	O	P
• DC equip. room, CH D	WHS	PX	I	Yes	P	O	P
• Battery room, CH A	CD	WHS,PX	I,HAD	Yes	P	O	P
• DC equip. room, CH A	WHS	PX	I	Yes	P	O	P
• Battery room, CH B	CD	WHS,PX	I,HAD	Yes	P	O	P
• DC equip. room, CH B	WHS	PX	I	Yes	P	O	P
• Cable shaft, train A	WHS	PX	I	Yes	P	O	P
• Cable shaft, train B	WHS	PX	I	Yes	P	O	P
Control Building - El. 120 ft							
• Lower cable, spreading room	PA	WHS,PX	I,L,S	Yes	P	O	P
• Cable shaft, train A	WHS	PX	I	Yes	P	O	P
• Communications room	H	PX,WHS	I	Yes	P	O	P
• Cable shaft, train B	WHS	PX	I	Yes	P	O	P
• Inverter room	H	PX,WHS	I	Yes	P	O	P

Table 9.5-1
FIRE PROTECTION FOR AREAS AND EQUIPMENT[a] (Sheet 4 of 9)

Areas of Equipment	Primary Fire Protection	Backup Fire Protection	Detection Device for Primary Fire Protection	Safety-Related Area	Accessibility Restrictions		
					Heat	Radiation	Toxic Combustion Products
Control Building - El. 140 ft							
• Control room	PX	WHS	I,V	Yes	P	O	P
• Cable shaft, train A	PX	WHS	I	Yes	P	O	P
• Computer room	H	PX,WHS	I,V	Yes	P	O	P
• BOP cable shaft (access via El. 120 ft)	WHS	PX	I	No	P	O	P
• Kitchen and office area	PX	WHS	I	No	P	O	P
Control Building - El. 160 ft							
• Upper cable spreading room	PA	WHS,PX	I,L,S	Yes	P	O	P
• Cable shaft, train A	WHS	PX	I	Yes	P	O	P
• Normal smoke exhaust room	WHS	PX	I	Yes	P	O	P
• BOP cable chase	WHS	PX	I	No	P	O	P
• HVAC intake plenum	WHS	PX	I	Yes	P	O	P
Auxiliary Building - El. 40 ft							
• ESF pump rooms, trains A and B (LPSI, HPSI, and containment spray)	PA	WHS, PX	I,S	Yes	P	O	P
Auxiliary Building - El. 51 ft 6 in., 70 ft. 77 ft. and 88 ft							
• West corridor, El. 51 ft	WHS	PX	I	Yes	P	O	P
• East corridor, El. 51 ft	WHS	PX	I	Yes	P	O	P
• ECW pump room, train A	WHS	PX	I	Yes	P	O	P

Table 9.5-1
FIRE PROTECTION FOR AREAS AND EQUIPMENT[(a)] (Sheet 5 of 9)

Areas of Equipment	Primary Fire Protection	Backup Fire Protection	Detection Device for Primary Fire Protection	Safety-Related Area	Accessibility Restrictions		
					Heat	Radiation	Toxic Combustion Products
Auxiliary Building - El. 51 ft 6 in., 70 ft. 77 ft, and 88 ft (Cont)							
• ECW pump room, train B	WHS	PX	I	Yes	P	O	P
• Shutdown cooling HX, train A	WHS	PX	I	Yes	P	O	P
• Shutdown cooling HX, train B	WHS	PX	I	Yes	P	O	P
• Reactor makeup pumps	WHS	PX	I	Yes	P	O	P
• Pipe penetration room, Train A (El. 77 ft And 70 ft)	WHS	PX	I	Yes	P	O	P
• Pipe penetration room, Train B (El. 77 ft And 70 ft)	WHS	PX	I	Yes	P	O	P
• Corridor cable trays, West side, El. 70 ft	WHS	PX	I	Yes	P	O	P
• Corridor cable trays, East side, El. 70 ft	WHS	PX	I	Yes	P	O	P
• Pipeway area, train A El. 88 ft	WHS	PX	I	Yes	P	O	P
• Pipeway area, train B El. 88 ft	WHS	PX	I	Yes	P	O	P
Auxiliary Building - El. 100 ft							
• Cable penetration room, CH B	PA	WHS,PX	I,L,S	Yes	P	O	P
• Corridor cable trays, west side	PA	WHS,PX	S,I,L	Yes	P	O	P
• Cable penetration room, CH C	PA	WHS,PX	I,L,S	Yes	P	O	P
• Corridor cable trays, east side	PA	WHS,PX	S,I,L	Yes	P	O	P

Table 9.5-1
FIRE PROTECTION FOR AREAS AND EQUIPMENT[a] (Sheet 6 of 9)

Areas of Equipment	Primary Fire Protection	Backup Fire Protection	Detection Device for Primary Fire Protection	Safety-Related Area	Accessibility Restrictions		
					Heat	Radiation	Toxic Combustion Products
Auxiliary Building - El. 120 ft							
• Cable penetration room, CH A	PA	WHS,PX	I,L,S	Yes	P	O	P
• Corridor cable trays, west side	PA	WHS,PX	S,I,L	Yes	P	O	P
• Cable penetration room, CH D	PA	WHS,PX	I,L,S	Yes	P	O	P
• Corridor cable trays, east side	PA	WHS,PX	S,I,L	Yes	P	O	P
• MG sets	WHS	PX	I	Yes	P	O	P
Auxiliary Building - El. 140 ft							
• Personnel access area	W	WHS,PX	I,S	No	P	O	P
• Storage area	W	WHS,PX	I,S	Yes	P	O	P
• Hot lab cold lab areas	PX	WHS	I	No	P	O	P
• Personnel decontamination	WHS	PX	I	No	P	O	P
• Locker room	W	PX	I,S	Yes	P	O	P
Radwaste Building							
• Baler area	W	WHS,PX	S	No	P	O	P
• Truck bay	WHS	PX	I	No	P	O	P
• MCC at El. 100 ft	WHS	PX	I	No	P	O	P
• Cable shaft at El. 100 ft	WHS	PX	I	No	P	O	P
• Radwaste control room, El. 120 ft	WHS	PX	V	No	P	O	P
• Cable shaft at El. 120 ft	WHS	PX	I	No	P	O	P

Table 9.5-1
FIRE PROTECTION FOR AREAS AND EQUIPMENT[(a)] (Sheet 7 of 9)

Areas of Equipment	Primary Fire Protection	Backup Fire Protection	Detection Device for Primary Fire Protection	Safety-Related Area	Accessibility Restrictions		
					Heat	Radiation	Toxic Combustion Products
Radwaste Building (Cont)							
• MCC at LC at El. 140 ft	WHS	PX	I	No	P	O	P
• Cable shaft at El. 140 ft	WHS	PX	I	No	P	O	P
Diesel Generator Building							
• Diesel gen., train A	PA	OH,PX	UV,S,HAD	Yes	P	O	P
• Fuel oil day tank vault, train A	PA	PX,WHS	S,HAD	Yes	P	O	P
• Diesel gen. train B	PA	OH,PX	UV,S,HAD	Yes	P	O	P
• Fuel oil day tank vault, train B	PA	PX,WHS	S,HAD	Yes	P	O	P
• Control room, train A	PX	WHS	I	Yes	P	O	P
• Control room, train B	PX	WHS	I	Yes	P	O	P
• Air filter, train A	WHS	PX	UV	Yes	P	O	P
• Air filter, train B	WHS	PX	UV	Yes	P	O	P
Fuel Building							
• Railroad bay and char-coal filtration units	W	WHS,PX	S,I	Yes	P	O	P
• Spent fuel pool HX and pump area, El. 100 ft	WHS	PX	I	Yes	P	O	P
• New fuel storage area El. 140 ft	WHS	PX	I	Yes	P	O	P
Containment Building							
• No. 1 steam generator cavity	WHS	PX	I,PE	Yes	P	O	P
• No. 2 steam generator cavity	WHS	PX	I,PE	Yes	P	O	P

Table 9.5-1
FIRE PROTECTION FOR AREAS AND EQUIPMENT[(a)] (Sheet 8 of 9)

Areas of Equipment	Primary Fire Protection	Backup Fire Protection	Detection Device for Primary Fire Protection	Safety-Related Area	Accessibility Restrictions: Heat	Radiation	Toxic Combustion Products
Containment Building (Cont)							
• Cable trays, El. 100 ft	WHS	PX	L,I	Yes	P	O	P
• Cable trays, El. 120 ft	WHS	PX	L,I	Yes	P	O	P
• CEDM area	PA	PX	I,HAD	Yes	P	O	P
• Cable trays, El. 140 ft	WHS	PX	L,I	Yes	P	O	P
• Air cooling unit, train A	WHS	PX	PE	Yes	P	O	P
• Air cooling unit, train B	WHS	PX	PE	Yes	P	O	P
Main Steam Support Structure							
• Motor-driven pump room	PX	PX	V	Yes	P	O	P
• Valve area, 100 ft to 160 ft	PA	PX	S,HAD	Yes	P	O	P
• Oil piping and reservoir for turbine-driven auxiliary feedwater pump	PA	PX	I,S	Yes	P	O	P
Dry Active Waste Processing and Storage Facility							
• Waste storage area	W	WHS,PX	S	No	P	O	P
• Processing area	W	WHS,PX	S	No	P	O	P
• Offices and change area	W	PX	S	No	P	O	P

Table 9.5-1

FIRE PROTECTION FOR AREAS AND EQUIPMENT[a] (Sheet 9 of 9)

LEGEND

System:	OH	Outside hydrants
	W	Wet pipe sprinkler system
	WS	Deluge water spray system
	PA	Automatic preaction sprinkler system
	CD	Fixed CO_2 system
	CDH	CO_2 hose reels
	H	Halon 1301 system
	WHS	Water hose station
	PX	Portable extinguishers
Detection:	V	Visual
	S	Sprinkler head (melting of fusible link)
	HAD	Heat-actuating device (fixed temp/rate of rise)
	I	Ionization detector (invisible smoke)
	L	Line-type heat detector
	UV	Ultraviolet detector (flame or spark)
	PE	Photoelectric smoke detector
Accessibility:	O	No special protective device required
	P	Protective device required

B. Fire Pumps and Distribution System

Fire water is supplied by three 50% horizontal centrifugal fire pumps, two of which are driven by diesel engines and the third by an electric motor. The fire pumps take suction from either or both of the fire water/well water reserve tanks and distribution to the power block loop is accomplished by two redundant discharge lines.

To minimize unnecessary starting of the fire pumps, a motor-driven jockey pump is provided to maintain fire water header pressure when there is little or no flow requirement. When flow to the fire water system is required, the fire pumps are designed to start sequentially to decreasingly lower pressures in the fire main.

C. Yard Mains, Hydrants, and Valves

The fire protection water main consists primarily of a closed 12-inch underground loop encompassing all units, the service and administration buildings, and site construction buildings. The underground piping throughout the yard area is either cement mortar-lined (ductile) cast iron, Class 150, with Tyton joints or reinforced fiberglass, ASTM D2996, with adhesive-bonded bell and spigot joints.

The yard main is provided with post-indicator valves for sectional control. Post-indicator valves are also located such that the yard loop for any individual power block can be isolated from the yard loops of the

remaining units. Manually-operated water supply gate valves, installed in the automatic preaction sprinkler, wet pipe sprinkler, and deluge water spray systems, are used during plant construction to isolate the parts of the fire protection system that are functional from those parts of the system still under construction.

Outside hydrants are provided at approximately 250-foot intervals within the power block area and as required near other hazards and near other remote buildings. Hydrants are equipped with 2-1/2-inch hose connections.

In the unlikely event that the plant fire pumps cannot furnish an adequate water supply to the distribution system, the yard main includes pump connections for obtaining water from the circulating water system cooling tower basin by using portable pumping units.

D. Wet Pipe Sprinkler Systems

Wet pipe sprinklers, hydraulically designed using NFPA Pamphlet No. 13 (1976) as guidance, are provided to protect the areas so indicated in table 9.5-1. Each wet pipe system provides fusible-link sprinkler heads arranged such that water flow densities meet the requirements of ANI, and also NFPA Pamphlet No.13 (1976).

E. Deluge Water Spray Systems

Deluge water spray systems, hydraulically designed using NFPA Pamphlet No. 15 (1973) as guidance, are provided to protect the equipment so indicated in table 9.5-1. Each deluge water spray system provides

open head spray nozzles arranged and directed such that water flow densities meet the guidelines of ANI, and also NFPA Pamphlet No. 15 (1973).

F. Automatic Preaction Sprinkler Systems

Automatic preaction sprinklers, hydraulically designed using NFPA Pamphlet No. 13 (1976) as guidance, are provided to protect the areas so indicated in table 9.5-1. Each automatic preaction system contains piping supervised by service air and fusible link sprinkler heads arranged such that flow densities meet the guidelines of ANI, and also NFPA Pamphlet No. 13 (1976).

G. Low-Pressure Carbon Dioxide Systems

Low-pressure carbon dioxide systems, designed using NPFA Pamphlet No. 12 (1973) as guidance, are provided for total flooding and local hand hose application in those areas so indicated in table 9.5-1. Each CO_2 flooding system, when activated, provides a 50% concentration of CO_2 by volume in the hazard area. Discharge nozzles are oriented such that direct impingement of CO_2 liquid/vapor upon equipment is avoided.

H. Halon 1301 Systems

Halon 1301 fire suppression flooding systems, designed using NFPA Pamphlet No. 12A (1973) as guidance, are provided to protect the areas so indicated in table 9.5-1. All system components are Underwriters

Laboratories (UL)-listed or Factory Mutual (FM)-approved. Each Halon system, when activated, provides a minimum (maximum) Halon concentration of 5% (7%) by volume in occupied hazard areas, and 5% (10%) by volume in unoccupied areas or areas evacuable within 1 minute as provided by NFPA Pamphlet 12A (1973), Section 2-1.1.3.

I. Standpipes and Hoses

Wet standpipes for fire hoses are designed using NFPA Pamphlet No. 14 (1976) as guidance. Standpipes are provided for all buildings and all floors. Four-inch standpipes are provided for multiple hose connections and 2-1/2-inch standpipes are provided for single hose connections. The standpipe hose connections are equipped with 1-1/2-inch hose valves and either 75 or 100 feet (or in isolated cases 125 or 150 feet) of 1-1/2-inch woven jacket lined hose. Adjustable spray nozzles are used for areas where nonelectrical fires might occur, and approved fog nozzles (Class C) are used in areas where electrical fires might occur.

J. Dry Chemical Systems

Dry chemical extinguishing systems consist of a 350-pound dry chemical powder tank and gas cylinder mounted on a mobile chassis. The unit is equipped with 50 feet of 3/4-inch hose and a nozzle designed for local application of dry chemical powder.

K. Portable Fire Extinguishers

Portable fire extinguishers for manual extinguishment of fires are provided throughout normally accessible areas of the plant and in occupied areas of the control room utilizing the guidelines of NFPA 10 (1975) as referenced in table 9B.3-1. Portable extinguishers of the multipurpose type for use on Classes A, B, and C fires have a capacity of 20 pounds of dry chemical (ABC powder) and are rated by UL as 10-A:40-B:C. The units are UL-labeled. Portable extinguishers for Classes B and C fires have a capacity of 20 pounds of carbon dioxide, have a minimum UL rating of 10-B:C, and are UL-labeled.

L. Fire Barriers

Fire barrier walls and floors, and walls within 50 feet of oil-filled transformers, are located and rated in accordance with ANI guidelines, Basic Fire Protection for Nuclear Power Plants, April 1976. All fire barriers applicable to safety-related areas are shown and discussed in appendix 9B. Where ventilation systems penetrate these barriers, fire dampers providing fire protection equal to or greater than the penetrated wall ratings are provided. All cable tray, conduit, HVAC duct, and piping penetrations through fire barriers are sealed using seal designs of equal or greater rating than the rating of the penetrated barriers. Penetration seals meet the acceptance

criteria of ASTM Standard E119 (1976) or IEEE-634 (1978).

Where door openings penetrate rated barriers, the openings are protected by door assemblies providing fire protection equal to or greater than the rating of the penetrated barrier. All fire doors shall be purchased as UL- or FM-labeled doors except as noted in the appendix 9A response to Question 9A.106.

M. Fire and Smoke Monitoring, Detection, and Alarm System

Fire and smoke monitoring, detection, and alarm is accomplished by ionization (I), photoelectric (PE), and ultraviolet (UV) detectors, and by heat responsive or heat-actuated devices (HAD) in areas as indicated in table 9.5-1.

Selection, placement, and spacing of fire monitoring, detection, and alarm devices are based on consideration of design, configuration, and employment of the area together with draft conditions due to natural or mechanical ventilation.

The fire and smoke monitoring, detection, and alarm system includes a supervisory circuit that indicates the failure of individual circuits and detectors. Both monitoring and supervisory alarm signals register locally and in the control room. In the control room, incoming FPS alarms activate audible and visual annunciators individually or in groups.

A computerized visual display is provided in the control room for the appraisal and trend evaluation of

incoming FPS alarms. The display alarm messages indicate the area of the plant that initiated the alarm and if an automatic or fixed manual fire extinguishing system is in operation. Fire protection system alarms are also indicated on local fire zone indicating panels.

9.5.1.2.2 System Operation

Operation of the FPS is described briefly as follows:

A. Fire Protection Water Supplies

Water for the fire water/well water reserve tanks is supplied by the site deep-well pumps. Both fire water/well water reserve tanks are normally filled simultaneously through either a two-inch or an eight-inch makeup control valve. Although the tanks are normally filled simultaneously, each tank may be filled individually by closing the appropriate isolation valves. During normal filling operations (tank levels above 400,000 gallons), the fire water/well water reserve tanks are filled through the two-inch control valve. For tank levels below 400,000 gallons, makeup is provided through the eight-inch control valve. Both deep-well pumps automatically start whenever either fire water/well water reserve tank level decreases below 388,000 gallons. Each deep-well pump is rated at approximately 1,400 gallons per minute. One pump is capable of completely filling one tank in less than eight hours.

Suction pipes for other water uses are located in such a manner as to avoid tapping the lower 300,000-gallon portion of each storage tank for that is dedicated for fire protection purposes.

The fire water/well water reserve tanks have provisions for chemical addition from a nearby chemical addition skid. Chemical addition to the fire water/well water reserve tanks and the fire protection water system is required for corrosion control.

The two fire water/well water reserve tanks are interconnected through normally open valves, both on the FPS water suction pipe side and on the makeup water supply side. Water level in the tanks is controlled by dual level controllers and the makeup control valves located in the common water supply line to the two tanks. Each tank is provided with a level controller, a local level indicator, and high and low level alarm switches. High and low level alarms are annunciated in the control room.

B. Fire Pumps and Distribution System

During normal operation, the fire protection water system is kept continuously full and pressurized by the jockey pump.

When significant flow (more than 40 gallons per minute) is required to the fire water system, the fire pumps are designed to start sequentially on decreasingly lower pressures in the fire main. Normally, the first fire pump to start would be the motor-driven fire pump

when the pressure in the fire main header drops to 95 psig. If the fire main pressure drops below 90 psig and remains below that point for at least 20 seconds, the first diesel-driven fire pump cycles on. The second diesel-driven fire pump will cycle on if the pressure in the fire main header drops below 85 psig and remains below that pressure for at least 30 seconds. These time delays for the diesel-driven pumps preclude excessive cycling when there is a sudden drop of fire main pressure through all three setpoints and when a single 1500 gallons per minute pump can fulfill the system demand. The diesel fire pumps continue to run until shut off manually by the operator.

In accordance with NFPA No. 20 (1976), remote alarms and indications are provided in the main control room for the following conditions:

- Diesel malfunction (common alarm includes items such as low lube oil pressure, high jacket water temperature, engine failure to start automatically, engine overspeed trip, loss of battery charger, battery failure, and fuel oil day tank low level)
- Controller main switch not in automatic
- Diesel pump running

To run performance tests, discharge of each fire pump can be routed back to the fire water/well water reserve

tanks through a flow element and through normally closed valves.

C. Yard Mains, Hydrants, and Valves

During normal operation, the yard main piping is kept continuously full and pressurized to 110 psig. If portions of the fire main need to be taken out of service for maintenance, appropriate post-indicator valves are manually closed to facilitate these repairs. The jockey pump maintains the yard main piping pressurized. Any failure of the yard main piping due to excessive leakage, greater than jockey pump capability, or rupture is detected by main fire pump operation without a fire alarm.

Post-indicator valves are positioned on the fire main such that no more than four side branches from the main are affected by the closing of two valves in one vicinity. Post-indicator valves are also located in each branch line from the main so that these lines can be isolated if necessary. Post-indicator valves are cast iron, with a nonrising stem with a 2-inch square operating nut. Valves are opened by turning the nut counterclockwise. Most post-indicator valves have post-indicators that extend a minimum distance of 3 feet above the ground. The post-indicator valves that do not have above grade post-indicators, are provided with position indicators located below grade and access covers to allow verification of valve position.

Operation of outside fire hydrants is intended for use only by trained firefighting personnel. Hydrants are of the dry-barrel type with a 6-inch flanged joint inlet, two 2-1/2-inch hose nozzles, and one 4-1/2-inch steamer nozzle, all with National Standard threads. The PVNGS fire department has emergency response vehicle(s) which carry an assortment of hoses, nozzles, and auxiliary equipment in lieu of hose houses.

D. Wet Pipe Sprinkler Systems

Wet pipe sprinkler system operation is initiated on a rise in ambient temperature to the melting point of fusible links on sealed sprinkler heads, thus permitting the spray heads to open. Flow of water through the alarm check valve energizes local alarms and registers an alarm condition in the control room. Once initiated, wet sprinkler system operation is terminated manually by shutting a local gate valve adjacent to the system alarm check valve or by shutting the appropriate post-indicator valve in the yard.

E. Deluge Water Spray Systems

Deluge water spray system operation (except those systems protecting electrical cable trays) is initiated by an electric thermostat-type heat responsive device that senses either a rapid rise in ambient temperature or attainment of a high fixed-temperature, and releases a tripping device that opens the deluge valve supplying water under pressure to open deluge nozzles. Actuation of the heat-responsive device also initiates a local

alarm and registers the alarm condition in the control room independently of water flow in the system. Manual release of the deluge valve tripping device also initiates local and remote alarms. System operation is terminated by manually shutting a local gate valve adjacent to the system deluge valve.

Deluge water spray system operation for those systems protecting electrical cable trays is initiated by a combination of line-type heat detectors and product-of-combustion detectors that sense heat and smoke respectively and release a tripping device that opens the deluge valve. Actuation of either of these detection devices without the other will initiate local and remote alarms but will not release the deluge valve.

F. Automatic Preaction Sprinkler Systems

Automatic preaction sprinkler system operation (except those systems protecting electrical cable trays and the turbine driven auxiliary feedwater pump room) is initiated by the product-of-combustion detectors. When a detector senses the products of combustion, it releases a tripping device which opens the deluge valve and pressurizes the system with water.

Automatic preaction sprinkler system operation for the turbine driven auxiliary feedwater pump room is initiated by cross-zoned, product-of-combustion detectors. When two of these detectors (one from each zone) sense the products of combustion, they release a

tripping device that opens the deluge valve and pressurizes the system with water.

Automatic preaction sprinkler system operation for those systems protecting electrical cable trays is initiated by either line-type heat detectors or product-of-combustion detectors. When either the line-type heat detectors sense heat or the product-of-combustion detectors sense smoke, they release a tripping device that opens the deluge valve and pressurizes the system with water.

Actuation of the detectors also initiates a local alarm and registers the alarm condition in the control room. Actual flow of water upon the hazard area does not occur until the rise in ambient temperature reaches the melting point of fusible links of sealed sprinkler heads, thereby permitting flow through the head. Once water flow is initiated, system operation can be terminated by manually shutting a local gate valve adjacent to the system deluge valve.

G. Low-Pressure Carbon Dioxide Systems

Operation of the automatic low-pressure carbon dioxide total flooding system is activated by fire detection devices located within the hazard areas using NFPA No. 72E-1978, Standard on Automatic Fire Detectors, as guidance. The fire detection devices are arranged in a cross-zone logic configuration to provide early warning and minimize the potential of inadvertent carbon dioxide (CO_2) discharges. The system can be activated

either automatically by the fire detection devices or manually. A timed predischarge alarm is provided to allow occupants in the hazard area to exit safely prior to CO_2 discharge. Operation status of the system is monitored in the control room as described in paragraph 9.5.1.2.1, listing M.

The following sequence of events takes place during activation of the CO_2 system:

1. Activation of one or more fire detection devices on a single zone circuit.

   a. Local alarm bell activates to warn personnel of a fire and potential CO_2 discharge.

   b. Alarm condition is registered in the control room.

2. Activation of one or more fire detection devices on two zone circuits.

   a. Predischarge alarm circuit energizes and local siren activates for personnel evacuation.

   b. A CO_2 system activation condition is registered in the control room.

   c. Fans and dampers are placed in a configuration to isolate the hazard area.

   d. Following the predischarge alarm, the CO_2 discharge circuit is energized for the required master valve and selector valve operation.

e. The selector valve for the hazard area opens and releases CO_2 for a predetermined discharge interval.

f. Upon completion of the discharge cycle, the discharge circuit is deenergized and flow of CO_2 is stopped.

The alarm condition is maintained until the system is reset manually.

Conveniently located pushbutton stations are provided for each hazard area for manual operation. These stations enable personnel to place the system in operation in the event that fire is observed before a detector has been actuated. The pushbutton systems have a guard or other design feature to prevent accidental actuation.

An electro-manual pilot cabinet is included for each master valve. These valves are normally energized so that the master valves open automatically in case of electric power interruption and pressure the discharge headers up to the selector valves. An operating lever also enables personnel to operate the master pilot valve manually, thereby opening the master valve.

An electro-manual pilot cabinet normally deenergized with a supervised 1/4-inch, lever-operated shutoff valve is also included for each hazard area. These serve to pilot the automatic selector valves on normal system operation. An operating lever enables personnel to operate the system manually in the event of electric

power interruption. The shutoff valve precludes the discharge of CO_2 into the hazard area while occupied by personnel.

Operation of CO_2 hose reels for local application is initiated by manually removing the playpipe from its support bracket, thereby causing the master valve at the storage tank to open and charge the piping up to the nozzle. Discharge of CO_2 is controlled by utilizing the squeeze-type valve at the nozzle. Replacement of the playpipe on its support closes the master valve.

H. Halon 1301 Systems

Halon 1301 system operation is prealarmed by the product of combustion and actuated by thermal detectors in the remote shutdown rooms, and by product-of-combustion detectors that are cross-zoned in the computer, communication, and inverter rooms. Actuation of the first circuit (or loop) on the cross-zoned systems accomplishes the following function:

- Energizes an audible and visual alarm

The actuation of second circuit (or loop) on the cross-zoned system shall accomplish the following functions:

- Audible and visual alarm energized. Predischarge alarm circuit energizes and local alarm sounds for personnel evacuation.
- HVAC dampers closed

- Magnetic door holders released, if applicable (i.e., if the doors are not normally closed)
- Halon discharged

Manual pull stations are provided for system actuation. The detection system trips the release valve assembly on the agent storage cylinder to discharge the total capacity of the agent storage cylinder. In this manner, a minimum (maximum) Halon 1301 concentration of 5% (7%) by volume is achieved in the occupied hazard areas, and 5% (10%) by volume in unoccupied areas or areas evacuable within 1 minute as provided by NFPA Pamphlet 12A (1973), Section 2-1.1.3. Alarms are also provided in the control room for Halon discharge and Halon system malfunctions. A concentration level of up to 7% Halon 1301 in the computer room may be inhaled by personnel for 4 or 5 minutes without risk of serious effects. The control room will remain habitable at all times.

I. Standpipes and Hoses

Inside hose stations are intended to be operated by plant personnel for the manual control of small fires. Adjustable spray nozzles are used for areas where non-electrical fires might occur, and approved fog nozzles (Class C) are used in areas where electrical fires might occur.

J. Dry Chemical Systems

The 350-pound dry chemical extinguisher is wheeled to the vicinity of Class A (ordinary combustible materials), Class B (flammable liquids, gases, and greases), or Class C (energized electrical equipment) fires. After it is wheeled to the appropriate fire area, the dry chemical extinguisher is operated manually by plant personnel.

K. Portable Fire Extinguishers

Appropriate portable extinguishers can be carried to the vicinity of Classes A, B, or C fires and can be manually operated by plant personnel for the control of small fires.

L. Fire Barriers

Fire barriers are generally passive fixtures and require no operation. Exceptions are HVAC dampers that pass through fire-rated walls and floors. Normally, the HVAC fire dampers are open, and their closure occurs only when heat causes their fusible links to melt or when activated by automatic gas extinguishing systems.

M. Fire and Smoke Monitoring, Detection, and Alarm Devices

Fire and smoke monitoring, detection, and alarm devices are activated by several different stages of a fire. Ionization detectors alarm at the presence of invisible combustion gases during the incipient stage of fire. Photoelectric detectors operate on a light principle

where smoke entering a light beam either obscures the beam's path or reflects light into a photocell. Flame detectors respond directly to the ultraviolet radiation emanating from a flickering flame sustained for at least 3 seconds in areas where fire developed rapidly with a minimum or absent incipient stage. Thermal detectors react to the attainment of a high fixed-temperature or rapid rise in ambient temperature, in excess of 15F per minute, and provide alarm service as well as release service for certain automatic systems as discussed above.

Failure of a single fire detection device is annunciated by the circuit's supervisory alarm. Such an indication prompts inspection and replacement or repair of the failed component. During the period when the failed fire detector is out of service, a detection capability continues to exist since more than one detector is installed in each area.

9.5.1.3 Safety Evaluation

The primary evaluation of the compliance of the PVNGS design with applicable regulatory and industry standards has been presented in appendix 9B, Fire Protection Evaluation Report. This report has been extensively referenced in the safety design bases evaluations of this section.

A. Safety Evaluation One

Fire protection has been achieved, consistent with 10CFR50, Appendix A, General Design Criterion 3,

Appendix R, Part III, Sections G, J, and O, and Appendix A to BTP APSCB 9.5-1 by the integrated consideration of fire prevention and fire suppression. Fire prevention measures have been incorporated in the plant design by physically separating ESF trains, reducing available combustible materials, installing fire barriers, and ensuring that adequate space and environmental controls have been provided to facilitate manual firefighting. Fire suppression methods incorporated in the design have been reported in appendix 9B. Additional consideration has been given to the effects of fire suppression activities and equipment on plant systems and structures. Water-resistant electrical equipment has been utilized where feasible and the measures described in evaluations B and C have been implemented.

B. Safety Evaluation Two

The consequences of failure or inadvertent operation of fire suppression systems have been minimized by ESF train separation, use of preaction systems, adequate floor drains to remove excess water, and use of fire suppression measures such as CO_2 or Halon 1301 in sensitive electrical and/or personnel areas. Appendix 9B contains additional, location specific, information regarding the potential failure of suppression systems.

C. Safety Evaluation Three

Fire suppression system components are seismically supported in plant areas where a nonseismically supported component could cause loss of function to safety-related systems or components as a result of an SSE.

D. Safety Evaluation Four

Site fire suppression systems or components that are required to be available by an operating unit during the construction of other units will be isolated from the effects of construction. Power block fire suppression systems are duplicated for each unit. These measures provide protection recommended by the ANI guidelines referred to in the design basis.

E. Safety Evaluation Five

Separation of structures, systems, and components important to safety is provided as noted in appendix 9B.

F. Safety Evaluation Six

The fire protection system provides the capability to fight fire throughout the plant, as noted in appendix 9B. The effects of fires are minimized as noted in evaluation A. Areas housing equipment necessary to achieve safe shutdown are accessible with respect to heat, smoke, toxic combustion products, and radiation as noted in appendix 9B. The location and intended use of firefighting components are as described in appendix 9B.

G. Safety Evaluation Seven

The plant fire protection water supply system is capable of supplying rated flow, even with equipment failures, to the extent noted in table 9.5-2.

A fire water jockey pump is provided.

H. Safety Evaluation Eight

Two fire pumps are diesel-driven. One is motor-driven from either of two sources of power.

I. Safety Evaluation Nine

Each branch fire protection water line to the turbine, auxiliary, control, containment, and diesel generator buildings may be supplied with water by an alternate flow path. Fire protection water to the fuel and radwaste buildings is provided through single paths due to the limited fire potentials in these buildings as noted in appendix 9B. Two-way-supplied fire hydrants, controlled by individual curb box valves, are installed at approximately 250-foot intervals within the power block area, and as required near other hazards and near other remote buildings.

J. Safety Evaluation Ten

Wet pipe sprinkler, automatic preaction sprinkler, and water spray systems are installed in the plant as described in appendix 9B.

K. Safety Evaluation Eleven

Low-pressure carbon dioxide flooding systems are installed in the plant as described in appendix 9B.

L. Safety Evaluation Twelve

Halon 1301 flooding fire suppression is provided in the control building as described in appendix 9B. Portable carbon dioxide extinguishers are provided in the control room as noted in appendix 9B. Design of these systems is such that their use will not result in an uninhabitable condition within the control room.

M. Safety Evaluation Thirteen

Fire hose stations are provided as described in appendix 9B.

N. Safety Evaluation Fourteen

Portable fire extinguishers are provided in accessible areas of the plant using the guidelines of NFPA 10 (1975) as referenced in table 9B.3-1.

Table 9.5-2
SINGLE FAILURE ANALYSIS IN FIRE PROTECTION SYSTEM
(Sheet 1 of 3)

Component	Normal Function	Failure Mode	Effects on Fire Protection System	Method of Detection
Fire water/ well water reserve tank	Contains half the primary source of fire protection water.	Leak or rupture	None. A second fire water/well water reserve tank is available with a volume of 300,000 gal.	Level alarms
Fire water jockey pump	Maintains system pressure when there is little or no flow requirement.	Fails to start due to loss of power or motor failure.	None. The electric motor-driven fire pump is available to maintain system Pressure.	Alarm in control room that electric motor-driven fire pump is running.
Electric motor-driven fire pump	Supplies up to 1500 gal/min to system.	Fails to start due to loss of power or motor failure.	None. Two diesel-driven fire pumps are available to provide full system demand of 3000 gal/min.	Alarm in control room that pump failed to start
Diesel-Driven fire pump	Supplies up to 1500 gal/min to system.	Fails to start due to engine malfunction or loss of battery.	None. One other diesel-driven pump and an electric motor-driven pump are available to provide full system demand of 3000 gal/min.	Alarm in control room that pump failed to start or trouble alarm

Table 9.5-2
SINGLE FAILURE ANALYSIS IN FIRE PROTECTION SYSTEM
(Sheet 2 of 3)

Component	Normal Function	Failure Mode	Effects on Fire Protection System	Method of Detection
Underground supply line to yard loops	Connects fire pump discharge header with yard loops.	Leak or rupture	None. Redundant supply line available to handle full system flow demand.	Flow to system with fire pump operating and absence of any fire alarm or fire hose usage
Underground yard loop in area of turbine, auxiliary, control, containment, and diesel generator buildings	Supplies fire protection water to each building noted.	Leak or rupture	None. Any single failure in this portion of the loop can be isolated by PIV valves such that redundant supply lines to these buildings are fed from the operating portions of the yard loop.	Flow to system with fire pump operating and absence of any fire alarm or fire hose usage
Underground yard loop in area of radwaste and fuel buildings	Supplies fire protection water to each building noted.	Leak or rupture	Loss of fire water to fixed sprinkler systems and inside hose stations for any one of the two buildings noted.	Flow to system with fire pump operating and absence of any fire alarm or fire hose usage

TABLE 9.5-2
SINGLE FAILURE ANALYSIS IN FIRE PROTECTION SYSTEM
(Sheet 3 of 3)

Component	Normal Function	Failure Mode	Effects on Fire Protection System	Method of Detection
Preaction sprinkler system	Spray water on areas containing ESF equipment if fire develops.	Pipe crack	None. Piping within the hazard area is normally dry.	Alarm in control room indicating loss of piping air pressure.
		Deluge valve failure	None. Piping within the hazard area would be pressurized, but closed-head sprinklers would prevent inadvertent water spray on ESF equipment.	Alarm in control room that deluge valve had opened.

O. Safety Evaluation Fifteen

Activation of automatic fire protection systems will generate an alarm in the control room. Fire and smoke monitoring and associated alarms are provided as described in appendix 9B.

P. Safety Evaluation Sixteen

Protective clothing and respirator equipment are available for fire department use in areas in which fire can produce an adverse environment.

Q. Safety Evaluation Seventeen

Fire dampers are provided in ventilation ducts that penetrate rated fire barriers. These dampers provide fire protection equal to or greater than the rating of the fire barrier penetrated.

R. Safety Evaluation Eighteen

Emergency lighting is provided as described in subsection 9.5.3. Emergency lighting provides for normal movement under emergency conditions. Applicable codes and regulations of the State of Arizona, the National Fire Codes of the National Fire Protection Association, and applicable sections of Title 29, Chapter XVII, Part 1910, Occupational Safety and Health Standards of the Code of Federal Regulations as set forth in the Federal Register Volume 37, Number 202, dated October 18, 1972, have been used as guidance in developing the plant fire protection system design.

9.5.1.4 Inspection and Testing Requirements

A. Preoperational Testing

Testing of the system is performed as described in section 14.2.

B. Post-Operational Testing

The PVNGS fire protection systems and equipment are tested and inspected at regular intervals. The NFPA codes, standards, and recommended practices are used as guidance in determining content and frequency of the periodic tests and inspections, as specifically committed to in other sections of this document.

The following fire protection features are subjected to periodic tests and/or inspections:

- Fire suppression water system
- Spray and sprinkler systems
- Carbon dioxide systems
- Fire hose stations
- Yard fire hydrants
- Halon systems
- Fire barriers (walls, fire doors, penetration seals, fire dampers)
- Fire detection instrumentation
- Fire pumps
- Emergency lighting

- RCP lube oil collection system
- Lightning protection
- Selected manual fire protection equipment
- Selected communications equipment

The fire protection test program is the responsibility of the Fire Protection Department Leader.

Equipment out of service including fire suppression, detection, and barriers is controlled through the administrative program and appropriate remedial actions taken. As conditions warrant, remedial actions include compensatory measures to ensure an equivalent level of fire protection in addition to timely efforts to make repairs and restore equipment to service.

No changes are made to the test and inspection procedures without ensuring compliance with the provisions of the facility operating license condition.

9.5.1.5 PVNGS Fire Protection Program

9.5.1.5.1 Overall Requirements of the PVNGS Fire Protection Program

The fire protection program at PVNGS has been established to protect the safety of personnel, to minimize property loss, to assure, in the event of a fire, the capability to safely shutdown the reactor and maintain it in a safe shutdown condition, and to minimize radioactive releases to the environment in the event of a fire. The fire protection program at PVNGS is an integrated effort involving design

features, trained personnel, equipment, and procedures to provide defense-in-depth protection of the public health and safety and to minimize the loss of property. The program consists of the following elements:

- Engineering design, procurement, and configuration management of safe shutdown capability and fire protection features
- Fire prevention including:
  - Control of transient combustible material
  - Control of ignition sources
  - Fire watch program
  - Periodic inspections
- Maintenance and testing of fire protection features
- Impairment and system status of fire protection features
- Training
- Fire response
- Quality assurance
- Licensing
- Risk management

The procedures, equipment, and personnel for implementing the fire protection program for buildings storing new fuel elements and for adjacent fire zones which could affect the fuel storage zone were operational before fuel was received at the site.

The program was fully operational prior to initial fuel loading.

9.5.1.5.2 Fire Protection Program Responsibilities

The Senior Vice President, Site Operations has overall management responsibility for the PVNGS Fire Protection Program.

The Vice President, Nuclear Engineering is responsible for the engineering design and configuration management of the Fire Protection Program Design Basis. These responsibilities have been delegated to the appropriate individuals within the Nuclear Engineering Organization.

The Vice President, Operations Support, is responsible for the overall direction, administration and supervision of the Fire Protection Program and for the procedures, equipment, and staffing necessary for implementing the day-to-day fire protection operations of the program. These responsibilities are delegated to leaders in Fire Protection.

The PVNGS Fire Department, which is comprised of the onshift emergency response personnel, is an organizational element of Fire Protection.

The Vice President, Operations Support is also responsible for ensuring programmatic implementation of the following: Fire Prevention activities, the performance of maintenance and testing, fire protection features impairment and system status, training, and fire response activities. These responsibilities have been delegated to the appropriate individuals within Fire Protection.

9.5.1.5.3 Fire Protection Administrative Controls

Administrative controls to maintain the performance of the fire protection systems and personnel at PVNGS are provided. These controls include:

A. Procedures designating plant staff positions responsible for the elements of the fire protection program.

B. Procedures to evaluate proposed plant modifications for their impact on the fire protection design basis.

C. Procedures to control transient combustible material and ignition sources in areas containing or representing a hazard to safety related areas; to provide fire watches; and to conduct periodic inspections to ensure continued compliance with these administrative controls.

D. Procedures to test fire protection features to demonstrate conformance with design and system readiness requirements; to delineate responsibilities for procedure development, performance, and evaluation of test results; and to identify frequency.

E. Methods to address the level of fire protection provided when a particular fire protection feature is impaired or during periods of maintenance.

F. Measures to provide identification of impairment and system status of fire protection features.

G. Training programs for fire protection/prevention and fire response activities as described in section 13.2.

H. Actions to be taken by plant personnel for fire emergency notification and response.

I. Strategies for fighting fires in all safety related areas and areas presenting hazards to safety related equipment.

J. Actions to mitigate the effect of a fire on the ability to safely shut down the reactor for alternative shutdown areas.

K. The fire protection QA Program to ensure the critical aspects of design, procurement, administrative controls, maintenance, and testing are applied to ensure that fire protection features are available and functional.

9.5.1.5.4 Fire Protection Program Qualifications

9.5.1.5.4.1 Fire Protection Engineer. Staff personnel include at least one fire protection engineer who provides review and technical assistance with the design, selection of equipment, inspection, tests, and overall review of the program. This individual meets the qualifications for member grade of the Society of Fire Protection Engineers.

9.5.1.5.4.2 Fire Department Personnel Qualifications. PVNGS maintains a full-time industrial fire department. Each fire department shift is comprised of a minimum of five professional firefighters at all times.

All fire department personnel are a minimum of 21 years of age and have a high school diploma or equivalent. All fire department members meet the medical and physical fitness requirements established by the PVNGS site physician and the Vice President Operations Support.

All personnel assigned to full-time firefighting activities have a minimum of 3 years of full-time firefighting, inspection, fire prevention, or nuclear plant experience. Volunteer firefighting experience is counted at a ratio of 2 to 1.

Each shift has an individual designated as the shift fire captain who is responsible for assessing the severity of a fire, for fire department response, and for directing the firefighting activities and strategies. The fire department has a minimum composition as described in section 13.1.2.6.

A licensed nuclear operator, designated as fire team advisor, who is trained and qualified in assessing the potential safety consequences of fire and fire suppressants on safe shutdown capabilities supports the fire department during fire emergencies in the power block. Fire Team Advisor qualifications are identified in the Fire Team Advisor Training Program Description.

9.5.2 COMMUNICATION SYSTEMS

The PVNGS communication system, comprised of internal (intraplant) and external (plant-to-offsite) communications, is designed to provide convenient and effective operational communications between various plant locations, and between the plant and offsite locations. The elements of the communication systems credited to address postulated fires are described in table 9B.3-1.

9.5.2.1 Design Bases

Various communication systems are provided in the plant to ensure reliable communication during plant startup, operation, shutdown, and maintenance under normal and emergency conditions. The design bases of these systems are:

A. An electronic private automatic branch exchange (EPABX) telephone system, a sound powered telephone system, a plant two-way radio system, an Emergency Evacuation Alarm System, and a public address system are provided to accomplish onsite communication between the control room and various plant locations.

B. Public and private telephone systems, the plant two-way radio system, the APS corporate two-way radio system, and telephone land lines for the Local Law Enforcement Agency (LLEA) are provided to permit plant-to-offsite communication on a continuous basis. Details of available, diverse, communication systems are provided in the PVNGS Emergency Plan. Details of the LLEA communication system are provided in the Security Plan.

C. The plant has a private ringdown telephone communication link via the fiber optics (sonet ring) system to the APS energy control center (ECC). Alternate links are provided by dial telephones via the plant EPABX.

D. An emergency evacuation alarm system is designed to warn personnel to evacuate the exclusion area in the event of a design basis accident (DBA).

E. Communication systems are provided with reliable backup power supplies for each subsystem as noted in table 9.5-3.

F. The communication systems comply with applicable local codes, standards, ordinances, and Federal Communications Commission (FCC) regulations.

G. Required communication systems will be capable of performing under conditions of maximum plant noise levels being generated during the various operating conditions including accident conditions. (Refer to table 9.5-4).

H. In high noise areas (greater than 95 dB), public address or unit evacuation systems are clearly audible or visible throughout the exclusion area. In areas where audible or visible evacuation signals cannot be assured, administrative measures will be provided.

Table 9.5-3
COMMUNICATION SYSTEMS POWER SUPPLIES

System	Power Supply
EPABX telephone system	UPS (battery[f] and charger)
PA system	Battery[a] and charger
Fiber Optics (sonet ring)	UPS (battery[a] and charger) associated with APS fiber optics equipment
Sound-powered telephone	None required[d]
Plant two-way radio system	UPS (battery[e] and charger)[d]
Two-way radio (mobile units)	Vehicle battery
Emergency evacuation alarm system (unit)	UPS (battery[b] and charger)
Emergency evacuation alarm system (area)	Solar panels with battery[c] Backup

a. 8-hour operation

b. 2-hour operation

c. 30-minute operation

d. Communication systems relied on to address postulated fires as described in table 9B.3-1.

e. Each plant two-way radio system uninterruptible power supply (UPS) can power its loads for at least four hours from the associated backup batteries before restoration of an ac power supply becomes necessary. Upon loss of the normal ac power supply, a backup ac power supply can be selected by means of a manual bus transfer switch. In the event of a station blackout, the system also has the capability of being supplied by the alternate ac station blackout generators.

f. 2-hour (targeted value) operation to support Emergency Plan.

9.5.2.2 System Description

The locations of permanent plant telephones and public address speakers within the power block are shown on station lighting and communication plan drawings. Design and configuration requirements for communications system (QF) components are based on regulatory commitments and the importance of a component's function in operating the plant in a safe manner. Design control is maintained in accordance with Installation Specification 13-JN-0999, which divides communication circuits into four types (Plant, EN-700, Extended, and Convenience) in order to maintain proper controls based on component function.

A complete list of available communication system links for intraplant and offsite emergency communications is provided in Table 3 of the PVNGS Emergency Plan.

9.5.2.2.1 Intraplant Communication Systems

9.5.2.2.1.1 EPABX Telephone System. The EPABX system is one of the principle means of communication within the plant, but is not credited for addressing postulated fires. The system provides lines of communications between site EPABX telephones including the unit control rooms and interfaces with the external public telephone system and the public address (PA) system. A backup power system is provided to supply emergency power to the EPABX telephone switches for 8 hours, which exceeds the 2 hour requirement from Table 9.5-3, to support the Emergency Plan. Notification is provided to the Unit 1 Control Room in the event that plant operations will be impacted by a failure of the backup power supply for the EPABX exchange located in the Service Building.

As a key communication system at PVNGS, the EPABX telephone system has been evaluated for communications during normal and emergency operation. Refer to the PVNGS Emergency Plan and the Security Plan for more information.

Table 9.5-4
SUMMARY OF ONSITE COMMUNICATIONS SYSTEM CAPABILITIES AND NOISE CONSIDERATIONS DURING TRANSIENTS AND/OR ACCIDENTS

Station	Maximum Anticipated Sound Levels (dBA)	Communication Systems Available and Maximum Background Noise for Effective Communication[a]				
		EPABX Telephone (dBA)	EPABX Telephone Jack (dBA)	Emergency Evacuation/ Public Address[b] (dBA)	Sound Power Phones[c,d] (dBA)	Portable 800 MHz Radio (dBA)[d]
Control room	70	92	-	-	118	95
Remote shutdown panel	75	92	-	102	118	95
Safety injection pump rooms	111	92	118	102	-	95
Shutdown heat exchanger rooms	90	92	118	102	-	95
ESF switchgear rooms	75	92	118	102	-	95
Piping penetration rooms	100	92	118	102	-	95
Radwaste building	102	92	118	102	-	95
Auxiliary feedwater pump rooms	110	92	118	102	-	95

a. Reference 1
b. Based on data supplied by vendors
c. Headset
d. Credited for mitigation of postulated fires as described in table 9B.3-1

9.5.2.2.1.2 Public Address System. The Public Address System consists of a master control cabinet, remote central amplifier, and speakers located throughout the plant in the areas that they serve. A backup power system is provided to supply emergency power for 8 hours. Emergency Evacuation Alarm System consoles are used to send announcements to the PA system. Telephones located inside and outside the power block may also send announcements to the PA system using dedicated access numbers. Operators may override the PA system from each control room EVAC System console and from control room telephones. The PA system has been evaluated for communications during normal and emergency operation. Refer to the PVNGS Emergency Plan for more information.

9.5.2.2.1.3 Emergency Evacuation Alarm System. An Emergency Evacuation Alarm System consisting of pole-mounted electronic outdoor warning sirens, powered by solar powered batteries, located outside each power block is provided to alert all personnel within the security boundaries of PVNGS. All sirens (both unit and area) are initiated from the siren command module in each unit’s main control room. A microphone is provided to permit announcements over the Emergency Evacuation Alarm System. Each unit emergency evacuation alarm system is provided with batteries with a 2-hour capacity. Evacuation/accountability is assured in high noise work areas (greater than 95 dB) by the use of audible alarms, flashing lights, and/or administrative measures. This communication system is not relied on for addressing postulated fires as described in Table 9B.3-1; however the Evacuation Alarm System has been evaluated for communications during normal and

emergency operation. Refer to the PVNGS Emergency Plan for more information.

9.5.2.2.1.4 Sound Powered Telephone System. A private, direct-line, sound powered telephone system is provided between the fuel building and the main control panel in the control room for each unit. A second independent system is provided between the main control room and maintenance control points throughout the unit. The systems can be connected together by a merge switch located in the control building, 140-foot elevation. This system is credited for addressing postulated fires as described in UFSAR table 9B.3-1.

As a primary communication system used by PVNGS fire department, the sound powered telephone system has been fully evaluated to ensure communication for normal and emergency operation. Refer to the PVNGS Emergency Plan, Security Plan, and UFSAR Table 9B.3-1 for more information.

9.5.2.2.1.5 Deleted

9.5.2.2.1.6 Plant Two-Way Radio System. The plant two-way radio system provides voice radio communications throughout the PVNGS site and the surrounding emergency planning zone (EPZ). It also provides a two-way radio communications link to the LLEA and, in conjunction with the APS corporate two-way radio system, a backup to the Notification and Alert Network (NAN) state and county emergency response organizations in the Phoenix metropolitan area. The PVNGS operations, security, and fire departments as well as numerous other site support groups utilize the radio system for their normal emergency radio

communications. The plant two-way system operates in a licensed frequency band.

Radio system user groups access the system with portable, mobile, and fixed radio transceivers which have been programmed and configured to be part of the system. The system uses a process known as trunking to time-share the available repeater frequencies. The system is designed to mitigate equipment failures through automatic reassignment of control functions in and the capability for direct portable-to-portable communication.

To enhance its reliability, the plant two-way radio system has redundant ac power feeds and battery-backed uninterruptible power supplies (UPSs). As described in UFSAR Table 9.5-3, the battery bank of each radio system UPS has been sized to power the associated radio system loads for a minimum of four hours before restoration of an ac power supply becomes necessary. In the event of a station blackout, the system also has the capability of being supplied by the alternate ac station blackout generators to support communications for safe shutdown activities. Refer to UFSAR section 8.3.1.1.10.

The plant two-way radio system, in conjunction with the sound powered telephone system, is relied upon to address postulated fires as described in UFSAR Table 9B.3-1. All of the portable radios that are part of the system have rechargeable batteries. A number of portable radios have been stored in recharger units in selected locations throughout the plant to provide ready access to the system for communications during fires and other emergencies.

As a primary communication system used by PVNGS operations, security, and fire departments, the plant two-way radio system and its failure modes have been fully evaluated to ensure communication during for normal for normal and emergency operation. Refer to the PVNGS Emergency Plan, Security Plan, and UFSAR Table 9B.3-1 for more information.

9.5.2.2.2 Plant-to-Offsite Communication Systems

9.5.2.2.2.1 Public Offsite Communications System. The EPABX interconnects with the Public Switch Network Provider, to provide communications with the local area PTNS from EPABX extensions in the plant, and ancillary buildings, including EOF and TSC. This provides direct dialing to locations outside the plant. Additional ringdown telephones in emergency centers are provided for emergency communications (paragraph 9.5.2.2.2.4).

The security centers have land lines directly connected to the public telephone system for the LLEA as a backup to the EPABX connected trunks. Refer to PVNGS Security Plan for details of this communication interface.

9.5.2.2.2.2 Private Offsite Communications System. The private offsite communications system provides communications via APS owned radio systems and microwave system and SRP-owned microwave systems. An 800 MHz control station has been integrated into the PVNGS plant two-way radio system to provide a direct radio link from the site security centers to the LLEA (Maricopa County Sheriff's Office) radio system. The APS corporate two-way radio system, in conjunction with the PVNGS plant two-way radio system, provides radio links to the five

Notification and Alert Network (NAN) state and county emergency response organizations in the Phoenix metropolitan area. Fiber optics ringdown telephone links provide communications with the APS ECC.

9.5.2.2.2.3 Security Force Communications. The plant two-way radio system is the primary means for security force communications. Refer to paragraphs 9.5.2.2.1.6 and 9.5.2.2.2.2 for a description of the system. The radio system uses multiple repeaters, redundant site central controllers, redundant ac power supplies, and battery-backed uninterruptible power supplies (UPSs) to meet the requirements for security force radio communications as specified in 10CFR73.55. Additionally, in the unlikely event of a total system failure, the security force portable radios are capable of direct portable-to-portable communications.

Refer to the PVNGS Security Plan for detail of PVNGS Security Force Communication.

9.5.2.2.2.4 Emergency Communication System. Diverse systems are provided to ensure means of intraplant-to-offsite communications under emergency operating conditions. Interfaces with these systems are located in the unit control rooms, TSC, EOF, and various emergency facilities. Refer to the PVNGS Emergency Plan (Section 7) to determine availability of PVNGS emergency response facility communications.

9.5.2.2.3 System Operation

Diverse systems are provided to ensure means of intraplant-to-offsite communications under normal and emergency operating conditions. The sound-powered telephone system and plant two-way radio system address postulated fires as described in table 9B.3-1. Intraplant communication systems have adequate flexibility to keep plant personnel informed of plant operational status. Refer to the PVNGS Emergency Plan (Section 7) to determine availability of PVNGS to offsite emergency response facility communications.

9.5.2.3 Inspection and Testing Requirements

The communications systems are conventional and have a history of successful operation at existing plants. Most of these systems are in routine use and this will ensure their availability. Those systems not frequently in use will be tested at periodic intervals to ensure functionality when required.

Plant operating procedures will provide for periodic preventive maintenance and surveillance testing to assure the functionality of the onsite communication system. Communication systems relied on to address postulated fires are included in the fire protection test program. Maintenance and testing will consist of, as a minimum, a yearly inspection of each telephone in the control room area, shutdown panel, and working stations. The telephone system in the control room area, shutdown panel, and working stations are routinely used by station personnel during normal station operation. Any telephone which does not

function properly will be reported to the testboard for immediate repair.

Those systems not frequently in use will be tested at periodic intervals to assure functionality when required.

9.5.3 LIGHTING SYSTEMS

This subsection discusses the unit and station lighting systems.

9.5.3.1 Design Bases

The lighting, including essential and emergency subsystems, associated with safety-related equipment is protected from winds, floods, missiles, and pipe ruptures to the extent that protection provided for specific ESF equipment also provides protection for the lighting system. Protection from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against the dynamic effects associated with the postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

9.5.3.1.1 Safety Design Bases

Safety design bases applicable to the lighting system are as follows:

A. Safety Design Basis One

Structures supporting the components of essential lighting and emergency lighting systems, which serve

the main control room and the remote shutdown room, shall be designed to retain structural integrity during and after a safe shutdown earthquake.

B. Safety Design Basis Two

The lighting system, comprised of normal, emergency, and essential subsystems, shall be designed so that a single failure of any subsystem or electrical component of a subsystem, assuming loss of offsite power, cannot terminate the system's ability to illuminate areas occupied during a reactor shutdown or emergency.

9.5.3.1.2 Power Generation Design Bases

Power generation design bases applicable to the lighting system are as follows:

A. Power Generation Design Basis One

Area lighting intensities provide the illumination required for comfort and worker efficiency in the performance of the visual activities required in that area. Outdoor lighting complies with the security provisions of ANSI N18.17-1973.

B. Power Generation Design Basis Two

Mercury-vapor fixtures and mercury switches are not used inside the containment building and fuel building. Sodium vapor lights are utilized in the containment and fuel building for illumination. These lights contain a trace amount of mercury. This has been evaluated as being acceptable.

C. Power Generation Design Basis Three

Lighting fixtures containing aluminum or aluminum alloys are not used inside the containment building.

9.5.3.1.3 Codes and Standards

Design and installation of the plant lighting systems use the guidance provided by the National Electrical Code (NFPA No. 70-1975/ANSI C1-75) and the Handbook of the Illuminating Engineering Society with the exception that Palo Verde uses a plant drawing system rather than detailed field markings to identify the loads being serviced by each branch circuit disconnect (NEC 110-22).

9.5.3.2 System Description

9.5.3.2.1 General Description

Unit lighting is divided into three subsystems: normal, essential, and emergency. The normal system is supplied from non-Class 1E ac buses. The essential system is connected to Class 1E ac buses. The emergency lighting system, consisting of batteries, battery chargers, and lamps, is fed from the same supply as the essential lighting system, where essential lighting is provided, or the normal lighting system, where no essential lighting is provided, and function on loss of the ac power source. Safe shutdown emergency lighting fixtures in an area/room are fed from the same circuits as the essential lighting fixtures for the same area/room. The safe shutdown lighting drawings (01, 02, 03-E-ZPL-001, 002, 003, 004) indicate all essential/emergency lighting which includes emergency battery lighting units which is required for the

local manual operation of safe shutdown equipment and access/egress routes thereto in the event of a fire.

9.5.3.2.2 Component Description

The three lighting categories are described briefly in the following paragraphs.

9.5.3.2.2.1 Normal Lighting. The normal lighting system is the system that provides the primary source of illumination for the entire station and is supplemented by essential lighting during normal plant operating modes. In each unit, the lighting load is distributed equally between two non-Class 1E lighting load centers, each consisting of 1000 kVA, 13,800-480/277-volt, dry-type transformers with 208/120 and 480/277-volt distribution subsystems. Areas remote from the lighting load center are fed from the local power sources. Lighting transformers for the system are solidly grounded at neutrals.

9.5.3.2.2.2 Essential Lighting. The essential lighting system supplements the normal lighting and provides sufficient illumination to allow personnel safe access/egress throughout each unit in the event of a failure of the normal lighting system. In addition, essential lighting is also designed to provide sufficient illumination necessary for the local manual operation of safe shutdown equipment in the event of a fire. The essential lighting system supplies the lighting in the main control room and the remote shutdown room. Redundancy is provided in the essential lighting system in the control room and remote shutdown panel room, to shut down and maintain the unit in a hot shutdown condition. The essential lighting

system serving the control room and remote shutdown panel area is fed from Class 1E motor control centers (MCCs), via Class 1E regulating transformers, and is not tripped on safety injection actuation signal (SIAS). The remainder of the essential lighting feeders for the plant area are tripped on SIAS and can be manually reconnected after diesel generator sequencing. The essential lighting system is normally energized and is supplied from two redundant Class 1E load centers.

9.5.3.2.2.3 Emergency Lighting. Emergency lighting has two different intended functions depending on the area where it is located.

In areas where operator local manual actions are required for safe shutdown in the event of fire, emergency lighting is provided in accordance with Appendix R to 10CFR Part 50, Section III.J. In these areas emergency lighting is designed to provide sufficient illumination for the operator to perform the required safe shutdown actions in the event of a loss of essential power. Appendix R emergency lighting is provided by either individual dc units, centralized dc/ac UPS systems, or in some limited cases portable lanterns. Both of the fixed systems (i.e., dc units and UPS) have a minimum 8-hour battery power supply.

Sealed beam battery-powered portable lanterns will also be readily available to the operators for the following: when access/egress or manual actions are required in the yard area (i.e., condensate storage tank pumphouse, reactor make-up watertank, alternate entrances to the diesel generator building) (this deviation to 10CFR50, Appendix R,

Section III.J, is discussed in Section 9B.2.0.E); and when actions are necessary beyond 8 hours or to serve as a compensatory measure for nonfunctional emergency lights. Some Appendix R designated emergency lighting also serves as station blackout lighting.

In other areas, where no safe shutdown action is required, emergency lighting is provided to support the safe access/egress of personnel as necessary. This emergency lighting uses batteries capable of providing a minimum of 1.5 hours of illumination in the event of a loss of essential power or normal power if no essential lighting is provided in the area. The individual dc emergency lighting units consist of a battery, lamps, and charger all included in a single fixture. The units provide illumination automatically on a loss of the ac power source. Areas without routine human habitation may not be equipped with emergency lighting (Reference NFPA 101, 1976).

The centralized dc/ac UPS systems consists of a battery source, charger, inverter, transfer switch, and a series of ac lighting fixtures (either fluorescent or incandescent). This system automatically transfers from the ac source to the battery source on a loss of ac power.

9.5.3.2.2.4 Portable Lighting

During maintenance activities or when equipment is not in-service, portable fluorescent drop lights can be utilized even though fluorescent lights contain trace amounts of mercury. The portable lights are to be removed after maintenance or prior to the equipment being placed in service.

If a fluorescent light is needed to illuminate an in-service plant component for remote monitoring, an evaluation will be performed to demonstrate that breakage of the light will not adversely impact plant equipment.

9.5.3.3 Safety Evaluation

The safety evaluations are numbered to correspond to the safety design bases and are as follows:

A. Safety Evaluation One

The batteries, UPS unit, and lighting fixtures of the control room horseshoe suspended ceiling in the control building are capable of withstanding the safe shutdown earthquake (SSE), and are seismically qualified by analysis and/or testing in accordance with IEEE Standard 344-1975. In accordance with Position C.2 of Regulatory Guide 1.29, MPS units and associated lighting fixtures, and self-contained, battery-powered emergency lighting units above safety-related equipment are installed in such a manner that during and after a SSE, their failure will not incapacitate the operator nor cause crippling damage to needed safety-related equipment. The MPS units and associated lighting fixtures, and the self-contained, battery-powered emergency lighting units serving plant areas outside of the control room horseshoe area are not required to function during or after a seismic event.

B. Safety Evaluation Two

Reliable lighting is provided to permit the operators to shut down the unit safely and to maintain it in a safe shutdown condition at any time. The lighting system is designed to provide lighting in those areas used during a reactor shutdown or emergency.

Essential lighting in the control room, remote shutdown panel room, and associated local control stations are fed from Class 1E buses. The essential lighting in the control room and at the remote shutdown panels is arranged so that alternate fixtures are fed by redundant buses to maximize the coverage of remaining fixtures in the event of a loss of one Class 1E bus. Physical separation by fire zone is provided to maintain independence of the redundant essential lighting circuits feeding the control room horseshoe area and the remote shutdown panel.

If the offsite (preferred) power supply to a Class 1E bus fails, the associated emergency diesel generator is started automatically. Prior to restoration of essential power, the emergency lighting system provides illumination. Lighting in the control room and remote shutdown area is automatically restored during emergency diesel generator sequencing. For a detailed description of the emergency lighting system refer to section 9.5.3.2.2.3.

A single failure analysis is provided in table 9.5-6.

9.5.3.4 Inspection and Testing Requirements

Normal and essential ac lighting circuits are normally energized and require no periodic testing. The emergency lighting system is inspected and tested periodically to ensure functionality of the system.

Table 9.5-6

LIGHTING SYSTEM SINGLE FAILURE ANALYSIS

Name	Failure/Malfunction	Effect On		
		Normal Lighting	Essential Lighting	Emergency Lighting
Onsite power	Auxiliary transformer short circuit	Complete loss--automatic transfer to startup source	None	None
13.8 kV balance of plant bus	Short circuit	Half lost	None	None
Offsite power	Total loss	None	Total loss—restored after diesels are started and loaded	Automatic energization of emergency lighting, deenergized after diesels started and loaded
4.16 kV engineered safety features bus	Short circuit	None	Half lost	Automatic energization of half of dc lighting
480V engineered safety features bus	Short circuit	None	Half lost	Automatic energization of half of dc lighting
480V essential lighting transformer	Short circuit	None	Half lost	Automatic energization of half of dc lighting
480V essential lighting bus	Short circuit	None	Half lost	Automatic energization of half of dc lighting
125V-dc Class 1E bus	Short circuit	None	None	None-self-contained battery units energized

9.5.4 DIESEL GENERATOR FUEL OIL STORAGE AND TRANSFER SYSTEM

Two fully redundant diesel generator fuel oil storage (DGFOS) and transfer facilities are provided for each of the three plant power generating units. This system provides onsite storage and delivery of fuel oil for operation of the two diesel generators provided as a part of the ESFS for each unit and which are required as a consequence of a loss of offsite power.

9.5.4.1 Design Bases

9.5.4.1.1 Safety Design Bases

A. Safety Design Basis One

   The DGFOS shall provide onsite storage of fuel oil for at least 7 days of continuous, concurrent operation of both diesel generators when operating at the maximum load of the onsite power system, as specified in section 8.3.

B. Safety Design Basis Two

   The DGFOS shall remain functional during and after the SSE.

C. Safety Design Basis Three

   A single failure of any active component shall not impair the DGFOS ability to mitigate the consequences of an accident or affect its ability to support a safe reactor shutdown.

D. Safety Design Basis Four

The DGFOS shall be capable of being operated and monitored from both the control room and from the local diesel generator control panel.

E. Safety Design Basis Five

The DGFOS shall supply the required fuel for the routine scheduled operational testing and inspection of the diesel generators without compromising system ability to meet its minimum operational requirements.

F. Safety Design Basis Six

The DGFOS shall have provisions for truck refill of each diesel generator fuel oil tank and each diesel generator day tank.

G. Safety Design Basis Seven

The DGFOS shall provide for flame arrestors on all storage tank vents.

H. Safety Design Basis Eight

Diesel fuel oil shall be maintained at a temperature above the cloud point: i.e., above the low temperature at which the separation of wax becomes visible.

I. Safety Design Basis Nine

The DGFOS shall be protected against missiles generated from other equipment failures or due to extreme natural phenomena effects, as discussed in sections 3.2, 3.3, 3.4, 3.5, and 3.6.

J. Safety Design Basis Ten

Fuel day tanks and the diesel generator building shall be fire-protected.

K. Safety Design Basis Eleven

The DGFOS shall be capable of being fully tested during normal unit operations.

9.5.4.1.2 Power Generation Design Bases

A. Power Generation Design Basis One

The DGFOS will not interfere with normal unit power generation activities during system tests and maintenance activities.

9.5.4.1.3 Codes and Standards

The DGFOS conforms to applicable portions of the following codes and standards:

- IEEE 308-1971, Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations
- IEEE 387-1972, Trial Use Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations
- IEEE 323-1974, General Guide for Qualifying Class 1 Electrical Equipment for Nuclear Power Generating Stations
- IEEE 344-1975, IEEE Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

- ASME Boiler and Pressure Vessel, Section III, Class 3
- National Fire Protection Association
- American Nuclear Insurers
- Underwriter's Laboratories
- National Association of Corrosion Engineers
- The PVNGS design complies with ANSI N195-1976 with exceptions as listed in section 1.8, under the response for Regulatory Guide 1.137.

9.5.4.2 System Description

The DGFOS is shown schematically in engineering drawings 01, 02, 03-M-DFP-001 and figure 9.5-5.

Two fully redundant DGFOSs are provided for each unit. Each DGFOS consists of one diesel fuel oil storage tank, one diesel fuel oil transfer pump, and one diesel fuel oil day tank per diesel generator along with the associated piping, valves, and instrumentation. Indications, alarms, and sensors are listed in table 9.5-7. Components are described in subsequent sections. Table 9.5-8 lists the major components in the DGFOS and their design specifications. The DGFOS is designed in accordance with the codes and standards specified in table 3.2-1. The DGFOS is designed to comply with Position C.2 of Regulatory Guide 1.137 as discussed in section 1.8.

In addition, cross-connection is provided between the fuel storage tanks which allows the diesel engines to be supplied with fuel from either tank. This configuration is not credited in the safety analysis for several reasons (1) Cross-connecting

the diesel fuel oil storage tanks during normal operations (in Modes 1, 2, 3, or 4) violates the independence and redundancy design criteria. (2) There is only one fuel transfer pump per storage tank which is powered by its associated divisional bus, i.e., there is not a redundant fuel transfer pump. (3) Aligning the operable transfer pump to the opposite diesel will cause its normally associated diesel to be considered inoperable. (4) Due to accessibility, aligning the manual cross connect valves will take a long time (on the order of hours).

Refer to PVNGS Technical Specifications for fuel oil sampling requirements. Should the day tank oil be found unacceptable, it is drained into drums for nonsafety-related uses. Should the storage tank oil be found unacceptable, storage tank and day tank contents may be processed to return the fuel oil to within specification requirements. If such processing is not feasible or successful, then all oil, including the day tank oil, will be removed and replaced with fresh oil.

Newly delivered oil will be sampled per Regulatory Guide 1.137 before the oil is placed in the storage tank.

Table 9.5-7

DIESEL GENERATOR FUEL OIL AND TRANSFER -- INDICATIONS, ALARMS, AND SENSORS
(Sheet 1 of 2)

Parameter	Local Indication	Local Diesel Generator Panel	Control Room	Comments
Fuel oil storage tank	• Gauge (level)	• Alarm (low level)	• Common trouble alarm	
Transfer pump dis-charge pressure	• Gauge (pressure)	• Alarm (low pressure)	• Alarm (low pressure)	Transfer pump starts auto-matically on low level in fuel oil day tank. Manual operation of transfer pump available locally at DG control panel
Transfer pump strainer D/P		• Alarm (high D/P)	• Common trouble alarm	
Fuel oil day tank level	• Gauge (level)	• Alarm (high or low level)	• Alarm (low level) • Common trouble alarm (high level)	Level con-troller con-trols transfer pump in replenishing day tank

Table 9.5-7

DIESEL GENERATOR FUEL OIL AND TRANSFER -- INDICATIONS, ALARMS, AND SENSORS

(Sheet 2 of 2)

Parameter	Local Indication	Local Diesel Generator Panel	Control Room	Comments
Fuel oil filter D/P	• Gauge (D/P)	• Alarm (high D/P)		Alarm indicates dirty fuel filters. Twin filters are provided for replacement during operation (a)
Fuel oil supply header pressure	• Gauge (pressure)	• Alarm (low pressure)		

a. This system has no automatic interlocks for filter change out - operator action required.

Table 9.5-8
DIESEL GENERATOR FUEL OIL STORAGE AND
TRANSFER SYSTEM DESIGN SPECIFICATIONS

Equipment or Parameter[a]	Quantity Per Station Generating Unit	Type or Capacity
Fuel oil storage tank	2 (one per diesel)	83,000[b] gal
Fuel oil storage transfer pump	2 (one per diesel)	15 gal/min
Fuel oil day tank	2 (one per diesel)	1,100[b] gal

a. All equipment Safety Class 3 and Seismic Category I.

b. Nominal Capacity

Diesel fuel oil will normally be supplied from Phoenix, Arizona, 34 miles to the east. Many major and independent oil companies have sufficient supply facilities in West Phoenix at the Southern Pacific Pipe Lines Terminal (tank farm). Companies such as Union Oil Company, Shell Oil Company, Chevron, and ARCO, among others, operate out of this Phoenix terminal. The Southern Pacific pipeline pumps fuel to the Phoenix terminal from Los Angeles, California, or El Paso, Texas. An additional storage terminal is located in Tucson, Arizona, approximately 100 miles from Phoenix. An interstate highway runs east and west between Phoenix and Blythe, California, approximately 110 miles west of the site, where fuel is also available. The highway is approximately 6 miles north of the site over an all-weather road.

As discussed in section 2.4 and paragraph 2.4.1.1, the plant site is above maximum probable flood level. Therefore, as a minimum, access to the site by helicopter is not affected by flooding in the highly unlikely event that an accident occurs concurrent with flooding throughout the Arizona desert such that all rail and roads are unusable for 7 days or more.

9.5.4.2.1 Diesel Generator Fuel Oil Storage Tanks

Each diesel generator fuel oil storage tank is buried underground and has a nominal capacity of 83,000 gallons, which provides for the following: (1) 7 days of continuous diesel operation at full load, (2) an unrecoverable fuel volume for sediment, which is already accounted for in the unavailable volume below the suction nozzle, and (3) sufficient fuel for required periodic testing of the diesel generators. The fuel oil storage tanks are protected from corrosion in accordance with Recommended Practice, Control of External Corrosion on Underground or Submerged Metallic Piping Systems, RP-01-69, as published by the National Association of Corrosion Engineers (NACE).

The diesel fuel oil storage tank internal corrosion is minimized as follows:

A. Testing of fuel oil when delivered, per ASTM requirements, will ensure oil of the proper quality is admitted to the storage tanks.

B. Periodic testing of oil samples for water and sediment will detect potential or actual corrosion problems.

C. The fuel oil transfer pumps take suction above the tank bottom and will not pull up any water or sediment.

D. Duplex strainers with differential pressure alarms filter the oil before introduction into the fuel oil day tank and can be cleaned.

E. The supply pipe from the day tank to the engine is above the tank bottom and will not withdraw sediment.

F. A duplex strainer with differential pressure alarms is provided on the inlet of the engine-driven fuel oil booster pump. A duplex filter with differential pressure alarm is provided on the discharge of the engine-driven fuel oil booster pump. Both can be cleaned or have elements replaced as required.

G. Low rainfall at the site (refer to section 2.3) will preclude water accumulation and subsequent corrosion.

H. APS diesel fuel storage tanks, throughout the many years of operation of other fossil plants, have experienced no history of corrosion problems.

I. The tank interior was sandblasted to remove scale and mill slag to minimize the potential for accumulation of corrosion and sediment during the tank life.

The external surface of the diesel fuel oil storage tank was cleaned in accordance with Steel Structures Painting Council (SSPC)-SP10-63. A 30 mil coat (dry film thickness) of Koppers Bituplastic 33 was applied in accordance with the manufacturer's directions. No internal coating is provided.

The PVNGS Technical Specifications require that any accumulated water in the storage tank is removed on a quarterly basis, and that the fuel is analyzed in accordance with the Diesel Fuel Oil Testing Program. Periodic water removal will preclude algae growth and periodic fuel oil quality testing will preclude the use of degraded fuel.

In the unlikely event that a storage tank must be cleaned, the requirements of ANSI N195 will be met. The tank will be emptied, cleaned, and refilled with fuel meeting the specifications described in Regulatory Guide 1.137, Position C.2.

The fuel oil storage tank fill lines are located outdoors, and terminate approximately 2-3/4 feet above ground level and 2 feet above a concrete surface. The fill line has a threaded cap. The vent has a turned down opening. Both openings are above the flood level discussed in section 2.4.

The tanks are installed in accordance with Occupational Safety and Health Administration OSHA 29CFR1910, Subpart H, Hazardous Materials, Section 1910.106. Appropriate instrument connections are installed. Tank vents are equipped with flame arrestors. Other fittings permit fuel oil replenishment by truck and water removal from the tank as required.

A vault built above each diesel fuel oil storage tank provides tornado and missile protection for the submersible transfer pump in the tank, connections on the tank, and transfer pump associated valving. The foundation of the vault is independent of the tank to avoid any load transfer to the tank shell. The vault is of water-proof design. The vault is considered to be

“water-proof” in that the walls extend above the site PMP flood water-surface elevation. In addition, the entire vault is located above the maximum predicted groundwater elevation. As such, the vault provides protection for the diesel generator fuel oil transfer system instrumentation and electrical equipment. The likelihood of significant water seepage through the vault structure is remote.

The vent lines are routed inside the vault and project through the top slab. The vent line has a flange connection inside the vault. This vent line can easily be replaced at the flange connection should the projection of this line become damaged by a tornado-generated missile. The diesel generator fuel oil storage tanks are located underground about 35 feet from the diesel generator building. In the unlikely event that either or both the truck fill line and the tank vent are damaged and cannot be removed at the tank flange connections, there are two unused flanged connections. These connections are located inside the vault on the tank as shown in engineering drawings 01, 02, 03-M-DFP-001. These connections could be used as temporary vent or fill connections.

A cathodic protection system is provided for the fuel oil storage tanks and piping. The plant cathodic protection system consists of a number of rectifiers and deep bed anodes producing a direct current flow through the ground to the metallic objects buried in the soil which require corrosion protection.

The cathodic protection rectifiers are distributed throughout the site with power supplied from non-Class 1E, 480V MCCs. The

rectifier positive output is impressed upon the deep well anodes. The ground grid interconnects the rectifier negative and the metal to be protected. The deep anode bed holes are drilled to various depths (approximately 20-200 feet below grade) and are 12 inches in diameter. The anodes are spaced approximately 10-35 feet apart in the hole.

Test stations with reference electrodes and test coupons are installed along buried pipes to monitor protection levels. Shunts are installed in each anode circuit to make current measurements. Trimming resistors are installed, where required in each anode circuit, to balance anode output current circuits.

9.5.4.2.2 Diesel Generator Fuel Oil Transfer Pumps

One fuel oil transfer pump is provided for each diesel generator. Each pump has a capacity of more than the consumption rate of a diesel generator at full power. Each pump is capable of nominally pumping 15 gallons per minute. Discharge valves are locked open. Strainers are provided in the fuel transfer line to the day tank of each train. The fuel oil transfer pumps are powered from the 480V, Class 1E power system as shown in table 8.3-1. In case of loss of offsite power, each pump is powered from its corresponding diesel generator.

9.5.4.2.3 Diesel Generator Fuel Oil Day Tanks

Each diesel generator fuel oil day tank has a usable nominal capacity of 1100 gallons. Tank fittings provide for tank fill, tank overflow, water removal, and recirculation. Each tank is

provided with appropriate instrumentation. Tank vents are equipped with flame arrestors. The tank level is controlled by high and low level switches. At the high position there is approximately 2.7 hours of fuel available at 100% engine rated power. At the low position, approximately 1.9 hours of fuel is available in the tank. This exceeds the one hour minimum fuel plus 10% required by ANSI N195-1976. The tank is located in a vault approximately 30 feet above the diesel engine, thereby ensuring a positive suction head for the diesel generator fuel oil feed pumps.

9.5.4.2.4 Piping Surfaces

Exterior surfaces of the diesel generator fuel oil underground piping are protected in accordance with American Water Works Association (AWWA) Standards.

9.5.4.3 System Operation

The diesel fuel oil transfer pump takes suction from the diesel generator fuel oil storage tank and discharges into the diesel generator fuel oil day tank.

Diesel fuel oil is supplied to the diesel generator fuel oil feed pumps from the day tanks by gravity feed.

The diesel generator fuel oil transfer pump is automatically started and stopped by a signal from the level controls in the diesel generator day tank. This pump is started at the low level regardless of whether the diesel engine is running or not. If the pump fails to start, a low-pressure condition in the pump discharge is annunciated in the main control room.

The operator can then manually start the transfer pump from a switch in the main control room. If the transfer pump still fails to operate, a low level day tank alarm is actuated to alert the operator to take corrective action. Fuel can then be supplied from the redundant train by opening valves on an interconnecting line and the diesel generator may be allowed to continue running. As stated at Section 9.5.4.2 this capability is not credited in the safety analysis.

The automatic pump in the system also may be actuated manually by the operator from the control room or from the diesel generator room local control panel.

9.5.4.4 Safety Evaluation

Safety evaluations are numbered to correspond to the safety design bases and include the following:

A. Safety Evaluation One

The capacity of each of the underground diesel generator fuel oil storage tanks is sufficient for 7-day operation plus an allocation for periodic testing of each of the diesel generators using diesel fuel oil which meets the specifications of ASTM D975, Table 1, having an API gravity of within 0.3 degree at 60F or a specific gravity of within 0.0016 at 60/60F, when compared to the supplier's certificate or an absolute specific gravity at 60/60F of greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity at 60F of greater than or equal to 27 degrees but less than or equal to 39 degrees, at the largest actual

operating load indicated in section 8.3. Cross-connect lines with double-locked closed valves are provided so that either transfer pump can discharge to the fuel oil day tank serving the redundant diesel generator. The cross-connect piping and valves are designed as Seismic Category I. As stated at Section 9.5.4.2 this capability is not credited in the safety analysis. Additional fuel can be delivered to the plant site by truck, rails, or helicopter within 7 days of concurrent operation of both diesel generators as required by section 9.5.4.1.1.A.

B. Safety Evaluation Two

The DGFOS, including cross-connect piping and valves, is designed to Seismic Category I requirements using the methods of section 3.9.

C. Safety Evaluation Three

The diesel generator fuel oil storage tanks, fuel oil day tanks, fuel oil transfer pumps, and the piping and valves between storage tanks, day tanks, and diesel generator engines are designed and constructed in compliance with ASME Boiler and Pressure Vessel Code, Section III, Class 3. Fuel oil tanks are sized, enclosed, and built in conformance with NFPA, ANI, NACE, API, and UL requirements.

A single failure analysis is provided in table 9.5-9.

Complete physical redundancy of mechanically active components is provided in the DGFOS. One fuel oil transfer pump is provided for each diesel generator.

The pump is powered from the bus to which the diesel generator it serves is connected. Failure of one pump or one diesel generator does not affect the operability of any component in another train. The two operating DGFOSs provided for each generating unit are physically separated from each other to prevent interaction from one unit to the other. While cross-connect capability exists for use when a failure has occurred in one of the DGFOS or transfer systems, cross-connecting the diesel fuel oil storage tanks during normal operations in Modes 1, 2, 3, or 4 would violate the independence and redundancy design criteria. The cross-connect is isolated by double isolation valves which are kept normally locked.

D. Safety Evaluation Four

The transfer pump can be operated from either the main control room or the local diesel control panel. Alarms and indications of day tank levels and transfer pump status are displayed in the main control room and at the local diesel control panel.

E. Safety Evaluation Five

Fuel reserve for testing is ensured by sizing the diesel generator fuel oil storage tanks to contain a sufficient allocation of fuel capacity above that required for 7-day full load operation.

F. Safety Evaluation Six

Each individual diesel generator's fuel oil storage tank and day tank is equipped with a fill pipe fitted with standard connections for refill from tank trucks.

Table 9.5-9

DIESEL GENERATOR FUEL OIL SYSTEM SINGLE FAILURE ANALYSIS

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Fuel oil transfer pump	Inoperable/mechanical or electrical failure	Low level in fuel oil day tank	Low level alarm in day tank	Pump in redundant train can be aligned to supply day tank[a]	Two full-capacity pumps per unit power supply from different MCCs in same load group There are two redundant diesel generators, each with its own fuel tank. There is one full-capacity fuel oil transfer pump in each fuel tank. Manual cross- connect to other pump is available.[a]
Transfer pump check valve	Fails open/ material failure	Piping drains to storage tank		Day tank will not drain. Flow path to tank will remain open	Fill line enters top of day tank. Manual cross-connect to other pump is available[a]
Duplex strainer	Clogged/dirty oil	Low level in fuel oil day tank	High-pressure differential alarm	Flow is diverted to redundant strainer	Strainer can be manually bypassed
Transfer piping	Line break/ corrosion or mechanical damage	Low header pressure	Low-pressure alarm	Redundant diesel remains in service Diesel can run 2.5 hours without replenishment	
Level control in fuel oil day tank	Failure to function/material failure or mechanical bind or electrical failure	Low level in oil day tank	Redundant low level alarm on day tank	Low level alarm	Operator starts pump
Cross-connect line shutoff valve	Fails open/ material failure	No effect on system performance	Handle position	Redundant valve in series	Valve is normally locked closed

a. As stated in Section 9.5.4.2 the cross-connect capability is not credited in the safety analysis.

G. Safety Evaluation Seven

System tank vents are equipped with flame arrestors as shown in engineering drawings 01, 02, 03-M-DFP-001.

H. Safety Evaluation Eight

Maintenance of the diesel fuel oil above the cloud point; i.e., above the low temperature at which the separation of wax becomes visible, is achieved by enclosing the equipment in heated buildings, and installation below the frost line.

I. Safety Evaluation Nine

The DGFOS components are of Seismic Category I design and are installed underground or in buildings that include no other system's components.

J. Safety Evaluation Ten

The fire protection system provides a preaction sprinkler system for each compartment of the diesel generator building as described in subsection 9.5.1.

K. Safety Evaluation Eleven

All components of the DGFOS are capable of being fully tested during normal unit operation.

9.5.4.5 Inspection and Testing Requirements

The diesel generator fuel oil storage tank for each diesel generator is tested by nondestructive methods in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class 3, and is subjected to routine tests and inspections during construction and installation.

Refer to the Technical Specifications for operational tests and inspections.

9.5.4.6 Instrumentation Applications

A pressure switch, installed on the transfer pump discharge, initiates an alarm in the control room and local diesel generator control panel if the day tank level is low and low pressure exists in this header. The alarm indicates that fuel oil is not being pumped to the day tank.

Level switches on each day tank start or stop the transfer pump at preset level points. Level switches also initiate low-low day tank level alarms in the control room and diesel generator panel in the generator room. Refer to section 7.4 for the DGFOS fuel oil transfer logic.

9.5.5 DIESEL GENERATOR COOLING WATER SYSTEM

The diesel generator cooling water system (DGCWS) removes waste heat of combustion from the diesel generator engine. The DGCWS then transfers this heat to the essential spray pond system through the jacket water heat exchanger. The DGCWS initially preheats the combustion air during diesel generator engine starts by providing warm water through the combustion air heaters. Each diesel generator engine is provided with an identical and independent DGCWS. The DGCWS is described in the following subsections.

9.5.5.1 Design Bases

9.5.5.1.1 Safety Design Bases

The DGCWS is designed to the following design bases:

A. Safety Design Basis One

The DGCWS shall remove rejected heat from each diesel engine at rated design load of the diesel generator.

B. Safety Design Basis Two

The DGCWS shall be designed such that a single failure of any component cannot cause loss of system ability to mitigate the consequences of an accident or to safely shut down the reactor.

C. Safety Design Basis Three

The DGCWS shall be designed to remain functional in the event of an SSE.

D. Safety Design Basis Four

In normal standby status, the DGCWS shall be maintained in a warmed condition in order for the diesel generator to start within the required load acceptance time frame.

9.5.5.1.2 Power Generation Design Bases

A. Power Generation Design Basis One Active components of the DGCWS are capable of being tested during plant operation in accordance with 10CFR50, General Design Criterion 46.

B. Power Generation Design Basis Two

The DGCWS is treated to minimize corrosion.

Protection of the DGCWS from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

Codes and standards applicable to the DGCWS are listed in table 3.2-1.

9.5.5.2 System Description

The arrangement of the diesel generators and components of the DGCWS is shown in engineering drawings 13-P-ZGL-701, 13-P-ZGL-702 and 01, 02, 03-M-DGP-001.

The DGCWS is procured as an integral part of the diesel generator system. Nominal operating parameters of the jacket water, combustion air, lube oil and fuel oil coolers[a] are listed in table 9.5-10.

(a). In units where DEC-00649 has been implemented, the diesel generator fuel oil coolers cooling function has been permanently retired.

Table 9.5-10
DIESEL GENERATOR COOLING WATER SYSTEM
NOMINAL OPERATING PARAMETERS

Component	Q (Btu/hr)	Cooling Water Flow, lbm/hr	Cooling Water ΔT, °F
Combustion Air Cooler	4,400,000	148,005	29.8
Jacket Water Cooler	5,520,000	289,575	19.1
Lube Oil Cooler	2,440,000	198,459	12.3
Fuel Oil Cooler[(a)]	51,000	5,944	11

NOTE: The listed heat loads are design loads from vendor submittals. The mass flow rates shown are actual flow measurements except for the fuel oil cooler which is a calculated value. No flow data was obtained for this cooler because it is not required for engine operation[(a)]. Therefore, the fuel oil coolers of all six emergency diesel generators have been functionally abandoned. The cooling water ΔT values shown are calculated based on the indicated heat loads and cooling water mass flow rates. This table shows nominal operating parameters. The minimum flow rates required, however, are based on the spray pond inlet temperature and the tube plugging/blockage criterion established for each cooler.

The DGCWS consists of a combustion air (intake) cooler, a closed loop jacket cooling system consisting of an engine-driven cooling water pump, a water-cooled jacket water heat exchanger, a surge tank (jacket water stand pipe), valves, instrumentation, and controls. The engine turbocharger is also cooled by the DGCWS. A small motor-driven recirculation jacket water pump, a heater, and a thermostat are included in the system to maintain the jacket water in a warm standby condition. Each diesel engine has its own independent DGCWS.

(a). In units where DEC-00649 has been implemented, the diesel generator fuel oil coolers cooling function has been permanently retired.

Cooling water from the essential spray pond system (ESPS) is used as the coolant in the jacket water heat exchanger.

Cooling water flow is from the water pump discharge through the jacket water heat exchanger, then through the engine, turbocharger, combustion air coolers, and governor oil cooler, then through the surge tank to the pump inlet. Adequate design margin for the diesel generator cooling water system is provided by the diesel manufacturer.

An automatic temperature regulating valve controls flow in the jacket water heat exchanger bypass line to maintain proper water temperature.

DGCWS makeup to the system surge tank is accomplished manually as needed from the demineralized water system. In addition, makeup can be provided from the Seismic Category I, Safety Class 3, safety-related condensate storage and transfer system. See Section 9.2.6 for details. A local gauge glass is provided for the surge tank. The DGCWS is treated for corrosion control; the cooling water chemistry control program is the same as that described in Section 9.2.2.1.4 for the essential cooling water system.

A 40 kW electric immersion heater in the DGCWS provides standby heating for the DGCWS. Water is circulated by a small warmup pump. Heater power and pump operation are controlled by a thermostat, to maintain water temperature within the manufacturer's recommended range.

Only vertical and horizontal piping runs are provided in order to eliminate air pockets. The height of the surge tank ensures that the pump suction piping and most of the remaining system

is initially filled with water. During startup, air trapped in the engine will be displaced by the pump discharge. The design, due to the height of the surge tank, ensures that the DGCWS remains filled with water.

9.5.5.2.1 Component Description

9.5.5.2.1.1 Jacket Water Heat Exchanger. The jacket water heat exchanger is a horizontal shell and tube type. The exchanger, which carries the jacket cooling water on the shell side, is designed to remove 5,520,000 Btu/hr, with the jacket water cooled from 170F to 160F. Jacket water cooling is accomplished by transferring heat to the essential spray pond system water, which flows through the heat exchanger tubes.

9.5.5.2.1.2 Jacket Water Pump. The jacket water pump is a centrifugal pump that is engine-driven by a chain drive, and is mounted on the front of the engine. Lubrication is automatic, from the engine oil supply. The pump operates at 1750 rpm, and is rated at 1350 gallons per minute at 70 feet (TDH).

9.5.5.2.1.3 Jacket Water Warmup (Circulating) Pump. The jacket water warmup pump is a centrifugal type, electric motor-driven pump and is mounted on the diesel engine auxiliary skid. It has a 5 hp driver, three phase, 460V, 60 Hz, and is rated at 175 gallons per minute at 40 feet (TDH). The heater is rated at 40 kW, 480V, three-phase, 60 Hz. Power is supplied from a 480V, Class 1E motor control center. With the pump control switch in the AUTO/STOP position and the heater control switch

in the AUTO position, the jacket water warmup pump and the jacket water warmup heater automatically start when the engine temperature is below the manufacturer's recommended lower setpoint. This setup ensures that the heater will be deenergized when the warmup pump is deenergized. The pump and heater continue to operate until the engine temperature rises above the manufacturer's recommended upper setpoint, which stops the operation of the pump and heater. There are no interlocks with other systems.

9.5.5.2.1.4 Temperature Control Valve. This is a self-contained, temperature-actuated, three-way valve that responds to the jacket water pump discharge temperature. The entire cooling water flow passes through the jacket water cooler when the jacket water temperature at the inlet to the valve exceeds approximately 175F.

9.5.5.2.1.5 Combustion Air Cooler/Heater. These coolers are of radiator-type design. Each cooler has two water sides, one side for ESPS cooling water to cool the combustion air after engine warmup, and one side for jacket cooling water to preheat the combustion air when the air is below 100F. The jacket water flow is bypassed around the cooler when the combustion air reaches 100F.

9.5.5.2.1.6 Surge Tank. The DGCWS surge tank is an atmospheric vessel which accommodates coolant expansion due to temperature changes and provides net positive suction head (NPSH) to the water pumps. The surge tank provides an adequate reserve to compensate for any minor leaks in the DGCWS. The

surge tank is equipped with a sight glass. Makeup is manually initiated via a manual valve. The tank volume is approximately 258 gallons.

9.5.5.2.1.7 Electric Immersion Heater. The electric immersion heater is rated at 40 kW, three-phase, 480V, and 60 Hz. Power is supplied from a 480V, Class 1E motor control center.

9.5.5.2.2 System Operation

When the diesel generator is not in operation, the DGCWS is heated by an electric immersion heater and circulated by a jacket water warmup pump. The heater and motor are controlled by a thermostat to keep the DGCWS within the manufacturer's recommended temperature range.

When the diesel engine starts, the engine-driven jacket water pump circulates the cooling water through the DGCWS, bypassing the jacket water heat exchanger. When the cooling water entering the temperature control valve reaches approximately 165F, the three-way thermostatic valve automatically modulates water to the jacket water heat exchanger to maintain approximately 170F cooling water out of the engine. When the cooling water entering the temperature control valve is approximately 175F, all water is directed to the jacket water heat exchanger. In this manner, the cooling water is maintained at the proper temperature for maximum engine efficiency.

During emergency operation, operator action is required to prevent engine damage in event of overheating. Alarm response

procedures described in paragraph 13.5.2.1, listing E, are prepared for alarms associated with this system, incorporate information from the troubleshooting guide, and provide operator guidance in alarm response.

The DGCWS is a closed system and is independent of any other plant cooling water system.

9.5.5.2.3 Unloaded Operation

See Section 8.3.1.1.4.12

9.5.5.3 Safety Evaluation

A. Safety Evaluation One

The DGCWS is sized to cool the diesel generator while operating at design load when the ESPS water is at a maximum temperature.

B. Safety Evaluation Two

Refer to table 9.5-11 for a single failure analysis of the DGCWS.

The DGCWS is independent of other plant cooling water systems; therefore, a single failure in any other cooling water system will not affect the DGCWS. A failure of the essential spray pond system, however, will result in a loss of essential spray pond system to the jacket water heat exchanger, which will result in an increase in temperature of the DGCWS and eventual engine shutdown. However, since there are independent redundant trains of the essential spray pond water system and independent, redundant diesel generator

systems, this type of failure cannot affect the redundant diesel generator system and prevent safe shutdown. Similarly, a single failure in the DGCWS cannot affect the associated ESPS train or the redundant diesel generator and prevent safe shutdown.

Table 9.5-11
DIESEL GENERATOR COOLING WATER SYSTEM
SINGLE FAILURE ANALYSIS (Sheet 1 of 2)

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Essential spray ponds system	Leak or rupture in supply line/ corrosion	Loss of cooling of combustion air, jacket circ. water loop and lube oil circ. loop	High temperature indication and alarm on jacket water circulating loop and lube oil circulating loop	Redundant diesel generator remains in service	
Circulating water temper-ature control valve	Fails to throttle flow to cooler/ valve sticks open	Continuous flow through cooler causing low temper-ature in system. Diesel runs cold, less efficient	Low temperature indication on jacket water circulating loop	Redundant diesel generator remains in service	Operator may throttle cooling water flow
	Fails to throttle flow to bypass/ heat ex-changer/valve sticks closed	Loss of cooling of jacket water circu-lating loop excessive temperature	High temperature indication and alarm on jacket water circu-lating loop	Redundant diesel generator remains in service	
Engine-driven circulating water pump	Inoperable/ mechanical failure	Low header pres-sure	Low-pressure alarm	Redundant diesel generator remains in service	
Surge tank	Leaks/corrosion	Low water level	Gauge	Makeup water re-places losses	

Table 9.5-11
DIESEL GENERATOR COOLING WATER SYSTEM
SINGLE FAILURE ANALYSIS (Sheet 2 of 2)

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Jacket water heat exchanger	Leaks/corrosion ruptures	Low level in surge tank	Gauge	Redundant diesel generator remains in service	
Standby electric jacketwater heater	Open circuit/ circuitry fault	Drop in circulating water temperature. Diesel generator not at optimum temperature to start	Low temperature indication and alarm on jacket water circulating loop	Redundant diesel generator remains in service	Diesel generator will start but may not do so within TS required time frame
Standby jacket water circulation pump	Inoperable/mechanical or electrical failure	Drop in jacket water temperature. Diesel generator not at optimum temperature to start	Low temperature indication and alarm on jacket water circulating loop	Redundant diesel generator remains in service	Diesel generator will start but may not do so within TS required time frame
Jacket water circulating water piping	Line break or major leak/vibration	Low level in surge tank. Diesel generator not operative	Gauge	Redundant diesel generator remains in service	

Table 9.5-12
DIESEL GENERATOR COOLING WATER SYSTEM - INDICATIONS, ALARMS, AND SENSORS
(Sheet 1 of 2)

Parameter	Local Indication	Local Engine Control Panel	Control Room	Comments
Engine jacket water heat exchanger temperature	• Gauge[a]			
Engine jacket water heat exchanger pressure	• Gauge (inlet and outlet)			
Circulating pump pressure	• Gauge (inlet and outlet)			Indicators are present for both standby circulating and engine-driven pumps
Engine supply pressure	• Gauge	• Alarm (low-pressure) • Gauge inlet and outlet	• Common trouble alarm	
Engine jacket water heat exchanger temperature	• Gauge (inlet and outlet)			

a. All instruments are checked during monthly testing of engine.

Table 9.5-12
DIESEL GENERATOR COOLING WATER SYSTEM - INDICATIONS, ALARMS, AND SENSORS
(Sheet 2 of 2)

Parameter	Local Indication	Local Engine Control Panel	Control Room	Comments
Engine return jacket water temperature	• Gauge	• Gauge • Alarm (high or low)	• Common trouble alarm	High temperature shuts down diesel in test mode only
Jacket water level control	• Gauge			

C. Safety Evaluation Three

The DGCWS is a supporting system to the diesel generator systems, and is designed to Seismic Category I requirements to assure that the system will remain functional during or after an SSE.

D. Safety Evaluation Four

The DGCWS immersion heater and warmup pump are Seismic Category I, and are powered from a Class 1E power supply in order to assure a warm engine and fast start and load acceptance. Low jacket water temperature will be alarmed at the local control panel and in the main control room.

9.5.5.4 Inspections and Testing Requirements

Testing of the diesel generator system is discussed in sections 8.3 and 14.2.

In lieu of thermal performance testing as required by Generic Letter 89-13, the Diesel Generator support system heat exchangers will be cleaned and inspected every other refueling outage.

9.5.6 DIESEL GENERATOR STARTING SYSTEM

Each diesel generator unit is composed of one diesel engine, one generator, and their associated controls. Therefore, the following discussion is limited to a diesel generator starting system (DGSS) for only one diesel engine.

A compressed air starting capability is provided for each diesel generator and is shown schematically in engineering

drawings 01, 02, 03-M-DGP-001 (Sheets 6 and 9). Equipment location is shown in engineering drawings 13-P-ZGL-701 and 702.

9.5.6.1 Design Bases

The DGSS has no power generation design bases. The following safety design bases establish the DGSS requirements:

A. Safety Design Basis One

   The DGSS shall provide a stored compressed air supply sufficient for accomplishing a diesel generator start in less than or equal to 10 seconds. As guidance for the receiver capacity, each air receiver shall be sized to accomplish five consecutive starts from the receiver design working pressure without being refilled.

B. Safety Design Basis Two

   The DGSS shall remain functional during and after an SSE.

C. Safety Design Basis Three

   The DGSS shall ensure that a single failure of any component cannot cause loss of the system capability to mitigate the consequences of an accident or to safely shut down the reactor.

D. Safety Design Basis Four

   The DGSS shall be capable of being monitored and controlled from either the control room or the local diesel generator control panel.

Protection from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4.

Missile protection is discussed in section 3.5. Protection against dynamic effects associated with postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

Codes and standards applicable to the DGSS are listed in table 3.2-1.

9.5.6.2 System Description

The DGSS, as shown schematically in engineering drawings 01, 02, 03-M-DGP-001, Sheets 6 and 9 consists of two independent and redundant networks of compressed air, each consisting of a motor-driven air compressor, air dryer, air receiver, pneumatic control valve and two solenoid pilot valves. To support maintenance activities, one of the two compressed air networks may be removed from service during plant operations for short periods of time. Each compressor is powered from a separate station service bus. Table 9.5-13 lists the major components in the DGSS and their design specifications.

Each air receiver is designed to provide sufficient air capacity to start the diesel generator in less than or equal to ten seconds. The startup time is defined as the total elapsed time between receipt of an automatic start signal and closure of the diesel generator circuit breaker in the safety-related ac power distribution system. Each air receiver is maintained in a ready-to-use state at a maximum pressure of approximately 250 psig. The tanks are provided with a pressure switch to start and stop the compressors as required. The low pressure alarm is set at a level to ensure that engine start time requirements are met. Low-pressure is alarmed locally and as a

common trouble alarm to the main control room. High pressure safety relief valves are provided. The compressors are not required during the starting operation or during diesel engine operation. The position of the air receiver outlet valve is monitored in the control room to ensure air availability. No operator action is required to prevent damage to the diesel engine upon low starting air pressure.

9.5.6.3 System Operation

Normally, each air compressor serves one air receiver. A piping cross connect is provided so, if one compressor or air dryer is unavailable, the functional compressor and air dryer may be used to charge both air receivers. The compressors start when the air storage tank pressure drops to approximately 240 psig and stop when the pressure reaches approximately

Table 9.5-13
DIESEL GENERATOR STARTING SYSTEM
DESIGN SPECIFICATIONS

Equipment or Parameter	Quantity Per Unit	Type or Capacity
AC motor air start compressor	4 (2 per diesel)	38 standard ft^3/min at 250 psig
Air dryer	4 (2 per diesel)	75 standard ft^3/min at 250 psig
Air storage tank (receivers)	4 (2 per diesel)	83 ft^3 at 250 psig

250 psig. Each compressor is capable of pressurizing a receiver from 100 psig to 250 psig in approximately 30 minutes. The compressors are powered from a 480V, non-Class 1E motor control center. The compressor motors are 15 hp, 460V, three-phase, 60 Hz at 1800 revolutions per minute. The air dryer, a combination radiator and refrigeration unit, reduces the compressed air dewpoint at the air receivers to less than 50F in a 70F ambient environment or at least 10F less than the lowest expected ambient temperature. Air samples may be taken at the air receivers to verify the dewpoint. A check valve between the air dryer and storage tank ensures that a broken line will not result in a sudden loss of air. Air from each of the storage tanks discharges into the diesel generator through a pneumatic admission valve, which is activated by solenoid pilot valves on receipt of a diesel generator start signal. The air piping interconnects downstream of the pneumatic admission valves. The admission system delivers air simultaneously to the time and pilot air distributor and to the individual air-start valves in each cylinder. Pilot air, delivered by the distributor, opens the air-start valves in proper sequence. Starting air is then admitted directly into the cylinders for fast, reliable cranking and starting.

9.5.6.4 Safety Evaluation

Evaluation of the safety design bases listed in paragraph 9.5.6.1 are described as follows:

A. Safety Evaluation One

   Sufficient storage capacity is provided in each compressed air tank to accomplish a diesel generator

start in less than or equal to 10 seconds. Sufficient storage capacity exists in each air receiver at its design working pressure to accomplish five consecutive engine starts without recharging the receiver.

B. Safety Evaluation Two

The DGSS, excluding the compressors and dryers, is designed to Seismic Category I requirements using the techniques of section 3.9.

C. Safety Evaluation Three

The DGSS, exclusive of the air compressors and air dryers, is designed in accordance with Seismic Category I requirements as specified in section 3.2. Any system, equipment, or structure which is not Seismic Category I and whose collapse could result in loss of a required function of the DGSS through either impact or flooding is analytically checked to determine that it will not collapse when subjected to seismic loading.

Diesel generator train redundancy and independency design provisions ensure that a single failure of any component cannot cause loss of system ability to mitigate the consequences of an accident or to safely shut down the reactor.

D. Safety Evaluation Four

Monitoring of the DGSS is provided at both the control room and the local diesel generator control panel.

9.5.6.5 Inspection and Testing Requirements

Testing of diesel generator systems is discussed in sections 8.3 and 14.2.

9.5.6.6 Instrumentation Applications

Each compressed air storage tank is provided with a pressure sensing device that initiates operation of the air compressors along with a pressure sensing device that actuates an alarm in the control room and at the local diesel generator control panel when the air pressure drops below a preset value. Other features are covered in paragraph 9.5.6.2.

Instruments are checked during monthly testing of the engine. Calibrations are routinely performed according to the PVNGS Preventative Maintenance Program, and alarms are verified operable.

9.5.7 DIESEL GENERATOR LUBRICATION SYSTEM

The diesel generator lubrication system (DGLS) provides clean, temperature-controlled, lubricating oil to the diesel engine for standby and operating modes. Each engine is provided with an independent system.

9.5.7.1 Design Bases

The following safety design bases list the requirements that must be met by the DGLS. The DGLS has no power generation design bases.

A. Safety Design Basis One

The DGLS shall provide adequate lubrication at a controlled temperature to the diesel generator.

B. Safety Design Basis Two

The DGLS shall ensure that a failure of any component cannot cause the loss of system ability to mitigate the consequences of an accident or to safely shut down the reactor.

C. Safety Design Basis Three

The DGLS shall remain functional during and after the SSE.

D. Safety Design Basis Four

The DGLS shall be maintained at an operating temperature that ensures the engine lubricates properly under all normal operating conditions. The DGLS shall maintain the lube oil at a normal keep warm temperature during standby that can assist the diesel engine in starting within the required load acceptance time frame.

Protection from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

Codes and standards applicable to the DGLS are listed in table 3.2-1.

9.5.7.2 System Description

The DGLS for each engine consists of one integral engine-driven circulating lubricating oil pump, one standby lube oil circulating (keeps warm and lubricated) pump, two standby oil heaters, one filter, basket strainers, one water-cooled lube oil cooler, valves, and instrumentation. Table 9.5-15 lists the major components in the lubrication system and their design specifications.

The manufacturer's recommendations are followed to analyze and replace the engine oil. The oil is sampled at a minimum of quarterly during engine operation and then analyzed for viscosity, foreign material (dirt and wear metals), water, acidity and Total Base Number (TBN). The oil will be replaced based on oil analysis as required.

The full flow lube oil filter contains 146 elements of wound viscose yarn of 16 micron rating. A built-in bypass is provided to ensure lubrication if the filter becomes clogged. The pressure differential across the lube oil filter is indicated through a differential pressure indicating device that is monitored by the operators. Two basket strainers are provided to prevent debris from a ruptured filter element from entering the engine.

In the unlikely event of system leakage, a low level switch in the engine crankcase provides an alarm at the diesel control board. Oil would flow into the floor drain system, which is separate for each engine.

Cooling water from the ESPS is used as the cooling medium in the lube oil cooler to control the lubrication oil temperature.

When the lube oil temperature is low, the lubrication oil is automatically diverted around the oil cooler by a threeway thermostat controlled bypass valve to elevate the lube oil temperature to the operating range. The lube oil cooler cools 670 gallons per minute of oil on the shell side with 401 gallons per minute of ESPS water on the tube side at 2,440,000 Btu/h.

The lube oil circulating pump and heaters are powered from a 480V, Class 1E motor control center.

Table 9.5-15
DIESEL GENERATOR LUBRICATION SYSTEM
DESIGN SPECIFICATIONS

Equipment or Parameter	Quantity	Type or Capacity
Engine-driven lube oil pump	1	670 gal/min
Lube oil filter	1	Full flow, replaceable element type
Lube oil cooler	1	Shell and tube type
Standby circulating lube oil pumps	1	112 gal/min at 50 psig
Electric resistance standby heaters	1	19 kW, 480V, 3 phase, 60 hz
	1	4 kW, 480V, 3 phase, 60 hz

Crankcase explosion relief valves are located at 12 of the 20 openings in the sides of the engine center frame, or block. These valves relieve pressure buildup from a primary explosion.

9.5.7.3 Safety Evaluation

A. Safety Evaluation One

The diesel engine-driven pump provides oil to the engine critical components during engine operation. Oil is kept at a constant pressure and temperature by use of regulating valves, recirculation lines, and a lube oil cooler. During periods of standby status, the motor-driven pump and electric oil heaters keep the critical components lubricated and warmed.

B. Safety Evaluation Two

The lubricating oil supply is sized to provide adequate diesel generator lubrication. The lubrication subsystem is capable of supplying lube oil without augmentation from other sources. The engine driven lube oil pump is chain driven. A single failure may be assessed as a failure of the diesel generator with which it is associated; in such a circumstance, safe shutdown is attained and maintained by the appropriate redundant diesel generator installation. A single failure analysis is presented in table 9.5-16.

C. Safety Evaluation Three

The DGLS is designed in accordance with Seismic Category I requirements as specified in section 3.2. The components (and supporting structures) of any system, equipment, or structure which is not Seismic Category I, and whose failure could result in loss of a required function of the DGLS through either impact or

flooding, are analytically determined to not fail when subjected to seismic loading.

D. Safety Evaluation Four

The DGLS is provided with a standby electric pump that circulates lube oil through the DGLS. Oil is heated by electric heaters when the engine is not operating. High lube oil viscosities that accompany low lube oil temperatures are thus prevented. This assists in quick engine starting and increases component life through proper lubrication during quick starts.

Diesel generator alarms associated with the DGLS are described in section 8.3. DGLS indications and alarms are summarized in table 9.5-17.

Pressure relief valves are provided on the discharge of each oil pump and on the engine supply header. A pressure regulator regulates oil pressure to the turbocharger. Oil flow is not monitored.

The recirculation oil pump and heaters are interlocked such that they operate only when the engine speed is less than 280 revolutions per minute. Except for shutdown functions, no other interlocks are provided.

Operator action is not required to prevent damage to the engine upon low oil pressure if EDG control air is available, as the engine will be automatically shut down. If EDG control air is not available, the EDG can be tripped manually to shut off the fuel racks by activating a lever on the side of the engine. During emergency operation, as discussed above, turbocharger protective functions are bypassed and operator action is

required. Oil filters and strainers may be manually bypassed for cleaning during operation. Oil may be added to the crankcase during operation at the indicated fill point. Alarm response procedures are available in each D.G. control room for alarms associated with this system. These procedures instruct the operator on appropriate action for each alarm.

Table 9.5-16
DIESEL GENERATOR LUBRICATION SYSTEM SINGLE FAILURE ANALYSIS

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Engine-driven oil pump	Inoperable/mechanical failure	Loss of adequate lubrication on critical sliding components	Low-pressure alarm and trip	Redundant diesel generator remains in service.	
Oil filter	Clogged/dirty oil	Oil flow is reduced	High-pressure differential alarm	Redundant diesel remains in service	Operator may bypass filter housing and change filter elements
Temperature control valve	Fails to throttle flow to cooler/ material failure	Oil flows through oil cooler causing low temperature in system	Low-temperature alarm	Diesel continues to run. Temperature may be maintained by reducing cooling water flow as required.	Operator may control cooling water flow manually.
	Fails to throttle flow to bypass/ material failure	Oil bypasses cooler causing high temperature in system	High-temperature alarm	Redundant diesel generator remains in service.	
Heat exchanger	Tube leaks or blockage/corrosion	Oil flow to engine is reduced	Low-pressure alarm in lube oil system or high-temperature alarm	Redundant diesel generator remains in service.	
Electric standby heater	Open circuit/ electrical failure	Oil temperature too low. Diesel generator not at optimum temperature to start	Low-temperature alarm	Redundant diesel generator in service.	Diesel generator starts but may not do so in the Tech Spec required time frame.
Standby oil circulating pump	Inoperable/mechanical or electrical failure	Oil temperature too low. Reduced lubrication to sliding surfaces at startup.	Low-temperature alarm	Redundant diesel generator in service.	Diesel generator starts but may not do so in the Tech Spec required time frame.
Lube oil piping	Line breaks or major leaks/corrosion or mechanical damage	No lube oil flow.	Low pressure alarm trip	Redundant diesel generator remains in service.	

Table 9.5-17
DIESEL GENERATOR LUBE OIL INDICATIONS AND ALARMS

Parameter	Local	Engine Control Panel (Local)	Control -Room	Comments
Lube oil pressure	• Gauge (engine pump disch. and motor driven pump disch.)			
	• Gauge (inlet and outlet of lube oil heat exch.)			
	• Gauge (inlet pressure to engine)	• Gauge (inlet pres. to engine) Alarm (inlet pres. to engine)	• High priority trouble alarm	• Low pressure will shut down diesel in test and emergency mode
	• Gauge (inlet pres. to turbocharger)	• Gauge (inlet pres. to turbocharger • Alarm (inlet pres. to turbocharger)	• High priority trouble alarm	• Low pressure will shut down diesel in test mode only
	• Gauge (LO filter differential pressure)	• Alarm (high D/P)	• High priority trouble alarm	• Diesel continues to run
Crankcase pressure	• Gauge (crankcase pressure)	• Alarm (high pressure)	• High priority trouble alarm	• High pressure will shut down diesel in test mode only
Lube oil temperature	• Gauge (lube oil cooler inlet temperature)	• Gauge (lube oil temperature) • Alarm (high oil temperature	• Low priority trouble alarm	• Diesel continues to run
	• Gauge (lube oil cooler outlet temperature			
	• Gauge (LO engine inlet temperature)	• Gauge (lube oil temperature • Alarm (low oil temperature	• Low priority trouble alarm	• Engine available for starting, but may not make Tech spec required time
Lube oil level	• Level gauge (engine crankcase)	• Alarm (low level)	• Low priority trouble alarm	• Diesel continues to run

Instruments are read at least monthly during engine testing. Calibrations are routinely performed according to the PVNGS calibration program and alarms verified operable.

9.5.7.4 Inspection and Testing Requirements

Testing of the diesel generator system is discussed in sections 8.3 and 14.2.

9.5.8 DIESEL GENERATOR COMBUSTION AIR INTAKE AND EXHAUST SYSTEM

This section discusses the mechanical features of the diesel generator combustion air intake and exhaust system. The diesel generator building ventilation system is discussed in subsection 9.4.7.

9.5.8.1 Design Bases

9.5.8.1.1 Safety Design Bases

The diesel generator combustion air intake and exhaust system is designed to meet the following safety design bases:

A. Safety Design Basis One

   The diesel generator combustion air intake and exhaust systems shall be capable of supplying adequate combustion air and disposing of resultant exhaust products to permit continuous short-term operation of the diesel generator at 110% of nameplate rating.

B. Safety Design Basis Two

The diesel generator combustion air intake and exhaust system shall be designed to remain functional during and after a safe shutdown earthquake.

C. Safety Design Basis Three

The diesel generator combustion air intake and exhaust system shall be designed so that a single failure of any component, assuming a loss of offsite power, cannot result in complete loss of the diesel generation function.

9.5.8.1.2 Power Generation Design Bases

The diesel generator combustion air intake and exhaust system is capable of being tested during plant operation in accordance with 10CFR50, General Design Criterion 10.

Protection of the diesel generator combustion air intake and exhaust system from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

Codes and standards applicable to the diesel generator combustion air intake and exhaust system are listed in table 3.2-1.

9.5.8.2 System Description

9.5.8.2.1 General Description

Each diesel engine is provided with an air intake and exhaust system. The major components of the system include an air intake filter, intake silencer, an exhaust silencer, combustion air cooler/heaters and associated piping and flexible connections, shown in engineering drawings 13-P-ZGL-701, -702 and 01, 02, 03-M-DGP-001.

9.5.8.2.2 System Operation

There are no active components within the diesel generator combustion air intake and exhaust system.

Combustion air flow or exhaust flow is not monitored, as there are no levels to be monitored.

Each power cylinder is equipped with a thermocouple to provide exhaust temperature indication at the local engine control panel. The exhaust temperature at the turbocharger inlet and outlet is provided from thermocouples. Indication is at the local engine control panel. Combustion air temperature is indicated locally, and thermocouples provide indication at the local engine control panel.

The turbocharger discharge pressure and the intake manifold pressures are indicated locally and at the local engine control panel.

A differential pressure switch on the combustion air piping downstream of the combustion air filter registers the pressure drop across the air filter locally.

There are no system interlocks.

Upon initiation of a diesel generator start signal, combustion air is drawn into the air intake filter, through the intake silencer, and delivered to the engine. The air intake filter, intake silencer, and the combustion air piping are sized to supply an adequate supply of air to the engine for short-term periods while operating at 110% of nameplate rating. The short-term rating is based upon 2 hours of operation every 24 hours. The air filter is an oil-impingement type with a low-pressure drop. The air filter is sized to provide adequate combustion air during dust storm conditions.

After the exhaust gas passes through the turbocharger, the exhaust gas enters the exhaust pipe, then passes through the exhaust silencer, and is piped out of the building. The exhaust piping and silencer are sized to prevent excess back-pressure on the engine for the short-term period when operating at 110% of nameplate rating.

During standby, warm jacket water cooling water flows through the heater section of the combustion air cooler/heaters.

Jacket water flow continues when the engine starts and operates until the combustion air reaches 100F to ensure smooth acceleration and load acceptance. When the combustion air reaches 100F due to turbocharger compression, the jacket water is shut off. Cooling water from the essential spray ponds flows in the cooler section upon a diesel generator start signal, and continues to flow to prevent excessively high combustion temperatures.

No operator action is required to prevent potential damage caused by the combustion air inlet and exhaust system to the engine. No local or remote alarms are required.

Instruments are checked during monthly testing of the engine. Calibrations are routinely performed according to the PVNGS M&TE, and alarms are verified operable.

9.5.8.3 Safety Evaluation

A. Safety Evaluation One

The diesel generator combustion air intake and exhaust system is capable of supplying an adequate quantity of filtered combustion air to the engine and of disposing of the resultant exhaust gases without creating an excessive backpressure on the engine.

The combustion air intake filter is located in a separate enclosure on the second floor of the diesel generator building and is protected against tornado missiles. The intake silencer is located inside the missile-proof diesel generator building.

The combustion air intake is located on the sidewall of the second floor of the diesel generator building below the roof level, approximately 40 feet above grade. The 59,920 cubic feet per minute engine exhaust and 105,000 cubic feet per minute ventilation exhaust discharge is in an upward direction from the diesel generator building roof through a rectangular chimney. The exhaust is carried in an exhaust pipe inside the chimney. The exhaust is directed vertically upward.

The top of the exhaust pipe and the chimney exit are approximately 90 feet above grade and about 50 feet above the air intake. These design features will preclude the recirculation of exhaust gases into the air intake.

The engine exhaust, which is approximately 35% of the building air flow, would be sufficiently mixed prior to reaching the combustion air intake filter. The above mixed intake air would not affect engine performance.

The combustion air intercooler cooler section utilizes spray pond water. The intercooler heater section carries jacketwater. Both the intercooler cooler and heater sections are fabricated from copper-nickel tubing. These corrosion-resistant materials minimize the possibility of tube leaks.

The diesel generator buildings are not equipped with gaseous fire protection systems, nor are they located near the gas storage facilities. The carbon dioxide storage tank is located at a distance of 220 feet, the hydrogen storage facility is 600 feet away, and the nitrogen storage system is 500 feet away. These distances are adequate to ensure that accidental releases of these gases will not degrade diesel performance.

The meteorological data presented in paragraphs 2.3.1.1.5 and 2.3.1.2.5 indicate that snow, hail, or freezing rain are extremely rare and very light. It is not probable that either the intake or

exhaust could be plugged by snow or ice. The intake and air filter are sized to adequately provide combustion air during dust storm conditions.

B. Safety Evaluation Two

The diesel generator combustion air intake and exhaust system is designed to Seismic Category I requirements as specified in section 3.2. The components (and supporting structures) of any system, equipment, or structure that are not Seismic Category I and whose failure could result in loss of a required function of the diesel generator combustion air intake and exhaust system through either impact or flooding are analyzed to determine that they will not fail when subjected to seismic loading.

C. Safety Evaluation Three

The diesel generator combustion air intake and exhaust system does not contain any active components. A single failure of any component cannot result in a complete loss of the diesel generator. A single failure is considered as a failure of the diesel generator with which the component is associated. In such a circumstance, safe shutdown is attained and maintained by the appropriate redundant diesel generator.

9.5.8.4 Inspection and Testing Requirements

Testing of the diesel generator system is discussed in subsection 8.3.1 and section 14.2.

9.5.9 STATION BLACKOUT EVALUATION

9.5.9.1 General

10 CFR Part 50.63 requires that each light water-cooled nuclear power plant be able to withstand and recover from a station blackout (SBO) of a specified duration.

The station blackout (SBO) coping requirements of 10 CFR 50.63, Loss of All Alternating Current Power, were previously met for the Palo Verde Nuclear Generating Station (PVNGS) by having the capability to cope with an SBO for up to four hours. Based on NUMARC 87-00, Revision 1 criteria, the June 14, 2004 loss of offsite power event at PVNGS resulted in a reclassification of PVNGS to a 16 hour SBO copying plant.

The SBO 16 hour copying evaluation was submitted to the NRC in APS letter 102-05370, dated October 28, 2005. Supplemental information was provided in APS letter 102-05465, dated April 19, 2006. The NRC approved the 16-hour SBO coping evaluation in a Safety Evaluation Report dated October 31, 2006.

The 16 hour coping strategy analysis assumes that Alternate AC (AAC) is started and loaded during the first hour. The operators will start a cool-down to shutdown cooling conditions. The Atmospheric Dump Valves (ADVs) will be used for heat removal, as required by station procedures.

9.5.9.2 16 Hour Coping Assessment

The ability of PVNGS to cope with an SBO was assessed, with the following results.

9.5.9.2.1 Condensate Inventory for Decay Heat Removal

The 16 hour coping duration evaluation, using the CENTS Code, requires approximately 242,000 gallons of condensate to make-up for decay heat, sensible heat, and the heat from SG inventory which is well within the design basis for the condensate storage tank.

9.5.9.2.2 Assessing the Class 1E Battery Capacity

There is no effect on the Class 1E batteries caused by the 16 hour coping period. The battery chargers are loaded onto at least one Station Blackout Generator (SBOG) at 1 hour. The batteries have more than adequate capacity to supply the required loads during the first hour of an SBO event.

9.5.9.2.3 Alternate AC Power Source

Two SBOGs designated as Alternate AC (AAC) power sources are available at 1 hour of the onset of the SBO event. Each SBOG has sufficient capacity and capability to operate those systems necessary for coping with an SBO for the required duration of 16 hours to bring the plant to and maintain the plant in a safe shutdown condition.

Additional information concerning the AAC power system is provided in Section 8.3.1.1.10.

9.5.9.2.4 Compressed Air

The SG ADVs are the primary means of heat removal during an SBO. The ADVs are air operated valves with a backup nitrogen accumulator. In addition, to ensure availability of control

air to support ADV operation for a 16 hour SBO, a backup supplemental compressed gas connection has been provided for use during an SBO condition. However, this backup supplemental compressed gas system is now functionally retired because the ADV accumulator tanks capacity have been increased.

9.5.9.2.5 Effects of Loss of Ventilation

a. Inside Containment

No design basis accidents (DBAs) (i.e., loss of coolant accidents (LOCAs) or steam line breaks) or beyond DBAs (i.e., resulting in core damage) are assumed coincident with an limited to (1) loss of cooling water, (2) loss of ventilation systems, and (3) limited reactor coolant pump (RCP) seal leakage. SBO results in a slow heatup of containment due to loss of ventilation and RCP leakage and temperatures in a 16 hour SBO are bounded by thermal profiles considered for DBA-LOCA event as presented in Section 6.2 of the UFSAR.

The design basis accident model is adjusted for SBO. The containment temperature and pressure response to a 16 hour SBO has been calculated considering both the sensible and the latent heat addition to the containment. The sensible heat is from the component hot surfaces including the primary and secondary system. The latent heat addition is from the RCS and the RCP seal leakage of 111 gpm (25 gpm/RCP plus 11 gpm TS 3.4.14 leakage) in addition to RCS discharge from pressurizer vent valves. The analysis credits a conservative heat transfer for passive heat sinks in the containment,

however no active cooling by sprays or air coolers is assumed. Selection of the heat transfer coefficient is based on leakage from RCP seals to containment environment that will produce a saturated atmosphere and the dominant means of heat transfer will be by condensation. Consistent with previous analyses of the long-term containment responses, the Uchida condensing heat transfer correlation is used. Additionally, one third of the total containment area was excluded in the model to provide acceptable conservatism in the theoretical model.

The peak temperature and pressure remain well below the LOCA and MSLB DBA for the duration of the 16 hour SBO. Therefore, equipment within the containment will perform their intended function for the duration of the event. The current equipment qualification (EQ, 10 CFR 50.49) bounds the SBO environment.

b. Outside Containment

For all rooms with essential equipment, the essential air handling unit (AHU) will be available after AAC is available (at 1 hour). Table 9.5-18 provides a list of rooms evaluated for the 16 hour SBO coping duration plant specific geometries and heat sources. Additionally a heat sink (floor) was included where the rooms were located in plant areas with no contact to soil. Additional heat source steam leakage was added to the AFW steam driven pump room evaluation to assure a bounding analysis.

Required SBO support equipment in the rooms were evaluated to ensure a basis existed to provide an adequate assurance of operation in accordance with NUMARC 87-00.

Table 9.5-18

Assessment of Equipment Operability Outside the Containment During SBO

In all cases essential heating ventilation and air conditioning (HVAC) will be available after AAC is available (at 1 hour)

Room	Room Classification NUMARC 87-00, 2.7.1(2)
Control Room	Condition 1
DC Equipment Rooms	Condition 2
Emergency Switchgear Rooms	Condition 1
Battery Rooms	Condition 1
Charging Pump Rooms	Condition 2
ESF Pump Rooms	Condition 1
AFW-Steam Driven Pump Room	Condition 3 (1)

[1]This room is Classified as Condition 3 based on its analyzed steady state temperature as modeled per NUREG 87-00 Revision 1(2.7.1(2) and 7.2.4, Appendices F and H). All components within this room are evaluated for the environmental conditions, with the Terry Turbine Control Panel being the limiting component.

9.5.9.2.6 Containment Isolation

A review of plant containment isolation valves was performed to ensure that containment integrity is provided during the SBO event. NUMARC 87-00, Section 7.2.5 defines “containment integrity” as the capability for valve position indication and closure of containment isolation valves independent of the preferred class 1E power supplies. The containment isolation valves requiring this capability are valves that may be in the open position at the onset of an SBO. Acceptable means of position indication include local mechanical indication, DC-powered indication and AAC-powered indication. All station containment isolation valves were identified by performing a review of the plant design bases. Based on this review, it is concluded that under SBO conditions, containment integrity is accomplished.

9.5.9.2.7 Reactor Coolant Inventory Loss

Sources of expected reactor coolant inventory loss during the SBO event include RCS leakage (11 gpm per TS 3.4.14) and losses due to RCP seal leakage (25 gpm/RCP per NUMARC 87-00). Analysis of the RCS during SBO indicates that expected rates of reactor coolant inventory loss do not result in the core uncovering in the first hour or the subsequent 15 hours of coping using AAC power source. Analysis further indicates that RCS makeup systems beyond those currently unavailable under DBEs are not required. Sufficient head exists to maintain core cooling under natural circulation.

The limiting SBO scenarios conditions were simulated using only qualified 1E components with the CENTS code. The analysis supports a determination of the plant's capability to cope for up to 16 hours under SBO conditions. The analysis is initiated from hot full power conditions (3990 MWt) with the maximum allowed RCS leakage of 11 gpm. Onset of SBO conditions are assumed to immediately cause RCP, turbine, and reactor trips, and failure of the RCP seals resulting in an additional total leakage of 100 gpm.

No operator action for RCS inventory loss is assumed within the first hour of the event. The following operator actions are assumed after actuation of the AAC power source at one hour:

a) Control of cooldown using ADVs.

b) The AFW system is adjusted to maintain SG level.

c) The HPSI flow is delivered to maintain RCS inventory, subcooling, and natural circulation.

d) At 4 hours – operators adjust ADVs for approximately a 30°F/hr cooldown and maintain pressure in the RCS using the pressurizer vent valve.

It is concluded that the ability to maintain adequate RCS inventory to ensure that the core can be cooled is achieved using the existing safety systems for 16 hours. The rates of coolant inventory loss under SBO conditions do not result in core uncovery and the station can cope with a 16 hour duration SBO event.

9.5.9.2.8 Emergency Lighting

The emergency lighting system with eight hour battery-backed power supplies provides illuminating requirements where local manual operation is required within the power block. This lighting illuminates automatically upon a loss of AC power. After 1 hour, the A train essential lighting is powered by the SBOGs.

9.5.9.2.9 Communications

The primary modes of communication during an SBO are the telephone system, the plant 2-way radio system, and the sound powered phone system. The telephone system has at least a 2 hour battery capability. The 2-way radio system has a 4 hour battery system and will be transferred to the SBOGs. The sound powered phone system requires no external power source to operate.

9.5.9.2.10 Station Procedures

Specific operator actions were considered as part of performing the design analyses supporting the 16 hour SBO coping period. As previously stated, these actions used the ADVs for RCS cooldown and the AFW system for SG level control. Based on design Reactor Coolant Pump seal leakage rates, RCS inventory control uses the HPSI system.

The governing Station operation procedures provide operator flexibility with respect to mitigating the effects of SBO due to variations in RCS leakage rates. For SBO conditions with limited RCS leakage, the charging system will be used for RCS inventory control. The pressurizer vent or auxiliary spray may also be used for RCS pressure control as station conditions and equipment availability allow.

9.5.10 REFERENCES

1. A. J. Smith, "Considerations in the Design of Communications Systems for Power Plants", T75090-1 IEEE PES Winter Meeting, New York, N.Y., September 1974.

APPENDIX 9A

RESPONSES TO NRC REQUESTS FOR INFORMATION

Historical Information

(Questions 9A.1 – 9A.61)

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TABLES

APPENDIX 9A

<u>QUESTION 9A.1</u> (NRC Question 430.4) (9.5.2)

The information regarding the onsite communications system (subsection 9.5.2) does not adequately cover the system capabilities during transients and accidents. Provide the following information:

(a) Identify all work stations on the plant site where it may be necessary for plant personnel to communicate with the control room or the emergency shutdown panel during and/or following transients and/or accidents (including fires) in order to mitigate the consequences of the event and to attain a safe cold plant shutdown.

(b) Indicate the maximum sound levels that could exist at each of the above identified working stations for all transients and accident conditions.

(c) Indicate the types of communication systems available at each of the above identified working stations.

(d) Indicate the maximum background noise level that could exist at each working station and yet reliably expect effective communication with the control room using:

  (1) the page party communications systems, and

  (2) any other additional communication system provided that working station.

(e) Describe the performance requirements and tests that the above onsite working stations communication systems will be required to pass in order to be assured that effective communication with the control room or emergency shutdown panel is possible under all conditions.

(f) Identify and describe the power source(s) provided for each of the communications systems.

(g) Discuss the protective measures taken to assure a functionally operable onsite communication system. The discussion should include the considerations given to component failures, loss of power, and the severing of a communication line or trunk as a result of an accident or fire.

RESPONSE:

(a) The onsite communications system is not required to prevent or mitigate the consequences of UFSAR chapter 15 design basis events nor to attain a safe cold plant shutdown. Nevertheless, paragraph 9.5.2.1.G and table 9.5-4 identify all working stations on the plant site where it may be necessary for plant personnel to communicate with the control room or the emergency shutdown panel during and/or following transients and/or accidents, including fires, and with the control room under conditions of normal operation.

(b) Table 9.5-4 has been added to show maximum sound levels anticipated at each station identified, communication systems available at each station identified, and the maximum background noise that could exist at each working station and yet reliably expect effective communication.

(c) Refer to listing (b) above.

(d) (1) PVNGS does not have a page party system.

(2) Refer to listing (b) above.

(e) The response is given in paragraph 9.5.2.3.

(f) Power sources to communication systems are described in table 9.5-3.

(g) Paragraph 9.5.2.3 discusses communication systems' availability. Calculation 13-MC-FP-316 provides the technical basis for the availability of the communications systems which address postulated fires.

Refer to subsection 9.5.2 for a discussion on the uninterruptable power systems and two-way portable radios.

UFSAR table 9B.3-1 describes the communication systems which are credited for addressing postulated fires.

QUESTION 9A.2 (NRC Question 430.5) (9.5.3)

Identify the vital areas and hazardous areas where emergency lighting is needed for safe shutdown of the reactor and the evacuation of personnel in the event of an accident. Tabulate the lighting system provided in your design to accommodate those areas so identified. Include the degree of compliance to Standard Review Plan 9.5.1 regarding emergency lighting requirements in the event of a fire.

RESPONSE: The lighting needed for the safe shutdown of the reactor and the evacuation of personnel in the event

of an accident is the essential lighting subsystem and the emergency lighting subsystem.

The safe shutdown lighting drawings 01, 02, 03- E-ZPL-001, E-ZPL-002, E-ZPL-003, E-ZPL-004 identify areas where lighting is needed to accomplish safe shutdown of the reactor and evacuation of personnel in the event of a fire. Paragraph 9.5.3.2 describes the power supplies for the essential and emergency lighting subsystems.

PVNGS compliance with Appendix A of NRC Branch Technical Position APCSB 9.5-1 is identified in FSAR section 9B.3, table 9B.3-1, item D.5.

QUESTION 9A.3 (NRC Question 430.6) (9.5.4)

Describe the instruments, controls, sensors and alarms provided for monitoring the diesel engine fuel oil storage and transfer system and describe their function. Discuss the testing necessary to maintain and assure a highly reliable instrumentation, control, sensors and alarm system and where the alarms are annunciated. Identify the temperature, pressure, and level sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe what operator actions are required during alarm conditions to prevent harmful effects to the diesel engine. Discuss the system interlocks provided. (SRP 9.5.4, Part III, Item 1).

RESPONSE: The description of instruments and controls for the diesel generator fuel oil storage and transfer system are shown in amended paragraph 9.5.4.2 and engineering

drawings 01, 02, 03-M-DFP-001. Calibration and testing is performed in accordance with the PVNGS preventative maintenance program.

QUESTION 9A.4 (NRC Question 430.7) (9.5.4)

The diesel generator structures are designed to seismic and tornado criteria and are isolated from one another by a reinforced concrete wall barrier. Describe the barrier (including openings) in more detail and its capability to withstand the effects of internally generated missiles resulting from a crankcase explosion, failure of one or all of the starting air receivers, or failure of any high or moderate energy line and initial flooding from the cooling system so that the assumed effects will not result in loss of an additional generator. (SRP 9.5.4, Part III, Item 2).

RESPONSE: The diesel generators are separated by a 1-foot 9-inch thick, penetration-free, concrete wall. The wall is able to withstand the effects of internally-generated missiles resulting from a crankcase explosion.

The diesel crankcase is provided with relief covers (see response to NRC Question 430.27). The starting air receivers and associated piping, constitute the only high energy lines in the building. They are separated from the redundant tanks of the other diesel engine by concrete walls 1 foot 9 inches thick with no openings.

In event of a moderate energy fluid piping crack, the redundant diesels are separated so that neither spray nor flooding can affect the other generator. The operator is

alerted by operation of sump pumps in the affected diesel engine compartment.

QUESTION 9A.5 (NRC Question 430.8) (9.5.4)

Describe your design provisions made to protect the fuel oil storage tank fill and vent lines from damage by tornado missiles. (SRP 9.5.4, Part II).

RESPONSE: The response is given in amended paragraph 9.5.4.2.1.

QUESTION 9A.6 (NRC Question 430.9) (9.5.4)

Discuss the means for detecting or preventing growth of algae in the diesel fuel storage tank. If it were detected, describe the methods to be provided for cleaning the affected storage tank. (SRP 9.5.4, Part III, Item 4).

RESPONSE: The response is given in paragraph 9.5.4.2.1.

QUESTION 9A.7 (NRC Question 430.10) (9.5.4)

In paragraph 9.5.4.2.1 you state that the diesel fuel oil storage tanks are protected from corrosion in accordance with recommended practice "Control or External Corrosion on Underground or Submerged Piping Systems," RP-01-69 as published by the National Association of Corrosion Engineers. This statement is incomplete; it does not discuss the buried piping or internal corrosion of the storage tanks due to water in the fuel oil. Expand the FSAR to include a more explicit description of proposed protection of underground piping.

Where corrosion protective coatings are being considered (piping and tanks) include additional industry standards which will be used in their application. Also discuss what provisions will be made in the design of the fuel oil storage and transfer system in the use of a impressed current type cathodic protection system, in addition to waterproof protective coatings, to minimize corrosion of buried piping or equipment. If cathodic protection is not being considered, provide your justification. (SRP 9.5.4, Part II, and Part III, Item 4).

RESPONSE: The response is given in amended paragraphs 9.5.4.2.1 and 9.5.4.2.4.

QUESTION 9A.8 (NRC Question 430.11)(3.2, 9.5.4 through 9.5.8)

The FSAR text and table 3.2-1 states that the components and piping systems for the diesel generator auxiliaries (fuel oil system, cooling water, lubrication, air starting, and intake and combustion system) that are mounted on the auxiliary skids are designed Seismic Category I and are ASME Section III Class 3 quality. The engine mounted components and piping are designed and manufactured to DEMA standards, and are Seismic Category I. This is not in accordance with Regulatory Guide 1.26 which requires the entire diesel generator auxiliary systems be designed to ASME Section III Class 3 or Quality Group C. Provide the industry standards that were used in the design, manufacture, and inspection of the engine mounted piping and components. Also show on the appropriate P&IDs where the quality group classification changes from Quality Group C.

RESPONSE: The engine-mounted piping for auxiliary systems is designed and manufactured by the engine manufacturer. The engine and engine-mounted auxiliaries (called the engine package) are designed and sold as standby units for nuclear service. The standard design of the engine package does not include ASME III items. The design specification specifically exempted the engine package from ASME Section III. Engineering drawings 01, 02, 03-M-DGP-001 shows quality group classification changes. The design specification requires the use of ANSI B16.5 flanges and B31.1 piping. The engine package is seismically analyzed to withstand a safe shutdown earthquake.

QUESTION 9A.9 (NRC Question 430.12) (9.5.4)

Paragraph 9.5.4.2 emergency diesel engine fuel oil storage and transfer system (EDEFSS) does not specifically reference Regulatory Guide 1.137 and ANSI Standard N195 "Fuel Oil Systems for Standby Diesel Generators." Indicate if you intend to comply with this regulatory guide and standard in your design of the EDEFSS; otherwise, provide justification for noncompliance. (SRP 9.5.4, Rev. 1, Part II, Item 12).

RESPONSE: The diesel generator fuel oil storage and transfer system is designed to comply with Position C.2 of Regulatory Guide 1.137 as discussed in Section 1.8.

Refer to paragraph 9.5.4.1.3 for PVNGS compliance with ANSI N195-1976.

QUESTION 9A.10 (NRC Question 430.13) (9.5.4)

Discuss what precautions have been taken in the design of the fuel oil system in locating the fuel oil day tank and connecting fuel oil piping in the diesel generator room with regard to possible exposure to ignition sources such as open flames and hot surfaces. (SRP 9.5.4, Part III, Item 6).

RESPONSE: The fuel oil day tank is located in a separate room from the diesel engine. Fuel oil piping is routed along the ceiling and building walls to avoid possible ignition sources. The fuel lines do not cross over the engine or pass near the exhaust piping.

QUESTION 9A.11 (NRC Question 430.14) (9.5.4)

Discuss the precautionary measures that will be taken to assure the quality and reliability of the fuel oil supply for emergency diesel generator operation. Include the type of fuel oil, impurity and quality limitations as well as diesel index number or its equivalent, cloud point, entrained moisture, sulfur, particulates, and other deleterious insoluble substances; procedure for testing newly delivered fuel, periodic sampling and testing of onsite fuel oil (including interval between tests), interval of time between periodic removal of condensate from fuel tanks and periodic system inspection. In your discussion include reference to industry (or other) standard which will be followed to assure a reliable fuel oil supply to the emergency generators. (SRP 9.5.4, Part III, Items 3 and 4).

RESPONSE: Refer to amended paragraph 9.5.4.2.

Fuel oil will meet the requirements of Position C.2 of Regulatory Guide 1.137 as discussed in section 1.8.

QUESTION 9A.12 (NRC Question 430.15) (9.5.4)

Provide additional justification to support your statement in paragraph 9.5.4.4 that sufficient additional fuel can be delivered to the plant site by truck, rail, or helicopter. In your discussion include sources where diesel quality fuel oil is available and distances traveled from the source to the plant. Also discuss how fuel oil will be delivered onsite under extremely unfavorable environmental conditions, including probable maximum flood conditions.

RESPONSE: The response is given in amended paragraph 9.5.4.2.

QUESTION 9A.13 (NRC Question 430.16) (9.5.4)

You state in paragraph 9.5.4.2 that the diesel generator fuel oil storage tank is provided with an individual fill and vent line. Indicate where these lines are located (indoor or outdoor) and the height these lines are terminated above finished ground grade. If these lines are located outdoors, discuss the provisions made in your design to prevent entrance of water into the storage tank during adverse environmental conditions.

RESPONSE: The response is given in amended paragraph 9.5.4.2.1.

QUESTION 9A.14 (NRC Question 430.17) (9.5.5)

Subsection 9.5.5 indicates that the function of the diesel generator cooling water system is to dissipate the heat transferred through the: 1) engine water jacket, 2) combustion air (intake) cooler, and 3) engine turbo charger. Provide information on the individual component heat removal rates (Btu/hr), flow (lbs/hr) and temperature differential (°F) and the total heat removal rate required. Also provide the design margin (excess heat removal capacity) included in the design of major components and subsystems. (SRP 9.5.5, Part III, Item 1).

RESPONSE: The response is given in amended paragraph 9.5.5.2 and table 9.5-10.

QUESTION 9A.15 (NRC Question 430.18) (9.5.5)

Provide the results of a failure mode and effects analysis to show that failure of a piping connection between subsystems (engine water jacket, lube oil cooler, service water system, combustion air (intake) cooler, and engine turbocharger cooler) does not cause total degradation of the diesel generator cooling water system. (SRP 9.5.5, Part III, Item 1a).

RESPONSE: Each engine is provided with a separate diesel generator cooling water system as discussed in subsection 9.5.5. No single failure can affect both diesel generator cooling water systems.

QUESTION 9A.16 (NRC Question 430.19) (9.5.5)

You state in paragraph 9.5.5.1 the diesel engine cooling water is treated as appropriate to minimize corrosion. Provide additional details of your proposed diesel engine cooling water system chemical treatment with regards to corrosion and organic fouling, and discuss how your proposed treatment complies with the engine manufacturers recommendations. (SRP 9.5.5, Part III, Item 1c).

RESPONSE: The closed loop jacket cooling water system, is discussed in section 9.5.5.2. The essential spray pond system, is treated with sulfuric acid for pH control and sodium hypochlorite for organic fouling. The supplier has been provided with the essential spray pond water analysis, and appropriate materials of construction have been selected.

QUESTION 9A.17 (NRC Question 430.20) (9.5.5)

Describe the instrumentation, controls, sensors and alarms provided for monitoring of the diesel engine cooling water system and describe their function. Discuss the testing necessary to maintain and assure a highly reliable instrumentation, controls, sensors, and alarm system, and where the alarms are annunciated. Identify the temperature, pressure, level, and flow (where applicable) sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe what operator actions are required during alarm conditions to

prevent harmful effects to the diesel engine. Discuss the systems interlocks provided. (SRP 9.5.6, Part III, Item 1c).

RESPONSE: The response is given in amended paragraph 9.5.5.2 and table 9.5-12.

QUESTION 9A.18 (NRC Question 430.21) (9.5.5)

The diesel generators are required to start automatically on loss of all onsite power and in the event of a LOCA. The diesel generator sets should be capable of operation at less than full load for extended periods without degradation of performance or reliability. Should a LOCA occur with availability of offsite power, discuss the design provisions and other parameters that have been considered in the selection of the diesel generators to enable them to run unloaded (on standby) for extended periods without degradation of engine performance or reliability. Expand your PSAR/FSAR to include and explicitly define the capability of your design with regard to this requirement. (SRP 9.5.5, Part III, Item 7).

RESPONSE: The response is given in amended section 8.3.1.1.4.12, 3rd paragraph.

QUESTION 9A.19 (NRC Question 430.22) (9.5.5)

You state in paragraph 9.5.5.2 each diesel engine cooling water system is provided with a surge tank to provide for system expansion and for venting air from the system. In addition to the items mentioned, the surge tank is to provide for minor system leaks at pump shafts seals, valve stems and other components, and to maintain required NPSH on the system

circulating pump. Provide the size of the expansion tank and location. Demonstrate by analysis that the expansion tank size will be adequate to maintain required pump NPSH and makeup water for 7 days continuous operation of the diesel engine at full rated load without makeup, or provide a Seismic Category I, Safety Class 3 makeup water supply to the expansion tank.

RESPONSE: The cooling water system expansion tank is located on the auxiliary skid. Makeup is provided from the condensate storage tank. Refer to amended paragraph 9.5.5.2 for additional discussion.

QUESTION 9A.20 (NRC Question 430.23) (9.5.5)

Provide the source of power for the diesel engine motor-driven recirculation jacket water pump and electric jacket water heater. Provide the motor and electric heater characteristics, i.e., motor hp, operating voltage, phase(s), frequency and kW output as applicable. Also include the pump capacity and discharge head. Revise the FSAR accordingly.

RESPONSE: The response is given in paragraphs 9.5.5.2.1.3 and 9.5.5.2.1.7.

QUESTION 9A.21 (NRC Question 430.24) (9.5.6)

Provide a discussion of the measures that have been taken in the design of the standby diesel generator air starting system to preclude the fouling of the air start valve or filter with moisture and contaminants such as oil carryover and rust. (SRP 9.5.6, Part III, Item 1).

RESPONSE: The starting air system is designed by the diesel engine manufacturer. The air compressors and other starting air equipment are provided as a package. As discussed in paragraph 9.5.6.3, a refrigerated air drier is supplied to preclude corrosion in the starting air system. All air piping will be cleaned and blown out prior to engine operation to remove contaminants.

<u>QUESTION 9A.22</u> (NRC Question 430.25) (9.5.6)

Describe the instrumentation, controls, sensors, and alarms provided for monitoring the diesel engine air starting system, and describe their function. Describe the testing necessary to maintain a highly reliable instrumentation, control, sensors, and alarm system and where the alarms are annunciated. Identify the temperature, pressure, and level sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe any operator actions required during alarm conditions to prevent harmful effects to the diesel engine. Discuss system interlocks provided. Revise your FSAR accordingly. (SRP 9.5.6, Part III, Item 1).

RESPONSE: The response is given in amended paragraphs 9.5.6.2 and 9.5.6.6.

<u>QUESTION 9A.23</u> (NRC Question 430.26) (9.5.6)

Provide the source of power for the diesel engine air starting system compressors and motor characteristics, i.e., motor hp,

operating voltage, phase(s), and frequency. Revise your FSAR accordingly.

RESPONSE: The response is given in revised paragraph 9.5.6.3.

QUESTION 9A.24 (NRC Question 430.27) (9.5.7)

For the diesel engine lubrication system in subsection 9.5.7, provide the following information: 1) define the temperature differentials, flowrate, and heat removal rate of the interface cooling system external to the engine and verify that these are in accordance with recommendations of the engine manufacturer; 2) discuss the measures that will be taken to maintain the required quality of the oil, including the inspection and replacement when oil quality is degraded; 3) describe the protective features (such as blowout panels) provided to prevent unacceptable crankcase explosion and to mitigate the consequences of such an event; and 4) describe the capability for detection and control of system leakage. (SRP 9.5.7, Part II, Items 8a, 8b, 8c, Part III, Item 1.)

RESPONSE: The response is given in amended table 9.5-10 and paragraphs 9.5.5.2 and 9.5.7.2.

QUESTION 9A.25 (NRC Question 430.28) (9.5.7)

What measures have been taken to prevent entry of deleterious materials into the engine lubrication oil system due to operator error during recharging of lubricating oil or normal operation? (SRP 9.5.7, Part III, Item 1c).

RESPONSE: The engine lubrication oil system has only one fill connection, which is clearly labeled on the diesel skid. There are no interconnections with other systems, therefore, operator-induced valving errors can be excluded as sources of foreign materials in the lubrication oil system. Additionally, the instruction manual includes a brief description of oil fill procedures.

QUESTION 9A.26 (NRC Question 430.29) (9.5.7)

Describe the instrumentation, controls, sensors, and alarms provided for monitoring the diesel engine lubrication oil system and describe their function. Describe the testing necessary to maintain a highly reliable instrumentation, control, sensors, and alarm system and where the alarms are annunciated. Identify the temperature, pressure, and level sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe any operator action required during alarm conditions to prevent harmful effects to the diesel engine. Discuss systems interlocks provided. Revise your FSAR accordingly. (SRP 9.5.7, Part III, Item 1e).

RESPONSE: The response is given in amended paragraph 9.5.7.3, listing D, and table 9.5-17.

QUESTION 9A.27 (NRC Question 430.30) (9.5.7)

Provide the source of power for the diesel engine prelube oil pump, and lube oil circulation heater and used lube oil tank transfer pump, and motor characteristics, i.e., motor hp,

operating voltage, phase(s), and frequency. Also provide the pump capacity and discharge head. Revise your FSAR accordingly.

RESPONSE: The response is given in amended subsection 9.5.7 and table 9.5-15. No used lube oil transfer pump is provided.

QUESTION 9A.28 (NRC Question 430.31) (9.5.7)

Several fires have occurred at some operating plants in the area of the diesel engine exhaust manifold and inside the turbocharger housing which have resulted in equipment unavailability. The fires were started from lube oil leaking and accumulating on the engine exhaust manifold and accumulating and igniting inside the turbocharger housing. Accumulation of lube oil in these areas, on some engines, is apparently caused from an excessively long prelube period, generally longer than 5 minutes, prior to manual starting of a diesel generator. This condition does not occur on an emergency start since the prelube period is minimal.

When manually starting the diesel generators for any reason, to minimize the potential fire hazard and to improve equipment availability, the prelube period should be limited to a maximum of 3 to 5 minutes unless otherwise recommended by the diesel engine manufacturer. Confirm your compliance with this requirement or provide your justification for requiring a longer prelube time interval prior to manual starting of the diesel generators. Provide the prelube time interval your diesel engine will be exposed to prior to manual start.

RESPONSE: The engine manufacturer has designed the engine prelube system to operate continuously to all engine parts, including the turbocharger.

QUESTION 9A.29 (NRC Question 430.32) (9.5.8)

Describe the instrumentation, controls, sensors, and alarms provided in the design of the diesel engine combustion air intake and exhaust system which alert the operator when parameters exceed ranges recommended by the engine manufacturer and describe any operator action required during alarm conditions to prevent harmful effects to the diesel engine. Discuss systems interlocks provided. Revise your FSAR accordingly. (SRP 9.5.8, Part III, Items 1 and 4).

RESPONSE: The response is given in revised paragraph 9.5.8.2.2.

QUESTION 9A.30 (NRC Question 430.33) (9.5.8)

Provide the results of an analysis that demonstrates that the function of your diesel engine air intake and exhaust system design will not be degraded to an extent which prevents developing full engine rated power or cause engine shutdown as a consequence of any meteorological or accident condition. Include in your discussion the potential and effect of fire extinguishing (gaseous) medium, recirculation of diesel combustion products, or other gases that may intentionally or accidentally be released onsite, on the performance of the diesel generator. (SRP 9.5.8, Part III, Item 3).

RESPONSE: The response is given in paragraph 9.5.8.3, listing A.

QUESTION 9A.31 (NRC Question 430.34) (9.5.8)

Discuss the provisions made in your design of the diesel engine combustion air intake and exhaust system to prevent possible clogging, during standby and in operation, from abnormal climatic conditions (heavy rain, freezing rain, dust storms, ice and snow) that could prevent operation of the diesel generator on demand. (SRP 9.5.8, Part III, Item 5).

RESPONSE: The response is given in amended paragraph 9.5.8.3, listing A.

QUESTION 9A.32 (NRC Question 430.35) (9.5.8)

Show by analysis that a potential fire in the diesel generator building together with a single failure of the fire protection system will not degrade the quality of the diesel combustion air so that the remaining diesel will be able to provide full rated power.

RESPONSE: Each engine has a separate intake and exhaust. Each intake occurs on the same side of the building as its diesel. Each engine is enclosed in a 3-hour resistant fire wall. Assuming a fire in one engine during operation of both engines, the combustion smoke would be discharged out the exhaust vent. Paragraph 9.5.8.3, listing A, states that this exhaust mixture could be directly sucked into the intake and not degrade engine performance. To

prevent suction of exhaust gases, the exhaust is directed vertically upward and released 50 feet above the intake.

QUESTION 9A.33 (NRC Question 430.36) (9.5.8)

Experience at some operating plants has shown that diesel engines have failed to start due to accumulation of dust and other deleterious material on electrical equipment associated with starting of the diesel generators (e.g., auxiliary relay contacts, control switches, etc.). Describe the provisions that have been made in your diesel generator building design, electrical starting system, and combustion air and ventilation air intake design(s) to preclude this condition to assure availability of the diesel generator on demand.

Also describe under normal plant operation what procedure(s) will be used to minimize accumulation of dust in the diesel generator room; specifically, address concrete dust control. In your response also consider the condition when Unit 1 is in operation and Unit 2 is under construction (abnormal generation of dust).

RESPONSE: The diesel engine control panels are located in rooms separated from their respective engine, and are ventilated with filtered air. Any electrical boxes located in the engine room are dust tight. Additionally, the floor of the diesel generator building is treated with a hardener for dust control.

Procedures governing housekeeping that implement the recommendations of Regulatory Guide 1.39 as modified in section 1.8 will be available onsite for NRC review

60 days prior to fuel load. These procedures control the accumulation of dust in the diesel generator rooms and, together with the design features described above, adequately assure the availability of the diesel generators on demand, including when Unit 1 is in operation and Unit 2 is under construction.

Section 4.5.3.1 of the PVNGS Environmental Report Operating License Stage (PVNGS ER-OL) describes the construction dust control program that, when combined with the physical distance between Units 1 and 2, will minimize construction related dust.

QUESTION 9A.34 (NRC Question 281.2) (9.1.3)

For the fuel pool cleanup system, indicate that chemical analyses at least weekly and continuous radiological monitoring will be made for measuring the efficiency of the filters and ion exchange resins to remove impurities and radioactive materials from the pool water. State what criteria (chemical parameters, decontamination factors, etc.) will be used to determine replacement of the filters and ion exchange resins.

RESPONSE: The response is given in amended paragraph 9.1.3.4.

Continuous radiological in-line monitoring is not a requirement for the system as outlined in Regulatory Guide 1.45 (also, see subsection 11.5.1 and table 9.3-3).

<u>QUESTION 9A.35</u> (NRC Question 281.3) (9.3.2)

Describe the provisions to meet the requirements of post-accident sampling of the primary coolant and containment atmosphere. The description should address all the requirements outlined in Section II.B.3 of Enclosure 3 in NUREG-0737 (Clarification of TMI Action Plan Requirements) and should include the appropriate P&IDs. In addition, if gas chromatography is used for reactor coolant analysis, special provisions (e.g., pressure relief and purging) should be provided to prevent high-pressure carrier gas from entering the reactor coolant. With respect to clarification (4) in Section II.B.3 of NUREG-0737, if the chloride concentration in the reactor coolant samples exceeds the limit in the Technical Specification, oxygen analysis will be mandatory. Provide also either (a) a summary description of procedures for sample collection, sample transfer or transport, and sample analysis, or (b) copies of procedures for sample collection, sample transfer or transport, and sample analysis.

RESPONSE: The response is given in amended subsection 9.3.2.

<u>QUESTION 9A.36</u> (NRC Question 460.4) (9.2)

Describe provisions for ensuring that the limits for radioactive concentrations are not exceeded in the demineralized water system and condensate storage facilities.

RESPONSE: Demineralized Water System: This system is nonradioactive and there is no radioactive input to the system. Refer to amended subsection 9.2.3.

Condensate Storage Facilities: This is a nonradioactive system. Refer to amended subsections 9.2.6 and 11.2.2.

QUESTION 9A.37 (NRC Question 460.5) (9.3 and 11.5)

a) Provide continuous process monitoring capability for the spent fuel pool and refueling pool treatment systems.

b) Clarify whether discrete sample analyses provisions are available for both the high and low TDS holdup and monitor tanks.

c) Describe the provisions for monitoring concentrate monitor tank activities.

d) Describe the process sampling provisions for grab sampling iodine in fuel storage area vent system, radwaste area vent system, and the evaporator vent system (these are required by Standard Review Plan, Section 11.5, Rev. 2, "Process and Effluent Radiological Monitoring and Sample Systems," See Table 1A).

RESPONSE:

a) Refer to amended paragraph 9.1.3.2.1.2.

b) Discrete sample capabilities are listed in table 9.3-3 (sheet 10 of 12). Refer to amended paragraph 11.2.2.3.

c) Sample capabilities are described in paragraph 11.2.2.3, and listed in table 9.3-3 (sheet 10 of 12).

d) Continuous iodine collection using a charcoal cartridge will be provided for the fuel building.

The radwaste area and evaporator vent are designed to be grab sampled from the grab sample connection on radiation monitor XJ-SQN-RU-14. Prior to release, the plant vent radiation monitors (XJ-SQN-RU-143 and XJ-SQN-RU-144) continuously collect an iodine sample using a charcoal cartridge. Additionally, areas in the radwaste building may be grab sampled for iodine using a movable airborne monitor.

QUESTION 9A.38 (NRC Question 460.6) (9.4 and 11.3)

Provide a table comparing the design features and radioactivity removal capability of each normal ventilation filter system to each position detailed in Regulatory Guide 1.140, Rev. 1 (October 1979), "Design, Testing and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants." For each item for which an exception is taken, the applicability of the proposed exception should be justified.

RESPONSE: The response is provided in table 1.8-3.

QUESTION 9A.39 (NRC Question 282.1) (9.1.2.3)

Provide fabrication details of the Boral tube inserts to be used in the spent fuel storage pool. Provide details of the kind and thickness of the cladding of the Boral. Explain how exposed Boral matrix (Boron carbide) is protected from the

borated pool water. Describe corrosion protection of the Boral tube.

RESPONSE: The response is given in amended paragraph 9.1.2.2.2.

<u>QUESTION 9A.40</u> (NRC Question 490.4) (9.3.4.5)

A. The process radiation monitor (PRM) is said to be a "trending device to warn the operator of possible fuel failure." Regardless of whether the amount of failed fuel is greater or less than 1%, is the PRM capable of providing an indication of the number of failed rods (e.g., 1 or 2 rods vs. 10 or 50 rods)? Is the reading continuous and direct so that the operator can readily note any potential rapid escalation of failing fuel?

B. The alarm setpoints are adjustable. To what equivalent percent failed fuel or number of failed rods are the setpoints intended to correspond? What action is triggered by the alarms?

C. If the PRM readings indicate the presence of leaking fuel rods during a given cycle, what surveillance will be performed during the next refueling outage to identify the leakers and nature of the damage?

RESPONSE: The response is given in amended section 11.5.

QUESTION 9A.41 (NRC Question 410.7) (9.3.1)

Concerning the compressed air system, provide the following additional information:

a) Describe the means provided to verify that proper instrument air quality will be maintained over the plant life to assure the safety function of the system (i.e., air-operated valves will fail in their safe position on loss of instrument air supply). Include the air quality limits which should not be exceeded in order to assure the above safety function.

b) Verify that a single failure of any air-operated valve to assume its fail safe position will not prevent the function of a safety-related system or compromise the ability to safely shut down.

RESPONSE:

a) The response is given in amended paragraph 9.3.1.5.

b) As there are two independent, 100% capacity trains of safety-related equipment available to perform ESF functions, a single failure in either train will not prevent the function of the other train.

QUESTION 9A.42 (NRC Question 410.8) (9.3.3)

You state in FSAR paragraph 9.3.3.2.1.1.2 that maximum abnormal leakage each ESF sump is estimated to be 50 gallons per minute. What is the basis for this assumption? It is our position that you verify that adequate protection has been provided for safety-related equipment assuming a total pipe rupture for all

nonseismic piping system (such as the fire protection system and nuclear cooling water system) and components (such as tanks) located in safety-related areas. This protection cannot assume credit for non-Seismic Category I sump pumps. Your response should include the time required for operator action if necessary to provide protection of essential equipment once indication from the Class 1E level switches is given.

RESPONSE:

The abnormal leakage of 50 gallons per minute conservatively bounds the total leakage from all ESF components, such as pumps, valves, etc. The auxiliary building is sized to accept 400,000 gallons of non-ESF leakage before any leakage would affect ESF components. For flooding considerations, all nonseismic piping was assumed to have failed. The water volume released will not exceed the design 400,000-gallon capacity. The auxiliary building rooms, including the ESF pump rooms on elevation 40, were analyzed for flooding due to rupture of the largest nonsafety-related piping for a duration of 30 minutes. Flooding was also analyzed based on operation of fire protection systems, such as hoses and sprinklers, for 15 minutes without operator action or without operation of the sump pumps.

<u>QUESTION 9A.43</u> (NRC Question 410.9) (9.3.3)

Engineering drawings 01, 02, 03-M-RDP-002 shows locked closed manual valves on the drain lines from both essential auxiliary feedwater system (AFS) pump rooms in the main steam support

structure. Describe the purpose of the valves and the means provided to prevent loss of function of the essential AFS pumps as a result of internal flooding.

RESPONSE: Refer to engineering drawings 01, 02, 03-M-RDP-002.

<u>QUESTION 9A.44</u> (NRC Question 410.10) (9.4)

Verify that the CESSAR interfaces for environmental conditions for equipment within the C-E scope of supply have been satisfied by the Palo Verde HVAC system designs.

RESPONSE: The CESSAR interfaces have been met by the HVAC system.

<u>QUESTION 9A.45</u> (NRC Question 410.11) (9.4)

FSAR table 9.4-1 identifies the weather conditions within the site area which serve as the design basis for HVAC system sizing based on ASHRAE data to 1972. Verify that weather conditions since 1972 have not resulted in the need to modify HVAC system designs in order to meet the environmental qualification limits for plant areas containing safety-related equipment.

RESPONSE: The design basis for HVAC systems used to meet environmental qualification envelope parameters is that the limits be met under outside air conditions of 113F dry bulb, 76F wet bulb. Comparison of actual site and Phoenix data since 1972, as shown in tables 2.3-8 and 2.3-9 with data obtained prior to 1972 (refer to table 2.3-11),

indicates that weather conditions have not become more severe.

QUESTION 9A.46 (NRC Question 410.12) (9.4)

Describe the measures provided for detecting and correcting dust accumulation on safety-related equipment in order to assure their availability on demand.

RESPONSE: PVNGS has developed a housekeeping program on equipment throughout the plant. Safety-related equipment is included in this program. The program provides for the periodic inspection and cleaning of equipment and will be a part of the preventative maintenance program.

QUESTION 9A.47 (NRC Question 410.13) (9.4)

Describe the affect on the safety function of the essential HVAC systems in the event of a single failure in a fire damper in the ventilation system ducts. It is our position that such a failure not compromise the safety function of the HVAC system.

RESPONSE: A single fire damper failure (actuation) in one ESF ventilation train will render that train inoperable. As another redundant 100% capacity ESF ventilation train is provided, there will be no adverse effect upon the safety function of essential ventilation. Also see engineering drawings 01, 02, 03-M-HJP-001, -002, and 01, 02, 03-M-HFP-001.

QUESTION 9A.48 (NRC Question 410.14) (9.4.1)

FSAR subsection 9.4.1 indicates that emergency ventilation is not provided for the upper and lower cable spreading room. Verify that safe operating conditions for essential equipment are maintained in these rooms during all accident modes (including long term plant cooldown). If this cannot be demonstrated, provide a safety grade means of indication of the conditions in these rooms with sufficient time for operator action to provide the necessary temporary cooling, or provide a safety-related emergency cooling system for these rooms.

RESPONSE: The response is given in amended subsection 9.4.1.

QUESTION 9A.49 (NRC Question 410.15) (9.4.1)

In the event of indication of radioactive contamination of the normal control room intake, the normal ventilation system is shut off and isolated as the essential control room system is started. However, the control building normal air handling unit or essential ESF switchgear room air handling unit (if operating) would continue to function and circulate potentially contaminated air to other areas of the control building. Describe the measures provided to prevent contamination of vital areas of the control building and still assure a proper environment for operation of essential equipment.

RESPONSE: The response is given in amended paragraph 9.4.1.2.1.1.

QUESTION 9A.50 (NRC Question 410.16) (9.4.1)

Expand table 9.4-4, "Single Failure Analysis for the Essential ESF Switchgear, ESF Equipment and Battery Rooms" to include the consequences of failure of any system component. This analysis should verify that a single failure in any safety-related damper or total failure of all nonsafety-related dampers and ducts in the ESF switchgear, ESF equipment and battery rooms HVAC system will not prevent at least one train of the essential ESF switchgear room HVAC system from performing its safety function.

RESPONSE: The response is provided in amended table 9.4-4.

QUESTION 9A.51 (NRC Question 410.17) (9.4.1)

Describe the measures for assuring a proper operating environment for essential control room and ESF switchgear room air handling units when the normal control building HVAC system is not available in emergency conditions.

RESPONSE: The response is given in amended subsection 9.4.1.

QUESTION 9A.52 (NRC Question 410.18) (9.4.1)

Verify that the control room HVAC air intake chlorine and radiation monitors are Seismic Category I.

RESPONSE: Control room HVAC air intake chlorine and radiation monitors are Seismic Category I.

<u>QUESTION 9A.53</u> (NRC Question 410.19) (9.4.1)

The essential fuel building and auxiliary building exhaust units serve only those auxiliary building equipment areas located below elevation 100 feet 0 inch. The charging pumps, letdown heat exchangers, and other CVCS equipment which contain radioactive fluid are located above the 100 foot 0 inch elevation. Describe the means provided for detecting potential radioactivity in these rooms under emergency conditions when the normal HVAC system is not available, and isolating them prior to release of unacceptable airborne contamination to the environment.

RESPONSE: There are three methods available to detect potential airborne radioactivity in the upper levels (above elevation 100 feet 0 inch) of the auxiliary building when normal HVAC is not operable:

- Noble gas monitor 13-J-SQN-RU-9 (see section 11.5)
- Fixed and portable area radiation monitors.

There is, however, little likelihood that airborne contamination due to leakage from the CVCS could be released at unacceptable levels. The use of the CVCS under post-accident conditions is not required. Before it could be used, non-Class 1E power or manual actions would have to be available. As two normal HVAC filtration units are provided on different non-Class 1E buses, it is reasonable to expect that at least one train of filtration could be placed in operation prior to use of the CVCS. Under this alignment, the auxiliary building upper level

(13-J-SQN-RU-10), auxiliary building ventilation exhaust inlet (13-J-SQN-RU-8), and plant vent (13-J-SQN-RU-143 and 13-J-SQN-RU-144) radiation monitors can also be used to monitor exhaust concentrations.

Without the HVAC system in operation, there would be no driving force for release, and, therefore, exfiltration rates would be low. If use of the CVCS is required without the availability of HVAC filtration, radiation monitoring will be required to ensure and confirm that unacceptable releases do not occur.

QUESTION 9A.54 (NRC Question 410.20) (9.4.2)

Describe the means provided for assuring the proper operating environment under normal and emergency conditions for the essential spray pond pumps in order to assure the availability of the ultimate heat sink.

RESPONSE: The spray pond pumphouse (both train A and train B) are cooled by ventilation air. Refer to amended subsection 9.4.8.

QUESTION 9A.55 (NRC Question 410.21) (9.4.2 and 9.4.5)

Describe the interaction in the essential fuel building and auxiliary building exhaust air handling units operation when they are being utilized for emergency operation for processing fuel building air and auxiliary building air before release to the environment. Specifically:

(a) Does continued operation of the normal fuel handling building ventilation system in the event of a safety

injection actuation result in potential contamination of the fuel building environment when the essential exhaust unit is processing contaminated auxiliary building air?

(b) Does contaminated fuel building air enter the auxiliary building through the interconnecting tunnel in the event of a fuel handling accident?

RESPONSE:

(a) No, the systems are separated up to the exhaust plenum.

(b) No, dampers HFA-M06 and HFB-M06 close on fuel building essential ventilation actuation signal (FBEVAS).

QUESTION 9A.56 (NRC Question 410.22) (9.4.3)

Describe the means provided for isolating the radwaste building ventilation system following a design basis event (such as a SSE) in order to prevent the release of potentially radioactive airborne contaminants through building openings.

RESPONSE: The radwaste building ventilation system will be automatically tripped following loss of offsite power. It can be manually tripped after any other design basis event. As noted in paragraph 15.7.3.5, dose consequences from the instantaneous unfiltered release of the contents of one waste gas decay tank will be less than 1% of 10CFR100 limits. Accordingly, isolation of radwaste building ventilation is not required.

APPENDIX 9A

QUESTION 9A.57 (NRC Question 410.23) (9.4.5)

Describe the means provided for assuring the proper operating environment for the spent fuel pool cooling pumps and thereby assure the safety of the spent fuel pool, when the normal fuel building HVAC system is isolated in a fuel handling accident, or not available due to a loss of offsite power.

RESPONSE: Infiltration of air to replace that being exhausted by the essential system will provide adequate cooling. The essential system is available during a fuel handling accident or a loss of offsite power.

QUESTION 9A.58 (NRC Question 410.24) (9.4.6)

Verify that loss of the normal main steam and feedwater penetration HVAC supply and exhaust system in the main steam support structure in an emergency situation will not result in an environment detrimental to essential equipment in the MSSS.

RESPONSE: MSSS does not require forced ventilation to maintain the equipment qualification profile noted in Appendix A of the Equipment Qualification Program Manual.

QUESTION 9A.59 (NRC Question 281.7) (9.1.3)

Your response to our previous Question 281.2 did not indicate any chemical or radionuclide limits for initiating replacement of filters and ion exchange resins. It is our position that chemical and radionuclide limits in the spent fuel pool water, such as conductivity, gross gamma and iodine activity, demineralizer differential pressure, pH, and crud level, are

needed for initiating corrective action to enable safe operating conditions in the pool. Verify that you will meet this position and provide the above information.

RESPONSE: The response is given in the amended response to Question 9A.34 (NRC Question 281.2).

QUESTION 9A.60 (NRC Question 281.8) (9.3.2 and 18.II.B.3)

Provide information that satisfies the attached proposed license conditions for post-accident sampling.

NUREG-0737, II.B.3 - Post-Accident Sampling Capability

REQUIREMENT

Provide a capability to obtain and quantitatively analyze reactor coolant and containment atmosphere samples, without radiation exposure to any individual exceeding 5 rem to the whole body or 75 rem to the extremities (GDC 19) during and following an accident in which there is core degradation. Materials to be analyzed and quantified include certain radionuclides that are indicators of severity of core damage (e.g., noble gases, iodines, cesiums, and nonvolatile isotopes), hydrogen in the containment atmosphere and total dissolved gases or hydrogen, boron and chloride in reactor coolant samples in accordance with the requirements of NUREG-0737.

To satisfy the requirements, the applicant should (1) review and modify his sampling, chemical analysis, and radionuclide determination capabilities as necessary to comply with NUREG-0737, II.B.3, and (2) provide the staff with information

pertaining to system design, analytical capabilities, and procedures in sufficient detail to demonstrate that the requirements have been met.

EVALUATION AND FINDINGS

The applicant has committed to a post-accident sampling system that meets the requirements of NUREG-0737, Item II.B.3 in Amendment, but has not provided the technical information required by NUREG-0737 for our evaluation.

Implementation of the requirement is not necessary prior to low power operation because only small quantities of radionuclide inventory will exist in the reactor coolant system and, therefore, will not affect the health and safety of the public. Prior to exceeding 5% power operation, the applicant must demonstrate the capability to promptly obtain reactor coolant samples in the event of an accident in which there is core damage consistent with the conditions stated below:

1. Demonstrate compliance with all requirements of NUREG-0737, II.B.3, for sampling, chemical and radionuclide analysis capability, under accident conditions.

2. Provide sufficient shielding to meet the requirements of GDC 19, assuming Regulatory Guide 1.4 source terms.

3. Commit to meet the sampling and analysis requirements of Regulatory Guide 1.97, Rev. 2.

4. Verify that all electrically powered components associated with post-accident sampling are capable of

being supplied with power and operated, within 30 minutes of an accident in which there is core degradation, assuming loss of offsite power.

5. Verify that valves which are not accessible for repair after an accident are environmentally qualified for the conditions in which they must operate.

6. Provide a procedure for relating radionuclide gaseous and ionic species to estimated core damage.

7. State the design or operational provisions to prevent high pressure carrier gas from entering the reactor coolant system from online gas analysis equipment, if it is used.

8. Provide a method for verifying that reactor coolant dissolved oxygen is at <0.1 ppm if reactor coolant chlorides are determined to be ≥ 0.15 ppm.

9. Provide information on (a) testing frequency and type of testing to ensure long term operability of the post-accident sampling system, and (b) operator training requirements for post-accident sampling.

In addition to the above licensing conditions, the staff is conducting a generic review of accuracy and sensitivity for analytical procedures and online instrumentation to be used for post-accident analysis. We will require that the applicant submit data supporting the applicability of each selected analytical chemistry procedure or online instrument along with documentation demonstrating compliance with the licensing conditions 4 months prior to exceeding 5% power operation, but

review and approval of these procedures will not be a condition for full-power operation. In the event our generic review determines a specific procedure is unacceptable, we will require the applicant to make modifications as determined by our generic review.

RESPONSE: See amended paragraph 9.3.2.2, tables 9.3-3, 9.3-4, and response to 18.II.B.3.

QUESTION 9A.61 (NRC Question 440.85) (18.II.K.3.25)

Your response to Item II.K.3.25 of NUREG-0737 states that the reactor coolant pump normal cooling water system (nonsafety grade nuclear cooling water system) is backed up by the essential cooling water system during loss of offsite ac power. Describe the manual action involved and the manual action time required for transferring the cooling water supplies. Also, state that your operating procedure allows enough time to restore the cooling water supplies to the RCP seals before you trip the RCPs. After the RCP trip, you may still need essential cooling water supply to the RCP seals.

RESPONSE: The response is given in subsection 18.II.K.3.25.

QUESTION 9A.62 (FPER Question 1) (9B.2)

Certain assumptions used in your fire hazard analysis are unacceptable. It is our position that reliance on the following items in your fire hazard analysis is not justifiable or applicable, namely:

(a) The use of Table 6-8A from the NFPA, Fire Protection Handbook, 14th Edition, as a basis for the duration of a fire as a function of combustible loading for various types of combustibles, and

(b) The assumption that the fire duration in all areas can be based on oxygen depletion, since a single failure of a fire damper or in the ventilation system could negate this assumption.

Revise your fire hazard analysis and conclusions based on deleting these assumptions from the original analysis.

RESPONSE:

(a) Appendix 9B states that "presently there is no test or analytical data to completely explain the combustion of plastic or oil in a typical nuclear power plant compartment." Appendix 9B only uses National Fire Protection Association (NFPA) Handbook curves (Table 6-8A) and T. Z. Harmathy curves as a state-of-the-art guide and description of one of many possible sets of fire events.

The fire evaluation for any given compartment considers the ability of the fire barriers to withstand the maximum heat release of a "flashover" fire with respect to the American Society of Testing Materials (ASTM) Standard E119 (1976) time-temperature fire curve and the various influences that are related to this particular fire. The report uses several of these rough yardsticks, as they

relate to the time-temperature curve, without completely depending on any one of them.

(b) The analysis regarding oxygen depletion is not used to determine the rating of fire barriers. Refer to the revised fire hazards analysis of appendix 9B.

QUESTION 9A.63 (FPER Question 2) (9B.2)

On Page II-3[a] under Item A.1.e.(3)[a], "Fire Suppression Systems/Safety Equipment Protection,"[a] as well as in other areas of the fire hazard analysis, you state that "there will be no inadvertent operation, careless operation, or rupture of extinguishing equipment." This statement does not comply with Appendix A, BTP 9.5-1, Section A.5, which states that "failure or inadvertent operation of the fire suppression system should not incapacitate safety-related systems or components." State that you will comply with this position.

RESPONSE: The statement has been deleted from the amended fire hazards analysis; the consequences of inadvertent operation of, or a crack in, a moderate energy line in the fire suppression system will meet the guidelines of BTP ASB 3-1 as indicated in the amended section 9B.3 response to BTP APCSB 9.5-1, Appendix A, Section A.5.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

QUESTION 9A.64 (FPER Question 3) (9B.2)

On Pages II-90[a], II-93[a], and in other areas of the fire hazard analysis, you do not list the cables as a combustible. Complete the fire hazard analysis in those areas to include cables as a combustible.

RESPONSE: Cable that is not enclosed in conduit is considered as a combustible in the revised fire hazards analysis.

QUESTION 9A.65 (FPER Question 4) (9B.3)

Appendix A of BTP 9.5-1, Section E.3(d), states that for interior firefighting, at least one hose stream with a maximum hose length of 75 feet should be capable to reach the fire location. State that your design complies with this position.

RESPONSE: The PVNGS design complies except as noted in the response to Question 9A.115.

QUESTION 9A.66 (FPER Question 5a) (9B.3)

Page III-3[a], Item A.4: Describe the provisions that will be provided to prevent lightning from initiating fires which could damage safety-related equipment or fire protection equipment.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

RESPONSE: The design of lightning protection for the structures is in accordance with the Underwriter's Laboratory Standard UL96A, 1964. All startup transformers and main transformers and 13.8 kV switchgear are protected with appropriate lightning arrestors. This protection eliminates or drastically reduces the surges from entering the protective equipment.

<u>QUESTION 9A.67</u> (FPER Question 5b) (9B.3)

Page III-3[a], Item A.4: Meet the position of Appendix A, Section A.5, which states that with only one of the fire pumps operating, the maximum water demand of any water spray or sprinkler system plus a demand of 750 gal/min for hand hose use is met.

RESPONSE: Refer to the response provided in amended table 9B.3-1, Sections E.2.(c) and E.2.(e).

<u>QUESTION 9A.68</u> (FPER Question 6) (9B.3)

Page III-12[a], Item D: For the following listed items, substantiate their fire resistance capabilities as they pertain to safety-related areas or high hazard areas by verifying that their construction will be in accordance with a particular fire-tested design. Identify the design, test method, and acceptance criteria.

a. Rated fire barriers including floor, ceiling, wall systems, structural members, and doors. Indicate the type

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

of protective material used and the design number in reference to ASTM Standard E119.

b. Fire dampers and fire doors, including the installation of the same in ventilating ducts penetrating fire barriers of safety-related areas; fire door dampers are required in a 3-hour rated fire barrier penetrations.

c. Fire barrier penetration seals around ducts, pipes, cables, cable trays, and conduit or any other openings. Verify that the seals will be the 3-hour requirements for ASTM E119 or other acceptable tests. Verify that the in-plant cable tray supports are similar to the ones used in the fire tests and that, in case of collapse of the trays, the resultant unsupported load and torque on the penetration seal will not affect the integrity of the seal.

d. Item D.1(e): Identify any safety-related area where noncombustible metal deck roof will be used and indicate how the 3-hour fire rating will be met to comply with Appendix A, BTP 9.5-1.

RESPONSE: The design, construction, test method, and acceptance criteria for the above items are as follows:

a. Fire-Rated Barriers

Structural concrete walls and floor thicknesses exceed the fire barrier requirements and, where applicable, are identified as fire barriers in order to ensure that penetrations are of equal rating.

Structural steel members, where required, are protected by spray-on fireproofing systems listed in the Underwriter's Laboratories Fire Resistance Directory (ULFRD) for the appropriate hourly ratings for beams and columns. Other structural steel members, where required, are protected by water suppression systems. (Refer also to the responses to Questions 9A.107, 9A.108, and 9A.110).

Acoustical or plaster ceilings and plaster walls are constructed in accordance with the appropriate design system listed in the ULFRD.

Depending on the manufacturer's product used, the following ULFRD designs or equivalents are used:

(1) Plaster partitions

UBC Table 43B No. 61 - 3 hours
U-409 - 1 hour

(2) Plaster ceilings

G519 - 1 hour where required

(3) Acoustical ceilings

G036 - 1 hour concealed suspension system
G204 - 1 hour exposed suspension system

(4) Fireproofing

X701 for columns
N706 for beams

(5) Doors and frames will bear the appropriate UL or FM fire rating label.

(6) Floors and roof slabs exceed minimum required thicknesses for structural reasons. No UL design is applicable.

(7) Gypsum board partitions

U-411 (UBC Table 43B No. 71) - 2 hours

(Refer to the response to Question 9A.109).

b. Fire Dampers and Fire Doors

Test method and acceptance criteria for dampers are in accordance with UL 555-79. Typically, the devices carry the UL label and are installed in sleeves which are attached to the duct work and supported by the walls. The devices are positioned between the two wall surfaces. A failure of the duct on either side will not violate the fire barrier. There are a few cases where the damper is not installed in the tested configuration. The dampers are mounted off the centerline of the wall or on the surface of the wall and are supported in part or totally by structural steel attached to the fire wall. Following is a fire protection evaluation of the areas where surface-mounted dampers are installed:

(1) Control Building

(a) Dampers installed on the interior wall of the HVAC shafts (2-hour shaft with 1-1/2-hour dampers) are exposed to no combustible load.

(b) Dampers installed on the exterior wall of the HVAC shafts are in fire zones with detection and automatic suppression systems (CO_2 or water). This would mitigate the effects of fire and limit the heat exposure. The duct supports are seismically designed and, therefore, are of substantial steel construction. They would withstand a design basis fire with automatic suppression.

(c) There is one surface-mounted damper at the 74-foot level (essential chiller room) of the control building in the 3-hour rated central wall. The total combustible (fire) loading in this fire zone (No. 1) is low and consists primarily of charcoal filters located about 40 feet away. This calculated fire severity is very conservative because it contains an allowance for transient charcoal sufficient to completely fill the filter. Smoke detection is installed in the room for early warning. This installation provides reasonable assurance that a fire will not propagate through the wall. On the other side of the damper is a 2-hour rated concrete soffit containing no combustibles. There is no direct communication with the adjacent fire area.

(2) Auxiliary Building

(a) Zone 37A corridor, 70-foot level. There is one surface-mounted damper in a 1-hour rated portion of a concrete wall. The total combustible (fire) loading is low and there is smoke detection installed in the zone for early warning. Spatial separation on either side of the wall between redundant safe shutdown equipment is approximately 60 feet total, with no intervening combustibles. This installation provides adequate separation and protection of safe shutdown equipment.

(b) Zone 52A corridor, 120-foot level. There is one surface mounted damper in a 1-hour rated portion of a concrete wall. The total combustible (fire) loading is moderate and consists primarily of cable trays protected by an automatic detection and water suppression system. Redundant safe shutdown equipment is also separated by approximately 80 feet to that located in zone 52D. This installation provides adequate separation and protection of safe shutdown equipment.

Based upon the above analysis of fire hazards, equipment separation, and fire suppression systems available, the surface mounted dampers in these areas

will provide adequate protection without fireproofing.

Typically, 3-hour dampers are used in 3-hour walls and 1-1/2-hour dampers are used in 2-hour and 1-hour walls. The fire dampers purchased for PVNGS are all of identical material and constructed to 3-hour standards. Where exact replication of a tested configuration cannot be achieved, the installation will meet the following criteria:

1. The continuity of the fire barrier material shall be maintained.
2. The thickness of the barrier shall be maintained.
3. The nature of the support assembly shall be unchanged from the tested configuration.
4. The application or "end use" of the fire barrier shall be unchanged from the tested configuration.
5. The configuration shall be reviewed by a qualified fire protection engineer and found to provide an equivalent level of protection.

(Refer to the response to Question 9A.108).

Class A doors are used in 3-hour fire walls, Class B doors are used in 2-hour fire walls, and Class C doors are used in 1-hour fire walls. (Refer to the response to Questions 9A.106).

c. Fire Barrier Penetration Seals

Testing and acceptance criteria are as specified in ASTM Standard E119 (1976) or IEEE-634 (1978). Seals are typically installed in the same manner as tested. Where exact replication of a tested configuration cannot be achieved, the installation will meet the following criteria:

1. The continuity of the fire barrier material shall be maintained.

2. The thickness of the barrier shall be maintained.

3. The nature of the support assembly shall be unchanged from the tested configuration.

4. The application or "end use" of the fire barrier shall be unchanged from the tested configuration.

5. The configuration shall be reviewed by a fire protection engineer and found to provide an equivalent level of protection.

Quality assurance, quality control, and other measures are made to ensure that the actual installation conforms to the specified requirements. The cable trays are supported by tray supports located close to the wall penetration to increase the reliability and integrity of the raceway system in case of fire. Consequently, the penetration seals will not be affected due to unsupported load. (Refer to the response to Question 9A.110.)

d. Metal Deck Roof

All roof slabs in safety-related areas are of structural concrete. Structural thickness exceeds the 3-hour fire separation requirements.

<u>QUESTION 9A.69</u> (FPER Question 7) (9B.3)

Page III-15[a], Item D.1.(i): Verify that the floor drains are of adequate size to handle any run-off from any water type fire protection and hand hose system. In areas without drains, analyze the effects of standing water and water seepage through any openings in the floors onto safety-related equipment.

Describe protection to be provided for any equipment susceptible to water damage.

RESPONSE: Refer to the response provided in amended table 9B.3-1, Section D.1.(i).

<u>QUESTION 9A.70</u> (FPER Question 8) (9B.3)

Page III-20[a], Item D.4.(a): Appendix A states that the products of combustion should be removed from the fire area and the removal should be controlled, monitored, and directed outside. Describe for your plant how heat, smoke, and toxic fumes will be removed from safety-related fire areas using either fixed or portable air handling units. Describe how exhaust and makeup air would be provided to achieve adequate air movement. Where portable air handling equipment is used, describe the route that would be used to reach the exterior,

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a. Page references are no longer applicable due to FPER reformatting for FSAR amendment 13.

considering the reduction of rated fan capacity due to duct length, time requirement in placing units into operation, and the ability to handle fire temperature gases. For areas where the ventilation system will be used, describe the access to and location of controls.

RESPONSE: The products of combustion, smoke, and gases will be removed from the safety-related zones and areas by means of portable smoke removal equipment.

In general, a fire floor or area will be exhausted to the outside, utilizing portable smoke removal equipment.

A. Auxiliary and Radwaste Buildings

The smoke will, in case of fire, be removed from the fire area by use of portable smoke removal equipment.

1. The fire department, with self-contained breathing apparatus and the smoke ejectors, will go to the fire area or room. The ejector along with flexible ducts will be placed so as to exhaust the smoke from the fire area to the outside.

   The smoke can be exhausted to outside through stairwells and opening on top of the stairwells.

The portable smoke ejectors are designed to withstand smoke and temperatures encountered for fire department operation.

The makeup air would partly be supplied by opening the appropriate outside doors.

B. Control Building

Smoke in the control building will be removed by the portable smoke removal equipment. The smoke will be vented to the outside either directly, or through HVAC chase or through stairwells. The fresh air is obtained by opening missile doors or stairwell doors or through corridor building.

C. Fuel Building

The fuel building is a large, open structure, where the smoke and hot air will seek to the ceiling or the space under the roof and the smoke will be exhausted by use of normal HVAC system, when it is available. Smoke from selected enclosed compartments will be exhausted by use of portable smoke removal equipment.

<u>QUESTION 9A.71</u> (FPER Question 9) (9B.3)

Page III-23[a]:

a. Item C.1: Verify that the complete fire alarm system, valve supervision and waterflow indication will conform to the following established standards: NFPA 72D (Class A systems), and NFPA (Class I circuits) including standby power.

b. Item C.2: Provide a plot plan showing the underground water supply, tanks, reservoirs, hydrant locations, and sectional control valves. Also, provide diagrammatic plans showing the water supply throughout the plant

a. Page references are no longer applicable due to FPER reformatting for FSAR amendment 13.

showing all valves, hose stations, headers, standpipes, sprinkler systems, and the location of fire pumps and piping.

RESPONSE:

a. The PVNGS design for the fire alarm system uses NFPA 72D (1975) (Class A systems) and NFPA 70 (1975) (Class I circuits as guidance in the containment building only and Class B systems in other buildings.

   The PVNGS design for fire alarm systems is as follows:

   1. Detection Systems

      a. Detectors to panel (Class A)

      b. Panels to concentrator (Class B)

      c. Secondary power supplies in safety-related areas are designed in accordance with NFPA 72D (1975), Paragraph 2223, except for panel 1JQKNE10D which serves the 140-foot elevation of the auxiliary building. The 140-foot elevation of the auxiliary building is normally occupied, and portable fire extinguishers and manual hose reels are provided.

   2. Detection Systems Actuating Water Suppression Systems

      a. Detector to panel (Class B) two independent detection circuits, protectowire, and smoke

detectors are provided in safety-related areas except containment spray (CS), high-pressure safety injection (HPSI), and low-pressure safety injection (LPSI) pump rooms. These rooms are separated from the remainder of the auxiliary building by 3-hour rated fire barriers.

b. Panels to concentrator (Class A) for safety-related areas except containment spray, HPSI, and LPSI pump rooms.

c. Secondary power to meet NPFA 72D (1975) Paragraph 2223

d. Panels to concentrator (Class B) for nonsafety-related areas.

b. See figure 9B-7 (formerly FPER Figure 30), which shows the underground water supply, tanks, reservoirs, hydrant locations, and sectional control valves. The PVNGS fire protection P&IDs 01, 02, 03-M-FPP-002, -003, -004, -006 and A0-M-FPP-001 and -005 showing all valves, hose stations, headers, standpipes, and sprinkler systems.

QUESTION 9A.72 (FPER Question 10) (9B.3)

Page III-25[a], Fire Pump Rooms: Item C.2.(c): State that you comply with the position in Appendix A which requires the fire pumps be separated from each other and adjacent areas by a 3-hour rated barrier, and the installation of automatic sprinklers over the diesel fire pumps be in accordance with NFPA 20. Also, verify that individual alarms are provided for each pump.

RESPONSE: The fire pump arrangement at PVNGS is designed such that each of the three fire pump units are isolated from each other by 2-hour fire walls, and each diesel pump room is protected per NFPA 20 (1976) by a wet pipe sprinkler system installed per the guidance of NFPA 13 (1976).

Further separation of the diesel-driven units is accomplished by "spatial separation," in that the motor-driven fire pump is located between the rooms containing the diesel units.

No significant combustible loading is located within the motor-driven pump room. The diesel fuel oil storage tanks are located outside the diesel pump rooms at opposite sides of the building.

Individual alarms are provided for each pump as described in the PVNGS position to BTP APCSB 9.5-1, Appendix A, Section E.2.(c).

a. Page references are no longer applicable due to FPER reformatting for FSAR amendment 13.

QUESTION 9A.73 (FPER Question 11) (9B.3)

Page III-15[a], Item D.1.(j): Certain areas, such as zones 37A and 37B (formerly zone 37A), 42C, 48, 52, 54 and 74A and 74B (formerly zone 74), housing redundant systems, deviate from the guidelines in BTP 9.5-1, Appendix A, which provide for fire barriers with a minimum 3-hour rating for protection of safety-related equipment. Therefore, in areas where redundant safety-related systems are exposed to a single fire hazard, describe the fire barrier, including fire resistance rating with reference to ASTM E119 test data, which will be provided for the protection of the redundant systems or cables.

RESPONSE: Components are protected with a noncombustible radiant energy shield or protective coating for the purpose of meeting the separation requirements of 10CFR50, Appendix R, Section III.G. Refer to the revised fire hazards analysis of section 9B.2 and the responses to Questions 9A.92, 9A.94, and 9A.95.

QUESTION 9A.74 (FPER Question 12) (9B.1)

Provide drawings showing the routing of cables serving the essential safe shutdown systems and equipment. Identify their function and show the routing to each piece of equipment from power source, control room, and remote shutdown panel. The drawings should show the minimum physical separation distance and/or barriers between redundant electrical circuitry and cable routings for each applicable system and/or component.

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a. Page references are no longer applicable due to FPER reformatting for FSAR amendment 13.

Control instrumentation, and motive power cable routings, should be included.

Verify that there are no significant electrical differences between the Unit 1 systems and/or components essential to achieve and maintain a safe shutdown to those of Units 2 and 3, or explicitly define and justify those differences.

RESPONSE: The following drawings of nuclear safety-related conduit and cable tray routings have been submitted separately:

A. Control Building

   1. 13-E-ZJC-001 through -004

   2. 13-E-ZJC-033 and -034

B. Auxiliary Building

   1. 13-E-ZAC-001 through -008

   2. 13-E-ZAC-010 through -013

   3. 13-E-ZAC-015 through -018

   4. 13-E-ZAC-065 and -066

C. Containment Building

   1. 13-E-ZCC-007 through -012

   2. 13-E-ZCC-041, -042, and -045

D. Fuel Handling Building

   1. 13-E-ZFC-001 and -002

E. Legend Sheet

1. 13-E-ZAC-050

These drawings show the routing of Channels A, B, C, and D raceways.

The safety-related aspects of Units 1, 2, and 3 are functionally identical, and differ only in minor field installation details. (Refer also to the response to Question 9A.92).

<u>QUESTION 9A.75</u> (FPER Question 13) (9B.1)

Identify any safety-related systems which are disabled by initiation of a fire protection system, either by a direct interlock or as a result of the application of extinguishing agents.

RESPONSE: There are no interlocks between fire suppression system and safety-related systems. Application of extinguishing agents cannot disable more than one train of a safety-related system.

<u>QUESTION 9A.76</u> (FPER Question 14) (9.5.1)

Describe the communication used between the plant fire brigade and the control room during a fire situation.

RESPONSE: There are many available, generally independent means of communication provided to the control room for communication with the fire department, including the plant two-way radio system, the plant telephone, sound powered phone system, face to face, and public address

systems. All of these may be used for communication between the plant fire department and the control room during a fire situation, if they are available. However, only the two communication systems listed below are necessary to allow all required communication between the plant fire department and the control room during a fire situation.

A. The plant two-way radio system, which establishes communication between the fixed and portable radios carried by plant personnel and fire department members outside the control room.

B. Sound-powered phone system

QUESTION 9A.77 (FPER Question 15) (9B.1 and 9B.2)

Identify those Class 1E electric systems and components required for achieving cold shutdown, including circuits emanating from independent power divisions which are spacially separated to satisfy independence criteria. In each case either demonstrate the capability of the design to withstand a single fire event, including exposure fire without loss of function, or modify the design accordingly. Also demonstrate that the plant can be brought to a safe cold shutdown in the event of loss of offsite power.

Supplement the information which has been provided to include all systems and components such as instruments and controls which are essential to achieve and/or maintain cold shutdown (safe shutdown). Also, identify any of these systems and/or components whose electrical circuitry and/or cables are not redundant.

RESPONSE: 10CFR50, Appendix R, has substantially clarified the scope of this question. For discussion of this issue, refer to sections 9B.1 and 9B.2.

QUESTION 9A.78 (FPER Question 16a) (9B.2)

Control Building

Page II-3[a], Item A.1.c.(2)[a] and Page II-7[a], Item A.2.c.(2)[a]: You state that two Class B and one Class A rated doors are in the rated fire barriers. Engineering drawing 13-A-ZYD-029 (formerly FPER Figure 1) shows three unlabeled doors in fire zone 1 and fire zone 2. Verify that the Class A rated fire door is installed in the 3-hour fire barrier between the essential chiller rooms, zones 1 and 2.

RESPONSE: Refer to the revised fire hazards analysis presented in section 9B.2.

QUESTION 9A.79 (FPER Question 16b) (9B.2)

Control Building

Page II-3[a], Item A.1.f[a] and Page II-3[a], Item A.2.f[a]:

(1) For the 3-hour rated outside air supply plenum shown in engineering drawing 13-A-ZYD-029 (formerly FPER Figure 1), describe how the outside air is supplied to chillers in zones 1 and 2, and verify that the soffit at elevation 91 feet 0 inch has a 3-hour rating.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

(2) Verify that the controls for manual smoke exhaust systems for fire zones 1 and 2 will be located outside the fire zones.

(3) Verify that you comply with the guidelines of Appendix A, BTP 9.5-1, Section D.1.(j), which require that the ventilation openings from the plenum and soffit as well as the ventilation openings at the floor and ceiling are cut off by 3-hour fire doors or dampers throughout the control building. Justify any deviation in your design from the guidelines of Appendix A.

RESPONSE:

(1) Outside air is supplied through the vertical chase to the 2-hour rated soffit plenum located at elevation 91 feet 0 inch in zone 2. The 3-hour rated horizontal concrete duct directs the outside air supply to the train A HVAC equipment located in fire zone 1. A 3-hour fire damper is provided at the concrete duct penetration into fire zone 1 at the column line JC wall. Sheet metal HVAC ducting directs the outside air supply from the plenum to the train B HVAC equipment located in fire zone 2 and to the normal HVAC equipment located in fire zones 1 and 2. These HVAC ducting connections to the soffit plenum are provided with 1-1/2-hour rated fire dampers and the outside air supply to the normal HVAC equipment ducting is also provided with 3-hour fire dampers at the column line JC wall penetrations.

(2) The smoke from fire zone 1, train A essential chiller room, and fire zone 2, train B, essential chiller room, will be removed by use of portable smoke removal equipment. Hence the controls for portable smoke removal equipment will be outside the fire zones 1 and 2. In case the existing fixed smoke removal system is available and could be used for smoke removal, it is controlled from the control room at elevation 140 feet and thus from a location outside the space. Only portable equipment, however, is relied on for smoke removal capability.

(3) Three-hour rated fire dampers and fire doors are provided to separate the train A and B equipment located in zones 1 and 2, respectively. The outside air supply chase is not safe shutdown related. The fire area boundary is located at the column line JC wall (zone 1 to zone 2 boundary) and does not include the outside air shaft.

QUESTION 9A.80 (FPER Question 16c) (9B.2)

Control Building

Page II-13[a], Item A.3.f[a]: You state that there is no ventilation provided in the cable shafts for train A and train B (fire zones 3A and 3B [formerly zone 3] in engineering drawing 13-A-ZYD-029 [formerly FPER Figure 1]). Indicate how smoke will be removed in the cable shaft (fire zones 3A and 3B [formerly zone 3]) during a fire.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

RESPONSE: The "cable shafts" are actually rooms at each elevation of the control building, with cable penetrations in the floors and ceilings. Smoke detection is provided for each "cable shaft" room.

The smoke venting from cable shafts will be performed by opening the doors between cable shafts and fire zones 1 and 2 (train A and B, essential chiller rooms) and then venting smoke from fire zones 1 and 2 via portable smoke removal equipment.

QUESTION 9A.81 (FPER Question 16d) (9B.2)

Control Building

Page II-32[a], Item B.5.a[a]: Verify that the emergency exhaust fans in the battery rooms, zones 8A and 8B (formerly zone 8), are supervised and upon failure indicate a trouble condition in the control room as stated in Regulatory Guide 1.120, Section C.6.g.

RESPONSE: The emergency exhaust fans in the battery rooms, zones 8A, 8B, 9A, and 9B (formerly zones 8 and 9) are supervised. Loss of emergency exhaust will alarm in the control room.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

QUESTION 9A.82 (FPER Question 16e) (9B.2)

Control Building

Page II-70[a], Item D.3[a]:

(1) Indicate the functions and quantity of safety-related cables above suspended ceilings and provide a list of such locations. Describe the fire protection systems for these locations.

(2) It is our position that smoke detectors should be installed in the control room cabinets and consoles, if redundant trains are in the same cabinet. Verify that you comply with this position. Also, describe the additional fire protection measures which will be provided.

(3) Verify that all rooms (kitchen, pantry, storeroom) shown engineering drawing 13-A-ZYD-029 (formerly FPER Figure 4) within the periphery of the 3-hour barriers of fire zone 17, excluding the computer room, have at least 1-hour cut-offs from the control room and have an automatic sprinkler protection.

RESPONSE:

(1) There are no safety-related cable trays located above suspended ceilings within the PVNGS power blocks. There are enclosed vertical raceways (8- by 8-inch metal gutters) which penetrate the corners of the suspended ceiling in the control room and the floor of the upper cable spreading room. However, these

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

raceways can be seen from the control room (ref. table 9B.3-1, item D.1.f). Portable fire extinguishers are provided in the vicinity and the area is manned 24 hours per day. There are train A safety-related conduits above the suspended ceilings of zones 57I, 57J, and 57N (elevation 140 feet 0 inch of the auxiliary building). A portion of the 140 foot 0 inch elevation floor is a fire area boundary providing separation from the redundant train B circuits.

(2) Smoke detectors are provided in the ventilation stream outside of each control room cabinet with redundant channels. In the event of a fire in a cabinet, early warning detection and the proximity of operating personnel and portable fire extinguishers will prevent damage to redundant safe shutdown channels.

(3) All rooms are separated from the control room proper by a 1-hour fire wall. No automatic sprinkler protection is provided. Smoke detectors are provided in each of these rooms. The rooms are of light hazard with no permanent cooking facilities (rangetop stove/oven). A portable microwave and small appliances (such as coffee pot and toaster oven) are located in the kitchen area. Portable fire extinguishers are available. (Refer to the response to Question 9A.118)

QUESTION 9A.83 (FPER Question 16f) (9B.3)

Control Building

Page III-40[a] Item D.5: You state that fixed CO_2 hose reels will be used as fire protection for cables passing through the switchgear room. CO_2 hose reels do not provide adequate protection to the cables. It is our position, stated in Appendix A, that automatic suppression systems be provided for cables passing through the switchgear room. State that you will comply with this position.

RESPONSE: Refer to the revised fire hazards analysis presented in section 9B.2.

QUESTION 9A.84 (FPER Question 16g) (9B.3)

Page III-15[a], Item D.1.(j) and Page III-18[a], Item D.3.(e): It is our position that 3-hour barriers should be provided around cable shafts in the control building. You state that for uncovered cable trays no fire breaks will be provided. Fire breaks should be installed as per Regulatory Guide 1.120, Section C.4.c(4), at a maximum distance of 20 feet for horizontal trays, and at each floor/ceiling level for vertical trays in areas that are not protected by automatic water systems. Between levels or in vertical cable chases fire stops should be installed at the midheight if the vertical run is 20 feet or more but less than 30 feet, or at 15-foot intervals in vertical runs of 30 feet or more. Also, indicate how an

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

internal fire will be detected and extinguished in a closed cable tray.

RESPONSE: Three-hour barriers enclose all cable shafts in the control building. In vertical cable trays, fire stops (penetration seals) are installed in each rated fire barrier. PVNGS design provides fire stops in horizontal trays penetrating fire rated walls and walls with sealed penetrations. The fire stops at the fire rated walls and floors will confine the fire to that zone without affecting the adjacent zones.

Where PVNGS used IEEE 383 cable rated at 210,000 BTU/hr during construction, its regulatory commitment to cable fire retardancy is IEEE 383 at 70,000 BTU/hr. As such, PVNGS now procures power block cable to IEEE 383 fire retardancy requirements, other nationally recognized standards (e.g., UL 1581 Vertical Tray Flame Test, UL 910, or UL 1666) which have been evaluated to meet or exceed IEEE 383 fire retardancy requirements, or other criteria (e.g., new standards) evaluated by Design (Electrical) Engineering for fire retardant equivalency. There are 27 cables installed at PVNGS that do not meet the IEEE 383 flame test. These 27 cables have been evaluated, for both electrical and fire protection properties, and "Accepted-As-Is" by Material Engineering Evaluation (MEE) 02480. Safety-related areas outside containment which have significant concentrations of cable are provided with automatic water suppression systems. The above active and passive protection features will minimize the spread of

fire in cable trays within a fire zone. No additional "fire breaks" are deemed necessary by the Fire Hazards Analysis nor by current NRC guidelines.

Cable tray covers are used in plant areas where the separation guidelines of Regulatory Guide 1.75 cannot be met. In these areas, the cable trays are protected by line-type thermal detectors or ionization detectors for early warning and/or suppression system actuation. Most of these cable trays are also protected by automatic preaction or deluge sprinkler systems. The cable trays not protected with automatic suppression systems are located inside containment, and manual firefighting with local hose stations or portable extinguishers would be used to extinguish the fire.

<u>QUESTION 9A.85</u> (FPER QUESTION 16h) (9B.2)

Page II-41[a], Item B.7[a]: You state in Section 7.4.1.10 of the PSAR, "Emergency Shutdown from Outside the Control Room," that you have the design capability to achieve and maintain a safe hot shutdown and a potential capability for subsequent cold shutdown of the reactor in the event the control room becomes inaccessible or inhabitable. In this regard, provide the responses to items below;

(1) Provide a list of essential safe shutdown equipment with a description of how remote instrumentation and control would be accomplished. Identify each safe shutdown equipment and its associated instrumentation and control

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

equipment for which electrical energy is essential for its proper operation.

(2) Assuming that the offsite power grid is not available, provide supporting information which may be used to conclude that electrical power, instrumentation, or control required for safe shutdown equipment will not be lost in the event a fire occurs in the main control room or cable spreading room.

(3) Identify and describe any changes in the original electrical design as a result of the incorporation of this emergency alternate method for achieving and maintaining a safe shutdown.

RESPONSE:

(1) Section 7.1 provides a list of essential safe shutdown equipment. Section 7.4 provides a description of the equipment. Additionally, the 10CFR50 Appendix R, III.G/III.L compliance assessment is presented in APS calculation 13-MC-FP-318. (See Section 9B.1.4.2.2)

(2) Safe shutdown can be achieved using only Class 1E powered equipment and limited, local-manual, operator action. As two cable spreading rooms are provided (one for each train), fire in one cable spreading room will not cause loss of function in the other cable spreading room and its associated train. Therefore, fire in a cable spreading room will not cause loss of function in more than one train and

will not prevent reaching safe shutdown from the control room.

A fire in the control room is prevented from affecting both safe shutdown trains by the use of transfer switches in the B train of safe shutdown equipment. Control can be maintained at the remote shutdown panel and local control stations utilizing equipment and components identified in safe shutdown equipment.

(3) Smoke detectors are provided in the control room to minimize the effect of a control room fire. Class 1E controls and Seismic Category I air supply are provided for the control of the main steam atmospheric dump valves, disconnect switches have been added for train B equipment and the control nests have been moved outside of the control room. Additional remote shutdown panel indication, and emergency lighting and sound-powered communication capabilities have been provided.

QUESTION 9A.86 (FPER Question 17) (9B.2)

Diesel Generator Building

(a) Engineering drawing 13-A-ZYD-031 (formerly FPER Figures 6 and 7);

(1) It appears in engineering drawing 13-A-ZYD-031 (formerly FPER Figures 6 and 7) that safety-related equipment is not separated in all areas of the diesel generator building by 3-hour rated construction, in

particular, the equipment located in fire zones 25A and 25B (formerly fire zone 25) as well as fire zones 21A, 21B, 22A, and 22B (formerly fire zones 21 and 22) which are connected by a pipe trench. Meet the Appendix A guidelines of 3-hour fire barriers.

(2) Provide the locations of all manual hose stations in the building.

(b) Page II-85[a], Item F.1.f[a]: Discuss and analyze how smoke ventilation will be accomplished, under fire conditions, in the diesel generator building.

(c) Page II-95[a], Item H.1.i[a]: Provide a fire hazard analysis assuming a leak in a fuel line of the day tank and spilling of its contents through the floor penetrations or as a result of the line failing in the room below. Seal all floor penetrations.

RESPONSE:

(a) Engineering drawing 13-A-ZYD-031

(1) Trains A and B within the diesel generator building (fire areas IV and V) are separated by 3-hour rated fire barriers. Refer to the fire hazards analysis provided in section 9B.2.

(2) No hose stations are provided inside the diesel generator building. However, hose stream coverage is provided as discussed in the response to Question 9A.115(a).

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a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

(b) Smoke removal will be accomplished through a combination of normal and emergency ventilation fans, if operable, or portable smoke removal units. As the diesel generators are separated by 3-hour rated fire boundaries, no safety impact results from delay in smoke removal.

c) The day tank rooms door curbs are sized to a height to contain the full volume of the day tank and its associated piping. Floor penetrations are sealed or (provided with noncombustible penetration sleeves which extend to at least the height of the door curb.

If a line fails in the room below and a fire occurs, the preaction sprinkler systems present in both the day tank rooms, and the rooms below, will be initiated.

QUESTION 9A.87 (FPER Question 18) (9B.2)

Fuel Building

a. Page II-107[a], Items I.2.c[a] and I.2.d[a]: Appendix A, Section F.13, states that fire detection for the spent fuel area should be provided. Verify that you comply with this position.

RESPONSE: Smoke detectors for the spent fuel area are provided.

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a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

QUESTION 9A.88 (FPER Question 19a) (9B.2)

Auxiliary Building

Page II-146[a], Item M.1.c(1)[a]: Engineering drawing 13-A-ZYD-023 (formerly FPER Figure 14) seems to show an open grating separating fire zone 38 from fire zone 37. An exposure fire in either of these zones could spread to the other zone. Provide automatic sprinklers in these zones at each level or provide fire barriers.

RESPONSE: Fire zones 37C and 37D (formerly zone 37) have been expanded to include fire zone 38. See engineering drawing 13-A-ZYD-023 (formerly FPER Figure 14) and the revised fire hazards analysis of section 9B.2.

QUESTION 9A.89 (FPER Question 19b) (9B.2)

Auxiliary Building

Page II-149[a], Item M.2.c(1)[a]: You state that all walls, ceilings, and floors are heavy concrete construction. Verify that equipment in the pipeways containing Train A and Train B are separated from each other by 3-hour fire barriers.

RESPONSE: The only safe shutdown equipment in the pipeways (zones 39A and 39B) other than piping is train A and train B raceway which contain the redundant power circuits for the condensate transfer pumps. This raceway is located in Fire Zone 39B. The susceptibility of piping to an exposure fire is negligible, and barrier separation

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

between train A and train B piping is not required. The condensate transfer pumps provide make-up to the essential chilled water expansion tank to maintain cold shutdown. In the event of a fire damaging both the train A and B condensate transfer pumps circuitry, makeup water for the essential chilled water expansion tank is available from the fire protection system. Therefore, the condensate transfer pumps are not required for safe shutdown for a fire in these fire zones.

QUESTION 9A.90 (FPER Question 19c) (9B.2)

Auxiliary Building

Page II-152[a]: You state that the electrical chase shafts "are open at the floor level to level 70." Appendix A, Section D.3, states that fire barriers and fire detection should be provided in cable shafts, both vertical and horizontal. Verify that you comply with Appendix A in that each electrical chase is cut off at each floor and describe how fire detection will be accomplished. Describe the fire rating of the cutoff used.

RESPONSE: Electrical chases previously shown in zones 40 and 41 have been incorporated into zones 37A and 37B and are cut off at floor levels 70 feet and 100 feet by a 3-hour fire barrier. Refer to the revised fire hazard analysis of section 9B.2.

Smoke detection is provided along with portable fire suppression.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

QUESTION 9A.91 (FPER Question 19d) (9B.2)

Page II-160[a], Item N.1[a] and Page II-179[a], Item 0.1[a]: Provide vertical and horizontal separation distances between trains A and B, in zones 42A, 42B, 47A, and 47B (formerly zones 42 and 47) where the containment walls are penetrated, or provide sufficient information to show that you meet the position in Appendix A, Section F.3-b.

RESPONSE: Zones 42A and 47A are separated from zones 42B and 47B by the south access shaft, a distance of greater than 40 feet.

QUESTION 9A.92 (FPER Question 19e) (9B.2)

Auxiliary Building

Page II-175[a], Item N.6[a]:

1. Fire zone 42C is not shown on figure 9B-21 (formerly FPER figure 15). Identify the location of zone 42C.
2. Describe the overall functions of channels C and B cable trays in this zone as well as the need for additional fire suppression and fire barriers to protect these safety-related cable trays.

RESPONSE:

1. Fire zone 42C is shown on engineering drawing 13-A-ZYD-024 (formerly FPER Figure 15).

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

2. The safe shutdown equipment in the channel C cable tray is the power and control circuitry for valve J-SIC-UV653. In the event of a fire in this fire zone the manual operation of this valve is required. The operation of this valve is required beyond 8 hours into the fire event. Therefore, no additional fire suppression or fire barriers are required to protect these safety-related cable trays. Reference Calculation 13-MC-FP-318.

<u>QUESTION 9A.93</u> (FPER Question 19f) (9B.2)

<u>Auxiliary Building</u>

Page II-184[a], Item 0.2[a]: Fire zone 48 contains train A and train B essential cooling water surge tanks with its associated control and instrumentation cables and a chemical storage area, but no fire detection system. Install a detection system.

RESPONSE: A smoke detection system is installed in this fire zone.

<u>QUESTION 9A.94</u> (FPER Question 19g) (9B.2)

Page II-209[a], Item 0.14[a]: Channels A and D safety-related cable trays are located in this area. Provide an analysis to show that the plant can be shut down in the event an exposure fire involves both divisions, or provide an automatic suppression and detection system.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

RESPONSE: Zone 52 has been subdivided into two parts -- zones 52A and 52D separated by a 1-hour rated fire barrier. The cable trays in zones 52A and 52D are provided with automatic water suppression and a zonal smoke detection system.

<u>QUESTION 9A.95</u> (FPER Question 19h) (9B.2)

Page II-215[a], Item 0.16.c(1)[a]: Fire zone 54 contains the reactor trip switchgear and cable trays for train A and train B. We do not have sufficient information to evaluate the area with regard to the guidelines given in Appendix A, Section D.1. Provide sufficient information and verify that you meet the guidelines of Appendix A, which states that 3-hour separation between the redundant trains in zone 54 be provided. Describe the additional measures that will be taken to properly protect each division.

RESPONSE: A failure of the reactor trip switchgear does not preclude a reactor trip.

<u>QUESTION 9A.96</u> (FPER Question 20a) (9B.2)

<u>Containment Building</u>

Page II-270[a], Item R.1.1.c(3)[a]: Describe the operational modes of the isolation valves in the ducts inside containment for the ventilation system during a fire situation. Provide an analysis of the loss of these valves due to a fire and the ability to perform a cold shutdown.

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a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

RESPONSE: Loss of function of the ventilation duct isolation valves has no adverse affect on achieving cold shutdown. The isolation valves in the containment building ventilation ducts are duplicate valves located at the containment building wall, one inside and one outside the wall for each ventilation duct penetration.

The refueling purge isolation valves are opened for control of airborne radioactivity during refueling only. The power-access purge valves are open for about 16 hours per week during normal power operation. Upon a containment isolation signal, both inside and outside containment isolation valves are closed. No other ventilation isolation valves are provided inside containment.

QUESTION 9A.97 (FPER Question 20b) (9B.2)

Containment Building

Page II-271[a], Item R.1.1.e[a]: You state that the standpipes inside containment are normally dry, and that primary fire suppression is manual hose streams. It is our position in Appendix A, Section F.1, that filled standpipes and fixed suppression systems be provided in containment. Modify your design to meet our guidelines.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

RESPONSE: When the containment building is occupied for any significant time period (such as during refueling or during a maintenance outage), the standpipes within the building will be pressurized with fire water.

During times when the containment building is not occupied, the standpipes will be filled and the isolation valve closed to assure that no fire water is inadvertently discharged within the containment building. Also refer to responses to Questions 9A.98 and 9A.130.

QUESTION 9A.98 (FPER Question 20c) (9B.2)

Containment Building

Page II-272[(a)], Item 2.1.1.k[(a)]:

1. For the reactor coolant pumps, provide an oil containment or collection system.

2. Verify that the redundant safe shutdown instrumentation sensing lines in the immediate area of the reactor coolant pumps are sufficiently separated to preclude the failure of the sensing lines from an exposure fire.

RESPONSE:

1. A system is provided to collect and contain lubricating oil from nonwelded joints for each reactor coolant pump and motor. The system is designed to remain functional after an SSE.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

2. In zones 63A and 63B, which contain the reactor coolant pumps (RCPs), there are 12 instrument nozzle taps with 3/8-inch diameter stainless steel sensing lines for redundant steam generator (S/G) level and pressure transmitters. The transmitters themselves are located outside the secondary shield and, therefore, beyond the area involved in a postulated fire in the vicinity of the RCPs. The sensing lines are routed 20 to 40 feet above a concrete floor. The most remote nozzle taps are separated from each other by approximately 15 feet horizontally along the circumference of the S/G. There is about 15 feet of horizontal separation between the RCP and the closest S/G nozzle. Operability of any one of the eight S/G level instruments is sufficient for the operator to fulfill his required safety function. There are no in situ combustibles directly under the sensing lines. An RCP oil collection system, which meets the requirements of 10CFR50, Appendix R, Section III.0 (refer to the response to Question 9A.126), has been provided to mitigate the effects of the major in situ combustible load. A transient load of 2-1/2 gallons of flammable liquid (approximately 400,000 Btu) would only yield a fire severity of about 1 minute in the vicinity of the S/G. Therefore, a fire of this magnitude and duration in this location would not cause the failure of all safe shutdown instrument sensing lines.

The instrument sensing lines for the differential pressure measurement across the primary side of the S/G are also located in the vicinity of the RCPs. The instrumentation is not required for safe shutdown. In event of failure of these sensing lines, the reactor coolant pressure boundary is breached. However, equipment required to mitigate this failure is located outside the S/G compartment, and both trains are unaffected by the fire. (Details of the analysis are available in chapter 15.)

QUESTION 9A.99 (FPER Question 20d) (9B.2)

Containment Building

Page II-282[a], Item 5.1.c[a]

1. The auxiliary feed pump rooms have an outside wall of 3-hour rating while the rest of the walls are heavy concrete construction. Appendix A, Section D.1(j), states that 3-hour separation including protection of all communicating openings around each auxiliary feedwater pump room be provided. Verify that you comply with this position in that the other walls and communicating openings have 3-hour rating.

2. It is our position that an outside entrance be provided for firefighting access to the motor-driven pump room rather than through the turbine-driven pump room.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

RESPONSE:

1. A description of the auxiliary feedwater pump rooms is provided in the revised fire hazards analysis of section 9B.2. The 3-hour fire wall that separates the auxiliary feedwater pump rooms has a watertight door. The door design is basically that of a ship's bulkhead door, i.e., reinforced steel plate leaf, heavy duty hinges, and multiple pressure "dogging" around the perimeter. A preaction sprinkler system is provided beneath the grating in the turbine-driven pump room. (Refer to the response to Question 9A.101.)

2. An emergency entrance from above is provided to the motor-driven pump room.

<u>QUESTION 9A.100</u> (FPER Question 20e) (9B.2)

<u>Containment Building</u>

Page II-282[a], Item 5.1.2(2)[a]: Secondary fire suppression to the auxiliary feed pump rooms is provided in part by "Manual Hose Streams from Hydrants on the Fire Main." Engineering drawing 13-A-ZYD-022 (formerly FPER Figure 23) does not show any hydrants near the auxiliary feed pump rooms. Show that there is a hydrant available or provide a 1-1/2-inch hose station for protection of these rooms in the immediate area.

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a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

RESPONSE: Figure 9B-7 shows a fire hydrant located plant northwest of the MSSS for use by the site fire department. Also, hose stations with sufficient hose to reach the MSSS (response to question 9A.115) are located in the turbine building. The hose station, however, is not relied on for secondary fire suppression capability.

QUESTION 9A.101 (FPER Question 20f) (9B.2)

Containment Building

Page II-284[a], Items 5.1.j[a] and 5.1.k[a]: Identify the redundant safety-related equipment or cabling in each of these compartments and demonstrate that a fire in one compartment will not affect the operation of the auxiliary feed pump in the other compartment.

RESPONSE: Redundant safe shutdown raceway for the auxiliary feedwater pumps are protected as described in the fire hazards analysis of section 9B.2. The turbine driven auxiliary feedwater pump room (zone 72 - train A) and the motor-driven auxiliary feedwater pump room (zone 73 - train B) are separated with a 3-hour fire barrier with a watertight door. See response to Question 9A.99.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

QUESTION 9A.102 (FPER Question 21) (9B.2)

Main Steam Support Structure

a. Page II-29[a], Items T.1.j[a] and T.1.k[a]: An internal or exposure fire will cause adverse effects on the safety division cabling and equipment in the support structure. Analyze, as a result of an exposure fire, the loss of redundant safety-related equipment or cabling, including control, power, or instrument cables, on the shutdown capability of the plant, and provide the necessary automatic fire suppression systems to minimize the damage.

RESPONSE: As a result of the analysis, an automatic suppression system and protective wrapping have been employed to minimize adverse effects on safety division cabling. Refer to the revised fire hazards analysis of section 9B.2.

QUESTION 9A.103 (FPER Question 22a) (9B.2)

Outside Areas

Page II-301[a], Item U.3.c.(1)[a]: Indicate on engineering drawing 13-A-ZYD-021 (formerly FPER Figure 27) the distance between zone 76 (ESF service transformers) and the switchgear building. Justify the 2-hour fire barriers separating zone 76 from zone 77, and show the separation distances between the safety-related transformers and the nonsafety-related transformers, as well as the distance from the fire barriers for the control building and diesel generator building.

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a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

RESPONSE: The distance between zone 76 (ESF service transformers) and the switchgear building is shown on engineering drawing 13-A-ZYD-021. Also shown is the distance between the ESF service transformers and the normal service transformers, and the distance between the fire barrier and the control and diesel generator buildings.

The ESF transformers are not part of the safety-related system. The area contains only nonsafety-related equipment. The nomenclature "ESF transformers" suggests that the transformers feed safety-related equipment; however, the Class 1E system starts at the incoming breakers to the ESF switchgear.

QUESTION 9A.104 (FPER Question 22b) (9B.2)

Outside Areas

Pages II-301[a] and Page II-304[a]: Provide drawings of the switchgear building showing areas of safety-related cables or equipment necessary for a safe cold shutdown, as well as the fire suppression and detection systems.

Provide a fire hazard analysis for this area.

RESPONSE: Refer to the fire hazards analysis provided in section 9B.2. The ESF transformers and switchgear are nonsafety-related equipment. The switchgear building has no safety-related equipment associated with it. The fire suppression and detection systems for this building

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

consist of two carbon dioxide hose reels and smoke detection.

QUESTION 9A.105 (FPER Question 22c) (9B.2)

Page II-323[a], Item U.13.g[a]: Verify that 3-hour fire rated vertical cutoffs on each level are provided in zones 86A and 86B (formerly zone 86) and indicate the distance between the cutoffs. Also, verify that the cable shaft is cut off at each floor level by a 3-hour rated barrier.

RESPONSE: As shown in engineering drawing 13-A-ZYD-029, zones 86A and 86B extend from below grade to elevation 160 feet 0 inch. Three-hour penetration seals are provided for all electrical trays entering zones 86A and 86B (formerly zone 86) from the auxiliary building (column line A-10) and the control building (column line J1). All trays within zones 86A and 86B are horizontal trays passing from the auxiliary building to the control building. A vertical wall separates train A cables from train B cables. It is not necessary to provide 3-hour ratings at each floor elevation in the zones, because each zone is one train related only. Automatic water suppression for all trays within zones 86A and 86B is described in section 9B.2.

a. Page/paragraph references are no longer applicable due to FPER reformatting for FSAR amendment 13.

QUESTION 9A.106 (FPER Audit Open Item No. 1) (9B.2)

Verify that doors in fire rated walls and partitions are listed for use in that type of wall or partition.

RESPONSE: All fire doors are purchased as labeled fire doors of the fire rating required for the wall rating, (i.e., 3-hour wall: A label, 3-hour door; 2-hour wall: B label, 1-1/2-hour door; 1-hour wall: C label, 3/4-hour door) with the exception of doors that have removable transoms and/or have both louver and glass view plates and control room security doors. The exceptions have been certified by the manufacturer[a],[c] to be constructed in accordance with UL listing or FM approval (but without label) offering the corresponding fire rating protection.

These doors are listed in the accompanying table:

	FIRE ZONE	DOOR NO.	WALL RATING	DOOR RATING	REMARKS
	28	F105	2 hr	B	WG&L
	29	F201	2 hr	B	WG&L
	42A	A102	2 hr	B	RT
	42A/42D	A110	2 hr	B	RT
	42B/42C	A118	2 hr	B	RT
	52A/47A	A201	2 hr	B	RT
	54/52D	A213	2 hr	B	RT
(b)	48/62L	A204	3 hr	-	RT
	47B/52D	A216	2 hr	B	RT
	55C/57N	A302	1 hr	C	WG&L
	57A/57N	A317	1 hr	C	WG&L
	57G/57N	A320	1 hr	C	WG&L
	57L/57N	A323	1 hr	C	WG&L
	57K/57N	A327	1 hr	C	WG&L
	57J/57N	A335	1 hr	C	WG&L
	59/60G	R107	2 hr	B	WG&L
	60G	R121	2 hr	B	WG&L
(d)	17	J303	3 hr	-	Security

where RT = removable transom

WG&L = wire glass and louver (series S6)

(e) The following are nonrated missile doors located in fire barriers:

FIRE ZONE	DOOR NO.	WALL RATING
14/Corridor Bldg.	J208	3 hr
Control Bldg./Corridor Bldg.	J318	3 hr
20/Corridor Bldg.	J408	3 hr
54/Corridor Bldg.	A212	3 hr
74A/Open Stairwell	C102	3 hr
74A/Open Stairwell	C201	3 hr
74A/Open Stairwell	C301	3 hr

Notes:

(a) Fenestra letter, September 13, 1983, certifies that the series S6 doors (WG&L) supplied are made with construction, material, and workmanship approved by UL for classification as 1-1/2-hour (B label) or 3/4-hour (C label) labeled doors.

(b) Door No. A204 is not labeled but is a hollow metal door constructed to general 3-hour fire door standards. This door opening is in a concrete wall separating the auxiliary building, zone 48, from the radwaste building, zone 62L. The total combustible (fire) loading in Zones 48 and 62L is low and consists primarily of cable insulation. There is a monorail passing through the upper transom doors, a cutout in the transom doors allows the monorail to penetrate the doors when they are closed. There is no redundant safe shutdown equipment in either zone, and these areas are open and readily accessible for manual firefighting. Automatic sprinklers have been added above both sides of the door to prevent any possibility of fire passing from one zone to the other through the monorail opening.

(c) Chicago Bullet Proof (CBP) Company letter, April 15, 1983, certifies that bullet proof door No. J303 is manufactured in accordance with UL procedures stated in UL files BP1942 for CBP bullet-resisting equipment and R8402 for CBP fire door assemblies.

(d) Door No. J303 is a combination bullet proof, fire-resisting, security door. The primary purpose of this door is to prevent a spread of fire from the adjacent stairwell or corridor into the control room.

Due to their operational requirements (i.e., security electric strike), the above door is provided with 1/2-inch long latch throw which is in deviation of NFPA-80, 1975 criteria of 3/4-inch latch throw, and, therefore, cannot be labeled.

With exception of the latch throw, all other aspects of the door construction are in accordance with the requirements of a 3-hour rated UL labeled door. The permanent combustible loading adjacent to door J303 on the stairwell side is light to none which minimizes the effects of fire on the door. Both the stairwell and corridor areas are open and readily accessible for manual firefighting.

(e) The doors must be modified to meet other regulatory criteria and in doing so they lose their fire rating. There are no unmitigated fire hazards within 50 ft of the doors, and they are located in exterior walls and do not separate redundant safe shutdown equipment. Where the above criterion has not been met, a redundant set of doors for door J318 have been manufactured to meet UL’s standards for listed

fire doors (door J319). Two other doors (J208 and J408), have local sprinkler protection installed. On the basis of the conditions identified above, the non-fire-rated missile doors identified represent an acceptable deviation from Section D.1 of Appendix A to BTP APCSB 9.5-1.

QUESTION 9A.107 (FPER Audit Open Item No. 2) (9B.2)

Verify that the lack of structural steel fireproofing will not cause structural collapse during a postulated fire in the following plant areas:

a. Floors and roof of diesel generator building

b. Elevation 140 feet in the main steam support structure

c. Auxiliary building zones: 42A and 42B
47A and 47B
55A (formerly 55) and 56B

RESPONSE:

a. The reinforced concrete floors and roof of the diesel generator building are self supporting. Other structural steel material is not required.

b. The main steam support structure (MSSS) is provided with water suppression on all levels except in zone 73 (elevation 81 feet 0 inch). Even an exposure fire cannot reach the roof support columns and/or structural beams. This structure is also open to the atmosphere at the roof line providing natural heat

ventilation. Additionally, water spray from the spray nozzles for elevation 140-foot area are arranged such that the columns and beams will be sprayed. These features will ensure that the structural steel will not collapse.

c. The structural steel in zones 42A and 42B and zones 47A and 47B is protected with cable tray and column sprinklers. Ceiling level sprinkler protection has been added to these zones. These systems have been modified to preaction with activation by smoke detection or heat sensed by the cable tray protectowire system, which gives early warning to the control room. The total combustible (fire) loading in Zones 42A and 47A is low and in Zones 42B and 47B is moderate. The primary combustible in these four zones consists of fire resistant cable insulation. These zones are also readily accessible for manual firefighting and have a hose station located just outside the door. The structural members are also very heavy steel beams and columns and are not easily deformed within the parameters of a design basis fire in these zones. The above will prevent structural collapse during a postulated fire in these zones.

Columns in zones 55A (formerly zone 55) and 56B have adequate protection from the ceiling level wet pipe water suppression system installed in these zones.

One-hour rated protection of structural steel supporting the fire barrier ceilings of zones 37C and 37D has been provided.

<u>QUESTION 9A.108</u> (FPER Audit Open Item No. 3) (9B.2)

Verify that the fire dampers installed in the plant are listed for the following uses:

a. Grouped dampers at floor/wall penetrations

b. Single dampers at 3-hour fire rated wall/floor penetrations

c. Dampers in drywall and metal lath and plaster partitions

RESPONSE:

a. The design for ganged fire dampers was tested and rated at 3 hours by Underwriter's Laboratory.

b. Single dampers at 3-hour rated wall/floor penetrations are rated for 3 hours. Those dampers presently labeled with 1-1/2-hour ratings are constructed to 3-hour standards. The labels have been upgraded to 3-hour ratings.

c. Dampers installed in drywall and metal lath and plaster partitions will be rated for the rating of the partition; e.g., a 1-1/2-hour damper is installed in a 2-hour partition. Waldinger drawing and field installation procedures indicate that to provide adequate fire seals, gaps which exceed 1/2 inch will be filled with "Carborundum Fiberfrax Durablanket" (6 pounds density). When small void areas do not allow the use of "Fiberfrax Durablanket," "Fiberfrax" bulk may be used to fill the void area by tamping full. The "Fiberfrax" material is UL approved.

Ruskin's installation instructions comply with UL Safety Standards 555.

In the actual installation of the dampers in the drywall and the metal lath and plaster partitions, the dampers are installed in the ductwork first, then the studwalls are built around the duct/dampers. The installation of the damper is in accordance with the field procedures and installation instructions, as for any masonry wall. However, since the size of the openings is tailored for the damper, Fiberfrax insulation material is not required. Deviations between the design and actual installation are evaluated in accordance with the criteria stated in the response to Question 9A.68.b.

UL Safety Standard 555 did not address fire dampers installed in gypsum board or metal lath and plaster walls when the Palo Verde units were initially constructed. The vendor, Ruskin Manufacturing, has subsequently issued installation instructions for installing UL Safety Standard 555 listed dampers in gypsum board walls. The actual installations of fire dampers in gypsum or metal lath and plaster barriers at Palo Verde were compared to these instructions. This comparison concluded that the fire dampers were installed in accordance with the manufacturer's instructions. This fact, together with the conservative design of the duct and hanger systems and the defense-in-depth fire protection features in the subject fire areas, provides reasonable assurance

that the duct and damper assembly will remain in place during a postulated fire. Therefore, the integrity of the fire barrier will not be compromised in the event of a postulated fire.

<u>QUESTION 9A.109</u> (FPER Audit Open Item No. 4) (9B.2)

Verify that the drywall and hollow concrete block partitions are 3-hour fire rated.

RESPONSE: The noted partitions are 3-hour fire rated because:

(1) <u>Block Walls</u>

- Designed per UBC-1973 (Table 43B[a], Item Nos. 27 through 30). The walls are fully grouted and reinforced throughout.
- Penetrations for conduit piping and cable trays are sealed in the same manner and with the same materials as those used for concrete walls.
- UL-rated fire dampers are installed in an approved design wherever HVAC ducting penetrates the barrier. (Refer to the response to Question 9A.108.)

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a. Testing for UBC fire ratings was performed in accordance with ASTM Standard E119 (1976) (equivalent to UL 263, Fire Tests of Building Construction Materials) as noted in UBC Standard No. 43-1

(2) Drywall/Metal Lath and Plaster (ML&P) Partitions

- Designed per UBC-1973 (Table 43B[a], Item No.

Notes:

(a) All existing joints on the fire wall between the remote shutdown panels have been removed and replaced with approved No. 15 closed joints.

(b) Several ML&P walls are reclassified as 1-hour fire barriers. Other ML&P walls are classified as "rated" where life safety is the only factor (separation of safe shutdown equipment is not a factor). Refer to the response to Question 9A.118.

(c) The acceptance criteria (UBC Section 43.114) for the testing performed for nonbearing walls and partitions are as follows:

1. The wall or partition shall have withstood the fire-endurance test without passage of flame or gases hot enough to ignite cotton waste, for a period equal to that for which classification is desired.

2. The wall or partition shall have withstood the fire and hose stream test as specified in Section 43.108, without passage of

a. Testing for UBC fire ratings was performed in accordance with ASTM Standard E119 (1976) (equivalent to UL 263, Fire Tests of Building Construction Materials) as noted in UBC Standard No. 43-1

flame, of gases hot enough to ignite cotton waste, or of the hose stream. The assembly shall be considered to have failed the hose stream test if an opening develops that permits a projection of water from the stream beyond the unexposed surface during the time of the hose stream test.

3. Transmission of heat through the wall or partition during the fire-endurance test shall not have been such as to raise the temperature of its unexposed surface more than 250F above the initial temperature.

- Conduit penetration seals are installed in a metal retaining sleeve as shown in ICMS Drawing No. M-01-90, Specification No. AM-208. (This design has been approved with a 3-hour rating by ANI for use in ML&P walls). The acceptance criteria (per ANI/MAERP Standard Method of Fire Tests of Cable and Pipe Penetration Fire Stops) for the testing performed for penetration seals are as follows:

  1. Fire shall not propagate to the unexposed side of the test assembly nor shall any visible flaming be observed.

  2. No individual thermocouple on the unexposed surface of the fire stop shall exceed 325F above ambient temperature.

3. No opening develops that permits a projection of water from the stream beyond the unexposed surface during the hose stream test.

- There are no cable trays that pass through 3-hour rated ML&P walls
- UL-rated fire dampers are installed in an approved design wherever HVAC ducting penetrates the barrier.

QUESTION 9A.110 (FPER Audit Open Item No. 5) (9B.2)

Verify that cable tray penetration seals will not fail upon tray collapse.

RESPONSE: The cable trays utilized at PVNGS are typically "trough" type trays that are 4 inches deep and 24 inches wide. The trays are constructed of 14 gauge sheet metal and are manufactured by U.S. Gypsum/Globe. The supports for the trays are "Unistrut" channels (typically P1000 or P1001), or equivalent, that are manufactured from 12 gauge strip steel. The cable trays are clamped to the supports. These design features are typical of the current designs that are utilized throughout the industry.

The cable trays that penetrate fire walls which protect safe shutdown and safety related equipment from potential fire hazards have one or more of the following design features:

a. The first support is located within 24 inches of the first barrier. This is typical of most of the cable tray installations. This design feature has received

NRC approval throughout the industry as a method of preventing tray collapse and penetration seal failure.

b. In cases where it was not possible to locate a support within 24 inches of the barrier, the support was located as close as possible to the barrier. In addition, most of these tray configurations are protected by an area and/or cable tray automatic suppression system.

c. In the few cases where an automatic suppression system is not provided, defense-in-depth fire protection features protect the tray from being deformed to the extent that the penetration seal would be compromised during a postulated fire. These defense-in-depth features include limited combustibles in the area, fire detection systems and an immediate response (within 30 minutes) from the on-site fire department if a fire were to occur.

Based on the above information and the cable tray fire testing that has been performed by the industry for cable trays, there is reasonable assurance that the cable trays will not fail to the extent that the penetration seals would be compromised during a postulated fire.

<u>QUESTION 9A.111</u> (FPER Audit Open Item No. 6) (9B.2)

Verify that lead powder/iron powder type penetration seals are appropriate for use in a fire-rated partition.

RESPONSE: All penetration seals which have a dual purpose (i.e., radiation shielding and fire protection) have been tested and rated for 3 hours.

QUESTION 9A.112 (FPER Audit Open Item No. 7) (9B.2)

Verify the presence of fire dampers at walls, floor, and shaft penetrations in the following areas:

a. Control building elevation 74 feet (zones 1 and 2)

b. Control building elevation 100 feet (zones 7A and 7B [formerly zone 7])

c. HVAC chase at zone 18A (formerly zone 18)

d. Auxiliary building, elevation 51 feet 6 inches (zones 30A, 30B, 31A, and 31B [formerly zones 30 and 31])

RESPONSE: Every duct that penetrates a fire barrier has a fire damper. As was observed during the audit, small ducting does not have access panels to allow maintenance personnel to reset fire dampers. The PVNGS design uses removable sections of duct to access the fire dampers in those ducts smaller than 12 inches.

QUESTION 9A.113 (FPER Audit Open Item No. 8) (9B.2)

Verify that a single break or ground fault condition will not cause the loss of power to multiplex concentrators.

RESPONSE: PVNGS uses the guidance of NFPA 72D (1975) (Section 2220) and BTP APCSB 9.5-1, Section E.1, regarding power supplies.

Each PVNGS unit's power block is equipped with remote terminal concentrators (RTCs). These RTCs are powered from the PVNGS security electrical distribution system. The security electrical distribution system is fed by offsite power, as the primary source, a diesel generator, the secondary source, which starts automatically on low system voltage and a tertiary source, another diesel generator, which is auto start but manually loaded onto the security electrical system. The security electrical distribution system supplies power to the RTCs through an uninterruptible power supply and parallel circuits to each unit. The loss of a power circuit will not affect more than two RTCs, and in most cases, only one RTC. The loss of power to an RTC does not preclude actuation of the fire protection system. The loss of power to an RTC does not affect the operation of the local fire panels since these are powered separately from the essential lighting system, with battery backup for areas required to be manned for safe shutdown.

<u>QUESTION 9A.114</u> (FPER Audit Open Item No. 9) (9B.2)

Verify that a trouble condition/fire alarm signal will continue to be displayed on multiplex system display until condition is rectified.

RESPONSE: The trouble condition/fire alarm signal remains displayed on the system display until the condition is acknowledged and cleared by an operator.

QUESTION 9A.115 (FPER Audit Open Item No. 10) (9B.3)

To meet Section E.3 of BTP ASB 9.5-1, the applicant committed to equip hose stations with not more than 100 feet of fire hose. The applicant should verify that the existing hose stations will be able to protect all of the following areas with not more than 100 feet of hose:

a. Zones 21A, 21B, 22A, 22B, 24A, and 24B (formerly zones 21, 22, and 24)

b. Zones 74A and 74B (formerly zone 74)

c. Zones 37C and 37D (formerly zone 37)

RESPONSE: The PVNGS commitment to BTP APCSB 9.5-1 stipulated that no more than 100 feet of 1-1/2-inch hose would be used for interior hose stations. That commitment has been met except as discussed below:

a. Zones 21A, 21B, 22A, 22B, 24A, and 24B (formerly zones 21, 22, and 24)

Zones 23A, 23B, 24A, 24B, 25A, and 25B (formerly zones 23, 24, and 25) can be reached from hose station No. 90 (in the control building) which is provided with a 150-foot length of hose.

Additionally, APS has installed another hose station, No. 108, with 150 feet of hose in the control building near the exit to the diesel generator building. This hose is able to reach zones 21A, 21B, 22A, and 22B (formerly zones 21 and 22).

b. <u>Zones 74A and 74B (formerly zone 74)</u>

Main steam support structure (MSSS) zones 74A and 74B (formerly zone 74) can be reached throughout the 100-foot (grade) elevation and 140-foot level from standpipe and hose stations at those levels located at the northwest corner of the turbine building. These hose reels are equipped with 150 feet of 1-1/2-inch hose from hose station No. 63 (100-foot elevation) and 100 feet of 1-1/2-inch hose from hose station No. 72 (140-foot elevation). The 120-foot elevation of the MSSS is an open grating and hose streams can be directed at all areas of that level upward from the 100-foot elevation and downward from the 140-foot elevation (which is also an open grating.) The hose nozzles will reach within 30 feet of all areas of the building.

c. <u>Zones 37C and 37D (formerly zone 37)</u>

All areas of the auxiliary building zones 37C and 37D (formerly zone 37) can be reached within 30 feet by 125 feet of 1-1/2-inch hose from hose station No. 25.

d. Zone 39A, pipeway, can be reached by Hose Station No. 29 or by 150 feet of 1 1/2 inch hose from Hose Station No. 31 located in Zone 39B.

e. <u>Zone 67A</u>

Zone 67A at the 100 - foot elevation of the Containment Bldg. can be reached from hose station No. 08, which is provided with a 150 - foot length of hose.

f. Zone 67B

Zone 67B at the 140 - foot elevation of the Containment Bldg. can be reached from hose station No. 13, which is provided with a 150 - foot length of hose.

g. Zone 66A

Zone 66A at the 140 - foot elevation of the Containment Bldg. can be reached from hose station No. 14, which is provided with a 150 - foot length of hose.

h. Zone 88A

Zone 88A at the 51 foot 6 inch elevation of the Auxiliary Bldg. can be reached from hose station No. 21, which is provided with a 150 - foot length of hose.

i. Zone 88B

Zone 88B at the 51 foot 6 inch elevation of the Auxiliary Bldg. can be reached from hose station No. 22, which is provided with a 150 - foot length of hose.

j. Zone 42D

Zone 42D at the 100 - foot elevation of the Auxiliary Bldg. can be reached from hose stations No. 33 and 35, which are provided with a 150 - foot length of hose.

k. Zone 42C

Zone 42C at the 100 - foot elevation of the Auxiliary Bldg. can be reached from hose station No. 36, which is provided with a 150 - foot length of hose.

l. Zone 52D

Zone 52D at the 120 - foot elevation of the Auxiliary Bldg. can be reached from hose station No. 40, which is provided with a 150 - foot length of hose.

m. Zone 57N

Zone 57N at the 140 - foot elevation of the Auxiliary Bldg. can be reached from hose station No. 44, which is provided with a 150 - foot length of hose.

n. Zone 62L

Zone 62L at the 120 - foot elevation of the Rad Waste Bldg. can be reached from hose station No. 54, which is provided with a 150 - foot length of hose.

QUESTION 9A.116 (FPER Audit Open Item No. 11) (9B.3)

The applicant in the Fire Protection Evaluation committed to comply with Section E.1 of BTP ASB 9.5-1 concerning the design and installation of fire detection systems. We observed that fire detectors were absent from the following areas which contain safety-related equipment.

a. Condensate transfer pump room (zone 83)

b. Elevation 131 feet, diesel generator building (zones 25A and 25B [formerly zone 25])

c. Above auxiliary control cabinets (control room)

d. In computer room adjacent to the control room, within the control room complex

e. (DELETED)

f. "Dead air space" such as in zones 37C and 37D (formerly zone 37) (elevation 70 feet, auxiliary building)

g. ECW heat exchanger rooms (zone 43)

h. Charging pump rooms (zones 46A, 46B, and 46C [formerly zone 46])

i. Spray chemical accumulator room

j. Spray chemical storage tank room (zone 51B)

RESPONSE: The area listed as "g" contains no safety-related equipment susceptible to fire damage. The only safety-related component within zone 43 is the essential cooling water heat exchanger (i.e., the heat exchanger shell). No significant combustible loading is present; therefore, no detectors are required.

Area "d," the computer room adjacent to the control room, has fire detectors to detect fire and activate the Halon suppression system.

Potential dead air spaces between heavy beam ceiling supports have been previously identified and reviewed (through site walkdowns) by the detector supplier. Additional detectors were added based on air flow and configuration. The remaining "dead air spaces," noted as area "f," are not of sufficient size to cause appreciable

delays in the response of the current detector arrangement.

The train related DG air start receiver/compressor rooms are part of Fire Zones 25A and 25B (area listed as b.). The only safety related component in the room is the air start receivers. The air dryer package in each room does not provide a significant combustible load contribution. The compressor oil system is not pressurized and the oil is contained in the base of the compressor crankcase. The limited combustible loading will not result in a challenge to the integrity of the air start receivers. Therefore, no detectors are required for the DG air start receiver/compressor rooms.

To address technical specification restrictions regarding operation with only one train of safety-related equipment available, additional detectors have been added to areas labeled "a," "b," "c," "h," "i," and "j". Note: Item "i" is interpreted to be the spray chemical storage tank room (zone 51B).

See referenced zone descriptions in appendix 9B.

QUESTION 9A.117 (FPER Audit Open Item No. 12) (9B.2)

Penetration seals are not provided at bus duct penetration of fire walls.

RESPONSE: Fire-rated penetration seals have been installed.

QUESTION 9A.118 (FPER Audit Open Item No. 13) (9B.2)

The fire wall in the control room complex is not continuous.

RESPONSE: The fire walls in the control room complex generally extend from the floor slab to the ceiling. The walls near the shift manager's office, kitchen, and lavatory are rated primarily for life safety reasons and extend only to the non-combustible (less than 25 flame spread rating) acoustic tile ceiling above the exit corridor (J-312) located on the plant north side of the shift manager's office. This is one of two egress paths out of the control room. From a life safety or control room evacuation standpoint, there is another egress path available. The other function of this exit corridor ceiling, because the walls are not continuous to the concrete floor slab above at the 160 ft. elevation, would be to impede a fire originating in the adjacent rooms such as rest rooms, kitchen, and/or shift manager office, from exposing the control room cabinets and equipment. In other words, a fire would have to propagate from an adjacent room, into the plenum space above its ceiling, then back down through the exit corridor ceiling into the electrical cabinet area of the control room complex. This downward direction would not be a normal propagation path for a fire and there are not sufficient combustibles to support this propagation path. The plenum space is non-combustible construction with approximately 10 feet of vertical air space and very low combustible loading primarily consisting of a limited amount of cable trays

with IEEE-383 cable. Smoke detection is installed above the ceiling for early warning. For the above reasons, the exit corridor ceiling does not have an hourly fire resistance rating. A postulated fire of this type would have no adverse effect on the ability to achieve and maintain safe shutdown as alternate shutdown capability from the remote shutdown panel remains available outside the control room. (Refer to the response to Audit Open Item 4(2)(b) [Question 9A.109]).

QUESTION 9A.119 (FPER Audit Open Item No. 14) (9B.2)

Curbs are not provided at diesel generator rooms to contain oil spill.

RESPONSE: Each diesel engine room contains a pipe trench with a sump and two sump pumps. Each trench is approximately 21 feet long, 4 feet wide and 6 feet deep. The sumps are approximately 5 feet deep x 4 feet square (with about 48 cubic feet of usable volume above the pump low level cutoff). The floors are sloped to floor drains which run to the sumps. The total volume in the trench and sump for each room is approximately 550 cubic feet, or 4115 gallons.

Each diesel generator contains approximately 1000 gallons of oil, and each sprinkler system is designed for approximately 350 gallons per minute. Therefore, there is capacity in the sump for all the oil and approximately 9 minutes of sprinkler flow. The usual criteria for curbs

is containment of all oil plus 10 minutes of sprinkler flow.

QUESTION 9A.120 (FPER Audit Open Item No. 15) (9B.2)

Removable block walls are provided throughout the plant for equipment servicing.

RESPONSE: A typical blockout is equal to the surrounding wall thickness (exceeding 24 inches). The design requires the solid concrete blocks to be staggered, both horizontally and vertically. There are no penetrations through the blockout. This design has the equivalent fire-resistance of a 3-hour barrier.

QUESTION 9A.121 (FPER Audit Open Item No. 16) (9B.2)

Unprotected openings were observed in the following fire walls:

a. Wall separating zones 1 and 2 (control building elevation 74 feet) from adjoining pipe chase.

b. Wall opening between elevation 120 feet of the main steam support structure and the turbine building.

c. Wall opening between elevation 88 feet of the auxiliary building and radwaste building.

d. Seismic gap (both horizontal and vertical) at the containment building.

RESPONSE:

a. The openings from fire zones 1 and 2 into the pipe chase area between the control and the auxiliary buildings have been sealed to a 3-hour rating.

b. The wall openings between the MSSS and the turbine building are unsealed to allow cooling of the hot piping anchor/support attachments at the concrete structure. A compartment devoid of in situ combustibles is located between zones 74A and 74B (formerly zone 74) of the MSSS and the turbine building. Ventilation exhaust fans use this compartment as a supply plenum to pull cooling air flow over the pipe support/anchors from the turbine building and the MSSS. The air flow is away from the safety-related equipment in zones 74A and 74B.

c. The openings between the pipe chase at elevation 88 feet 0 inch of the auxiliary building and the radwaste building have been sealed to a 3-hour rating.

d. The 6-inch (nominal) gap between the auxiliary building and the containment building has been sealed so as to provide a continuous 3-hour rated boundary.

QUESTION 9A.122 (FPER Audit Open Item No. 17) (9B.2)

Fusible-link type open devices were observed on fire doors throughout the plant.

RESPONSE: The fusible-link, hold-open devices on swinging type (hinged) fire doors have been removed. Verification of the position of the doors in rated fire barriers will be performed in accordance with section 13.5.

QUESTION 9A.123 (FPER Audit Open Item No. 18) (9B.2)

A PVC drain pipe was observed to penetrate a fire-rated floor assembly.

RESPONSE: Chlorinated polyvinyl chloride (CPVC) piping is used as vent piping from the battery room acid drain neutralizing pit. The vent piping does not penetrate boundaries separating trains A and B. Accordingly, adequate separation is provided. The small pipe opening is exposed to the essential chiller room elevation 74 feet, which is the room below the PVC pipe opening. The essential chiller rooms (zones 1 and 2) have a 26-foot ceiling height and the total combustible (fire) loading is categorized as low, consisting of charcoal contained in metal filter units. The calculated fire severity is very conservative since it provides an allowance for transient charcoal sufficient to refill the filter. This exposure is light and does not present a significant danger of fire spread between these zones and the zones above, which are in the same train. Smoke detection is provided, and manual fixed suppression is provided for the charcoal filters.

The vent piping also penetrates the nominal 8-inch thick, 3 hour rated concrete block walls between fire zones 6A

(DC Equipment Room C), 8A (Battery Room C) and 9A (Battery Room A), all in the same train (A) at approximate elevation 108 feet. The configuration is similar but involves only one wall for the Train B side between zones 8B and 9B (battery rooms) at approximate elevation 113 feet. The penetrations are located between column lines J1-J3 and JB-JD. The zones have a 20 foot ceiling height. The DC Equipment Room, Zone 6A has a moderate combustible (fire) loading consisting primarily of fire resistant IEEE 383-rated cable. The Battery Rooms, Zones 8A, 9A, 8B and 9B have a combustible (fire) loading classed as low, consisting almost entirely of thermoplastic battery casings. Smoke and heat detection is provided. Primary suppression for the battery rooms is automatic CO_2 total flooding; therefore, a fire would be automatically detected and suppressed in its early stages. With the automatic detection and suppression provided and the readily accessible location at the 100-foot level, prompt fire department response would also be expected, to manually extinguish the fire and prevent spread to adjacent fire zones. The vent pipes are located at approximately 8 to 13 feet above the floor and are in the corners of the rooms several feet away from combustibles which could potentially result in direct flame exposure and approximately 7 to 12 feet below the ceiling where heat from a fire would accumulate; therefore damage to equipment in the adjacent zone (same train) would not be expected to occur before either automatic or manual suppression is accomplished to prevent it. The

penetrations are all in fire barriers located within the same train. Barriers separating redundant safe shutdown equipment do not contain CPVC pipe penetrations. Therefore, the arrangement will have no adverse effect on the ability to achieve and maintain safe shutdown of the plant.

QUESTION 9A.124 (FPER Audit Open Item No. 19) (9B.3)

To meet Section E.3 of BTP ASB 9.5-1, the applicant committed to provide automatic sprinkler protection for the following areas. We noticed that sprinklers were missing in these areas which is contrary to the commitment:

a. Elevation 140 feet, main steam support structure (zones 74A and 74B [formerly zone 74])

b. Auxiliary building, elevation 51 feet 6 inches (zones 30A, 30B, 32A, and 32B [formerly zones 30 and 32]) (partial system).

RESPONSE:

a. The sprinkler system for the main steam support structure at elevation 140 feet has been installed both above and below elevation 140 feet to service all of zones 74A and 74B.

b. The sprinkler system for the LPSI and containment spray pump rooms has the sprinkler nozzles located below the grating in the center of the room and none on the ceiling. The combustible loading for any of the compartments during normal plant operations will

be well below a value that would challenge the integrity of the 3-hr fire rated barriers. The installation has been approved by the insurers. Per Paragraph 4-1.2 of NFPA 13-1976, a partial installation may be approved by the authorities having jurisdiction. The present design is adequate. The sprinkler system is part of the original plant design and is not required to meet BTP APCSB 9.5-1 or 10CFR50, Appendix R. The pumps are surrounded by 3-hour fire barriers.

<u>QUESTION 9A.125</u> (FPER Audit Open Item No. 20) (9B.2)

In Amendment 3 to the Fire Protection Evaluation, the applicant committed to provide 8-hour, battery-powered emergency lighting units in all areas needed for operation of safe shutdown equipment. We noticed that an emergency light was not installed in the ECW pump room (zones 34A and 34B [formerly zone 34]) which is contrary to that commitment.

RESPONSE: Zones 34A and 34B (formerly zone 34) do not have safe shutdown equipment that requires operator manual action in the event of a fire. Therefore, 8-hour emergency lighting is not required to be installed in these zones. However, 1-1/2 hour emergency lighting is provided in zones 34A and 34B.

<u>QUESTION 9A.126</u> (FPER Audit Open Item No. 21) (9B.1)

In Amendment 3 to the Fire Protection Evaluation, the applicant committed to comply with Section III.0 of Appendix R concerning

an oil collection system for the reactor coolant pumps. We were concerned that the piping, oil collection tank, and protection for the lift pumps would not collect oil leakage after a safe shutdown earthquake. The applicant agreed to respond to our concern by providing design details of the system.

RESPONSE: The pressurized[a] and unpressurized portions of reactor coolant pump (RCP) lube oil system (for pump and motor) have been analyzed to determine whether or not the components would survive an SSE without pressurized spray or leakage. Based upon that analysis, various mechanical joints (e.g., flanges), RTD connections, and sight glasses in the unpressurized section were identified as potential leakage paths. Piping and welded joints within the pressurized section were determined to remain intact. The lift pump discharge connection flange is considered subject to failure and is housed within a light weight silicon-treated, glass cloth shroud attached to the top of the lube oil reservoir. The shroud provides an envelope for the oil spray, and serves to collect and direct the oil to the collection system like any other oil leakage. The light weight shroud is attached to the lube oil reservoir by multiple fasteners on each side of the reservoir to assure it will remain functional for a SSE.

a. The external portions of the RCP lube oil system that can be considered pressurized are normally operated for about 30 minutes prior to starting the RCP and 30 minutes during the RCP shutdown sequence. The system may be periodically pressurized to replenish the RCP thrust bearing with recovered oil from leaking oil seals. The lift pump is normally secured. All other pressurized portions of the system are internal to the pump and motor.

The shroud will be inspected every refueling outage and as part of the fire protection test program.

To collect any leakage from the postulated leakage points, the criteria given in Section III.0 of 10CFR50, Appendix R, were applied. Postulated leakage points are provided with open "cans", catch trays, or enclosed in shields. These devices drain by gravity to a piping system. The interface point between the RCP collection devices and the piping system is an open funnel. The piping system drains by gravity to two collection tanks. Each tank can contain all the oil from two RCPs, plus 10%, and is equipped with a flame arrestor and sight glass. The tanks are located below the RCPs, and are not near any ignition sources. No flanges are provided in the collection piping, except at the collection tanks.

In addition to collecting devices, some modifications were made to eliminate leakage points by seal welding threaded joints or removing flanges and replacing the flange by a welded connection. Part of the collection system within the pump housing utilizes compression-type tube fittings. (As the drain system is not pressurized, compression-type fittings are justified for this application.)

<u>QUESTION 9A.127</u> (FPER Audit Open Item No. 22) (9B.2)

The applicant should commit to the reapplication of fire-proofing to all sections of structural steel that have lost the original fireproofing due to construction activities.

RESPONSE: We commit to the reapplication of fireproofing to all sections of structural steel that have lost the original fireproofing due to construction activities.

QUESTION 9A.128 (FPER Audit Open Item No. 23) (9B.3)

To comply with Section E.1 of BTP ASB 9.5-1, the applicant should clarify which fire alarm/detection circuits are Class A and Class B.

RESPONSE:

Plant Areas Protected by Detection Only

All wiring from the detectors to the local fire panels is Class A. All wiring from the local fire panels to the security system is Class B. The security system is Class A.

Plant Areas Protected by Water Suppression or CO_2

The initiating device circuits for the CO_2 systems protecting ESF switchgear rooms and battery rooms are Class B from the detectors to the local fire panel and from the fire panel to the security system remote terminal concentrator. However, there are two independent detection zones (circuits) serving each of these rooms. They are cross-zoned for actuation of the CO_2 system. If one zone experienced a trouble condition, operations personnel would be dispatched to investigate. The other zone would still be able to transmit a fire alarm signal to the control room. If a fire condition existed, the CO_2 system could be manually initiated to extinguish the fire

from just outside the switchgear room. Since the switchgear and battery rooms are located in the control building, immediate response would be anticipated. The redundant trains and separate rooms are surrounded by 3-hour fire barriers. Portable extinguishers and manual hose stations equipped with Class C nozzles are also provided. Therefore, the installed detection and suppression systems meet the BTP APCSB 9.5-1, Appendix A, "Guidelines for Specific Plant Areas", Item D.5 and D.7 switchgear and station battery rooms. In addition, the cable trays in the switchgear rooms are adequately protected as described above against a potential fire which might develop. In summary, failure of one detection zone will not prevent a fire alarm to the control room. Failure of the Class B circuit from the local control panel to the remote terminal concentrator will not prevent automatic actuation of the CO_2 suppression system.

The following water suppression systems are wired Class B from the detectors to the local fire panel, and Class A from the local fire panel to the security system. The signals that are wired Class A are the ac power on, water flow, alarm, and trouble. In case of a wet pipe system, only the water flow switch is Class A.

1. Fuel building railroad bay, elevation 100 feet, zone 27

2. Upper cable spreading room, elevation 160 feet of control building, zone 20

3. Lower cable spreading room, elevation 120 feet of control building, zone 14
4. Diesel generator rooms A and B, elevation 100 feet, zones 21A and 21B (formerly zone 21)
5. Diesel generator fuel oil day tank rooms, elevation 131 feet, zones 23A and 23B (formerly zone 23)
6. Auxiliary building systems, elevation 100 feet, zones 42C, 42D, 46A, 46B, and 46C (formerly zone 46)
7. Electrical penetration rooms, C and B, elevation 100 feet, zones 42A and 42B
8. Electrical penetration rooms, A and D, elevation 120 feet, zones 47A and 47B
9. Auxiliary building systems, elevation 120 feet, zones 52A and 52D
10. Dead space compartments A and B. Areas between control building and auxiliary building elevation 100 feet and 120 feet (zones 86A and 86B).
11. Turbine-driven auxiliary feed pump, elevation 80 feet of MSSS, zone 72
12. MSSS, zones 74A and 74B (formerly zone 74), elevation 100 feet, 120 feet, and 140 feet. (Note: This system is wired such that it utilizes a detection only signal to actuate the water suppression system.)

Fire Pump House

The diesel fire pumps have Class A circuits for indicating "pump running" to the control room. Indication "system

failure," including "controller not in Auto," is Class B. The Class A circuits for the motor-driven fire pump are "motor running" and "loss of power."

QUESTION 9A.129 (Audit Open Item No. 24) (9B.3)

To comply with Section B.5 of BTP ASB 9.5-1, the applicant should develop a procedure to restrict the use of the emergency radio communications frequency to authorized personnel. In addition, the applicant should clarify the need to use a fixed repeater and to commit to protect it from damage if one is installed.

RESPONSE: Emergency radio communications at PVNGS are accomplished on the plant two-way radio system. Refer to UFSAR section 9.5.2.2.1.6 for a description of the radio system. Because the system employs trunking repeater technology, there is no single frequency reserved for emergency radio communications. The system has a total of seven repeaters and therefore seven different frequency pairs. At any given time, one of the repeaters will be handling the radio system control channel function and the remaining six will be serving as talk channels. A particular radio conversation may occur on any one of the six talk channel frequency pairs regardless of whether it is a routine communication or an emergency communication. Talk channel repeaters are automatically assigned by the system to handle both private and "talkgroup" radio conversations. A talkgroup essentially defines a particular set of user radios (e.g., all of the fire department radios or all of the security force radios).

Each of the system's portable, mobile, and fixed radio transceivers has been preprogrammed to permit affiliation with one or more PVNGS talkgroups. The programmed talkgroups can be selected one at a time using the transceiver's mode selector switch. Talkgroup radio conversations occur between radios which are set to the same talkgroup. When one of the radios in a talkgroup is keyed to begin a conversation, the system responds by assigning a talk channel repeater to the talkgroup if one is available. The talkgroup retains sole use of the assigned repeater for the duration of the conversation or until a sufficiently long gap occurs between transmissions. At the end of the conversation, the talk channel repeater becomes available for other conversations. Talk channel repeater assignments are made on a "first come, first served" basis until all six talk channel repeaters are in use. When all six talk channel repeaters are busy, additional requests for a talk channel are prioritized, based on the function of the talkgroup selected on the requesting radio, and placed in a queue in the radio system memory. When one of the six active talkgroup conversations ends, the associated talk channel repeater is released, and the queued requests are processed in accordance with talkgroup priority to reassign the newly available repeater to a new talkgroup conversation.

The portable, mobile, and fixed radio transceivers used by the PVNGS fire and operations departments have preprogrammed talkgroups which are used exclusively by

those organizations for fire department communications and safe shutdown communications. The portable, mobile, and fixed radio transceivers used by the PVNGS security force has pre-programmed talkgroups which are used exclusively by that organization for security communications. These emergency talkgroups are not available on radios used by other PVNGS departments. Consequently, use of the emergency talkgroups by unauthorized personnel is not an issue. The radio system priority levels which have been assigned to the PVNGS fire department, operations department, and security force radio talkgroups guarantee that these emergency response organizations will experience little or no delay in acquiring an open talk channel when needed.

The use of PVNGS fire department emergency talkgroups during fires and other emergencies is controlled under the Fire Response Procedure.

The radio system uses multiple repeaters, redundant site central controllers, redundant ac power supplies, and battery-backed uninterruptible power supplies (UPSs) to enhance the ability of the system to withstand equipment failures, power failures, fires, and other damage.

QUESTION 9A.130 (FPER Audit Open Item No. 25) (9B.1)

In Amendment 3 to the Fire Protection Evaluation, the applicant proposed to utilize administrative controls to prevent fire damage to redundant shutdown division inside containment.

Administrative controls alone are insufficient to justify an exemption from the Appendix R requirements for protection of

redundant safe shutdown systems in containment. The applicant should provide the technical requirements in Section III.G.2 for inside containment to provide reasonable assurance that one train of equipment will be free of fire damage.

RESPONSE: APS has reviewed the separation of safe shutdown components within containment. Fire protection is based primarily on adequate separation between redundant equipment or alternate paths to accomplish a safety function when equipment is not totally redundant. Smoke detectors, portable fire extinguishers and manual hose stations are provided as described in section 9B.2. Administrative controls for transient combustibles, however effective, are not assumed to eliminate the possibility of all postulated fires.

With the current design (backfit to provide a radiant energy shield[a] for the train A pressurizer auxiliary spray circuitry from the train B circuitry) PVNGS meets 10CFR50, Appendix R, Section III.G.2, separation criteria with the exception that there are some intervening combustibles consisting of insulated cable with intermittent installations of Thermo-Lag 330-1 material.

a. The radiant energy shield for the train A pressurizer auxiliary spray valve and circuitry consists of metallic reflectorized insulation to protect the valve body and Thermo-Lag 330-1 insulation to protect the valve's circuitry. The Thermo-Lag 330-1 insulation is provided on the Train A raceway until at least 20 feet of separation is provided between this raceway and the redundant, Train B raceway. Beyond the Train A raceway section that is protected by Thermo-Lag 330-1, the raceway is located such that the concrete pressurizer shield walls provide additional radiant energy shielding between the two redundant trains.

At a minimum, intervening cable is IEEE-383 qualified. (Tests conducted by Electric Power Research Institute indicate that flame spread in a horizontal tray would be less than in a vertical tray). Vertical cable trays exist within containment but they do not transit between redundant safe shutdown trains. Thermo-Lag 330-1 is also used in various location inside the containment building. This material, however, does not represent a more easily ignited combustible than the cables. The Thermo-Lag 330-1 installations are, in most cases, less than four feet in length along the cable trays. The minimum horizontal cable tray distance for a fire to spread between redundant trains is 50 feet, as in the pressurizer auxiliary spray circuitry. In this case, it is a stack of two trays. Table 9A-1 (formerly FPER Table A-2) itemizes the extent of horizontal cable tray lengths between trains.

Also, the containment building height will dissipate heat from any fire exposing the cable trays as opposed to fire in a confined space or small room, thus further reducing the potential for flame spread.

APS requests approval for deviation from the technical provisions of Appendix A of BTP APCSB 9.5-1 and from Appendix R, Section III.G.2, of 10CFR50 for the intervening combustibles listed in table 9A-1 (formerly FPER Table A-2) because:

1. The cable and Thermo-Lag 330-1 material are limited in quantity.

2. The cable and Thermo-Lag 330-1 material are fire-resistant and demonstrate limited flame spread.

3. The minimum horizontal cable tray distance for a fire to spread between redundant trains is in excess of 20 feet, and ranges from 50 feet to 166 feet.

4. The space is not confined, thus allowing heat to dissipate.

For these reasons, a postulated fire will not affect both redundant safe shutdown trains.

10CFR50, Appendix R, Section III.G.2.f requires separation of cables and equipment and associated non-safety circuits of redundant trains by a non-combustible radiant energy heat shield (RES). The RES protecting the Train A pressurizer auxiliary spray valve and associated circuits deviates from this requirement in that Thermo-Lag 330-1, which has been determined to be combustible, is utilized as part of the RES. Testing has shown that Thermo-Lag is a combustible material with an ignition temperature of approximately 1000°F. APS meets this Appendix R requirement based on qualitative and independent quantitative engineering analyses that demonstrate that the RES for the Train A pressurizer auxiliary spray valve will not be exposed to temperatures in excess of 1000°F. Therefore, the RES as designed and installed meets the intent of 10CFR50, Appendix R, which is to ensure that the ability to achieve and maintain safe shutdown in the event of a postulated fire is maintained.

The Appendix R Safe Shutdown Analysis assumes that for fires inside containment, specifically Fire Zones 65 (pressurizer cubicle) and 67A (general area, northwest containment), the Train B pressurizer auxiliary spray valve will be disabled. The Train A auxiliary spray valve will remain operable since the valve and associated circuits are protected with a RES which is comprised of Thermo-Lag 330-1 and metallic reflectorized insulation. A description of the fire zones and the physical location of the RES is described below.

The Train A auxiliary spray valve is located above the pressurizer, in the pressurizer cubicle, at approximately the 154 ft. elevation. The valve has flex conduit running east from the valve to the east wall of the cubicle where the raceway enters a junction box. A rigid conduit from the junction box runs to the north wall where it turns west and runs for an additional two feet. The conduit then exits the cubicle through the north wall in an embedded conduit. The valve and this portion of the valve's circuit are located in Fire Zone 65. Metallic reflectorized insulation is provided for the valve body as part of the RES. This insulation has been previously approved for use as a RES. The entire circuit in the pressurizer cubicle (Fire Zone 65) is enclosed with a Thermo-Lag 330-1 RES, with the exception of the solenoid actuator, which is mounted above the valve body.

Once the circuit exits the north wall of the pressurizer cubicle, it enters Fire Zone 67A. The north wall of the pressurizer cubicle defines the southern boundary for this

fire zone. The Thermo-Lag 330-1 enclosed conduit exits the pressurizer cubicle at approximately the 154 ft. elevation, runs vertically down the north side of the north wall of the pressurizer cubicle, through two junction boxes, to the 138 ft. elevation. The conduit then turns west and runs horizontally along the north wall of the pressurizer cubicle until the wall turns south. The conduit runs south along the wall, where the RES ends after approximately five feet. The unprotected circuit continues on to the containment electrical penetration, where it exits the containment building.

The following fire mitigation features assure that the RES will not be subjected to temperatures in excess of 1000°F, thereby preventing ignition of the RES:

a) <u>Low Fire Loading</u> - the fire loading in both of the affected fire zones is low. The resultant postulated fire size is so small that the RES would not be exposed to temperatures that would be sufficient to cause combustion of the RES. In addition, the spatial separation between the RES and the fixed combustibles is such that any credible fire would not expose the RES to temperatures in excess of 1000°F.

b) Fire Protection Features - the existing fire protection features in, or near, these fire zones include smoke detectors at the ceiling level, line-type heat detectors in the cable trays, manual hose stations, portable fire extinguishers* and reinforced concrete walls.

c) Fixed Ignition Sources - the lack of fixed ignition sources in both fire zones is such that a fire due to these sources is highly unlikely.

d) Transient Combustible and Ignition Source Administrative Controls - the procedural restrictions for transient combustibles and/or transient ignition sources in either fire zone while the unit is in Modes 1, 2, 3 or 4 ensures that a fire due to these sources is highly unlikely.

e) Ventilation Features and Ceiling Height - these features ensure that a hot gas layer will not form from any postulated fire.

f) Independent Quantification of Potential Fire Effects on the RES - credible fires due to fixed combustibles in the subject fire zones and the resultant exposure to the RES has been evaluated in Engineering Study 13-CS-A12. This study has determined that the RES would not be subjected to temperatures in excess of 1000°F during a postulated fire.

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*The portable fire extinguishers are removed from containment in Modes 1-4, but would be brought into containment by the Fire Department on an as-needed basis in the event of a fire in containment.

g) Emergency Response Capability - APS maintains a dedicated, on-site, professional Fire Department to respond to fire emergencies.

In summary, the qualitative and quantitative analyses described above demonstrate the acceptability of using Thermo-Lag as the RES for the Train A pressurizer auxiliary spray valve and associated circuits. The design and programmatic fire protection features ensure that the RES would not be exposed to temperatures such that combustion of the RES material would occur in the event of any credible fire. Therefore, the ability to achieve and maintain safe shutdown conditions would not be impacted by any postulated fire scenario. The RES, as designed, meets the intent of 10CFR50, Appendix R, Section III.G.2.f.

Table 9A-1

CABLE TRAY LENGTHS BETWEEN TRAINS

Safe Shutdown Function	Minimum Continuous Cable Tray Span Between Trains (feet)	Quantity of Intervening Combustible Material
Pressurizer pressure Pressurizer level	67	1 tray stack with 5 trays and intermittent installations of Thermo-Lag 330-1 material
Shutdown cooling isolation	80	1 tray stack with 2 trays and intermittent installations of Thermo-Lag 330-1 material
RCS hot leg and cold leg temperature	166	1 tray stack with 4 trays and intermittent installations of Thermo-Lag 330-1 material
Steam generator pressure Steam generator level	140[a]	1 tray stack with 2 trays and intermittent installations of Thermo-Lag 330-1 material
Pressurizer auxiliary spray	50	1 tray stack with 2 trays and intermittent installations of Thermo-Lag 330-1 material

a. Only one steam generator is required to achieve shutdown.

QUESTION 9A.131 (FPER Audit Open Item No. 26) (9B.2)

The applicant should document in the Fire Protection Evaluation the fire hazards analysis for the corridor areas on elevation 40 feet and 51 feet 6 inches of auxiliary building.

RESPONSE: Engineering drawing 13-A-ZYD-023 (formerly FPER Figures 11 and 12) have been revised to show new zones 87A, 87B, 88A, and 88B. These new zones are documented in section 9B.2 in the manner of other identified fire zones.

QUESTION 9A.132 (FPER Audit Open Item No. 27) (9B.2)

The applicant should protect the propane piping in the corridor on elevation 140 feet of the auxiliary building so as not to be subject to damage from corridor traffic.

RESPONSE: The propane line at elevation 140 feet has been rerouted to be above the structural framework of the drop ceiling so as to be protected from impact from personnel transiting through the corridor.

Note: Propane is no longer used, but the piping is still in use for other gasses and remains routed above the drop ceiling.

QUESTION 9A.133 (FPER Audit Open Item No. 28) (9B.2)

The applicant should assess the need for forced ventilation in the flammable gas storage room in elevation 140 feet of the auxiliary building.

RESPONSE: Ventilation for flammable gas storage, per the guidance contained in NFPA 51 (1974), Paragraph 22, (fuel gas cylinder storage) has been provided.

QUESTION 9A.134 (NRC Request for Additional Information, RSB)[a] (9.3.4)

By letter (NRC to C-E) dated March 27, 1984, the staff expressed concern related to the availability of the auxiliary pressurizer spray (APS) system to perform its required safety functions for CESSAR System 80 plants (Palo Verde, WNP-3) which are designed without PORVs. As noted in the subject letter, the staff considers that the CESSAR System 80 APS should be treated as safety-related in accordance with Appendix A to 10CFR50 and 10CFR100 since it is required for safe shutdown of the plant and to mitigate the consequences of a SGTR accident should the main pressurizer spray system become unavailable. APS flow is initiated from the control room by opening at least one of the redundant (parallel) auxiliary spray valves (CH-203 or CH-205) in combination with the closure of the existing loop charging valve (CH-240). The staff expressed concern that a failure of CH-240 to close would negate the safety function of the APS system.

After being informed of the staff's concern, C-E committed (September 18, 1984 letter) to modify CESSAR System 80 to provide a valve in series with the existing loop charging valve (CH-240). However, discussions with C-E revealed that CH-240 and the new series valve would be powered from non-Class 1E

a. Letter from G. W. Knighton, NRC, to E. E. Van Brunt, Jr., APS, dated December 13, 1984.

buses even though the valves are considered to be safety-related. The staff finds this unacceptable since these valves are required to perform a safety function as discussed above and no analysis has been provided to justify the use of nonsafety-related buses to provide power for operation of the subject valves. It should be noted that Branch Technical Position RSB 5-1 states that suitable redundancy should be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

It is the staff's position that if equipment (pumps, valves) is required to perform a safety-related function, the mechanical and electrical components including any associated electrical power source should be treated as safety-related and implemented as such. Thus, the existing loop charging valve (CH-240) and the additional series valve used to isolate normal charging flow should satisfy the single failure criterion and should not be dependent on the use of nonsafety-related equipment including power supplies. Specifically, each valve should be powered from a separate, electrically independent Class 1E power source, or the use of non-Class 1E power to the valves should be justified on some other defined basis.

It is the staff's understanding that the Palo Verde (first CESSAR System 80 reference plant) applicant has elected to implement C-E's proposed design and intends to power the series loop charging valves from nonsafety-related power buses. Although it is recognized that these valves will fail closed on

loss of power, information provided to date is insufficient to determine that all possible failures or design basis events will result in a fail-safe (closed) condition. Therefore, a failure modes and effects analysis should be performed by the Palo Verde applicant to show that the capability of the subject valves to perform the intended protective functions cannot be degraded below an acceptable level as a result of all possible circumstances (i.e., low voltage, low frequency, design basis events, etc.) associated with the offsite power supply system and its associated non-Class 1E buses. Alternately, the staff will consider the implementation of Class 1E electrical protective devices within the non-Class 1E power system as a means to assure that the capability of the valves to perform the intended safety functions is not degraded below an acceptable level. The applicant should provide for staff review information to describe the results of the required analysis and any non-Class 1E power supply system design changes that may be proposed as a result of the analysis.

RESPONSE: CH-240 and the new series valve (CH-239) are to be powered from non-Class 1E buses. These valves will fail closed on loss of power.

The concern specifically addresses insufficient information to determine that all possible failures or design basis events associated with the offsite power supply system and its associated non-Class 1E buses, will result in a fail-safe (closed) condition such that the protective functions are performed.

The failure modes and effects analysis (FMEA) provided as table 9A-2 examines the non-Class 1E dc power system that isolates the control solenoids for loop isolation valves CHE-239 and CHE-240. It demonstrates that there is no credible event that could prevent the delivery of auxiliary pressurizer spray. The analysis considered loss of power, grounding, short circuiting, overvoltage, undervoltage, loss of air, and a seismic event. Due to spatial separation, a pipe break or a fire cannot defeat the ability of the system to close. Refer to the PVNGS fire hazards analysis in appendix 9B and the PVNGS spurious actuation analysis submitted by ANPP-31101, dated November 13, 1984.

Auxiliary pressurizer spray has no safety function during a LOCA, and, consequently, LOCA effects were not analyzed.

However, due to the NRC's concern, Class 1E overvoltage protection isolation relays will be added to the non-Class 1E control circuitry for valves CHE-PDY-239B and CHE-PDY-240B. This plant modification will be complete prior to restart following the first refueling outage of PVNGS Unit 1, prior to exceeding 5% power for PVNGS Unit 2, and prior to fuel load for PVNGS Unit 3.

TABLE 9A-2

AUXILIARY PRESSURIZER SPRAY POWER SUPPLIES (Sheet 1 of 9)

Failure Modes and Effects Analysis				
Component Name	Component Function	Failure Mode	Effect On Subsystem	Effect on System
Unit Auxiliary Transformer (13-E-MAA-002) and ac Electrical Distribution System	Supply 480V power to the non-Class 1E battery chargers	Loss of power	Loss of power to battery chargers	No effect for approximately 2 hours. The battery provides power to the dc bus. After 2 hours, bus voltage drops and power is lost to the distribution panel.
		Overvoltage	None, battery chargers provide regulation	None
		Undervoltage	None, battery chargers provide regulation	None
Battery Charger and Associated Circuit Breakers[(f)]	Supplies power to the non-Class 1E bus	Fail to provide dc power to bus	Battery begins to discharge to supply loads if swing battery charger unavailable	No effect for approximately 2 hours. The battery provides power to the dc bus. After 2 hours, but voltage drops and power is lost to the distribution panel.
Swing Battery Charger	Supplies power to the non-Class 1E bus	Fails to provide dc power to bus	None, two normal battery chargers supply dc power	None

TABLE 9A-2

AUXILIARY PRESSURIZER SPRAY POWER SUPPLIES (Sheet 2 of 9)

Failure Modes and Effects Analysis				
Component Name	Component Function	Failure Mode	Effect On Subsystem	Effect on System
Battery (E-NKN-F17) (13-E-NKA-001)	Supplies power to the non-Class 1E bus	Fails to provide dc power	Loss of standby power to the bus	No effect. The batteries serve as the source of standby power to the bus. The charger provides the dc power under normal conditions
DC Bus (E-NKN-M45) (13-E-NKA-001)	Distributes power to the non-Class 1E bus	Fault	Loss of dc power to distribution panel	Valves CHE-239 and CHE-240 close, enabling auxiliary pres-surizer spray
		Undervoltage	No effect until voltage drops below dropout voltage of CHE-PDY-240B and CHE-PDY-239B, then solenoids close	Valves CHE-240 and CHE-239 close after voltage drops below dropout voltage, enabling auxiliary pressurizer spray
Distribution Panel Feeder Circuit Breaker (NC) (13-E-NKA-001)	Provides pro-tection in case of fault and provides power during normal conditions	Fails open	Loss of dc power to distribution panel	Valves CHE-239 and CHE-240 close, enabling auxiliary pressurizer spray

TABLE 9A-2

AUXILIARY PRESSURIZER SPRAY POWER SUPPLIES (Sheet 3 of 9)

Failure Modes and Effects Analysis				
Component Name	Component Function	Failure Mode	Effect On Subsystem	Effect on System
Distribution Panel dc Bus (13-E-NKA-004)	Distributes power to the non-Class 1E loads	Fault	Loss of dc power to distribution panel	Valves CHE-239 and CHE-240 close, enabling auxiliary pressurizer spray
Distribution Panel Circuit Breaker D42-16 (13-E-NKA-004)	Provides protection in case of fault and provides power during normal conditions	Fails open	Loss of dc power to auxiliary relay cabinet	Valve CHE-239 and CHE-240 close, enabling auxiliary pressurizer spray
Disconnect Switch DS-16-10 (13-E-CHB-052)	Provides isolation for maintenance and provides power during normal conditions	Fails open	Loss of dc power to CHE-PDY-240B	Valve CHE-240 closes, enabling auxiliary pressurizer spray
Disconnect Switch DS-16-14 (13-E-CHB- 073)	Provides isolation for maintenance and provides power during normal conditions	Fails open	Loss of dc power to CHE-PDY-239B	Valve CHE-239 closes, enabling auxiliary pressurizer spray

TABLE 9A-2

AUXILIARY PRESSURIZER SPRAY POWER SUPPLIES (Sheet 4 of 9)

Failure Modes and Effects Analysis				
Component Name	Component Function	Failure Mode	Effect On Subsystem	Effect on System
Fuse CHF-51 (13-E-CHB-052)	Provides protection in case of fault land provides power during normal conditions	Fails open	Loss of dc power to CHE-PDY-240B	Valve CHE-240 closes, enabling auxiliary pressurizer spray
Fuse CHF-73 (13-E-CHB-073)	Provides protection in case of fault and provides power during normal conditions	Fails open	Loss of dc power to CHE-PDY-239B	Valve CHE-239 closes, enabling auxiliary pressurizer spray
Cable (Schemes RC and RE) (13-E-CHB-052)	Provides power	Open circuit	Loss of dc power to CHE-PDY-240B	Valve CHE-240 closes, enabling auxiliary pressurizer spray
		Ground Fault	Generate dc power to ground alarm	None
		Cable conductor short	Indicator light failure[(a)]	None
Cable (Schemes RC and RD) (13-E-CHB-073)	Provides power	Open circuit	Loss of dc power to CHE-PDY-239B	Valve CHE-239 closes, enabling auxiliary pressurizer spray pressurizer spray

TABLE 9A-2

AUXILIARY PRESSURIZER SPRAY POWER SUPPLIES (Sheet 5 of 9)

Failure Modes and Effects Analysis

Component Name	Component Function	Failure Mode	Effect On Subsystem	Effect on System
		Ground fault	Generate dc power to ground alarm	None
		Cable conductor short	Indicator light failure[a]	None
Cable (Schemes RB and RD for CHE-240 and RG and RH for CHE-239) (13-E-CHB-052) and 13-E-CHB-073	Provides power	Open circuit	Loss of indicator lights	None
		Ground fault	Generate ground alarm	None
		Cable conductor short	Incorrect indicator light[b]	None
Cable (Scheme RA) (13-E-CHB-052)	Provides power	Open circuit	Loss of dc power to CHE-PDY-240B	Valve CHE-240 closes, enabling auxiliary pressurizer spray
		Ground fault	Generate dc power to ground alarm	None
		Cable conductor short	Loss of dc power to CHE-PDY-240B[c]	Valve CHE-240 closes, enabling auxiliary pressurizer spray
Cable (Scheme RA) (13-E-CHB-073)	Provides power	Open circuit	Loss of dc power to CHE-PDY-239B	Valve CHE-239 closes, enabling auxiliary pressurizer spray

TABLE 9A-2

AUXILIARY PRESSURIZER SPRAY POWER SUPPLIES (Sheet 6 of 9)

Failure Modes and Effects Analysis				
Component Name	Component Function	Failure Mode	Effect On Subsystem	Effect on System
		Ground fault	Generate dc power to ground alarm	None
		Cable con-ductor short	Loss of power to CHE-PDY-239B[c]	Valve CHE-239 closes, enabling auxiliary pressurizer spray
Cable (Schemes RF) (13-E-CHB-052)	Provides power	Open circuit	Loss of dc power to CHE-PDY-240B	Valve CHE-240 closes, enabling auxiliary pressurizer spray
		Ground fault	Generate dc power to ground alarm	None
		Cable con-ductor short	DC power provided to CHE-PDY-240B[d]	Valve CHE-240 opens, disabling auxiliary pressurizer spray if CHE-239 is open; otherwise no effect[e]
Cable (Scheme RE) (13-E-CHB-073)	Provides power	Open circuit	Loss of dc power to CHE-PDY-239B	Valve CHE-239 closes, enabling auxiliary pressurizer spray
		Ground fault	Generate dc power to ground alarm	None
		Cable con-ductor short	DC power provided to CHE-PDY-239B[d]	Valve CHE-239 opens, disabling pressurizer spray if CHE-240 is open; otherwise no effect[e]

TABLE 9A-2

AUXILIARY PRESSURIZER SPRAY POWER SUPPLIES (Sheet 7 of 9)

Failure Modes and Effects Analysis				
Component Name	Component Function	Failure Mode	Effect On Subsystem	Effect on System
Switch (HS-240) (13-E-CHB-052)	Provides power or provides isolation	Opens	Loss of dc power to CHE-PDY-240B	Valve CHE-240 closes, enabling auxiliary pressurizer spray
		Closes	DC power provided to CHE-PDY-240B	Valve CHE-240 opens, disabling auxiliary pressurizer spray if CHE-239 is open; otherwise no effects[e]
Switch (HS-239) (13-E-CHB-073)	Provides power or provides isolation	Opens	Loss of dc power to CHE-PDY-239B	Valve CHE-239 closes, enabling auxiliary pressurizer spray
		Closes	DC power provided to CHE-PDY-239B	Valve CHE-239 opens, disabling auxiliary pressurizer spray if CHE-240 is open; otherwise no effect[e]
Solenoid (CHE-PDY-240B) (13-E-CHB-052)	Provides air to CHE-240	Opens	Air provided to CHE-240	Valve CHE-240 opens, disabling auxiliary pressurizer spray if CHE-239 is open; otherwise no effect[e]
		Closes	Loss of air to CHE-240	Valve CHE-240 closes, enabling auxiliary pressurizer spray

TABLE 9A-2

AUXILIARY PRESSURIZER SPRAY POWER SUPPLIES (Sheet 8 of 9)

Failure Modes and Effects Analysis				
Component Name	Component Function	Failure Mode	Effect On Subsystem	Effect on System
Solenoid (CHE-PDY-239B) (13-E-CHB-073)	Provides air to CHE-239	Opens	Air provided to CHE-239	Valve CHE-239 opens, disabling auxiliary pressurizer spray if CHE-240 is open; otherwise no effect[e]
		Closes	Loss of air to CHE-239	Valve CHE-239 closes, enabling auxiliary pressurizer spray
Air Supply	Supply air to CHE-240 and CHE-239	Loss of air	Loss of air to CHE-240 and CHE-239	Valves CHE-240 and CHE-239 close, enabling pressurizer spray

Footnotes

a. The red and green indicator lamps have GE 756 bulbs which are rated at 0.08 amps at 14 volts, corresponding to 175 ohms. Since two bulbs are connected in parallel, 88 ohms will be used. The voltage dropping resistors provide an additional 675 ohms, so the total circuit resistance is approximately 763 ohms (plus cable resistance). At a maximum battery voltage of 140 V-dc, the indicating lamp circuits would be limited to a maximum of 0.18 amps. As the required (minimum) solenoid valve operating (inrush) current is 1.5 amps, a cross-connected short could not cause the solenoid valve to open.

b. These cables do not contain conductors that could operate the solenoid.

c. This cable is a two-conductor that provides power to the solenoid. A cable conductor short could only deenergize the solenoid.

TABLE 9A-2

AUXILIARY PRESSURIZER SPRAY POWER SUPPLIES (Sheet 9 of 9)

d. A cable conductor short could short-circuit (jumper) the switch, causing energization of the solenoid. For this condition to disable auxiliary pressurizer spray, both solenoids would have to be identically affected by a cable conductor short and all bus, motor control center, and distribution panel breakers and the elementary scheme fuses would need to be incapable of being deenergized. The scheme cable for CHE-240 is routed in Seismic Category I cable tray and has a different routing (except within the Seismic Category I control cabinet) from the scheme cable for CHE-239, which is routed in non-Seismic Category I conduit that has been analyzed to withstand Seismic Category I design loads without damaging adjacent Seismic Category I equipment.

e. Note that the redundant valve is unaffected by the postulated failure.

f. Three battery chargers are connected to the dc bus. Only two of the three chargers are required to keep the battery in a fully charged state.

APPENDIX 9B

FIRE PROTECTION EVALUATION REPORT

APPENDIX 9B

FIRE PROTECTION EVALUATION REPORT

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TABLES

FIGURES

9B.1 INTRODUCTION AND METHODOLOGY

9B.1.1 INTRODUCTION

This appendix presents an evaluation of the fire protection provided for PVNGS Units 1, 2, and 3. The evaluation has been made by comparing the PVNGS fire protection features to the guidelines contained in Appendix A of the Branch Technical Position (BTP) APCSB 9.5-1 (revised February 24, 1977) and to 10CFR50, Appendix R, Part III, Sections G, J, and O (issued September 1, 1982). Units 1, 2, and 3 are replicate plants with virtually identical fire protection systems within the power block. All three units are served from a common underground fire water main loop using common fire pumps and water storage tanks. This report provides an evaluation that is applicable to all three units.

The objective of the PVNGS fire protection program is to minimize both the probability and consequences of fire such that in the event of a fire, the plant may be brought to a safe (cold) shutdown both with and without the availability of offsite power. This is accomplished by using a defense-in-depth approach that includes a suitable combination of fire prevention, detection and suppression capabilities, and plant safety systems designed with redundancy and separation to safely withstand the effects of a fire.

The plant design has been reviewed and design provisions have been included for the preservation of at least one success path which can accomplish the safe shutdown functions. Physical barriers (i.e., walls or rated fire-retardant protective coatings) or spatial separation is the predominant means for

establishing this protection. Alternate shutdown capability is provided in the event of control room evacuation.

The results of the evaluation program are that PVNGS can reach and maintain cold shutdown conditions following a postulated fire. Details of the plant design which provide that assurance are set forth in sections 9B.2 and 9B.3 of this appendix. The fire protection provisions of PVNGS are examined from three viewpoints: (1) to provide a fire hazards analysis, (2) to identify the compliance with Appendix A of BTP APCSB 9.5-1, and (3) to identify the compliance with 10CFR50, Appendix R, Part III, Sections G, J, and O.

9B.1.2 EVALUATION CRITERIA

PVNGS has been evaluated to determine that the overall fire protection program provides reasonable assurance that a fire will not cause an undue risk to the health and safety of the public, will not prevent the performance of necessary safe shutdown functions, and will not significantly increase the risk of radioactive release to the environment. Appendix A of BTP APCSB 9.5-1 and 10CFR50, Appendix R, Part III, Sections G, J, and O provide specific guidelines which can be used to review the fire protection program for an operating plant. These guidelines have been addressed whenever applicable; but to provide broader guidelines, the following criteria have also served as the basis for the evaluation of the PVNGS fire protection program:

A. General Design Criterion 3 (10CFR50, Appendix A)

Fire Protection - "Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat-resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and firefighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components." (See subsection 3.1.3.)

B. Defense-in-Depth Criterion (Paraphrased from BTP APCSB 9.5-1, Section B.1)

The fire protection program should extend the concept of defense-in-depth to fire protection in fire areas important to safety, with the following objectives:

- to prevent fires from starting;
- to detect rapidly, control, and extinguish promptly those fires that do occur;

- to provide protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by the fire suppression activities will not prevent the safe shutdown of the plant.

C. Single Failure Criterion (BTP APCSB 9.5-1, Section C.1.c.(2))

"A single active failure or a crack in a moderate-energy line (pipe) in the fire suppression system should not impair both the primary and backup fire suppression capability...."

D. Fire Suppression Systems Capacity and Capability (Paraphrased from BTP APCSB 9.5-1, Appendix A, Section E.2.(e))

Fire suppression capability shall be provided, with capacity adequate to extinguish any fire which may credibly occur and have adverse effects on equipment and components important to safe shutdown in the event of a fire.

E. Backup Fire Suppression Capability (BTP APCSB 9.5-1, Section C.1.c.(1))

"Total reliance should not be placed on a single fire suppression system. Appropriate backup fire suppression capability should be provided."

F. Occurrence of Fire and Other Phenomena (BTP APCSB 9.5-1, Section C.1.d.(1))

"Fires need not be postulated to be concurrent with nonfire-related failures in safety systems, other plant accidents, or the most severe natural phenomena."

Although specific guidelines may indicate particular provisions for fire protection, the overall adequacy of the fire protection program and potential modifications to it shall be based upon evaluation of the effects of potential fire hazards throughout the plant consistent with the above criteria. This overall adequacy is documented through the fire hazards analysis of section 9B.2.

9B.1.3 METHOD OF ANALYSIS

The guidelines set forth in the BTP APCSB 9.5-1, Appendix A, were the basic means for development of the fire protection program. A detailed comparison of the Appendix A guidelines against the PVNGS design is presented in section 9B.3. Section 9B.2 is the fire hazards analysis, performed as part of the Appendix A requirements, and delineates the design provisions for compliance with the requirements of 10CFR50, Appendix R, Part III, Sections G and O. Provisions for compliance with 10CFR50, Appendix R, Part III, Section J, are delineated in section 9.5.3. The fire hazards analysis is presented by fire areas which are further subdivided into analysis areas and fire zones to adequately define specific plant locations.

9B.1.3.1 Fire Hazards Analysis Methodology

The fire hazards analysis was performed to (1) consider potential in-situ and transient fire hazards; (2) determine the consequences of fire in any location in the plant on the ability to safely shut down the reactor or on the ability to minimize the release of radioactivity to the environment; and (3) specify features for fire detection, fire suppression, and fire containment and alternative shutdown capability as required for each fire area containing structures, systems, and components important to safety in accordance with NRC guidelines and regulations.

The supporting analysis technique to determine the relative fire loading used in this report is as follows:

A. Estimate the approximate total combustible load in pounds for each type of combustible material present in each fire zone.

   (A combustible load is any material that will burn or sustain the combustion process, whether or not it exhibits flame, under the exposure fire conditions that can exist at their point of application.) Cables routed through conduit and paint applied to noncombustible surfaces are not included in the combustible loading.

   The total combustible (fire) loading includes both in situ and postulated transient combustible loads. The transient combustible load is dependent upon the type and quantity of the in situ load in each fire zone and is determined as follows:

- In each fire zone, a transient combustible load of at least 50 pounds of ordinary combustibles (approximately 400,000 Btu) or 2-1/2 gallons of flammable liquid (approximately 400,000 Btu) is postulated, and when applicable, either of the following:

- Where the predominant combustibles are consumable items, the replacement of combustibles (minimum 400,000 Btu) is considered in calculating the total transient combustible load. For example, a lube oil or charcoal filter replacement may introduce a quantity of transient oil or charcoal equal to that of the in situ load into the fire zone, or

- Where cable tray and conduit routings are the predominant combustible, an average 300 feet of replacement cable (approximately 400,000 Btu) is considered in calculating the total transient combustible load.

B. Derive the total heat release, in Btu, from the heat of combustion of the materials for the number of pounds of combustibles in the zone assuming complete combustion.

The total Btu heat release is divided by the square footage of the floor surface area of the fire zone (Btu per square foot).

C. The approximate average combustible (fire) loading (Btu/ft^2) for each zone is then categorized as follows:

- Low - Less than 60,000 Btu/ft^2 (less than 45 minutes)
- Moderate - 60,000 to 160,000 Btu/ft^2 (45 minutes to 2 hours)
- High - Over 160,000 Btu/ft^2 (over 2 hours)

These categories are more conservative than those referenced in the National Fire Protection Association (NFPA) Fire Protection Handbook, 14th edition, Chapter 8, page 6-82, British Fire Loading Studies. These studies also include a secondary higher limit for combustible loading in limited isolated areas. At combustible loading in limited isolated areas. At PVNGS some variation is expected, but because each fire zone represents a relatively small compartment within the building, no further breakdown of combustible loading, beyond the average for the zone, is calculated. Due to the fact that combustible loading in each zone is approximate, borderline cases may be classified in the next higher category to allow for minor fluctuations. The protection provided for each zone is included in the fire hazards analysis.

Table 9B.1-1 is provided from NFPA Handbook Table 6-8A which shows estimated fire severities

based on combustible loading. This table gives an approximate equivalent fire severity in hours by comparing heat release rates from building fire tests of known combustible (fire) loadings (Btu/ft^2) to the standard time-temperature curve used by the American Society for Testing and Materials (ASTM) E119 (1976) in fire resistance testing of building materials. This table is provided for reference.

9B.1.3.2 Appendix R Compliance Assessment Methodology

A detailed comparison of the 10CFR50, Appendix R, guidelines against the PVNGS design was conducted. This comparison evaluated the capability to safely shut down the plant in the event of an exposure fire that could impact electrical equipment, cables, or components necessary for safe shutdown.

A summary of the methodology is as follows:

- Identify performance goals for safe shutdown.
- Identify those plant systems and flowpaths required to satisfy safe shutdown performance goals.
- Identify specific plant components required for safe shutdown. Include those components required to be operated and those components whose spurious actuation could adversely impact safe shutdown capability. Also consider components whose failure could result in inadvertent safety signal actuation.

Table 9B.1-1

ESTIMATED FIRE SEVERITY FOR OFFICES AND LIGHT COMMERCIAL OCCUPANCIES[(a)]

Heat Potential Assumed Btu/ft^2	Equivalent Fire Severity Approximately Equivalent to that Test Under Standard Curve for the Following Periods
40,000	30 min
80,000	1 hr
120,000	1-1/2 hr
160,000	2 hr
240,000	3 hr
320,000	4-1/2 hr

a. Fire Protection Handbook, 14th Edition, NFPA, Section 6, Chapter 8, Table 6-8A.

- Identify cables whose fire-induced failure could adversely impact safe shutdown capability and determine their routing.
- Determine survivability of plant safe shutdown capability in the event of a fire in any given plant area.
- Determine compliance based upon component redundancy, operator actions, fire rated enclosures, and licensing evaluations or deviations.
- For those compliance strategies crediting an operator action, determine the feasibility of the action. A

manual action is considered feasible if there is adequate time, manpower, lighting, and communication to perform the action.

For PVNGS, many of the safe shutdown performance goals can be performed by two independent, redundant trains which are separated from a common fire by rated physical boundaries and/or by separation distances which make the spread of fire improbable. Either of these trains is capable of performing the safe shutdown function. Where fully redundant capability is not provided, alternate success paths which may involve systems having similar, but not identical, capabilities are used to assure that the safe shutdown function capabilities can, indeed, be performed. This capability to accomplish the safety functions is maintained both with and without offsite power.

9B.1.4 FIRE HAZARDS ANALYSIS DEFINITIONS AND FORMAT

9B.1.4.1 Definitions

A. Fire Areas

Fire areas are those portions of a building or plant that are separated from other areas by boundary fire barriers which will contain the spread and adverse effects of a fire. The fire areas were determined in part by plant design features relating to fire safety and in part to minimize the likelihood of fires resulting in significant radioactive release. These features included overall plant layout, fire-resistant characteristics of construction, quantity,

type, and location of radioactive and combustible materials and separation criteria relating to safe shutdown trains. Fires in nonsafety-related, nonradioactive structures within the plant, which do not contain safe shutdown components or cables, were not considered as affecting the safe shutdown of the plant and therefore were not specifically included as part of the fire hazards analysis. However, fire detection and suppression capabilities have been provided in these locations, even though they are not required to protect safety-related or safe-shutdown equipment or ensure operator access or egress for manual safe-shutdown actions or mitigate radiological releases in the event of a fire. Fire protection features for these areas (e.g., barriers, detection, suppression) are not required to be included in the scope of the NRC-mandated fire protection quality assurance program.

PVNGS has also evaluated the capability to safely shut down the plant in the event of an exposure fire that could impact redundant electrical equipment, cables, or components necessary for safe shutdown. Based on this evaluation, fire areas as shown on figures 9B-1 through 9B-6 and engineering drawing 13-P-00B-005 were defined.

Each of the fire areas is discussed in detail in the fire hazards analysis, section 9B.2.

B. Analysis Areas

Analysis areas are groupings of fire zones (or in some cases a single fire zone) that will contain a postulated fire. Analysis area selection was based on (1) fire rated boundaries, (2) an approved deviation request which demonstrates the adequacy of the separation or boundary, or (3) an engineering evaluation in accordance with Generic Letter 86-10 can be justified. Consideration in selection of analysis areas was also given to ease of operator actions required to be performed for safe shutdown due to the fire, cable routing, and components affected by cables lost due to fire within the group of zones selected.

C. Fire Zones

Fire zones are subdivisions of fire areas which may contain either combustible material, radioactive material, or equipment/components available to achieve and maintain safe shutdown in the event of a fire. Some fire zones have been established to better define and represent specific plant locations (e.g., rooms, corridors, tanks, etc.) in order to optimize fire protection response as discussed in sections 9B.2 and 9B.3 and referred to in BTP APCSB 9.5-1, Appendix A.

9B.1.4.2 Fire Hazards Analysis Format

The fire hazards analysis is organized by fire area. As necessary, each fire area is further subdivided into analysis areas and fire zones. The following information is provided for each subdivision:

9B.1.4.2.1 Fire Areas

A. Area Boundary Description

To orient the reader, a brief statement is provided describing the fire area, its location within the plant, and a figure reference. The boundaries of the fire area are then explicitly described, including those walls which are fire rated.

B. Deviations from 10CFR50, Appendix R, Section III.G

A detailed discussion of the fire area specific deviations from the requirements of 10CFR50, Appendix R, is provided.

9B.1.4.2.2 Analysis Areas

Following the description of each fire area, the analysis area(s) within the fire area are detailed. Each analysis area includes:

A. Location

To orient the reader, a brief statement is provided describing the analysis area, its location within the plant, and a figure reference.

B. Analysis Area Boundaries

The boundaries of the analysis area are explicitly described, including those boundary walls which are fire rated.

C. Safe Shutdown Related Components and Cables

A listing of systems with safe shutdown related cables and of major safe shutdown related components within each analysis area is presented.

D. Summary and Conclusions

This section summarizes how safe shutdown is assured from the information presented in the 10CFR50, Appendix R, III.G/III.L compliance assessment (APS Calculation Number 13-MC-FP-318) based on component redundancy, operator action, fire rated enclosures, spatial separation, alternate shutdown capability, or an existing deviation.

9B.1.4.2.3 Fire Zones

Following the description of each analysis area, the fire zones within the fire area are detailed. Each fire zone analysis includes:

A. Location

To orient the reader, a brief statement is provided describing the fire zone, its location within the plant, and a figure reference.

B. Fire Prevention Features

The boundaries of the fire zone are explicitly described, including those zone boundary walls which are fire-rated. Openings through zone boundaries such as zone access (i.e., doors, personnel hatches), sealed electrical and pipeway penetrations, and rated HVAC dampers are also noted. In addition, structural steel members protected from fire and raceways that are coated/wrapped to meet the separation requirements of 10CFR50, Appendix R, Section III.G, are identified. HVAC ducting and electrical cable tray supports are coated/wrapped as necessary as described in the appendix 9A responses to Questions 9A.108, 9A.109, and 9A.110.

C. Safety-Related Equipment and Components

A listing of safety-related equipment and components not required for safe shutdown within each fire zone is presented.

D. Nonsafety-Related Equipment and Components

A listing of significant nonsafety-related equipment and components within each fire zone is presented.

This listing was compiled both as an aid in the identification of combustibles and of equipment and components which may be lost in the event of a fire.

E. Radioactive Material

The presence of radioactive material in tanks, filters, demineralizers, and piping is noted as

applicable. Radioactive material present in smoke detectors and radiation monitors (i.e., check sources) is generally found throughout the plant and is not specifically described. Radioactive sources are controlled in accordance with section 12.2 and unless otherwise noted are classified as none and have not been listed.

F. Combustible Loading

The combustible (fire) loading within a fire zone is determined and categorized as low, moderate, or high. For the methodology, see section 9B.1.3.1.

G. Fire Detection

The type of fire detection system utilized within the fire zone is noted.

H. Fire Suppression

Primary and secondary means of fire suppression available to extinguish a fire are listed. If a means of suppression to be used is not located within the fire zone, it has been noted and its physical location relative to the fire zone stated.

I. Ventilation

A description of smoke abatement capabilities from the fire zone is presented.

J. Drainage

The quantity and size of floor drains within a fire zone are noted. The drainage system has been sized

to prevent flooding in the event of fire suppression system operation. (See section 9.3.3.2.1.1.2)

K. Emergency Communications

The presence of sound-powered phone jacks within the fire zone is noted.

9B.2 FIRE HAZARDS ANALYSIS

9B.2.0 INTRODUCTION

This section presents the results of the PVNGS fire hazards analysis performed for each of the fire areas (figures 9B-1 through 9B-6 and engineering drawing 13-P-00B-005) and fire zones (engineering drawings 13-A-ZYD-029, -031, -030, -023, -024, -026, -022, and –021).

The fire protection features provided for safe shutdown and safety-related structures, systems, and components (including access and egress for manual operator actions) or in areas important to safety where significant radioactive release is credible in the event of fire, are required to be included in the fire protection quality assurance program (Reference table 9B.3-1, Item C, Quality Assurance Program). Fire protection features which are not relied upon for protection of safe shutdown or safety-related structures, systems, and components or to ensure operator actions for safe shutdown or to control the release of radioactive material in the event of a fire are not required to be included in the fire protection quality assurance program. Examples of areas not required to be included in the quality assurance program are found in Miscellaneous Analysis Area section 9B.2.20. See also the deviation described below in section 9B.2.0.A.1.

With each fire area description, a detailed itemization of fire area specific deviations from the separation requirements of 10CFR50, Appendix R, Section III.G, is also presented. In addition, several generic deviations with relevance to many of the fire areas are:

A. In general, exterior walls, basemats, and roofs are not rated when:

1. They are not required to separate a safe shutdown-related train inside the fire area from a significant fire hazard (e.g., oil filled transformers) outside the fire area, and

2. They do not separate safety-related areas from nonsafety-related areas that present a significant fire threat to the safety-related areas.

The existing design which includes nonrated exterior walls, basemats, and roofs is an acceptable alternative to the separation requirements of 10CFR50, Appendix R, Section III.G.2.

B. Some fire doors have been modified to include security system hardware. In general, the modifications have a minimal impact on the door fire resistance as the modification affects a limited area of one side of the door. Further, these modifications are necessary to provide adequate station security. The modifications are in accordance with industry practice and are considered acceptable in that without modification the doors would cause a condition detrimental to overall facility safety.

C. Some fire doors have not been installed in strict compliance with the originally tested configuration which formed the basis for labeling per NFPA-80. The

deviations are limited to door-to-frame gaps, door-to-floor gaps, and latchset throw. All fire doors, however, are or will be purchased as labeled fire doors except as noted in question 9A-106.

The fire door installation deviations from the tested configuration and NFPA-80 have been found acceptable based on additional fire tests performed at Warnock-Hersey laboratory. The special test configurations were chosen to conservatively represent the configurations as installed in the field. Since the field installation of the fire doors is not in strict compliance with the original tested configuration, the requirement to maintain a label from a nationally recognized laboratory on the fire doors per NFPA-80 is no longer applicable. Maintenance of fire doors with respect to door-to-frame gaps, door-to-floor gaps and latch throw shall conform to the special test configuration as tested at Warnock-Hersey laboratory. All other aspects of the fire doors, other than gaps and latch throw, will be maintained in accordance with NFPA-80.

Minor deviations of the installed fire doors from the Warnock-Hersey tested configuration will be safety reviewed and evaluated and documented on a case-by-case basis by a qualified fire protection engineer.

D. DELETED

E. Five different safe shutdown actions for postulated fire scenarios exist that require activity in outside

yard areas which are not provided with 8-hour battery-powered emergency lights specified in Section III.J of Appendix R to 10CFR50. Portable hand-held lanterns will be used in these outside areas in lieu of fixed 8-hour battery-powered emergency lighting units (refer to subsection 9.5.3.2.2.3).

1. Access to the Train B Diesel Generator Local Control Panel During a Postulated Fire in Fire Zone 5B

   For a postulated fire in Zone 5B (train B switchgear room located in the control building at the 100-foot elevation), the train B diesel generator must be disabled at the local control panel located in Zone 22B of the diesel generator building to preclude or overcome adverse consequences of an engineered safety features actuation signal to train B components. The normal access path to Zone 22B from the control room is through Zone 5B, but if a fire exists in Zone 5B an alternate path is via the southwest exit door of the control building, through the control building hardened barrier controlled access point, and across the outside yard area, and into the train B side of the diesel generator building through the missile door. No fixed 8-hour battery-powered emergency lighting is installed in the outside yard area for this access/egress path. However, fixed

8-hour battery-powered emergency lighting is provided for access/egress and required actions inside the control building, the control building hardened barrier controlled access point, and the diesel generator building. Portable hand-held lanterns are readily available for use by the operators for traversing the outside area, and pole-mounted security lighting, though not provided for Appendix R compliance, also provides illumination for this outside area.

2. Access to the Condensate Storage Tank Pump House During a Postulated Fire in Fire Zones 42B or 42C.

For a postulated fire in Zones 42B (train B electrical penetration room located in the auxiliary building at the 100-foot elevation) or 42C, (east corridors located in the auxiliary building at the 100-foot elevation), the train B condensate manual discharge valve located in Zone 83, the condensate storage tank pump house, must be closed to preclude the loss of condensate storage tank volume via gravity draining through a spurious opening of a remotely operated discharge valve. The access/egress path to the condensate storage tank pump house is from the control building through the turbine breezeway, across the outside yard area, and through the condensate

storage tank hardened barrier controlled access point. No fixed 8-hour battery-powered emergency lighting is installed in the outside yard area for this access/egress path. However, fixed 8-hour lighting is provided for access/egress and required actions inside the control building, turbine breezeway, condensate storage tank hardened barrier controlled access point, and condensate storage tank pump house. Portable hand-held lanterns are readily available for use by the operators for traversing the outside area, and pole-mounted security lighting, though not provided for Appendix R compliance, also provides illumination for this outside area.

3. Access to the Condensate Storage Tank Pump House During a Postulated Fire in Fire Zones 42D, 47A, or 52A.

For a postulated fire in Zones 42D (west corridors located in the auxiliary building at the 100-foot elevation), 47A (train A electrical penetration room located in the auxiliary building at the 120-foot elevation), or 52A (west corridors located in the auxiliary building at the 120-foot elevation), the train A condensate manual discharge valve located in Zone 83, the condensate storage tank pump house, must be closed to preclude the loss of condensate storage tank volume via gravity

draining through a spurious opening of a remotely operated discharge valve. The access/egress path to the condensate storage tank pump house is from the control building through the turbine breezeway, across the outside yard area, and through the condensate storage tank hardened barrier controlled access point. No fixed 8-hour battery-powered emergency lighting is installed in the outside yard area for this access/egress path. However, fixed 8-hour lighting is provided for access/egress and required actions inside the control building, turbine breezeway, condensate storage tank hardened barrier controlled access point, and condensate storage tank pump house. Portable hand-held lanterns are readily available for use by the operators for traversing the outside area, and pole-mounted security lighting, though not provided for Appendix R compliance, also provides illumination for this outside area.

4. Access to the Condensate Storage Tank Pump House During a Postulated Fire in Fire Zone 17.

   For a postulated fire in Zone 17 (control room area), the condensate storage tank level must be monitored using the local level indicator located in Zone 83, the condensate storage tank pump house. The access/egress path to the condensate storage tank pump house is from the

control building through the turbine breezeway, across the outside yard area, and through the condensate storage tank hardened barrier controlled access point. No fixed 8-hour battery-powered emergency lighting is installed in the outside yard area for this access/egress path. However, fixed 8-hour lighting is provided for access/egress and required actions inside the control building, turbine breezeway, condensate storage tank hardened barrier controlled access point, and condensate storage tank pump house. Portable hand-held lanterns are readily available for use by the operators for traversing the outside area, and pole-mounted security lighting, though not provided for Appendix R compliance, also provides illumination for this outside area.

5. Access to and Operation of a Manual Isolation Valve at the Reactor Makeup Water Tank During a Postulated Fire in Fire Zones 14, 52D, 53, 50B, or 86B.

   For a postulated fire in Zone 14 (lower cable spreading room located in the control building at the 120-foot elevation), 52D (east corridor located in the auxiliary building at the 120 foot elevation), 53 (process radiation monitor and boronometer room located in the auxiliary building at the 120-foot elevation), 50B (valve gallery located in the auxiliary

building at the 120-foot elevation), or 86B (train B compartment between the auxiliary and control buildings between the 74-foot and the 156-foot, 4-inch elevations), a 3-inch manual valve (P-CHN-V771) located in an outside area at the reactor makeup water tank in Zone 79 must be closed to ensure the ability to prevent an inadvertent boron dilution. The access/egress path to the subject valve from the control room is via the southwest exit door of the control building, through the control building hardened barrier controlled access point, and across the outside yard area. No fixed 8-hour battery powered emergency lighting is installed in the outside yard area at the location of the subject valve or for access/egress across the outside yard to the valve location. Fixed 8-hour battery-powered lighting is provided for the access/egress route inside the control building and control building hardened barrier controlled access point. Portable hand-held lanterns are readily available for use by the operators for traversing the outside area and for operating the manual valve, and pole-mounted security lighting, though not provided for Appendix R compliance, also provides illumination for the outside transit area.

For the five situations presented above, the affected potential safe-shutdown activities consist of simply traversing outside

yard areas between buildings in four cases, or traversing an outside yard area to operate a 3-inch manual valve at an outside yard area in the fifth case. These are short duration, non-complex activities, where the use of portable lanterns can provide sufficient illumination for the required tasks with minimal distraction or interference. The traversing or valve closing that may be required to be performed in the outside yard areas can be easily performed by utilizing a hand-held lantern. The lanterns will be readily available in or near the control room at elevations 140 feet and 100 feet. They are regularly maintained to ensure proper operation and will only need to be energized for the relatively short time that an operator is outside the plant buildings. In addition to utilizing hand-held lanterns for illumination in these outside areas, pole-mounted security lights are installed in the outside yard areas which, though not provided for Appendix R compliance, also provide a reliable source of yard illumination for traversing. The security lights are supplied by their own backup diesel generator which would not be affected by the fires identified in the above scenarios. Access/egress routes through plant buildings will continue to be provided with fixed 8-hour battery-powered emergency lights, as will the safe-shutdown areas inside the plant buildings.

F. A deviation is taken from Appendix R, Section III.L using the guidance provided in Generic Letter 86-10, Questions 3.8.4 and 5.3.10, to the extent that it requires the reactor coolant system process variables, as discussed below, to be maintained within those predicted for a normal loss of AC power

and the reactor coolant make-up function to be capable of maintaining the reactor coolant level within the level indication in the pressurizer.

Discussion

10CFR50, Appendix R, Section III.L states:

1. During the postfire shutdown, the reactor coolant system process variables shall be maintained within those predicted for a loss of normal a.c. power, and the fission product boundary integrity shall not be affected; i.e., there shall be no fuel clad damage, rupture of any primary coolant boundary, or rupture of the containment boundary.

2. The performance goals for the shutdown functions shall be:

    a. The reactivity control function shall be capable of achieving and maintaining cold shutdown reactivity conditions. The reactor coolant makeup function shall be capable of maintaining the reactor coolant level above the top of the core for BWRs and be within the level indication in the pressurizer for PWRs.

    b. The reactor heat removal function shall be capable of achieving and maintaining decay heat removal.

c. The process monitoring function shall be capable of providing direct readings of the process variables necessary to perform and control the above functions.

d. The supporting functions shall be capable of providing the process cooling, lubrication, etc., necessary to permit the operation of the equipment used for safe shutdown functions.

Generic Letter 86-10, Question 3.8.4 states:

> The damage to the system in the control room for a fire that causes evacuation of the control room cannot be predicted. A bounding analysis should be made to assure that safe conditions can be maintained from outside the control room.

A bounding analysis was performed for the control room fire scenario to assure that safe shutdown conditions could be maintained from outside the control room. This bounding analysis (ref. calculation 13-MC-FP-318, 10CFR50 Appendix R IIIG/IIIL Compliance Assessment and 13-MC-FP-317, 10CFR50 Appendix R Operational Considerations) assumed the worst case spurious actuations as well as loss of all automatic function (such as ESFAS, DG auto start and sequencing) of components whose control circuits could be affected by a fire in the control room. This conservative analysis indicated that the required reactor coolant system process variables and their indications, i.e., pressurizer level, RCS temperature and

pressure could exceed those predicted for a loss of offsite power. These transients could occur until positive control of equipment affected by the fire and restoration of charging flow is established within 30 minutes.

Conclusions

The bounding analysis evaluated the consequences of these transients and demonstrated that safe shutdown can be accomplished satisfactorily (ref. calculation 13-MC-FP-317, 10CFR50 Appendix R Operational Considerations and calculation 13-MC-FP-316, 10CFR50 Appendix R Manual Action Feasibility) and concluded that:

1. The plant would not be placed in an unrecoverable condition,
2. Fuel damage would not occur, and
3. The process variables would be restored once positive control of the equipment and restoration of charging flow was established, within 30 minutes. This has been verified to be accomplished by a timed walkdown of the Control Room Fire procedure.

Therefore there is no adverse effect on the ability to achieve and maintain safe shutdown in the event of any postulated fire as a result of this deviation.

9B.2.1 FIRE AREA I

9B.2.1.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area I (figure 9B-1, 9B-3, 9B-4, engineering drawing 13-P-00B-005, and (9B-5) contains train A components found in the control building. The fire area includes Analysis Area IA (Zone 1, HVAC Chase J-102, and HVAC Chase J-104), IB (Zones 3A, 4A, 11A, 15A, and 18A), IC (Zone 86A), ID (Zones 6A, 7A, 8A, and 9A), IE (Zone 10A), IF (Zone 5A and Stair C), and IG (Zone 20) engineering drawing 13-A-ZYD-029.

At elevation 74 feet 0 inch, Fire Area I is below grade and bounded to the north by a 3-hour rated barrier common to Fire Area XV, to the east by a 3-hour rated barrier common to Fire Area II (the east wall of Zone 86A is a nonrated barrier common to Fire Area II), and to the west and south by nonrated exterior walls. The west walls of Zones 3A and 86A are 3-hour rated and nonrated, respectively, with both walls common to Fire Area X. The southwest stairwell walls are 2-hour rated. The basemat is nonrated.

At elevation 100 feet 0 inch, Fire Area I is bounded to the north by a 3-hour rated barrier common to Fire Area XV, to the south by a 3-hour rated barrier common to the diesel/control building seismic gap and by a non-rated heavy concrete exterior wall, and a 2-hour rated wall common to the southwest stairwell,

to the east by 3-hour rated barriers common to Fire Area II, and to the west by a 3-hour rated barrier common to Fire Area X. The east and west wall of Zone 86A common to Fire Areas II and X, respectively, is nonrated. The east wall to Zone 10A, common to Zone 10B, is 2-hour rated. The ceilings to Zones 5A, 6A, 7A, 8A, 9A, and 10A are 3-hour rated and common to Fire Area II.

At elevation 120 feet 0 inch, Fire Area I consists of the northwest and southwest corners of the control building. In the northwest corner, Fire Area I includes the northwest HVAC chase and Zones 11A and 86A, bounded to the north by a 3-hour rated barrier common to Fire Area XV, to the south and east by 2-hour and 3-hour rated barriers common to Fire Area II and to the west by a 3-hour rated barrier common to Fire Area X. The east and west wall of Zone 86A common to Fire Areas II and X is nonrated. In the southwest corner, Fire Area I includes the southwest HVAC chase, bounded to the north and east by 2-hour rated barriers common to Fire Area II, to the south by a 2-hour rated wall common to the southwest stairwell and to the west by a 3-hour rated barrier common to Fire Area X.

At elevation 140 feet 0 inch, Fire Area I consists of the northwest and southwest corners of the control building. In the northwest corner, Fire Area I includes the northwest HVAC chase and Zones 15A and 86A, bounded to the north by a 3-hour rated barrier

common to Fire Area XV, to the south and east by 2-hour and 3-hour rated barriers common to Fire Area III and by a nonrated barrier common to Fire Area II, and to the west by a 3-hour rated barrier common to Fire Area X. The west and east walls of Zone 86A, common to Fire Areas X and II, respectively, are nonrated. The ceiling to Zone 86A is a nonrated barrier and common to the roof. In the southwest corner, Fire Area I includes the southwest HVAC chase, bounded to the north and east by 2-hour rated barriers common to Fire Area III, to the south by a 3-hour rated wall common to the southwest stairwell and to the west by a 3-hour rated barrier common to Fire Area X.

At elevation 160 feet 0 inch, Fire Area I is bounded to the north by nonrated and 3-hour rated exterior walls, to the south by a 2-hour rated wall common to the southwest stairwell, a nonrated exterior wall, a 3-hour rated barrier common to the diesel/control building seismic gap and a 2-hour rated barrier common to Fire Area II (Zone 19), to the west by a 3-hour rated exterior wall, and to the east by 3-hour rated barriers common to Fire Area II (Zone 18B) and the corridor building and a 2-hour rated barrier common to Fire Area II (Zone 19). The floor of Zone 20 is 3-hour rated and common to Fire Area III. The ceiling, which is also the roof of the control building, is nonrated.

B. Deviations from 10CFR50, Appendix R, Section III.G

1. A deviation is requested from Section III.G.2 to the extent that it requires 3-hour rated barriers to separate circuits of redundant trains.

<u>Discussion</u>

The south and east walls of the northwest HVAC chase (which is adjacent to Fire Area I, Zones 1, 3A, 4A, 5A, 11A, 15A, 18A, 20, and 86A) are common boundaries with Fire Area II (Zone 14) at elevation 120 feet 0 inch and Fire Area III (Zone 17) at elevation 140 feet 0 inch. The HVAC chase has walls of reinforced concrete construction rated for 2 and 3 hours. For a fire to propagate between redundant trains, the fire must burn through at least two 2-hour rated fire barriers. The HVAC chase itself is virtually devoid of combustibles. Fire dampers used in the 2-hour rated wall sections are identical in material and construction to 3-hour labeled devices. Fire detection and automatic suppression are provided in the vicinity of the chase at elevations 100 feet 0 inch, 120 feet 0 inch, and 160 feet 0 inch. Fire detection alone is provided in the vicinity of the chase at elevations 74 feet 0 inch and 140 feet 0 inch. Fire department response (within 20 minutes) is expected, well before degradation

to the existing fire barriers would occur. Access to the chase for the fire department response is available at elevation 100 feet 0 inch (through Zone 5A) and at elevation 120 feet 0 inch (through Zone 11A).

Conclusion

The existing design provides equivalent protection of that required by Section III.G.2, and upgrading the existing design for 3-hour ratings would not significantly enhance the protection currently provided.

2. A deviation is requested from Section III.G.2 to the extent that it requires 3-hour rated barriers to separate circuits of redundant trains.

Discussion

The north and east walls of the southwest HVAC chase (adjacent to Fire Area I, Zones 1 and 5A) are common boundaries with Fire Area II (Zone 14) at elevation 120 feet 0 inch and with Fire Area III (Zone 17) at elevation 140 feet 0 inch. The HVAC chase has walls of reinforced concrete construction rated for 2 and 3 hours. For a fire to propagate between redundant trains, the fire must burn through at least two 2-hour rated fire barriers. The HVAC chase itself is virtually devoid of combustibles. Fire dampers used in the 2-hour rated wall

sections are identical in material and construction to 3-hour labeled devices. Fire detection and automatic suppression are provided in the vicinity of the chase at elevations 100 feet 0 inch and 120 feet 0 inch. Fire detection alone is provided in the vicinity of the chase at elevations 74 feet 0 inch and 140 feet 0 inch. Fire department response (within 20 minutes) is expected, well before degradation to the existing fire barriers would occur. Access to the chase for the fire department response is available at elevation 100 feet 0 inch (through Zone 5A).

Conclusion

The existing design provides equivalent protection of that required by Section III.G.2, and upgrading the existing design for 3-hour ratings would not significantly enhance the protection currently provided.

3. A deviation is requested from Section III.G.2 to the extent that it requires 3-hour barriers to separate circuits of redundant trains.

Discussion

The north wall of the southwest stairwell (adjacent to Fire Area I, Zones 1, 5A, and 20) is a common boundary with Fire Area II (Zone 14) at elevation 120 feet 0 inch and with Fire Area III (Zone 17) at elevation 140 feet 0 inch.

The stairwell has walls of reinforced concrete construction rated for 2 and 3 hours. For a fire to propagate between redundant trains, the fire must burn through at least two 2-hour rated fire barriers. The stairwell itself is devoid of combustibles. Fire doors utilized in the stairwell are B label (1-1/2 hours). Fire detection and automatic suppression are provided in the vicinity of the stairwell at elevations 100 feet 0 inch, 120 feet 0 inch, and 160 feet 0 inch. Fire detection only is provided in the vicinity of the stairwell at elevations 74 feet 0 inch and 140 feet 0 inch. Fire department response (within 20 minutes) is expected, well before degradation of the existing barriers would occur.

Conclusion

The existing design provides equivalent protection of that required by Section III.G.2, and upgrading the existing design for 3-hour ratings would not significantly enhance the protection currently provided.

4. A deviation is requested to Section III.G.2 to the extent that it requires installation of a 1 hour fire rated barrier and an area-wide suppression system.

Discussion

The west wall of Zone 86A is a fire area boundary between Fire Area I and Fire Area X at elevations 74 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch. The boundary contains two 6-inch (nominal) seismic gaps which are covered with nonrated, solid 18-gauge sheet metal flashings on each side of a reinforced concrete stub wall or pillar. The metal flashings would retard the passage of heat and/or smoke. Fire Area X contains no safe shutdown equipment or cables. Therefore, a postulated fire within Zone 86A would have no effect upon safe shutdown capability, even if the fire did spread into Fire Area X.

Within the Fire Area X side of this boundary, there are negligible combustibles; the compartment adjacent to the seismic gap is a large HVAC and pipe chase with floor dimensions approximately 13 feet by 50 feet. Within Fire Area I, Zone 86A is separated from the remainder of the fire area by 2- and 3-hour rated walls. Zone 86A is separated from Zone 86B (Fire Area II) by a nonrated barrier (see Fire Area I, deviation No. 5, for the Zone 86A/Zone 86B separation considerations). Zonal detection and automatic deluge water spray covers the predominant in situ combustible (cable trays at elevations 100 feet 0 inch and 120 feet 0 inch).

The combustible (fire) loading for Zone 86A is high. This apparently high combustible loading is attributed to the calculation method, in that the combustible material is located in an area with a relatively small floor area combined with a high ceiling. Fire department response (within 20 minutes) is expected, well before significant degradation of the existing fire barriers would occur. Access to Zone 86A for fire department response is available at elevation 100 feet 0 inch (through Zone 5A).

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2, and upgrading the existing design to a 1-hour rating plus suppression would not significantly enhance protection currently provided.

5. A deviation is requested to Section III.G.2 to the extent that it requires 3-hour rated barriers to separate circuits of redundant trains.

Discussion

The central wall of the dead space compartment between the auxiliary and control buildings is a fire area boundary common to Fire Area I (Zone 86A) and Fire Area II (Zone 86B) at elevations 74 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch. The wall

is reinforced concrete with a nominal 6-inch seismic gap. The seismic gap is covered by solid 1/4-inch steel plates bolted to each side of the concrete wall. The fit is snug and there is no path for heat or smoke to travel through the plate steel.

The dead air space between the steel plates will have an insulating quality, thus minimizing radiant heat transfer to the other side as well as eliminating convected heat through the barrier. Zonal detection and automatic deluge water spray covers the predominant in situ combustible (cable trays at elevations 100 feet 0 inch and 120 feet 0 inch). Train A cable tray are located 8 to 9 feet from the center wall in zone 86A. Train B cable trays are located more than 10 feet from the opposite side of the center wall in Zone 86B. The compliance strategies for the components associated with the "N" raceways do not rely on components whose cables are within 10 feet of the center wall. The total combustible (fire) loading for each of Zones 86A and 86B is high. This apparently high combustible loading is attributed to the calculation method, in that the combustible material is located in an area with a relatively small floor area combined with a high ceiling. Fire department response (within 20 minutes) is expected before significant degradation of the

existing fire barriers would occur. Access to Zone 86A for fire department response is available at elevation 100 feet 0 inch (through Zone 5A). Access to Zone 86B for fire department response is available at elevation 100 feet 0 inch (through Zone 5B).

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2, and upgrading the existing design to a 3-hour rating would not significantly enhance the protection currently provided.

6. A deviation is requested from Section III.G.2 to the extent that it requires 3-hour rated barriers to separate circuits of redundant trains.

Discussion

The east wall of Fire Zone 10A is a 2-hour rated barrier common to Fire Area II, Fire Zone 10B. The wall, which separates the two remote shutdown panel rooms, is of metal lath and plaster construction and contains a 3-hour rated fire door. This fire area boundary is not rated at 3 hours due to the lack of a tested configuration featuring a 3-hour rated door frame installed in a 3-hour rated metal lath and plaster wall. Only train A circuitry is routed

through Zone 10A. Zone 10B contains both train B circuitry and some train A conduit.

The combustible (fire) loading in Zones 10A and 10B is moderate. Each of the fire zones is protected by smoke detectors and thermal detectors. A Halon 1301 suppression system prealarmed by smoke and actuated by thermal detectors is installed in each fire zone. Fire department response (within 20 minutes) is expected, well before significant degradation of the existing fire barriers would occur. Access to each of Zones 10A and 10B is possible through the adjacent ESF switchgear rooms.

<u>Conclusion</u>

The existing design provides equivalent protection to that required by Section III.G.2, and upgrading the existing design to a 3-hour rating would not significantly enhance the protection currently provided.

7. See subsection 9B.2.2 for a deviation common to Fire Area II and the section 9B.2 introduction for generic deviations.

9B.2.1.2 <u>Analysis Area IA</u>

A. Location

Analysis Area IA consists of Fire Zone 1, HVAC Chase J-102, and HVAC Chase J-104.

Fire Zone 1 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 74 feet 0 inch.

HVAC Chase J-102 is located in the control building at elevations 100 feet 0 inch, 120 feet 0 inch, 140 feet 0 inch, and 160 feet 0 inch.

HVAC Chase J-104 is located in the control building at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Zone 3A 3-hour rated wall common to Zone 86A at column line J1

South: 2-hour rated wall common to the southwest stairwell at column line J4
Nonrated exterior wall of heavy concrete construction at column line J4

East: 3-hour rated wall common to Fire Area II, Zone 2, at column line JC

West: Nonrated exterior wall of heavy concrete construction at column line JA 3-hour rated wall common to Zone 3A

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Zones 5A, 6A, 7A, 8A, 9A, and 10A

HVAC Chase J-102

North: 2-hour rated wall common to Zone 86A at elevation 100 feet 0 inch

3-hour rated wall common to Zone 86A at elevations 120 feet 0 inch and 140 feet 0 inch

Nonrated exterior wall of heavy concrete construction at elevation 160 feet 0 inch

South: 2-hour rated wall common to Zones 5A and 20

2-hour rated wall common to Fire Area II, Zone 14

2-hour rated wall common to Fire Area III, Zone 17

East: 2-hour rated wall common to Zones 5A and 20

2-hour rated wall common to Fire Area II, Zone 14

2-hour rated wall common to Fire Area III, Zone 17

West: 3-hour rated wall common to Zones 4A, 11A, 15A, and 18A

Floor: Open to Zone I at elevation 100 feet 0 inch

Ceiling: 3-hour rated barrier common to Zone 20 at elevation 169 feet 4 inch

<u>HVAC Chase J-104</u>

North: 2-hour rated wall common to Zone 5A

2-hour rated wall common to Fire Area II, Zone 14

2-hour rated wall common to Fire Area III, Zone 17

South: 2-hour rated wall common to the south stairwell at elevation 100 feet 0 inch and elevation 120 feet 0 inch

3-hour rated wall common to the south stairwell at elevation 140 feet 0 inch

East: 2-hour rated wall common to Zone 5A

2-hour rated wall common to Fire Area II, Zone 14

2-hour rated wall common to Fire Area III, Zone 17

West: 3-hour rated exterior wall

Floor: Open to Zone 1 at elevation 100 feet 0 inch

Ceiling: 3-hour rated barrier common to Zone 20

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control (Unit 2 & 3 only)

  Essential chilled water

Essential cooling water

Control building HVAC

Miscellaneous HVAC

Main steam

Essential spray pond

Nuclear sampling

- Train B cables associated with the following systems:

  Control building HVAC

- Nontrain related cables associated with the following systems:

  Control building HVAC (Units 2 & 3 only)

- Train A essential chiller and associated components

- Train A essential chilled water expansion tank and associated components

- Train A essential cooling water components

- Train A control building engineered safety feature switchgear room essential air handling unit and associated dampers

- Train A control room essential air handling unit and associated dampers

- Train B control room HVAC damper

D. Summary and Conclusions

Safe shutdown capability will be provided by utilizing redundant train B systems available from the control room, in conjunction with operator action, outside this analysis area, to prevent or overcome the consequences of spurious operation of train A components or to establish equipment lineups required to achieve the shutdown function. One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.1.3 Analysis Area IB

A. Location

Analysis Area IB consists of fire zones 3A, 4A, 11A, 15A, and 18A.

Fire Zone 3A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 74 feet 0 inches.

Fire Zone 4A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inches.

Fire Zone 11A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inches.

Fire Zone 15A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 140 feet 0 inches.

Fire Zone 18A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 160 feet 0 inches.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Zone 86A at column line J1

South: 3-hour rated wall common to Zone 1 (elevation 74 feet 0 inch)

3-hour rated wall common to Zone 5A (elevation 100 feet 0 inch)

3-hour rated wall common to Fire Area II, Zone 14 (elevation 120 feet 0 inch)

3-hour rated wall common to Fire Area III, Zone 17 (elevation 140 feet 0 inch)

3-hour rated wall common to Zone 20 (elevation 160 feet 0 inch)

East: 3-hour rated wall common to Zone 1 (elevation 74 feet 0 inch)

3-hour rated wall common to the northwest HVAC chase (elevation 100 feet 0 inch, 120 feet 0 inch, 140 feet 0 inch, 160 feet 0 inch)

West: 3-hour rated wall common to Fire Area X at column line JA (elevation 74 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, 140 feet 0 inch)

3-hour rated exterior wall at column JA (elevation 160 feet 0 inch)

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of heavy concrete construction

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Diesel fuel oil and transfer

  Diesel generator

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Diesel generator HVAC

  Control building HVAC

  Miscellaneous HVAC

Nuclear cooling water

Reactor coolant

Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Essential spray pond

Nuclear sampling

Electrical power distribution

Engineered safety feature actuation

D. Summary and Conclusions

Safe shutdown capability will be provided by utilizing redundant train B systems available from the control room, in conjunction with operator action, outside this analysis area, to prevent or overcome the consequences of spurious operation of train A components or to establish equipment lineups required to achieve the shutdown function.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.1.4 Analysis Area IC

A. Location

Analysis Area IC consists of Fire Zone 86A.

Fire Zone 86A (engineering drawing 13-A-ZYD-029) is the compartment between the auxiliary and control buildings between the auxiliary and control buildings between elevations 74 feet 0 inch and 156 feet 4 inches.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Fire Area XV at column line A10

South: 3-hour rated wall at column line J1 common to:

- Zones 1 and 3A at elevation 74 feet 0 inch
- Zones 4A and 6A at elevation 100 feet 0 inch
- Zone 11A and the northwest HVAC chase at elevation 120 feet 0 inch
- Zone 15A and the northwest HVAC chase at elevation 140 feet 0 inch

2-hour rated wall common to Zone 5A and the northwest HVAC chase at column line J1 (elevation 100 feet 0 inch)

3-hour rated wall common to Fire Area II, Zone 14, at column line J1 (elevation 120 feet 0 inch)

3-hour rated wall common to Fire Area III, Zone 17, at column line J1 (elevation 140 feet 0 inch)

East: Nonrated wall of heavy concrete construction common to Fire Area II, Zone 86B, at column line JC

West: Nonrated wall common to Fire Area X at column line JA

Floor: Nonrated basemat of light concrete paving at elevation 74 feet 0 inch

Ceiling: Nonrated roof at elevation 156 feet 0 inch

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Control building HVAC

  Miscellaneous HVAC

  Nuclear cooling water

  Reactor coolant

Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Nuclear sampling

Electrical power distribution

Engineered safety feature actuation

- Nontrain related cables associated with the following system:

  Reactor coolant

D. Summary and Conclusions

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided. The redundant train B system will remain available from the control room, in conjunction with operator action, outside of this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.1.5 Analysis Area ID

A. Location

Analysis Area ID consists of Fire Zones 6A, 7A, 8A, and 9A

Fire Zones 6A, 7A, 8A, and 9A (engineering drawing 13-A-ZYD-029) are located in the control building at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Zone 86A at column line J1

South: 3-hour rated wall common to Zone 5A and 10A

East: 3-hour rated wall common to Fire Area II, Zones 6B, 7B, 8B, and 9B at column line JC

West: 3-hour rated wall common to Zone 5A

Floor: 3-hour rated barrier common to Zone 1

Ceiling: 3-hour rated barrier common to Fire Area II, Zone 14

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Diesel generator

  Control building HVAC

  Main steam

  Safety injection and shutdown cooling

  Electrical power distribution

  Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Control building HVAC

  Reactor coolant

- Train A battery chargers
- Train A 125 V-dc control centers and distribution panels
- Various train A control building HVAC components
- Channel A and C battery room ventilation exhaust fans and associated equipment
- Train A 480/120V voltage regulator
- Train A 120 V-ac vital instrument distribution panel A
- Train A, Channel C, 480 V-ac inverter
- Train A 120 V-ac inverter
- Train A 120 V-ac swing inverter, if implemented per DMWO 3232547
- Train A battery C
- Train A battery A

D. Summary and Conclusions

One train of systems necessary to achieve and maintain hot standby and cold shutdown, has been demonstrated to remain available for use based on fire barriers provided. The redundant train B system

will remain available from the control room, in conjunction with operator action, both inside and outside of this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.1.6 Analysis Area IE

A. Location

Analysis Area IE consists of Fire Zone 10A.

Fire Zone 10A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North:	3-hour rated wall common to Zone 7A
	3-hour rated wall common to Fire Area II, Zone 7B
South:	3-hour rated area boundary wall common to the diesel/control building seismic gap at column line J4
East:	2-hour rated wall common to Fire Area II, Zone 10B
West:	1-hour rated wall common to Zone 5A
Floor:	3-hour rated barrier common to Zone 1

3-hour rated barrier common to Fire Area II, Zone 2

Ceiling: 3-hour rated barrier common to Fire Area II, Zone 14

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Diesel fuel oil and transfer

  Diesel generator

  Diesel generator HVAC

  Control building HVAC

  Miscellaneous HVAC

  Reactor coolant

  Ex-core neutron monitoring

  Main steam

  Safety injection and shutdown cooling

  Essential spray pond

  Electrical power distribution

  Engineered safety feature actuation

- Train A remote shutdown panel A

  Train A auxiliary feedwater pump instrumentation and control

- Various train A control building ventilation dampers

- Train A atmospheric dump valve control

D. Summary and Conclusions

Safe shutdown capability will be provided by utilizing redundant train B systems available from the control room, in conjunction with operator action, outside this analysis area, to prevent or overcome the consequences of spurious operation of train A components or to establish equipment lineups required to achieve the shutdown function.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.1.7 Analysis Area IF

A. Location

Analysis Area IF consists of Fire Zone 5A and Stairwell C.

Fire Zone 5A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

Stairwell C is located in the control building at elevations 74 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, 140 feet 0 inch, and 160 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Zone 4A

2-hour rated wall common to Zone 86A at column line J1

2-hour rated walls common to the northwest HVAC chase

South: 2-hour rated walls common to the southwest HVAC chase

Non-rated heavy concrete exterior wall at column line J4

East: 3-hour rated walls common to Zones 6A, 7A, 8A, and 9A

1-hour rated wall common to Zone 10A

West: 3-hour rated wall common to Fire Area X at column line JA

2-hour rated wall common to the northwest HVAC chase

Floor: 3-hour rated barrier common to Zone 1

Ceiling: 3-hour rated barrier common to Fire Area II, Zone 14

Stairwell C

North: 2-hour rated barrier common to Zone 1, Zone 5A, Zone 20, and Fire Area II, Zone 14

2-hour rated barrier common to the southwest HVAC chase at elevation 100 feet 0 inch and 120 feet 0 inch

3-hour rated barrier at elevation 140 feet 0 inch common to the southwest HVAC chase and Fire Area III, Zone 17

South: Nonrated exterior wall of heavy concrete construction at elevations 74 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, 140 feet 0 inch, and 160 feet 0 inch

East: Nonrated exterior wall of heavy concrete construction at elevations 74 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, 140 feet 0 inch, and 160 feet 0 inch

West: Nonrated exterior wall of heavy concrete construction at elevations 74 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, 140 feet 0 inch, and 160 feet 0 inch

Floor: Nonrated floor of heavy concrete construction

Ceiling: Nonrated roof of heavy concrete construction

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Diesel fuel oil and transfer

  Diesel generator

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Diesel generator HVAC

  Control building HVAC

  Miscellaneous HVAC

  Reactor coolant

  Ex-core neutron monitoring

  Main steam

  Safety injection and shutdown cooling

  Essential spray pond

  Electrical power distribution

  Engineered safety feature actuation

- Non-train related cables associated with the following systems

  Control building HVAC

  Reactor coolant

- Train A 4.16 kV, Class 1E switchgear
- Train A 480V, Class 1E motor control centers
- Train A 480V, Class 1E load centers
- Train A 125 V-dc distribution auxiliary relay cabinets
- Train A 120 V-ac distribution panels
- Train A engineered safety feature switchgear room ventilation isolation dampers and solenoid valves
- Train A engineered safety feature equipment room essential air handling unit and associated dampers
- Train A control building isolation dampers

D. Summary and Conclusions

One train of systems necessary to achieve and maintain hot standby and cold shutdown, has been demonstrated to remain available for use based on fire barriers provided. The redundant train B system will remain available from the control room, in conjunction with operator action, outside of this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.1.8 Analysis Area IG

A. Location

Analysis Area IG consists of Fire Zone 20.

Fire Zone 20 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 160 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated exterior wall of heavy concrete construction at column line Jl

3-hour rated wall common to Zone 18A

3-hour rated wall common to Fire Area II, Zone 18B

2-hour rated wall common to the northwest HVAC chase

South: Nonrated exterior wall of heavy concrete construction at column line J4

3-hour rated area boundary wall common to the diesel/control building seismic gap at column line J4

2-hour rated wall common to the southwest stairwell

2-hour rated wall common to Fire Area II, Zone 19

East: 3-hour rated wall common to the corridor building at column line JE

2-hour rated wall common to Fire Area II, Zone 19

3-hour rated wall common to Fire Area II, Zone 18B

West: 3-hour rated exterior wall at column line JA

2-hour rated wall common to the northwest HVAC chase

Floor: 3-hour rated barrier common to Fire Area III, Zones 16 and 17

Ceiling: Nonrated roof of heavy concrete construction

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Diesel fuel oil and transfer

  Diesel generator

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Diesel generator HVAC

Control building HVAC

Nuclear cooling water

Reactor coolant

Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Essential spray pond

Nuclear sampling

Electrical power distribution

Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

D. Summary and Conclusions

Safe shutdown capability will be provided by utilizing redundant train B systems available from the control room, in conjunction with operator action, outside this analysis area, to prevent or overcome the consequences of spurious operation of train A components or to establish equipment lineups required to achieve the shutdown function.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain

available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.1.9 Fire Area I, Fire Zone 1, Train A Essential Chiller Room

A. Location

Fire Zone 1 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 74 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 3A

3-hour rated wall common to Zone 86A at column line J1

South: 2-hour rated wall common to the southwest stairwell at column line J4

Nonrated exterior wall of heavy concrete construction at column line J4

East: 3-hour rated wall common to Fire Area II, Zone 2, at column line JC

West: Nonrated exterior wall of heavy concrete construction at column line JA

3-hour rated wall common to Zone 3A

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Zones 5A, 6A, 7A, 8A, 9A, and 10A

2. Zone Access

- One Class B door in the 2-hour rated south wall to the southwest stairwell
- One Class A door in the 3-hour rated east wall to Zone 2
- One Class A sliding door in the 3-hour rated east wall to Zone 2

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

Building structural columns and beams are protected by coatings with 3-hour fire ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Control building engineered safety feature normal air handling unit
- Control building normal air handling unit
- Chemical addition tank
- Neutralizing sump
- Control building outside air normal air washer unit
- Conduit
- Sump Pump

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
    - Polycarbonate battery casing
    - Cable insulation
    - Oil
    - Hydraulic fluid
    - Charcoal
2. Transient Combustible Load Type
    - Charcoal
    - Ordinary combustible

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel

2. Secondary

Two portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Nine 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.1.10 Fire Area I, Fire Zone 3A, Train A Cable Shaft

A. Location

Fire Zone 3A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 74 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 86A at column line J1

South: 3-hour rated wall common to Zone 1

East: 3-hour rated wall common to Zone 1

West: 3-hour rated wall common to Fire Area X at column line J1

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Zone 4A

2. Zone Access

One Class A door in the 3-hour rated south wall to Zone 1

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

Cable Insulation

2. Transient Combustible Load Type

- Cable insulation
- Ordinary combustible

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 1.

2. Secondary

Two portable CO_2 fire extinguishers are located in adjacent Zone 1.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.1.11 Fire Area I, Fire Zone 4A, Train A Cable Shaft

A. Location

Fire Zone 4A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 86A at column line J1

South: 3-hour rated wall common to Zone 5A

East: 3-hour rated wall common to the northwest HVAC chase

West: 3-hour rated wall common to Fire Area X at column line JA

Floor: 3-hour rated barrier common to Zone 3A

Ceiling: 3-hour rated barrier common to Zone 11A

2. Zone Access

   One Class A door in the 3-hour rated south wall to Zone 5A

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

Cable insulation

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Moderate

G. Fire Detection

Ionization smoke detector(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 5A.

2. Secondary

Two portable CO_2 fire extinguishers are located in adjacent Zone 5A.

I. Ventilation

None. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

None

K. Emergency Communication

None

9B.2.1.12 Fire Area I, Fire Zone 5A, Train A ESF Switchgear Room

A. Location

Fire Zone 5A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 4A

2-hour rated wall common to Zone 86A at column line J1

2-hour rated walls common to the northwest HVAC chase

South: 2-hour rated walls common to the southwest HVAC chase

2-hour rated wall common to the southwest stairwell at column line J4

non-rated heavy concrete exterior wall at column line J4

East: 3-hour rated walls common to Zones 6A, 7A, 8A, and 9A

1-hour rated wall common to Zone 10A

West: 3-hour rated wall common to Fire Area X at column line JA

2-hour rated wall common to the northwest HVAC chase

Floor: 3-hour rated barrier common to Zone 1

Ceiling: 3-hour rated barrier common to Fire Area II, Zone 14

2. Zone Access

- One Class B door in the 2-hour rated south wall to the southwest stairwell
- One nonrated missileproof door in the non-rated south exterior wall at column line J4
- One Class A door (pair) in the 3-hour rated east wall to Zone 6A
- One Class C door in the 1-hour rated east wall to Zone 10A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   - Train A isolation relay cabinet

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation
      - Battery casing (polycarbonate)
      - Thermo-Lag 330-1

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Cable insulation

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

   Actuation of the ionization smoke detector system(s) and the thermal detector system(s) activates the

automatic CO_2 gas system. Either detector system alone provides early warning.

H. Fire Suppression

1. Primary

Automatic CO_2 total flooding

2. Secondary

One manual hose reel, two portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Two 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.1.13 Fire Area I, Fire Zone 6A, Train A (Channel C) DC Equipment Room

A. Location

Fire Zone 6A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 86A at column line J1

South: 3-hour rated wall common to Zone 8A

East: 3-hour rated wall common to Fire Area II, Zone 6B, at column line JC

West: 3-hour rated wall common to Zone 5A

Floor: 3-hour rated barrier common to Zone 1

Ceiling: 3-hour rated barrier common to Fire Area II, Zone 14

2. Zone Access

- One Class A door (pair) in the 3-hour rated west wall to Zone 5A
- One Class A door in the 3-hour rated east wall to Zone 6B
- One Class A door in the 3-hour rated south wall to Zone 8A, if implemented per DMWO 3232547

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Thermo-Lag 330-1
   - Cable insulation

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 5A.

2. Secondary

Two portable CO_2 fire extinguishers are located in Zone 5A.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communication

Sound powered phone jack(s) is provided.

9B.2.1.14 Fire Area I, Fire Zone 7A, Train A (Channel A) DC Equipment Room

A. Location

Fire Zone 7A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 9A

South: 3-hour rated wall common to Zones 5A and 10A

East: 3-hour rated wall common to Fire Area II, Zone 7B, at column line JC

West: 3-hour rated wall common to Zone 5A

Floor: 3-hour rated barrier common to Zone 1

Ceiling: 3-hour rated barrier common to Fire Area II, Zone 14

2. Zone Access

One Class A door (pair) in the 3-hour rated west wall to Zone 5A

One Class A door in the 3-hour rated east wall to Zone 7B, if implemented per DMWO 3232547

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating. (Refer to the appendix 9A response to Question 9A.112.)

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Essential lighting isolation transformer V01
- Line voltage regulator V13

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible

- Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detectors system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 5A.

2. Secondary

   Two portable CO_2 fire extinguishers are located in adjacent Zone 5A.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.1.15 Fire Area I, Fire Zone 8A, Train A (Channel C) Battery Room

A. Location

Fire Zone 8A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 6A

South: 3-hour rated wall common to Zone 9A

East: 3-hour rated wall common to Fire Area II, Zone 8B, at column line JC

West: 3-hour rated wall common to Zone 5A

Floor: 3-hour rated barrier common to Zone 1

Ceiling: 3-hour rated barrier common to Fire Area II, Zone 14

2. Zone Access

One Class A door in the 3-hour rated west wall to Zone 5A

One Class A door in the 3-hour rated north wall to Zone 6A, if implemented per DMWO 3232547

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings. (Refer to the appendix 9A response to Question 9A.123.)

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Conduit
   - Normal exhaust fan

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Thermoplastic battery cases
      - Cable insulation

   2. Transient Combustible Load Type

      - Ordinary combustible

- Thermoplastic battery cases

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Actuation of the ionization smoke detector system(s) and the thermal detector system(s) activates the automatic CO_2 gas system. Either detector system alone can provide early warning.

H. Fire Suppression Systems

1. Primary

   Automatic CO_2 total flooding

2. Secondary

   One manual hose reel and two portable CO_2 fire extinguishers are located in adjacent Zone 5A.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.1.16 Fire Area I, Fire Zone 9A, Train A (Channel A) Battery Room

A. Location

Fire Zone 9A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	3-hour rated wall common to Zone 8A
South:	3-hour rated wall common to Zone 7A
East:	3-hour rated wall common to Fire Area II, Zone 9B, at column line JC
West:	3-hour rated wall common to Zone 5A
Floor:	3-hour rated barrier common to Zone 1
Ceiling:	3-hour rated barrier common to Fire Area II, Zone 14

2. Zone Access

One Class A door in the 3-hour rated west wall to Zone 5A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings. (Refer to the appendix 9A response to Question 9A.123.)

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Conduit
   - Normal exhaust fan

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Thermoplastic battery cases
      - Cable insulation

   2. Transient Combustible Load Type

      - Ordinary combustible

- Thermoplastic battery cases

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Actuation of the ionization smoke detector system(s) and the thermal detector system(s) activates the automatic CO_2 gas system. Either detector system alone can provide early warning.

H. Fire Suppression

1. Primary

   Automatic CO_2 total flooding

2. Secondary

   One manual hose reel and two portable CO_2 fire extinguishers are located in adjacent Zone 5A.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.1.17 Fire Area I, Fire Zone 10A, Train A Remote Shutdown Room

A. Location

Fire Zone 10A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	3-hour rated wall common to Zone 7A
	3-hour rated wall common to Fire Area II, Zone 7B
South:	3-hour rated area boundary wall common to the diesel/control building seismic gap at column line J4
East:	2-hour rated wall common to Fire Area II, Zone 10B
West:	1-hour rated wall common to Zone 5A
Floor:	3-hour rated barrier common to Zone 1
	3-hour rated barrier common to Fire Area II, Zone 2
Ceiling:	3-hour rated barrier common to Fire Area II, Zone 14

2. Zone Access

- One Class B door in the 2-hour rated east wall to Zone 10B

- One Class C door in the 1-hour rated west wall to Zone 5A

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Building columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train A remote shutdown panel C
- Remote shutdown panel N

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation

- Paper
- Plastic (telephones)
- Polycarbonate battery casing
- Thermo-Lag 330-1

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning and thermal detectors will actuate the automatic Halon 1301 gas system.

H. Fire Suppression

1. Primary

Automatic Halon 1301 fire extinguishing system.

2. Secondary

One manual hose reel and two portable CO_2 fire extinguishers are located in adjacent Zone 5A.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.1.18 Fire Area I, Fire Zone 11A, Train A Cable Shaft

A. Location

Fire Zone 11A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	3-hour rated wall common to Zone 86A at column line J1
South:	3-hour rated wall common to Fire Area II, Zone 14
East:	3-hour rated wall common to the northwest HVAC chase
West:	3-hour rated wall common to Fire Area X at column line JA
Floor:	3-hour rated barrier common to Zone 4A
Ceiling:	3-hour rated barrier common to Zone 15A

2. Zone Access

   - One Class A door in the 3-hour rated south wall to Zone 14

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      Cable insulation

2. Transient Combustible Load Type

    - Ordinary combustible
    - Cable insulation

3. Total Combustible (Fire) Loading

    High

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

    One manual hose reel is located in adjacent Zone 14.

2. Secondary

    Four portable CO_2 fire extinguishers are located in adjacent Zone 14.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

None

K. Emergency Communications

None

9B.2.1.19 Fire Area I, Fire Zone 15A, Train A Cable Shaft

A. Location

Fire Zone 15A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	3-hour rated wall common to Zone 86A at column line J1
South:	3-hour rated wall common to Fire Area III, Zone 17
East:	3-hour rated wall common to the northwest HVAC chase
West:	3-hour rated wall common to Fire Area X at column line JA
Floor:	3-hour rated barrier common to Zone 11A
Ceiling:	3-hour rated barrier common to Zone 18A

2. Zone Access

One Class A door in the 3-hour rated south wall to Zone 17

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

   Cable insulation

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

Five portable CO_2 fire extinguishers in adjacent zone 17.

2. Secondary

Four portable pressurized water fire extinguishers are located in adjacent Zone 17 and a manual hose station outside the control room.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

None

K. Emergency Communications

None

9B.2.1.20 Fire Area I, Fire Zone 18A, Train A Cable Shaft

A. Location

Fire Zone 18A (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 160 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	3-hour rated exterior wall at column line J1
South:	3-hour rated wall common to Zone 20
East:	3-hour rated wall common to the northwest HVAC chase
West:	3-hour rated exterior wall at column line JA
Floor:	3-hour rated barrier common to Zone 15A
Ceiling:	Nonrated roof of heavy concrete construction

2. Zone Access

One Class A door in the 3-hour rated south wall to Zone 20

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

   Cable insulation

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

   Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 20.

2. Secondary

Four portable CO_2 fire extinguishers are located in adjacent Zone 20.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

None

K. Emergency Communications

None

9B.2.1.21 Fire Area I, Fire Zone 20, Upper Cable Spreading Room

A. Location

Fire Zone 20 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 160 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction at column line J1

3-hour rated wall common to Zone 18A

3-hour rated wall common to Fire Area II, Zone 18B

2-hour rated wall common to the northwest HVAC chase

South: Nonrated exterior wall of heavy concrete construction at column line J4

3-hour rated area boundary wall common to the diesel/control building seismic gap at column line J4

2-hour rated wall common to the southwest stairwell

2-hour rated wall common to Fire Area II, Zone 19

East: 3-hour rated wall common to the corridor building at column line JE

2-hour rated wall common to Fire Area II, Zone 19

3-hour rated wall common to Fire Area II, Zone 18B

West: 3-hour rated exterior wall at column line JA

2-hour rated wall common to the northwest HVAC chase

Floor: 3-hour rated barrier common to Fire Area III, Zones 16 and 17

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One Class B door in the 2-hour rated south wall to the southwest stairwell
- One nonrated missile door in the 3-hour rated east wall to the corridor building (Refer to Appendix 9A response to Question 9A.106)

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train A ERFDAD termination cabinets
- Train A radiation monitor

D. Nonsafety-Related Equipment and Components

- Cable trays and conduit
- Nontrain-related ERFDAD termination cabinets

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Thermo-Lag 330-1
   - Cable insulation
2. Transient Combustible Load Type
   - Ordinary combustible
   - Cable insulation
3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Actuation of either ionization detector system(s) or line-type thermal detector system(s) activates the automatic preaction water sprinkler system. Either detector system alone can provide early warning capability.

H. Fire Suppression

1. Primary

Automatic preaction water sprinkler system

2. Secondary

One manual hose reel, four portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Six 6-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.1.22 Fire Area I, Fire Zone 86A, Train A Compartment Between Auxiliary and Control Buildings

A. Location

Fire Zone 86A (engineering drawing 13-A-ZYD-029) is the compartment between the auxiliary and control

buildings between elevations 74 feet 0 inch and 156 feet 4 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XV at column line A10

South: 3-hour rated wall at column line J1 common to:

- Zones 1 and 3A at elevation 74 feet 0 inch
- Zones 4A and 6A at elevation 100 feet 0 inch
- Zone 11A and the northwest HVAC chase at elevation 120 feet 0 inch
- Zone 15A and the northwest HVAC chase at elevation 140 feet 0 inch

2-hour rated wall common to Zone 5A and the northwest HVAC chase at column line J1 and elevation 100 feet 0 inch

3-hour rated wall common to Fire Area II, Zone 14, at column line J1 and elevation 120 feet 0 inch

3-hour rated wall common to Fire Area III, Zone 17, at column line J1 and elevation 140 feet 0 inch

East: Nonrated wall of heavy concrete construction common to Fire Area II, Zone 86B, at column line JC

West: Nonrated wall common to Fire Area X at column line JA

Floor: Nonrated basemat of light concrete paving at elevation 74 feet 0 inch

Ceiling: Nonrated roof at elevation 156 feet 0 inch

2. Zone Access

One Class B door in the 2-hour rated south wall, elevation 100 feet 0 inch, to Zone 5A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Thermo-Lag 330-1

2. Transient Combustible Load Type

- Ordinary combustible
- Cable Insulation

3. Total Combustible (Fire) Loading

High

G. Fire Detection

Actuation of both the ionization detector system(s) and the line-type thermal detector system(s) activates the automatic water spray system. Either detection system alone can provide early warning capability.

H. Fire Suppression

1. Primary

Automatic deluge water spray system covering the cable trays only. (At elevations 100 feet 0 inch and 120 feet 0 inch only, see engineering drawing 13-A-ZYD-029)

2. Secondary

Two portable CO_2 fire extinguishers and one manual hose reel are located at elevation 100 feet 0 inch in adjacent Zone 5A.

I. Ventilation

Manually controlled smoke venting through the seismic gap in the ceiling. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.2 FIRE AREA II

9B.2.2.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area II contains train B components found in the control building. This fire area includes Analysis Areas IIA (Zone 2, 19, HVAC Chase J-115, outside

airchase J-A09 and HVAC Chase J-118), IIB (Zones 3B, 4B, 11B, 15B, and 18B), IIC (Zone 86B), IID (Zones 6B, 7B, 8B, and 9B), IIE (Zone 10B), IIF (Zone 5B), and IIG (Zones 12, 13, 14, and 19) (engineering drawing 13-A-ZYD-029).

At elevation 74 feet 0 inch, Fire Area II is below grade and bounded to the north by a 3-hour rated barrier common to Fire Area XV, to the west by a 3-hour rated barrier common to Fire Area I, and to the south and east by nonrated exterior walls and 2-hour rated walls common to the east stairwell and a cable riser shaft. The east exterior wall of Zone 3B is 3-hour rated. The wall of Zone 86B common to Fire Area I, Zone 86H, is nonrated. The basemat is nonrated. An HVAC equipment access area is located near the southeast corner and is fitted with a 3-hour rated missileproof hatch at grade level.

At elevation 100 feet 0 inch, Fire Area II is bounded to the north by a 3-hour rated barrier common to Fire Area XV, to the west by 3-hour rated barriers common to Fire Area I, to the east by a 3-hour rated barrier common to the corridor building, and a non-rated heavy concrete exterior wall and to the south by a 3-hour rated barrier common to the diesel/control building seismic gap. The west wall of Zone 86B common to Fire Area I, Zone 86A, is nonrated. The east wall of Zone 86B common to the corridor building is nonrated. The west wall of Zone 10B common to Fire Area I, Zone 10A, is 2-hour rated.

At elevation 120 feet 0 inch, Fire Area II is bounded to the north by 3-hour rated barriers common to Fire Areas I and XV and by 2-hour rated barriers common to the northwest HVAC chase (Fire Area I), to the west by a 3-hour rated barrier common to Fire Area X, to the east by a 3-hour rated barrier common to the corridor building and by a non-rated heavy concrete exterior wall. The east wall of Zone 86B common to the corridor building is nonrated. The west wall of Zone 86B common to Fire Area I, Zone 86A, is nonrated. Fire Area II is bounded to the south by 2-hour rated barriers common to Fire Area I, the southwest HVAC chase and stairwell by a 3-hour rated barrier common to the diesel/control building seismic gap and by a nonrated exterior wall. The ceilings to Zones 12, 13, and 14 are 3-hour rated and common to Fire Area III.

At elevation 140 feet 0 inch, Fire Area II consists of the northeast and southeast corners of the control building. In the northeast corner, Fire Area II consists of Zones 15B and 86B, bounded to the north by a 3-hour rated barrier common to Fire Area XV, to the south by 3-hour rated barriers common to Fire Area III, to the west by 3-hour rated barriers common to Fire Areas I and III, and to the east by a 3-hour rated barrier common to the corridor building. The east wall of Zone 86B common to the corridor building is nonrated. The west wall of Zone 86B common to Fire Area I, Zone 86A, is nonrated. The ceiling to

Zone 86B is a nonrated barrier common to the roof. In the southeast corner, Fire Area II includes the southeast outside air and HVAC chases, bounded to the north and west by 2-hour rated barriers common to Fire Area III, to the south by a 3-hour rated barrier common to the diesel/control building seismic gap, and to the southeast by non-rated heavy concrete exterior walls.

At elevation 160 feet 0 inch, Fire Area II consists of the northeast and southeast corners of the control building. In the northeast corner, Fire Area II consists of Zone 18B, bounded to the north by a 3-hour rated exterior wall, to the west and south by 3-hour rated barriers common to Fire Area I, and to the east by a 3-hour rated barrier common to the corridor building. In the southeast corner, Fire Area II includes Zone 19 and is bounded to the north and west by 2-hour rated barriers common to Fire Area I, to the south by a 3-hour rated barrier common to the diesel/control building seismic gap and a nonrated exterior wall, and to the east by a 3-hour rated barrier common to the corridor building and a nonrated heavy concrete exterior wall. The floor to Zone 19 is a 3-hour rated barrier partially common to Fire Area III. The ceiling to Zones 18B and 19, which is also the roof of the control building, is nonrated.

B. Deviations from 10CFR50, Appendix R, Section III.G

1. A deviation is requested from Section III.G.2 to the extent that it requires 3-hour rated barriers to separate circuits of redundant trains.

<u>Discussion</u>

The west and north walls of the southeast outside air and HVAC chases (adjacent to Fire Area II, Zones 2, 5B, 12, 13, 14, and 19) are common boundaries with Fire Area III, Zones 16 and 17, at elevation 140 feet 0 inch. The outside air and HVAC chases have walls of reinforced concrete construction rated for 2 or 3 hours. For a fire to propagate between redundant trains, the fire must burn through at least two 2-hour rated fire barriers. The outside air and HVAC chases are virtually devoid of combustibles. Fire dampers used in the two hour rated wall portions are identical in material and construction to 3-hour labeled devices. Each floor section is also provided with a fire damper. Fire detection and automatic suppression are provided in the vicinity of the chase at elevations 100 feet 0 inch, 120 feet 0 inch, and 160 feet 0 inch. Fire detection is provided in the vicinity of the chase at elevations 74 feet 0 inch and 140 feet 0 inch. Fire department response

(within 20 minutes) is expected before degradation to the existing fire barriers would occur. Access to the chase for the fire department response is available at elevation 100 feet 0 inch (through Zone 5B).

Conclusion

The existing design provides equivalent protection of that required by Section III.G.2, and upgrading the existing design for 3-hour ratings would not significantly enhance the protection currently provided.

2. A deviation is requested to Section III.G.2 to the extent that it requires installation of a 1-hour fire-rated barrier and an area-wide suppression system.

Discussion

The east wall of Zone 86B is a fire area boundary between Fire Area II and the corridor building at elevations 90 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch. The boundary contains a 6-inch (nominal) seismic gap which is covered with nonrated, solid, 18-gauge sheet metal flashings on each side of a reinforced concrete stub wall. The metal flashings would retard the passage of heat and/or smoke. The corridor building contains – non-safety related HVAC damper control cables and non-safety related RCP control cables. The

ability to achieve and maintain safe shutdown is demonstrated by calculations 13-MC-FP-316 and 13-MC-FP-318.

Within Fire Area II, Zone 86B is separated from the remainder of the fire area by 2- and 3-hour rated walls. Zone 86B is separated from Zone 86A (Fire Area I) by a nonrated barrier (see Fire Area I, deviation No. 5, for the Zone 86A/Zone 86B separation considerations). Zonal detection and automatic deluge water spray covers the predominant in situ combustible (cable trays at elevation 100 feet 0 inch and 120 feet 0 inch). The total combustible (fire) loading for Zone 86B is high. The apparently high combustible loading is attributed to the calculation method in that the combustible material is located in an area with a relatively small floor space combined with high ceilings. Fire department response (within 20 minutes) is expected before significant degradation of the existing fire barriers would occur. Access to Zone 86A for fire department response is available at elevation 100 feet 0 inch (through Zone 5A).

Because the metal flashings are tight against the concrete stub walls, smoke and hot gases would not propagate to the adjoining area pending arrival of the fire department.

Therefore, these boundaries form valid fire areas, as required by section III of appendix R.

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2, and upgrading the existing design to a 1-hour rating plus suppression would not significantly enhance protection currently provided.

3. This deviation evaluation assesses the adequacy of preaction cable tray fire suppression versus general area fire suppression in Fire Area II, Fire Zone 14, Lower Cable Spreading Room. Appendix R, Section III.G.2.c requires enclosure of cables, equipment and associated non-safety circuits of one redundant train in a fire barrier having a 1-hour rating. In addition, fire detectors and an (areawide) automatic fire suppression system shall be installed in the fire area. The deviation is for the automatic fire suppression system which is installed for the protection of the cable trays in the fire area but not at the ceiling level for full areawide protection.

Discussion

Fire Area II, Fire Zone 14, Lower Cable Spreading Room contains Train B cables. This zone is bounded on all sides, including floors

and ceilings by 1, 2 and 3 hour rated continuous fire barriers.

There is a small (2' x 6') enclosed vertical cable chase along the north wall in Zone 14, floor elevation 120 feet at column JC - J1. The chase contains Train A, IEEE 383 fire rated cables. The enclosure around the Train A cables is 2-hour fire rated, 8-inch concrete masonry unit (CMU) block construction from floor to ceiling (UL Design U904 and Uniform Building Code Table No. 43-B). There are two 4' x 4' access hatches with Class B labeled, 1-1/2 hour rated hatch covers. The chase is sealed with 3-hour fire seals at the floor and ceiling. The installed chase enclosure exceeds the 1-hour fire barrier requirement of 10CFR50, Appendix R, Section III.G.2.C.

Fire detection in the zone consists of thermistor wire in each cable tray and smoke detection at the ceiling. Preaction water spray suppression systems are installed in each cable tray. Manual hose stations and portable fire extinguishers are provided. The cable spreading room is typically not subject to transient combustibles and does not contain equipment or components which require frequent maintenance, surveillance or testing activities. The room is a very low personnel activity room and the potential for fire involving transient

combustibles is extremely low. The room is readily accessible for manual fire fighting.

The train separation and protection provided complies with Appendix R, Section III G.2.c, except that the suppression system installed is a preaction water spray system covering all the cable trays in lieu of ceiling level coverage for the entire area. The unsprinklered areas of the room are those without cable trays and are not in the immediate proximity of the Train A cable chase. The enclosed cable chase is not exposed to unprotected combustible loads. The chase does not contain a sprinkler system nor combustibles other than the IEEE-383 fire resistant cables.

Cable tray only suppression for compliance with 10CFR50, Appendix R, Section III.G.2.c has been previously accepted by the NRC in lieu of general ceiling area sprinkler protection in another PVNGS fire zone as described in NUREG 0857, Supplement No. 6, Safety Evaluation Report related to the operation of PVNGS, Section 9.5.1.6, dated October 1984, Page 9-10.

Conclusion

The existing design provides equivalent protection to that required by 10CFR50, Appendix R, Section III.G.2.c. and provides an acceptable level of protection to assure that

there will be no adverse impact on the ability to achieve and maintain safe shutdown.

4. See subsection 9B.2.1 for deviations common to Fire Area I and section 9B.2, Fire Hazards Analysis, for generic deviations.

9B.2.2.2 Analysis Area IIA

A. Location

Analysis Area IIA consists of Fire Zone 2, HVAC Chase J-115, HVAC Chase J-118, outside Air Chase J-A09 and Fire Zone 19.

Fire Zone 2 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 74 feet 0 inch.

HVAC Chase J-115 is located in the control building at elevation 100 feet 0 inch.

HVAC Chase J-118 is located in the control building at Elevation 91 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

Outside Air Chase J-A09 is located in the control building at elevations 91, 100, 120, 140, and 160 feet 0 inch.

Fire Zone 19, fan room, is located at elevation 160 feet 0 inch.

B. Analysis Area Boundaries

Fire Zone 2

North: 3-hour rated wall common to Zone 3B

3-hour rated wall common to Zone 86B at column line J1

South: Nonrated exterior wall of heavy concrete construction at column line J4

East: 2-hour rated wall common to the east stairwell at column line JE

Nonrated area boundary exterior wall of heavy concrete construction at column line JE

3-hour rated wall common to Zone 3B

2-hour rated wall common to the cable riser shaft between elevations 80 feet 0 inch and 100 feet 0 inch, at column line JE

West: 3-hour rated wall common to Fire Area I, Zone 1, at column line JC

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Zones 5B, 6B, 7B, 8B, 9B, and 10B

3-hour rated barrier common to Fire Area I, Zone 10A

NOTE

> A 3-hour rated outside air plenum and a 2-hour rated soffit to the southeast HVAC chase are located near column line J4.

HVAC Chase J-115

North: 3-hour rated wall common to Zone 86B

South: 2-hour rated wall common to Zone 5B

East: 3-hour rated wall common to Zone 4B

West: 2-hour rated wall common to Zone 5B

Floor: Open to Zone 2

Ceiling: 3-hour rated barrier common to Zone 14

HVAC Chase J-118

North: 3-hour rated wall common to Zone 5B

2-hour rated wall common to Zones 12 and 13

2-hour rated wall common to Fire Area III, Zone 17

South: 3-hour rated wall common to the diesel/control building seismic gap at column line J4, 5 feet 6 inches west of column line JE at elevation 140 feet 0 inch

East: Nonrated wall of heavy concrete construction

West: Nonrated wall of heavy concrete construction common to the outside air chase

Floor: Open to Zone 2

Ceiling: Nonrated barrier common to Zone 19

<u>Outside Air Chase J-A09</u>

North: 3-hour rated soffit common to Zone 3

3-hour rated wall common to Zone 5B

2-hour rated wall common to Zones 12 and 13

2-hour rated wall common to Fire Area III, Zone 17

Nonrated wall common to Zone 19

South: 3-hour rated wall common to diesel/control building seismic gap at column line J4

East: 2-hour rated wall common to HVAC Chase J-118

Nonrated wall common to Zone 19

West: 3-hour rated wall common to Zone 1

2-hour rated wall common to Zone 5B

2-hour rated wall common to Zone 14

2-hour rated wall common to Zone 16

Nonrated wall common to Zone 19

<u>Fire Zone 19</u>

North: 2-hour rated wall common to Zone 20

South: 3-hour rated wall common to diesel generator building exhaust stack and nonrated concrete exterior wall

East: Nonrated concrete exterior wall

West: 2-hour rated wall common to Zone 20

C. Safe Shutdown Related Components and Cables

- Train B cables associated with the following systems:

  Chemical and volume control (Units 2 & 3 only)

  Essential chilled water

  Essential cooling water

  Control building HVAC

  Miscellaneous HVAC

  Main steam

  Essential spray pond

  Nuclear sampling

  Engineered safety featured actuation

- Train A cables associated with the following system: Control building HVAC

- Train B essential chiller and associated components

- Train B essential chilled water expansion tank and associated level control equipment

- Train B control room essential air handling unit and associated components

- Train A and train B dampers associated with control room cooling

- Train B engineered safety feature switchgear room essential air handling unit and associated dampers
- Engineered safety feature activation (CREFAS)

D. Summary and Conclusion

Safe shutdown capability will be provided by utilizing redundant train A systems available from the control room, in conjunction with operator action, outside this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function. One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.2.3 Analysis Area IIB

A. Location

Analysis Area IIB consists of Fire Zones 3B, 4B, 11B, 15B, and 18B.

Fire Zone 3B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 74 feet 0 inch.

Fire Zone 4B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

Fire Zone 11B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inch.

Fire Zone 15B (engineering drawing 13-A-ZYD-029) is located in the control building between elevations 132 feet 0 inch and 160 feet 0 inch.

Fire Zone 18B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 160 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Zone 86B at column line J1

South: 3-hour rated wall common to Zone 2 (elevation 74 feet 0 inch)

3-hour rated wall common to Zone 5B (elevation 100 feet 0 inch)

3-hour rated wall common to Zone 14 (elevation 120 feet 0 inch)

3-hour rated wall common to Zone 14 (between elevation 132 feet 0 inch and 140 feet 0 inch)

3-hour rated wall common to Fire Area III, Zone 17 (elevation 140 feet 0 inch)

3-hour rated wall common to Fire Area I, Zone 20 (elevation 160 feet 0 inch)

East: 3-hour rated wall at column line JE (elevation 74 feet 0 inch)

West: 3-hour rated wall common to Zone 2 (elevation 74 feet 0 inch)

3-hour rated wall common to the northeast HVAC Chase (elevation 100 feet 0 inch)

3-hour rated wall common to Zone 14 (elevation 120 feet 0 inch)

3-hour rated wall common to Zone 14 (between elevation 132 feet 0 inch and 140 feet 0 inch)

3-hour rated wall common to Fire Area III, Zone 17 (elevation 140 feet 0 inch)

3-hour rated wall common to Fire Area I, Zone 20 (elevation 160 feet 0 inch)

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of heavy concrete construction

C. Safe Shutdown Related Components and Cables

- Train B cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

Diesel fuel oil and transfer

Diesel generator

Essential chilled water

Essential cooling water

Auxiliary building HVAC

Diesel generator HVAC

Control building HVAC

Nuclear cooling water

Reactor coolant

Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Essential spray pond

Nuclear sampling

Electrical power distribution

Engineered safety feature actuation.

- Nontrain related cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

D. Summary and Conclusion

Safe shutdown capability will be provided by utilizing redundant train A systems available from

the control room, in conjunction with operator action, outside this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.2.4 Analysis Area IIC

A. Location

Analysis Area IIC consists of Fire Zone 86B.

Fire Zone 86B (engineering drawing 13-A-ZYD-029) is the compartment between the auxiliary and control buildings between elevations 74 feet 0 inch and 156 feet 4 inches.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Fire Area XV at column line A10

South: 3-hour rated wall at column line J1 common to:

- Zones 2 and 3B at elevation 74 feet 0 inch
- Zones 4B and 6B at elevation 100 feet 0 inch

- Zones 11B and 14 at elevation 120 feet 0 inch
- Zone 15B between elevations 132 feet 0 inch and 156 feet 4 inches

2-hour rated wall common to Zone 5B and the northeast HVAC chase at column line Jl (elevation 100 feet 0 inch)

3-hour rated wall common to Fire Area III, Zone 17, at column line Jl (elevation 140 feet 0 inch)

East: Nonrated exterior wall at column line JE and elevation 74 feet 0 inch

Nonrated wall common to the corridor building at column line JE, at elevations 100 feet 0 inch, 120 feet 0 inch and 140 feet 0 inch

West: Nonrated wall of heavy concrete construction common to Fire Area I, Zone 86A, at column line JC

Floor: Nonrated basemat of light concrete paving at elevation 74 feet 0 inch

Ceiling: Nonrated roof of heavy concrete construction at elevation 156 feet 4 inches

C. Safe Shutdown Related Components and Cables

- Train B cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Nuclear cooling water

  Reactor coolant

  Ex-core neutron monitoring

  Main steam

  Safety injection and shutdown cooling

  Nuclear sampling

  Electrical power distribution

  Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Chemical and volume control

  Control building HVAC

  Nuclear cooling water

  Reactor coolant

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided. The redundant train A system will remain available from the control room, in conjunction with operator action, outside of this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.2.5 Analysis Area IID

A. Location

Analysis Area IID consists of Fire Zones 6B, 7B, 8B, and 9B.

Fire Zone 6B, 7B, 8B, and 9B (engineering drawing 13-A-ZYD-029) are located in the control building at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Zone 86B at column line J1

South: 3-hour rated wall common to Zone 5B and 10B

3-hour rated wall common to Fire Area I, Zone 10A

East: 3-hour rated wall common to Zone 5B

West: 3-hour rated wall common to Fire Area I, Zone 6A, 7A, 8A, and 9A at column line JC

Floor: 3-hour rated barrier common to Zone 2

Ceiling: 3-hour rated barrier common to Zone 14

C. Safe Shutdown Related Components and Cables

- Train B cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Essential chilled water

  Diesel generator HVAC

  Control building HVAC

  Main steam

  Safety injection and shutdown cooling

  Electrical power distribution

  Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Control building HVAC

  Reactor coolant

- Various train A and train B control building HVAC components

- Train B battery rooms ventilation exhaust fans and associated equipment

- Train B 125 V-dc control centers and distribution panels
- Train B battery B
- Train B battery D
- Train B battery chargers
- Train B 120 V-ac vital instrument distribution panel B
- Train B 120 V-ac inverters and voltage regulator
- Train A 120 V-ac swing inverter, if implemented per DMWO 3232547

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown, has been demonstrated to remain available for use based on fire barriers provided. The redundant train A system will remain available from the control room, in conjunction with operator action, outside of this analysis area to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.2.6 Analysis Area IIE

A. Location

Analysis Area IIE consists of Fire Zone 10B.

Fire Zone 10B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Zone 7B

South: 3-hour rated wall common to the diesel/control building seismic gap at column line J4

East: 1-hour rated wall common to Zone 5B

West: 2-hour rated wall common to Fire Area I, Zone 10A

Floor: 3-hour rated barrier common to Zone 2

Ceiling: 3-hour rated barrier common to Zone 14

C. Safe Shutdown Related Components and Cables

- Train B cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Essential chilled water

  Essential cooling water

  Control building HVAC

  Reactor coolant

  Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Nuclear sampling

Electrical power distribution

Engineered safety feature actuation

- Train A cables associated with the following systems:

  Control building HVAC

  Electrical power distribution

- Nontrain related cables associated with the following systems:

- Control building HVAC

- Train A battery room fire dampers

- Train B remote shutdown room fire damper

- Train B remote shutdown panel

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided. The redundant train A system will remain available from the control room, in conjunction with operator action, outside of this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve

the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.2.7 Analysis Area IIF

A. Location

Analysis Area IIF consists of Fire Zone 5B.

Fire Zone 5B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Zone 4B

2-hour rated wall common to Zone 86B at column line J1

2-hour rated walls common to the northeast HVAC chase

South: 3-hour rated walls common to the southeast outside air and HVAC chases

3-hour rated wall common to the diesel/control building seismic gap at column line J4

East: 3-hour rated wall common to the corridor building and non-rated heavy concrete exterior wall at column line JE

2-hour rated wall common to the northeast HVAC chase

2-hour rated wall common to the southeast outside air chase

West: 3-hour rated walls common to Zones 6B, 7B, 8B, and 9B

1-hour rated wall common to Zone 10B

Floor: 3-hour rated barrier common to Zone 2

Ceiling: 3-hour rated barrier common to Zones 12, 13, and 14

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Control building HVAC

- Train B cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Diesel fuel oil and transfer

  Diesel generator

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Diesel generator HVAC

  Control building HVAC

Miscellaneous HVAC

Reactor coolant

Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Essential spray pond

Nuclear sampling

Electrical power distribution

Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Control building HVAC

  Reactor coolant

- Train B engineered safety feature switchgear room ventilation isolation dampers and solenoid valves
- Train B engineered safety feature equipment room air handling unit and associated dampers
- Train A battery room fire dampers
- Train B battery room fire dampers
- Various ventilation dampers
- Train B 4.16 kV Class 1E switchgear
- Train B 480V Class 1E motor control centers

- Train B 480V Class 1E load centers
- Train B 120 V-ac distribution panels
- Train B 125 V-dc distribution auxiliary relay cabinets

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown, has been demonstrated to remain available for use based on fire barriers provided. The redundant train A system will remain available from the control room, in conjunction with operator action, outside of this analysis area to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.2.8 Analysis Area IIG

A. Location

Analysis Area IIG consists of Fire Zones 12, 13, and 14.

Fire Zone 12 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inch.

Fire Zone 13 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inch.

Fire Zone 14 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Fire Area I, Zone 11A

3-hour rated wall common to Fire Area I, Zone 86A, at column line J1

2-hour rated wall common to Fire Area I, the northwest HVAC chase

3-hour rated wall common to Zone 86B at column line Jl

3-hour rated wall common to Zone 11B

3-hour rated wall common to Zone 15B between elevations 132 feet 0 inch and 140 feet 0 inch

South: 2-hour rated wall common to the southeast HVAC and outside air chases

2-hour rated walls common to Fire Area I, the southwest stairwell and HVAC chase

3-hour rated wall common to the diesel/control building seismic gap at column line J4

Nonrated exterior wall at column line J4 (elevation 120 feet 0 inch)

East: non-rated exterior wall at column line JE

3-hour rated wall common to the corridor building at column line JE

2-hour rated wall common to the southeast outside air chase (elevation 120 feet 0 inch)

3-hour rated wall common to Zones 11B and 15B (elevation 120 feet 0 inch)

West: 3-hour rated wall common to Fire Area X at column line JA 2-hour rated wall common to

Fire Area I, the northwest HVAC chase

2-hour rated wall common to Fire Area I, the southwest HVAC chase

2-hour rated wall common to Fire Area I, the southwest HVAC chase

Floor: 3-hour rated barrier common to Fire Area I, Zones 5A, 6A, 7A, 8A, 9A, and 10A (elevation 120 feet 0 inch)

3-hour rated barrier common to Zones 5B, 6B, 7B, 8B, 9B, and 10B (elevation 120 feet 0 inch)

3-hour rated barrier common to Fire Area III, Zone 17 (160 feet 0 inch)

Ceiling: 3-hour rated barrier common to Fire Area III, Zones 16 and 17 (elevation 120 feet 0 inch)

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Control building HVAC

  Main steam

  Electrical power distribution

  Engineered safety feature actuation

- Train B cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Diesel fuel oil and transfer

  Diesel generator

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Diesel generator HVAC

  Control building HVAC

  Nuclear cooling water

  Reactor coolant

  Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Essential spray pond

Nuclear sampling

Electrical power distribution

Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Chemical and volume control

  Control building HVAC

  Nuclear cooling water

  Reactor coolant

- Communications room isolation dampers

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided. The redundant train A system will remain available from the control room, in conjunction with operator action, outside of this analysis area to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.2.9 Fire Area II, Fire Zone 2, Train B Essential Chiller Room

A. Location

Fire Zone 2 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 74 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 3B

3-hour rated wall common to Zone 86B at column line J1

South: Nonrated exterior wall of heavy concrete construction at column line J4

East: 2-hour rated wall common to the east stairwell at column line JE

Nonrated area boundary exterior wall of heavy concrete construction at column line JE

3-hour rated wall common to Zone 3B

2-hour rated wall common to the cable riser shaft between elevations 80 feet

0 inch and 100 feet 0 inch, at column line JE

West: 3-hour rated wall common to Fire Area I, Zone 1, at column line JC

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Zones 5B, 6B, 7B, 8B, 9B, and 10B

3-hour rated barrier common to Fire Area I, Zone 10A

NOTE

A 3-hour rated outside air plenum and a 2-hour rated soffit to the southeast HVAC chase are located near column line J4.

2. Zone Access

- One Class B door in the 2-hour rated east wall to the east stairwell
- One Class A sliding door in the 3-hour rated west wall to Zone 1
- One Class A door in the 3-hour rated west wall to Zone 1

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating. (Refer to the appendix 9A response to Question 9A.112.)

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Chemical addition tank
   - Neutralizing sump
   - Control room normal air handling unit
   - Conduit
   - Sump pumps

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation
      - Oil
      - Charcoal
      - Polycarbonate battery casing

- Lubricating grease

2. Transient Combustible Load Type

   - Charcoal
   - Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel

2. Secondary

   Two portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside through the corridor building using portable smoke removal equipment.

J. Drainage

Seven 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.2.10 Fire Area II, Fire Zone 3B, Train B Cable Shaft

A. Location

Fire Zone 3B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 74 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 86B at column line J1

South: 3-hour rated wall common to Zone 2

East: 3-hour rated exterior wall at column line JE

West: 3-hour rated wall common to Zone 2

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Zone 4B

2. Zone Access

One Class A door in the 3-hour rated south wall to Zone 2

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings

4. Fire Dampers

None

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation

   2. Transient Combustible Load Type

      - Cable insulation
      - Ordinary Combustible

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

   Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 2.

2. Secondary

Two portable CO_2 fire extinguishers are located in adjacent Zone 2.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside through the corridor building. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.2.11 Fire Area II, Fire Zone 4B, Train B Cable Shaft

A. Location

Fire Zone 4B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 86B at column line J1

South: 3-hour rated wall common to Zone 5B

East: 3-hour rated wall common to the corridor building at column line JE

West: 3-hour rated wall common to the northeast HVAC chase

Floor: 3-hour rated barrier common to Zone 3B

Ceiling: 3-hour rated barrier common to Zone 11B

2. Zone Access

   One Class A door in the 3-hour rated south wall to Zone 5B

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour fire ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

High

G. Fire Detection

Ionization smoke detector(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 5B.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 5B. One portable CO_2 fire extinguisher and one manual hose reel are located in the adjacent corridor building near Zone 5B.

I. Ventilation

Manually controlled smoke venting to the adjacent zone where portable smoke removal equipment exhausts smoke to the smoke removal HVAC chase. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

None

K. Emergency Communications

None

9B.2.2.12 Fire Area II, Fire Zone 5B, Train B ESF Switchgear Room

A. Location

Fire Zone 5B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 4B

2-hour rated wall common to Zone 86B at column line J1

2-hour rated walls common to the northeast HVAC chase

South: 3-hour rated walls common to the south-east outside air and HVAC chases

3-hour rated wall common to the diesel/control building seismic gap at column line J4

East: 3-hour rated wall common to the corridor building and non-rated heavy concrete exterior wall at column line JE

2-hour rated wall common to the northeast HVAC chase

West: 3-hour rated walls common to Zones 6B, 7B, 8B, and 9B

1-hour rated wall common to Zone 10B

Floor: 3-hour rated barrier common to Zone 2

Ceiling: 3-hour rated barrier common to Zones 12, 13, and 14

2. Zone Access

- One Class A door in the 3-hour rated south wall to Fire Area V (DG Building)
- One Class A door (pair) in the 3-hour rated east wall to the corridor building

- One Class A door (pair) in the 3-hour rated west wall to Zone 6B
- One Class C door in the 1-hour rated west wall to Zone 10B

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train B isolation relay cabinet

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Lubricating grease
- Polycarbonate battery casing
- Cable insulation
- Plastic
- Thermo-Lag 330-1

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Actuation of the ionization smoke detector system(s) and the thermal detector system(s) activates the automatic CO_2 gas system. Either detector system alone provides early warning.

H. Fire Suppression

1. Primary

Automatic CO_2 total flooding

2. Secondary

One manual hose reel and one portable CO_2 fire extinguisher. One portable CO_2 fire

extinguisher and one manual hose reel are located in the adjacent corridor building.

I. Ventilation

Manually controlled smoke exhaust venting to the smoke removal HVAC chase using portable smoke removal equipment.

J. Drainage

Two 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.2.13 Fire Area II, Fire Zone 6B, Train B (Channel D) DC Equipment Room

A. Location

Fire Zone 6B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 86B at column line J1

South: 3-hour rated wall common to Zone 8B

East: 3-hour rated wall common to Zone 5B

West: 3-hour rated wall common to Fire Area I, Zone 6A, at column line JC

Floor: 3-hour rated barrier common to Zone 2

Ceiling: 3-hour rated barrier common to Zone 14

2. Zone Access

- One Class A door (pair) in the 3-hour rated east wall to Zone 5B
- One Class A door in the 3-hour rated west wall to Zone 6A

3. Sealed Penetrations

Seals equal or exceed fire barrier rating.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Polycarbonate battery casing
- Thermo-Lag 330-1

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 5B.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent zone 5B. One portable CO_2 fire extinguisher and one manual hose reel are

located in adjacent corridor building near Zone 5B.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to the adjacent zone where portable smoke removal equipment exhausts smoke to the smoke removal HVAC chase.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.2.14 Fire Area II, Fire Zone 7B, Train B (Channel B) DC Equipment Room

A. Location

Fire Zone 7B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 9B

South: 3-hour rated wall common to Zones 5B and 10B

3-hour rated wall common to Fire Area I, Zone 10A

East: 3-hour rated wall common to Zone 5B

West: 3-hour rated wall common to Fire Area I, Zone 7A, at column line JC

Floor: 3-hour rated barrier common to Zone 2

Ceiling: 3-hour rated barrier common to Zone 14

2. Zone Access

One Class A door (pair) in the 3-hour rated east wall to Zone 5B

One Class A door in the 3-hour rated west wall to Zone 7A, if implemented per DMWO 3232547

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating. (Refer to the appendix 9A response to Question 9A.112.)

5. Protected Raceways

None

6. Protected Structural Members

Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Essential lighting isolation transformer V02

- Line voltage regulator V14

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Cable insulation
   - Polycarbonate battery casing
   - Thermo-Lag 330-1
2. Transient Combustible Load Type
   - Ordinary combustible
   - Cable insulation
3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 5B.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 5B. One portable CO_2 fire extinguisher and one manual hose reel are located in adjacent corridor building near Zone 5B.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to the adjacent zone where portable smoke removal equipment exhausts smoke to the smoke removal HVAC chase.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.2.15 Fire Area II, Fire Zone 8B, Train B (Channel D) Battery Room

A. Location

Fire Zone 8B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 6B

South: 3-hour rated wall common to Zone 9B

East: 3-hour rated wall common to Zone 5B

West: 3-hour rated wall common to Fire Area I, Zone 8A, at column line JC

Floor: 3-hour rated barrier common to Zone 2

Ceiling: 3-hour rated barrier common to Zone 14

2. Zone Access

   One Class A door in the 3-hour rated east wall to Zone 5B

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings. (Refer to the appendix 9A response to Question 9A.123.)

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

- Conduit
- Normal exhaust fan

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Thermoplastic battery cases
   - Cable insulation

2. Transient Combustible Load Type

   - Thermoplastic battery cases
   - Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Actuation of the ionization smoke detector system(s) and the thermal detector system(s) activates the automatic CO_2 gas system. Either detector system alone can provide early warning.

H. Fire Suppression Systems

1. Primary

   Automatic CO_2 total flooding

2. Secondary

One manual hose reel and one portable CO_2 fire extinguisher are located in adjacent Zone 5B. One portable CO_2 fire extinguisher and one manual hose reel are located in the adjacent corridor building near Zone 5B.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to the adjacent zone where portable smoke removal equipment exhausts smoke to the smoke removal HVAC chase.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.2.16 Fire Area II, Fire Zone 9B, Train B (Channel B) Battery Room

A. Location

Fire Zone 9B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 8B

South: 3-hour rated wall common to Zone 7B

East: 3-hour rated wall common to Zone 5B

West: 3-hour rated wall common to Fire Area I, Zone 9A, at column line JC

Floor: 3-hour rated barrier common to Zone 2

Ceiling: 3-hour rated barrier common to Zone 14

2. Zone Access

One Class A door in the 3-hour rated east wall to Zone 5B

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings. (Refer to the appendix 9A response to Question 9A.123.)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Conduit
- Normal exhaust fan

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Thermoplastic battery cases
   - Cable insulation
2. Transient Combustible Load Type
   - Thermoplastic battery cases
   - Ordinary combustible
3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Actuation of the ionization smoke detectors system(s) and the thermal detector system(s) activates the automatic CO_2 gas system. Either detector system alone can provide early warning.

H. Fire Suppression

1. Primary

   Automatic CO_2 total flooding

2. Secondary

One manual hose reel and one portable CO_2 fire extinguisher are located in adjacent Zone 5B. One portable CO_2 fire extinguisher and one manual hose reel are located in adjacent corridor building near Zone 5B.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to the adjacent zone where portable smoke removal equipment exhausts smoke to the smoke removal HVAC chase.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.2.17 Fire Area II, Fire Zone 10B, Train B Remote Shutdown Room

A. Location

Fire Zone 10B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 7B

South: 3-hour rated wall common to the diesel/control building seismic gap at column line J4

East: 1-hour rated wall common to Zone 5B

West: 2-hour rated wall common to Fire Area I, Zone 10A

Floor: 3-hour rated barrier common to Zone 2

Ceiling: 3-hour rated barrier common to Zone 14

2. Zone Access

- One Class B door in the 2-hour rated west wall to Zone 10A

- One Class C door in the 1-hour rated east wall to Zone 5B

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train B remote shutdown panel D

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Paper
   - Plastic (telephones)
   - Polycarbonate battery casing
   - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning and thermal detectors will actuate the automatic Halon 1301 gas system.

H. Fire Suppression

1. Primary

Automatic Halon 1301 fire extinguishing system

2. Secondary

One manual hose reel and one portable CO_2 fire extinguisher are located in adjacent Zone 5B. One portable CO_2 fire extinguisher and one manual hose reel are located in adjacent corridor building near Zone 5B.

I. Ventilation

(Refer to the appendix 9A response to Question 9A.70.) Manually controlled smoke venting to the adjacent zone where portable smoke removal equipment exhausts smoke to the smoke removal HVAC chase.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.2.18 Fire Area II, Fire Zone 11B, Train B Cable Shaft

A. Location

Fire Zone 11B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	3-hour rated wall common to Zone 86B at column line J1
South:	3-hour rated wall common to Zone 14
East:	3-hour rated wall common to the corridor building at column line JE
West:	3-hour rated wall common to Zone 14
Floor:	3-hour rated barrier common to Zone 4B
Ceiling:	3-hour rated barrier common to Zone 15B at elevation 132 feet 0 inch

2. Zone Access

One Class A door in the 3-hour rated south wall to Zone 14

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

All building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

Cable insulation

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

High

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 14.

2. Secondary

Four portable CO_2 fire extinguishers are located in adjacent Zone 14. One portable CO_2 fire extinguisher and one manual hose reel are located in the adjacent corridor building near Zone 14.

I. Ventilation

None. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

None

K. Emergency Communications

None

9B.2.2.19 Fire Area II, Fire Zone 12, Communications Room

A. Location

Fire Zone 12 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 1-hour rated wall common to Zone 14

South: 2-hour rated wall common to the southeast HVAC chase

East: Nonrated exterior wall at column line JE

3-hour rated wall common to the corridor building at column line JE

West: 1-hour rated wall common to Zone 13

Floor: 3-hour rated barrier common to Zone 5B

Ceiling: 3-hour rated barrier common to Fire Area III, Zone 17

2. Zone Access

One Class B door (pair) in the 1-hour rated north wall to Zone 14

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating, with the exception of fire dampers in the north and west walls in Unit 1 communicating with Fire Zones 14 and 13 respectively, which are not installed in accordance with the fire tested configuration. The barriers containing these dampers are not required to achieve separation in accordance with 10CFR50, Appendix R, Section III.G.2.

5. Protected Raceways

None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit and cable trays

   In-plant communications

   Battery and communications equipment

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Plastic
      - Cable insulation
      - Thermo-Lag 330-1

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Cable insulation

   3. Total Combustible (Fire) Loading

      Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning and in a cross-zoned mode actuates the automatic Halon 1301 gas system.

H. Fire Suppression

1. Primary

Automatic Halon 1301 gas system

2. Secondary

One manual hose reel and four portable CO_2 fire extinguishers are located in adjacent Zone 14.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.2.20 Fire Area II, Fire Zone 13, Inverter Room

A. Location

Fire Zone 13 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 1-hour rated wall common to Zone 14

South: 2-hour rated wall common to the southeast HVAC and outside air chases, 1-hour rated wall common to Zone 14

East: 1-hour rated wall common to Zone 12

West: 1-hour rated walls common to Zone 14

Floor: 3-hour rated barrier common to Zone 5B

Ceiling: 3-hour rated barrier common to Fire Area III, Zones 16 and 17

2. Zone Access

One Class B door (pair) in the 1-hour rated north wall to Zone 14

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating, with the exception of fire dampers in the east and west walls in Unit 1 communicating with Fire Zones 12 and 14 respectively, which are not installed in accordance with the fire tested configuration. The barriers containing these dampers are not required to achieve

separation in accordance with 10CFR50, Appendix R, Section III.G.2.

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Inverter equipment
   - Conduit and cable trays

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation
      - Thermo-Lag 330-1
      - Plastic

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

   Ionization smoke detector systems are provided for early warning and in a cross-zoned mode actuates the automatic Halon 1301 gas system.

H. Fire Suppression

1. Primary

   Automatic Halon 1301 gas system

2. Secondary

   One manual hose reel and four portable CO_2 fire extinguishers are located in adjacent Zone 14.

I. Ventilation

   Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

   None

K. Emergency Communications

   Sound powered phone jack(s) is provided.

9B.2.2.21 Fire Area II, Fire Zone 14, Lower Cable Spreading Room

A. Location

Fire Zone 14 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area I, Zone 11A

3-hour rated wall common to Fire Area I, Zone 86A, at column line J1

2-hour rated wall common to Fire Area I, the northwest HVAC chase

3-hour rated wall common to Zone 86B at column line J1

3-hour rated wall common to Zones 11B and 15B

1-hour rated wall common to Zone 13

South: 2-hour rated walls common to Fire Area I, the southwest stairwell and HVAC chase

3-hour rated wall common to the diesel/control building seismic gap at column line J4

	Nonrated exterior wall at column line J4
	1-hour rated wall common to Zone 12
	1-hour rated wall common to Zone 13
East:	3-hour rated wall common to the corridor building at column line JE
	2-hour rated wall common to the southeast outside air chase
	1-hour rated wall common to Zone 13
	3-hour rated wall common to Zones 11B and 15B
West:	3-hour rated wall common to Fire Area X at column line JA
	2-hour rated wall common to Fire Area I, the northwest HVAC chase
	2-hour rated wall common to Fire Area I, the southwest HVAC chase
Floor:	3-hour rated barrier common to Fire Area I, Zones 5A, 6A, 7A, 8A, 9A, and 10A
	3-hour rated barrier common to Zones 5B, 6B, 7B, 8B, 9B, and 10B
Ceiling:	3-hour rated barrier common to Fire Area III, Zones 16 and 17

2. Zone Access

   - One nonrated missile door in the 3-hour rated east wall to the corridor building (Refer to Appendix 9A response to Question 9A.106)
   - One Class A door in the 3-hour rated south wall to Fire Area V (DG Building)
   - One Class B door in the 2-hour rated south wall to the southwest stairwell

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating, with the exception of fire dampers in the east and south walls in Unit 1 communicating with Fire Zones 13 and 12 respectively, which are not installed in accordance with the fire tested configuration. The barriers containing these dampers are not required to achieve separation in accordance with 10CFR50, Appendix R, Section III.G.2.

5. Protected Raceways

   Train A auxiliary feedwater main steam and electrical power distribution cables are

enclosed in a 2-hour rated cable chase near column lines J1/JC.

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   Train B ERFDAD cabinets

   Train B radiation monitors

D. Nonsafety-Related Equipment and Components

   Cable trays and conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Plastic
   - Polycarbonate battery casing
   - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

   Actuation of either the ionization smoke detector system(s) or the line-type thermal detector system(s) activates the automatic preaction water sprinkler system. Either detector system alone can provide early warning capability.

H. Fire Suppression

   1. Primary

      Automatic zoned preaction water sprinkler system

   2. Secondary

      One manual hose reel and four portable CO_2 fire extinguishers

I. Ventilation

   Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

   Six 6-inch drains

K. Emergency Communications

   Sound powered phone jack(s) is provided.

9B.2.2.22 Fire Area II, Fire Zone 15B, BOP Cable Shaft

A. Location

Fire Zone 15B (engineering drawing 13-A-ZYD-029) is located in the control building between elevations 132 feet 0 inch and 160 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 86B at column line Jl

South: 3-hour rated wall common to Fire Area III, Zone 17

3-hour rated wall common to Zone 14 between elevations 132 feet 0 inch and 140 feet 0 inch

East: 3-hour rated wall common to the corridor building at column line JE

West: 3-hour rated wall common to Fire Area III, Zone 17

3-hour rated wall common to Zone 14 between elevations 132 feet 0 inch and 140 feet 0 inch

Floor: 3-hour rated barrier common to Zone 11B at elevation 132 feet 0 inch

Ceiling: 3-hour rated barrier common to Zone 18B

2. Zone Access

   One Class A door in the 3-hour rated west wall to Zone 14 at elevation 132 feet 0 inch.

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Cable trays

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      Cable insulation

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable Insulation

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 14 at elevation 120 feet 0 inch.

2. Secondary

   Four portable CO_2 fire extinguishers are located in adjacent Zone 14 at elevation 120 feet 0 inch.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

None

K. Emergency Communications

None

9B.2.2.23 Fire Area II, Fire Zone 18B, BOP Cable Shaft

A. Location

Fire Zone 18B (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 160 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated exterior wall at column line J1

South: 3-hour rated wall common to Fire Area I, Zone 20

East: 3-hour rated wall common to the corridor building at column line JE

West: 3-hour rated wall common to Fire Area I, Zone 20

Floor: 3-hour rated barrier common to Zone 15B

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

One Class A door in the 3-hour rated south wall to Zone 20

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Cable trays and conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      Cable insulation

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 20.

2. Secondary

   Four portable CO_2 fire extinguishers are located in adjacent Zone 20.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

None

K. Emergency Communications

None

9B.2.2.24 Fire Area II, Fire Zone 19, Normal Smoke Exhaust Room

A. Location

Fire Zone 19 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 160 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to Fire Area I, Zone 20

South: 3-hour rated wall common to the diesel/control building seismic gap at column line J4

Nonrated exterior wall of heavy concrete construction at column line J4

East: 3-hour rated wall common to the corridor building at column line JE

Nonrated exterior wall of heavy concrete construction at column line JE

West: 2-hour rated wall common to Fire Area I, Zone 20, at column line JD

Floor: 3-hour rated barrier common to Fire Area III, Zone 17

Open continuation of the southeast HVAC chase

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

One Class B door in the 2-hour rated north wall to Zone 20.

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barrier are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Normal smoke exhaust fan
- Conduit

- Communication equipment uninterruptible power supply, and batteries (In those units where DMWO 4493762 has been implemented)

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Lubricating grease
   - Rubber
   - Communication equipment uninterruptible power supply, and batteries (In those units where DMWO 4493762 has been implemented)
   -

2. Transient Combustible Load Type

   - Ordinary combustible
   - Lubricating grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

Two manual hose reels are located in adjacent Zone 20 and the corridor building.

2. Secondary

Four portable CO_2 fire extinguishers are located in adjacent Zone 20. One portable CO_2 fire extinguisher is located in the adjacent corridor building.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside. (Refer to the appendix 9A response to Questions 9A.70 and 9A.80.)

J. Drainage

None

K. Emergency Communications

None

9B.2.2.25 Fire Area II, Fire Zone 86B, Train B Compartment Between Auxiliary and Control Buildings

A. Location

Fire Zone 86B (engineering drawing 13-A-ZYD-029) is the compartment between the auxiliary and control buildings between elevations 74 feet 0 inch and 156 feet 4 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XV at column line A10

South: 3-hour rated wall at column line J1 common to:

- Zones 2 and 3B at elevation 74 feet 0 inch
- Zones 4B and 6B at elevation 100 feet 0 inch
- Zones 11B and 14 at elevation 120 feet 0 inch
- Zone 15B between elevations 132 feet 0 inch and 156 feet 4 inches

2-hour rated wall common to Zone 5B and the northeast HVAC chase at column line Jl and elevation 100 feet 0 inch

3-hour rated wall common to Fire Area III, Zone 17, at column line Jl and elevation 140 feet 0 inch

East: Nonrated exterior wall at column line JE and elevation 74 feet 0 inch

Nonrated wall common to the corridor building at column line JE, at elevations 100 feet 0 inch, 120 feet 0 inch and 140 feet 0 inch

West: Nonrated wall of heavy concrete construction common to Fire Area I, Zone 86A, at column line JC

Floor: Nonrated basemat of light concrete paving at elevation 74 feet 0 inch

Ceiling: Nonrated roof of heavy concrete construction at elevation 156 feet 4 inches

2. Zone Access

One Class B door in the 2-hour rated south wall, elevation 100 feet 0 inch, to Zone 5B

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Thermo-Lag 330-1

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

High

G. Fire Detection

Actuation of both the ionization detector system(s) and the line-type thermal detector system(s) activates the automatic water spray system. Either detection system alone can provide early warning capability.

H. Fire Suppression

1. Primary

Automatic deluge water spray system. (At elevations 100 feet 0 inch and 120 feet 0 inch only, see engineering drawing 13-A-ZYD-029.)

2. Secondary

One portable CO_2 fire extinguisher and one manual hose reel are located at elevation 100 feet 0 inch in adjacent Zone 5B. One portable CO_2 fire extinguisher and one manual hose reel are located in adjacent corridor building near Zone 5B.

I. Ventilation

Manually controlled smoke venting through the seismic gap in the ceiling. (Refer to the appendix 9A responses to Questions 9A.70 and 9A.80.)

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.3 FIRE AREA III

9B.2.3.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area III (engineering drawing 13-P-00B-005) contains both train A and train B components found in the control and computer rooms of the control building at elevation 140 feet 0 inch. This fire area includes Analysis Area IIIA only (fire zones 16 and 17) (engineering drawing 13-A-ZYD-029).

Fire Area III is bounded to the north by 3-hour rated barriers common to Fire Areas I and II, and by 2-hour

rated barriers common to the northwest HVAC chase (Fire Area I). The south boundaries are 3-hour rated barriers common to Fire Areas I, IV, and V, a non-rated heavy concrete exterior wall, 2-hour rated barriers common to the southwest HVAC chase (Fire Area I), and 2-hour rated barriers common to the southeast outside air and HVAC chases (Fire Area II). The west boundary is a 3-hour rated barrier common to Fire Area X. The east boundary is a 3-hour rated barrier common to the corridor building and a non-rated heavy concrete exterior wall. Fire Area III does not include the vestibule adjacent to the corridor building. The walls of the vestibule are 3-hour rated. The ceiling above and floor below Fire Area III are 3-hour rated barriers.

B. Deviations from 10CFR50, Appendix R, Section III.G

1. The main control room (Zone 17) contains redundant safe shutdown cables and equipment. Alternative safe shutdown capability is provided as required by Section III.G.3 of Appendix R.

2. See subsection 9B.2.1 for deviations common to Fire Area I and subsection 9B.2.2 for a deviation common to Fire Area II.

3. A deviation is taken from Section III.L to the extent that it allows credit for only one action in the control room prior to evacuation. (See Generic Letter 86-10, Question 3.8.4.)

In accordance with the guidance of Generic Letter 86-10, Questions 3.8.4 and 5.3.10, a bounding analysis was performed for the control room fire scenario to assure that safe shutdown conditions could be maintained from outside the control room (ref. calculation 13-MC-FP-318, 10CFR50 Appendix R IIIG/IIIL Compliance Assessment and 13-MC-FP-317, Appendix R Operational Considerations). This bounding analysis assumed worst case spurious actuations as well as loss of all automatic function (such as ESFAS, DG auto start and sequencing) of components whose control circuits could be affected by a fire in the control room. This conservative analysis indicated that the steam generator may overfill in approximately two minutes if a main steam isolation signal is not initiated prior to control room evacuation. This assures a malfunction of the main feedwater control valves upon reactor trip. The action to isolate main steam is located on the same control board as the reactor trip push-button. The action in the control room prevents a very unlikely series of events, which includes spurious actuation and failure of specific automatic functions. If these series of events were to occur, however, main steam can be isolated outside the control room, regardless of the circuit damage in the control room.

9B.2.3.2 Analysis Area IIIA

A. Location

Analysis Area IIIA consists of Fire Zones 16 and 17. Fire Zones 16 and 17 (engineering drawing 13-A-ZYD-029) are located in the control building at elevation 140 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Fire Area I, Zone 86A, at column line J1

3-hour rated wall common to Fire Area II, Zone 86B, at column line J1

3-hour rated wall common to Fire Area I, Zone 15A

3-hour rated wall common to Fire Area II, Zone 15B

2-hour rated wall common to Fire Area I, the northwest HVAC chase

South: 2-hour rated walls common to Fire Area I, the southwest HVAC chase

2-hour rated wall common to Fire Area II, the southeast outside air and HVAC chases

Nonrated exterior wall at column line J4

3-hour rated wall common to the diesel/ control building seismic gap at column line J4

East: 2-hour rated wall common to Fire Area II, the outside air chase

3-hour rated wall common to the corridor building at column line JE

NOTE

Entrance to the control room is made through a 3-hour rated vestibule, which is not considered part of Zone 17.

Non-rated heavy concrete exterior wall at column line JE

3-hour rated wall common to Fire Area II, Zone 15B

West: 3-hour rated wall common to Fire Area X at column line JA

2-hour rated wall common to Fire Area I, the northwest HVAC chase

2-hour rated wall common to the air lock

Floor: 3-hour rated barrier common to Fire Area II, Zones 12, 13, and 14

Ceiling: 3-hour rated barrier common to Fire Area I, Zones 19 and 20

C. Safe Shutdown Related Components and Cables

- Train A and train B and nontrain related cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

Condensate storage and transfer

Diesel fuel oil and transfer

Diesel generator

Essential chilled water

Essential cooling water

Auxiliary building HVAC

Diesel generator HVAC

Control building HVAC

Miscellaneous HVAC

Nuclear cooling water

Reactor coolant

Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Essential spray pond

Nuclear sampling

Electrical power distribution

Engineered safety feature actuation

- Train A control panels and circuits
- Train B control panels and circuits
- Train A NSSS process protection instrumentation
- Train B NSSS process protection instrumentation

- Train A BOP analog instrumentation cabinet
- Train B BOP analog instrumentation cabinet
- Train A MSIV logic cabinet
- Train B MSIV logic cabinet
- Various train A and train B control room fire dampers

D. Summary and Conclusion

Alternate shutdown is credited for a fire in this area. One train of systems, Train B, has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Sections III.G and III.L.

9B.2.3.3 Fire Area III, Fire Zone 16, Computer, Office, and Storage Rooms

A. Location

Fire Zone 16 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to Zone 17

South: non-rated heavy concrete exterior wall at column line J4

3-hour rated wall common to the diesel/control building seismic gap at column line J4

East: 2-hour rated walls common to Zone 17

2-hour rated wall common to Fire Area II, the outside air chase

West: 2-hour rated wall common to Zone 17 and the air lock

Floor: 3-hour rated barrier common to Fire Area II, Zones 13 and 14

Ceiling: 3-hour rated barrier common to Fire Area I, Zone 20

2. Zone Access

- One Class B door (pair) in the 2-hour rated north wall to Zone 17
- One Class B door in the 2-hour rated west wall to Zone 17

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Computer equipment
   - Conduit and gutters

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Polycarbonate battery casing
      - Cable insulation
      - Magnetic tape
      - Vinyl asbestos floor tile
      - Paper
      - Plastic

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Vinyl asbestos floor tile

3. Total Combustible (Fire) Loading

High

G. Fire Detection

The computer room ionization smoke detector system(s) is provided for early warning and in a cross-zoned mode will actuate the automatic Halon 1301 gas system in the computer room. The computer room is also provided with an ionization smoke detector system located above the suspended ceiling for early warning only. The office and storage rooms are provided with ionization smoke detector system(s) for early warning only.

H. Fire Suppression

1. Primary

Automatic Halon 1301 gas system for the computer room

2. Secondary

Five portable CO_2 fire extinguishers, four portable pressurized water fire extinguishers, and one manual hose reel are located in adjacent Zone 17.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.3.4 Fire Area III, Fire Zone 17, Control Room

A. Location

Fire Zone 17 (engineering drawing 13-A-ZYD-029) is located in the control building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area I, Zone 86A, at column line J1

3-hour rated wall common to Fire Area II, Zone 86B, at column line J1

3-hour rated wall common to Fire Area I, Zone 15A

2-hour rated wall common to Fire Area I, the northwest HVAC chase

3-hour rated wall common to Fire Area II, Zone 15B

South: 2-hour rated walls common to Zone 16

2-hour rated walls common to Fire Area I, the southwest HVAC chase

3-hour rated wall common to the southwest stairwell at column line J4

2-hour rated wall common to Fire Area II, the southeast outside air and HVAC chases

East: 3-hour rated wall common to the corridor building at column line JE

NOTE

Entrance to the control room is made through a 3-hour rated vestibule, which is not considered part of Zone 17.

Non-rated heavy concrete exterior wall at column line JE

3-hour rated wall common to Fire Area II, Zone 15B

West: 3-hour rated wall common to Fire Area X at column line JA

2-hour rated wall common to Fire Area I, the northwest HVAC chase

Floor: 3-hour rated barrier common to Fire Area II, Zones 12, 13, and 14

Ceiling: 3-hour rated barrier common to Fire Area I, Zones 19 and 20

2. Zone Access

- One Class A door (pair) in the 3-hour rated east wall to the vestibule adjacent to the corridor building
- One Class A door in the 3-hour rated wall to the southwest stairwell

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Building structural columns and beams are protected by coatings with 3-hour ratings.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- ERFDAD and instrumentation cabinets
- Plant protection system cabinets
- Qualified safety parameter display system isolation cabinets
- Safety-related equipment status systems cabinets

- Site radiation monitoring system control room cabinets

D. Nonsafety-Related Equipment and Components

- Water heater
- Cable trays, conduit, and gutters
- Instrument cabinets
- Plant annunciator cabinets
- Electrical instrumentation and protection cabinets

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

    - Cable insulation
    - Vinyl asbestos floor tile
    - Carpet or resilient floor covering
    - Paper, clothing, wood, and plastic
    - Polycarbonate battery casing
    - Thermo-Lag 330-1
    - Corian Desk Top

2. Transient Combustible Load Type

    - Ordinary combustible

- Vinyl asbestos floor tile

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   Five portable CO_2 fire extinguishers

2. Secondary

   Four portable pressurized water fire extinguishers, one manual hose reel

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.4 FIRE AREA IV

9B.2.4.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area IV contains train A components found in the diesel generator building. This fire area includes Analysis Area IVA (Zones 21A, 22A, 23A, 24A, and 25A) (engineering drawing 13-A-ZYD-031) only.

At elevations 100 feet 0 inch and 115 feet 0 inch, Fire Area IV is bounded to the north by a 3-hour rated barrier common to the diesel/control building seismic gap, to the east by 3-hour rated barriers common to Fire Area V, and to the west and south by nonrated exterior walls. A portion of the ceiling of Zone 21A is 3-hour rated and common to Fire Area V, the central staircase. The basemat is nonrated.

At elevation 131 feet 0 inch, Fire Area IV is bounded to the north by a 3-hour rated barrier common to the diesel/control building seismic gap, to the east by a 3-hour rated barrier common to Fire Area V, and to the west and south by nonrated exterior walls. The ceiling to Zones 23A and 25A, which is also the roof of the diesel generator building, is nonrated.

At elevation 146 feet 0 inch, Fire Area IV includes the train A exhaust stack bounded to the north by a 3-hour rated barrier common to the diesel/control building seismic gap, to the east by a 3-hour rated barrier common to the train B exhaust stack (Fire Area V), and to the south and west by nonrated exterior walls. Above elevation 180 feet 4 inches, Fire Area IV is bounded by nonrated exterior walls. The top of the exhaust stack is covered by a nonrated

barrier at elevation 193 feet 9 inches, with openings to atmosphere on the north and south faces.

B. Deviations from 10CFR50, Appendix R, Section III.G

1. A deviation is requested to Section III.G.2 to the extent that it required 3-hour, fire-rated barriers to separate circuits of redundant trains.

Discussion:

The diesel generator building is separated from the control building by a 6-inch seismic gap which is necessary to allow for relative seismic motion of the two buildings. The gap extends from elevation 94 feet 0 inch to the roof at elevation 148 feet 0 inch. In essence, the seismic gap creates a closed space which adjoins train A and B fire areas associated with the diesel generator and control buildings. Control cables associated with the diesel generators are routed from the diesel generator building Fire Areas IV and V into the control building Fire Areas I and II. The train A and train B cables transverse the seismic gap through conduit expansion/deflection fittings and open cable trays. There is no fire-rated barrier providing vertical separation or fire detection and automatic suppression within the 6-inch seismic gap. Cable routing outside of the seismic gap

space, however, is in full compliance with the separation criteria of Section III.G.

This configuration is considered an acceptable deviation due to the following technical reasons:

a. The diesel generator building and the control building are separated by two, independent, 3-hour fire-rated walls. All penetrations through the walls are sealed with materials of equivalent fire resistance. This configuration assures that a fire originating in either the control building or diesel generator building will not propagate into the seismic gap.

b. The doorway penetrations through the seismic gap (100- and 120-foot elevations) are to be sealed with a 1-hour, fire-rated assembly. The purpose for the addition of fire-rated seals at the door penetrations is to eliminate fire exposure to safe shutdown circuits due to transient combustibles. The corridor and stairway area where the seals will be installed is void of fixed combustibles. The only fire exposure to the seal would be due to transient combustibles. Using the criteria in paragraph 9B.1.3.2, listing F,

combustible loading, anticipated fires due to transient combustibles would have a duration much less than 1 hour. The installation of a 1-hour, fire-rated assembly, therefore, will provide adequate protection against fires occurring in the corridor and stairway area.

c. The area within the seismic gap contains minimal exposed combustibles. There are two train A and two train B cable trays which transverse the gap. The horizontal separation between the tray stacks is approximately 23 feet 1 inch. The total weight of cable insulation is approximately 6 pounds. The cables are at a minimum IEEE-383 qualified at 70,000 Btu/hr for flame testing. Conduits that penetrate the two fire walls utilize an expansion/ deflection fitting to transverse the gap. The fittings consist of a tin/copper braided bonding jumper, bronze end couplings, molded neoprene rubber sleeve, and stainless steel bands. Neoprene rubber is used as a weather shield across the top of the gap. The spacial configuration of the trays and conduits in conjunction with limited combustibles will eliminate the potential for fire spread.

d. The expansion/deflection fittings used to transverse the seismic gap will provide a significant level of fire resistance. Since the assembly is not a fire-tested device, a rating cannot be claimed. Based on the natural fire-resistant characteristics of neoprene rubber, however, it is reasonable to assume that some degree of resistance to heat transfer will be obtained. The wall thickness of the neoprene sleeve is greater than 1/2 inch for all fittings and is tightly secured over the end couplings by stainless steel bands.

e. There are no exterior fixed combustibles to present an exposure hazard to the seismic gap. The openings of the gap at the exterior walls are provided with sheet metal flashing. In addition, sidewalks on both sides of the gap opening provide effective curbing against liquid spills.

f. Flammable liquid spills from within the diesel generator building will not expose the seismic gap. This condition has been previously evaluated and documented in the response to Question 9A.119 in appendix 9A.

g. There are no credible ignition sources within the seismic gap. The gap is

effectively sealed against external sources and the cables are provided with circuit protection to prevent auto-ignition due to fault conditions. In addition, the buildings are provided with lightning protection.

h. The configuration of the conduit and tray penetrations through the seismic gap provides adequate separation between redundant circuits and protection from a hot gas layer below the roof seal. Since there are no fixed or transient combustibles below the penetrations, fire propagation is not a credible event. All safe shutdown circuits are routed through the gap at approximately elevation 110 feet 0 inch. The horizontal distance between train A and B cables, routed through expansion/deflection fittings, is approximately 11 feet 3 inches and the distance between redundant trays is approximately 23 feet 1 inch. The vertical distance from the highest cable to the roof seal is approximately 35 feet. With the limited fixed combustibles within the gap and elimination of transient combustibles, the development of a thermal gas layer over 35 feet thick is highly unlikely. In essence, the cable separation in

conjunction with the vertical distance to the roof provides reasonable assurance that, if a fire occurred, one train of cables will remain undamaged.

2. See subsection 9B.2.0 for generic deviations.

9B.2.4.2 Analysis Area IVA

A. Location

Analysis Area IVA consists of Fire Zones 21A, 22A, 23A, 24A, and 25A.

Fire Zone 21A (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevations 100 feet 0 inch and 115 feet 0 inch.

Fire Zone 22A (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 100 feet 0 inch.

Fire Zones 23A and 25A (engineering drawing 13-A-ZYD-031) are located in the diesel generator building at elevation 131 feet 0 inch.

Fire Zone 24A (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 115 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Fire Area V, the central staircase, at column line G2 (elevation 100 feet 0 inch and 115 feet 0 inch)

3-hour rated area boundary wall common to the diesel/control building seismic gap at column line G1

3-hour rated wall common to Fire Area V, the central staircase Vestibule Room G211 (elevation 131 feet 0 inch)

South: Nonrated exterior wall of heavy concrete construction at column line G3

One 7 x 16-foot opening to the outside for room air intake (elevation 131 feet 0 inch)

East: 3-hour rated wall common to Fire Area V, Zone 21B, at column line GB

3-hour rated wall common to Fire Area V, the central staircase

3-hour rated wall common to Vistible Room G211.

3-hour rated wall common to Fire Area V, Zone 23B, at column line GB

3-hour rated wall common to Fire Area V, Zone 25B, at column line GB

West: Nonrated exterior wall of heavy concrete construction at column line GA

Nonrated walls of heavy concrete construction about the diesel combustion air intake stack

Floor: Nonrated basemat of heavy concrete construction at elevation 100 feet 0 inch, including a sump pit at elevation 89 feet 0 inch

Nonrated basemat of heavy concrete construction including pipe trench to elevation 94 feet 0 inch

Ceiling: Nonrated roof of heavy concrete construction above Fire Zone 25A

3-hour rated roof above Fire Zone 23A

3-hour rated barrier common to Vestibule Room G211.

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Diesel fuel oil and transfer

  Diesel generator

  Diesel generator HVAC

  Electrical power distribution

- Train A diesel generator fuel oil day tank, day tank level controller, and associated equipment

- Train A diesel generator and associated control and regulating panels and equipment

- Train A diesel engine and associated starting and control components

- Train A diesel generator cooling water components
- Train A diesel generator control room air handling unit and diesel generator room exhaust fan

D. Summary and Conclusions

Safe shutdown capability will be provided by utilizing redundant train B systems available from the control room, in conjunction with operator action, outside this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.4.3 Fire Area IV, Fire Zone 21A, Train A Diesel Generator Room

A. Location

Fire Zone 21A (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevations 100 feet 0 inch and 115 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall, at column line G2, common to:

- Zone 22A at elevation 100 feet 0 inch
- Zone 24A at elevation 115 feet 0 inch

3-hour rated wall common to Fire Area V, the central staircase, at column line G2

South: Nonrated exterior wall of heavy concrete construction at column line G3

East: 3-hour rated wall common to Fire Area V, Zone 21B, at column line GB

West: Nonrated exterior wall of heavy concrete construction at column line GA

Floor: Nonrated basemat of heavy concrete construction at elevation 100 feet 0 inch, including a sump pit at elevation 89 feet 0 inch

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 25A

3-hour rated barrier common to Zone 23A

3-hour rated barrier common to Fire Area V, the central staircase

3-hour rated barrier common to Vestibule Room G211.

2. Zone Access

   - One non-rated door in the 2-hour rated north wall to Zone 22A

   - One nonrated missileproof door in the nonrated west exterior wall

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Sump pump

   - 25-ton hoist and monorail

   - 25-ton crane

- Diesel generator room normal unit heaters
- Intake air silencer
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Oil/grease
   - Diesel fuel oil
2. Transient Combustible Load Type
   - Ordinary combustible
   - Oil
3. Total Combustible (Fire) Loading

   High

G. Fire Detection

Actuation of the ultraviolet or thermal detector systems activates the automatic preaction sprinkler system.

H. Fire Suppression

1. Primary

   Automatic preaction water sprinkler system
2. Secondary

One portable CO_2 fire extinguisher. One manual hose reel is located in the adjacent control building at elevation 100 feet 0 inch. Outside hydrant is available if access is blocked by the diesel generator control room roll-up door.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment. (Refer to the appendix 9A response to Question 9A.86).

J. Drainage

Seven 4-inch drains

K. Emergency Communications

None

9B.2.4.4 Fire Area IV, Fire Zone 22A, Train A Diesel Generator Control Room

A. Location

Fire Zone 22A (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated area boundary wall common to the diesel/control building seismic gap at column line G1

South: 2-hour rated wall common to Zone 21A at column line G2

East: 3-hour rated wall common to Fire Area V, the central staircase

West: Nonrated exterior wall of heavy concrete construction at column line GA

Floor: Nonrated basemat of heavy concrete construction including pipe trench to elevation 94 feet 0 inch

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 24A

2. Zone Access

- One Class A door in the 3-hour rated east wall to the central staircase

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Neutral grounding transformer
- Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Cable insulation
   - Polycarbonate battery cases
   - Thermo-Lag 330-1

2. Transient Combustible Load Type
   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One portable CO_2 fire extinguisher

2. Secondary

One manual hose reel is located in the adjacent control building at elevation 100 feet 0 inch.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment. (Refer to the appendix 9A response to Question 9A.86.)

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.4.5 Fire Area IV, Fire Zone 24A, Train A Combustion Air Intake Room

A. Location

Fire Zone 24A (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 115 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated area boundary wall common to the diesel/control building seismic gap at column line G1

South: 2-hour rated wall common to Zone 21A at column line G2

East: 3-hour rated wall common to Fire Area V, the central staircase

West: Nonrated exterior wall of heavy concrete construction at column line GA

Floor: Nonrated barrier of heavy concrete construction common to Zone 22A

Ceiling: 2-hour rated barrier common to Zone 25A

2. Zone Access

- Two Class A doors in the 3-hour rated east wall to the central staircase

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Diesel generator control room normal air handling unit
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   Oil

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ultraviolet smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in the adjacent control building at elevation 120 feet 0 inch.

2. Secondary

One portable CO_2 fire extinguisher is located in the adjacent control building at elevation 120 feet 0 inch.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment. (Refer to the appendix 9A response to Question 9A.86.)

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.4.6 Fire Area IV, Fire Zone 23A, Train A Fuel Oil Day Tank Vault

A. Location

Fire Zone 23A (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 131 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 25A

3-hour rated wall common to the central staircase Vestibule Room G211.

South: 3-hour rated wall common to Zone 25A

East: 3-hour rated wall common to Fire Area V, Zone 23B, at column line GB

West: 3-hour rated wall common to Zone 25A

Floor: 3-hour rated barrier common to Zone 21A

Ceiling: 3-hour rated roof

2. Zone Access

- One Class A door in the 3-hour rated west wall to Zone 25A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   Fuel oil

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

Thermal detector system(s) is provided to actuate the automatic preaction sprinkler system and for early warning. (Refer to the appendix 9A response to Question 9A.73.)

H. Fire Suppression

1. Primary

   Automatic preaction water sprinkler system

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 25A.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment. (Refer to the appendix 9A response to Question 9A.86).

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.4.7 Fire Area IV, Fire Zone 25A, Train A Silencer Room

A. Location

Fire Zone 25A (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 131 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated area boundary wall common to the diesel/control building seismic gap at column line G1

South: Nonrated exterior wall of heavy concrete construction at column line G3

One 7 x 16-foot opening to the outside for room air intake

East: 3-hour rated wall common to Fire Area V, Zone 25B

3-hour rated walls about Zone 23A

3-hour rated wall common to Fire Area V, the central staircase

3-hour rated wall common to Vestibule Room G211.

West: Nonrated exterior wall of heavy concrete construction at column line GA

Nonrated walls of heavy concrete construction about the diesel combustion air intake stack

Floor: Nonrated barrier of heavy concrete construction common to Zone 21A

2-hour rated barrier common to Zone 24A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One Class A door in the 3-hour rated east wall to the central staircase

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Air compressors
   - Air dryers
   - Diesel generator room normal exhaust fan
   - Air compressor room vent fan
   - Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      Grease/oil

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ultraviolet detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One portable CO_2 fire extinguisher

2. Secondary

   One manual hose reel is located in the adjacent control building at elevation 120 feet 0 inch.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment. (Refer to the appendix 9A response to Question 9A.86.)

J. Drainage

Three 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.5 FIRE AREA V

9B.2.5.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area V contains train B components found in the diesel generator building. This fire area includes Analysis Area VA (Zones 21B, 22B, 24B, 23B, and 25B) (engineering drawing 13-A-ZYD-031).

At elevations 100 feet 0 inch and 115 feet 0 inch, Fire Area V is bounded to the north by a 3-hour rated barrier common to the diesel/control building seismic gap, to the west by 3-hour rated barriers common to Fire Area IV, and to the east and south by nonrated exterior walls. The basemat is nonrated.

At elevation 131 feet 0 inch, Fire Area V is bounded to the north by a 3-hour rated barrier common to the diesel/control building seismic gap, to the west by a 3-hour rated barrier common to Fire Area IV, and to the east and south by nonrated exterior walls. A portion of the stairwell floor is 3-hour rated and common to Zone 21A. The ceiling to Zones 23B and 25B, which is also the roof of the diesel generator building, is nonrated.

At elevation 146 feet 0 inch, Fire Area V includes the train B exhaust stack bounded to the north by a 3-hour rated barrier common to the diesel/control building seismic gap, to the west by a 3-hour rated barrier common to the train A exhaust stack (Fire Area IV), and to the south and east by nonrated

exterior walls. Above elevation 180 feet 4 inches, Fire Area V is bounded by nonrated exterior walls. The top of the exhaust stack is covered by a nonrated barrier at elevation 193 feet 9 inches, with openings to atmosphere on the north and south faces.

B. Deviations from 10CFR50 Appendix R, Section III.G.

1. See paragraph 9B.2.4.1, subitem B, for deviation concerning the seismic gap separating the diesel generator building and control building.

2. See subsection 9B.2.0 for generic deviations.

9B.2.5.2 Analysis Area VA

A. Location

Fire Zone 21B (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevations 100 feet 0 inch and 115 feet 0 inch.

Fire Zone 22B (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 100 feet 0 inch.

Fire Zones 23B and 25B (engineering drawing 13-A-ZYD-031) are located in the diesel generator building at elevation 131 feet 0 inch.

Fire Zone 24B (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 115 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated area boundary wall common to the diesel/control building seismic gap at column line G1

3-hour rated wall common to Vestibule Room (G211).

South: 3-hour rated wall common to the central staircase at column line G2 and Fire Area IV

3-hour rated wall common to the central staircase and the Vestibule Room (G211)

Nonrated exterior wall of heavy concrete construction at column line G3

One 7 x 16-foot opening to the outside for room air intake

East: Nonrated exterior wall of heavy concrete construction at column line GC

Nonrated walls of heavy concrete construction about the diesel combustion air intake stack (elevation 131 feet 0 inch)

West: 3-hour rated wall common to Fire Area IV, Zone 21A, at column line GB

3-hour rated wall common to Vestibule Room (G211)

3-hour rated wall common to Fire Area IV, Zones 22A and 24A

3-hour rated wall common to Fire Area IV, Zone 23A, at column line GB

3-hour rated wall common to Fire Area IV, Zone 25A (elevation 131 feet 0 inch)

Floor: Nonrated basemat of heavy concrete construction at elevation 100 feet 0 inch, including a sump pit at elevation 89 feet 0 inch

Nonrated basemat of heavy concrete construction including pipe trench to elevation 94 feet 0 inch

Ceiling: 3-hour rated barrier common to Vestibule Room (G211)

3-hour rated roof (above Fire Zone 23B)

Nonrated roof of heavy concrete construction (above Fire Zone 25B)

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Diesel fuel oil and transfer

  Diesel generator

- Train B cables associated with the following systems:

  Diesel fuel oil and transfer

  Diesel generator

  Diesel generator HVAC

  Electrical power distribution

- Train B diesel generator fuel oil day tank, day tank level controller, and associated equipment

- Train B diesel generator and associated control and regulating panels and equipment

- Train B diesel engine and associated starting and control components

- Train B diesel generator cooling water components

- Train B diesel generator control room air handling unit and exhaust fan

D. Summary and Conclusions

The Train A diesel fuel oil transfer pump control circuit is in room G211, which is enclosed with three hour rated barriers and therefore not susceptible to fire damage. The train A fuel oil transfer pump will therefore be available for use by the Control Room.

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on

fire barriers provided, with the exception of the diesel fuel transfer pumps as described above. The redundant train A system will remain available from the control room, in conjunction with operator action, outside of this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.5.3 Fire Area V, Fire Zone 21B, Train B Diesel Generator Room

A. Location

Fire Zone 21B (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevations 100 feet 0 inch and 115 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall, at column line G2, common to:

- Zone 22B at elevation 100 feet 0 inch
- Zone 24B at elevation 115 feet 0 inch

2-hour rated wall common to the central staircase at column line G2

South: Nonrated exterior wall of heavy concrete construction at column line G3

East: Nonrated exterior wall of heavy concrete construction at column line GC

West: 3-hour rated wall common to Fire Area IV, Zone 21A, at column line GB

Floor: Nonrated basemat of heavy concrete construction at elevation 100 feet 0 inch, including a sump pit at elevation 89 feet 0 inch

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 25B

3-hour rated barrier common to Zone 23B

2-hour rated barrier common to the central staircase

3-hour rated barrier common to Vestibule Room G211

2. Zone Access

- One non-rated door in the 2-hour rated north wall to Zone 22B
- One nonrated missileproof door in the nonrated east exterior wall

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

- Sump pump
- 25-ton hoist and monorail
- 5-ton crane
- Diesel generator room normal unit heaters
- Intake air silencer
- Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

- Oil/grease
- Diesel Fuel

2. Transient Combustible Load Type

- Ordinary combustible
- Oil

3. Total Combustible (Fire) Loading

High

G. Fire Detection

Actuation of the ultraviolet or thermal detector systems activates the automatic preaction water sprinkler system.

H. Fire Suppression

1. Primary

Automatic preaction water sprinkler system

2. Secondary

One portable CO_2 fire extinguisher.

Additionally, one manual hose reel is located in adjacent control building at elevation 100 feet 0 inch.

Outside hydrant is available if access is blocked by the diesel generator control room roll-up door.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment. (Refer to the appendix 9A response to Question 9A.86.)

J. Drainage

Seven 4-inch drains

K. Emergency Communications

None

9B.2.5.4 Fire Area V, Fire Zone 22B, Train B Diesel Generator Control Room

A. Location

Fire Zone 22B (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Fire Boundaries and Rated Fire Barriers

North: 3-hour rated area boundary wall common to the diesel/control building seismic gap at column line G1

South: 2-hour rated wall common to Zone 21B at column line G2

East: Nonrated exterior wall of heavy concrete construction at column line GC

West: 2-hour rated wall common to the central staircase

Floor: Nonrated basemat of heavy concrete construction including pipe trench to elevation 94 feet 0 inch

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 24B

2. Zone Access

- One Class A door in the 2-hour rated west wall to the central staircase

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Neutral grounding transformer
- Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Polycarbonate battery cases

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One portable CO_2 fire extinguisher

2. Secondary

One manual hose reel is located in the control building at elevation 100 feet 0 inch

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

(Refer to the appendix 9A response to Question 9A.86.)

J. Drainage

Two 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.5.5 Fire Area V, Fire Zone 24B, Train B Combustion Air Intake Room

A. Location

Fire Zone 24B (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 115 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated area boundary wall common to the diesel/control building seismic gap at column line G1

South: 2-hour rated wall common to Zone 21B at column line G2

East: Nonrated exterior wall of heavy concrete construction at column line GC

West: 2-hour rated wall common to the central staircase

Floor: Nonrated barrier of heavy concrete construction common to Zone 22B.

Ceiling: 2-hour rated barrier common to Zone 25B

2. Zone Access

- Two Class A doors in the 2-hour rated west wall to the central staircase

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Diesel generator control room normal air handling unit
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   Oil

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ultraviolet smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in the adjacent control building at elevation 120 feet 0 inch.

2. Secondary

   One portable CO_2 fire extinguisher is located in the adjacent control building at elevation 120 feet 0 inch.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment. (Refer to the appendix 9A response to Question 9A.86.)

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.5.6 Fire Area V, Fire Zone 23B, Train B Fuel Oil Day Tank Vault

A. Location

Fire Zone 23B (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 131 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	3-hour rated wall common to Zone 25B
	3-hour rated wall common to the central staircase Vestibule Room G211
South:	3-hour rated wall common to Zone 25B
East:	3-hour rated wall common to Zone 25B
West:	3-hour rated wall common to Fire Area IV, Zone 23A, at column line GB
Floor:	3-hour rated barrier common to Zone 21B
Ceiling:	3-hour rated roof

2. Zone Access

   - One Class A door in the 3-hour rated east wall to Zone 25B

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      Fuel oil

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

Thermal detector system(s) is provided to actuate the automatic preaction sprinkler system and for early warning. (Refer to the appendix 9A response to Question 9A.73.)

H. Fire Suppression

1. Primary

   Automatic preaction water sprinkler system

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 25B.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment. (Refer to the appendix 9A response to Question 9A.86.)

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.5.7 Fire Area V, Fire Zone 25B, Train B Silencer Room

A. Location

Fire Zone 25B (engineering drawing 13-A-ZYD-031) is located in the diesel generator building at elevation 131 feet 0 inch

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated area boundary wall common to the diesel/control building seismic gap at column line G1

South: Nonrated exterior construction at column line G3

One 7- x 16-foot opening to the outside for room air intake

East: Nonrated exterior wall of heavy concrete construction at column line GC

Nonrated walls of heavy concrete construction about the diesel combustion air intake stack

West: 2-hour rated wall common to the central staircase

3-hour rated wall common to Vestibule Room G211

3-hour rated walls common to Zone 23B

3-hour rated wall common to Fire Area IV, Zone 25A

Floor: Nonrated barrier of heavy concrete construction common to Zone 21B

2-hour rated barrier common to Zone 24B

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One Class A door in the 2-hour rated west wall to the central staircase

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Air compressors
- Air dryers
- Diesel generator room normal exhaust fan
- Air compressor room vent fan
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   Oil/grease

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ultraviolet detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One portable CO_2 fire extinguisher

2. Secondary

One manual hose reel is located in adjacent control building at elevation 120 feet 0 inch.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment. (Refer to the appendix 9A response to Question 9A.86.)

J. Drainage

Three 4-inch drains

K. Emergency Communications Sound powered phone jack(s) is provided.

9B.2.6 FIRE AREA VI

9B.2.6.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area VI (figures 9B-3, 9B-4, and engineering drawing 13-P-00B-005) is the fuel building and includes all components located within the building. This fire area includes Zones 27, 28, 29, and 29A (engineering drawing 13-A-ZYD-030).

Fire Area VI is bounded to the north, south, east, and west by nonrated exterior barriers, except at the southeast corner where 3-hour rated barriers are common to Fire Areas XV and XVI. Both the basemat and roof are nonrated barriers.

No safe shutdown equipment is present in Fire Area VI.

B. Deviations from 10CFR50, Appendix R, Section III.G

See subsection 9B.2.0 for generic deviations.

9B.2.6.2 Fire Area VI, Fire Zone 27, Exhaust Essential Air Filtration Unit Area and Railroad Bay

A. Location

Fire Zone 27 (engineering drawing 13-A-ZYD-030) is located in the fuel building at elevations 100 feet 0 inch and 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction at column line Fl

South: Nonrated exterior wall of heavy concrete construction at column line F3

East: Nonrated wall of heavy concrete construction, at column line FC, common to Zone 28 at elevation 100 feet 0 inch

Nonrated splash curtain, at column line FC, common to Zone 29A at elevation 120 feet 0 inch

Nonrated wall of heavy concrete construction common to the cask loading pit, at Zone 29A at column line FC

Nonrated walls of heavy concrete construction about the sump pump and storage room, common to Zones 28 and 29A

West: Nonrated exterior wall of heavy concrete construction at column line FA

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated partial ceiling at elevation 140 feet 0 inch with open interface to Zone 29A.

2. Zone Access

- One nonrated door in the nonrated west exterior wall
- One nonrated rollup door in the nonrated north exterior wall
- Open corridor to Zone 28 at elevation 100 feet 0 inch

3. Sealed Penetrations

None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train A fuel and auxiliary building exhaust essential air filtration unit
- Train B fuel and auxiliary building exhaust essential air filtration unit

D. Nonsafety-Related Equipment and Components

- New fuel handling crane
- Sump pumps
- Cable trays and conduit

E. Radioactive Material

Fire Zone 27 will contain radioactive materials during fuel loading and unloading shipping operations only.

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation

- Wood
- Charcoal
- Plastic
- Rubber
- Grease
- Hydraulic fluid

2. Transient Combustible Load Type

- Ordinary combustible
- Charcoal

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

A wet pipe sprinkler system is provided, except for the sump pump and storage room. A manual water spray system is provided for the charcoal filters.

NOTE

A wet pipe sprinkler system is positioned at the ceiling to Zone 29A and will service Zone 27 through the open area of the Zone 27 partial ceiling.

2. Secondary

Two manual hose reels and two portable ABC powder fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Six 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.6.3 Fire Area VI, Fire Zone 28, Spent Fuel Pool Cooling Pumps and Heat Exchangers Area

A. Location

Fire Zone 28 (engineering drawing 13-A-ZYD-030) is located in the fuel building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zones 27 and 29A near column line F2

2-hour rated wall common to the southeast stairwell

South: Nonrated exterior wall of heavy concrete construction at column line F3

3-hour rated wall common to an elevator shaft at column line F3

East: 3-hour rated wall common to Fire Areas XV and XVI at column line FF

2-hour rated wall common to the southeast stairwell.

West: Nonrated wall of heavy concrete construction common to Zone 27 at column line FC

Floor: Nonrated basemat of heavy concrete construction at elevation 100 feet 0 inch with a piping penetration pit below

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 29

3-hour rated barrier common to Zone 29A

2. Zone Access

   - Open corridor to Zone 27
   - One Class B door in the 2-hour rated southeast stairwell south wall
   - One Class A door in the 3-hour rated east wall to Fire Area XV (Aux Building)
   - One nonrated door in the nonrated south exterior wall

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   - Train A spent fuel cooling system pump
   - Train A spent fuel pool heat exchanger
   - Train B spent fuel cooling system pump
   - Train B spent fuel pool heat exchanger

D. Nonsafety-Related Equipment and Components

- Spent fuel pool cleanup pumps
- Cable trays and conduit

E. Radioactive Material

Fire Zone 28 contains radioactive materials in process piping.

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Grease and oil
   - Plastic

2. Transient Combustible Load Type

   - Ordinary combustible
   - Grease and oil

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel

2. Secondary

One portable ABC powder fire extinguisher

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Six 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.6.4 Fire Area VI, Fire Zone 29, Electrical Equipment Area

A. Location

Fire Zone 29 (engineering drawing 13-A-ZYD-030) is located in the fuel building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated walls common to the new fuel storage racks, Zone 29A

Nonrated wall of heavy concrete construction common to the new fuel inspection pit, Zone 29A

Nonrated wall of heavy concrete construction common to the fuel transfer canal

2-hour rated wall common to the southeast stairwell

South: 3-hour rated wall common to an elevator shaft at column line F3

Nonrated exterior wall of heavy concrete construction at column line F3

East: 3-hour rated wall common to Fire Areas XV and XVI at column line FF

2-hour rated wall common to the southeast stairwell

West: Open to Zone 27 at column line FC

Floor: Nonrated barrier of heavy concrete construction common to Zone 28

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 29A

2. Zone Access

- One Class A door in the 3-hour rated east wall to Fire Area XV
- One Class B door in the 2-hour rated west wall of the southeast stairwell
- Open corridor to Zone 27

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Motor control center
   - Load center
   - Cable trays and conduit

E. Radioactive Material

   None

F Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation
      - Oil and grease
      - Rubber

- Plastic
- Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel

2. Secondary

   One portable CO_2 fire extinguisher

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Two 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.6.5 Fire Area VI, Fire Zone 29A, New and Spent Fuel Storage Areas

A. Location

Fire Zone 29A (engineering drawing 13-A-ZYD-030) is located in the fuel building at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction at column line Fl

South: Nonrated wall of heavy concrete construction about the spent fuel pool common to Zone 28 at elevation 100 feet 0 inch

Nonrated walls of heavy concrete construction common to the fuel transfer canal at elevations 100 feet 0 inch and 120 feet 0 inch

Nonrated walls of heavy concrete construction about the new fuel inspection pit common to Zones 27 and 29 at elevation 120 feet 0 inch

3-hour rated walls about the new fuel storage racks common to Zone 29 at elevation 120 feet 0 inch

Nonrated exterior wall of heavy concrete construction at column line F3 at elevation 140 feet 0 inch

3-hour rated wall common to an elevator shaft at column line F3 and elevation 140 feet 0 inch

East: Nonrated exterior walls of heavy concrete construction at column line FF

3-hour rated area boundary wall common to Fire Areas XV and XVI at elevation 140 feet 0 inch at the southeast corner

2-hour rated walls about the southeast stairwell at elevation 140 feet 0 inch

West: Nonrated wall of heavy concrete construction common to Zone 27 and about the cask loading pit at elevations 100 feet 0 inch and 120 feet 0 inch

Nonrated exterior wall of heavy concrete construction at column line FA and elevation 140 feet 0 inch

Nonrated splash curtain at column line FC, common to Zone 27 at elevation 120 feet 0 inch

Floor: Nonrated area boundary basemat of heavy concrete construction for the spent fuel pool

Nonrated barriers of heavy concrete construction for the new fuel inspection pit

Nonrated barrier of heavy concrete construction common and partially open to Zone 27

2-hour rated new fuel storage rack cover at elevation 140 feet 0 inch

3-hour rated barrier beneath the new fuel storage racks area, common to Zone 28.

Ceiling: Nonrated barrier of heavy concrete construction common to the roof

2. Zone Access

- One Class A door (pair) in the 3-hour rated east wall to Fire Area XV (Aux. Building elevation 140 feet 0 inch)
- One Class B door in the 2-hour rated west wall of the southeast stairwell
- Partial open floor to Zone 27 at elevation 140 feet 0 inch

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of corresponding rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- New fuel storage racks
- Spent fuel storage racks
- Fuel pool control panel
- Spent fuel handling machine
- Upender hydraulic drive unit
- Pool cooling purification panel
- New fuel elevator drive package
- 5-ton monorail
- 10-ton new fuel handling crane
- 150-ton cask handling crane
- Conduit

E. Radioactive Material

Fire Zone 29A is designated for the storage of radioactive material consisting of new and spent reactor fuel assemblies.

F. Combustible Loading

1. In Situ Combustible Load Type

- Oil and grease
- Cable insulation
- Plastic
- Rubber
- Wood
- Hydraulic fluid

2. Transient Combustible Load Type

- Ordinary combustible
- Oil and grease

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided over the new fuel area for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located at elevation 120 feet 0 inch. One manual hose reel is located at elevation 140 feet 0 inch.

2. Secondary

Three portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

- Three 4-inch drains at elevation 120 feet 0 inch
- Eleven 4-inch drains at elevation 140 feet 0 inch

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.7 FIRE AREA VII

9B.2.7.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area VII (figure 9B-3) contains train A essential spray pond components found in the outside areas. This fire area includes Analysis Area VIIA (Zone 84A) only (engineering drawing 13-A-ZYD-021).

Fire Area VII is the train A half of the spray pond pump house. The train B half of the pump house is adjacent to the south. The pump house is divided by a 3-hour rated barrier and bounded by the yard to the north, east, and west.

B. Deviations from 10CFR50, Appendix R, Section III.G

See subsection 9B.2.0 for generic deviations.

9B.2.7.2 Analysis Area VIIA

A. Location

Analysis Area VIIA consists of Fire Zone 84A.

Fire Zone 84A (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated exterior wall of heavy concrete construction common to the yard

South: 3-hour rated wall at column line S1, separating the train A half of the pump house from the train B half (Fire Area VIII, Zone 84B)

East: Nonrated exterior wall of heavy concrete construction common to the yard

West: Nonrated exterior wall of heavy concrete construction common to the yard

C. Safe Shutdown Components and Cables

- Train A cables associated with the following systems:

  Miscellaneous HVAC

  Essential spray pond

- Train A essential spray pond pump and associated flow control valves

- Train A essential spray pond pump house exhaust fan

D. Summary and Conclusions

Safe shutdown capability will be provided by utilizing redundant train B systems available from the control room to achieve hot standby and cold shutdown. This area has been evaluated to be in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.7.3 Fire Area VII, Fire Zone 84A, Train A Spray Pond Pump House

A. Location

Fire Zone 84A (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction common to the yard

South: 3-hour rated wall at column line S1, separating the train A half of the pump house from the train B half (Fire Area VIII, Zone 84B)

East: Nonrated exterior wall of heavy concrete construction common to the yard

West: Nonrated exterior wall of heavy concrete construction common to the yard

2. Zone Access

   One nonrated gate in the train A pump room nonrated north exterior wall

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

Oil and grease

2. Transient Combustible Load Type

- Ordinary combustible
- Oil and grease

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Smoke detectors are provided in the pump house for early warning.

H. Fire Suppression

Manual hose streams from hydrants on the yard fire main.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.8 FIRE AREA VIII

9B.2.8.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area VIII (figure 9B-3) contains train B essential spray pond components found in the outside areas. This fire area includes Analysis Area VIIIA (Zone 84B) only (engineering drawing 13-A-ZYD-021).

Fire Area VIII is the train B half of the spray pond pump house. The train A half of the pump house is adjacent to the north. The pump house is divided by a 3-hour rated barrier and bounded by the yard to the south, east, and west.

B. Deviations from 10CFR50, Appendix R, Section III.G

See subsection 9B.2.0 for generic deviations.

9B.2.8.2 Analysis Area VIIIA

A. Location

Analysis Area VIIIA consists of Fire Zone 84B.

Fire Zone 84B (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall at column line S1, separating the train B half of the pump house from the train A half (Fire Area VII, Zone 84A)

South: Nonrated exterior wall of heavy concrete construction common to the yard

East: Nonrated exterior wall of heavy concrete construction common to the yard

West: Nonrated exterior wall of heavy concrete construction common to the yard

C. Safe Shutdown Related Components and Cables

- Train B cables associated with the following systems:

  Miscellaneous HVAC

  Essential spray pond

- Train B essential spray pond pump and associated flow control valves

  Train B essential spray pond pump house exhaust fan

D. Summary and Conclusion

Safe shutdown capability will be provided by utilizing redundant train A systems available from the control room to achieve hot standby and cold shutdown. This area has been evaluated to be in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.8.3 Fire Area VIII, Fire Zone 84B, Train B Spray Pond Pump House

A. Location

Fire Zone 84B (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall at column line S1, separating the train B half of the pump house from the train A half (Fire Area VII, Zone 84A)

South: Nonrated exterior wall of heavy concrete construction common to the yard

East: Nonrated exterior wall of heavy concrete construction common to the yard

West: Nonrated exterior wall of heavy concrete construction common to the yard

2. Zone Access

One nonrated gate in the train B pump room nonrated south exterior wall

3. Sealed Penetrations

None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In-Situ Combustible Load Type

      Oil and grease

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

Smoke detectors are provided in the pump house for early warning.

H. Fire Suppression

Manual hose streams from hydrants on the yard fire main

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.9 FIRE AREA IX

9B.2.9.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area IX (figure 9B-3) contains the condensate storage tank pump house components found in the outside areas. This fire area includes Analysis Area IXA (Zone 83) only (engineering drawing 13-A-ZYD-021).

Fire Area IX is located in the yard north-northeast of the containment building (Fire Area XI), north of the main steam support structure (Fire Area XII), and south of the abandoned auxiliary boilers (Zone 85A).

B. Deviations From 10CFR50, Appendix R, Section III.G

1. A deviation is requested to Section III.G.2 to the extent that it requires redundant equipment to be separated by at least 20 feet without intervening combustibles, fire detection, and fire suppression.

<u>Discussion</u>

The train A and train B condensate transfer pumps are located in a common pump house. The pump house structure, including the dividing wall between the two pumps, is of nonrated, reinforced concrete construction. The dividing wall is a floor-to-ceiling solid wall extending from the structure west wall to a point just past the pump foundation such that the two pumps and associated drivers are physically separated. Electrical circuits for the two pumps are routed in conduit. The pumps are approximately 15 horizontal feet apart. The in situ combustible loading is predominantly the oil and grease associated with the pumps themselves. The combustible (fire) loading in Zone 83 is low. Fire detection is provided which will alert the fire department in event of fire.

The safety function performed by the condensate transfer system is to provide makeup for the essential chilled water surge tank, essential cooling water surge tank, and the diesel

generator cooling water systems. Loss of the pumps will not preclude the operator from achieving hot shutdown. Establishing an alternate makeup from the FP system for the cooling water systems, can be accomplished in a time frame which permits the operator to achieve cold shutdown within 72 hours.

Conclusion

One train of equipment required to achieve hot shutdown is currently free of fire damage. Loss of both trains of condensate transfer pumps will not preclude the operator from achieving hot shutdown. Establishment of an alternate makeup from the FP system for the cooling water systems can be accomplished in a time frame which permits the operator to achieve cold shutdown within 72 hours.

2. See subsection 9B.2.0 for generic deviations.

9B.2.9.2 Analysis Area IXA

A. Location

Analysis Area IXA consists of Fire Zone 83 only.

Fire Zone 83 (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch. The condensate tunnel is located at elevation 87 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated exterior wall of heavy concrete construction common to the yard south of the abandoned auxiliary boilers (Zone 85A)

South: Nonrated exterior wall of heavy concrete construction common to the yard NNE of the containment building and north of the main steam support structure

East: Nonrated exterior wall of heavy concrete construction common to the yard

West: Nonrated exterior wall of heavy concrete construction common to the condensate storage tank

NOTE

The two condensate transfer pumps are each located within the same pump house. However, a nonrated dividing wall of heavy concrete construction extends from the structure west wall to a point just past the pump foundation such that the two pumps, along with their drivers, are physically separated. The pumps are approximately 15 horizontal feet apart. The tunnel extends southward from the pump house along the 3-hour rated east wall of the main steam support structure and the nonrated east wall of the auxiliary building, fire Area XV, at column line AL.

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Condensate storage and transfer

- Train B cables associated with the following systems:

  Condensate storage and transfer

  Main steam

- Train A condensate transfer pump and associated components

- Train B condensate transfer pump and associated components

- Condensate storage tank and associated level control components and instrumentation

D. Summary and Conclusions

Based on the previously described deviation, (item 9B.2.9.1.B.1). Loss of both trains of condensate transfer pumps will not preclude the operator from achieving hot shutdown. Establishment of an alternate makeup from the FP system for the cooling water systems can be accomplished in a time frame which permits the operator to achieve cold shutdown within 72 hours. One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided.

The redundant train A main steam system will remain available from the control room, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.9.3 Fire Area IX, Fire Zone 83, Condensate Storage Tank, Pump House and Tunnel

A. Location

Fire Zone 83 (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet. The condensate tunnel is at elevation 87 feet.

B. Fire Protection Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction common to the yard south of the abandoned auxiliary boilers (Zone 85A)

South: Nonrated exterior wall of heavy concrete construction common to the yard NNE of the containment building, and north of the main steam support structure

East: Nonrated exterior wall of heavy concrete construction common to the yard

West: Nonrated exterior wall of heavy concrete construction common to the condensate storage tank. The west

nonrated wall of the condensate tunnel common to the east nonrated wall of the auxiliary building, Fire Area XV at elevation 88 feet.

2. Zone Access

   One nonrated gate in the nonrated north wall of the pump house, leading to the yard

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   - Train A condensate storage tank to nonessential auxiliary feedwater pump valves

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

   Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Smoke detectors are located in the pump house.

H. Fire Suppression

Manual hose streams from hydrants on the fire yard main.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.10 FIRE AREA X

9B.2.10.1 Fire Area Description

A. Area Boundary Description

Fire Area X (figures 9B-1, 9B-3, 9B-4, and engineering drawing 13-P-00B-005) is the radwaste building and includes all components located within the building. This fire area includes Zones 58, 59, 60, 60D, 60E, 60F, 60G, 61A, 61B, 61C, 62, 62A, 62B, 62C, 62D, 62E, 62F, 62G, 62H, 62I, 62J, 62K, and 62L (engineering drawing 13-A-ZYD-026).

Fire Area X is bounded to the north, south, and west by nonrated exterior barriers. A portion of the north barrier is adjacent to the 3-hour rated south barrier of Fire Area XV (auxiliary building). A 6-by 10-foot pipe chase extends into the auxiliary building (Fire Area XV) at elevation 120 feet 0 inch and column lines R1 and RE. Inside the auxiliary building the chase is bounded by 3-hour rated barriers on all sides. The east barrier of Fire Area X is common to the 3-hour rated west barrier of Fire Areas I, II, and III (control building). The northeast corner common to the dead space between the auxiliary and control buildings (Fire Area I, Zone 86A) is nonrated and includes a pipe chase which descends to elevation 88 feet 0 inch; the walls about the pipe chase are nonrated. Both the basemat and roof are nonrated barriers.

No safe shutdown nor safety-related equipment is present within Fire Area X.

B. Deviations from 10CFR50, Appendix R, Section III.G

See subsection 9B.2.1 for a deviation common to Fire Area I, subsection 9B.2.15 for a deviation common to Fire Area XV, and subsection 9B.2.0 for generic deviations.

9B.2.10.2 Fire Area X, Fire Zone 58, Waste Compactor, Truck Loading, and Storage Area

A. Location

Fire Zone 58 (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated walls of heavy concrete construction common to Zone 59

South: Nonrated exterior wall of heavy concrete construction at column line R4

East: 2-hour rated wall common to Zones 60 and 60G at column line RB and at elevation 100 feet 0 inch

2-hour rated wall common to Zones 60 and 60E at column line RB and at elevation 110 feet 0 inch

West: Nonrated exterior wall of heavy concrete construction at column line RA

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open at elevation 120 feet 0 inch

2. Zone Access

- One nonrated door (pair) in the 2-hour rated east wall at elevation 100 feet 0 inch to Zone 60G
- One nonrated door in the nonrated south exterior wall at elevation 100 feet 0 inch
- One nonrated door in the nonrated west exterior wall at elevation 100 feet 0 inch
- One nonrated rollup door in the nonrated west exterior wall at elevation 100 feet 0 inch

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater ratings.

5. Protected Raceways

None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Area radiation monitors
   - 55-gallon drum uprighting device
   - 55-gallon drum grapple
   - 55-gallon drum pallet grapple
   - 80-cubic foot container grapple
   - Dry waste compactor
   - Cement feed tank
   - Chemical addition skid
   - Secondary flush skid
   - Additive feed skid
   - Cable trays and conduits

E. Radioactive Material

   Area containing radioactive material

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Charcoal

- Paper and fabric
- Plastic
- Rubber
- Resin
- Wood
- Cable insulation
- Hydraulic fluid
- Grease and oil

2. Transient Combustible Load Type

- Ordinary combustible
- Hydraulic fluid

3. Total Combustible (Fire) Loading

Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel. Partial coverage over the dry waste compactor area with a wet pipe sprinkler system.

2. Secondary

One portable CO_2 fire extinguisher

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Five 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.10.3 Fire Area X, Fire Zone 59, Waste Solidification Area

A. Location

Fire Zone 59 (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction at column line R1

South: Nonrated walls of heavy concrete construction common to Zone 58

East: 2-hour rated wall common to Zone 60E at column line RB.

West: Nonrated exterior wall of heavy concrete construction at column line RA

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open at elevation 120 feet 0 inch

2. Zone Access

- Two nonrated gates in the nonrated south walls at elevation 100 feet 0 inch to Zone 58

- Open ceiling to space also common to Zone 58

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Area radiation monitors
- Waste feed tank
- Radwaste feed pump skid
- 10-ton transfer cart
- Capping machine assembly
- Waste cement mixer
- Conduit

E. Radioactive Material

Area containing radioactive material consisting of spent filters, spent resins and evaporator concentrates, and evaporator concentrates and other stored radioactive materials.

F. Combustible Loading

1. In Situ Combustible Load Type

    - Oil and grease
    - Cable insulation
    - Clothing
    - Paper
    - Plastic
    - Rubber

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 58.

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 58.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Six 4-inch drains

K. Emergency Communications

None

9B.2.10.4 Fire Area X, Fire Zone 60, LRS Waste Holdup Pump Room and Valve Gallery

A. Location

Fire Zone 60 (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 60G

South: Nonrated exterior wall of heavy concrete construction at column line R4

East: Nonrated wall of heavy concrete construction common to Zone 60G at column line RC

West: 2-hour rated wall common to Zone 58 at column line RB

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 62F

2. Zone Access

- One nonrated gate in the nonrated north wall to Zone 60G

- Open nonrated gate in the nonrated east wall to Zone 60G

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - LRS waste holdup pumps
   - LRS recycle monitor tank pump
   - Conduit

E. Radioactive Material

   Radioactive material in process equipment.

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Oil and grease
      - Plastic

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   Two manual hose reels are located in adjacent Zone 60G. One manual hose reel is located in adjacent Zone 58.

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 60G. One portable CO_2 fire extinguisher is located in adjacent Zone 58.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Three 4-inch drains

K. Emergency Communications

None

9B.2.10.5 Fire Area X, Fire Zone 60D, Electrical Chase

A. Location

Fire Zone 60D (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to an HVAC and pipe chase at column line R3

South: 2-hour rated wall common to the southeast staircase

2-hour rated wall common to Zone 60G

East: 3-hour rated wall common to Fire Area I at column line JA

West: 2-hour rated wall common to Zone 60G at column line RD

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 2-hour rated barrier common to Zone 62D

2. Zone Access

One Class B door in the 2-hour rated west wall to Zone 60G

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Heat tracing panels
   - Cable trays and conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      Cable insulation

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

   Ionization smoke detector system is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 60G.

2. Secondary

   Two portable CO_2 fire extinguishers are located in adjacent Zone 60G.

I. Ventilation

   Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

   One 4-inch drain

K. Emergency Communications

   None

9B.2.10.6 Fire Area X, Fire Zone 60E, Controlled Machine Shop, and Tool and Storage Area

A. Location

Fire Zone 60E (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction, adjacent to the 3-hour rated wall of Fire Area XV, at column line R1

Nonrated exterior wall of heavy concrete construction at column line R1

Open to a pipe chase above elevation 114 feet 0 inch

South: Nonrated wall of heavy concrete construction common to Zone 60G

East: Nonrated wall of heavy concrete construction common to Zone 60G

West: 2-hour rated wall common to Zone 59 at column line RB

2-hour rated wall common to Zone 58 at column line RB and elevation 110 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to northwest HVAC chase and Zones 62E, 62F, and 62L

2. Zone Access

   - One nonrated door (pair) in the nonrated south wall to Zone 60G

   - One nonrated door (pair) in the nonrated east wall to Zone 60G

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Area radiation monitor

   - Tools and supplies

- 2-ton monorail
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Paper and fabric
   - Oil
   - Rubber
   - Plastic

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One portable CO_2 fire extinguisher

2. Secondary

Two manual hose reels are located in adjacent Zone 60G.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Five 4-inch drains

K. Emergency Communications

None

9B.2.10.7 Fire Area X, Fire Zone 60F, Spent Resin Transfer/ Dewatering Pump Room and Valve Gallery

A. Location

Fire Zone 60F (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated walls of heavy concrete construction common to Zone 62 at elevation 100 feet 0 inch

Nonrated wall of heavy concrete construction common to a pipe chase above elevation 110 feet 0 inch

South: Nonrated walls of heavy concrete construction common to Zone 60G

East: Nonrated wall of heavy concrete construction common to Zone 60G at elevation 100 feet 0 inch

Nonrated wall of heavy concrete construction common to a valve gallery above elevation 110 feet 0 inch

West: Nonrated wall of heavy concrete construction common to Zone 60G at elevation 100 feet 0 inch

Nonrated wall of heavy concrete construction common to a pipe chase above elevation 114 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 62L and 62B

2. Zone Access

- One nonrated gate in the nonrated south wall to Zone 60G
- Open doorway in the nonrated south wall to an aisle

3. Sealed Penetrations

None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Spent resin transfer/dewatering pump
   - Cable trays and conduits

E. Radioactive Material

   Radioactive material in process equipment

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Plastic

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Grease

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 60G.

2. Secondary

Two portable CO_2 fire extinguishers are located in adjacent Zone 60G.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.10.8 Fire Area X, Fire Zone 60G, Corridor Area

A. Location

Fire Zone 60G (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	North Corridor	- 3-hour rated wall common to Fire Area XV at column line A10
	Central Corridor	- Nonrated walls of heavy concrete construction common to Zones 60E, 60F, and 62
South:	Central Corridor	- Nonrated walls of heavy concrete construction common to Zones 60, 61A, and 61C
	SW Corridor	- Nonrated exterior wall of heavy concrete construction at column line R4
	SE Corridor	- Nonrated exterior wall of heavy concrete construction at column line R4
East:	North Corridor	- Nonrated wall of heavy concrete construction common to Zones 60F and 62
	Central Corridor	- Nonrated wall of heavy concrete construction common to an HVAC and pipe chase at column line RD
	SW Corridor	- Nonrated wall of heavy concrete construction common to Zones 61B and 61C
	SE Corridor	- 2-hour rated walls common to Zone 60D

			2-hour rated wall common to the southeast stairwell
West:	North Corridor	-	Nonrated wall of heavy concrete construction common to Zone 60E
	Central Corridor	-	2-hour rated wall common to Zone 58 at column line RB
	SW Corridor	-	Nonrated wall of heavy concrete construction common to Zone 60
	SE Corridor	-	Nonrated walls of heavy concrete construction common to Zone 61A
Floor:	Nonrated basemat of heavy concrete construction		
Ceiling:	Nonrated barriers of heavy concrete construction common to Zones 62A, 62B, 62E, 62F, and 62L		

2. Zone Access

- One Class A door (pair) in the 3-hour rated north wall to Fire Area XV (Zone 42D)
- One nonrated door (pair) in the 2-hour rated central corridor west wall to Zone 58
- One nonrated door in the nonrated SW corridor south exterior wall

- One Class B door in the 2-hour rated SE corridor east wall to the southeast stairwell

3. Sealed Penetrations

   Seals equal or exceed fire barrier rating.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Concentrate monitor tank level panel
   - Motor control center
   - Cable trays and conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

- Plastic
- Rubber
- Cable insulation
- Fabric
- Oil/grease

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided at the motor control center for early warning.

H. Fire Suppression

1. Primary

Two manual hose reels

2. Secondary

Two portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Seven 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.10.9 Fire Area X, Fire Zone 61A, LRS Concentrate Monitor Tank Rooms

A. Location

Fire Zone 61A (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 60G

South: Nonrated exterior wall of heavy concrete construction at column line R4

East: Nonrated walls of heavy concrete construction common to Zone 60G

West: Nonrated wall of heavy concrete construction common to Zones 61B and 61C

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 62B and 62C

2. Zone Access

- One nonrated gate in the nonrated east wall to Zone 60G
- One nonrated gate in the nonrated west wall to Zone 61C

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- LRS concentrate monitor tanks
- Conduit

E. Radioactive Material

Radioactive material in process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   Plastic

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   Two manual hose reels are located in adjacent Zone 60G

2. Secondary

   Two portable CO_2 fire extinguishers are located in adjacent Zone 60G.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.10.10 Fire Area X, Fire Zone 61B, LRS Concentrate Monitor Pumps Room

A. Location

Fire Zone 61B (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 61C

South: Nonrated exterior wall of heavy concrete construction at column line R4

East: Nonrated wall of heavy concrete construction common to Zone 61A

West: Nonrated wall of heavy concrete construction common to Zone 60G

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 62C and 62E

2. Zone Access

One nonrated gate in the nonrated west wall to Zone 60G

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- LRS concentrate monitor pumps
- Conduit

E. Radioactive Material

Radioactive evaporator concentrate material in process

F. Combustible Loading

1. In Situ Combustible Load Type

   - Oil and grease
   - Plastic

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 60G.

2. Secondary

   Two portable CO_2 fire extinguishers are located in adjacent Zone 60G.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.10.11 Fire Area X, Fire Zone 61C, Operating Aisle and Valve Gallery

A. Location

Fire Zone 61C (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 60G

South: Nonrated wall of heavy concrete construction common to Zone 61B

East: Nonrated wall of heavy concrete construction common to Zone 61A

West: Nonrated wall of heavy concrete construction, common to Zone 60G

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 62B and 62E

2. Zone Access

One open doorway in the nonrated north wall to Zone 60G

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

Radioactive material in process.

F. Combustible Loading

1. In Situ Combustible Load Type

   - Grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   Two manual hose reels are located in adjacent Zone 60G.

2. Secondary

   Two portable CO_2 fire extinguishers are located in adjacent Zone 60G.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.10.12 Fire Area X, Fire Zone 62, High and Low Activity Spent Resin Tank Rooms

A. Location

Fire Zone 62 (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 100 feet 0 inch and 110 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction, adjacent to the 3-hour rated wall of Fire Area XV, at column line R1

South: Nonrated walls of heavy concrete construction common to Zone 60F and to Zone 60G at elevation 100 feet 0 inch

Nonrated wall of heavy concrete construction common to a valve gallery above elevation 110 feet 0 inch

East: Nonrated wall of heavy concrete construction common to an HVAC and pipe chase

West: Nonrated wall of heavy concrete construction, common to Zone 60G

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 62A

2. Zone Access

Two nonrated gates in the nonrated south walls to an aisle

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- High activity spent resin tank
- Low activity spent resin tank
- Conduit

E. Radioactive Material

Radioactive spent resins in process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

None

2. Transient Combustible Load Type

- Ordinary combustible
- Resin

3. Total Combustible (Fire) Loading

High

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in Zone 60G.

2. Secondary

Two portable CO_2 fire extinguishers are located in Zone 60G.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.10.13 Fire Area X, Fire Zone 62A, Boric Acid Condensate Ion Exchanger, LRS Mixed Bed Ion Exchangers, LRS Adsorption Bed, and Valve Gallery

A. Location

Fire Zone 62A (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction, adjacent to the 3-hour rated wall of Fire Area XV, at column line R1

South: Nonrated wall of heavy concrete construction common to Zone 62L

East: Nonrated wall of heavy concrete construction common to an HVAC and pipe chase at column line RD

West: Nonrated wall of heavy concrete construction common to Zone 62L

Floor: Nonrated barrier of heavy concrete construction common to Zones 60G and 62

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 62H and 62I

2. Zone Access

- One nonrated gate in the nonrated south wall to Zone 62L

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Boric acid condensate ion exchanger
- LRS mixed bed ion exchangers
- LRS adsorption bed

- Conduit

E. Radioactive Material

Radioactive material in process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

- Plastic
- Oil and grease

2. Transient Combustible Load Type

- Ordinary combustible
- Resin beads

3. Total Combustible (Fire) Loading

High

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 62L.

2. Secondary

Two portable CO_2 fire extinguishers are located in adjacent Zone 62L.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Six 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.10.14 Fire Area X, Fire Zone 62B, Radwaste Control Room

A. Location

Fire Zone 62B (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 62L

South: Nonrated wall of heavy concrete construction common to Zone 62C

East: Nonrated wall of heavy concrete construction common to Zone 62L

West: Nonrated wall of heavy concrete construction common to Zone 62E

Floor: Nonrated barrier of heavy concrete construction common to Zones 60G, 61A, and 61C

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 62J

2. Zone Access

One nonrated door (pair) in the nonrated north wall to zone 62L

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Radwaste system control panels
- Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Paper and fabric
- Plastic
- Rubber
- Wood

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization Smoke Detector System(s) is provided for early warning.

H. Fire Suppression

1. Primary

Two manual hose reels are located in adjacent Zone 62L.

2. Secondary

Two portable CO_2 fire extinguishers are located in adjacent Zone 62L.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.10.15 Fire Area X, Fire Zone 62C, Acid, Caustic, and Antifoam Tanks and Pumps Room

A. Location

Fire Zone 62C (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 62B

South: Nonrated exterior wall of heavy concrete construction at column line R4

East: Nonrated wall of heavy concrete construction common to Zone 62L

West: Nonrated wall of heavy concrete construction common to Zone 62E

Floor: Nonrated barrier of heavy concrete construction common to Zones 61A and 61B

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 62I

2. Zone Access

One nonrated gate in the nonrated east wall to Zone 62L

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Acid batch tank
- Acid tank
- Caustic batch tank
- Caustic tank

- Antifoam tank
- Antifoam pump
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
    - Plastic
    - Oil and grease
2. Transient Combustible Load Type
    - Ordinary combustible
    - Oil and grease
3. Total Combustible (Fire) Loading

    Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

    One manual hose reel is located in adjacent Zone 62L.

2. Secondary

    One portable CO_2 fire extinguisher is located in adjacent Zone 62L.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.10.16 Fire Area X, Fire Zone 62D, Electrical Chase

A. Location

Fire Zone 62D (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to an HVAC and pipe chase at column line R3

South: 2-hour rated wall common to the southeast stairwell

2-hour rated wall common to Zone 62L.

East: 3-hour rated wall common to Fire Area II at column line JA

West: 2-hour rated wall common to Zone 62L at column line RD

Floor: 2-hour rated barrier common to Zone 60D

Ceiling: 2-hour rated barrier common to Zone 62G

2. Zone Access

One Class B door in the 2-hour rated west wall to Zone 62L

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater ratings.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Radios
- Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   Cable insulation

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 62L.

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 62L.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.10.17 Fire Area X, Fire Zone 62E, Boric Acid Concentrator and Valve Gallery

A. Location

Fire Zone 62E (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 62L

South: Nonrated exterior wall of heavy concrete construction at column line R4

East: Nonrated wall of heavy concrete construction common to Zones 62B and 62C

West: Nonrated walls of heavy concrete construction common to Zone 62F

Floor: Nonrated barrier of heavy concrete construction common to Zones 60G, 61B, and 61C

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 62I

2. Zone Access

- Two nonrated gates in the nonrated west walls to Zone 62F

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Boric acid concentrator
- Conduit

E. Radioactive Material

Radioactive material in process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

- Oil and grease
- Plastic

2. Transient Combustible Load Type

- Ordinary combustible
- Oil and grease

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 62L.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 62L.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Three 4-inch drains

K. Emergency Communications

None

9B.2.10.18 Fire Area X, Fire Zone 62F, Evaporator Equipment Rooms and Valve Gallery

A. Location

Fire Zone 62F (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevations 120 feet 0 inch and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to zone 62L at elevation 120 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 62I at column line R3 at elevation 140 feet 0 inch

South: Nonrated exterior wall of heavy concrete construction at column line R4

East: Nonrated walls of heavy concrete construction common to Zone 62E at elevation 120 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 62I at elevation 140 feet 0 inch

West: 2-hour rated wall common to the open space above Zones 58 and 59 at column line RB and at elevation 120 feet 0 inch

Nonrated exterior wall of heavy concrete construction at column line RB and at elevation 140 feet 0 inch

Floor: Nonrated barrier of heavy concrete construction common to Zones 60 and 60G

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 62I at elevation 120 feet

Nonrated roof of heavy concrete construction at elevations 120 feet and 140 feet

2. Zone Access

- One nonrated door in the nonrated north wall to Zone 62L

3. Sealed Penetrations

Seals equal or exceed fire barrier rating.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater ratings.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Evaporator concentrate pumps
   - Evaporator steam condensate pump
   - Evaporator main recycle pump
   - Evaporator surface condenser
   - Evaporator vapor body
   - 3-ton monorail
   - Cable trays and conduits
   - Evaporator distilation pumps, cooling and heating element

E. Radioactive Material

   Radioactive material in process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Oil and grease
- Plastic

2. Transient Combustible Load Type

- Ordinary combustible
- Oil and grease

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 62L.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 62L.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Five 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.10.19 Fire Area X, Fire Zone 62G, Electrical Chase

A. Location

Fire Zone 62G (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to an HVAC and pipe chase at column line R3

South: 2-hour rated wall common to the southeast stairwell

2-hour rated wall common to Zone 62K

East: 3-hour rated wall common to Fire Area III at column line JA

West: 2-hour rated wall common to Zone 62J at column line RD

Floor: 2-hour rated barrier common to Zone 62D

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

One Class B door in the 2-hour rated south wall to the southeast stairwell

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater ratings.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   Cable insulation

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 62K

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 67K.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.10.20 Fire Area X, Fire Zone 62H, Waste Gas Compressor Rooms and Valve Galleries

A. Location

Fire Zone 62H (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 62I

South: Nonrated walls of heavy concrete construction common to Zone 62J

East: Nonrated wall of heavy concrete construction common to an HVAC and pipe chase

West: Nonrated walls of heavy concrete construction common to Zone 62I

Floor: Nonrated barrier of heavy concrete construction common to Zones 62A and 62L

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

   - One nonrated gate in the nonrated north wall to Zone 62I
   - One nonrated gate in the nonrated south wall to Zone 62J
   - One nonrated gate in the nonrated west wall to Zone 62I

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Waste gas compressors
   - Conduit

E. Radioactive Material

   Radioactive gases in process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   - Oil and grease
   - Plastic

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 62I.

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 62I.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Five 4-inch drains

K. Emergency Communications

None

9B.2.10.21 Fire Area X, Fire Zone 62I, Access Corridors and Ion Exchanger Hatch Laydown Area

A. Location

Fire Zone 62I (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	North Corridor	- Nonrated wall of heavy concrete construction, adjacent to the 3-hour rated wall of Fire Area XV, at column line R1 Nonrated exterior wall of heavy concrete construction at column line Rl
	South Corridor	- Nonrated wall of heavy concrete construction common to Zone 62J

South:	North Corridor	- Nonrated wall of heavy concrete construction common to Zone 62H
	South Corridor	- Nonrated exterior wall of heavy concrete construction at column line R4
	Central Corridor	- Nonrated wall of heavy concrete construction common to Zone 62F
East:	North Corridor	- Nonrated wall of heavy concrete construction common to an HVAC and pipe chase
	South Corridor	- Nonrated wall of heavy concrete construction common to Zone 62K
	Central Corridor	- Nonrated walls of heavy concrete construction common to Zones 62H and 62J
West:	Nonrated wall of heavy concrete construction common to Zone 62F	
	Nonrated exterior wall of heavy concrete construction at column line RB	
	Nonrated walls of heavy concrete construction common to the northwest HVAC chase	

Floor: Nonrated barrier of heavy concrete construction common to Zones 62A, 62C, 62E, 62F, and 62L

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One Class A door (pair) in the 3-hour rated north wall to Fire Area XV (Aux. Building)
- One open doorway in the nonrated south corridor east wall to Zone 62K

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Waste gas decay tank exhaust monitor
- Load center

- H_2 and O_2 analyzer
- Waste gas area combined exhaust monitor
- 10-ton monorail
- Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
    - Cable insulation
    - Hydrogen
    - Plastic
    - Oxygen
    - Paper
    - Rubber
2. Transient Combustible Load Type
    - Ordinary combustible
    - Cable insulation
3. Total Combustible (Fire) Loading

    Low

G. Fire Detection

Ionization smoke detector system(s) is provided at the load center and sorting area for early warning.

H. Fire Suppression

1. Primary

One manual hose reel

2. Secondary

One portable CO_2 fire extinguisher

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Eight 4-inch drains

K. Emergency Communication

Sound powered phone jack(s) is provided.

9B.2.10.22 Fire Area X, Fire Zone 62J, Waste Gas Decay and Surge Tank Rooms and Valve Gallery

A. Location

Fire Zone 62J (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated walls of heavy concrete construction common to Zone 62H

South: Nonrated walls of heavy concrete construction common to Zones 62I and 62K

East: Nonrated wall of heavy concrete construction common to an HVAC and pipe chase

2-hour rated wall common to Zone 62G

West: Nonrated walls of heavy concrete construction common to Zone 62I

Floor: Nonrated barrier of heavy concrete construction common to Zones 62B and 62L

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One nonrated gate in the nonrated north wall to Zone 62H
- Two nonrated gates in the nonrated west walls to Zone 62I
- One nonrated gate in the nonrated south wall to Zone 62I

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Waste gas surge tank
   - Waste gas decay tanks
   - Conduit

E. Radioactive Material

   Radioactive gases in process equipment

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Hydrogen
      - Oil/grease

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 62I.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent 62I.

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

Five 4-inch drains

K. Emergency Communications

None

9B.2.10.23 Fire Area X, Fire Zone 62K, Hatch Laydown Area

A. Location

Fire Zone 62K (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 62J

2-hour rated wall common to Zone 62G

South: Nonrated exterior wall of heavy concrete construction at column line R4

East: 2-hour rated wall common to the southeast stairwell

West: Nonrated wall of heavy concrete construction common to Zones 62I and 62J

Floor: Nonrated barrier of heavy concrete construction common to Zone 62L

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One Class B door in the 2-hour rated east wall to the southeast stairwell
- One open doorway in the nonrated west wall to Zone 62I
- One nonrated watertight steel equipment hatch in the nonrated floor to Zone 62L

3. Sealed Penetrations

   Seals equal or exceed fire barrier rating.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater ratings.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Motor control center
   - Cable trays and conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      Cable insulation

   2. Transient Combustible Load Type

      - Ordinary combustible

- Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided at the motor control center for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel nozzle

2. Secondary

   One portable CO_2 fire extinguisher

I. Ventilation

Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.10.24 Fire Area X, Fire Zone 62L, Corridor Area

A. Location

Fire Zone 62L (engineering drawing 13-A-ZYD-026) is located in the radwaste building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XV at column line A10

Nonrated wall of heavy concrete construction common to Zone 62A

Nonrated exterior wall of heavy concrete construction at column line R1

Nonrated walls of heavy concrete construction common to the northwest HVAC chase

South: Nonrated wall of heavy concrete construction common to Zones 62B, 62E, and 62F

Nonrated exterior wall of heavy concrete construction at column line R4

East: Nonrated wall of heavy concrete construction common to Zone 62A

Nonrated wall of heavy concrete construction common to HVAC and pipe chases

2-hour rated walls common to Zone 62D

2-hour rated wall common to the southeast stairwell

West: Nonrated wall of heavy concrete construction common to the open space above Zones 58 and 59

Nonrated wall of heavy concrete construction common to Zones 62B and 62C

Floor: Nonrated barrier of heavy concrete construction common to Zones 60E, 60F, and 60G

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 62H, 62I, 62J, and 62K

2. Zone Access

- One nonrated door (pair) and transom in the 3-hour rated north wall to Fire Area XV (Aux. Building)
- One Class B door in the 2-hour rated east wall to the southeast stairwell

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Cable trays and conduit
   - 5-ton monorail
   - Radwaste control room normal air handling unit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation
      - Plastic

   2. Transient Combustible Load Type

      - Ordinary combustible

- Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

   None

H. Fire Suppression

1. Primary

   Two manual hose reels. Sprinkler coverage at the access door to Fire Area XV, Zone 48

2. Secondary

   Two portable CO_2 fire extinguishers

I. Ventilation

   Manually controlled smoke exhaust venting to the adjacent zone/outside using portable smoke removal equipment.

J. Drainage

   Six 4-inch drains

K. Emergency Communications

   Sound powered phone jack(s) is provided.

9B.2.11 FIRE AREA XI

9B.2.11.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area XI (figures 9B-1, 9B-2, 9B-3, 9B-4, and engineering drawing 13-P-00B-005) is the containment building and includes all components located within the building. This fire area includes Analysis Area XIA (Fire Zones 66A, 67A, and 71A), XIB (Zones 66B, 67B, and 71B), XIC (Zone 63A), XID (Zone 63B), XIE (Zone 64), XIF (Zone 65), and XIG (Zone 70) (engineering drawing 13-A-ZYD-022).

Fire Area XI is cylindrical in shape, bounded to the south by a 3-hour rated barrier common to Fire Areas XV, XVI, and XVII, to the east by a 3-hour rated barrier to a seismic gap common to the unrated barrier of Fire Area XII, and to the north and west by a nonrated exterior barrier. The basemat and roof of the containment building are nonrated.

B. Deviations from 10CFR50, Appendix R, Section III.G

1. A deviation is requested from Section III.G.2 to the extent that it requires separation of cables and equipment by a horizontal distance of more than 20 feet without intervening combustibles or fire hazards.

Discussion

A description of the existing condition is provided in the appendix 9A response to Question 9A.130.

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2, and upgrading the existing design would not significantly enhance the protection currently provided.

2. See the response to Question 9A.130 in Appendix 9A for a deviation from 10CFR50, Appendix R, Section III.G.2.f, regarding separation of cables and equipment and associated non-safety related circuits of redundant trains by a non-combustible radiant energy heat shield.

3. See subsection 9B.2.0 for generic deviations.

9B.2.11.2 Analysis Area XIA

A. Location

Analysis Area XIA consists of Fire Zones 66A, 67A, and 71A.

Fire Zone 66A and 67A (engineering drawing 13-A-ZYD-022) are located in the containment building at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

Fire Zone 71A (engineering drawing 13-A-ZYD-022) is located in the containment building at elevation 140 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated wall of heavy concrete construction common to Zone 63B at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 64 at elevation 80 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 70 at elevations 100 feet 0 inch and 120 feet 0 inch

Nonrated exterior wall of heavy concrete construction

Nonrated wall of steel construction common to Zone 67B (elevation 140 feet 0 inch)

South: 3-hour rated wall common to Fire Area XV at elevations 80 feet 0 inch and 140 feet 0 inch

3-hour rated barrier common to Fire Area XVI at elevations 100 feet 0 inch and 120 feet 0 inch

3-hour rated barrier common to the south access shaft

Nonrated wall of heavy concrete construction common to Zone 63A at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 64 at elevation 80 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 65 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 70 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 63A

East: Open to Zone 66B at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of steel construction common to Zone 71B at elevation 140 feet 0 inch

Open to Zone 67B at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

West: Nonrated exterior wall of heavy concrete construction

Floor: Nonrated basemat of heavy concrete construction

Nonrated barrier of steel construction common to Zone 67B

Ceiling: Nonrated barrier of steel construction common to the containment atmosphere

Open to the containment atmosphere

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

  Ex-core neutron monitoring

  Main steam

  Safety injection and shutdown cooling

  Nuclear sampling

  Engineered safety feature actuation

- Train B cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

  Main steam

  Safety injection and shutdown cooling

  Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

- Train A nuclear sampling isolation valves
- Train A shutdown cooling high/low pressure interface valves
- Train A safety injection tank 1A vent and isolation valves
- Train B safety injection tank 1A vent valve
- Train A safety injection tank 1B vent and isolation valves
- Train A safety injection tank 2A vent valve
- Train A safety injection tank 2B vent valve
- Train B safety injection tank 2B vent and isolation valves
- Train B steam generator 1 and 2 level transmitters
- Train A steam generator 1 blowdown sample isolation valves
- Train B steam generator 2 blowdown sample isolation valves
- Train A pressurizer pressure and level instrumentation

- Train B pressurizer pressure and level instrumentation
- Train A and train B steam generator 2 pressure transmitters
- Nontrain related reactor coolant pump bleedoff isolation valves
- Nontrain related pressurizer spray valves
- Nontrain related regenerative heat exchanger
- Nontrain related seal injection control valves
- Nontrain related reactor coolant pump seal bleedoff control valves
- Nontrain related nuclear cooling instruments and valves
- Train A reactor coolant pump bleed off valves
- Non train related charging line valves

D. Summary and Conclusions

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on spatial separation and the radiant energy shield provided on the raceway for the train A pressurizer auxiliary spray valve. The redundant train A system will remain available from the control room, in conjunction with operator action, inside and outside of this analysis area to prevent or overcome the

consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function.

9B.2.11.3 Analysis Area XIB

A. Location

Analysis Area XIB consists of Fire Zones 66B, 67B, and 71B.

Fire Zone 66B and 67B (engineering drawing 13-A-ZYD-022) are located in the containment building at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

Fire Zone 71B (engineering drawing 13-A-ZYD-022) is located in the containment building at elevation 140 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated walls of heavy concrete construction common to Zone 63B at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 70 at elevations 120 feet 0 inch and 140 feet 0 inch

Nonrated exterior wall of heavy concrete construction

Nonrated wall of heavy concrete construction common to Zone 63B

South: 3-hour rated wall common to Fire Area XV at elevations 80 feet 0 inch and 140 feet 0 inch

3-hour rated wall common to Fire Area XVII at elevations 100 feet 0 inch and 120 feet 0 inch

3-hour rated barrier common to the south access shaft

Nonrated walls of heavy concrete construction common to Zone 63A at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 70 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated wall of steel construction common to Zone 66A (elevation 140 feet 0 inch)

East: 3-hour rated wall to a seismic gap common to the unrated barrier of Fire Area XII

West: Open to Zones 66A and 67A at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of steel construction common to Zone 71A at elevation 140 feet 0 inch

Nonrated wall of steel construction common to Zone 66A

Floor: Nonrated basemat of heavy concrete construction

Nonrated barrier of steel construction common to Zone 66A

Ceiling: Open to the containment atmosphere (above Fire Zones 66B and 67B)

Nonrated barrier of steel construction common to the containment atmosphere (above Fire Zone 71B)

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Chemical and volume control (Unit 1 only)

  Reactor coolant

  Main steam

  Safety injection and shutdown cooling

  Engineered safety feature actuation

- Train B cables associated with the following systems:

  Chemical and volume control

  Nuclear cooling water

  Reactor coolant

Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

- Train B and nontrain related nuclear cooling water flow control valves
- Train A steam generator 1 blowdown isolation valve
- Train B steam generator 2 blowdown isolation valve
- Train A steam generator level transmitter
- Train B steam generator level transmitter
- Train A steam generator 1 pressure transmitter
- Train B steam generator 1 pressure transmitter
- Train A safety injection tank 2A vent valve
- Train B safety injection tank 1A vent valve
- Train A safety injection tank 1B vent and isolation valves
- Train B safety injection tank 1B vent valve

- Train B safety injection tank 2B vent and isolation valves
- Train B safety injection tank 2A vent and isolation valves
- Train B shutdown cooling high/low pressure interface valves

D. Summary and Conclusions

One train of systems necessary to achieve and maintain hot standby and cold shutdown conditions independent of the subject fire area, in conjunction with operator action, both inside and outside this analysis area, to establish equipment lineups, has been demonstrated to remain available due to spatial separation provided. This area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.11.4 Analysis Area XIC

A. Location

Analysis Area XIC consists of Fire Zone 63A only.

Fire Zone 63A (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated wall of heavy concrete construction common to Zones 67A and 67B

Nonrated wall of heavy concrete construction common to Zone 71A at elevation 140 feet 0 inch

South: Nonrated wall of heavy concrete construction common to:

- The reactor vessel shield at elevations 80 feet 0 inch and 100 feet 0 inch
- Zone 70 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Open to Zone 63B at elevation 80 feet 0 inch

East: Nonrated wall of heavy concrete construction common to Zone 67B

West: Nonrated wall of heavy concrete construction common to:

- Zones 64 and 67A at elevation 80 feet 0 inch
- Zones 65 and 67A at elevations 100 feet 0 inch and 120 feet 0 inch
- Zone 67A at elevation 140 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the containment atmosphere at elevation 155 feet 0 inch

Nonrated barrier of heavy concrete construction common to Zone 70 at elevation 100 feet 0 inch

C. Safe Shutdown Related Components and Cables

- Train A, train B, and nontrain related cables associated with the following system:

  Reactor coolant

- Train A safety injection and shutdown cooling
- Train A reactor coolant head vent valve
- Train A reactor coolant loop 1 temperature instrumentation
- Train B reactor coolant loop 1 temperature instrumentation
- Reactor coolant pump seal coolers and associated components
- Reactor coolant pump 1A
- Reactor coolant pump 1B

D. Summary and Conclusions

One train of systems necessary to achieve and maintain hot standby and cold shutdown conditions independent of the subject fire area, in conjunction with operator action outside of this analysis area to prevent or overcome the consequences of spurious operation of component, or to establish equipment lineups, has been demonstrated to remain available

due to spatial separation provided. This area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.11.5 Analysis Area XID

A. Location

Analysis Area XID consists of Fire Zone 63B only.

Fire Zone 63B (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated wall of heavy concrete construction common to:

- The reactor vessel shield at elevations 80 feet 0 inch and 100 feet 0 inch
- Zone 70 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Open to Zone 63A at elevation 80 feet 0 inch

South: Nonrated wall of heavy concrete construction common to Zones 66A and 66B
Nonrated wall of heavy concrete construction common to Zone 71B at elevation 140 feet 0 inch

East: Nonrated wall of heavy concrete construction common to Zone 66B

West: Nonrated wall of heavy concrete construction common to:

- Zones 64 and 66A at elevation 80 feet 0 inch
- Zone 66A at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the containment atmosphere at elevation 155 feet 0 inch

Nonrated barrier of heavy concrete construction common to Zone 70 at elevation 100 feet 0 inch

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

- Train B cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

- Nontrain related cables associated with the following system:

  Reactor coolant

- Train A and train B letdown isolation valves
- Train A and train B reactor coolant loop 2 temperature instruments
- Reactor coolant pump seal coolers and associated components
- Reactor coolant pump 2A
- Reactor coolant pump 2B

D. Summary and Conclusions

One train of systems necessary to achieve and maintain hot standby and cold shutdown conditions independent of the subject fire area, in conjunction with operator action outside of this analysis area to prevent or overcome the consequences of spurious operation of component, or to establish equipment lineups, has been demonstrated to remain available due to spatial separation provided. This area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.11.6 Analysis Area XIE

A. Location

Analysis Area XIE consists of Fire Zone 64.

Fire Zone 64 (engineering drawing 13-A-ZYD-022) is located in the containment building at elevation 80 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated wall of heavy concrete construction common to Zones 63A and 67A

South: Nonrated wall of heavy concrete construction common to Zones 63B and 66A

East: Nonrated wall of heavy concrete construction common to Zones 63A and 63B

West: Nonrated wall of heavy concrete construction common to Zones 66A and 67A

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 65, 67A, and 70

C. Safe Shutdown Related Components and Cables

None

D. Summary and Conclusion

Normal shutdown is credited for a fire in this area. The safe shutdown equipment credited for a fire in this area is expected to remain available in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.11.7 Analysis Area XIF

A. Location

Analysis Area XIF consists of Fire Zone 65.

Fire Zone 65 (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 100 feet 0 inch and 120 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated wall of heavy concrete construction common to Zone 67A

South: Nonrated wall of heavy concrete construction common to Zone 67A

Nonrated walls of heavy concrete construction common to Zone 70

East: Nonrated wall of heavy concrete construction common to Zone 63A

West: Nonrated wall of heavy concrete construction common to Zone 67A

Floor: Nonrated barrier of heavy concrete construction common to Zones 63A, 64, and 67A

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 67A at elevation 161 feet 6 inches

C. Safe Shutdown Related Components and Cables

- Train A and train B cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

- Pressurizer
- Train A and train B pressurizer auxiliary spray valves
- Train A and train B pressurizer vent valves
- Train A and train B reactor coolant system vent valves
- Nontrain related pressurizer relief valves
- Train A and train B 1E pressurizer backup and proportional heaters
- Nontrain related pressurizer backup and proportional heaters

D. Summary and Conclusions

The following systems are affected for a fire in this analysis area:

One train of systems necessary to achieve and maintain hot standby and cold shutdown conditions independent of the subject fire area, in conjunction with operator action, outside this analysis area, to establish equipment lineups, has been demonstrated to remain available due to spatial separation and the

radiant energy shield provided on the Train A pressurizer auxiliary spray valve and raceway. This area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.11.8 Analysis Area XIG

A. Location

Analysis Area XIG consists of Fire Zone 70.

Fire Zone 70 (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Analysis Area Boundaries

North: Nonrated wall of stainless steel and heavy concrete construction common to:

- Zones 63A, 65, 67A, and 67B at elevation 100 feet 0 inch and 120 feet 0 inch
- Zone 63A at elevation 140 feet 0 inch

South: Nonrated wall of stainless steel and heavy concrete construction common to:

- Zones 63B, 66A, and 66B at elevations 100 feet 0 inch and 120 feet 0 inch
- Zone 63B at elevation 140 feet 0 inch

East: Nonrated wall of stainless steel and heavy concrete construction common to Zones 66B

and 67B at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

West: Nonrated wall of stainless steel and heavy concrete construction common to:

- Zones 65 and 67A at elevation 100 feet 0 inch
- Zone 67A at elevation 120 feet 0 inch
- Zones 66A and 67A at elevation 140 feet 0 inch

Floor: Nonrated barrier of stainless steel and heavy concrete construction common to Zones 63A, 63B, 64, 66A, and 66B

Ceiling: Open to the containment atmosphere

C. Safe Shutdown Related Components and Cables

- Train A and train B cables associated with the following system:

  Reactor coolant

- Train A and train B reactor vessel head vent valves

D. Summary and Conclusions

One train of systems necessary to achieve and maintain hot standby and cold shutdown conditions independent of the subject fire area has been demonstrated to remain free of fire damage due to spatial separation provided. Based on area

construction this analysis area is in compliance with the criteria of 10CFR50, Appendix R, Section III.G.

9B.2.11.9 Fire Area XI, Fire Zone 63A, No. 1 Reactor Coolant Pumps and Steam Generator Area

A. Location

Fire Zone 63A (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zones 67A and 67B

Nonrated wall of heavy concrete construction common to Zone 71A at elevation 140 feet 0 inch

South: Nonrated wall of heavy concrete construction common to:

- The reactor vessel shield at elevations 80 feet 0 inch and 100 feet 0 inch
- Zone 70 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Open to Zone 63B at elevation 80 feet 0 inch

East: Nonrated wall of heavy concrete construction common to Zone 67B

West: Nonrated wall of heavy concrete construction common to:

- Zones 64 and 67A at elevation 80 feet 0 inch
- Zones 65 and 67A at elevations 100 feet 0 inch and 120 feet 0 inch
- Zone 67A at elevation 140 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the containment atmosphere at elevation 155 feet 0 inch

Nonrated barrier of heavy concrete construction common to Zone 70 at elevation 100 feet 0 inch

2. Zone Access

- Open to the containment atmosphere at elevation 155 feet 0 inch
- Open to Zone 63B at elevation 80 feet 0 inch

- One nonrated gate in the nonrated west wall to Zone 67A at elevation 80 feet 0 inch
- One nonrated gate in the nonrated east wall to Zone 67B at elevation 80 feet 0 inch and elevation 100 feet 0 inch
- Open doorway in the nonrated west wall to Zone 64 at elevation 80 feet 0 inch

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

- Cable trays and conduit
- Cavity cooling fans
- Lube oil collection tank
- Jib cranes and supports

E. Radioactive Material

Radioactive material in process piping and equipment.

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Oil and grease
   - Hydraulic fluid

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Low

NOTE

Refer to the appendix 9A response to Question 9A.126 for a description of the reactor coolant pump lube oil collection system and compliance with 10CFR50, Appendix R, Section III.0.

G. Fire Detection

Line-type thermal detectors installed in the cable trays and ionization and photoelectric smoke detectors are provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 67A at elevation 80 feet 0 inch. One manual hose reel is located in adjacent Zone 67B at elevation 80 feet 0 inch.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 67A at elevation 80 feet 0 inch. One portable CO_2 fire extinguisher is located in adjacent Zone 67B at elevation 80 feet 0 inch.

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

- Two 4-inch drains at elevation 87 feet 0 inch
- One 4-inch drain at elevation 80 feet 0 inch

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.11.10 Fire Area XI, Fire Zone 63B, No. 2 Reactor Coolant Pumps and Steam Generator Area

A. Location

Fire Zone 63B (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to:

- The reactor vessel shield at elevations 80 feet 0 inch and 100 feet 0 inch
- Zone 70 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Open to Zone 63A at elevation 80 feet 0 inch

South: Nonrated wall of heavy concrete construction common to Zones 66A and 66B

Nonrated wall of heavy concrete construction common to Zone 71B at elevation 140 feet 0 inch

East: Nonrated wall of heavy concrete construction common to Zone 66B

West: Nonrated wall of heavy concrete construction common to:

- Zones 64 and 66A at elevation 80 feet 0 inch
- Zone 66A at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the containment atmosphere at elevation 155 feet 0 inch

Nonrated barrier of heavy concrete construction common to Zone 70 at elevation 100 feet 0 inch

2. Zone Access

- Open to the containment atmosphere at elevation 155 feet 0 inch
- Open to Zone 63A at elevation 80 feet 0 inch
- One nonrated gate in the nonrated west wall to Zone 66A at elevation 80 feet 0 inch
- One nonrated gate in the nonrated east wall to Zone 66B at elevation 80 feet 0 inch

- One nonrated gate in the nonrated east wall to Zone 66B at elevation 100 feet 0 inch

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

   - Train A conduit[a]
   - Train B conduit[a]

D. Nonsafety-Related Equipment and Components

   - Cable trays and conduit
   - Cavity cooling fans
   - Lube oil collection tank
   - Jib cranes and supports

E. Radioactive Material

   Radioactive material in process piping and equipment

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Hydraulic fluid
- Oil and grease

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Low

NOTE

Refer to the appendix 9A response to Question 9A.126 for a description of the reactor coolant lube oil collection system and compliance with 10CFR50, Appendix R, Section III.0.

G. Fire Detection

Ionization and photoelectric smoke detectors are provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 66A at elevation 80 feet 0 inch. One manual hose reel is located on each level in

adjacent Zone 66B at elevations 80 feet 0 inch and 100 feet 0 inch.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 66A at elevation 80 feet 0 inch. One portable CO_2 fire extinguisher is located on each level in adjacent Zone 66B at elevations 80 feet 0 inch and 100 feet 0 inch.

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

- Two 4-inch drains at elevation 88 feet 0 inch
- One 4-inch drain at elevation 80 feet 0 inch

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.11.11 Fire Area XI, Fire Zone 64, Reactor Drain Tank Room

A. Location

Fire Zone 64 (engineering drawing 13-A-ZYD-022) is located in the containment building at elevation 80 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zones 63A and 67A

South: Nonrated wall of heavy concrete construction common to Zones 63B and 66A

East: Nonrated wall of heavy concrete construction common to Zones 63A and 63B

West: Nonrated wall of heavy concrete construction common to Zones 66A and 67A

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 65, 67A, and 70

2. Zone Access

Open doorway in the nonrated north wall to Zone 63A

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Reactor drain tank
   - Conduit

E. Radioactive Material

   Radioactive material in process piping and equipment.

F. Combustible Loading

   1. In Situ Combustible Load Type

      None

   2. Transient Combustible Load Type

      Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

   None

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 67A.

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 67A.

I. Ventilation

   Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

   One 4-inch drain

K. Emergency Communications

   None

9B.2.11.12 Fire Area XI, Fire Zone 65, Pressurizer Room

A. Location

Fire Zone 65 (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 100 feet 0 inch and 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 67A

South: Nonrated wall of heavy concrete construction common to Zone 67A

Nonrated walls of heavy concrete construction common to Zone 70

East: Nonrated wall of heavy concrete construction common to Zone 63A

West: Nonrated wall of heavy concrete construction common to Zone 67A

Floor: Nonrated barrier of heavy concrete construction common to Zones 63A, 64, and 67A

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 67A at elevation 161 feet 6 inches

2. Zone Access

- One nonrated door in the nonrated south wall to Zone 67A at elevation 100 feet 0 inch
- One open doorway in the nonrated south wall to Zone 67A at elevation 120 feet 0 inch
- Stairs leading to Zone 67A at elevation 146 feet 0 inch

3. Sealed Penetration

   None

4. Fire Dampers

   None

5. Protected Raceways

   Train A pressurizer auxiliary spray valve and raceway is protected by a radiant energy shield consisting of metallic reflectorized insulation and 1/2-inch-thick Thermo-Lag insulation.

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Conduit
   - Pressurizer area normal recirculation fans

E. Radioactive Material

Radioactive material in process piping and equipment.

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Grease
   - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Line-type thermal detectors are provided for early warning.

H. Fire Suppression

1. Primary

   Two portable CO_2 fire extinguishers are located in adjacent Zone 67A at elevation 100 feet 0 inch. One portable CO_2 fire extinguisher is located in adjacent Zone 67A at elevation 120 feet 0 inch.

2. Secondary

One portable CO_2 fire extinguisher is located in Zone 7B at elevation 100 feet 0 inch.

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

None

K. Emergency Communications

None

9B.2.11.13 Fire Area XI, Fire Zone 66A, Southwest Perimeter of the Containment Building

A. Location

Fire Zone 66A (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 63B at

elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 64 at elevation 80 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 70 at elevations 100 feet 0 inch and 120 feet 0 inch

Open to Zone 67A at elevations 80 feet 0 inch and 140 feet 0 inch

South: 3-hour rated wall common to Fire Area XV at elevations 80 feet 0 inch and 140 feet 0 inch

3-hour rated barrier common to Fire Area XVI at elevations 100 feet 0 inch and 120 feet 0 inch

3-hour rated barrier common to the south access shaft

East: Open to Zone 66B at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of steel construction common to Zone 71B at elevation 140 feet 0 inch

West: Nonrated exterior wall of heavy concrete construction

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the containment atmosphere

2. Zone Access

   - Open to the containment atmosphere
   - Open to Zone 66B
   - Open to Zone 67A at elevations 80 feet 0 inch and 140 feet 0 inch
   - One nonrated gate in the nonrated east wall to Zone 63B at elevation 80 feet 0 inch
   - Nonrated personnel access hatch at elevation 140 feet 0 inch, in the 3-hour rated south wall to Fire Area XV

3. Sealed Penetrations

   Containment penetrations are of special construction, but not fire-rated.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

- Train B containment refueling purge supply isolation damper
- Train B containment power ascension purge exhaust isolation damper
- Train A containment isolation valve
- Train A containment hydrogen control damper
- Train A containment sump isolation valve

D. Nonsafety-Related Equipment and Components

- Radwaste sump pump
- Regenerative heat exchanger
- Normal air cooling unit
- Normal air cooling unit duct heater
- Fuel carriage winch
- Hydraulic power rack
- Transfer system control console
- Cable trays and conduit

E. Radioactive Material

Radioactive material in process piping and equipment.

F. Combustible Loading

1. In Situ Combustible Load Type

    - Thermo-Lag 330-1

- Cable insulation
- Oil and grease
- Plastic

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization and line-type thermal detection systems covering the cable trays are provided for early warning.

H. Fire Suppression

1. Primary

   Four manual hose reels one each at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

2. Secondary

   Six portable CO_2 fire extinguishers, two each at elevations 80 feet 0 inch and 100 feet 0 inch, one each at elevations 120 feet 0 inch and 140 feet 0 inch

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operations. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

- Three 4-inch drains at elevation 80 feet 0 inch
- Three 4-inch drains at elevation 100 feet 0 inch

K. Emergency Communications

Sound powered phone pack(s) is provided.

9B.2.11.14 Fire Area XI, Fire Zone 66B, Southeast Perimeter of the Containment Building

A. Location

Fire Zone 66B (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated walls of heavy concrete construction common to Zone 63B at elevations 80 feet 0 inch, 100 feet

0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 70 at elevations 120 feet 0 inch and 140 feet 0 inch

Open to Zone 67B at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

South: 3-hour rated wall common to Fire Area XV at elevations 80 feet 0 inch and 140 feet 0 inch

3-hour rated wall common to Fire Area XVII at elevations 100 feet 0 inch and 120 feet 0 inch

3-hour rated barrier common to the south access shaft

East: 3-hour rated wall to a seismic gap common to the unrated barrier of Fire Area XII

West: Open to Zone 66A at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of steel construction common to Zone 71B at elevation 140 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the containment atmosphere

2. Zone Access

- Open to the containment atmosphere
- Open to Zones 66A and 67B
- One nonrated gate in the nonrated west wall to Zone 63B at elevation 80 feet 0 inch
- One nonrated gate in the nonrated west wall to Zone 63B at elevation 100 feet 0 inch

3. Sealed Penetrations

Containment penetrations are of special construction, but not fire-rated.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members None

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train B containment hydrogen control damper
- Train B containment sump isolation valve

- Train B containment isolation valve
- Train A containment refueling purge exhaust damper
- Train A containment building power ascension purge exhaust isolation damper
- Train A containment radwaste drain system isolation valve

D. Nonsafety-Related Equipment and Components

- Radwaste sump pump
- Wet layup pump
- Normal air cooling unit
- Normal air cooling unit duct heater
- Cable trays and conduit

E. Radioactive Material

Radioactive material in process piping and equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Oil and grease
   - Hydraulic fluid
   - Plastic
   - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization and line-type thermal detection systems covering the cable trays are provided for early warning.

H. Fire Suppression

1. Primary

   Three manual hose reels, one each at elevations 80 feet 0 inch, 100 feet 0 inch, and 120 feet 0 inch

2. Secondary

   Four portable CO_2 fire extinguishers, one each at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned

on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

- Three 4-inch drains at elevation 80 feet 0 inch
- Two 4-inch drains at elevation 100 feet 0 inch
- Two 4-inch drains at elevation 120 feet 0 inch
- Three 4-inch drains at elevation 140 feet 0 inch

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.11.15 Fire Area XI, Fire Zone 67A, Northwest Perimeter of the Containment Building

A. Location

Fire Zone 67A (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction

South: Nonrated wall of heavy concrete construction common to Zone 63A at elevations 80 feet 0 inch, 100 feet

0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 64 at elevation 80 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 65 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 70 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Open to Zone 66A at elevations 80 feet 0 inch and 140 feet 0 inch

East: Open to Zone 67B at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of steel construction common to Zone 71A at elevation 140 feet 0 inch

West: Nonrated exterior wall of heavy concrete construction

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the containment atmosphere

2. Zone Access

   - Open to the containment atmosphere
   - Open to Zone 66A at elevations 80 feet 0 inch and 140 feet 0 inch
   - Open to Zone 67B
   - One nonrated gate in the nonrated east wall to Zone 63A at elevation 80 feet 0 inch
   - Nonrated equipment hatch in the nonrated north exterior wall

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   Train A pressurizer auxiliary spray valve raceway is protected by a radiant energy shield consisting of 1/2 inch thick Thermo-Lag insulation.

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

- Normal air cooling unit
- Normal air cooling unit duct heater
- Cable trays and conduit

E. Radioactive Material

Radioactive material in process piping and equipment

F. Combustible Loading

1. In Situ Combustible Load Type
   - Cable insulation
   - Oil and grease
   - Plastic
   - Thermo-Lag 330-1
2. Transient Combustible Load Type
   - Ordinary combustible
   - Cable insulation
3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Line-type thermal detection system covering the cable trays are provided for early warning.

H. Fire Suppression

1. Primary

Three manual hose reels, one each at elevations 80 feet 0 inch, 100 feet 0 inch, and 120 feet 0 inch

2. Secondary

Six portable CO_2 fire extinguishers, two each at elevations 80 feet 0 inch and 100 feet 0 inch, one each at elevations 120 feet 0 inch and 140 feet 0 inch

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

Three 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.11.16 <u>Fire Area XI, Fire Zone 67B, Northeast Perimeter of the Containment Building</u>

A. Location

Fire Zone 67B (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations

80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction

South: Nonrated walls of heavy concrete construction common to Zone 63A at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of heavy concrete construction common to Zone 70 at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Open to Zone 66B at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

East: 3-hour rated wall to a seismic gap common to the unrated barrier of Fire Area XII

West: Open to Zone 67A at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Nonrated walls of steel construction common to Zone 71A at elevation 140 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the containment atmosphere

2. Zone Access

   - Open to the containment atmosphere
   - Open to Zones 66B and 67A
   - One nonrated gate in the nonrated west wall to Zone 63A at elevation 80 feet 0 inch
   - One nonrated gate in the nonrated west wall to Zone 63A at elevation 100 feet 0 inch
   - One nonrated emergency exit air lock in the nonrated north exterior wall at elevation 100 feet 0 inch

3. Sealed Penetrations

   Containment penetrations are of special construction, but not fire-rated.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Wet layup pump
- Normal air cooling unit
- Normal air cooling unit duct heater
- Closure head lift rig assembly
- Cable trays and conduit

E. Radioactive Material

Radioactive material in process piping and equipment

F. Combustible Loading

1. In Situ Combustible Load Type
    - Cable insulation
    - Oil and grease
    - Plastic
    - Rubber
    - Thermo-Lag 330-1
2. Transient Combustible Load Type
    - Ordinary combustible
    - Cable insulation
3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Line-type thermal detection system covering cable trays is provided for early warning.

H. Fire Suppression

1. Primary

Four manual hose reels, one each at elevations 80 feet 0 inch, 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

2. Secondary

Three portable CO_2 fire extinguishers, one each at elevations 80 feet 0 inch, 100 feet 0 inch, and 140 feet 0 inch

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

Ten 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.11.17 Fire Area XI, Fire Zone 70, Refueling Pool and Canal Area

A. Location

Fire Zone 70 (engineering drawing 13-A-ZYD-022) is located in the containment building at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of stainless steel and heavy concrete construction common to:

- Zones 63A, 65, 67A, and 67B at elevation 100 feet 0 inch and 120 feet 0 inch
- Zone 63A at elevation 140 feet 0 inch

South: Nonrated wall of stainless steel and heavy concrete construction common to:

- Zones 63B, 66A, and 66B at elevations 100 feet 0 inch and 120 feet 0 inch
- Zone 63B at elevation 140 feet 0 inch

East: Nonrated wall of stainless steel and heavy concrete construction common to Zones 66B and 67B at elevations

100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

West: Nonrated wall of stainless steel and heavy concrete construction common to:

- Zones 65 and 67A at elevation 100 feet 0 inch
- Zone 67A at elevation 120 feet 0 inch
- Zones 66A and 67A at elevation 140 feet 0 inch

Floor: Nonrated barrier of stainless steel and heavy concrete construction common to Zones 63A, 63B, 64, 66A, and 66B

Ceiling: Open to the containment atmosphere

2. Zone Access

Open to the containment atmosphere.

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

Incore instrumentation transfer assembly

D. Nonsafety-Related Equipment and Components

- Fuel upender and carriage
- Core support barrel lift rig
- Refueling machine
- Cable trays and conduits

E. Radioactive Material

Radioactive material in process piping and equipment

F. Combustible Loading

1. In Situ Combustible Load Type
    - Plastic
    - Rubber
    - Cable Insulation
    - Hydraulic fluid (Fyrquel)
    - Oil and grease
2. Transient Combustible Load Type
    - Ordinary combustible
    - Cable insulation
3. Total Combustible (Fire) Loading

    Low

G. Fire Detection

Ionization and line-type thermal detection systems installed covering the cable trays are provided for early warning.

H. Fire Suppression

1. Primary

One portable CO_2 fire extinguisher in each of adjacent Zones 66B and 67B at elevation 140 feet 0 inch

2. Secondary

One portable CO_2 fire extinguisher in each of adjacent Zones 66A and 67A at elevation 140 feet 0 inch

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

Two 10-inch and one 4-inch refueling pool drains

K. Emergency Communications

None

9B.2.11.18 Fire Area XI, Fire Zone 71A, North Preaccess Normal Air Filtration Unit Area

A. Location

Fire Zone 71A (engineering drawing 13-A-ZYD-022) is located in the containment building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	Nonrated wall of steel construction common to Zones 67A and 67B
South:	Nonrated wall of heavy concrete construction common to Zone 63A
East:	Nonrated wall of steel construction common to Zone 67B
West:	Nonrated wall of steel construction common to Zone 67A
Floor:	Nonrated barrier of steel construction common to Zones 67A and 67B
Ceiling:	Nonrated barrier of steel construction common to the containment atmosphere

2 Zone Access

Nonrated unit access doors in the nonrated north wall to Zones 67A and 67B

3. Sealed Penetrations

None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Preaccess normal air filtration unit
   - Conduit

E. Radioactive Material

   Potentially contaminated charcoal media

F. Combustible Loading

1. In Situ Combustible Load Type

   - Charcoal
   - Grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Charcoal

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

Photoelectric smoke detection system(s) is provided for early warning.

H. Fire Suppression

1. Primary

Local manually controlled water spray system

2. Secondary

One manual hose reel is located in adjacent Zone 67B. One portable CO_2 fire extinguisher is located in adjacent Zone 67A.

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

The air filtration unit is equipped with internal drains.

K. Emergency Communications

None

9B.2.11.19 Fire Area XI, Fire Zone 71B, South Preaccess Normal Air Filtration Unit Area

A. Location

Fire Zone 71B (engineering drawing 13-A-ZYD-022) is located in the containment building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 63B

South: Nonrated wall of steel construction common to Zones 66A and 66B

East: Nonrated wall of steel construction common to Zone 66B

West: Nonrated wall of steel construction common to Zone 66A

Floor: Nonrated barrier of steel construction common to Zones 66A and 66B

Ceiling: Nonrated barrier of steel construction common to the containment atmosphere

2. Zone Access

Nonrated unit access doors in the nonrated south wall to Zones 66A and 66B

3. Sealed Penetrations

None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   Train A and B conduits

D. Nonsafety-Related Equipment and Components

   - Preaccess normal air filtration unit
   - Conduit

E. Radioactive Material

   Potentially contaminated charcoal media

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Charcoal
      - Grease

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Charcoal

   3. Total Combustible (Fire) Loading

      High

G. Fire Detection

Photoelectric smoke detection system(s) is provided for early warning.

H. Fire Suppression

1. Primary

Local manually controlled water spray system

2. Secondary

One manual hose reel is located in adjacent Zone 66A. One portable CO_2 fire extinguisher is located in each of adjacent Zones 66A and 66B.

I. Ventilation

Recirculation from containment normal cooling fan and recirculation from reactor cavity cooling fan during normal plant operation. The refueling purge and power access purge systems are manually turned on to exhaust air to the outside. These systems are turned on prior to entry into containment. These systems, when available, will be used to remove smoke.

J. Drainage

The air filtration unit is equipped with internal drains

K. Emergency Communications

None

9B.2.12 FIRE AREA XII

9B.2.12.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area XII (figures 9B-1, 9B-3, 9B-4, and engineering drawing 13-P-00B-005) contains train A and train B components found in the main steam support structure (MSSS). This fire area includes Analysis Areas XIIA (Zone 74A), XIIB (Zone 72), and XIIC (Zones 73 and 74B) (engineering drawing 13-A-ZYD-022).

At elevation 81 feet 0 inch, Fire Area XII is below grade and bounded to the north by a nonrated exterior wall, and a 3-hour rated barrier common to a turbine building stairwell, to the south by a 3-hour rated wall common to Fire Area XV and a 3-hour rated exterior wall, to the east by a 3-hour rated exterior wall, and to the west by a 3-hour rated barrier common to Fire Area XI. The basemat is nonrated.

Above elevation 100 feet 0 inch, Fire Area XII is above grade and bounded to the north by a nonrated exterior wall and a 3-hour rated barrier common to a turbine building stairwell, to the south by a 3-hour rated barrier common to Fire Areas XV and XVII and a 3-hour rated exterior wall, to the east by a nonrated exterior wall adjacent to the turbine building, and to the west by an unrated barrier to a seismic gap common to the 3-hour rated barrier of Fire Area XI. A nonrated missile barrier roof is raised above the

tops of these four walls, supported by steel structural members.

B. Deviations from 10CFR50, Appendix R, Section III.G

1. A deviation is requested from Section III.G.2 to the extent that it requires a 3-hour rated barrier between adjacent fire areas separating circuits of redundant trains.

   Discussion

   The mechanical penetrations in the containment boundary are not rated. Mechanical containment penetrations are fitted with flued heads constructed of steel with a minimum thickness of 1/8 inch. The special construction of the flued heads was designed to maintain the integrity of the containment building.

   Conclusion

   The existing design provides equivalent protection to that required by Section III.G.2. The design is standard within the industry.

2. A deviation is requested from Section III.G.2 to the extent that it requires a 1-hour fire barrier between redundant safe shutdown equipment in addition to fire detection and automatic fire suppression.

   Discussion

   The MSSS is a single fire area provided with fire detection and automatic suppression

throughout, except in Zones 72 and 73 which are provided with fire detection and partial automatic suppression. The MSSS above elevation 100 feet 0 inch contains redundant safe shutdown components and conduit in both Zone 74A and Zone 74B. In order to meet interface requirements set by the NSSS vendor (to satisfy single failure criteria), Zone 74A contains both train A and train B valves which service the north (No. 1) steam generator, and Zone 74B contains both train A and train B valves which service the south (No. 2) steam generator.

Within the MSSS, there is a central wall of reinforced concrete construction separating Zones 74A and 74B. This wall is heavy concrete construction. Piping and conduit penetrations are sealed to a 3-hour fire rating. The wall contains a 3-hour constructed door at elevation 100 feet 0 inch. The door has been certified by the manufacturer to be constructed to 3-hour fire door standards, but is not labeled since it is slightly oversized and has a removable transom. There is also an 8.5-foot high opening between the top of the wall (elevation 156 feet 0 inch) and the bottom of the missile shield which allows the structure to vent pressures developed during postulated high energy line breaks. (Note: This opening extends about the entire perimeter of Area XII at elevation

156 feet 0 inch.) Closure of the MSSS would be detrimental to overall facility safety.

A postulated fire in either zone can result in the loss of operability of both ADVs associated with one steam generator due to actuator, solenoid valve, or pneumatic supply accumulator damage. However, hot standby and cold shutdown can be obtained by manual operation (via handwheel) of the unaffected ADVs.

The total combustible (fire) loading in each zone is moderate. Since detection and automatic water suppression is provided, full development of the fire is not expected. Additionally, fire department response is expected within 20 minutes. The MSSS is accessible via stairwells from the yard and from the turbine building.

Conclusion

The existing design assures that one train of equipment necessary to achieve hot shutdown is operable locally. Fire damage to valve actuating equipment required to reach cold shutdown is limited such that an ADV can be manually operated within a reasonable time. Additionally, to meet complete fire barrier separation per Section III.G.2 requires modifications which would be detrimental to

overall facility safety and would not enhance the current level of protection.

3. A deviation is requested from Section III.G.2 to the extent that it requires a 3-hour rated barrier to separate circuits of redundant trains.

Discussion

The central wall of the MSSS separating the auxiliary feedwater (AFW) pump rooms is 3-hour rated below elevation 100 feet 0 inch except that it contains a nonrated watertight door. Because the door is constructed of steel and has automatic water suppression on each side, it would act as an effective fire barrier. Replacement of the watertight door with a rated fire door would degrade overall facility safety by subjecting both pumps to potential loss due to flooding of the subcompartments.

Zones 72 and 73 have smoke detection and an automatic preaction sprinkler system providing coverage for lube oil hazard and common doorway.

The total combustible (fire) loading in Zone 72 is low and in Zone 73 is moderate. Fire department response is expected within 20 minutes.

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2. Modification to meet the requirement would be detrimental to overall facility safety.

4. A deviation is requested from Section III.G.2 to the extent that it requires installation of a 1-hour fire rated barrier in addition to an area-wide suppression system.

Discussion

The east wall of the MSSS is nonrated above elevation 100 feet 0 inch. There is a second nonrated wall which abuts the turbine building from approximately elevation 110 feet 0 inch to elevation 140 feet 0 inch and establishes two void spaces adjacent to Zones 74A and 74B, respectively. Each void is approximately 10 feet by 20 feet and has no combustibles. No detection or suppression is provided within this void space, but both Zones 74A and 74B have automatic suppression and detection. (For additional information, refer to the appendix 9A response to Question 9A.121).

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2, and upgrading the existing design to a 1-hour

rating would not significantly enhance the protection currently provided.

5. DELETED

6. DELETED

7. Following is a fire protection evaluation of the fire barrier separating Analysis Areas XIIA (Zone 74A) from XIIB (Zone 72), which are both located within safety train A.

   Discussion

   The elevation 100 feet 0 inch floor of the MSSS separating Analysis Areas XIIA (Zone 74A) from XIIB (Zone 72), both of which are located within safety train A, is heavy reinforced concrete construction, 3 feet 6 inches thick with sealed penetrations. The floor contains one nonrated equipment hatch, 5 feet x 9 feet in size, covered by a 1/2-inch thick steel plate reinforced with T sections. The plate overlaps the opening by approximately 6 inches all around and is fastened down with 1/2-inch bolts 6 inches apart around the perimeter. A 4-inch curb surrounds the hatch opening. The equipment hatch has an integral manway[a] that is constructed of 3/8 inch steel top plate with a 1/2 inch thick metal frame. Both Analysis Areas

[a] The equipment hatch manway has been installed only in those units where DMWO 4345887 has been implemented.

XIIA and XIIB are protected by smoke detection and an automatic preaction sprinkler system. The total combustible (fire) loading in Zone 72 is low and in Zone 74A is moderate.

Conclusion

The substantial construction of the floor, steel hatch cover and equipment hatch manway[a], together with the other fire protection features, will prevent the passage of flames, smoke, and hot gases through the barrier. Access to the unaffected analysis area will remain available to perform any manual actions as may be required. The train B side of the building (Analysis Area XIIC) would also remain free of fire damage.

8. See subsection 9B.2.0 for generic deviations.

9B.2.12.2 Analysis Area XIIA

A. Location

Analysis Area XIIA consists of Fire Zone 74A.

Fire Zone 74A (engineering drawing 13-A-ZYD-022) is located in the MSSS at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

[a] The equipment hatch manway has been installed only in those units where DMWO 4345887 has been implemented.

B. Analysis Area Boundaries

North: 3-hour rated wall common to a turbine building stairwell

Nonrated exterior wall of heavy concrete construction

Open to the atmosphere above elevation 156 feet 0 inch

South: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 74B (Ref. 9B.2.12.1.B.2)

Open to Zone 74B above elevation 156 feet 0 inch

East: Nonrated exterior wall, adjacent to the turbine building, of heavy concrete construction

Open to the atmosphere above elevation 156 feet 0 inch

West: An unrated barrier to a seismic gap common to the 3-hour rated wall of Fire Area XI

Open to the atmosphere above elevation 156 feet 0 inch

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 72 (Ref. 9B.2.12.1.B.7)

Ceiling: Nonrated missile barrier roof raised above the top of the four walls, supported by steel structural beams

C. Safe Shutdown Related Components and Cables

- Train A and train B cables associated with the following systems:

  Auxiliary feedwater

  Auxiliary building HVAC

  Main steam

- Train A steam generator 1 auxiliary feedwater pump steam supply valves
- Train A steam generator 1, line 1, atmospheric dump valve and associated components
- Train B steam generator 1, line 2, atmospheric dump valve and associated components
- Train A and train B steam generator 1 feedwater isolation valves
- Train B steam generator 1 blowdown isolation valve
- Steam generator 1 main steam isolation valves and bypass valves
- Steam generator 1 safety relief valves

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown conditions independent of the subject fire area, in conjunction with operator action, to prevent or overcome the consequences of spurious operation of components, has been demonstrated to remain available due to spatial separation and fire barriers provided. This area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.12.3 Analysis Area XIIB

A. Location

Analysis Area XIIB consists of Fire Zone 72

Fire Zone 72 (engineering drawing 13-A-ZYD-022) is located in the MSSS at elevation 81 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to a turbine building stairwell

Nonrated exterior wall of heavy concrete construction

South: 3-hour rated wall common to Zone 73

East: 3-hour rated exterior wall

West: An unrated barrier to a seismic gap common to the 3-h Fire Area XI

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Barrier of heavy concrete construction with electrical pipe and penetrations sealed to a 3-hour rating common to Zone 74A (Ref. 9B.2.12.1.B.7) our rated wall of

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Auxiliary building HVAC

  Main steam

- Train B cables associated with the following systems:

  Auxiliary feedwater

  Main steam

- Train A auxiliary feedwater pump, control panel, and associated components
- Train A auxiliary feedwater regulation and isolation valves
- Train A auxiliary feedwater pump room essential air control unit and associated components
- Train A atmospheric dump valve's associated components

- Train B atmospheric dump valve associated components
- Train B steam generator 1 auxiliary feedwater flow instrumentation

D. Summary and Conclusion

Safe shutdown capability will be provided by utilizing redundant train B systems available from the control room, in conjunction with operator action, both inside and outside this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.12.4 Analysis Area XIIC

A. Location

Analysis Area XIIC consists of Fire Zones 73 and 74B.

Fire Zone 73 (engineering drawing 13-A-ZYD-022) is located in the MSSS at elevation 81 feet 0 inch.

Fire Zone 74B (engineering drawing 13-A-ZYD-022) is located in the MSSS at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Zone 72 (elevation 80 feet 0 inch)

Wall of heavy concrete construction with electrical pipe penetrations sealed to a 3-hour rating common to Zone 74A (Ref. 9B.2.12.1.B.2) (elevation 100 feet 0 inch, 120 feet inch and 140 feet 0 inch)

Open to Zone 74A above elevation 156 feet 0 inch

South: 3-hour rated wall common to Fire Area XV (elevation 80 feet 0 inch)

3-hour rated wall common to:

- Fire Area XVII at elevations 100 feet 0 inch and 120 feet 0 inch
- Fire Area XV at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Open to the atmosphere above elevation 156 feet 0 inch

East: 3-hour rated exterior wall (elevation 80 feet 0 inch)

Nonrated exterior wall of heavy concrete construction adjacent to the turbine building (elevation 100 feet 0 inch, 120 feet 0 inch and 140 feet 0 inch)

Open to the atmosphere above elevation 156 feet 0 inch

West: An unrated barrier to a seismic gap common to the 3-hour rated wall of Fire Area XI

Open to the atmosphere above elevation 156 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof raised above the top of the four walls, supported by steel structural beams

C. Safe Shutdown Related Components and Cables

- Train A and train B cables associated with the following systems:

  Auxiliary feedwater

  Auxiliary building HVAC

  Main steam

- Train B auxiliary feedwater pump and associated components
- Train B auxiliary feedwater regulating and isolation valves
- Train A and train B steam generator 2 auxiliary feedwater flow instrumentation
- Train B auxiliary feedwater pump room essential air control unit and associated components

- Train A steam generator 2, line 2, atmospheric dump valve and associated components
- Train B steam generator 2, line 1, atmospheric dump valve and associated components
- Train A and train B steam generator 2 feedwater isolation valves
- Steam generator 2 main steam isolation valves and bypass valve
- Train A steam generator 2 auxiliary feedwater pump steam supply valves
- Train A steam generator 2 blowdown isolation valve
- Steam generator 2 safety relief valves

D. Summary and Conclusions

Cable EHA06AC1RB is enclosed in a 1-hour rated protective envelope with appropriate detection and suppression and, therefore, is not susceptible to fire damage.

One train of the systems necessary to achieve and maintain hot standby and cold shutdown conditions independent of the subject fire area (with the above exception), in conjunction with operator action, to prevent or overcome the consequences of spurious operation of components, has been demonstrated to remain available due to spatial separation and fire

barriers provided. This area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.12.5 Fire Area XII, Fire Zone 72, Turbine-Driven Auxiliary Feedwater Pump Room

A. Location

Fire Zone 72 (engineering drawing 13-A-ZYD-022) is located in the main steam support structure at elevation 81 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to a turbine building stairwell

Nonrated exterior wall of heavy concrete construction

South: 3-hour rated wall common to Zone 73

East: 3-hour rated exterior wall

West: An unrated barrier to a seismic gap common to the 3-hour rated wall of Fire Area XI

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 74A (Ref. 9B.2.12.1.B.7)

2. Zone Access

   - One nonrated watertight door in the 3-hour rated south wall to Zone 73. (Refer to the appendix 9A response to Question 9A.99.)

   - One nonrated watertight door in the 3-hour rated north wall to the stairwell

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

- Oil and grease
- Plastic

2. Transient Combustible Load Type

- Ordinary combustible
- Oil and grease

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detection is provided for actuating the deluge valve of the preaction sprinkler system and early warning.

H. Fire Suppression

1. Primary

Automatic preaction sprinkler system covering lube oil hazard

2. Secondary

One portable CO_2 fire extinguisher and/or yard hydrant

I. Ventilation

Flow to outside

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.12.6 Fire Area XII, Fire Zone 73, Motor-Driven Auxiliary Feedwater Pump Room

A. Location

Fire Zone 73 (engineering drawing 13-A-ZYD-022) is located in the main steam support structure at elevation 81 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 72

South: 3-hour rated wall common to Fire Area XV

East: 3-hour rated exterior wall

West: An unrated barrier to a seismic gap common to the 3-hour rated wall of Fire Area XI

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction to Zone 74B

2. Zone Access

   - One nonrated watertight door in the 3-hour rated north wall to Zone 72. (Refer to the appendix 9A response to Question 9A.99.)

   - One nonrated watertight emergency hatch in the nonrated ceiling to Zone 74B

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Thermo-Lag 330-1
   - Oil and grease
   - Plastic

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detection is provided for early warning.

H. Fire Suppression

1. Primary

   One portable CO_2 fire extinguisher. Partial coverage by a preaction water sprinkler system near the nonrated door in the north wall

2. Secondary

   One portable CO_2 fire extinguisher (located in adjacent Zone 72) and/or yard hydrant

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.12.7 Fire Area XII, Fire Zone 74A, Main Steam Isolation and Dump Valves Area

A. Location

Fire Zone 74A (engineering drawing 13-A-ZYD-022) is located in the main steam support structure at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to a turbine building stairwell

Nonrated exterior wall of heavy concrete construction

Open to the atmosphere above elevation 156 feet 0 inch

South: Wall of heavy concrete construction with electrical and pipe penetrations

sealed to a 3-hour rating common to Zone 74B (Ref. 9B.2.12.1.B.2)

Open to Zone 74B above elevation 156 feet 0 inch

East: Nonrated exterior wall, adjacent to the turbine building, of heavy concrete construction

Open to the atmosphere above elevation 156 feet 0 inch

West: An unrated barrier to a seismic gap common to the 3-hour rated wall of Fire Area XI

Open to the atmosphere above elevation 156 feet 0 inch

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 72 (Ref. 9B.2.12.1.B.7)

Ceiling: Nonrated missile barrier roof raised above the top of the four walls, supported by steel structural beams

2. Zone Access

- One 3-hour constructed maintenance door (pair) and transom in the nonrated south wall to Zone 74B at elevation 100 feet 0 inch (Ref. 9B.2.12.1.B.2)

- Three nonrated missile doors in the 3-hour rated north wall to the stairwell, one each at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch. (Refer to the appendix 9A response to Question 9A.106.)

- One nonrated missile door in the nonrated north exterior wall at elevation 100 feet 0 inch

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   Train B auxiliary feedwater system and auxiliary building HVAC safe shutdown related conduits are enclosed by 1-hour rated protective envelopes.

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Thermo-Lag 330-1
- Plastic
- Oil/grease
- Rubber
- Cable insulation
- Hydraulic fluid (Fyrquel)

2. Transient Combustible Load Type

- Ordinary combustible
- Hydraulic fluid (Fyrquel)

3. Total Combustible (Fire) Loading

Moderate

G. Fire Detection

Heat actuated devices are provided for actuating the deluge valve of the preaction sprinkler system and to provide early warning.

H. Fire Suppression

1. Primary

Automatic preaction sprinkler system

2. Secondary

One portable CO_2 fire extinguisher at 100 feet 0 inch. A manual hose reel located in the

adjacent turbine building may be used as an additional backup. The hose station, however, is not relied on for secondary fire suppression capability.

I. Ventilation

Flow to outside

J. Drainage

One 4-inch drain is provided at elevation 100 feet 0 inch.

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.12.8 Fire Area XII, Fire Zone 74B, Main Steam Isolation and Dump Valves Area

A. Location

Fire Zone 74B (engineering drawing 13-A-ZYD-022) is located in the main steam support structure at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 74A (Ref. 9B.2.12.1.B.2)

Open to Zone 74A above elevation 156 feet 0 inch

South: 3-hour rated wall common to:

- Fire Area XVII at elevations 100 feet 0 inch and 120 feet 0 inch
- Fire Area XV at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch

Open to the atmosphere above elevation 156 feet 0 inch

East: Nonrated exterior wall of heavy concrete construction adjacent to the turbine building

Open to the atmosphere above elevation 156 feet 0 inch

West: An unrated barrier to a seismic gap common to the 3-hour rated wall of Fire Area XI

Open to the atmosphere above elevation 156 feet 0 inch

Floor: Nonrated barrier of heavy concrete construction common to Zone 73

Ceiling: Nonrated roof raised above the top of the four walls, supported by steel structural beams

2. Zone Access

   - One 3-hour constructed maintenance door (pair) and transom in the north wall to Zone 74A at elevation 100 feet 0 inch (Ref. 9B.2.12.1.B.2)

   - Two 3-hour constructed doors in the north wall to Zone 74A, one each at elevations 120 feet 0 inch and 140 feet 0 inch (Ref. 9B.2.12.1.B.2)

   - One nonrated watertight emergency hatch in the nonrated floor to Zone 73

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   Train A auxiliary building HVAC safe shutdown related conduits are enclosed by 1-hour rated protective envelopes.

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Thermo-Lag 330-1
   - Cable insulation
   - Oil/grease
   - Hydraulic fluid (Fyrquel)

2. Transient Combustible Load Type

   - Ordinary combustible
   - Hydraulic fluid (Fyrquel)

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Heat actuated devices are provided for actuating the deluge valve of the preaction sprinkler system and to provide early warning.

H. Fire Suppression

1. Primary

   Automatic preaction sprinkler system

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 74A at elevation 100 feet 0 inch. A manual hose reel located in the adjacent turbine building may be used as an additional backup. The hose station, however, is not relied on for secondary fire suppression capability.

I. Ventilation

Flow to outside

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.13 FIRE AREA XIII

9B.2.13.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area XIII (figure 9B-1) contains the train A ESF pump rooms of the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches. This fire area includes Analysis Area XIIIA (Zones 30A, 31A, and 32A) only (engineering drawing 13-A-ZYD-023).

Fire Area XIII is below grade and bounded to the north, south, and west by 3-hour rated barriers common to Fire Area XV, and to the east by 3-hour

rated barriers common to Fire Areas XIV and XV. The ceiling is 3-hour rated and common to Fire Area XV. The basemat is nonrated.

B. Deviations from 10CFR50, Appendix R, Section III.G

See subsection 9B.2.0 for generic deviations.

9B.2.13.2 Analysis Area XIIIA

A. Location

Analysis Area XIIIA consists of Fire Zones 30A, 31A, and 32A.

Fire Zones 30A, 31A, and 32A (engineering drawing 13-A-ZYD-023) are located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Analysis Area Boundaries

North: 3-hour rated wall common to:

- Fire Area XV, Zone 87A, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88A, at elevation 51 feet 6 inches

South: 3-hour rated wall common to Fire Area XV, Zone 90

3-hour rated wall at column line A9 common to:

- Fire Area XV, Zone 87A, at elevation 40 feet 0 inch

- Fire Area XV, Zone 88A, at elevation 51 feet 6 inches

East: 3-hour rated wall common to Fire Area XIV, Zone 31B, at column line AF

3-hour rated wall common to Fire Area XV, Zone 90, at column line AE

West: 3-hour rated wall at column line AD common to:

- Fire Area XV, Zone 87A, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88A, at elevation 51 feet 6 inches.

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Fire Area XV, Zones 35A, 37A, 37B, and 37E

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary building HVAC

  Safety injection and shutdown cooling

- Train A low-pressure safety injection pump room essential air control unit and associated components

- Train A low-pressure safety injection pump and associated system valves
- Train A high-pressure safety injection pump
- Train A containment spray pump
- Train A high-pressure safety injection pump room essential air control unit and associated components
- Train A high-pressure safety injection discharge isolation valve
- Train A high-pressure safety injection long-term recirculation isolation valve
- Train A high-pressure safety injection pump recirculation to refueling water tank valve

D. Summary and Conclusion

Safe shutdown capability will be provided by utilizing redundant train B systems available from the control room.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.13.3 Fire Area XIII, Fire Zone 30A, Train A Containment Spray Pump Room

A. Location

Fire Zone 30A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to:

- Fire Area XV, Zone 87A, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88A, at elevation 51 feet 6 inches

South: 3-hour rated wall common to Zone 32A

East: 3-hour rated wall common to Zone 31A at column line AE

West: 3-hour rated wall at column line AD common to:

- Fire Area XV, Zone 87A, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88A, at elevation 51 feet 6 inches.

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Fire Area XV, Zones 35A and 37A

2. Zone Access

   One Class A door in the 3-hour rated west wall to Zone 88A

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train A containment spray pump essential air cooling unit
- Train A containment spray recirculation to refueling water tank valve.

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In-Situ Combustible Load Type

- Cable insulation
- Oil and grease

2. Transient Combustible Load Type

- Ordinary combustible
- Oil and grease

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detection is provided for early warning and to actuate the preaction water sprinkler system.

H. Fire Suppression

1. Primary

Preaction water sprinkler system

2. Secondary

Two manual hose reels and two portable ABC powder fire extinguishers are located in adjacent Zone 88A.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.13.4 Fire Area XIII, Fire Zone 31A, Train A High-Pressure Safety Injection Pump Room

A. Location

Fire Zone 31A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to:

- Fire Area XV, Zone 87A, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88A, at elevation 51 feet 6 inches

South: 3-hour rated wall common to Fire Area XV, Zone 90

East: 3-hour rated wall common to Fire Area XIV, Zone 31B, at column line AF

West: 3-hour rated wall common to Zone 30A at column line AE

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Fire Area XV, Zones 37B and 37E

2. Zone Access

One Class A door in the 3-hour rated north wall to Zone 88A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detection is provided for early warning and to actuate the preaction water sprinkler system.

H. Fire Suppression

1. Primary

   Preaction water sprinkler system

2. Secondary

Two manual hose reels and two portable ABC powder fire extinguishers are located in adjacent Zones 88A and 88B.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.13.5 Fire Area XIII, Fire Zone 32A, Train A Low-Pressure Safety Injection Pump Room

A. Location

Fire Zone 32A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 30A

South: 3-hour rated wall at column line A9 common to:

- Fire Area XV, Zone 87A, at elevation 40 feet 0 inch

- Fire Area XV, Zone 88A, at elevation 51 feet 6 inches

East: 3-hour rated wall common to Fire Area XV, Zone 90, at column line AE

West: 3-hour rated wall at column line AD common to:

- Fire Area XV, Zone 87A, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88A, at elevation 51 feet 6 inches

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Fire Area XV, Zone 35A

2. Zone Access

One Class A door in the 3-hour rated south wall to Zone 88A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   In process equipment

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation
      - Oil and grease

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

   Ionization smoke detection is provided for early warning and to actuate the preaction water sprinkler system.

H. Fire Suppression

1. Primary

Preaction water sprinkler system

2. Secondary

One manual hose reel and two portable ABC powder fire extinguishers are located in adjacent Zone 88A.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.14 FIRE AREA XIV

9B.2.14.1 Fire Area Description

A. Area Boundary Description

Fire Area XIV (figure 9B-1) contains the train B ESF pump rooms of the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches. This fire area includes Analysis Area XIVA (Zones 30B, 31B, and 32B) only (engineering drawing 13-A-ZYD-023).

Fire Area XIV is below grade and bounded to the north, south, and east by 3-hour rated barriers common to Fire Area XV, and to the west by 3-hour rated barriers common to Fire Areas XIII and XV. The ceiling is 3-hour rated and common to Fire Area XV. The basemat is nonrated.

B. Deviations from lOCFR50, Appendix R, Section III.G

See subsection 9B.2.0 for generic deviations.

9B.2.14.2 Analysis Area XIVA

A. Location

Analysis Area XIVA consists of Fire Zones 30B, 31B, and 32B.

Fire Zones 30B, 31B, and 32B (engineering drawing 13-A-ZYD-023) are located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Analysis Area Boundaries

North: 3-hour rated wall common to:

- Fire Area XV, Zone 87B, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88B, at elevation 51 feet 6 inches

South: 3-hour rated wall common to Fire Area XV, Zone 89

3-hour rated wall at column line A9 common to:

- Fire Area XV, Zone 87B, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88B, at elevation 51 feet 6 inches

East: 3-hour rated wall at column line AH common to:

- Fire Area XV, Zone 87B, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88B, at elevation 51 feet 6 inches

West: 3-hour rated wall common to Fire Area XIII, Zone 31A, at column line AF

3-hour rated wall common to Fire Area XV, Zone 89, at column line AG

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Fire Area XV, Zones 35B, 37B, and 37E

C. Safe Shutdown Related Components and Cables

- Train B cables associated with the following systems:

  Auxiliary building HVAC

  Safety injection and shutdown cooling

- Train B low-pressure safety injection pump room essential air control unit and associated components
- Train B low-pressure safety injection pump and associated system valves
- Train B high-pressure safety injection pump and associated system valves
- Train B containment spray pump
- Train B high-pressure safety injection pump room essential air control unit and associated components
- Train B high-pressure safety injection long-term recirculation isolation valve.
- Train B high-pressure safety injection header discharge isolation valve.
- Train B high-pressure safety injection pump recirculation to refueling water tank valve.

D. Summary and Conclusion

Safe shutdown capability will be provided by utilizing redundant train A systems available from the control room.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.14.3 Fire Area XIV, Fire Zone 30B, Train B Containment Spray Pump Room

A. Location

Fire Zone 30B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to:

- Fire Area XV, Zone 87B, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88B, at elevation 51 feet 6 inches

South: 3-hour rated wall common to Zone 32B

East: 3-hour rated wall at column line AH common to:

- Fire Area XV, Zone 87B, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88B, at elevation 51 feet 6 inches

West: 3-hour rated wall common to Zone 31B at column line AG

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Fire Area XV, Zones 35B and 37B

2. Zone Access

   One Class A door in the 3-hour rated east wall to Zone 88B

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train B containment spray pump room essential air cooling unit
- Train B containment spray pump recirculation to refueling water tank valve

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Oil and grease

2. Transient Combustible Load Type

- Ordinary combustible
- Oil and grease

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detection is provided for early warning and will actuate the preaction water sprinkler system.

H. Fire Suppression

1. Primary

Automatic preaction water sprinkler system

2. Secondary

Two manual hose reels and two portable ABC powder fire extinguishers are located in adjacent Zone 88B.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.14.4 Fire Area XIV, Fire Zone 31B, Train B High-Pressure Safety Injection Pump Room

A. Location

Fire Zone 31B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to:

- Fire Area XV, Zone 87B, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88B, at elevation 51 feet 6 inches

South: 3-hour rated wall common to Fire Area XV, Zone 89

East: 3-hour rated wall common to Zone 30B at column AG

West: 3-hour rated wall common to Fire Area XIII, Zone 31A, at column line AF

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Fire Area XV, Zone 37E

2. Zone Access

One Class A door in the 3-hour rated north wall to Zone 88B

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detection is provided for early warning and will actuate the preaction water sprinkler system.

H. Fire Suppression

1. Primary

   Preaction water sprinkler system

2. Secondary

Two manual hose reels and two portable ABC powder fire extinguishers are located in adjacent Zones 88A and 88B.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.14.5 Fire Area XIV, Fire Zone 32B, Train B Low-Pressure Safety Injection Pump Room

A. Location

Fire Zone 32B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Zone 30B

South: 3-hour rated wall at column line A9 common to:

- Fire Area XV, Zone 87B, at elevation 40 feet 0 inch

- Fire Area XV, Zone 88B, at elevation 51 feet 6 inches

East: 3-hour rated wall at column line AH common to:

- Fire Area XV, Zone 87B, at elevation 40 feet 0 inch
- Fire Area XV, Zone 88B, at elevation 51 feet 6 inches

West: 3-hour rated wall common to Fire Area XV, Zone 89, at column line AG

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to Fire Area XV, Zone 35B

2. Zone Access

One Class A door in the 3-hour rated south wall to Zone 88B

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   In process equipment

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation
      - Oil and grease

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

   Ionization smoke detection is provided for early warning and will actuate the preaction water sprinkler system.

H. Fire Suppression

1. Primary

Automatic preaction water sprinkler system

2. Secondary

One manual hose reel and two portable ABC powder fire extinguishers are located in adjacent Zone 88B.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15 FIRE AREA XV

9B.2.15.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area XV (figures 9B-1, 9B-2, 9B-3, 9B-4, and engineering drawing 13-P-00B-005) contains train A and train B components found in the auxiliary building. This fire area includes Analysis Area XVA (Zones 33A, 34A, 35A, 36, 37A, 37C, 39A, 87A, 88A, and 90), XVB (Zones 33B, 34B, 35B, 37B, 37D, 37E, 39B, 87B, 88B, and 89), XVC (Zones 42D, 43, 44, 45,

48, 49A, 49B, 49C, 49D, 49E, 49F, 49G, 49H, 50A, 52A, 55A, 55C, 55E, 56A, 56B, 56C, 57A, 57B, 57C, 57D, 57E, 57F, 57G, 57H, 57J, 57K, 57L, 57M, 57N, and 57P), XVD (Zones 42C, 50B, 51A, 51B, 52D, 53, and 54), XVE (Zone 46A), XVF (Zone 46B), and XVG (Zone 46E) (engineering drawings 13-A-ZYD-023 and -024).

At elevations 40 feet 0 inch and 51 feet 6 inches, Fire Area XV is below grade and encloses Fire Areas XIII and XIV by 3-hour rated barriers. Fire Area XV is bounded to the north, south, east, and west by nonrated exterior walls. The basemat is nonrated. A portion of the north corridor ceiling, which is common to the south access shaft, is a 3-hour rated barrier.

At elevation 70 feet 0 inch, Fire Area XV is below grade, bounded to the north by both nonrated and 3-hour rated barriers common to the south access shaft, a nonrated exterior wall, and 3-hour rated barriers common to Fire Areas XI and XII; to the south by 3-hour rated barriers common to Fire Areas I, II, and X, and a nonrated exterior wall, to the east by 2-hour rated barriers common to the east stairwell and nonrated exterior walls, and to the west by a 2-hour rated barrier common to the west elevator, stairwell, and HVAC chase, and nonrated exterior walls. Portions of the floor are 3-hour rated barriers common to Fire Areas XIII and XIV.

At elevation 88 feet 0 inch, Fire Area XV is below grade, bounded to the north by a 3-hour rated barrier common to the south access shaft, a nonrated exterior wall, and 3-hour rated barriers common to Fire Areas XI and XII, to the south by 3-hour rated barriers common to Fire Areas I, II, and X, and a nonrated exterior wall, to the east by 2-hour rated barriers common to the east stairwell and nonrated exterior walls, and to the west by a 2-hour rated barrier common to the west elevator, stairwell, and HVAC chase, and nonrated exterior walls. Portions of the ceiling are 1-hour rated barriers common to Fire Areas XVI and XVII.

At elevations 100 feet 0 inch and 120 feet 0 inch, Fire Area XV is bounded to the north by 2-hour rated barriers common to Fire Areas XVI and XVII, a 3-hour rated barrier common to Fire Area XII, and both nonrated and 3-hour rated barriers common to the south access shaft, to the south by 3-hour rated barriers common to Fire Areas I, II, and X, to the east by 2-hour rated barriers common to the east stairwell, 3-hour rated exterior walls and a 3-hour rated barrier common to the corridor building, and to the west by a 2-hour rated barrier common to the west elevator, stairwell, and HVAC chase, a 3-hour rated barrier common to Fire Area VI, and a nonrated exterior wall.

At elevation 140 feet 0 inch, Fire Area XV is bounded to the north by nonrated walls common to the south

access shaft, 3-hour rated exterior wall, and 3-hour rated barriers common to Fire Areas XI and XII, to the south by a 3-hour rated barrier common to Fire Areas I, II, and X, to the east by 2-hour rated barriers common to the east stairwell, 3-hour rated exterior walls, and a 3-hour rated barrier common to the corridor building, and to the west by a 2-hour rated barrier common to the west elevator, stairwell, and HVAC chase, a 3-hour rated barrier common to Fire Area VI, and a nonrated exterior wall. Portions of the floor are 2 and 3-hour rated barriers common to Fire Areas XVI and XVII. The ceiling, which is also the roof of the auxiliary building, is nonrated.

B. Deviations from lOCFR50, Appendix R, Section III.G

1. A deviation is requested from Section III.G.2 to the extent that it requires 3-hour rated barriers between adjacent fire areas separating circuits of redundant trains.

Discussion

The personnel access hatch at elevation 140 feet 0 inch and the mechanical and electrical penetrations in the containment boundary are not rated. The personnel access hatch is of special construction (refer to FSAR figure 6.2.4-1 for details of access hatch construction) designed to maintain the integrity of the containment boundary. The access hatch opens to Zone 66A, which has a moderate combustible (fire) loading.

Mechanical containment penetrations are fitted with flued heads constructed of steel with a minimum thickness of 1/8 inch. Electrical containment penetrations are fitted with a stainless steel header plate with a thickness of 1.78 inches.

The special construction of the flued heads and header plates was designed to maintain the integrity of the containment building.

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2. The design is standard within the industry.

2. A deviation is requested from Section III.G.2 to the extent that it requires a 1-hour rated barrier in addition to fire detection and fire suppression.

Discussion

Elevation 100 feet 0 inch of Fire Area XV contains the train A, train B and train E charging pumps, with their associated power and control electrical cables, in adjacent Zones 46A, 46B and 46E respectively.

The walls, floor, and ceiling of fire zones 46A, 46B and 46E are of reinforced concrete construction with all electrical and pipe penetrations sealed to an equivalent 3-hour fire

barrier rating. There is a non-rated personnel doorway opening to the north side corridor from each room. There are unsealed HVAC duct penetrations without flashings in the pump rooms and entry valve gallery area on the northside of the pump rooms. These HVAC ducts are not provided with fire dampers. The floor of fire zone 46E has two non-rated penetrations commom to fire zone 39B, access hatch and HVAC penetration, that are protected with steel cover plates. A horizontal distance of approximately 20 feet exists between the personnel doorway openings and the respective charging pumps. In the event of a fire in either charging pump room A or B, the high pressure safety injection system (HPSI) and the reactor coolant gas vent system (RCGVS) components are available for safe shutdown. These components provide reactor coolant system inventory and pressure control. A horizontal distance of at least 20 feet exists between the redundant safe shutdown circuits of the HPSI and charging pump components. The total combustible loading in each of the pump rooms is low and in the adjoining corridor, Fire Zone 42C, is moderate. A smoke detection and an automatic preaction water sprinkler system are provided in each of the pump rooms, and a cable tray fire detection and an automatic suppression system are provided for the cable trays running

in the corridors (Zone 42C) just outside the rooms. Fire department response is expected in less than 30 minutes.

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2, and upgrading the existing openings to 1-hour rated configuration would not significantly enhance the protection currently provided.

3. A deviation is requested from Section III.G.2 to the extent that it requires (1) separation of redundant trains by a horizontal distance of more than 20 feet with no intervening combustibles, and (2) fire detection and suppression.

Discussion

The redundant essential cooling water system (ECWS) pumps and their associated air handling units are located at elevation 70 feet 0 inch in Zones 34A and 34B. Fire detection systems are provided for the pump rooms and the corridors (Zones 37A and 37B), which represent the only unrestricted fire path between the redundant components. The zone boundary walls, ceilings, and portions of the floors are of nonrated, reinforced concrete construction. The remainder of the floors common to Fire Areas XIII and XIV is 3-hour rated. The total combustible (fire)

loading inside each pump room is low. Although there are no continuous, rated fire boundaries separating the ECWS pump rooms, a separation distance of approximately 200 feet exists. Two stacked cable trays are routed through the intervening distance of Zones 37A and 37B. Zones 37A and 37B have a total combustible (fire) loading classed as low. Fire department response is expected within 30 minutes of the alarm condition.

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2. Modification to meet Section III.G.2 would not significantly enhance the protection currently provided.

4. A deviation is requested from Section III.G.2 to the extent that it requires: (1) separation of redundant trains by a horizontal distance of more than 20 feet with no intervening combustibles, and (2) fire detection and suppression.

Discussion

The ECWS surge tanks with their associated level control and instrumentation cables are located at elevation 120 feet 0 inch in adjacent Zones 48 and 52A. The redundant devices and circuits are separated by approximately 20 feet.

Smoke detection is provided in Zone 48. Smoke detection and cable tray suppression are provided in Zone 52A. Intervening combustibles exist in each zone, but the 20-foot separation between redundant control and instrument cables (run in conduit) is primarily located in Zone 48, where the total combustible (fire) loading is low, including an allowance for transient combustibles. The total combustible (fire) loading in Zone 52A is moderate. The fire department is expected to respond within 30 minutes. The normal operating conditions (prior to the postulated fire) would maintain at least a minimum tank level in the ECWS surge tank which would assure continued operability of the ECWS system while the operator achieved hot shutdown. Local refill capability is all that is required to restore the system capabilities needed to achieve cold shutdown. (Refer also to the appendix 9A response to Question 9A.93.)

Conclusion

The existing design assures one train of equipment necessary to achieve hot shutdown is free of fire damage. The design also assures that fire damage is unlikely, or at worst that damage to at least one train of equipment may occur and the other train is available to achieve cold shutdown. In addition, alternate makeup for the EW cooling water system can be

accomplished in a time frame which permits the operator to achieve cold shutdown within 72 hours.

5. A deviation is requested from Section III.G.2 to the extent that it requires (1) separation of redundant trains by a horizontal distance of more than 20 feet with no intervening combustibles, and (2) fire detection and suppression.

Discussion

The redundant shutdown cooling heat exchangers are located in separate subcompartments (Zones 35A and 35B) at elevation 70 feet 0 inch separated by approximately 50 feet and at least two nonrated walls. The zone boundary walls, ceilings, and floors are nonrated, reinforced concrete construction (except for removable blockwalls as described in the appendix 9A response to Question 9A.120). The total combustible (fire) loading in each zone is low. The adjacent corridor (Zone 37B) contains a stack of two cable trays, and has a total combustible (fire) loading also classed as low, including an allowance for transient combustibles. Smoke detectors are provided in both Zones 35A and 35B, and in Zone 37B. Fire department response is expected within 30 minutes. Within that time frame the heat

exchangers are not subject to fire damage since they are passive, mechanical components.

Conclusion

The existing design assures that fire damage to at least one train of equipment necessary to achieve cold shutdown is limited and the other train is available to achieve cold shutdown.

6. A deviation is requested from Section III.G.2 to the extent that it requires (1) separation of redundant trains by a horizontal distance of more than 20 feet with no intervening combustibles, and (2) fire detection and suppression.

   Discussion

   The redundant essential cooling water heat exchangers are located in separate compartments of Zone 43 at elevation 100 feet 0 inch. The zone boundary walls (including a central wall along column line A8), ceilings, and floors are nonrated, reinforced concrete construction (except for removable panels in the exterior wall which are required for heat exchanger retubing). The total combustible (fire) loading within Zone 43 is low, including an allowance for transient combustibles. Even without fire department response, a fire would not damage the heat exchangers to the degree that they could not perform their function. The adjacent

corridor (Zone 42D) outside these rooms contains cable trays and has a total combustible (fire) loading classed as moderate. Within Zone 42D ionization smoke detector and thermal detector systems are provided which actuate a preaction water suppression system for the cable trays, except for three nonsafety-related cable trays, located between column lines AA and AB, which are provided with detection only. The cable tray suppression system will prevent the heat exchangers from being involved in postulated cable tray fires. Fire department response to an alarm from Zone 42D is expected in less than 30 minutes.

Conclusion

The existing design assures that at least one train of equipment necessary to achieve hot or cold shutdown is free of fire damage.

7. A deviation is requested from Section III.G.2 to the extent that it requires 3-hour rated area boundaries.

Discussion

The south wall of Zone 48 (access door between the auxiliary building and the radwaste building) at elevation 120 feet 0 inch utilizes a nonrated door and transom at the boundary to Fire Area X. The door contains a monorail passing through the upper transom and the

transom has been modified to include a cutout for the monorail. The total combustible (fire) loading on either side of the door is low. Zonal fire detection is provided in Zone 48. A fixed sprinkler system has been positioned on both sides of the door to act as a water curtain and prevent the possibility of fire passing from one area to the other.

Fire department response is expected in less than 30 minutes. (Refer also to the appendix 9A response to Question 9A.106.)

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2, and modification to meet Section III.G.2 would not significantly enhance the protection provided.

8. A deviation is requested from Section III.G.2 to the extent that it requires either a 1-hour rated barrier or separation by a horizontal distance of 20 feet or more without intervening combustibles, and fire detection and suppression.

Discussion

Redundant trains of safe shutdown raceway exist on all elevations of Fire Area XV in the auxiliary building, except for elevation 40 feet 0 inch, which contains no safe shutdown raceway,

and elevation 140 feet 0 inch, which contains only train A safe shutdown conduit. Redundant safe shutdown raceway within Fire Area XV are separated by a combination of features providing spatial separation, and thereby precluding fire spread along the shortest path between redundant safe shutdown equipment. For example, the design employs small, fire-rated walls to block corridors, and sealing of piping penetrations in nonrated walls when either action can be shown to be beneficial. Another feature is the addition of localized water suppression in zones which have a higher likelihood of initiating a fire, or in those zones where additional protection for safe shutdown equipment is required. For Fire Area XV, the following table lists corresponding zones of safe shutdown equipment (by building elevation) and the total combustible (fire) loading along the separation path. Fire protection features which enhance the existing separation are also listed. Wherever fire detection is provided, fire department response is expected within 30 minutes. In all cases listed, detection is provided along the separation path.

<u>Fire Area XV Safe Shutdown Equipment and Total Combustible Loading</u>

<u>Elevation 40 feet 0 inch</u>

No safe shutdown raceway located in Fire Area XV at this elevation

Elevation 51 feet 6 inches

- Train A safe shutdown raceway located in Zone 88A
- Train B safe shutdown raceway located in Zone 88B
- 80 feet minimum horizontal separation along south corridor between column lines AD and AH
- Total combustible (fire) loading along separation path (Zone 88A, Zone 90, Zone 89, Zone 88B) is low
- Fire detection along separation path (no automatic fire suppression provided) for all zones
- 3-hour rated ECCS pump room walls, and across north corridor at column line AF
- Nonrated reinforced concrete construction wall with unsealed penetrations across south corridor at column line AF
- No redundant raceway below
- Redundant raceway above uses same separation path.

Elevation 70 feet 0 inch

- Train A safe shutdown raceway located in Zones 34A, 35A, 37A, and 37C
- Train B safe shutdown raceway located in Zones 34B, 35B, 37B, and 37D
- 80 feet minimum horizontal separation distance along south corridor between column lines AD and AH
- Total combustible (fire) loading along separation path (Zone 37C, Zone 34A, Zone 35A, Zone 37A, Zone 37B, Zone 35B, Zone 34B, Zone 37D) is low to moderate
- Fire detection along separation path (no automatic suppression provided) for all zones
- 1-hour rated wall in north corridor, 3-hour rated wall along column line AE except for south corridor (open), and nonrated reinforced concrete construction between north corridor and piping penetration rooms (2-hour rated wall about stairwell)
- Redundant raceway below uses same separation path
- Redundant raceway above is a continuation of the raceway at this elevation.

Elevation 88 feet 0 inch

- Train A safe shutdown raceway located in Zone 37C
- Train B safe shutdown raceway located in Zone 37D
- Train A and B safe shutdown raceway located in Zone 39B. (Note: These raceways contain redundant power and control circuits for the condensate transfer pumps which are only required to be stopped to achieve and maintain safe shutdown. In the event of a fire damaging both train A and train B circuitry, makeup water for the essential chilled water system may be added through connections provided on the fill side of the system's surge tanks. Makeup water to this system is available from the fire protection system.
- 80 feet minimum horizontal separation distance along north pipe chase between column lines AD and AH
- Total combustible (fire) loading along separation path (Zone 37C, Zone 39A, Zone 39B, Zone 37D) is low to moderate.
- Fire detection along separation path (no automatic suppression provided) for all zones

- Heavy concrete construction wall between pipe chase zones and piping penetration areas, 3-hour fire-rated vertical cable chases, and heavy concrete construction floor and ceiling with penetration seals for radiation shielding. 1-hour rated ceiling below Fire Area XVI (Zone 42A) and Fire Area XVII (Zone 42B)

- Redundant raceway below is a continuation of the raceway at this elevation.

- Redundant raceway above uses a similar separation path.

Elevation 100 feet 0 inch

- Train A safe shutdown raceway, for charging pump A, located in Zones 42C, 42D, 46A, 46B and 46E. (Reference Fire Area XV deviation no. 2)

- Train B safe shutdown raceway, for charging pump B, located in Zones 42C, 46A and 46B. (Reference Fire Area XV deviation no. 2)

- Train A safe shutdown raceway, for area air handling unit (AHU), located in Zone 42C.

- Train B safe shutdown raceway, for HPSI valve, located in Zone 42C.

- Train A safe shutdown raceway, for HPSI valve, located in Zone 42D.

- 25-foot minimum horizontal separation distance along north (Zone 42D) and south (Zone 42C) corridors for redundant circuits along with a 1-hour rated fire barrier across the corridors and fire detection and automatic cable tray sup-pression provided in both zones.
- Train A charging pump conduit in the south corridor of Zone 42C is provided with a protective envelope affording equivalent 1-hour rated fire barrier protection and cable tray detection and automatic suppression is provided in Zone 42C.
- Train A charging pump conduit in zones 46E and 46B is separated from the south corridor of Zone 42C by three hour fire rated barriers.
- Train A safe shutdown conduit in the north end of the Zone 42C east corridor (contain circuits for the area AHU are provided with a protective envelope affording equivalent 1-hour rated fire barrier protection and zonal detection and automatic water suppression.
- Total combustible (fire) loading along separation path (Zone 46E) is low.

The total combustible (fire) loading in Zone 42D and 42C is moderate.

- Fire detection/suppression in separation paths

  Zone 42C - Cable tray fire detection and automatic suppression

  Zone 42D - Cable tray fire detection and automatic suppression

  Zone 46A - Zonal fire detection and automatic suppression

  Zone 46B - Zonal fire detection and automatic suppression

  Zone 46E - Zonal fire detection and automatic suppression

- Column line AG wall between the north and south corridors is reinforced concrete construction with all penetrations sealed to provide 3-hour fire rating except for an HVAC duct penetration through the wall near column line A7. The opening is 12 inches wide by 12 inches high located 8 feet 10 inches above the floor.

- The floors and ceilings of Zones 44, 45, 46A, and 46B are reinforced concrete construction with all penetrations sealed to provide 3-hour fire rating.

- The floor and ceiling of Zone 46E is of reinforced concrete construction with sealed electrical and piping penetrations to a 3-hour fire rating and is also a pressure boundary. The floor has two non-rated penetrations common to fire zone 39B for personnel access and an HVAC duct penetration. The penetrations have steel cover plates.
- The 100 foot floor is reinforced concrete construction with sealed electrical and pipe penetrations to a 3-hour fire rating and is also a pressure boundary. There are non-fire rated penetrations which include several equipment and personnel hatches with steel cover plates, two stairs with non-rated doors and non-rated enclosed concrete pipe chases at column lines A7/AC and A9/AG. The combustible loading on the floor below at the 88 foot elevation pipeway consisting of piping and valves is very low which, combined with the heavy concrete floor, does not present an exposure fire hazard to cables and equipment required for safe shutdown located at the 100 foot elevation.
- The walls of Zone 46A, 46B, and 46E are described in Fire Area XV deviation No. 2.

Elevation 120 feet 0 inch

- Train A safe shutdown raceway in Zone 52A with redundant train B safe shutdown raceway in Zones 48, 51B, 53, and 50A (Note: See Fire Area XV, deviation No. 4, for the Zone 48 separation considerations.)

- Redundant train A and train B safe shutdown raceway in Zone 52D. The train A conduit in the north end of the Zone 52D east corridor is a continuation of the raceway described at elevation 100 feet 0 inch directly below and are provided with a protective envelope affording equivalent 1-hour rated fire barrier protection at this elevation also.

- 80 feet minimum horizontal separation distance along north corridor (Zones 52A and 52D) between column lines AD and AH with a 1-hour rated fire barrier across the corridor and fire detection and automatic cable tray suppression provided in both zones.

  Additionally, there are the following barriers:

  - 3-hour rated wall sections along column line AF between A7 and A8, and along column line AG between A8 and A10.

- Reinforced concrete construction wall along column line A8 between AF and AG with all penetrations sealed to provide a 3-hour fire rating.
- Reinforced concrete construction wall along column line A7 between AE and AF having two open HVAC ducting penetrations and an access door opening from the Zone 52D corridor to Zone 50A.

- Total combustible (fire) loading in separation paths (Zone 52A, Zone 50A, Zone 51B, Zone 53, Zone 52D) moderate, including allowance for transient combustibles.

- Fire detection/suppression in separation paths

  Zone 52A - Cable tray fire detection and automatic suppression system

  Zone 52D - Cable tray fire detection and automatic suppression system

  Zone 50B - None

  Zone 53 - None

  Zone 50A - None

Elevation 140 feet 0 inch

- Train A safe shutdown raceway in Zones 56B, 56C, 57N, and 57J
- 20 feet minimum horizontal distance between redundant trains located at elevations 120 feet and 140 feet. (Note: Nonrated hatch opening in floor between Zones 56C and 52D below.)
- Total combustible (fire) loading in separation path (Zone 56B, Zone 56C, Zone 52D) is moderate.
- Fire detection/suppression in separation path

  Zone 56B - Zonal fire detection and automatic wet pipe sprinkler system

  Zone 56C - Automatic wet pipe sprinkler system (including coverage above hatch)

  Zone 52D - Area suppression in northeast corner of Zone 52D, but none directly below hatch area.
- 2-hour and 3-hour rated barrier floor above Fire Area XVI (Zone 47A) and Fire Area XVII (Zone 47B). 3-hour rated barrier floor above Analysis Area XVD (zones 50B, 51A, 51B, 52D, 53, and 54) except for steel plate covered hatch and the 2-hour rated

walls of the duct chase west column AH at column A7.

Remainder of the floor area is reinforced concrete construction with all penetrations sealed to provide an equivalent 3-hour fire rating except for the steel plate covered hatch the unsealed sample piping chase opening into Zone 57C, and the HVAC shaft penetration in Zone 57J which has a 2-hour fire rating.

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2, and upgrading the existing design to 1-hour rated walls, floors, and ceilings or installing area-wide detection and suppression would not significantly enhance the protection currently provided.

9. See subsection 9B.2.16 for a deviation common to Fire Area XVI, subsection 9B.2.17 for a deviation common to Fire Area XVII, and subsection 9B.2.0 for generic deviations.

9B.2.15.2 Analysis Area XVA

A. Location

Analysis Area XVA consists of Fire Zones 33A, 34A, 35A, 36, 37A, 37C, 39A, 87A, 88A, and 90

Fire Zone 33A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 40 feet 0 inch and 51 feet 6 inches.

Fire Zones 34A, 35A, and 36 (engineering drawing 13-A-ZYD-023) are located in the auxiliary building at elevation 70 feet 0 inch.

Fire Zones 37A and 37C (engineering drawing 13-A-ZYD-023) are located in the auxiliary building at elevation 70 feet 0 inch and 88 feet 0 inch.

Fire Zone 39A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 88 feet 0 inch.

Fire Zone 87A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 40 feet 0 inch)

Fire Zone 88A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 51 feet 6 inches.

Fire Zone 90 (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 40 feet 0 inch and 51 feet 6 inches.

B. Analysis Area Boundaries

<u>Elevations 40 feet 0 inch and 51 feet 6 inch</u>

North: Nonrated exterior wall of heavy concrete construction, north of fire zone 33A

3-hour rated wall common to Fire Area XIII, Zone 31A

North Corridor - 2-hour rated walls common to the west stairwell and access area at column line A6

Nonrated exterior wall of heavy concrete construction at column line A6

South Corridor - 3-hour rated wall common to Fire Area XIII, Zone 32A

South: Nonrated exterior wall of heavy concrete construction at column line A10

North Corridor - 3-hour rated wall common to Fire Area XIII, Zones 30A and 31A

South Corridor - Nonrated exterior wall of heavy concrete construction at column line A10

East: Nonrated exterior wall of heavy concrete construction, east of fire Zone 33A

Nonrated wall of heavy concrete construction common to Zone 89 at column line AF

Central Corridor - 3-hour rated wall common to Fire Area XIII, Zones 30A and 32A

North Corridor - 3-hour rated wall common to Zone 87B (north corridor) at column line AF

3-hour rated wall common to Zone 88B (north corridor) at column line AF

West: Nonrated exterior wall of heavy concrete construction, west of Fire Zone 33A

Nonrated exterior wall of heavy concrete construction at column line AC

2-hour rated wall common to the northwest stairwell at column line AC

3-hour rated wall common to Fire Area XIII, Zone 32A, at column line AE

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 35A, 37A, and 37B

3-hour rated barrier common to the south access shaft

Elevations 70 feet 0 inch and 88 feet 0 inch

North: 3-hour rated wall common to Fire Area XI

Nonrated exterior wall of heavy concrete construction at column line A1

3-hour rated wall common to the south access shaft

South: Nonrated exterior wall of heavy concrete construction at column line A10

3-hour rated wall common to Fire Area X at column line A10

East: Nonrated wall of heavy concrete construction common to the south access shaft at elevation 70 feet 0 inch

3-hour rated wall common to the south access shaft at elevation 88 feet 0 inch

3-hour rated wall common to Zone 37B at column line AE, elevation 70 feet 0 inch

Open to Zone 39B at column line AE

Nonrated wall of heavy concrete construction common to Zone 39B at column line AE between column lines A7 and A8

North Corridor - 1-hour rated wall common to Zone 37B at column line AE

South Corridor - Open corridor to Zone 37B at column line AE

West: Nonrated exterior wall of heavy concrete construction at column line AA4 and AA

2-hour rated wall common to the west elevator and stairwell and HVAC chase at column line AA

3-hour rated wall at column line AA

Floor: 3-hour rated barrier common to Fire Area XIII, Zones 30A and 32A

Ceiling: 1-hour rated barrier common to Fire Area XVI, Zone 42A

Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zones 42D and 43 (Ref 9B.2.15.1.B.8)

NOTE

Fire Zone 37A includes the two west electrical chases located at elevation 88 feet 0 inch. These chases are enclosed by 3-hour rated walls and ceilings, with floors open to the west corridors of elevation 70 feet 0 inch.

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Chemical and volume control

  Essential cooling water

  Auxiliary building HVAC

  Nuclear cooling water

  Main steam

  Safety injection and shutdown cooling

- Train B cables associated with the following systems:

Chemical and volume control

Main steam

Nuclear sampling

- Nontrain related cables associated with the following systems:

  Chemical and volume Control

  Nuclear cooling water

  Nuclear sampling

- Train B reactor coolant pump seal bleedoff valve
- Nontrain related charging flowpath suction valves
- Train A, train B and nontrain related seal injection flowpath valves
- Train A essential chilled water valves
- Train A nuclear cooling to essential cooling crosstie valves
- Train A essential cooling water pump and associated components
- Train A essential cooling water pump room essential air control unit and associated components
- Train A steam generator 2 blowdown sample isolation valves

- Train B steam generator 1 blowdown sample isolation valves
- Train A safety injection and shutdown cooling instrumentation and isolation and control valves
- Train A shutdown cooling heat exchanger and associated components
- Train B nuclear sampling isolation valves
- Nontrain related nuclear sampling valves
- Train A high-pressure safety injection discharge valves
- Train A high-pressure safety injection long-term recirculation isolation valve
- Train B high-pressure safety injection discharge valves
- Train A containment sump isolation valve
- Train A refueling water tank to safety injection pump valve

D. Summary and Conclusions

Safe shutdown capability will be provided by utilizing redundant systems available from the control room, in conjunction with operator action, both inside and outside this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.15.3 Analysis Area XVB

A. Location

Analysis Area XVB consists of Fire Zones 33B, 34B, 35B, 37B, 37D, 37E, 39B, 87B, 88B, and 89

Fire Zone 33B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 40 feet 0 inch and 51 feet 6 inches.

Fire Zones 34B and 35B (engineering drawing 13-A-ZYD-023) are located in the auxiliary building at elevation 70 feet 0 inch.

Fire Zones 37B, 37D, and 37E (engineering drawing 13-A-ZYD-023) are located in the auxiliary building at elevation 70 feet 0 inch and 88 feet 0 inch.

Fire Zone 39B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 88 feet 0 inch.

Fire Zone 87B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 40 feet 0 inch)

Fire Zone 88B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 51 feet 6 inches.

Fire Zone 89 (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 40 feet 0 inch and 51 feet 6 inches.

B. Analysis Area Boundaries

<u>Elevations 40 feet 0 inch and 51 feet 6 inch</u>

North: Nonrated exterior wall of heavy concrete construction, north of fire zone 33B

3-hour rated wall common to Fire Area XIV, Zone 31B

North Corridor - 2-hour rated wall common to the northeast stairwell and access area at column line A6

Nonrated exterior wall of heavy concrete construction at column line A6

South Corridor - 3-hour rated wall common to Fire Area XIV, Zone 32B

South: Nonrated exterior wall of heavy concrete construction at column line A10

North Corridor - 3-hour rated wall common to Fire Area XIV, Zones 30B and 31B

East: Nonrated exterior wall of heavy concrete construction, east of fire zone 33B

Nonrated exterior wall of heavy concrete construction at column line AJ

3-hour rated wall common to Fire Area XIV, Zone 32B, at column line AG

2-hour rated wall common to the northeast stairwell at column line AJ

West: Nonrated exterior wall of heavy concrete construction, west of fire zone 33B

Nonrated wall of heavy concrete construction common to Zone 90 at column line AF

Central Corridor - 3-hour rated wall common to Fire Area XIV, Zones 30B and 32B

North Corridor - 3-hour rated wall common to Zone 87A at column line AF

3-hour rated wall common to Zone 88A at column line AF

Floor: Nonrated basemat of heavy concrete construction

Ceiling: 3-hour rated barrier common to the south access shaft, between column lines AF and AG

Nonrated barrier of heavy concrete construction common to Zones 35B, 37B, and 37E

Elevations 70 feet 0 inch and 88 feet 0 inch

North: 3-hour rated wall common to Fire Area XI

3-hour rated wall common to Fire Area XII at column line A1

2-hour rated wall common to the east stairwell at column line A6.

3-hour rated wall common to the south access shaft

North Corridor - Nonrated walls of heavy concrete construction common to the south access shaft

South: 3-hour rated wall common to Fire Areas I and II at column line A10

2-hour rated wall common to the east stairwell

East: Nonrated exterior wall of heavy concrete construction at column line AL

2-hour rated wall common to the east stairwell

West: 3-hour rated wall common to Zone 35A at column line AE

1-hour rated wall common to zone 37A (north corridor) at column line AE

Open to Zone 37A (south corridor) at column line AE

Open to Zone 39A at column line AE

Nonrated wall of heavy concrete construction common to Zone 39A at column line AE, between column lines A7 and A8

Nonrated wall of heavy concrete construction common to the south access shaft at column line AG, elevation 70 feet 0 inch

3-hour rated wall common to the south access shaft at column line AG, elevation 88 feet 0 inch

Floor: Nonrated basemat of heavy concrete construction

3-hour rated barrier common to Fire Area XIII, Zone 31A

3-hour rated barrier common to Fire Area XIV, Zone 30B, 31B, and 32B

Ceiling: Barrier of heavy concrete construction with all electrical and pipe penetrations sealed to a 3-hour rating common to Zone 45 at elevation 100 feet 0 inch

1-hour rated barrier common to Fire Area XVII, Zone 42B

Barrier of heavy concrete construction with all electrical and pipe penetrations sealed to a 3-hour rating common to Zones 42C, 42D, 44, 45, 46A, 46B, and 46E (Ref. 9B.2.15.1.B.8)

NOTE

Fire Zone 37B includes the two east electrical chases located at elevation 88 feet 0 inch. These chases are enclosed by 3-hour rated walls and ceilings, with floors open to the east corridors of elevation 70 feet 0 inch.

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Condensate storage and transfer

  Nuclear cooling water

  Main steam

- Train B cables associated with the following systems:

  Chemical and volume control

  Condensate storage and transfer

  Essential cooling water

  Auxiliary building HVAC

  Nuclear cooling water

  Main steam

  Safety injection and shutdown cooling

  Nuclear sampling

- Nontrain related cables associated with the following system:

Nuclear cooling water

- Train B charging suction flowpath valves
- Train B seal injection valves
- Train B essential chilled water valves
- Train B essential cooling water pump and associated components
- Train B essential cooling to nuclear cooling water crosstie valves
- Train B essential cooling water pump room essential air control unit and associated components
- Train A and train B and nontrain related nuclear cooling water system isolation valves
- Train B safety injection and shutdown cooling instrumentation isolation and control valves
- Train B shutdown cooling heat exchanger and associated components
- Train B nuclear sampling isolation valves
- Train A high-pressure safety injection discharge isolation valves
- Train B high-pressure safety injection discharge isolation valves
- Train B containment sump valve

D. Summary and Conclusions

Safe shutdown capability will be provided by utilizing redundant train A systems available from the control room, in conjunction with operator action, both inside and outside this analysis area, to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function.

This analysis area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.15.4 Analysis Area XVC

A. Location

Analysis Area XVC consists of Fire Zones 42D, 43, 44, 45, 48, 49A, 49B, 49C, 49D, 49E, 49F, 49G, 49H, 50A, 52A, 55A, 55C, 55E, 56A, 56B, 56C, 57A, 57B, 57C, 57D, 57E, 57F, 57G, 57H, 57J, 57K, 57L, 57M, 57N, and 57P.

Fire Zones 42D, 43, 44, and 45 (engineering drawing 13-A-ZYD-023) are located in the auxiliary building at elevation 100 feet 0 inch.

Fire Zones 48, 49A, 49B, 49C, 49D, 49E, 49F, 49G, 49H, 50A, and 52A (engineering drawing 13-A-ZYD-023) are located in the auxiliary building at elevation 120 feet 0 inch.

Fire Zones 55A, 55C, 55E, 56A, 56B, 56C, 57A, 57B, 57C, 57D, 57E, 57F, 57G, 57H, 57J, 57K, 57L, 57M,

57N, and 57P (engineering drawing 13-A-ZYD-023) are located in the auxiliary building at elevation 140 feet 0 inch.

B. Analysis Area Boundaries

Elevation 100 feet 0 inch

North: 2-hour rated wall common to Fire Area XVI, Zone 42A, at column lines A3 and A6

Nonrated walls of heavy concrete construction common to the south access shaft

South: 3-hour rated wall common to Fire Area X at column line A10

3-hour rated wall common to Fire Area I at column line A10

East: Nonrated walls of heavy concrete construction common to the south access shaft

2-hour rated wall common to Fire Area XVI, Zone 42A, at column line AB

Nonrated wall of heavy concrete construction common to Zone 46E at column line AG

1-hour rated wall common to Zone 42C at column line AG

West: 2-hour rated wall common to the west stairwell, HVAC chase, and elevator at column line AA

3-hour rated wall common to Fire Area VI at column line AA

Nonrated exterior wall of heavy concrete construction at column line AA

Floor: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zones 37C, 37E, 39A, and 39B (Ref. 9B.2.15.1.B.8)

3-hour rated barriers common to the Zone 37A electrical chases

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 51A and 52D

Elevation 120 feet 0 inch

North: Nonrated wall of heavy concrete construction common to the south access shaft

2-hour rated walls common to Fire Area XVI, Zone 47A, at column lines A3 and A6

Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 52D at column line A7 (Ref. 9B.2.15.1.B.8)

Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 51A at column line A8 (Ref. 9B.2.15.1.B.8)

South: 3-hour rated wall common to Fire Area X at column line A10

3-hour rated wall common to Fire Area X, a pipe chase, at column line A9

East: 1-hour rated wall common to Zone 52D at column line AE

2-hour rated wall common to Fire Area XVI, Zone 47A, at column line AB

Nonrated wall of heavy concrete construction common to the south access shaft

3-hour rated wall common to Zone 51B at column line AG

3-hour rated wall common to Fire Area X, a pipe chase

West: 2-hour rated wall common to the west elevator, stairwell, and HVAC chase at column line AA

Nonrated exterior wall of heavy concrete construction at column line AA

3-hour rated wall common to Fire Area VI at column line AA

3-hour rated wall common to Fire Area X, a pipe chase, at column line AE

Floor: An open pipe chase, which extends down to Zone 39B, is located in the southeast corner

Elevation 140 feet 0 inch

North: 3-hour rated exterior wall at column line A1

3-hour rated wall common to Fire Area XI

Nonrated walls of heavy concrete construction common to the south access shaft

3-hour rated wall common to Fire Area XII

South: 3-hour rated wall common to Fire Areas I and II at column line A10

3-hour rated wall common to Fire Area X at column line A10

East: Nonrated wall of heavy concrete construction common to the south access shaft

3-hour rated exterior wall at column line AL

3-hour rated wall common to the corridor building at column line AL

2-hour rated walls common to the east stairwell

West: 3-hour rated wall common to Fire Area VI at column line AA

2-hour rated wall common to the west elevator

2-hour rated wall common to the west stairwell at column line AA

2-hour rated wall common to the west HVAC chase at column line AA

Nonrated exterior wall of heavy concrete construction at column line AA

Nonrated wall of heavy concrete construction common to the south access shaft at column line AG

Floor: 2-hour rated barrier common to Fire Area XVI, Zone 47A

3-hour rated barrier common to Fire Area XVII, Zone 47B

Nonrated barrier of heavy concrete construction common to Zones 50B, 51A, 51B, 52D, 53, and 54

Ceiling: Nonrated roof of heavy concrete construction

NOTE

The HVAC chase near column lines A7 and AH is surrounded by 2-hour rated walls.

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Miscellaneous HVAC

  Nuclear cooling water

  Reactor coolant

  Ex-core neutron monitoring

  Main steam

  Safety injection and shutdown cooling

  Nuclear sampling

  Electrical power distribution

  Engineered safety feature actuation

- Train B cables associated with the following systems:

  Chemical and volume control

  Essential cooling water

  Engineered safety feature actuation

- Nontrain related cables associated with the following system:

  Chemical and volume control

  Nuclear cooling water

  Reactor coolant

  Nuclear sampling

- Nontrain related seal injection heat exchanger and associated components

- Nontrain related charging to seal injection control valve

- Train A essential cooling water surge tank and associated level control components

- Train B essential cooling water surge tank and associated level control components

- Train A essential cooling water system heat exchanger and associated components

- Train B essential cooling water system heat exchanger and associated components

- Nontrain related nuclear sampling hotleg sample cooler and associated components

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided. The redundant train B system

will remain available from the control room, in conjunction with operator action, both inside and outside of this analysis area to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.15.5 Analysis Area XVD

A. Location

Analysis Area XVD consists of Fire Zones 42C, 50B, 51A, 51B, 52D, 53, and 54.

Fire Zone 42C (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

Fire Zones 50B, 51A, 51B, 52D, 53, and 54 (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Analysis Area Boundaries

Elevation 100 feet 0 inch

North:	North Corridor	-	2-hour rated wall common to Fire Area XVII, Zone 42B, at column line A6 3-hour rated wall common to Fire Area XII
	South Corridor	-	Wall of heavy concrete construction with penetrations

			sealed to a 3-hour rating common to Zones 46A, 46B, and 46E at column line A9 (Ref. 9B.2.15.1.B.2)
South:	North Corridor	-	Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 46A, 46B, and 46E at column line A7 (Ref. 9B.2.15.1.B.2)
	South Corridor	-	3-hour rated wall common to Fire Areas I and II at column line A10
East:	3-hour rated exterior wall at column line AL		
	3-hour rated wall common to the corridor building at column line AL		
	2-hour rated walls common to the east stairwell		
West:	North Corridor	-	1-hour rated wall common to Zone 42D at column line AG 3-hour rated wall common to the south access shaft at column line AG
	South Corridor	-	1-hour rated wall common to Zone 42D at column line AG

East Corridor - 2-hour rated wall common to Zone 42B

Wall of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 46A (Ref. 9B.2.15.1.B.2)

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 37D and 39B (Ref. 9B.2.15.1.B.8)

3-hour rated barriers common to the Zone 37B electrical chases

Elevation 120 feet 0 inch

North: 2-hour rated wall common to Fire Area XVII, Zone 47B, at column line A6

3-hour rated walls common to the south access shaft

3-hour rated wall common to Fire Area XII

South: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 49F and 50A, and the central staircase (Ref. 9B.2.15.1.B.8)

3-hour rated wall common to Fire Areas I and II at column line A10

East: 3-hour rated exterior wall at column line AL

3-hour rated wall common to the corridor building at column line AL

2-hour rated walls common to the east stairwell

West: 1-hour rated wall common to Zone 52A at column line AE

2-hour rated wall common to Fire Area XVII, Zone 47B

3-hour rated wall common to Zones 49G and 50A at column line AG

3-hour rated wall common to the central stairwell at column line AF

Floor: Nonrated barrier of heavy concrete construction common to Zones 42D, 45, 46A, 46B, and 46E

Ceiling: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zones 56C, 57J, 57K, and 57N (Ref. 9B.2.15.1.B.8)

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

Auxiliary building HVAC

Main steam

Safety injection and shutdown cooling

Engineered safety feature actuation

- Train B cables associated with the following systems:

Auxiliary feedwater

Chemical and volume control

Condensate storage and transfer

Essential chilled water

Essential cooling water

Auxiliary building HVAC

Nuclear cooling water

Reactor coolant

Ex-core neutron monitoring

Main steam

Safety injection and shutdown cooling

Nuclear sampling

Electrical power distribution

Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

Chemical and volume control

Nuclear cooling water

Reactor coolant

Nuclear sampling

- Train A and train B charging pumps 2 and 3 controls
- Volume control tank to charging system isolation valves

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided. The redundant train A system will remain available from the control room, in conjunction with operator action, inside and outside of this analysis area to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.15.6 Analysis Area XVE

A. Location

Analysis Area XVE consists of Fire Zone 46A

Fire Zone 46A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 42C at column line A7 (Ref. 9B.2.15.1.B.2)

South: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 42C at column line A9 (Ref. 9B.2.15.1.B.2)

East: Wall of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 42C (Ref. 9B.2.15.1.B.2)

West: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46B (Ref. 9B.2.15.1.B.2)

Floor: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 39B (Ref. 9B.2.15.1.B.8)

Ceiling: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 54 (Ref. 9B.2.15.1.B.8)

C. Safe Shutdown Related Components and Cables

- Train A and train B cables associated with the following system:

  Chemical and volume control

- Train A charging pump and associated components

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown conditions, in conjunction with operator action, to prevent or overcome the consequences of spurious operation of components, has been demonstrated to remain available due to fire barriers provided. This area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.15.7 Analysis Area XVF

A. Location

Analysis Area XVF consists of Fire Zone 46B

Fire Zone 46B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 42C at column line A7 (Ref. 9B.2.15.1.B.)

South: Wall of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 42C at column line A9 (Ref. 9B.2.15.1.B.2)

East: Wall of heavy concrete construction with electrical and pipe penetrations sealed to

a 3-hour rating common to Zone 46A (Ref. 9B.2.15.1.B.2)

West: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46E at column line AH (Ref. 9B.2.15.1.B.2)

Floor: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 39B (Ref. 9B.2.15.1.B.8)

Ceiling: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zones 53 and 54 (Ref. 9B.2.15.1.B.8)

C. Safe Shutdown Related Components and Cables

- Train A, train B, and nontrain related cables associated with the following system:

  Chemical and volume control

- Train B charging pump and associated components

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown conditions, in conjunction with operator action, to prevent or overcome the consequences of spurious operation of components, has been demonstrated to remain available due to fire barriers provided. This area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.15.8 Analysis Area XVG

A. Location

Analysis Area XVG consists of Fire Zone 46E

Fire Zone 46E (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Analysis Area Boundaries

North: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 42C at column line A7 (Ref. 9B.2.15.1.B.2)

South: Wall of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 42C at column line A9 (Ref. 9B.2.15.1.B.2)

East: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46B at column line AH (Ref. 9B.2.15.1.B.2)

West: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 45 at column line AG (Ref. 9B.2.15.1.B.8)

Floor: Barrier of heavy concrete construction with electrical and piping penetrations sealed to a 3-hour rating common to Zone 39B (Ref. 9B.2.15.1.B.8)

Ceiling: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zones 50B and 51B (Ref. 9B.2.15.1.B.8)

C. Safe Shutdown Related Components and Cables

- Train A and nontrain related cables associated with the following system:

  Chemical and volume control

- Charging pump number 3 and associated components

- Train B conduit

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown conditions has been demonstrated to remain available due to fire barriers provided. This area meets the requirements of 10CFR50, Appendix R, Section III.G.

9B.2.15.9 Fire Area XV, Fire Zone 33A, Train A Pipe Chase

A. Location

Fire Zone 33A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction

South: Open to Zone 87A at elevation 40 feet 0 inch. 2-hour rated wall common to the north stairwell at elevation 51 feet 6 inches

East: Nonrated exterior wall of heavy concrete construction

West: Nonrated exterior wall of heavy concrete construction

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to Zone 37C at elevation 70 feet 0 inch plane

2. Zone Access

- Open to Zone 87A at elevation 40 feet 0 inch
- Open to Zone 37C at elevation 70 feet 0 inch plane

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

None

E. Radioactive Material

In process piping

F. Combustible Loading

1. In Situ Combustible Load Type

None

2. Transient Combustible Load Type

Ordinary combustible

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 87A.

2. Secondary

Two portable ABC powder fire extinguishers are located in adjacent Zone 87A.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.10 Fire Area XV, Fire Zone 33B, Train B Pipe Chase

A. Location

Fire Zone 33B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers North:

North: Nonrated exterior wall of heavy concrete construction

South: Open to Zone 87B at elevation 40 feet 0 inch. 2-hour rated wall common to the north stairwell at elevation 51 feet 6 inches

East: Nonrated exterior wall of heavy concrete construction

West: Nonrated exterior wall of heavy concrete construction

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to Zone 37D at elevation 70 feet 0 inch plane

2. Zone Access

- Open to Zone 87B at elevation 40 feet 0 inch
- Open to Zone 37D at elevation 70 feet 0 inch plane

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

None

E. Radioactive Material

In process piping

F. Combustible Loading

1. In Situ Combustible Load Type

None

2. Transient Combustible Load Type

Ordinary combustible

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 87B.

2. Secondary

Two portable ABC powder fire extinguishers are located in adjacent Zone 87B.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.11 Fire Area XV, Fire Zone 87A, West Corridors

A. Location

Fire Zone 87A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 40 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	North Corridor	-	Open to Zone 33A at column line A6 Nonrated exterior wall of heavy concrete construction at column line A6
	South Corridor	-	3-hour rated wall common to Fire Area XIII, Zone 32A
South:	North Corridor	-	3-hour rated wall common to Fire Area XIII, Zones 30A and 31A
	South Corridor	-	Nonrated exterior wall of heavy concrete construction at column line A10
East:	Central Corridor	-	3-hour rated wall common to Fire Area XIII, Zones 30A and 32A

North Corridor	-	3-hour rated wall common to Zone 87B (north corridor) at column line AF
South Corridor	-	Nonrated wall of heavy concrete construction common to Zone 90 at column line AE

West: Nonrated exterior wall of heavy concrete construction at column line AC

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 88A

2. Zone Access

- Stairwell through the nonrated north corridor ceiling to Zone 88A
- Stairwell through the nonrated south corridor ceiling to Zone 88A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - ESF A sump and pumps
   - Auxiliary steam condensate receiver tank radiation monitor
   - Conduit

E. Radioactive Material

   In process piping

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Polycarbonate Battery Cases
      - Cable Insulation

   2. Transient Combustible Load Type

      Ordinary combustible

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

Two manual hose reels

2. Secondary

Two portable ABC powder fire extinguishers

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Five 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.12 Fire Area XV, Fire Zone 87B, East Corridors

A. Location

Fire Zone 87B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 40 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	North Corridor	-	Open to Zone 33B at column line A6 Nonrated exterior wall of heavy concrete construction at column line A6
	South Corridor	-	3-hour rated wall common to Fire Area XIV, Zone 32B
South:	North Corridor	-	3-hour rated wall common to Fire Area XIV, Zones 30B and 31B
	South Corridor	-	Nonrated exterior wall of heavy concrete construction at column line A10
East:	Nonrated exterior wall of heavy concrete construction at column line AJ		
West:	Central Corridor	-	3-hour rated wall common to Fire Area XIV, Zones 30B and 32B

South Corridor	-	Nonrated wall of heavy concrete construction common to Zone 89 at column line AG
North Corridor	-	3-hour rated wall common to Zone 87A (north corridor) at column line AF

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 88B

2. Zone Access

- Stairwell through the north corridor ceiling to Zone 88B
- Stairwell through the south corridor ceiling to Zone 88B

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - ESF B sump and pump
   - Conduit

E. Radioactive Material

   In process piping

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Polycarbonate Battery Cases
      - Cable Insulation

   2. Transient Combustible Load Type

      Ordinary combustible

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

   None

H. Fire Suppression

   1. Primary

      Two manual hose reels

2. Secondary

Two portable ABC powder fire extinguishers

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Five 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.13 Fire Area XV, Fire Zone 89, Cooling Water Holdup Tank Room

A. Location

Fire Zone 89 (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XIV, Zone 31B

South: Nonrated exterior wall of heavy concrete construction at column line A10

East: 3-hour rated wall common to Fire Area XIV, Zone 32B, at column line AG

Nonrated wall of heavy concrete construction at column line AG common to:

- Zone 87B at elevation 40 feet 0 inch
- Zone 88B at elevation 51 feet 6 inches

West: Nonrated wall of heavy concrete construction common to Zone 90 at column line AF

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 37B and 37E

2. Zone Access

- Open doorway in the nonrated east wall to Zone 87B at elevation 40 feet 0 inch
- Open doorway in the nonrated east wall to Zone 88B elevation 51 feet 6 inches

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Cooling water holdup tank
   - Cooling water holdup tank pumps
   - Chemical drain tank pumps
   - Chemical drain tanks
   - Non-ESF sump and pumps
   - Conduit

E. Radioactive Material

   In process piping

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Oil and grease
      - Plastic

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 87B. One manual hose reel is located in adjacent Zone 88B.

2. Secondary

   One portable ABC powder fire extinguisher is located in adjacent Zone 87B. One portable ABC powder fire extinguisher is located in adjacent Zone 88B.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Three 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.14 Fire Area XV, Fire Zone 90, Equipment Drain Tank Room

A. Location

Fire Zone 90 (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 40 feet 0 inch and 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XIII, Zone 31A

South: Nonrated exterior wall of heavy concrete construction at column line A10

East: Nonrated wall of heavy concrete construction common to Zone 89 at column line AF

West: Nonrated wall of heavy concrete construction at column line AE common to:

- Zone 87A at elevation 40 feet 0 inch
- Zone 88A at elevation 51 feet 6 inches

3-hour rated wall common to Fire Area XIII, Zone 32A, at column line AE

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 37B

2. Zone Access

- Open doorway in the nonrated west wall to Zone 87A at elevation 40 feet 0 inch
- Open doorway in the nonrated west wall to Zone 88A at elevation 51 feet 6 inches

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Equipment drain tank

- Auxiliary steam condensate receiver tank radiation monitor pump
- Auxiliary steam condensate receiver tank
- Auxiliary steam condensate pumps
- Vent condenser
- Conduit
- Reactor drain tank pumps

E. Radioactive Material

In process piping

F. Combustible Loading

1. In Situ Combustible Load Type
   - Oil and grease
2. Transient Combustible Load Type
   - Ordinary combustible
   - Oil and grease
3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 87A. One manual hose reel is located in adjacent Zone 88A.

2. Secondary

One portable ABC powder fire extinguisher is located in adjacent Zone 87A. One portable ABC powder fire extinguisher is located in adjacent Zone 88A.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Four 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.15 Fire Area XV, Fire Zone 88A, West Corridors

A. Location

Fire Zone 88A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	North Corridor	- 2-hour rated walls common to the west stairwell and access area
		Nonrated exterior wall of heavy concrete construction at column line A6
	South Corridor	- 3-hour rated wall common to Fire Area XIII, Zone 32A
South:	North Corridor	- 3-hour rated wall common to Fire Area XIII, Zones 30A and 31A
	South Corridor	- Nonrated exterior wall of heavy concrete construction at column line A10
East:	North Corridor	- 3-hour rated wall common to Zone 88B (north corridor) at column line AF
	South Corridor	- Nonrated wall of heavy concrete construction common to Zone 90 at column line AE

Central Corridor - 3-hour rated wall common to Fire Area XIII, Zones 30A and 32A

West: Nonrated exterior wall of heavy concrete construction at column line AC

2-hour rated wall common to the northwest stairwell

Floor: Nonrated barrier of heavy concrete construction common to Zone 87A

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 35A, 37A, and 37B

3-hour rated barrier common to the south access shaft

2. Zone Access

- One Class B door in the 2-hour rated east wall of the northwest stairwell
- One Class A door in the 3-hour rated north corridor east wall to Zone 88B
- Stairwell through the nonrated south corridor floor to Zone 87A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Lubricating oil
      - Cable insulation

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

   Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   Two manual hose reels

2. Secondary

   Two portable ABC powder fire extinguishers

I. Ventilation

   Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

   Five 4-inch drains

K. Emergency Communications

   Sound powered phone jack(s) is provided (not in service).

9B.2.15.16 Fire Area XV, Fire Zone 88B, East Corridors

A. Location

   Fire Zone 88B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 51 feet 6 inches.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	North Corridor	-	2-hour rated wall common to the northeast stairwell and access area Nonrated exterior wall of heavy concrete construction at column line A6
	South Corridor	-	3-hour rated wall common to Fire Area XIV, Zone 32B
South:	South Corridor	-	Nonrated exterior wall of heavy concrete construction at column line A10
	North Corridor	-	3-hour rated wall common to Fire Area XIV, Zones 30B and 31B
East:	Nonrated exterior wall of heavy concrete construction at column line AJ 2-hour rated wall common to the north-east stairwell		
West:	Central Corridor	-	3-hour rated wall common to Fire Area XIV, Zones 30B and 32B

South Corridor	-	Nonrated wall of heavy concrete construction common to Zone 89 at column line AG
North Corridor	-	3-hour rated wall common to Zone 88A at column line AF

Floor: Nonrated barrier of heavy concrete construction common to Zone 87B

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 35B and 37B

3-hour rated barrier common to the south access shaft, between column lines AF and AG

2. Zone Access

- One Class B door in the 2-hour rated west wall of the northeast stairwell
- One Class A door in the 3-hour rated north corridor west wall to Zone 88A
- Stairwell through the nonrated south corridor floor to Zone 87B

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation
      - Lubricating oil

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   Two manual hose reels

2. Secondary

   Two portable ABC powder fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Five 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.17 Fire Area XV, Fire Zone 34A, Train A Essential Cooling Water System Pump Room

A. Location

Fire Zone 34A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 70 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 37A

South: Nonrated wall of heavy concrete construction common to Zone 36 at column line A8

East: Nonrated wall of heavy concrete construction common to Zone 35A at column line AC

Nonrated wall of heavy concrete construction common to a pipe chase at column line AC

West: Nonrated wall of heavy concrete construction common to Zone 37A at column line AB

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 39A

2. Zone Access

One nonrated door (pair) in the nonrated west wall to Zone 37A

3. Sealed Penetrations

None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

- Essential cooling water system chemical addition tank
- Essential cooling water system radiation monitor
- Conduit
- Monorail

E. Radioactive Material

   In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type
   - Cable insulation
   - Oil and grease
2. Transient Combustible Load Type
   - Ordinary combustible

- Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning

H. Fire Suppression

1. Primary

   Two manual hose reels are located in adjacent Zone 37A.

2. Secondary

   Two portable ABC powder fire extinguishers are located in adjacent Zone 37A.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.18 Fire Area XV, Fire Zone 34B, Train B Essential Cooling Water System Pump Room

A. Location

Fire Zone 34B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 70 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 37B at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 37B at column line A9

East: Nonrated wall of heavy concrete construction common to Zone 37B at column line AK

West: Nonrated wall of heavy concrete construction common to Zone 35B at column line AJ

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 39B

2. Zone Access

   One nonrated door (pair) in the nonrated east wall to Zone 37B

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Essential cooling water system chemical addition tank
   - Essential cooling water system radiation monitor
   - Conduit
   - Monorail

E. Radioactive Material

   In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

 - Cable insulation
 - Oil and grease

2. Transient Combustible Load Type

 - Ordinary combustible
 - Grease and oil

3. Total Combustible (Fire) Loading

 Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning

H. Fire Suppression

1. Primary

 Two manual hose reels are located in adjacent Zone 37B.

2. Secondary

 Two portable ABC powder fire extinguishers are located in adjacent Zone 37B.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.19 Fire Area XV, Fire Zone 35A, Train A Shutdown Cooling Heat Exchanger and Valve Gallery Rooms

A. Location

Fire Zone 35A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 70 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 37A at column line A7

Nonrated wall of heavy concrete construction common to a pipe chase at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 37A at column line A9

East: 3-hour rated wall common to Zone 37B at column line AE

West: Nonrated wall of heavy concrete construction common to Zones 34A and 36 at column line AC

Floor: Nonrated barrier of heavy concrete construction common to Zone 88A

3-hour rated barrier common to Fire Area XIII, Zones 30A and 32A

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 39A

2. Zone Access

Open doorway in the nonrated north wall to Zone 37A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

Train A isolation valve to shutdown cooling heat exchanger

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   - Oil and grease
   - Polycarbonate battery casing

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 37A. One manual hose reel is located in adjacent Zone 37B.

2. Secondary

One portable ABC powder fire extinguisher is located in adjacent Zone 37A. One portable ABC powder fire extinguisher is located in adjacent Zone 37B.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.15.20 Fire Area XV, Fire Zone 35B, Train B Shutdown Cooling Heat Exchanger and Valve Gallery Rooms

A. Location

Fire Zone 35B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 70 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 37B at column line A7

Nonrated wall of heavy concrete construction common to a pipe chase at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 37B at column line A9

East: Nonrated wall of heavy concrete construction common to Zone 34B at column line AJ

West: Nonrated wall of heavy concrete construction common to Zone 37B at column line AG

Nonrated wall of heavy concrete construction common to Zone 37E at column line AG

Floor: Nonrated barrier of heavy concrete construction common to Zone 88B

3-hour rated barrier common to Fire Area XIV, Zones 30B and 32B

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 39B

2. Zone Access

Open doorway in the nonrated north wall to Zone 37B

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   Train B isolation valve to shutdown cooling heat exchanger

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   - Polycarbonate Battery Cases
   - Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning

H. Fire Suppression

1. Primary

Two manual hose reels are located in adjacent Zone 37B.

2. Secondary

Three portable ABC powder fire extinguishers are located in adjacent Zone 37B.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.15.21 Fire Area XV, Fire Zone 36, Reactor Makeup Water and Boric Acid Makeup Pump Room

A. Location

Fire Zone 36 (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 70 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 34A at column line A8

South: Nonrated wall of heavy concrete construction common to Zone 37A at column line A9

East: Nonrated wall of heavy concrete construction common to Zone 35A at column line AC

West: Nonrated wall of heavy concrete construction common to Zone 37A at column line AB

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 39A

2. Zone Access

Open doorway in the nonrated south wall to Zone 37A

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Reactor makeup water pumps
   - Boric acid makeup pumps
   - Conduit

E. Radioactive Material

   In process equipment

F. Combustible Loading

   1. In Situ Combustible Load Type

      Oil and grease

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

Ionization smoke detector(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 37A.

2. Secondary

Two portable ABC powder fire extinguishers are located in adjacent Zone 37A.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.22 Fire Area XV, Fire Zone 37A, West Corridors and Electrical Chases

A. Location

Fire Zone 37A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 70 feet 0 inch and 88 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

NOTE

Fire Zone 37A includes the two west electrical chases located at elevation 88 feet 0 inch. These chases are enclosed by 3-hour rated walls and ceilings, with floors open to the west corridors of elevation 70 feet 0 inch. The following description applies to the Zone 37A west corridors.

North:	North Corridor	-	Nonrated walls of heavy concrete construction common to Zone 37C at column line A6
			2-hour rated walls common to the north stairwell
	South Corridor	-	Nonrated wall of heavy concrete construction common to Zones 35A and 36 at column line A9
South:	North Corridor	-	Nonrated wall of heavy concrete construction common to Zone 35A at column line A7
			Nonrated wall of heavy concrete construction common to Zone 34A

			Nonrated walls of heavy concrete construction common to a pipe chase
	South Corridor	-	Nonrated exterior wall of heavy concrete construction at column line A10
			3-hour rated wall common to Fire Area X at column line A10
East:	North Corridor	-	1-hour rated wall common to Zone 37B at column line AE
	South Corridor	-	Open corridor to Zone 37B at column line AE
	West Corridor	-	Nonrated wall of heavy concrete construction common to Zones 34A and 36 at column line AB
West:	Nonrated exterior wall of heavy concrete construction at column line AA		
	2-hour rated wall common to the west HVAC chase at column line AA		
Floor:	Nonrated basemat of heavy concrete construction		

Nonrated barrier of heavy concrete construction common to Zone 88A

3-hour rated barrier common to Fire Area XIII, Zone 30A

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 39A

2. Zone Access

- One Class C door in the 1-hour rated north corridor east wall to Zone 37B
- Open stairwell through the nonrated north corridor north wall to Zone 37C
- Open south corridor to Zone 37B at column line AE.

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Chloride analyzer
- Monorail
- Cable trays and conduit

E. Radioactive Material

In process piping

F. Combustible Loading

1. In Situ Combustible Load Type

   Cable insulation

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   Two manual hose reels

2. Secondary

Two portable ABC powder fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Seven 4-inch drains

K. Emergency Communications

None

9B.2.15.23 Fire Area XV, Fire Zone 37B, East Corridors and Electrical Chases

A. Location

Fire Zone 37B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 70 feet 0 inch and 88 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

NOTE

Fire Zone 37B includes the two east electrical chases located at elevation 88 feet 0 inch. These chases are enclosed by 3-hour rated walls and ceilings, with floors open to the east corridors of elevation 70 feet 0 inch. The following description applies to the Zone 37B east corridors.

North:	North Corridor	-	Nonrated walls of heavy concrete construction common to the south access shaft
			2-hour rated walls common to the north stairwell
			Nonrated walls of heavy concrete construction common to Zone 37D at column line A6
			2-hour rated wall common to the east stairwell at column line A6
	South Corridor	-	Nonrated wall of heavy concrete construction common to Zones 34B and 35B at column line A9
South:	North Corridor	-	Nonrated wall of heavy concrete construction common to Zone 37E
			Nonrated walls of heavy concrete construction common to a pipe chase
			Nonrated wall of heavy concrete construction common to Zones 34B and 35B at column line A7

	South Corridor	-	3-hour rated wall common to Fire Areas I and II at column line A10
East:	East Corridor	-	Nonrated exterior wall of heavy concrete construction at column line AL
	Central Corridor	-	Nonrated walls of heavy concrete construction common to Zone 37E
			Nonrated wall of heavy concrete construction common to Zone 35B at column line AG
West:	East Corridor	-	Nonrated wall of heavy concrete construction common to Zone 34B at column line AK
	Central Corridor	-	3-hour rated wall common to Zone 35A at column line AE
			1-hour rated wall common to zone 37A (north corridor) at column line AE

Open to Zone 37A (south corridor) at column line AE

Floor: Nonrated basemat of heavy concrete construction

3-hour rated barrier common to Fire Area XIII, Zone 31A

Nonrated barrier of heavy concrete construction common to Zones 88B, 89, and 90

3-hour rated barrier common to Fire Area XIV, Zone 30B

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 39B

2. Zone Access

- One Class C door in the 1-hour rated central corridor west wall to Zone 37A
- Open to Zone 37A (south corridor)
- One Class B door in the 2-hour north wall to the east stairwell

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Gas stripper instrument rack
   - Gas stripper control cabinet
   - Cable trays and conduit
   - Monorail

E. Radioactive Material

   In process equipment

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Thermo-Lag 330-1
      - Cable insulation
      - Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   Three manual hose reels

2. Secondary

   Three portable ABC powder fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Ten 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.24 Fire Area XV, Fire Zone 37C, Train A Piping Penetration Room

A. Location

Fire Zone 37C (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 70 feet 0 inch and 88 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XI

Nonrated exterior wall of heavy concrete construction at column line A1

South: Nonrated wall of heavy concrete construction at column line A6 common to:

- Zone 37A at elevation 70 feet 0 inch
- Zone 39A at elevation 88 feet 0 inch

2-hour rated wall common to the north corridor north stairwell at column line A6 and elevation 70 feet 0 inch

3-hour rated wall common to the Zone 37A electrical chase at elevation 88 feet 0 inch

East: Nonrated wall of heavy concrete construction common to the south access shaft

West: Nonrated exterior wall of heavy concrete construction at column line AA4 and AA

2-hour rated wall common to the west elevator and stairwell and HVAC chase at column line AA

Floor: Nonrated basemat of heavy concrete construction

Open to Zone 33A

Ceiling: 1-hour rated barrier common to Fire Area XVI, Zone 42A

Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 42D (Ref. 9B.2.15.1.B.8)

2. Zone Access

One Class B door in the 2-hour rated east wall of the Northwest Stairwell.

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetration in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Structural steel supporting the fire barrier has been provided with coating of 1-hour rating. (Refer to the appendix 9A response to 9A.107.)

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train A containment hydrogen control valves

D. Nonsafety-Related Equipment and Components

- Boronometer (abandoned in-place)
- Liquid nitrogen storage container and refill manifold
- Conduit
- Sampling equipment

E. Radioactive Material

In process piping

F. Combustible Loading

1. In Situ Combustible Load Type

   - Rubber

- Plastic
- Cable insulation
- Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 37A.

2. Secondary

   One portable ABC powder fire extinguisher is located in adjacent Zone 37A.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.25 Fire Area XV, Fire Zone 37D, Train B Piping Penetration Room

A. Location

Fire Zone 37D (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 70 feet 0 inch and 88 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XI

3-hour rated wall common to Fire Area XII

South: 2-hour rated wall common to the north stairwell at elevation 70 feet 0 inch and at column line A6

Nonrated walls of heavy concrete construction common to Zone 37B at elevation 70 feet 0 inch and at column line A6

3-hour rated wall common to the Zone 37B electrical chase at elevation 88 feet 0 inch and at column line A6

Nonrated wall of heavy concrete construction common to Zone 39B at elevation 88 feet 0 inch and at column line A6

2-hour rated wall common to the east stairwell

East: Nonrated exterior wall of heavy concrete construction at column line AL

2-hour rated wall common to the east stairwell.

West: Nonrated wall of heavy concrete construction common to the south access shaft at column line AG

Floor: Open to Zone 33B

Nonrated basemat of heavy concrete construction

Ceiling: 1-hour rated barrier common to Fire Area XVII, Zone 42B

Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 42C (Ref. 9B.2.15.1.B.8)

2. Zone Access

   One Class B door in the 2-hour rated west wall of the east stairwell at elevation 70 feet 0 inch

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   Structural steel supporting the fire barrier has been provided with coating of 1-hour rating. (Refer to the appendix 9A response to Question 9A.107.)

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train B containment hydrogen control isolation valves
- Train A containment isolation valve
- Train B containment isolation valve

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

In process piping

F. Combustible Loading

1. In Situ Combustible Load Type

- Thermo-Lag 330-1
- Plastic
- Rubber
- Cable insulation
- Oil and grease

2. Transient Combustible Load Type

- Ordinary combustible
- Oil and grease

3. Total Combustible (Fire) Loading

Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 37B.

2. Secondary

One portable ABC powder fire extinguisher is located in adjacent Zone 37B.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

One 4-inch drain

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.26 Fire Area XV, Fire Zone 37E, Gas Stripper Room

A. Location

Fire Zone 37E (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevations 70 feet 0 inch and 88 feet 0 inch

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 37B at elevation 70 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 39B at elevation 88 feet 0 inch and at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 37B at elevation 70 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 39B at elevation 88 feet 0 inch and at column line A8

East: Nonrated wall of heavy concrete construction common to Zones 35B and 37B at elevation 70 feet 0 inch and at column line AG

Nonrated wall of heavy concrete construction common to Zone 39B at elevation 88 feet 0 feet and at column line AG

West: Nonrated wall of heavy concrete construction common to Zone 37B and a pipe chase at elevation 70 feet 0 inch

Nonrated wall of heavy concrete construction common to Zone 39B at elevation 88 feet 0 inch and at column line AF

Floor: 3-hour rated barrier common to Fire Area XIII, Zone 31A

3-hour rated barrier common to Fire Area XIV, Zone 31B

Nonrated barrier of heavy concrete construction common to Zone 89

Ceiling: Barriers of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 39B at elevation 88 feet 0 inch and Zone 45 at elevation 100 feet 0 inch (Ref. 9B.2.15.1.B.8)

2. Zone Access

One nonrated gate in the nonrated west wall to Zone 37B

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Gas stripper

- Conduit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

    - Cable insulation
    - Oil and grease

2. Transient Combustible Load Type

    - Ordinary combustible
    - Oil and grease

3. Total Combustible (Fire) Loading

    Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

    One manual hose reel is located in adjacent Zone 37B.

2. Secondary

    One portable ABC powder fire extinguisher is located in adjacent Zone 37B.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.15.27 Fire Area XV, Fire Zone 39A, Train A Pipeway

A. Location

Fire Zone 39A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 88 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 37C at column line A6

3-hour rated walls common to the Zone 37A electrical chase

3-hour rated wall common to the south access shaft

South: Nonrated exterior wall of heavy concrete construction at column line A10

3-hour rated wall common to Fire Area X at column line A10

East: Open to Zone 39B at column line AE

Nonrated wall of heavy concrete construction common to Zone 39B at column line AE between column lines A7 and A8

West: Nonrated exterior wall of heavy concrete construction at column line AA

2-hour rated wall common to the west stairwell and HVAC chase

3-hour rated walls common to the Zone 37A west electrical chase

Floor Nonrated barrier of heavy concrete construction common to Zones 34A, 35A, 36, and 37A

Ceiling: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 42D and 43 (Ref. 9B.2.15.B.1.8)

2. Zone Access

- Open to Zone 39B at column line AE
- Non-rated stairwell through the south corridor ceiling to Zone 42D

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   In process piping

F. Combustible Loading

1. In Situ Combustible Load Type

   Cable insulation

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel in Zone 39A and one located in adjacent Zone 39B

2. Secondary

One portable ABC powder fire extinguisher

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Eleven 4-inch drains

K. Emergency Communications

None

9B.2.15.28 Fire Area XV, Fire Zone 39B, Train B Pipeway

A. Location

Fire Zone 39B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 88 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 37D at column line A6

3-hour rated walls common to the Zone 37B electrical chases

2-hour rated wall common to the east stairwell at column line A6.

3-hour rated wall common to the south

South: 3-hour rated wall common to Fire Areas I and II at column line A10

East: Nonrated exterior wall of heavy concrete construction at column line AL

West: Open to Zone 39A at column line AE

Nonrated wall of heavy concrete construction common to Zone 39A at column line AE, between column lines A7 and A8

Floor: Nonrated barrier of heavy concrete construction common to Zones 34B, 35B, 37B, and 37E

Ceiling: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to

Zones 42D, 44, and 45
(Ref. 9B.2.15.1.B.8)

Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46A (Ref. 9B.2.15.1.B.8)

Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 42C, 46B, and 46E
(Ref. 9B.2.15.1.B.8)

2. Zone Access

- Open to Zone 39A at column line AE
- Open stairwell leading up to Zone 42C

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

In process piping

F. Combustible Loading

1. In Situ Combustible Load Type

    - Thermo-Lag 330-1
    - Cable Insulation

2. Transient Combustible Load Type

    Ordinary combustible

3. Total Combustible (Fire) Loading

    Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

    Two manual hose reels

2. Secondary

    Two portable ABC powder fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Thirteen 4-inch drains

K. Emergency Communications

None

9B.2.15.29 Fire Area XV, Fire Zone 42C, East Corridors

A. Location

Fire Zone 42C (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	North Corridor	-	2-hour rated wall common to Fire Area XVII, Zone 42B, at column line A6
			3-hour rated wall common to Fire Area XII

	South Corridor	-	Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 46A, 46B and 46E at column line A9 (Ref. 9B.2.15.1.B.2)
South:	North Corridor	-	Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour ratings common to Zones 46A, 46B and 46E at column line A7 (Ref. 9B.2.15.1.B.2)
	South Corridor	-	3-hour rated wall common to Fire Areas I and II at column line A10
East:	3-hour rated exterior wall at column line AL		
	3-hour rated wall common to the corridor building at column line AL		
	2-hour rated walls common to the east stairwell		
West:	North Corridor	-	1-hour rated wall common to Zone 42D at column line AG

		3-hour rated wall common to the south access shaft at column line AG
South Corridor	-	1-hour rated wall common to Zone 42D at column line AG
East Corridor	-	2-hour rated wall common to Zone 42B
		Wall of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 46A (Ref. 9B.2.15.1.B.2)

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 37D and 39B (Ref. 9B.2.15.1.B.8)

3-hour rated barriers common to the Zone 37B electrical chases

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 51B, 52D, 53, and 54

2. Zone Access

- One Class C door (pair) in the 1-hour rated north corridor west wall to Zone 42D

- One Class C door (pair) in the 1-hour rated south corridor west wall to Zone 42D
- One Class A rollup door in the 3-hour rated east exterior wall
- One Class B door in the 2-hour rated east wall to the east stairwell

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the fire rated barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   Train A chemical and volume control system, and auxiliary building HVAC conduits are enclosed by 1-hour protective envelopes.

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train A and train B hydrogen recombiner equipment
- Train B post-LOCA analyzer

D. Nonsafety-Related Equipment and Components

- Hydrogen purge exhaust air filtration unit
- Cable trays and conduit
- Motor control center
- Lower level exhaust radiation monitor

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
    - Thermo-Lag 330-1
    - Lubricating grease
    - Cable insulation
2. Transient Combustible Load Type
    - Ordinary combustible
    - Cable insulation
3. Total Combustible (Fire) Loading

    Moderate

G. Fire Detection

Actuation of either ionization smoke detectors or line-type thermal detectors activates an alarm and the preaction water sprinkler system and will pressurize the piping with water. Either detector system alone can provide early warning capability.

H. Fire Suppression

1. Primary

Automatic preaction water sprinkler system, covering cable trays only

2. Secondary

Two manual hose reels and two portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Eight 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.30 Fire Area XV, Fire Zone 42D, West Corridors

A. Location

Fire Zone 42D (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	North Corridor	- 2-hour rated wall common to Fire Area XVI, Zone 42A, at column lines A3 and A6 Nonrated walls of heavy concrete construction common to the south access shaft
	South Corridor	- Nonrated walls of heavy concrete construction common to Zones 43, 44, and 45 at column line A9
South:	North Corridor	- Nonrated walls of heavy concrete construction common to Zones 43, 44, and 45 at column line A7
	South Corridor	- 3-hour rated wall common to Fire Area X at column line A10 3-hour rated wall common to Fire Area I at column line A10
East:	North Corridor	- 1-hour rated wall common to Zone 42C at column line AG

			2-hour rated wall common to Fire Area XVI, Zone 42A, at column line AB
	South Corridor	-	1-hour rated wall common to Zone 42C at column line AG
	Central Corridor	-	Nonrated wall of heavy concrete construction common to Zone 44 at column line AE
West:	North Corridor	-	2-hour rated wall common to the west stairwell, HVAC chase, and elevator at column line AA
			3-hour rated wall common to Fire Area VI at column line AA
			Nonrated exterior wall of heavy concrete construction at column line AA
	South Corridor	-	Nonrated exterior wall of heavy concrete construction at column line AA

Central Corridor - Nonrated wall of heavy concrete construction common to Zone 43

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 39A and 39B.
(Ref. 9B.2.15.1.B.8)

3-hour rated barriers common to the Zone 37A electrical chases

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 48, 49A, 49B, 49D, 49E, 49G, 49H, 50A, 52A, and 52D

2. Zone Access

- One Class C door (pair) in the 1-hour rated north corridor east wall to Zone 42C
- One 3-hour rated door (pair) in the 3-hour rated south corridor south wall to Fire Area X (Radwaste Building)
- One Class C door (pair) in the 1-hour rated south corridor east wall to Zone 42C
- One Class B door in the east wall of the west stairwell

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Cable trays and conduit
   - Load centers
   - Motor control center

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Lubricating grease
      - Cable insulation
      - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Actuation of either ionization smoke detector or line-type thermal detector systems activates the automatic preaction water sprinkler system. Either detector system alone can provide early warning capability. Ionization smoke detectors are provided in the southwest corridor to provide only early warning capability.

H. Fire Suppression

1. Primary

   Automatic preaction water sprinkler system covering cable trays only (excluding south corridor between column lines AA and AD)

2. Secondary

   Three manual hose reels and three portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Seven 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.31 Fire Area XV, Fire Zone 43, Essential Cooling Water Heat Exchanger Rooms

A. Location

Fire Zone 43 (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 42D at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 42D at column line A9

East: Nonrated wall of heavy concrete construction common to Zone 42D

West: Nonrated exterior wall of heavy concrete construction at column line AA

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations

sealed to a 3-hour rating common to Zone 39A (Ref. 9B.2.15.1.B.8)

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 48, 49A, 49B, 49C, 49D, and 50A

2. Zone Access

- One nonrated door in the nonrated north wall to Zone 42D
- One nonrated door in the nonrated south wall to Zone 42D
- Two nonrated doors in the nonrated east wall to Zone 42D

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

Oil and grease

2. Transient Combustible Load Type

- Ordinary combustible
- Oil and grease

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

Two manual hose reels are located in adjacent Zone 42D.

2. Secondary

Two portable CO_2 fire extinguishers are located in adjacent Zone 42D.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.15.32 Fire Area XV, Fire Zone 44, Letdown and Seal Injection Heat Exchanger and Valve Gallery Rooms

A. Location

Fire Zone 44 (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 42D at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 42D at column line A9

East: Nonrated wall of heavy concrete construction common to Zone 45 at column line AF

West: Nonrated wall of heavy concrete construction common to Zone 42D at column line AE

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 39B (Ref. 9B.2.15.1.B.8)

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 49F and 50A

2. Zone Access

- One non-rated gate in the nonrated north wall to Zone 42D
- One nonrated gate in the nonrated south wall to Zone 42D

3. Sealed Penetrations

(Refer to Fire Area XV deviation 8)

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Conduit
- Letdown heat exchanger

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 42D.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 42D.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Three 4-inch drains

K. Emergency Communications

None

9B.2.15.33 Fire Area XV, Fire Zone 45, Crud Pump and Crud Tank Rooms

A. Location

Fire Zone 45 (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 42D at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 42D at column line A9

Nonrated wall of heavy concrete construction common to a pipe chase

East: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46E at column line AG (Ref. 9B.2.15.1.B.8)

Nonrated wall of heavy concrete construction common to a pipe chase

West: Nonrated wall of heavy concrete construction common Zone 44 at column line AF

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 39B and 37E (Ref. 9B.2.15.1.B.8)

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 50A and barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 51A (Ref. 9B.2.15.1.B.8)

2. Zone Access

   Non-rated gate in the nonrated north wall to Zone 42D

3. Sealed Penetrations

   (Refer to Fire Area XV deviation 8)

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Crud pump and crud tank
   - Conduit

E. Radioactive Material

   Area containing components designed to retain and collect radioactivity in process equipment.

F. Combustible Loading

   1. In Situ Combustible Load Type

      Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible

   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel is located in adjacent Zone 42D.

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 42D.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Three 4-inch drains

K. Emergency Communications

None

9B.2.15.34 Fire Area XV, Fire Zone 46A, Train A Charging Pump and Valve Gallery Rooms

A. Location

Fire Zone 46A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 42C at column line A7 (Ref. 9B.2.15.1.B.2)

South: Wall of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 42C at column line A9 (Ref. 9A.120)

East: 3-hour rated wall common to Zone 42C

West: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46B (Ref. 9B.2.15.1.B.2)

Floor: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 39B (Ref. 9B.2.15.1.B.8)

Ceiling: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 54 (Ref. 9B.2.15.1.B.8)

2. Zone Access

Non-rated gate in the north wall to Zone 42C

3. Sealed Penetrations

(Refer to Fire Area XV deviations 2 and 8.)

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Hydrogen compressors
- Conduit
- Normal air handling unit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   - Oil and grease
   - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Actuation of ionization smoke detector system(s) activates the automatic preaction water sprinkler system. The detector system(s) can provide early warning capability. (Refer to the appendix 9A response to Question 9A.116.)

H. Fire Suppression

1. Primary

   Automatic preaction water sprinkler system

2. Secondary

   One manual hose reel and one portable CO_2 fire extinguisher are located in adjacent Zone 42C.

I. Ventilation

Manually controlled smoke venting of adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Three 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.35 Fire Area XV, Fire Zone 46B, Train B Charging Pump and Valve Gallery Rooms

A. Location

Fire Zone 46B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 42C at column line A7 (Ref. 9B.2.15.1.B.2)

South: Wall of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 42C at column line A9 (Ref. 9A.120)

East: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46A (Ref. 9B.2.15.1.B.2)

West: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46E at column line AH (Ref. 9B.2.15.1.B.2)

Floor: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 39B (Ref. 9B.2.15.1.B.8)

Ceiling: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zones 53 and 54 (Ref. 9B.2.15.1.B.8)

2. Zone Access

Non-rated gate in the north wall to Zone 42C

3. Sealed Penetrations

(Refer to Fire Area XV deviations 2 and 8.)

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - CVCS chemical addition unit
   - Conduit
   - Normal air handling unit

E. Radioactive Material

   In process equipment

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Oil and grease
      - Thermo-Lag 330-1

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

   Actuation of ionization smoke detector system(s) activates the automatic preaction water sprinkler

system. The detector system(s) provides early warning capability. (Refer to the appendix 9A response to Question 9A.116.)

H. Fire Suppression

1. Primary

Automatic preaction water sprinkler system

2. Secondary

One manual hose reel and one portable CO_2 fire extinguisher are located in adjacent Zone 42C.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Three 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.36 Fire Area XV, Fire Zone 46E, Standby Charging Pump and Valve Gallery Room

A. Location

Fire Zone 46E (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 42C at column line A7 (Ref. 9B.2.15.1.B.2)

South: Wall of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zone 42C at column line A9 (Ref. 9B.2.15.1.B.2)

East: Wall of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46B at column line AH (Ref. 9B.2.15.1.B.2)

West: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 45 at column line AG (Ref. 9B.2.15.1.B.8)

Floor: Barrier of heavy concrete construction with electrical and piping penetrations sealed to a 3-hour rating common to Zone 39B (Ref. 9B.2.15.1.B.8)

Ceiling: Barrier of heavy concrete construction with penetrations sealed to a 3-hour rating common to Zones 50B and 51B (Ref. 9B.2.15.1.B.8)

2. Zone Access

Non-rated gate in the north wall to Zone 42C

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- HVAC control panel
- Conduit
- Normal air handling unit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   - Oil and grease
   - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Actuation of ionization smoke detector system(s) activates the automatic preaction water sprinkler system. The detector system(s) can provide early warning capability. (Refer to the appendix 9A response to Question 9A.116.)

H. Fire Suppression

1. Primary

   Automatic preaction water sprinkler system

2. Secondary

   One manual hose reel and one portable CO_2 fire extinguisher are located in adjacent Zone 42C.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.37 Fire Area XV, Fire Zone 48, Train B Essential Cooling Water Surge Tank and South Corridor

A. Location

Fire Zone 48 (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 49H at column line A7

Open to Zone 52A at column line A7

South: 3-hour rated wall common to Fire Area X at column line A10

East: Nonrated wall of heavy concrete construction common to Zones 49A, 49C, 49E, and 50A

West: Nonrated exterior wall of heavy concrete construction at column line AA

Floor: Nonrated barrier of heavy concrete construction common to Zones 42D and 43

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 57D, 57E, 57F, 57M, and 57N

2. Zone Access

- One nonrated door (pair) in the 3-hour rated south wall to Fire Area X. (Refer to the appendix 9A response to Question 9A.106.)
- Open to Zone 52A at column line A7

3. Sealed Penetrations

Seals equal or exceed fire barrier rating.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Cable trays and conduit
- Boric acid batch tank
- Monorail

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
    - Cable insulation
    - Plastic
    - Thermo-Lag 330-1
2. Transient Combustible Load Type
    - Ordinary combustible
    - Cable insulation
3. Total Combustible (Fire) Loading

    Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel

NOTE

The passage to Fire Area X through the 3-hour rated south wall is protected by a fixed sprinkler system water curtain.

2. Secondary

One portable CO_2 fire extinguisher

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Four 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.38 Fire Area XV, Fire Zone 49A, Boric Acid and Reactor Makeup Water Filter Rooms

A. Location

Fire Zone 49A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

a. Boric Acid Filter Room:

North: Nonrated wall of heavy concrete construction common to Zone 49H at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 49C

East: Nonrated wall of heavy concrete construction common to Zone 49B

West: Nonrated wall of heavy concrete construction common to Zone 48 at column line AC

Floor: Nonrated barrier of heavy concrete construction common to Zone 43

Ceiling: Nonrated barrier of heavy concrete construction at elevation 129 feet 0 inch

b. Reactor Makeup Water Filter Room:

North: Nonrated wall of heavy concrete construction common to Zone 49H at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 49D

East: Nonrated wall of heavy concrete construction common to Zone 49F at column line AE

West: Nonrated wall of heavy concrete construction common to Zone 49B

Floor: Nonrated barrier of heavy concrete construction common to Zone 42D

Ceiling: Nonrated barrier of heavy concrete construction at elevation 129 feet 0 inch

2. Zone Access

   None

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

- Reactor makeup water filter
- Boric acid filter

E. Radioactive Material

Area containing components designed to retain and collect radioactivity in process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

   None

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel is located in Zone 52A.
   One manual hose reel is located in Zone 48.

2. Secondary

   One portable CO_2 fire extinguisher is located in Zone 52A. One portable CO_2 fire extinguisher is located in Zone 48.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.39 Fire Area XV, Fire Zone 49B, Liquid Radwaste System and Fuel Pool Purification Filter Rooms

A. Location

Fire Zone 49B (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 49H at column line A7

South: Nonrated wall of heavy concrete construction common to Zones 49C and 49D

East: Nonrated wall of heavy concrete construction common to Zone 49A

West: Nonrated wall of heavy concrete construction common to Zone 49A

Floor: Nonrated barrier of heavy concrete construction common to Zone 42D and 43

Ceiling: Nonrated barrier of heavy concrete construction at elevation 129 feet 0 inch

2. Zone Access

   None

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Liquid radwaste system filters
   - Fuel pool purification filters

E. Radioactive Material

Area containing components designed to retain and collect radioactivity in process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

None

2. Transient Combustible Load Type

Ordinary combustible

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in Zone 52A.

One manual hose reel is located in Zone 48.

2. Secondary

One portable CO_2 fire extinguisher is located in Zone 52A. One portable CO_2 fire extinguisher is located in Zone 48.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains (one in each room)

K. Emergency Communications

None

9B.2.15.40 Fire Area XV, Fire Zone 49C, Reactor Drain and Seal Injection Filter Rooms

A. Location

Fire Zone 49C (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zones 49A and 49B

South: Nonrated wall of heavy concrete construction to Zone 50A at column line A8

East: Nonrated wall of heavy concrete construction common to Zone 49D at column line AD

West: Nonrated wall of heavy concrete construction common to Zone 48 at column line AC

Floor: Nonrated barrier of heavy concrete construction common to Zone 43

Ceiling: Nonrated barrier of heavy concrete construction at elevation 129 feet 0 inch

2. Zone Access

None

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Reactor drain filter
- Seal injection filter

E. Radioactive Material

Area containing components designed to retain and collect radioactivity in process equipment.

F. Combustible Loading

1. In Situ Combustible Load Type

None

2. Transient Combustible Load Type

Ordinary combustible

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in Zone 52A.

One manual hose reel is located in Zone 48.

2. Secondary

One portable CO_2 fire extinguisher is located in Zone 52A. One portable CO_2 fire extinguisher is located in Zone 48.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.15.41 Fire Area XV, Fire Zone 49D, Purification and Backflushable Purification Filter Rooms

A. Location

Fire Zone 49D (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zones 49A and 49B

South: Nonrated wall of heavy concrete construction to Zone 50A at column line A8

East: Nonrated wall of heavy concrete construction common to Zone 49F at column line AE

West: Nonrated wall of heavy concrete construction common to Zone 49C at column line AD

Floor: Nonrated barrier of heavy concrete construction common to Zones 42D and 43

Ceiling: Nonrated barrier of heavy concrete construction at elevation 129 feet 0 inch

2. Zone Access

   None

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Purification filters

E. Radioactive Material

   Area containing components designed to retain and collect radioactivity in process equipment

F. Combustible Loading

   1. In Situ Combustible Load Type

      None

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel is located in Zone 48.

2. Secondary

   One portable CO_2 fire extinguisher is located in Zone 52A. One portable CO_2 fire extinguisher is located in Zone 48

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.15.42 Fire Area XV, Fire Zone 49E, Fuel Pool Purification and Preholdup Ion Exchanger Rooms

A. Location

Fire Zone 49E (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	Nonrated wall of heavy concrete construction common to Zone 50A at column line A9
South:	3-hour rated wall common to Fire Area X at column line A10
East:	3-hour rated wall common to Fire Area X, a pipe chase
West:	Nonrated wall of heavy concrete construction common to Zone 48 at column line AC
Floor:	Nonrated barrier of heavy concrete construction common to Zone 42D
Ceiling:	Nonrated barrier of heavy concrete construction common to Zone 57M

2. Zone Access

None

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Fuel pool purification ion exchangers
   - Pre-holdup ion exchanger

E. Radioactive Material

   Area containing components designed to retain and collect radioactivity in process equipment.

F. Combustible Loading

   1. In Situ Combustible Load Type

      None

   2. Transient Combustible Load Type

      Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

   None

H. Fire Suppression

1. Primary

   One manual hose reel is located in Zone 57N at elevation 140 feet 0 inch.

2. Secondary

   One portable pressurized water fire extinguisher is located in Zone 57N at elevation 140 feet 0 inch.

I. Ventilation

   Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

   One 4-inch drain

K. Emergency Communications

   None

9B.2.15.43 Fire Area XV, Fire Zone 49F, Crud Tank and Crud Tank Vent Filter Room

A. Location

Fire Zone 49F (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	Nonrated wall of heavy concrete construction common to Zone 52D at column line A7
South:	Nonrated wall of heavy concrete construction common to Zone 50A at column line A8
East:	Nonrated wall of heavy concrete construction common to Zone 50A
West:	Nonrated wall of heavy concrete construction common to Zones 49A and 49D
Floor:	Nonrated barrier of heavy concrete construction common to Zone 44
Ceiling:	Nonrated barrier of heavy concrete construction at elevation 129 feet 0 inch

2. Zone Access

None

3. Sealed Penetrations

   (Refer to Fire Area XV deviation 8)

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Crud tank filter
   - Crud tank vent filter

E. Radioactive Material

   Area containing components designed to retain and collect radioactivity in process equipment.

F. Combustible Loading

   1. In Situ Combustible Load Type

      None

   2. Transient Combustible Load Type

      Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

   None

H. Fire Suppression

1. Primary

   One portable CO_2 fire extinguisher is located in Zone 48.

2. Secondary

   One portable CO_2 fire extinguisher is located in Zone 52A.

I. Ventilation

   Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

   One 4-inch drain

K. Emergency Communications

   None

9B.2.15.44 Fire Area XV, Fire Zone 49G, Purification and Deborating Ion Exchanger Rooms

A. Location

Fire Zone 49G (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	Nonrated wall of heavy concrete construction common to Zone 50A
South:	3-hour rated wall common to Fire Area X at column line A10
East:	3-hour rated wall common to Zone 51B, at column line AG
West:	3-hour rated wall common to Fire Area X, a pipe chase, at column line AE
Floor:	Nonrated barrier of heavy concrete construction common to Zone 42D
Ceiling:	Nonrated barrier of heavy concrete construction common to Zone 57M

2. Zone Access

None

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Purification exchanger
   - Deborating ion exchanger

E. Radioactive Material

   Area containing components designed to retain and collect radioactivity in process equipment

F. Combustible Loading

   1. In Situ Combustible Load Type

      None

   2. Transient Combustible Load Type

      Ordinary combustible

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One portable pressurized water fire extinguisher is located in Zone 57N at elevation 140 feet 0 inch.

2. Secondary

One portable pressurized water fire extinguisher is located in the radwaste building, Zone 62I, at elevation 140 feet 0 inch.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.15.45 Fire Area XV, Fire Zone 49H, LRS Filters Valve Gallery

A. Location

Fire Zone 49H (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 52A

South: Nonrated wall of heavy concrete construction common to Zones 48, 49A, and 49B at column line A7

East: 1-hour rated wall common to Zone 52D at column line AE

West: Nonrated wall of heavy concrete construction common to Zone 52A

Floor: Nonrated barrier of heavy concrete construction common to Zone 42D

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 52A at elevation 127 feet 2 inches

2. Zone Access

Two nonrated gates in the nonrated north wall to Zone 52A

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      None

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

   3. Total Combustible (Fire) Loading

      High

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 52A.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 52A.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.15.46 Fire Area XV, Fire Zone 50A, Valve Gallery

A. Location

Fire Zone 50A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zones 49C, 49D, and 49F at column line A8

Nonrated wall of heavy concrete construction common to Zone 52D at column line A7

Nonrated wall of heavy concrete construction common to Zone 51A at column line A8

South: Nonrated wall of heavy concrete construction common to Zones 49E and 49G at column line A9

3-hour rated wall common to Fire Area X, a pipe chase, at column line A9

East: 3-hour rated wall common to Zone 51B at column line AG

West: Nonrated wall of heavy concrete construction common to Zone 48 at column line AC

Nonrated wall of heavy concrete construction common to Zone 49F

Floor: Nonrated barrier of heavy concrete construction common to Zones 42D, 43, 44, and 45

An open pipe chase which extends down to Zone 39B is located in the southeast corner

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 57F, 57G, 57L, and 57N

2. Zone Access

- One nonrated gate in the nonrated west wall to Zone 48
- One open doorway in the nonrated west wall to Zone 48 at elevation 129 feet 0 inch
- One nonrated doorway in the nonrated north wall to Zone 52D

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings. (Refer to Fire Area XV deviation 8)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Cable tray and conduits

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Oil/grease
      - Polycarbonate battery casing

   2. Transient Combustible Load Type

      - Ordinary combustible

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

   None

H. Fire Suppression

   1. Primary

      One manual hose reel is located in Zone 52D.
      One manual hose reel is located in Zone 48.

2. Secondary

One portable CO_2 fire extinguisher is located in Zone 52D. One portable CO_2 fire extinguisher is located in Zone 48.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Eight 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.47 Fire Area XV, Fire Zone 50B, Valve Gallery

A. Location

Fire Zone 50B (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 52D at column line A7

South: Nonrated wall of heavy concrete construction common to Zone 51B at column line A8

East: Nonrated wall of heavy concrete construction common to Zone 53 at column line AH

West: Nonrated wall of heavy concrete construction common to Zone 51A at column line AG

Floor: Nonrated barrier of heavy concrete construction common to Zone 46E

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 57J

2. Zone Access

   One nonrated gate in the nonrated south wall to Zone 51B

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

   (Refer to Fire Area XV deviation 8)

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

In process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

None

2. Transient Combustible Load Type

- Lubricating oil
- Ordinary combustible
- Plastic

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization Smoke Detector System(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 53

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 53.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.15.48 Fire Area XV, Fire Zone 51A, Volume Control Tank Room

A. Location

Fire Zone 51A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

   North: Nonrated wall of heavy concrete construction common to Zone 52D at column line A7

   South: Wall of heavy concrete construction with electrical and pipe penetrations

sealed to a 3-hour rating common to Zone 50A at column line A8 (Ref. 9B.2.15.1.B.8)

East: Nonrated wall of heavy concrete construction common to Zone 50B at column line AG

West: 3-hour rated wall common to the central stairwell at column line AF

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 45 (Ref. 9B.2.15.1.B.8)

Ceiling: Nonrated barrier of heavy concrete construction common to Zone 57K

2. Zone Access

None

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

(Refer to Fire Area XV deviation 8)

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

Area containing components designed to retain and collect radioactivity in process equipment

F. Combustible Loading

1. In Situ Combustible Load Type

Hydrogen

2. Transient Combustible Load Type

Ordinary combustible

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

None

H. Fire Suppression

None

NOTE

Zone 51A is completely enclosed with walls of heavy concrete construction so as to protect plant personnel from the high radiation levels within the zone; due to the lack of zone access, no portable suppression means are possible.

I. Ventilation

None

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.15.49 Fire Area XV, Fire Zone 51B, Spray Chemical Storage Tank Room

A. Location

Fire Zone 51B (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 50B at column line A8

South: 3-hour rated wall common to Fire Area I at column line A10

East: Nonrated wall of heavy concrete construction common to Zone 53 at column line AH

West: 3-hour rated wall common to Zones 49G and 50A at column line AG

Floor: Barrier of heavy concrete construction common to Zones 42C and 46E. Electrical and pipe penetrations common to Zone 46E are sealed to a 3-hour rating (Ref. 9B.2.15.1.B.8)

Ceiling: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 57J (Ref. 9B.2.15.1.B.8)

2. Zone Access

   One open doorway in the nonrated east wall to Zone 53

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train A and B spray chemical addition pumps (Abandoned in place)
- Train A conduit
- Chemical spray storage tank

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
   - 35% hydrazine
   - Lubricating grease
2. Transient Combustible Load Type

   Ordinary combustible
3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 53.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 53.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.50 Fire Area XV, Fire Zone 52A, West Corridors

A. Location

Fire Zone 52A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to the south access shaft

2-hour rated walls common to Fire Area XVI, Zone 47A, at column lines A3 and A6

South: Open to Zone 48 at column line A7

Nonrated wall of heavy concrete construction common to Zone 49H

Nonrated wall of heavy concrete construction common to the filter access area, at column line A7, above elevation 127 feet 2 inches

East: 1-hour rated wall common to Zone 52D at column line AE

2-hour rated wall common to Fire Area XVI, Zone 47A, at column line AB

Nonrated wall of heavy concrete construction common to the south access shaft

West: 2-hour rated wall common to the west elevator, stairwell, and HVAC chase at column line AA

Nonrated exterior wall of heavy concrete construction at column line AA

3-hour rated wall common to Fire Area VI at column line AA

Floor: Nonrated barrier of heavy concrete construction common to Zone 42D

Ceiling: Nonrated barrier of heavy concrete construction common to Zones 57A, 57B, 57C, 57H, 57N, and 57P

2-hour rated barrier common to Zones 55A and 55C

2. Zone Access

- One Class C door in the 1-hour rated east wall to Zone 52D
- One Class B door in the 2-hour rated west wall to the west stairwell
- Open to Zone 48 at column line A7
- One Class A door (pair) in the 3-hour rated west wall to Fire Area VI (Fuel Building)

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train A post-LOCA analyzer cabinet

D. Nonsafety-Related Equipment and Components

- 120 V-ac distribution panel
- Load center
- Cable trays and conduit
- Concentrator panel

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Oxygen (oxidizer)
   - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Actuation of either ionization smoke detector system(s) or line-type thermal detector system(s) activates the automatic preaction water sprinkler system and will pressurize the piping with water. Either detector system alone can provide early warning.

H. Fire Suppression

1. Primary

   Automatic preaction water sprinkler system covering the cable trays only (excluding corridor adjacent to the west elevator and stairwell)

2. Secondary

   One manual hose reel and two portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Four 4-inch drains

K. Emergency Communications

None

9B.2.15.51 Fire Area XV, Fire Zone 52D, East Corridors

A. Location

Fire Zone 52D (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to Fire Area XVII, Zone 47B, at column line A6

3-hour rated walls common to the south access shaft

3-hour rated wall common to Fire Area XII

South: Nonrated wall of heavy concrete construction common to Zones 50B and 51A at column line A7

2-hour rated walls common to Zone 54

Open to Zone 53 at column line A7

Wall of heavy concrete construction with electrical and pipe penetrations

sealed to a 3-hour rating common to Zones 49F and 50A, and the central staircase (Ref. 9B.2.15.1.B.8)

East: 3-hour rated exterior wall at column line AL

2-hour rated walls common to the east stairwell

West: 1-hour rated wall common to Zone 52A at column line AE

2-hour rated wall common to Fire Area XVII, Zone 47B

Floor: Nonrated barrier of heavy concrete construction common to Zones 42C and 42D

Ceiling: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 56C, 57J, 57K, and 57N (Ref. 9B.2.15.1.B.8)

2. Zone Access

- One Class C door (pair) in the 1-hour rated west wall to Zone 52A
- One Class B door in the 2-hour rated east wall to the east stairwell

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   Train A auxiliary building HVAC conduits are enclosed by 1-hour protective envelopes.

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   - Train A and B control element drive mechanism control system (CEDMCS) auxiliary cabinets

D. Nonsafety-Related Equipment and Components

   - Load centers
   - Motor control center
   - Auxiliary relay cabinets
   - Auxiliary building upper level exhaust radiation monitor
   - Cable trays and conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Thermo-Lag 330-1

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Actuation of either ionization smoke detector or line-type thermal detector system(s) activates the automatic preaction water sprinkler system. Either detector system can provide early warning.

H. Fire Suppression

1. Primary

   Automatic preaction water sprinkler system, covering cable trays only except in northeast corner (north of column line A3) which has area coverage

2. Secondary

   Two manual hose reels and two portable CO_2 fire extinguishers

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Eight 4-inch drains

K. Emergency Communications

None

9B.2.15.52 Fire Area XV, Fire Zone 53, Process Radiation Monitor and Boronometer Room

A. Location

Fire Zone 53 (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Open to Zone 52D at column line A7

South: 3-hour rated wall common to Fire Area II at column line A10

East: 2-hour rated walls common to Zone 54

West: Nonrated wall of heavy concrete construction common to Zones 50B and 51B at column line AH

Floor: Barrier of heavy concrete construction common to Zone 42C and concrete

barrier with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46B (Ref. 9B.2.15.1.B.8)

Ceiling: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 57J (Ref. 9B.2.15.1.B.8)

2. Zone Access

- Open to Zone 52D
- Two Class B doors (pairs) in the 2-hour rated east wall to Zone 54

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Process radiation monitor
- Boronometer (abandoned in-place)
- Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   Cable insulation

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel

2. Secondary

   One portable CO_2 fire extinguisher

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Four 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.53 Fire Area XV, Fire Zone 54, Reactor Trip Switchgear Room and CEDM Control System

A. Location

Fire Zone 54 (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated walls common to Zone 52D

South: 3-hour rated wall common to Fire Area II at column line A10

East: 3-hour rated exterior wall at column line AL

3-hour rated wall common to the corridor building at column line AL

West: 2-hour rated walls common to Zone 53

Floor: Barrier of heavy concrete construction common to Zone 42C concrete barrier with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 46A (Ref. 9B.2.15.1.B.8)

Ceiling: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 57J (Ref. 9B.2.15.1.B.8)

2. Zone Access

- One nonrated missile door (pair) in the 3-hour rated east wall to the corridor building
- Two Class B doors (pairs) in the 2-hour rated west wall to Zone 53
- One Class B door (pair) in the 2-hour rated north wall to Zone 52D

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

(Refer to Fire Area XV deviations 2 and 8)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   - Train A and B reactor trip switchgear
   - Train A and B control element drive mechanism (CEDM) control cabinets

D. Nonsafety-Related Equipment and Components

   - Cable trays and conduit
   - CEDM control cabinet room normal ACU

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation
      - Oil and grease

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

   3. Total Combustible (Fire) Loading

      Moderate

G. Fire Detection

Ionization smoke detector system(s) and line-type thermal detector system(s) are provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 53. One manual hose reel is located in adjacent Zone 52D.

2. Secondary

One portable CO_2 fire extinguisher is located in adjacent Zone 53. One portable CO_2 fire extinguisher is located in adjacent Zone 52D.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Five 4-inch drains

K. Emergency Communication

Sound powered phone jack(s) is provided.

9B.2.15.54 Fire Area XV, Fire Zone 55A, Personnel Access Hatch Area

A. Location

Fire Zone 55A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated exterior wall at column line Al

South: Open to Zone 55C

Open to Zone 55E

East: 3-hour rated wall common to Fire Area XI

2-hour rated wall common to Zone 56A at column line AC2

West: 3-hour rated wall common to Fire Area VI at column line AA

2-hour rated wall common to the west elevator

Floor: 2-hour rated barrier common to Fire Area XVI, Zone 47A

2-hour rated barrier common to Zone 52A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One Class A door (pair) in the 3-hour rated west wall to Fire Area VI (Fuel Building)
- Open to Zone 55C

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

NOTE

Containment penetrations are of special construction, but not fire-rated.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Cable trays and conduit

- Personnel access hatch to the containment building

E. Radioactive Material

Area containing radioactive materials

F. Combustible Loading

1. In Situ Combustible Load Type

   - Fabric and paper
   - Cable insulation
   - Grease and oil
   - Plastic
   - Rubber

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   Automatic wet pipe sprinkler system

2. Secondary

One manual hose reel is located in Zone 57N. One portable pressurized water fire extinguisher is located in adjacent Zone 55C.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.55 Fire Area XV, Fire Zone 55C, Clothing Storage

A. Location

Fire Zone 55C (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Open to Zone 55A

South: 1-hour rated wall common to Zone 57N at column A6

East: Nonrated block wall common to Zone 55E

West: 2-hour rated wall common to the west stairwell at column line AA

Floor: 2-hour rated barrier common to Fire Area XVI, Zone 47A

2-hour rated barrier common to Zone 52A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One Class B door in the 2-hour rated west wall to the west stairwell
- One certified door (pair) in the 1-hour rated south wall to Zone 57N (See response to Question 9A.106)
- Open to Zone 55A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

Train A conduits

D. Nonsafety-Related Equipment and Components

Cable trays and conduit

E. Radioactive Material

Area containing radioactive materials

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Rubber
- Plastic
- Fabric
- Paper

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

Automatic wet pipe sprinkler system

2. Secondary

Hose station located in adjacent Zone 57N

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.56 Fire Area XV, Fire Zone 55E, Decontamination Washdown Area

A. Location

Fire Zone 55E (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Open to Zone 55A

South: 1-hour rated wall common to Zone 57N at column line A6

East: 2-hour rated wall common to Zone 56A at column line AC2

West: Nonrated block wall common to Zone 55C

Floor: 2-hour rated barrier common to Fire Area XVI, Zone 47A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

Open to Zone 55A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

Area containing radioactive clothing

F. Combustible Loading

1. In Situ Combustible Load Type

- Fabric
- Rubber

2. Transient Combustible Load Type

Ordinary combustible

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

Automatic wet pipe sprinkler system

2. Secondary

Hose station located in adjacent Zone 57N

One pressurized water fire extinguisher is located in adjacent Zone 55C.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.15.57 Fire Area XV, Fire Zone 56A, Storage and Electrical Room (West)

A. Location

Fire Zone 56A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XI

South: 1-hour rated wall common to Zone 57N at column A6

East: Nonrated wall of heavy concrete construction common to the south access shaft

West: 2-hour rated wall common to Zones 55A and 55E at column line AC2

Floor: 2-hour rated barrier common to Fire Area XVI, Zone 47A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

   One Class C door (pair) in the 1-hour rated south wall to Zone 57N

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

   NOTE

   Containment penetrations are of special construction, but not fire-rated.

4. Fire Dampers

   Duct penetrations in the rated fire barrier are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train A containment refueling purge supply isolation damper
- Train A containment power ascension purge supply isolation damper

D. Nonsafety-Related Equipment and Components

- Conduit

- Storage of miscellaneous items

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Oil and grease
   - Cable insulation
   - Charcoal
   - Fabric
   - Paper
   - Wood
   - Plastic
   - Rubber

2. Transient Combustible Load Type

   - Ordinary combustible
   - Plastic

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

Automatic wet pipe sprinkler system

2. Secondary

One manual hose reel is located in adjacent Zone 57N

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.58 Fire Area XV, Fire Zone 56B, Storage and Electrical Equipment Room (East)

A. Location

Fire Zone 56B (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XII

South: 1-hour rated wall common to Zones 57N and 57J at column line A6

East: 1-hour rated wall common to Zone 56C

Nonrated wall of heavy concrete construction common to Zone 56C

West: Nonrated wall of heavy concrete construction common to the south access shaft at column line AG

3-hour rated wall common to Fire Area XI

Floor: 3-hour rated barrier common to Fire Area XVII, Zone 47B

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One Class C door in the 1-hour rated south wall to Zone 57J
- One nonrated door (pair) in the nonrated east wall to Zone 56C

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   - Train B containment refueling purge exhaust isolation damper
   - Train B containment refueling purge exhaust pump
   - Train B containment power ascension purge exhaust isolation damper
   - Containment purge exhaust radiation monitor

D. Nonsafety-Related Equipment and Components

   - Motor control centers
   - Load center
   - Cable trays and conduit
   - Containment purge exhaust radiation monitor
   - Storage of miscellaneous items

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Cable insulation

- Oil and grease
- Plastic

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

Automatic wet pipe sprinkler system

2. Secondary

One manual hose reel is located in adjacent Zone 57N. One ABC powder fire extinguisher is located in adjacent Zone 56C.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.59 Fire Area XV, Fire Zone 56C, Northeast Corridor

A. Location

Fire Zone 56C (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated common to Fire Area XII

South: Open to Zone 57N at column line A6

East: 3-hour rated exterior wall at column line AL

2-hour rated walls common to the east stairwell

West: 1-hour rated wall common to Zone 56B. Nonrated wall of heavy concrete construction common to Zone 56B

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 52D (Ref. 9B.2.15.1.B.8)

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

    - One Class B door in the 2-hour rated west wall of the east stairwell

    - One non-rated door (pair) in the non-rated portion of the west wall to Zone 56B

    - Open to Zone 57N

3. Sealed Penetrations

    Seals equal or exceed fire barrier ratings.

    (Refer to Fire Area XV deviation 8)

4. Fire Dampers

    Duct penetrations in the rated fire barrier are provided with fire dampers of equal or greater rating.

5. Protected Raceways

    None

6. Protected Structural Members

    None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

    None

D. Nonsafety-Related Equipment and Components

    - Cable trays and conduit

    - Domestic hot water heaters

- Monorail

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   Cable insulation

2. Transient Combustible Load Type

   - Ordinary combustible
   - Cable insulation

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   Automatic wet pipe sprinkler system

2. Secondary

   One portable ABC powder fire extinguisher

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.60 Fire Area XV, Fire Zone 57A, Hot Laboratory

A. Location

Fire Zone 57A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of metal lath and plaster common to Zone 57B

1-hour rated wall common to Zone 57N

South: 1-hour rated wall common to Zone 57N at column A8

East: Nonrated wall of heavy concrete construction common to Zone 57K at column AE

Nonrated wall of metal lath and plaster common to Zone 57B at column line AD

2-hour rated wall common to Zone 57P at column line AD

West: Nonrated walls of heavy concrete construction common to Zones 57C and 57D

Floor: Nonrated barrier of heavy concrete construction common to Zones 49H and 52A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One Class C door in the 1-hour rated north wall to Zone 57N
- One certified door in the 1-hour rated south wall to Zone 57N (See response to Question 9A.106)
- One nonrated door in the nonrated east wall to Zone 57K

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

(Refer to Fire Area XV deviation 8)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Laboratory equipment and fume hoods
- Conduit

E. Radioactive Material

Area containing components designed for collecting and testing for radioactivity.

F. Combustible Loading

1. In Situ Combustible Load Type
   - Paper and fabric
   - Rubber
   - Cable insulation
   - Lubricating oil
   - Resin
   - Wood
   - Organic chemicals
   - Oxygen (oxidizer)
   - Plastic
2. Transient Combustible Load Type
   - Ordinary combustible

- Oxygen (oxidizer)

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

   Ionization smoke detector system(s), both above and below the suspended ceiling, is provided for early warning.

H. Fire Suppression

   1. Primary

      Two ABC powder and one CO_2 fire extinguishers

   2. Secondary

      One manual hose reel is located in adjacent Zone 57N

I. Ventilation

   Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

   Three 4-inch drains

K. Emergency Communications

   Sound powered phone jack(s) is provided

9B.2.15.61 Fire Area XV, Fire Zone 57B, Cylinder Storage Area

A. Location

Fire Zone 57B (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	2-hour rated wall common to Zone 57P
South:	Nonrated wall of metal lath and plaster construction common to Zone 57A
East:	1-hour rated wall common to Zone 57N
West:	Nonrated wall of metal lath and plaster construction common to Zone 57A at column line AD
Floor:	Nonrated barrier of heavy concrete construction common to Zone 52A
Ceiling:	Nonrated roof of heavy concrete construction

2. Zone Access

Nonrated door in the nonrated west wall to Zone 57A

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

   (Refer to Fire Area XV deviation 8)

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Hydrogen
      - Rubber
      - Oxygen (oxidizer)

- Nitrous Oxide (oxidizer)

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel is located in Zone 57N.

2. Secondary

   Two ABC powder fire extinguishers and one CO_2 fire extinguisher are located in adjacent Zone 57A.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.62 Fire Area XV, Fire Zone 57C, Sample Room

A. Location

Fire Zone 57C (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to a pipe chase

1-hour rated wall common to Zone 57N

South: Nonrated walls of heavy concrete construction common to Zones 57A and 57D

East: Nonrated wall of heavy concrete construction common to Zone 57A

West: Nonrated wall of heavy concrete construction common to Zone 57H

Floor: Nonrated barrier of heavy concrete construction common to Zones 48 and 52A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

Nonrated door in the nonrated east wall to Zone 57A

3. Sealed Penetrations

   Seals equal or exceed fire barrier rating

   (Refer to Fire Area XV deviation 8)

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Laboratory equipment and two fume hoods.
   - Conduit

E. Radioactive Material

   Area containing radioactive materials.

F. Combustible Loading

   1. In Situ Combustible Load Type

      Plastic

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   Two portable ABC powder fire extinguishers are located in adjacent Zone 57A.

2. Secondary

   One portable CO_2 fire extinguisher is located in adjacent Zone 57A.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Three 4-inch drains

K. Emergency Communications

None

9B.2.15.63 Fire Area XV, Fire Zone 57D, Counting Room

A. Location

Fire Zone 57D (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zones 57C and 57H at column line A7

South: 1-hour rated wall common to Zone 57N at column line A8

East: Nonrated wall of heavy concrete construction common to Zone 57A

West: 1-hour rated wall common to Zone 57N at column line AB

Floor: Nonrated barrier of heavy concrete construction common to Zone 48

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

One nonrated door in the nonrated east wall to Zone 57A

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

   (Refer to Fire Area XV deviation 8)

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Laboratory equipment
- Conduit

E. Radioactive Material

Area containing radioactive materials.

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Charcoal

- Paper and fabric
- Plastic
- Rubber
- Wood
- Organics
- Acetone

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One portable ABC powder fire extinguisher and one portable CO_2 fire extinguisher

2. Secondary

   One manual hose reel is located in Zone 57N.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.64 Fire Area XV, Fire Zone 57E, Sample Counting Room

A. Location

Fire Zone 57E (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 1-hour rated wall common to Zone 57N

South: 1-hour rated wall common to Zone 57N

Nonrated wall of heavy concrete construction common to Zone 57M

East: Nonrated wall of metal lath and plaster construction common to Zone 57F

West: 1-hour rated wall common to Zone 57N

Floor: Nonrated barrier of heavy concrete construction common to Zone 48

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

    - One Class C door in the 1-hour rated west wall to Zone 57N
    - One Class C door in the 1-hour rated north wall to Zone 57N

3. Sealed Penetrations

    Seals equal or exceed fire barrier ratings.

    (Refer to Fire Area XV deviation 8)

4. Fire Dampers

    Duct penetrations in the fire-rated barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

    None

6. Protected Structural Members

    None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Laboratory equipment
- Conduit

E. Radioactive Material

Area containing radioactive materials.

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Paper and fabric
- Rubber
- Wood
- Plastic

2. Transient Combustible Load Type

Ordinary combustible

3. Total Combustible (Fire) Loading

Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 57N.

2. Secondary

One pressurized water fire extinguisher is located in adjacent Zone 57N.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.65 Fire Area XV, Fire Zone 57F, Personnel Decontamination and Radiation Protection Workroom

A. Location

Fire Zone 57F (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 1-hour rated wall common to Zone 57N

South: Nonrated masonry block wall common to Zone 57M

East: Nonrated wall of metal lath and plaster construction common to Zone 57G

West: Nonrated wall of metal lath and plaster construction common to Zone 57E

Floor: Nonrated barrier of heavy concrete construction common to Zones 48 and 50A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

Three Class C doors in the 1-hour rated north wall to Zone 57N

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

(Refer to Fire Area XV deviation 8)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Laboratory equipment

- Conduit

E. Radioactive Material

Area containing radioactive materials.

F. Combustible Loading

1. In Situ Combustible Load Type

    - Organics
    - Rubber
    - Cable insulation
    - Paper and fabric
    - Plastic

2. Transient Combustible Load Type

    Ordinary combustible

3. Total Combustible (Fire) Loading

    Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

    One manual hose reel is located in adjacent Zone 57N

2. Secondary

   One pressurized water fire extinguisher is located in Zone 57N.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.15.66 Fire Area XV, Fire Zone 57G, First Aid Room

A. Location

Fire Zone 57G (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

   North: 1-hour rated wall common to Zone 57N

   South: Nonrated masonry block wall common to Zone 57M

   East: Nonrated wall of heavy concrete construction common to Zone 57L at column line AE

West: Nonrated wall of metal lath and plaster common to Zone 57F

Floor: Nonrated barrier of heavy concrete construction common to Zone 50A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

One certified door (pair) in the 1-hour rated north wall to Zone 57N (See response to Question 9A.106)

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

(Refer to Fire Area XV deviation 8)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Laboratory equipment
- Conduit

E. Radioactive Material

Area containing radioactive material

F. Combustible Loading

1. In Situ Combustible Load Type

    - Paper and fabric
    - Rubber
    - Plastic
    - Wood
    - Organics

2. Transient Combustible Load Type

    Ordinary combustible

3. Total Combustible (Fire) Loading

    Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

    One manual hose reel is located in adjacent Zone 57N.

2. Secondary

One pressurized water fire extinguisher is located in adjacent Zone 57N.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.67 Fire Area XV, Fire Zone 57H, Hot Instrumentation and Control Shop

A. Location

Fire Zone 57H (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 1-hour rated wall common to Zone 57N

South: Nonrated wall of heavy concrete construction common to Zone 57D at column line A7

East: Nonrated wall of heavy concrete construction common to Zone 57C

1-hour rated wall common to Zone 57N

West: 1-hour rated wall common to Zone 57N

Floor: Nonrated barrier of heavy concrete construction common to Zone 52A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- Two Class C doors in the 1-hour rated west wall to Zone 57N
- One Class C door (pair) in the 1-hour rated north wall to Zone 57N

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

(Refer to Fire Area XV deviation 8)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-related Equipment and Components

- Domestic hot water heater
- Tools and equipment
- Conduit

E. Radioactive Material

Area containing radioactive material

F. Combustible Loading

1. In Situ Combustible Load Type
   - Hydrazine
   - Paper and fabric
   - Rubber
   - Plastic
2. Transient Combustible Load Type

   Ordinary combustible
3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

Automatic wet pipe sprinkler system

2. Secondary

One manual hose reel is located in adjacent Zone 57N. One pressurized water fire extinguisher is located in Zone 55C.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains

K. Emergency Communications

None

9B.2.15.68 <u>Fire Area XV, Fire Zone 57J, Locker Rooms, Operations Support Center, Radiation Protection Leads and Radiation Protection Island</u>

A. Location

Fire Zone 57J (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 1-hour rated wall common to Zone 57N and 56B

South: 3-hour rated wall common to Fire Areas I and II at column line A10

East: 3-hour rated exterior wall at column line AL

West: Nonrated wall of heavy concrete construction common to Zones 57K, 57L, 57M, and 57N at column line AG

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 50B, 51B, 52D, 53, and 54 (Ref. 9B.2.15.1.B.8)

Ceiling: Nonrated roof of heavy concrete construction

NOTE

The HVAC chase near column lines A7/AH is surrounded by 2-hour rated concrete walls.

2. Zone Access

- Two Class C doors (one pair) in the 1-hour rated east wall to Zone 57N at column line A6

- One Class C door in the 1-hour rated north wall to Zone 57N
- One pair of Class A doors in the 3-hour rated east wall to the corridor building
- One nonrated door in the nonrated west wall to Zone 57N
- Open at west side to corridor, Zone 57N, at column line A8

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

   (Refer to Fire Area XV deviation 8)

4. Fire Dampers

   Duct penetrations in the fire-rated barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Cable trays and conduit

- Supplies

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Paper and fabric
   - Charcoal
   - Rubber
   - Plastic
   - Wood
   - Methane (P-10 gas)

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

   Automatic wet pipe sprinkler system

2. Secondary

One manual hose reel, three pressurized water, and one CO_2 fire extinguisher

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Twelve 2-inch drains

K. Emergency Communications

None

9B.2.15.69 Fire Area XV, Fire Zone 57K, Cold Laboratory

A. Location

Fire Zone 57K (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 1-hour rated wall common to Zone 57N

South: 1-hour rated wall common to Zone 57N

East: Nonrated wall of heavy concrete construction common to Zone 57J at column line AG

West: Nonrated wall of heavy concrete construction common to Zone 57A at column line AE

Floor: Barrier of heavy concrete construction with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 49F, 50A and a concrete barrier with electrical and pipe penetrations sealed to a 3-hour rating common to Zones 51A and 52D (Ref. 9B.2.15.1.B.8)

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One certified door in the 1-hour rated south wall to Zone 57N (See response to Question 9A.106)
- One nonrated door in the nonrated west wall to Zone 57A

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

(Refer to Fire Area XV deviation 8)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Cable trays and conduit
   - Laboratory equipment

E. Radioactive Material

   None

F. Combustible Loading

   1. In-Situ Combustible Load Type

      - Cable insulation
      - Paper and fabric
      - Plastic
      - Rubber
      - Oil and grease
      - Diesel fuel oil
      - Organics
      - Wood

- Resin
- Mipolam floor

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

Ionization smoke detector system(s), both above and below the suspended ceiling, is provided for early warning.

H. Fire Suppression

1. Primary

   One dry portable ABC powder and one CO_2 fire extinguisher

2. Secondary

   One manual hose reel is located in adjacent Zone 57N

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

Two 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is available.

9B.2.15.70 Fire Area XV, Fire Zone 57L Chemistry

A. Location

Fire Zone 57L (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 1-hour rated wall common to Zone 57N

South: Nonrated masonry block wall common to Zone 57M

East: Nonrated wall of heavy concrete construction common to Zone 57J at column line AG

West: Nonrated wall of heavy concrete construction common to Zone 57G at column line AE

Floor: Nonrated barrier of heavy concrete construction common to Zone 50A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

One Class C door in the 1-hour rated north wall to Zone 57N

One certified door in the 1-hour rated north wall to Zone 57N (See response to Question 9A.106)

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

   (Refer to Fire Area XV deviation 8)

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   - Conduit
   - Radiation protection equipment

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

- Vinyl flooring
- Paper and fabric
- Rubber
- Cable insulation
- Plastic
- Wood

2. Transient Combustible Load Type

- Ordinary combustible
- Vinyl flooring

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

Two manual hose reels are located in adjacent Zones 57N and 57J.

2. Secondary

One portable ABC powder and portable CO_2 fire extinguishers are located in Zone 57K.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.71 Fire Area XV, Fire Zone 57M, Ion Exchangers Access Area

A. Location

Fire Zone 57M (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated masonry block wall common to Zones 57F, 57G, and 57L

South: 3-hour rated wall common to Fire Area X at column line A10

East: Nonrated wall of heavy concrete construction common to Zone 57J at column line AG

West: 1-hour rated concrete block wall common to Zone 57N

Floor: Nonrated barrier of heavy concrete construction common to Zones 48, 49E, and 49G

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

One Class C door (pair) in the 1-hour rated west wall to Zone 57N

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

- Monorail
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Plastic
- Cable insulation
- Rubber
- Paper fabric
- Wood

2. Transient Combustible Load Type

Ordinary combustible

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One manual hose reel is located in adjacent Zone 57N.

2. Secondary

One pressurized water fire extinguisher is located in adjacent Zone 57N.

I. Ventilation

Manually controlled smoke venting to adjacent zone where portable smoke removal equipment exhausts smoke to the outside.

J. Drainage

None

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.15.72 Fire Area XV, Fire Zone 57N, Corridor Area

A. Location

Fire Zone 57N (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: North Corridor - 1-hour rated walls common to Zones 55C, 55E, 56A, and 56B at column line A6

2-hour rated wall common to the east stairwell at column line A6

Open to Zone 56C at column line A6

Nonrated walls of heavy concrete construction

			common to the south tendon access shaft
	South Corridor	-	1-hour rated wall common to Zones 57A, 57D, and 57K at column line A8
South:	North Corridor	-	1-hour rated walls common to Zones 57A, 57B, 57C, 57H, and 57K
			2-hour rated walls common to Zone 57P
	South Corridor	-	1-hour rated wall common to Zones 57E, 57F, 57G, and 57L
	West Corridor	-	3-hour rated wall common to Fire Area X at column line A10
East:	North Corridor	-	3-hour rated exterior wall at column line AL
			Nonrated wall of metal lath and plaster construction common to Zone 57J at column line AG
	South Corridor	-	Open to Zone 57J at column line AG
	West Corridor	-	1-hour rated walls common to Zones 57D, 57E, 57H, and 57M

West:	North Corridor	-	2-hour rated wall common to the west stairwell at column line AA
	West Corridor	-	2-hour rated wall common to the west HVAC chase at column line AA
			Nonrated exterior wall of heavy concrete construction at column line AA
Floor:	North Corridor	-	Nonrated barrier of heavy concrete construction common to Zone 52A and a concrete barrier with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 52D (Ref. 9B.2.15.1.B.8)
	South Corridor	-	Nonrated barrier of heavy concrete construction common to Zones 48, 50A and a concrete barrier with electrical and pipe penetrations sealed to a 3-hour rating common to Zone 51B and 54 (Ref. 9B.2.15.1.B.8)

West Corridor - Nonrated barrier of heavy concrete construction common to Zones 48 and 52A

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One certified door (pair) in the 1-hour rated wall to Zone 55C (See response to Question 9A.106)
- Open to Zone 57J at column line AG
- One nonrated door at the nonrated wall to Zone 57J at column line AG
- One Class A door (pair) in the 3-hour rated wall to Fire Area X (Radwaste Building)

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

(Refer to Fire Area XV deviation 8)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Vinyl flooring
- Thermo-Lag 330-1
- Wood

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Ionization smoke detector system(s) is provided for early warning.

H. Fire Suppression

1. Primary

Four manual hose reels

2. Secondary

One pressurized water fire extinguisher

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

None

K. Emergency Communications

None

9B.2.15.73 Fire Area XV, Fire Zone 57P, Flammable Storage Area

A. Location

Fire Zone 57P (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 140 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to Zone 57N

South: 2-hour rated wall common to Zone 57B

East: 2-hour rated wall common to Zone 57N

West: 2-hour rated wall common to Zone 57A

Floor: Nonrated barrier of heavy concrete construction common to Zone 52A.

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

One Class B door (pair) in the 2-hour rated north wall to Zone 57N

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

(Refer to Fire Area XV deviation 8)

4. Fire Dampers

Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

Train A conduit

D. Nonsafety-Related Equipment and Components

- Acetylene cylinder

- Hydrogen cylinder
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Acetylene
   - Hydrogen
   - Plastic

2. Transient Combustible Load Type

   - Ordinary combustible
   - Acetylene

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

None

H. Fire Suppression

1. Primary

   One manual hose reel is located in the adjacent Zone 57N.

2. Secondary

Two portable ABC powder and one portable CO_2 fire S[Run WPS extinguisher are located in adjacent Zone 57A.

I. Ventilation

Flow through air filtration unit to outside

J. Drainage

None

K. Emergency Communications

None

9B.2.16 FIRE AREA XVI

9B.2.16.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area XVI (figures 9B-3 and 9B-4) contains the train A electrical penetration rooms of the auxiliary building at elevations 100 feet 0 inch and 120 feet 0 inch. This fire area includes Analysis Area XVIA (Zones 42A and 47A) (engineering drawing 13-A-ZYD-024).

Fire Area XVI is bounded to the north by a 3-hour rated barrier common to Fire Area XI, and a 3-hour rated exterior wall. Fire Area XVI is bounded to the west by a 3-hour rated barrier common to Fire Area VI, and by 2-hour rated barriers common to the north corridors of Fire Area XV. Fire Area XVI is

bounded to the south by a 2-hour rated barrier common to Fire Area XV, and to the east by a 2-hour rated barrier common to the south access shaft. The floor and ceiling are 1-hour and 2-hour rated barriers, respectively, common to Fire Area XV.

B. Deviations from 10CFR50, Appendix R, Section III.G

1. A deviation is requested from Section III.G.2 to the extent that it requires a 3-hour rated barrier between adjacent fire areas separating circuits of redundant trains.

<u>Discussion</u>

The mechanical and electrical penetrations in the containment boundary are not rated Mechanical containment penetrations are fitted with flued heads constructed of steel with a minimum thickness of 1/8 inch Electrical containment penetrations are fitted with a stainless steel header plate with a thickness of 1.78 inches. The special construction of the flued heads and header plates was designed to maintain the integrity of the containment building.

<u>Conclusion</u>

The existing design provides equivalent protection to that required by Section III.G.2. The design is standard within the industry.

9B.2.16.2 Analysis Area XVIA

A. Location

Analysis Area XVIA consists of Fire Zones 42A and 47A.

Fire Zone 42A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 100 feet 0 inch.

Fire Zone 47A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Fire Area XI

3-hour rated exterior wall at column line A1

South: 2-hour rated walls common to Fire Area XV, Zone 42D, at column lines A3 and A6 (Zone 42A)

2-hour rated wall common to Fire Area XV, Zone 52A, at column line A6 (Zone 47A)

East: 2-hour rated wall common to the south access shaft

West: 2-hour rated wall common to Fire Area XV, Zone 42D, at column line AB (Zone 42A)

3-hour rated wall common to Fire Area VI at column line AA

2-hour rated wall common to Fire Area XV, Zone 52A, at column line AB (Zone 47A)

Floor: 1-hour rated barrier common to Fire Area XV, Zone 37C

Ceiling: 2-hour rated barrier common to Fire Area XV, Zones 55A, 55C, 55E, and 56A

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Miscellaneous HVAC

  Nuclear cooling water

  Reactor coolant

  Ex-core neutron monitoring

  Main steam

  Safety injection and shutdown cooling

  Nuclear sampling

  Electrical power distribution

  Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Chemical and volume control

  Nuclear cooling water

  Reactor coolant

  Nuclear sampling

- Train A electrical penetration room essential air control unit and associated components
- Train A 480 V-ac Class 1E motor control centers
- Train A 125 V-dc distribution auxiliary relay cabinets

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided. The redundant train B system will remain available from the control room, in conjunction with operator action, outside of this analysis area to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.16.3 Fire Area XVI, Fire Zone 42A, Train A (Channel C) Electrical Penetration Room

A. Location

Fire Zone 42A (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XI

3-hour rated exterior wall at column line A1

South: 2-hour rated walls common to Fire Area XV, Zone 42D, at column lines A3 and A6

East: 2-hour rated wall common to the south access shaft

West: 2-hour rated wall common to Fire Area XV, Zone 42D, at column line AB

3-hour rated wall common to Fire Area VI at column line AA

Floor: 1-hour rated barrier common to Fire Area XV, Zone 37C

Ceiling: 2-hour rated barrier common to Zone 47A

2. Zone Access

   - One Certified door (pair) in the 2-hour rated south wall to Zone 42D (See response to question 9A.106)

   - One Class B door (pair) in the 2-hour rated west wall to Zone 42D

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

   NOTE

   Containment penetrations are of special construction, but not fire-rated.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Structural steel in this zone is protected by an automatic preaction ceiling level sprinkler system.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

- SCR power controller
- Pressurizer heater panels
- Load center
- Fuse boxes
- Motor control centers
- Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
    - Cable insulation
    - Plastic
    - Thermo-Lag 330-1
2. Transient Combustible Load Type
    - Ordinary combustible
    - Cable insulation
3. Total Combustible (Fire) Loading

    Low

G. Fire Detection

Actuation of either the ionization smoke detector or the line-type thermal detector systems activates an

early warning alarm and the automatic preaction system.

H. Fire Suppression

1. Primary

Automatic preaction sprinkler system covering the cable trays and structural columns

2. Secondary

One manual hose reel and one portable CO_2 fire extinguisher are located in adjacent Zone 42D.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Two 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.16.4 Fire Area XVI, Fire Zone 47A, Train A (Channel A) Electrical Penetration Room

A. Location

Fire Zone 47A (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XI

3-hour rated exterior wall at column line A1

South: 2-hour rated wall common to Fire Area XV, Zone 52A, at column line A6

East: 2-hour rated wall common to the south access shaft

West: 2-hour rated wall common to Fire Area XV, Zone 52A, at column line AB

3-hour rated wall common to Fire Area VI at column line AA

Floor: 2-hour rated barrier common to Zone 42A

Ceiling: 2-hour rated barrier common to Fire Area XV, Zones 55A, 55C, 55E, and 56A

2. Zone Access

- One Class B door in the 2-hour rated south wall to Zone 52A
- One Certified door (pair) in the 2-hour rated west wall to Zone 52A (See response to question 9A.106)

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

   NOTE

   Containment penetrations are of special construction, but not fire-rated.

4. Fire Dampers

   Duct penetrations in the fire-rated barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   None

6. Protected Structural Members

   Structural columns in this zone are protected by an automatic preaction ceiling level sprinkler system.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

- Cable insulation
- Plastic
- Thermo-Lag 330-1

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Low

G. Fire Detection

Actuation of either of the ionization smoke detector or of the line-type thermal detector systems activates the automatic preaction water sprinkler system and will pressurize the piping with water. Either detection system alone can provide an early warning alarm capability.

H. Fire Suppression

1. Primary

Automatic preaction water sprinkler system covering the cable trays and structural columns

2. Secondary

Two portable CO_2 fire extinguishers and one manual hose reel are located in adjacent Zone 52A.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Three 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.17 FIRE AREA XVII

9B.2.17.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area XVII (figures 9B-3 and 9B-4) contains the train B electrical penetration rooms of the auxiliary building at elevations 100 feet 0 inch and 120 feet 0 inch. This fire area includes Analysis Area XVIIA (Zones 42B and 47B) (engineering drawing 13-A-ZYD-024).

Fire Area XVII is bounded to the north by 3-hour rated barriers common to Fire Areas XI and XII, and to the west by a 2-hour rated barrier common to the south access shaft. Fire Area XVII is bounded to the south and east by 2-hour rated barriers common to the

north corridors of Fire Area XV. The floor and ceiling are 1-hour and 3-hour rated barriers, respectively, common to Fire Area XV.

B. Deviations from 10CFR50, Appendix R, Section III.G

1. A deviation is requested from Section III.G.2 to the extent that it requires a 3-hour rated barrier between adjacent fire areas separating circuits of redundant trains.

Discussion

The mechanical and electrical penetrations in the containment boundary are not rated. Mechanical containment penetrations are fitted with flued heads constructed of steel with a minimum thickness of 1/8 inch. Electrical containment penetrations are fitted with a stainless steel header plate with a thickness of 1.78 inches. The special construction of the flued heads and header plates was designed to maintain the integrity of the containment building.

Conclusion

The existing design provides equivalent protection to that required by Section III.G.2. The design is standard within the industry.

9B.2.17.2 Analysis Area XVIIA

A. Location

Analysis Area XVIIA consists of Fire Zones 42B and 47B

Fire Zone 42B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

Fire Zone 47B (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Analysis Area Boundaries

North: 3-hour rated wall common to Fire Area XI

3-hour rated wall common to Fire Area XII

South: 2-hour rated wall common to Fire Area XV, Zone 42C (elevation 100 feet 0 inch), at column line A6

2-hour rated wall common to Fire Area XV, Zone 52D (elevation 120 feet 0 inch), at column line A6

East: 2-hour rated wall common to Fire Area XV, Zone 42C (elevation 100 feet 0 inch)

2-hour rated wall common to Fire Area XV, Zone 52D (elevation 120 feet 0 inch)

West: 3-hour rated wall common to the south access shaft, at column line AG

Floor: 1-hour rated barrier common to Fire Area XV, Zone 37D

Ceiling: 3-hour rated barrier common to Fire Area XV, Zone 56B

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Auxiliary feedwater

  Auxiliary building HVAC

  Main steam

- Train B cables associated with the following systems:

  Auxiliary feedwater

  Chemical and volume control

  Condensate storage and transfer

  Essential chilled water

  Essential cooling water

  Auxiliary building HVAC

  Nuclear cooling water

  Reactor coolant

  Ex-core neutron monitoring

  Main steam

  Safety injection and shutdown cooling

  Nuclear sampling

Electrical power distribution

Engineered safety feature actuation

- Nontrain related cables associated with the following systems:

  Chemical and volume control

  Reactor coolant

- Train B electrical penetration room essential air control unit and associated components
- Train B 480 V-ac Class 1E motor control centers
- Train B 125 V-dc distribution auxiliary relay cabinets
- Auxiliary relay cabinet

D. Summary and Conclusion

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided. The redundant train A system will remain available from the control room, in conjunction with operator action, outside of this analysis area to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.2.

9B.2.17.3 Fire Area XVII, Fire Zone 42B, Train B (Channel B) Electrical Penetration Room

A. Location

Fire Zone 42B (engineering drawing 13-A-ZYD-023) is located in the auxiliary building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XI

3-hour rated wall common to Fire Area XII

South: 2-hour rated wall common to Fire Area XV, Zone 42C, at column line A6

East: 2-hour rated wall common to Fire Area XV, Zone 42C

West: 3-hour rated wall common to the south access shaft, at column line AG

Floor: 1-hour rated barrier common to Fire Area XV, Zone 37D

Ceiling: 2-hour rated barrier common to Zone 47B

2. Zone Access

   - One Certified door (pair) in the 2-hour rated east wall to Zone 42C (See response to question 9A.106)

   - One Class B door in the 2-hour rated south wall to Zone 42C

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

   NOTE

   Containment penetrations are of special construction, but not fire-rated.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   Train A auxiliary building HVAC conduits are enclosed by 1-hour protective envelopes.

6. Protected Structural Members

   Structural columns in this zone are protected by an automatic preaction ceiling level sprinkler system.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   Auxiliary relay cabinet

D. Nonsafety-Related Equipment and Components

- Cable trays and conduit
- 125 V-dc distribution panel
- Voltage regulators
- Motor control center
- Containment atmosphere radiation monitor

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Cable insulation
   - Plastic
   - Rubber
   - Thermo-Lag 330-1
2. Transient Combustible Load Type
   - Ordinary combustible
   - Cable insulation
3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

Actuation of either the ionization smoke detector and/or line-type thermal detector systems activates

an alarm and the automatic preaction sprinkler system. Either detector system alone can provide early warning capability.

H. Fire Suppression

1. Primary

Automatic preaction water sprinkler system, covering cable trays and structural columns

2. Secondary

One manual hose reel and one portable CO_2 fire extinguisher are located in adjacent Zone 42C.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Two 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.17.4 Fire Area XVII, Fire Zone 47B, Train B (Channel D) Electrical Penetration Room

A. Location

Fire Zone 47B (engineering drawing 13-A-ZYD-024) is located in the auxiliary building at elevation 120 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 3-hour rated wall common to Fire Area XI

3-hour rated wall common to Fire Area XII

South: 2-hour rated wall common to Fire Area XV, Zone 52D, at column line A6

East: 2-hour rated wall common to Fire Area XV, Zone 52D

West: 3-hour rated wall common to the south access shaft at column line AG

Floor: 2-hour rated barrier common to Zone 42B

Ceiling: 3-hour rated barrier common to Fire Area XV, Zone 56B

2. Zone Access

- One Class B door in the 2-hour rated south wall to Zone 52D
- One Certified door (pair) in the 2-hour rated east wall to Zone 52D (See response to question 9A.106)

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   Duct penetrations in the rated fire barriers are provided with fire dampers of equal or greater rating.

5. Protected Raceways

   Train A auxiliary Building HVAC conduits are enclosed by 1-hour protective envelopes.

6. Protected Structural Members

   Structural columns in this zone are protected by a water spray system.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

- Train B containment atmosphere radiation monitor

D. Nonsafety-Related Equipment and Components

- Electrical penetrations alarm panel
- Load center
- Auxiliary relay cabinet
- Cable trays and conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Thermo-Lag 330-1

- Cable insulation
- Plastic

2. Transient Combustible Load Type

- Ordinary combustible
- Cable insulation

3. Total Combustible (Fire) Loading

Moderate

G. Fire Detection

Actuation of either ionization smoke detector or the line-type thermal detector system(s) activates the automatic preaction water sprinkler system and will pressurize the piping with water. Either detector system can provide early warning capability.

H. Fire Suppression

1. Primary

Automatic preaction water sprinkler system covering cable trays and structural columns

2. Secondary

One portable CO_2 fire extinguisher and one manual hose reel are located in adjacent Zone 52D.

I. Ventilation

Manually controlled smoke exhaust venting to the outside using portable smoke removal equipment.

J. Drainage

Three 4-inch drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.18 FIRE AREA XVIII

9B.2.18.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area XVIII (figure 9B-3) contains train A diesel generator fuel oil storage components found in the outside areas. This fire area includes Analysis Area XVIIIA (Zone 78A) only (engineering drawing 13-A-ZYD-021).

Fire Area XVIII is located to the southwest of the diesel generator building (Fire Area IV). The Unit 1 and Unit 2 train A and train B (Fire Area XIX) diesel generator fuel oil storage tanks and pumps are buried side by side. The Unit 3 train B (Fire Area XIX) tank and pump are buried separate from Fire Area XVIII, to the southeast of the diesel generator building.

B. Deviations from 10CFR50, Appendix R, Section III.G

See subsection 9B.2.0 for generic deviations.

9B.2.18.2 Analysis Area XVIIIA

A. Location

Analysis Area XVIII consists of Fire Zone 78A.

Fire Zone 78A (engineering drawing 13-A-ZYD-021) is located at the outside areas below grade.

B. Analysis Area Boundaries

The diesel generator fuel oil storage tank is buried underground with earth coverage that is adequate for missile protection. Above the tank is a concrete vault, which includes a missileproof structural cover at grade level. The foundation of the vault is independent of the tank to avoid any load transfer to the tank shell.

C. Safe Shutdown Related Components and Cables

- Train A cables associated with the following systems:

  Diesel fuel oil and transfer

  Diesel generator

- Train A diesel generator fuel oil transfer pump and associated components

- Train A diesel generator fuel oil storage tank and associated components

D. Summary and Conclusion

Safe shutdown capability will be provided by utilizing redundant train B systems available from the control room.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.18.3 Fire Area XVIII, Fire Zone 78A, Train A Underground Diesel Generator Fuel Oil Storage Tank and Pump

A. Location

Fire Zone 78A (engineering drawing 13-A-ZYD-021) is located at the outside areas below grade.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

The diesel generator fuel oil storage tank is buried underground with earth coverage which is adequate for missile protection. Above the tank is a concrete vault which includes a missile-proof structural cover at grade level. The foundation of the vault is independent of the tank to avoid any load transfer to the tank shell.

2. Zone Access

- One nonrated manhole in the nonrated ceiling of the vault to the yard
- One nonrated hatch in the nonrated ceiling of the vault to the yard

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

Diesel Oil

2. Transient Combustible Load Type

   - Ordinary combustible
   - Diesel oil in tank truck

3. Total Combustible (Fire) Loading

   Due to a lack of oxygen, a fire in the buried tank and vault is not considered a credible event.

G. Fire Detection

None

H. Fire Suppression

Manual hose streams from hydrants on the yard fire main

I. Ventilation

None

J. Drainage

None

K. Emergency Communications

None

9B.2.19 FIRE AREA XIX

9B.2.19.1 Fire Area Description

A. Area Boundary Descriptions

Fire Area XIX (figure 9B-3) contains train B diesel generator fuel oil storage components found in the

outside areas. This fire area includes Analysis Area XIXA (Zone 78B) only (engineering drawing 13-A-ZYD-021).

Fire Area XIX of Units 1 and 2 is located to the southwest of the diesel generator building (Fire Area IV). The train A (Fire Area XVIII) and train B diesel generator fuel oil storage tanks and pumps are buried side by side. The Unit 3 train B tank and pump are buried separate from train A (Fire Area XVIII) to the southeast of the diesel generator building (Fire Area V).

B. Deviations From 10CFR50, Appendix R, Section III.G

See subsection 9B.2.0 for generic deviations.

9B.2.19.2 Analysis Area XIXA

A. Location

Analysis Area XIXA consists of Fire Zone 78B.

Fire Zone 78B (engineering drawing 13-A-ZYD-021) is located in the outside areas below grade.

B. Analysis Area Boundaries

The diesel generator fuel oil storage tank is buried underground with earth coverage that is adequate for missile protection. Above the tank is a concrete vault, which includes a missileproof structural cover at grade level. The foundation of the vault is independent of the tank to avoid any load transfer to the tank shell.

C. Safe Shutdown Related Components and Cables

- Train B cables associated with the following systems:

  Diesel fuel oil and transfer

  Diesel generator

- Train B diesel generator fuel oil transfer pump and associated components

- Train B diesel generator fuel oil storage tank and associated components

D. Summary and Conclusion

Safe shutdown capability will be provided by utilizing redundant train A systems available from the control room.

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.19.3 Fire Area XIX, Fire Zone 78B, Train B Underground Diesel Generator Fuel Oil Storage Tank and Pump

A. Location

Fire Zone 78B (engineering drawing 13-A-ZYD-021) is located in the outside areas below grade.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

   The diesel generator fuel oil storage tank is buried underground with earth coverage which is adequate for missile protection. Above the tank is a concrete vault which includes a missileproof structural cover at grade level. The foundation of the vault is independent of the tank to avoid any load transfer to the tank shell.

2. Zone Access

   - One nonrated manhole in the nonrated ceiling of the vault to the yard
   - One nonrated hatch in the nonrated ceiling of the vault to the yard

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

None

D. Nonsafety-Related Equipment and Components

Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

Diesel Oil

2. Transient Combustible Load Type

- Ordinary combustible
- Diesel oil in tank truck

3. Total Combustible (Fire) Loading

Due to a lack of oxygen, a fire in the buried tank and vault is not considered a credible event.

G. Fire Detection

None

H. Fire Suppression

Manual hose streams from hydrants on the yard fire main

I. Ventilation

None

J. Drainage

None

K. Emergency Communications

None

9B.2.20 MISCELLANEOUS ANALYSIS AREAS

The miscellaneous analysis areas described in item 9B.2.20 (figure 9B-3) contain components located in the turbine building, the corridor building and in the yard area. These analysis areas include Zones 79, 80, 81, the turbine building, the corridor building and the breezeway (engineering drawing 13-A-ZYD-021). These zones are found within each of the three PVNGS units. They contain some components (as noted in item C, Safe Shutdown Related Components and Cables), which may require operator actions for fires postulated in the control building or other safety-related areas. However, for fires that may occur in the following miscellaneous analysis areas, safe shutdown can be achieved and maintained from the control room, in conjunction with operator action, outside these analysis areas to achieve the shutdown function. Therefore, the fire barriers and fire protection equipment serving these miscellaneous areas are not required to be included in the fire protection quality assurance program. The portable fire extinguishers and hose stations located in the corridor building adjacent to the control building

have been classified as quality augmented (QAG) as they may be credited for use on fires in the control building.

9B.2.20.1 Turbine Building

A. Location

The analysis area is located to the east of the auxiliary building and main steam support structure.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of metal siding

South: Nonrated exterior wall of metal siding

2-hour rated exterior wall of masonry block construction at the turbine switchgear room

East: Nonrated exterior wall of metal siding

2-hour rated exterior wall of masonry block construction at the turbine switchgear room

West: Nonrated exterior wall of metal siding

2-hour rated exterior wall of concrete block construction at the turbine building battery room

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of built-up roofing on rigid insulation on metal decking

2. Analysis Area Access

One nonrated door in the nonrated north wall to the exterior at elevation 100 feet

One nonrated door in the nonrated north wall to the exterior at elevation 100 feet

Two nonrated doors in the nonrated east wall to the maintenance facility at elevation 100 feet

One Class B door in the 2-hour rated east wall of the turbine building switchgear room to the exterior at elevation 100 feet

One nonrated door in the nonrated east wall to the exterior at elevation 100 feet

Two nonrated doors in the nonrated south wall to the exterior at elevation 100 feet

One Class B door in the 2-hour rated west wall of the turbine building battery room to the exterior at elevation 100 feet

One nonrated door in the nonrated exterior west wall of stairway T112 at elevation 100 feet

One nonrated door in the nonrated east wall to the exterior at elevation 100 feet

One nonrated door in the nonrated west wall to the exterior at elevation 140 feet

One nonrated door in the nonrated west wall to the exterior at elevation 176 feet

3. Protected Raceways

   None

4. Protected Structural Members

   Two-hour rated fireproofing on beams and columns in the turbine building battery room

C. Safe Shutdown Related Components and Cables

- Nontrain related cables associated with the following system:

  Reactor coolant

- Train A auxiliary steam to auxiliary feedwater turbine isolation valve

D. Safety-Related Components and Cables Not Required for Safe Shutdown

   None

E. Nonsafety-Related Equipment and Components

- Balance-of-plant equipment
- Auxiliary feedwater pump and motor

F. Radioactive Material

   None

G. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation

- Oil, grease
- Fyrquel
- Resin
- Battery casing
- Hydrogen
- Charcoal
- Plastic (polyurethane and polisocyanurate foam, vinyl floor tile and cove molding)
- Wood

2. Transient Combustible Load Type

   - Cable insulation
   - Oil, grease
   - Fyrquel
   - Ordinary combustibles

3. Total Combustible (Fire) Loading

   High

H. Fire Detection

Smoke detectors in the feedwater pump area, at motor control centers, and in the switchgear and battery rooms at elevation 100 feet provide early warning. Smoke detectors near load and motor control centers at elevation provide early warning. Heat detectors in the lube oil room at elevation 140 feet actuate

the deluge system. Heat detectors in the hydrogen seal oil unit at elevation 140 feet actuate the deluge system and provide early warning. Thermal detectors at turbine bearings at elevation 176 feet provide early warning and preactivate the sprinkler system.

I. Fire Suppression

1. Primary

Automatic wet pipe sprinkler systems on elevations 100 feet and 140 feet. Automatic preaction sprinkler system covering the main turbine bearings at elevation 176 feet. Automatic deluge systems covering the feedwater pumps and lube oil centrifuge at elevation 100 feet. Automatic deluge system covering the lube oil room and hydrogen seal oil unit at elevation 140 feet. Manual deluge system covering the oil lines at the turbine bearings at elevation 176 feet.

2. Secondary

Hose stations and portable extinguishers are located throughout the area.

J. Ventilation

Manually controlled smoke venting to the outside.

K. Drainage

Numerous 4-inch drains

L. Emergency Communications

Telephones and sound powered telephone jacks throughout the area.

M. Summary and Conclusions

Safe shutdown capability will be provided by utilizing redundant systems available from the control room, in conjunction with operator action, outside this analysis area to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function

One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.20.2 Corridor Building

A. Location

The analysis area consists of the corridor building abutting the east side of the control building and auxiliary building.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of metal siding

South: Nonrated exterior wall of metal siding

East: Nonrated exterior wall of metal siding at column line JF and open to operations support building

West: 3-hour rated wall of the control building and the auxiliary building

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

One Class A door in the 3-hour rated west wall to Fire Area II, Zone 5B at elevation 100 feet

One nonrated door in the nonrated east wall to the exterior at elevation 100 feet

Open to the operations support building at the south wall of stairway A at 110 feet

One nonrated missile door in the 3-hour rated west wall to Fire Area II, Zone 14, at elevation 120 feet

One nonrated missile door in the 3-hour rated west wall to Fire Area XV, Zone 54, at elevation 120 feet

Open to the operations support building at the south wall of stairway A at 130 feet

One nonrated missile door in the 3-hour rated west wall to Fire Area III, Zone 17, at elevation 140 feet

One Class A door in the 3-hour rated west wall to Fire Area XV, Zone 57J, at elevation 140 feet

One nonrated door in the nonrated north wall to the exterior at elevation 140 feet

One Class C door in the 1-hour rated east wall of stairway A at elevation 140 feet

One nonrated door in the nonrated east wall to the operations support building at elevation 140 feet

Open to the operations support building at the south wall of stairway A at elevation 150 feet

One nonrated missile door in the 3-hour rated west wall to Fire Area I, Zone 20 at 160 feet

3. Protected Raceways

None

4. Protected Structural Members

1-hour fireproofing on all beams and columns between column line JE and column line JH

C. Safe Shutdown Related Components and Cables

- Nontrain related cables associated with the following systems:

Control building HVAC

Reactor coolant

D. Safety-Related Components and Cables Not Required for Safe Shutdown

None

E. Nonsafety-Related Equipment and Components

- Offsite power circuits
- Balance-of-plant cables
- Radio transmitter (160 feet)
- Preaction system valves for cable spreading rooms (120 feet and 160 feet)

F. Radioactive Material

None

G. Combustible Loading

1. In Situ Combustible Load Type
    - Cable insulation
    - Plastic, paper, wood
2. Transient Combustible Load Type
    - Cable insulation
    - Ordinary combustibles
3. Total Combustible (Fire) Loading

    Moderate

H. Fire Detection

Smoke detectors in balance-of-plant cable shaft for early warning

I. Fire Suppression

1. Primary

Hose stations

2. Secondary

Portable extinguishers

J. Ventilation

Manually controlled smoke venting to the outside

K. Drainage

None

L. Emergency Communications

Telephones

M. Summary and Conclusions

The following system is affected for a fire in this analysis area:

Control building HVAC

The following nontrain related system is affected for a fire in this analysis area:

Reactor Coolant

One train of systems necessary to achieve and maintain hot standby and cold shutdown, has been demonstrated to remain available for use based on

fire barriers provided. Either train A or train B systems will remain available from the control room, in conjunction with operator action, outside of this analysis area to prevent or overcome the consequences of spurious operation of components or to establish equipment lineups required to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.20.3 Fire Zone 79, Reactor Makeup Water Tank

A. Location

Analysis Area 79 consists of Fire Zone 79.

Fire Zone 79 (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Open to the yard

South: Open to the yard north of the holdup tank (Zone 80)

East: Adjacent to the nonrated west wall, of heavy concrete construction, of the fuel building (Fire Area VI)

West: Open to the yard

NOTE

The reactor makeup water tank is constructed of austenitic stainless steel.

2. Zone Access

Open to the yard (north, south, and west)

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safe Shutdown Related Components and Cables

- Nontrain related reactor makeup water tank and associated components

D. Safety-Related Components and Cables Not Required for Safe Shutdown

None

E. Nonsafety-Related Equipment and Components

- 5-kW heaters
- Conduit

F. Radioactive Material

Radioactive material in the tank

G. Combustible Exposure Fire Loading

1. In Situ Combustible Load Type

   Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible Exposure (Fire) Loading

   Low

H. Fire Detection

None

I. Fire Suppression

Manual hose stream from hydrants on the yard fire main

J. Ventilation

Natural convection

K. Drainage

None

L. Emergency Communications

None

M. Summary and Conclusions

No safe shutdown systems are affected for a fire in this analysis area.

Safe shutdown capability will remain available from the control room. One train of systems necessary to achieve hot standby and cold shutdown has been evaluated to remain available for safe shutdown in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.20.4 Fire Zone 80, Holdup Tank, Pump House, and Essential Pipe Tunnel

A. Location

Fire Zone 80 (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet. The essential pipe tunnel is at elevation 86 feet.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

NOTE

The holdup tank is located to the southwest of the fuel building which is of heavy concrete construction. The holdup tank is constructed of reinforced concrete with an austenitic stainless steel liner plate.

North: Holdup tank is open to the yard south of the reactor makeup water tank (Zone 79). Essential pipe tunnel common to nonrated concrete south wall of fuel building, Fire Area VI

South: Open to the yard

East: Open to the yard west of the refueling water tank (Zone 81). Essential pipe tunnel common to nonrated concrete west wall of Auxiliary Building, Fire Area XV.

West: Open to the yard

2. Zone Access

The essential pipe tunnel is accessed through the pump house at the west end.

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safe Shutdown and Safety-Related Equipment and Components

Train A and B piping

D. Nonsafety-Related Equipment and Components

- Holdup tank
- Conduit

- Heaters
- Sump pumps

E. Radioactive Material

Radioactive material in the tank and process piping

F. Combustible Loading

1. In Situ Combustible Load Type

   Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

Manual hose streams from hydrants on the yard fire main

I. Ventilation

Natural convection

J. Drainage

None

K. Emergency Communications

None

L. Summary and Conclusions

Normal shutdown is credited for a fire in this area. One train of safe shutdown equipment is expected to remain available due to fire barriers and spatial separation in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.20.5 Fire Zone 81, Refueling Water Tank

A. Location

Analysis Area 81 consists of Fire Zone 81.

Fire Zone 81 (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Adjacent to the nonrated south wall, of heavy concrete construction, of the fuel building (Fire Area VI)

South: Open to the yard north of the radwaste building and carbon dioxide storage unit

East: Adjacent to the nonrated west wall, of heavy concrete construction, of the auxiliary building

West: Open to the yard east of the holdup tank (Zone 80)

NOTE

The refueling water tank is constructed of reinforced concrete with an austenitic stainless steel liner plate.

2. Zone Access

   Open to the yard (south and west)

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safe Shutdown Related Components and Cables

- Train A and train B cables associated with the following system:

  Chemical and volume control

  Engineered safety feature actuation

- Refueling water tank, level transmitters, and associated components

D. Safety-Related Components and Cables Not Required for Safe Shutdown

None

E. Nonsafety-Related Equipment and Components

- Holdup pumps
- Heaters
- Conduit

F. Radioactive Material

Radioactive material in the tank

G. Combustible Loading

1. In Situ Combustible Load Type

   None

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

H. Fire Detection

None

I. Fire Suppression

Manual hose streams from hydrants on the yard fire main

J. Ventilation

Natural convection

K. Drainage

None

L. Emergency Communications

None

M. Summary and Conclusions

The following systems are affected for a fire in this analysis area:

Chemical and volume control and engineered safety feature actuation.

Based on other component losses for this analysis area, the loss of refueling water tank level indication will not adversely affect safe shutdown capability.

One train of systems necessary to achieve and maintain hot standby and cold shutdown has been demonstrated to remain available for use based on fire barriers provided. Either train A or train B systems will remain available from the control room to achieve the shutdown function, in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.20.6 Breezeway

A. Location

Along north side of the corridor building, the east side of the auxiliary and main steam support structure, and the west side of the turbine building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Open to the yard area

South: Adjacent to the nonrated north wall of the corridor building

East: Adjacent to the nonrated west wall of the turbine building

West: Adjacent to the 3-hour rated east wall of the auxiliary building and the nonrated east wall of the main steam support structure

Floor: Nonrated slab of concrete construction

Ceiling: Open

2. Zone Access

Open to yard (north and east)

3. Protected Raceways

None

4. Protected Structural Members

None

C. Safe Shutdown Related Components and Cables

- Nontrain related cables associated with the following system:

  Reactor coolant

- Heater drain pumps

- Condensate pumps
- Nuclear cooling water pumps

D. Safety-Related Components and Cables Not Required for Safe Shutdown

None

E. Nonsafety-Related Equipment and Components

None

F. Radioactive Material

None

G. Combustible Loading

1. In Situ Combustible Load Type

   Ordinary combustibles

2. Transient Combustible Load Type

   Ordinary combustibles

3. Total Combustible (Fire) Loading

   Low

H. Fire Detection

None

I. Fire Suppression

None

J. Ventilation

Natural convection

K. Drainage

None

L. Emergency Communications

Telephone

M. Summary and Conclusions

The following nontrain related system is affected for a fire in this analysis area:

Reactor coolant.

Safe shutdown capability will be provided by utilizing redundant systems available from the control room, in conjunction with manual actions, outside of this analysis area to prevent or overcome the consequences of spurious operation of components.

This area is in accordance with 10CFR50, Appendix R, Section III.G.

9B.2.21 MISCELLANEOUS FIRE ZONES

The miscellaneous fire zones (figure 9B-3) contain nonsafe shutdown related components found outside of the power block, in the yard area; this includes Zones 75A, 75B, 76, 77, 85A, 85B, 91A, 91B, 91C, 91D, 92A, 92B, 92C, 92D, 99A, 99B, 99C and 99D (engineering drawing 13-A-ZYD-021). The zones are found with each of the three PVNGS units, except for two facilities shared by all three units. These facilities are the decontamination and laundry facility (Zones 91A, 91B, 91C, and 91D), which is located south of the Unit 1 radwaste building,

and the fire pump house (Zones 92A, 92B, 92C, and 92D), which is located in the northeast section of the station.

9B.2.21.1 Fire Zone 75A, Main Transformers and Bus

A. Location

Fire Zone 75A (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to Zone 75B at column line 3

South: Open to the yard

East: Nonrated exterior wall of heavy concrete construction at column line P

West: Nonrated exterior wall of heavy concrete construction at column line F

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the atmosphere

NOTE

The three main transformers are separated by two 2-hour rated walls, one each at column lines J and N.

2. Zone Access

Open to the south (yard)

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

   Main transformers and bus

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Transformer oil
      - Grease

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

3. Total Combustible (Fire) Loading

High

G. Fire Detection

Heat-actuated detectors to activate the automatic water spray systems

H. Fire Suppression

1. Primary

Automatic water spray systems

2. Secondary

Manual hose streams from the hydrants on the yard fire main

I. Ventilation

Natural convection

J. Drainage

The main transformers are connected to sump drains.

K. Emergency Communications

None

9B.2.21.2 Fire Zone 75B, Auxiliary Transformer

A. Location

Fire Zone 75B (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall adjacent to the turbine building at column line 1

South: 2-hour rated wall common to Zone 75A at column line 3

East: Open to the yard

West: Nonrated wall of heavy concrete construction at column line H

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the atmosphere

2. Zone Access

Open to the east (yard)

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components

None

D. Nonsafety-Related Equipment and Components

- Auxiliary transformer and bus
- Neutral grounding resistors

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
    - Transformer oil
    - Grease
2. Transient Combustible Load Type
    - Ordinary combustible
    - Oil and grease
3. Total Combustible (Fire) Loading

    High

G. Fire Detection

Heat actuated detectors to actuate the automatic water spray systems

H. Fire Suppression

1. Primary

    Automatic water spray system

2. Secondary

    Manual hose streams from the hydrants on the yard fire main

I. Ventilation

Natural convection

J. Drainage

The auxiliary transformer is connected to a sump drain

K. Emergency Communications

None

9B.2.21.3 Fire Zone 76, ESF Service Transformers and Switchgear

A. Location

Fire Zone 76 (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

NOTE

There are two ESF service transformers with related 13.8 kV switchgear, one located to the west of the normal service transformers (Zone 77), the other to the east.

North:	Both transformers	-	2-hour rated wall common to the switchgear building at column line T7

South:	Both transformers	-	Open to the yard
East:	Western transformer	-	2-hour rated wall common to Zone 77 at column line B
	Eastern transformer	-	Open to the yard
West:	Western transformer	-	2-hour rated wall common to the yard at column line A
	Eastern transformer	-	2-hour rated wall common to Zone 77 at column line D
Floor:	Nonrated basemat of heavy concrete construction		
Ceiling:	Open to the atmosphere		

2. Zone Access

   Open to the yard (south and east)

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

- ESF service transformers and 13.8 kV switchgear
- Neutral grounding resistors

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Transformer oil
   - Grease
   - Rubber
2. Transient Combustible Load Type
   - Ordinary combustible
   - Oil and grease
3. Total Combustible (Fire) Loading

   High

G. Fire Detection

   Heat actuated detectors to actuate the automatic water spray system

H. Fire Suppression

1. Primary

Automatic water spray system (for ESF service transformer area)

2. Secondary

Manual hose streams from the hydrants on the yard fire main

I. Ventilation

Natural convection

J. Drainage

The ESF service transformers connected to sump drains

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.21.4 Fire Zone 77, Normal Service Transformers

A. Location

Fire Zone 77 (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated barrier common to the switchgear building at column line T7

South: Open to the yard

East: 2-hour rated barrier common to Zone 76, eastern ESF service transformer, at column line D

West: 2-hour rated barrier common to Zone 76, western ESF service transformer, at column line B

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Open to the atmosphere.

NOTE

Within Zone 77 the two normal service transformers are separated by a 2-hour rated barrier at column line C.

2. Zone Access

Open to the yard (south)

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components

None

D. Nonsafety-Related Equipment and Components

- Neutral grounding resistors
- Normal service transformers

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Transformer oil
   - Grease
   - Rubber
2. Transient Combustible Load Type
   - Ordinary combustible
   - Oil and grease
3. Total Combustible (Fire) Loading

   High

G. Fire Detection

Heat actuated detectors to actuate the automatic water spray systems.

H. Fire Suppression

1. Primary

   Automatic water spray systems

2. Secondary

Manual hose streams from the hydrants on the yard fire main

I. Ventilation

Natural convection

J. Drainage

The normal service transformers are connected to sump drains.

K. Emergency Communications

Sound powered phone jack(s) is provided.

9B.2.21.5 Fire Zone 85A, Common Auxiliary Boilers (Abandoned)

A. Location

Fire Zone 85A (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Open to the yard

South: Open to the yard north of the condensate water storage tank

East: Open to the yard

West: Open to the yard

2. Zone Access

   Open to the yard

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

   - Conduit
   - Common auxiliary boilers (abandoned)
   - Feed pumps
   - Force draft vents

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      None

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Burner front is protected by manual hose streams from hydrants on the yard fire main. Boiler does not contain or expose safety related equipment.

G. Fire Detection

None

H. Fire Suppression

1. Primary

   Manual hose streams from hydrants on the yard fire main

2. Secondary

   None

I. Ventilation

Natural convection

J. Drainage

None

K. Emergency Communications

None

9B.2.21.6 Fire Zone 85B, Lube Oil Storage Tanks

A. Location

Fire Zone 85B (engineering drawing 13-A-ZYD-021) is located in the outside areas at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Concrete dike common to the yard

South: Concrete dike common to the yard, north of the turbine building

East: Concrete dike common to the yard

West: Concrete dike common to the yard

NOTE

The concrete dike surrounding the two lube oil storage tanks is sized to contain the oil from a tank rupture. Each tank is constructed of carbon steel.

2. Zone Access

- Ladder access over the dike wall at the southeast corner
- Ladder access over the dike wall at the northwest corner

3. Sealed Penetrations

None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

- Dirty lube oil storage tank
- Clean lube oil storage tank
- Lube oil transfer pump
- Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

   Oil and grease

2. Transient Combustible Load Type

   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

High

G. Fire Detection

Heat-actuated detectors to actuate the automatic water spray system

H. Fire Suppression

1. Primary

Automatic water spray system

2. Secondary

Manual hose streams from hydrants on the yard fire main

I. Ventilation

Natural convection

J. Drainage

One 1-inch drain (normally capped) to remove rain water from inside the dike

K. Emergency Communications

None

9B.2.21.7 Fire Zone 91A, Clean Clothing Storage Area

A. Location

Fire Zone 91A (engineering drawing 13-A-ZYD-021) is located in the decontamination and laundry facility at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction at column line L1

Nonrated wall of heavy concrete construction common to Zone 91D at column line L5

South: Nonrated wall of heavy concrete construction common to Zone 91B at column line L1.2

East: Nonrated exterior wall of heavy concrete construction at column line LC.

West: Nonrated walls of heavy concrete construction common to Zone 91D at column lines LB.1 and LB.3

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One nonrated door in the nonrated west wall to Zone 91D
- One nonrated door in the nonrated south wall to Zone 91B

- One open pass-through window in the nonrated south wall to Zone 91B
- One nonrated door (pair) in the nonrated east exterior wall

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

   - Clean clothing
   - Protective clothing
   - Clothing radiation monitor
   - Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type

- Paper and fabric
- Plastic
- Rubber
- Cable insulation
- Lubricating oil

2. Transient Combustible Load Type

Ordinary combustible

3. Total Combustible (Fire) Loading

High

G. Fire Detection

None

H. Fire Suppression

1. Primary

One pressurized water fire extinguisher

2. Secondary

Manual hose stream from a hydrant on the yard fire main is available.

I. Ventilation

Flow through air filtration unit to outside

J. Drainage

None

K. Emergency Communications

None

9B.2.21.8 Fire Zone 91B, Bagged Contaminated Clothing Hold Area

A. Location

Fire Zone 91B (engineering drawing 13-A-ZYD-021) is located in the decontamination and laundry facility at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 91A at column line L1.2

Nonrated wall of heavy concrete construction common to Zone 91D at column line L1.3

South: Nonrated exterior wall of heavy concrete construction at column line L2

East: Nonrated exterior wall of heavy concrete construction at column line LC

West: Nonrated wall of heavy concrete construction common to Zone 91C at column line LB

Nonrated wall of heavy concrete construction common to Zone 91D at column line LB.1

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

- One nonrated door in the nonrated north wall to Zone 91A
- One open pass-through window in the nonrated north wall to Zone 91A
- One nonrated door (pair) in the nonrated east exterior wall

3. Sealed Penetrations

None

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components

None

D. Nonsafety-Related Equipment and Components

- Bagged contaminated clothing
- Protective clothing
- Drycleaning machines
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Paper and fabric
   - Cable insulation
   - Plastic
   - Wood
   - Rubber
   - Oil and grease
2. Transient Combustible Load Type
   - Ordinary combustible
   - Oil and grease
3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

1. Primary

One portable CO_2 and one pressurized water fire extinguisher

2. Secondary

Manual hose stream from a hydrant on the yard fire main is available.

I. Ventilation

Flow through air filtration unit to outside

J. Drainage

Five 4-inch drains

K. Emergency Communications

None

9B.2.21.9 Fire Zone 91C, Tools and Supplies Storage

A. Location

Fire Zone 91C (engineering drawing 13-A-ZYD-021) is located in the decontamination and laundry facility at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of heavy concrete construction common to Zone 91D at column line L1.3

South:	Nonrated exterior wall of heavy concrete construction at column line L2
East:	Nonrated wall of heavy concrete construction common to Zone 91B at column line LB
West:	Nonrated wall of heavy concrete construction common to Zone 91D at column line LA.4
Floor:	Nonrated basemat of heavy concrete construction
Ceiling:	Nonrated roof of heavy concrete construction

2. Zone Access

   One nonrated door in the nonrated north wall to Zone 91D

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

None

D. Nonsafety-Related Equipment and Components

- Tools and supplies
- Conduit

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Paper and fabric
   - Oil and grease
   - Plastic
   - Rubber
   - Wood
   - Cable insulation

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

None

H. Fire Suppression

Two portable CO_2 and two pressurized water fire extinguishers are located in adjacent Zone 91D. Manual hose stream from a hydrant on the yard fire main is available.

I. Ventilation

Flow through air filtration unit to outside

J. Drainage

None

K. Emergency Communications

None

9B.2.21.10 Fire Zone 91D, Contaminated and Clean Parts Laydown and Disassembly Areas

A. Location

Fire Zone 91D (engineering drawing 13-A-ZYD-021) is located in the decontamination and laundry facility at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of heavy concrete construction at column line L1

South: Nonrated exterior wall of heavy concrete construction at column line L2

Nonrated wall of heavy concrete construction common to Zone 91A at column line L5

Nonrated wall of heavy concrete construction common to Zones 91B and 91C at column line L1.3

East: Nonrated wall of heavy concrete construction common to Zone 91A at column line LB.3

Nonrated wall of heavy concrete construction common to Zones 91A and 91B at column line LB.1

Nonrated wall of heavy concrete construction common to Zone 91C at column line LA.4

West: Nonrated exterior wall of heavy concrete construction at column line LA

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of heavy concrete construction

2. Zone Access

   - One nonrated door in the nonrated north exterior wall
   - One nonrated door in the nonrated east wall to Zone 91A
   - One nonrated door in the nonrated south wall to Zone 91C
   - One nonrated door in the nonrated west exterior wall
   - One nonrated rollup door in the nonrated west exterior wall

3. Sealed Penetrations

   None

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

None

D. Nonsafety-Related Equipment and Components

- Turbulator

- Stainless steel tanks
- Ultrasonic clean system
- Decontamination spray booth
- Steamerette
- Pressure washer
- Two-ton monorail
- Sump and pump
- Conduit

E. Radioactive Material

Area designed to clean contaminated parts and equipment.

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Paper and fabric
   - Oil and grease
   - Plastic
   - Rubber
   - Wood

2. Transient Combustible Load Type

   Ordinary combustible

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

   None

H. Fire Suppression

1. Primary

   Two portable CO_2 and two pressurized water fire extinguishers

2. Secondary

   Manual hose stream from a hydrant on the yard fire main is available.

I. Ventilation

   Flow through air filtration unit to outside

J. Drainage

   Nine 4-inch drains

K. Emergency Communications

   None

9B.2.21.11 Fire Zone 92A, Fire Pump Room No. 1 and Fuel Oil Day Tank

A. Location

   Fire Zone 92A (engineering drawing 13-A-ZYD-021) is located in the fire pump house at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to Zone 92D

South: Nonrated exterior wall of concrete block construction at column line 1

East: Nonrated exterior wall of concrete block construction at column line A

West: 2-hour rated wall common to Zone 92C at column line B

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of Built-Up construction

NOTE

Fire Zone 92A includes the fuel day tank located to the southeast of the fire pump house.

2. Zone Access

- One Class B door in the 2-hour rated north wall to Zone 92D
- One nonrated door in the nonrated east exterior wall
- One nonrated rollup door in the nonrated east exterior wall
- One nonrated louver-damper in the nonrated south exterior wall

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

   - Fuel oil day tank
   - Fire water pump (diesel-driven)
   - Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Oil and grease
      - Diesel oil
      - Polycarbonate battery casing

2. Transient Combustible Load Type

- Oil and grease
- Ordinary combustible

3. Total Combustible (Fire) Loading

Moderate

G. Fire Detection

None

H. Fire Suppression

1. Primary

Automatic wet pipe sprinkler system

2. Secondary

One portable CO_2 fire extinguisher

I. Ventilation

Flow to outside

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.21.12 Fire Zone 92B, Fire Pump Room No. 3 and Fuel Oil Day Tank

A. Location

Fire Zone 92B is located in the fire pump house at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated wall common to Zone 92D

South: Nonrated exterior wall of concrete block construction at column line 1

East: 2-hour rated wall common to Zone 92C at column line C

West: Nonrated exterior wall of concrete block construction at column line D

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of Build-Up construction

NOTE

Fire Zone 92B includes the fuel day tank located to the southwest of the fire pump house.

2. Zone Access

- One Class B door in the 2-hour rated north wall to Zone 92D
- One nonrated door in the nonrated west exterior wall
- One nonrated rollup door in the nonrated west exterior wall
- One nonrated louver damper in the nonrated south exterior wall

3. Sealed Penetrations

   Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

   - Fire water pump (diesel-driven)
   - Fuel oil day tank
   - Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Oil and grease
      - Diesel fuel
      - Polycarbonate battery casing

2. Transient Combustible Load Type

   - Oil and grease
   - Ordinary combustible

3. Total Combustible (Fire) Loading

   Moderate

G. Fire Detection

None

H. Fire Suppression

1. Primary

   Automatic wet pipe sprinkler system

2. Secondary

   One portable CO_2 fire extinguisher

I. Ventilation

Flow to outside

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.21.13 Fire Zone 92C, Fire Pump Room No. 2

A. Location

Fire Zone 92C (engineering drawing 13-A-ZYD-021) is located in the fire pump house at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated wall of concrete block construction common to Zone 92D

South: Nonrated exterior wall of concrete block construction at column line 1

East: 2-hour rated wall common to Zone 92A at column line B

West: 2-hour rated wall common to Zone 92B at column line C

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of Built-Up construction

2. Zone Access

- One nonrated door in the nonrated north wall to Zone 92D

- One nonrated louver damper in the nonrated south exterior wall

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

   - Jockey pump
   - Fire water pump (electric motor-driven)
   - Conduit

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      Oil and grease

   2. Transient Combustible Load Type

      - Ordinary combustible
      - Oil and grease

   3. Total Combustible (Fire) Loading

      Low

G. Fire Detection

   None

H. Fire Suppression

1. Primary

One portable CO_2 fire extinguisher

2. Secondary

Manual hose stream from a hydrant on the yard fire main is available. One portable CO_2 fire extinguisher is located in each of adjacent Zones 92A, 92B, and 92D.

I. Ventilation

Flow to outside

J. Drainage

One 4-inch drain

K. Emergency Communications

None

9B.2.21.14 Fire Zone 92D, Domestic Water Pump Room

A. Location

Fire Zone 92D (engineering drawing 13-A-ZYD-021) is located in the fire pump house at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: Nonrated exterior wall of concrete block construction at column line 3

South: 2-hour rated walls common to Zones 92A and 92B

Nonrated wall of concrete block construction common to Zone 92C

East: Nonrated exterior wall of concrete block construction at column line A

West: Nonrated exterior wall of concrete block construction at column line D

Floor: Nonrated basemat of heavy concrete construction

Ceiling: Nonrated roof of Built-Up construction

2. Zone Access

- One Class B door in the 2-hour rated south wall to Zone 92A
- One Class B door in the 2-hour rated south wall to Zone 92B
- One nonrated door in the nonrated south wall to Zone 92C
- One nonrated rollup door in the nonrated east exterior wall
- Two nonrated louver dampers in the nonrated north exterior wall

3. Sealed Penetrations

Seals equal or exceed fire barrier ratings.

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

- Domestic water transfer pumps
- Well water booster pumps
- Conduit

E. Radioactive Material

   None

F. Combustible Loading

1. In Situ Combustible Load Type
   - Oil and grease
   - Plastic
2. Transient Combustible Load Type
   - Ordinary combustible
   - Oil and grease

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

   None

H. Fire Suppression

1. Primary

   One portable CO_2 fire extinguisher

2. Secondary

   Manual hose stream from a hydrant on the yard fire main is available. One portable CO_2 fire extinguisher is located in each of adjacent Zones 92A, 92B, and 92C.

I. Ventilation

   Flow to outside

J. Drainage

   Three 4-inch drains

K. Emergency Communications

   None

9B.2.21.15 Low Level Radioactive Materials Storage Facility (LLRMSF)

A. Location

   The LLRMSF is located approximately 500 feet northeast of the Unit 1 cooling towers.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:

South:

East:

West: All are non-rated exterior walls of heavy precast concrete construction.

Floor: Non-rated basemat of heavy concrete construction.

Roof: Non-rated roof of precast concrete construction.

2. Zone Access

- Non-rated personnel access doors in the non-rated east and south walls.
- Non-rated roll-up doors in the non-rated east and south walls.

3. Sealed Penetrations

Non-fire rated seals are provided for radiation shielding.

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

   All precast concrete construction.

C. Safety-Related Equipment and Components Not Required for Safe Shutdown

   None

D. Nonsafety-Related Equipment and Components

   Area radiation monitors

E. Radioactive Material

   Area containing radioactive material

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Ordinary combustibles (rack storage to 16 feet)
      - Paper, plastic, rubber, resin
      - Wood pallets

   2. Transient Combustibles

      - Ordinary combustibles including radioactive materials
      - Vehicles in truck bay

   3. Total Combustible (Fire) Loading

      High

G. Fire Detection

   Photoelectric detector in the HVAC duct

H. Fire Suppression

1. Primary

Wet pipe sprinkler system

2. Secondary

One manual hose station

I. Ventilation

Manually controlled smoke exhaust venting to the outside portable smoke removal equipment.

J. Drainage

Retention within building

K. Emergency Communications

None

9B.2.21.16 Fire Zone 99A, Power Potential Transformer (PPT) "A" (In those units with DMWO 3771114 implemented)

A. Location

Fire Zone 99A (engineering drawing 13-A-ZYD-021) is located in the outside areas, adjacent to the plant southeast corner of the Turbine Building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated exterior refractory composite removable wall at column line 7

Note that the height of this wall (facing the Turbine Building) is extended to 24 feet above grade in order to ensure the spatial separation (line of sight) requirements of NFPA 850.

South: 2-hour rated exterior wall of concrete construction at column line 8

East: 2-hour rated wall of concrete construction common to Zone 99B at column line S

West: 2-hour rated exterior wall of concrete construction at column line R

Note that the height of this wall (facing the Turbine Building) is extended to 24 feet above grade in order to ensure the spatial separation (line of sight) requirements of NFPA 850.

Floor: Non-rated basemat of concrete construction with a 12” layer of rock over a sump pit

Ceiling: Open to the atmosphere

2. Zone Access

- One non-rated security gate in the 2-hour rated south exterior wall at column line 8
- One 3’ by 7’ opening in the 2-hour rated east wall to Fire Zone 99B at column line S

3. Sealed Penetrations

Sealed equal or exceed fire barrier rating

4. Fire Dampers

None

5. Protected Raceways

None

6. Protected Structural Members

None

C. Safety-Related Equipment and Components

None

D. Nonsafety-Related Equipment and Components

- Power Potential Transformer and bus

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

- Transformer oil

2. Transient Combustible Load Type

   - Ordinary Combustible
   - Oil

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

None

H. Fire Suppression

1. Primary

   Manual spray from single nozzle installed inside cubicle from hydrants on the yard main

2. Secondary

   Manual hose streams from the hydrants on the yard fire main

I. Ventilation

Natural convection

J. Drainage

The Power Potential Transformer is connected to a sump drain

K. Emergency Communications

None

9B.2.21.17 Fire Zone 99B, Power Potential Transformer (PPT) "B" (In those units with DMWO 3771114 implemented)

A. Location

Fire Zone 99B (engineering drawing 13-A-ZYD-021) is located in the outside areas, adjacent to the plant southeast corner of the Turbine Building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North:	2-hour rated exterior refractory composite removable wall at column line 7
South:	2-hour rated exterior wall of concrete construction at column line 8
East:	2-hour rated wall of concrete construction common to Zone 99C at column line T
West:	2-hour rated wall of concrete construction common to Zone 99A at column line S
Floor:	Non-rated basemat of concrete construction with a 12" layer of rock over a sump pit
Ceiling:	Open to the atmosphere

2. Zone Access

   - One 3’ by 7’ opening in the 2-hour rated east wall to Fire Zone 99C at column line T

   - One 3’ by 7’ opening in the 2-hour rated west wall to Fire Zone 99A at column line S

3. Sealed Penetrations

   Sealed equal or exceed fire barrier rating

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

   - Power Potential Transformer and bus

E. Radioactive Material

   None

F. Combustible Loading

   1. In Situ Combustible Load Type

      - Transformer oil

2. Transient Combustible Load Type

   - Ordinary Combustible
   - Oil

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

None

H. Fire Suppression

1. Primary

   Manual spray from single nozzle installed inside cubicle from hydrants on the yard main

2. Secondary

   Manual hose streams from the hydrants on the yard fire main

I. Ventilation

Natural convection

J. Drainage

The Power Potential Transformer is connected to a sump drain.

K. Emergency Communications

None

9B.2.21.18 Fire Zone 99C, Power Potential Transformer (PPT) "C" (In those units with DMWO 3771114 implemented)

A. Location

Fire Zone 99C (engineering drawing 13-A-ZYD-021) is located in the outside areas, adjacent to the plant southeast corner of the Turbine Building at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 2-hour rated exterior refractory composite removable wall at column line 7

South: 2-hour rated exterior wall of concrete construction at column line 8

East: 2-hour rated exterior wall of concrete construction at column line U

West: 2-hour rated wall of concrete construction common to Zone 99B at column line T

Floor: Non-rated basemat of concrete construction with a 12" layer of rock over a sump pit

Ceiling: Open to the atmosphere

2. Zone Access

   - One non-rated security gate in the 2-hour rated east exterior wall at column line U
   - One 3′ by 7′ opening in the 2-hour rated west wall to Fire Zone 99B at column line T

3. Sealed Penetrations

   Sealed equal or exceed fire barrier rating

4. Fire Dampers

   None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

None

D. Nonsafety-Related Equipment and Components

- Power Potential Transformer and bus

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Transformer oil

2. Transient Combustible Load Type

   - Ordinary Combustible
   - Oil

3. Total Combustible (Fire) Loading

   High

G. Fire Detection

None

H. Fire Suppression

1. Primary

   Manual spray from single nozzle installed inside cubicle from hydrants on the yard main

2. Secondary

   Manual hose streams from the hydrants on the yard fire main

I. Ventilation

Natural convection

J. Drainage

The Power Potential Transformer is connected to a sump drain

K. Emergency Communications

None

9B.2.21.19 Fire Zone 99D, Power Control Room (PCR) (In those units with DMWO 3771114 implemented)

The PCR is an unoccupied NEMA type 3S outdoor enclosure to provide a degree of protection to personnel against access to hazardous parts; to provide a degree of protection for the equipment inside the enclosure against ingress of solid falling objects (falling dirt and windblown dust); and to provide a degree of protection with respect to harmful effects on the equipment due to ingress of water (rain, sleet, snow).

The PCR enclosure is constructed of two compartments. The lower compartment will house the plenum, risers, diffusers, and support structures. The upper compartment, divided into three rooms, will house all cables & wiring, the PCR building and all internal PCR equipment. The interior walls are 18ga (minimum) G90 galvanized or galvannealed sheet metal. The two interior walls each contain two doors for egress between rooms. The floors of the PCR will be covered with a rubber-like floor mat.

A. Location

Fire Zone 99D (engineering drawing 13-A-ZYD-021) is located in the outside areas, adjacent to the plant southeast corner of the Turbine Building, plant south of Fire Zone 99C, at elevation 100 feet 0 inch.

B. Fire Prevention Features

1. Zone Boundaries and Rated Fire Barriers

North: 18ga (minimum) G90 galvanized or galvannealed sheet metal wall panels with minimum R13 level insulation

South: 18ga (minimum) G90 galvanized or galvannealed sheet metal wall panels with minimum R13 level insulation

East: 18ga (minimum) G90 galvanized or galvannealed sheet metal wall panels with minimum R13 level insulation

West: 18ga (minimum) G90 galvanized or galvannealed sheet metal wall panels with minimum R13 level insulation

Floor: Basemat of concrete construction

Ceiling: 18ga (minimum) G90 galvanized or galvannealed sheet metal with minimum R19 level insulation

2. Zone Access

- Two locked 1.5 hour (min) 3′ x 6′-8″ Emergency Exit doors in the east exterior wall
- Two locked 1.5 hour (min) 3′-6″ x 6′-8″ personnel egress doors in the west exterior wall

3. Sealed Penetrations

Sealed equal or exceed fire barrier rating

4. Fire Dampers

None

5. Protected Raceways

   None

6. Protected Structural Members

   None

C. Safety-Related Equipment and Components

   None

D. Nonsafety-Related Equipment and Components

- EX2100e Panel
- BOP / Mark VI
- Rectifier Cabinets (4)
- Remote Server Panel
- 480V Distribution Panels (3)
- 120V Distribution Panels (2)
- Marshaling Panel
- Relay Panel
- Air Handling Units (3)
- Control Power Transformers (2)
- VESDA Panel
- Fire Protection Panel
- vNSA Icon Panel
- Heaters (3)
- Lights and Receptacles

E. Radioactive Material

None

F. Combustible Loading

1. In Situ Combustible Load Type

   - Cable insulation
   - Paper
   - Cloth
   - Plastics
   - Rubber

2. Transient Combustible Load Type

   - Ordinary Combustibles

3. Total Combustible (Fire) Loading

   Low

G. Fire Detection

- Equipped with a VESDA VLI Aspirating Smoke Detection System with detectors with signal output
- Smoke detection system with an alarm contact tied to electrical equipment control system alarm
- Three internal fire alarm strobes and two outside strobes with two outside horns

H. Fire Suppression

1. Primary

- Manually initiated Stat-X fire suppression system with two remote manual pull stations to initiate system

- Four external PCR mounted Halotron clean agent fire extinguishers, one per exterior door

2. Secondary

Manual hose streams from the hydrants on the yard fire main

I. Ventilation

Self-contained with HVAC units

J. Drainage

None

K. Emergency Communications

None

9B.2.22 ISFSI FIRE ZONES

The ISFSI Facility fire zone and the ISFSI Route fire zone are both located outside the power block on the 100’-0” elevation. The ISFSI Facility fire zone is located approximately 1,000 feet Southeast of the Unit 1 turbine building. The ISFSI Route fire zone consists of the cask transport path from outside the Unit 1, 2, and 3 fuel building railcar bay rollup doors to the ISFSI Facility.

Refer to the ISFSI 72.212 Evaluation Report and the PVNGS ISFSI fire hazards analysis for detailed requirements related to DFS operations in these fire zones.

There is no safe shutdown equipment within the ISFSI Facility fire zone or the ISFSI Route fire zone.

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9B.3 COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1

9B.3.1 COMPLIANCE SUMMARY

The review of the fire protection program at PVNGS against the guidelines set forth in Appendix A to BTP APCSB 9.5-1 has played an integral part in the overall evaluation.
Table 9B.3-1 provides a detailed comparison of the Appendix A guidelines for plants under construction and operating plants against the PVNGS position. For each case of noncompliance, the bases constituting justification for the deviation are also provided.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 1 of 69)

A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Personnel Responsibility for the overall fire protection program should be assigned to a designated person in the upper level of management. This person should retain ultimate responsibility even though formulation and assurance of program implementation is delegated. Such delegation of authority should be to staff personnel prepared by training and experience in fire protection and nuclear plant safety to provide a balanced approach in directing the fire protection programs for nuclear power plants. The qualification requirements for the fire protection engineer or consultant who will assist in the design and selection of equipment, inspect and test the completed physical aspects of the system, develop the fire protection program, and assist in the firefighting training for the operating plant should be stated. Subsequently, the FSAR should discuss the training and the updating provisions such as fire drills provided for maintaining the competence of the station firefighting and operating crew, including personnel responsible for maintaining and inspecting the fire protection equipment. The fire protection staff should be responsible for: (a) coordination of building layout and systems design with fire area requirements, including consideration of potential hazards associated with postulated design basis fires	1. Personnel Same	1. Personnel The architect/engineer (A/E) for PVNGS utilized fire protection engineers to assist in the design and selection of equipment and the development of the fire protection program in general. These fire protection engineers had/have the following qualifications: • Registered as Professional Engineers (fire protection discipline) • Qualified for Members of Society of Fire Protection Engineers Current responsibilities, qualifications and administrative controls for the fire protection program are discussed in UFSAR paragraph 9.5.1.5. Training for the station firefighting and operating crews, including personnel responsible for maintenance, is discussed in UFSAR paragraph 9.5.1.5 or section 13.2.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 2 of 69)

A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Personnel (Continued) (b) design and maintenance of fire detection, suppression, and extinguishing system (c) fire prevention activities, (d) training and manual firefighting activities of plant personnel and the fire brigade (NOTE: NFPA 6, Recommendations for Organization of Industrial Fire Loss Prevention, contains useful guidance for organization and operation of the entire fire loss prevention program.)	1. Personnel (Continued)	1. Personnel (Continued)
2. Design Bases The overall fire protection program should be based upon evaluation of potential fire hazards throughout the plant and the effect of postulated design basis fires relative to maintaining ability to perform safety shutdown functions and minimize radioactive releases to the environment.	2. Design Bases Same	2. Design Bases The evaluation of applicable fire hazards has been performed. (See section 9B.2.)
3. Backup Total reliance should not be placed on a single automatic fire suppression system. Appropriate backup fire suppression capability should be provided.	3. Backup Same	3. Backup Backup fire suppression capability is provided for each automatic fire suppression system by the installation of manual hose stations, portable fire extinguishers and/or hose streams from hydrants on the yard fire main.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 3 of 69)

A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
4. Single Failure Criterion A single failure in the fire suppression system should not impair both the primary and backup fire suppression capability. For example, redundant fire water pumps with independent power supplies and controls should be provided. Postulated fires or fire protection system failures need not be considered concurrent with other plant accidents or the most severe natural phenomena. However, in the event of the most severe earthquake, i.e., the safe shutdown earthquake (SSE), the fire suppression system should be capable of delivering water to manual hose stations located within hose reach of areas containing equipment required for safe plant shutdown. The fire protection systems should, however, retain their original design capability for (1) natural phenomena of less severity and greater frequency (approximately once in 10 years) such as tornadoes, hurricanes, floods, ice storms, or small intensity earthquakes which are characteristic of the site geographic region and (2) for potential man-created, site-related events such as oil barge collisions, aircraft crashes which have a reasonable probability of occurring at a specific plant site.	4. Single Failure Criterion A single failure in the fire suppression system should not impair both the primary and backup fire suppression capability. For example, redundant fire water pumps with independent power supplies and controls should be provided. Postulated fires or fire protection system failures need not be considered concurrent with other plant accidents or the most severe natural phenomena.	4. Single Failure Criterion PVNGS complies with the "single failure criterion" based on the definition of "backup" fire suppression being interpreted as follows for each specific hazard: NOTE: Postulated fires or fire protection system failures are not considered concurrent with other plant accidents or the most severe natural phenomena. • For hazards which depend upon water as both primary and backup suppression, PVNGS has redundant fire water pumps with independent power supplies. Piping between fire pumps and any of the several buildings within the plant is routed such that two separate flow paths exist, with sectional valves located such that a failure in either flow path can be isolated. • For any building which loses internal fire water protection due to a single failure of the fire water piping within the building, backup suppression capability is available from outside hydrants and/or inside portable extinguishers. • Specifically for the auxiliary and control buildings a single failure of the internal fire water piping does not impair both automatic sprinkler/spray systems and all of the internal fire water hose stations for any fire zone; i.e., if the failure for any specific hazard impairs the automatic sprinkler systems, at least one Class 2 hose station is still available in the fire zone. Specifically for the turbine building, a single failure of any fire water piping still allows full coverage of any location by either automatic sprinkler systems or by internal fire water hose stations.
The effects of lightning strikes should be included in the overall plant fire protection program.	The effects of lightning strikes should be included in the overall plant fire protection program.	PVNGS minimizes the effects of lightning strikes by providing lightning protection for the structure in accordance with the Underwriter's Laboratory Standard UL96A, 1964. All startup transformers, main transformers, and 13.8 kV switchgear are protected with appropriate lightning arrestors. (See appendix 9A response to Question 9A.66.)

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 4 of 69)

A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
5. Fire Suppression Systems Failure or inadvertent operation of the fire suppression system should not incapacitate safety-related systems or components. Fire suppression systems that are pressurized during normal plant operation should meet the guideline specified in APCSB-1, Protection Against Postulated Piping Failures in Fluid Systems Outside Containment.	5. Fire Suppression Systems Same	5. Fire Suppression Systems PVNGS complies. Inadvertent operation of a fire suppression system will not incapacitate safety-related systems due to the following reasons. • Preaction sprinkler systems are used in safety-related areas. These systems are not pressurized with water during normal operation. • Electrical cables are insulated and not subject to water damage. • Mechanical equipment such as heat exchangers, tanks, and piping will not be damaged by wetting due to sprinkler actuation. To obviate the possibility of damage to safety-related systems due to failure of a fire suppression system, all of the normally pressurized fire suppression systems have been analyzed to meet the guidelines specified in BTP APCSB 3-1. The fire suppression piping, in the fire zones where safety-related equipment or components are located, meet the project Seismic Category IX criteria stated below. Seismic Category IX structures and components are those non-Seismic Category I structures and components whose failure due to SSE loads could impact adjacent Seismic Category I structures or components. Seismic Category IX structures and components have been designed to experience no structural failure that might result in the malfunction of adjacent seismic Category I structures or components when subjected to the vibratory motions of the SSE in combination with the normal operating loads. A dynamic or equivalent static analysis has been performed using the relevant building response spectra to demonstrate structural integrity. Seismic Category IX requirements are an addition to any Seismic Category II or III requirements.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 5 of 69)

A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
6. Fuel Storage Areas The fire protection program (plans, personnel, and equipment) for buildings storing new reactor fuel and for adjacent fire zones which could affect the fuel storage zone should be fully operational before fuel is received at the site.	6. Fuel Storage Areas Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	6. Fuel Storage Areas PVNGS complies. The fire protection program for the fuel building, where the new reactor fuel is stored, was fully operational prior to the receipt of fuel. The fire protection program for the adjacent fire zones to the fuel storage area (Zone 29A at elevation 140 feet 0 inch) was also implemented prior to the receipt of fuel at Unit 1. The combustible loading in the adjacent fire zones is low. Ionization smoke detectors are installed, for early warning, in the new fuel storage area and also in the following adjacent fire zones. • Zone 27 at elevation 100 feet 0 inch • Zone 28 at elevation 100 feet 0 inch • Zone 29 at elevation 120 feet 0 inch Hose stations and fire extinguishers are provided at elevations 100 feet 0 inch, 120 feet 0 inch, and 140 feet 0 inch. (See section 9B.2, Fire Hazards Analysis, for more details.)
7. Fuel Loading The fire protection program for an entire reactor unit should be fully operational prior to initial fuel loading in that reactor unit.	7. Fuel Loading Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	7. Fuel Loading PVNGS complies.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 6 of 69)

A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
8. Multiple-Reactor Sites On multiple-reactor sites where there are operating reactors and construction of remaining units is being completed, the fire protection program should provide continuing evaluation and include additional fire barriers, fire protection capability, and administrative controls necessary to protect the operating units from construction fire hazards. The superintendent of the operating plant should have the lead responsibility for site fire protection.	8. Multiple-Reactor Sites Same	8. Multiple-Reactor Sites Construction of Units 1, 2, and 3 is complete. The PVNGS fire protection program provides continuing evaluation of the fire protection/prevention measures to protect the operating unit(s) from construction fire hazards. Fire barriers between operating plants are not deemed necessary. Each unit complex is separated from any other unit complex by a distance of approximately 500 feet. Responsibilities for the fire protection program are discussed in section A.1 of this table.
9. Simultaneous Fires Simultaneous fires in more than one reactor need not be postulated, where separation requirements are met. A fire involving more than one reactor unit need not be postulated except for facilities shared between units.	9. Simultaneous Fires Same	9. Simultaneous Fires PVNGS does not postulate simultaneous fires in more than one reactor since no facilities, except for the fire water pumps, the water supply tanks, and the underground fire water main loop, are common. A separation distance of approximately 500 feet exists between units. The failure of the shared facilities will not affect the safe shutdown capability of the units. The two diesel-driven fire water pumps (50% capacity each) are protected by a wet pipe sprinkler system. (See section E.2.C of this table for more details).

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 7 of 69)

B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Administrative procedures consistent with the need for maintaining the performance of the fire protection system and personnel in nuclear power plants should be provided. Guidance is contained in the following publications: NFPA 4 - Organization for Fire Services NFPA 4A - Organization for Fire Department NFPA 6 - Industrial Fire Loss Prevention NFPA 7 - Management of Fire Emergencies NFPA 8 - Management Responsibility for Effects of Fire on Operation NFPA 27 - Private Fire Brigades	1. Same	1. Administrative procedures consistent with the need for maintaining the performance of the fire protection system and personnel in nuclear power plants are provided.
2. Effective administrative measures should be implemented to prohibit bulk storage of combustible materials inside or adjacent to safety-related buildings or systems during operation or maintenance periods. Regulatory Guide 1.39, Housekeeping Requirements for Water-Cooled Nuclear Power Plants, provides guidance on housekeeping, including the disposal of combustible materials.	2. Same	2. PVNGS complies by providing administrative "Control of Combustibles" procedure.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 8 of 69)

B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Normal and abnormal conditions or other anticipated operations such as modifications (e.g., breaking fire stops, impairment of fire detection, and suppression systems) and refueling activities should be reviewed by appropriate special actions and procedures such as fire watches or temporary fire barriers implemented to assure adequate fire protection and reactor safety. In particular:	Same	3. PVNGS complies. Normal and abnormal conditions or other anticipated operations/modifications and refueling activities are covered by administrative control procedures, and appropriate compensatory measures will be implemented to assure adequate fire protection and reactor safety.
(a) Work involving ignition sources such as welding and flame cutting should be done under closely controlled conditions. Procedures governing such work should be reviewed and approved by persons trained and experienced in fire protection. Persons performing and directly assisting in such work should be trained and equipped to prevent and combat fires. If this is not possible, a person qualified in fire protection should directly monitor the work and function as a fire watch.		(a) PVNGS complies by providing administrative control of "hot work".
(b) Leaktesting, and similar procedures such as air flow determination, should use one of the commercially available aerosol techniques. Open flames or combustion generated smoke should not be permitted.		(b) PVNGS complies by prohibiting open flames and combustion generated smoke from being used for leaktesting or air flow tests.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 9 of 69)

B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
(c) Use of combustible material, e.g., HEPA and charcoal filters, dry ion exchange resins, or other combustible supplies, in safety-related areas should be controlled. Use of wood inside buildings containing safety-related systems or equipment should be permitted only when suitable noncombustible substitutes are not available. If wood must be used, only fire-retardant treated wood (scaffolding, lay down blocks) should be permitted. Such materials should be allowed into safety-related areas only when they are to be used immediately. Their possible and probable use should be considered in the fire hazard analysis to determine the adequacy of the installed fire protection systems.		(c) PVNGS complies by controlling the use of combustible material in safety-related areas. Use of wood inside buildings containing safety-related systems or equipment is permitted only when suitable noncombustible substitutes are not available. If wood is to be used, only fire-retardant treated wood (scaffolding, lay down blocks) is permitted. Such materials are allowed into safety-related areas only when they are to be used immediately. Transient combustibles are considered in section 9B.2 to determine the adequacy of the installed fire protection system. Exceptions allowed are furniture and fixtures of wood, wood components, or composite materials of pressed wood with plastic laminate surfaces, e.g., desks, cabinets, shelves, tables, counter tops, bulletin boards, etc., and miscellaneous wood articles in safety-related areas such as control, computer, and office areas which are included in the fire hazard analysis. The combustible loading in each fire zone has been estimated and protection described in the fire hazard analysis. Redundant safe shutdown equipment is protected such that one train will remain free of fire damage, or alternate shutdown capability is provided.
4. Nuclear power plants are frequently located in remote areas, at some distance from public fire departments. Also, first response fire departments are often volunteer. Public fire department response should be considered in the overall fire protection program. However, the plant should be designed to be self-sufficient with respect to firefighting activities and rely on supplemental or backup capability.	4. Same	4. PVNGS complies by providing a plant fire protection system and program that is designed to be self-sufficient. The Phoenix Fire Department provides backup assistance when requested.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 10 of 69)

B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
5. The need for good organization, training, and equipping of fire brigades at nuclear power plant sites requires effective measures be implemented to assure power discharge of these functions. The guidance in Regulatory Guide 1.101, Emergency Planning for Nuclear Power Plants, should be followed as applicable.	5. Same	5. PVNGS complies by implementing effective measures to insure proper organization, training, and equipping of the plant fire department. The guidance in Regulatory Guide 1.101, Emergency Planning for Nuclear Power Plants, is followed where applicable.
(a) Successful firefighting requires testing and maintenance of the fire protection equipment, emergency lighting, and communication, as well as practice as brigades for the people who must utilize the equipment. A test plan that lists the individuals and their responsibilities in connection with routine tests and inspections of the fire detection and protection systems should be developed. The test plan should contain the types, frequency, and detailed procedures for testing. Procedures should also contain instructions on maintaining fire protection during these periods when the fire protection system is impaired or during periods of plant maintenance, e.g., fire watches or temporary hose connections to water systems.	(a) Same	(a) PVNGS complies by developing a test plan that lists the individuals and their responsibilities in connection with routine plant tests and inspections of the plant fire protection system. The test plan contains the types, frequency, and detailed procedures for testing. The procedures contain instructions on maintaining fire protection during those periods when the fire protection system is impaired or during periods of plant maintenance. Section D.5 describes the emergency lighting and communication equipment credited for addressing postulated fires.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 11 of 69)

B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
(b) Basic training is a necessary element in effective firefighting operation. In order for a fire brigade to operate effectively, it must operate as a team. All members must know what their individual duties are. They must be familiar with the layout of the plant, equipment location, and operation in order to permit effective firefighting operations during times when a particular area is filled with smoke or is insufficiently lighted. Such training can only be accomplished by conducting drills several times a year (at least quarterly) so that all members of the fire brigade have had the opportunity to train as a team testing itself in the major areas of the plant. The drills should include the simulated use of equipment in each area and should be preplanned and post-critiqued to establish the training objective of the drills and determine how well these objectives have been met. These drills should periodically (at least annually) include local fire department participation where possible. Such drills also permit supervising personnel to evaluate the effectiveness of communications within the fire brigade and with the on scene fire team leader, the reactor operator in the control room, and the offsite command post.	(b) Same	(B) PVNGS complies by providing appropriate training of the plant fire department. All members are instructed in what their individual duties are. They are familiar with the layout of the plant and equipment location and operation. This permits effective firefighting operations during times when a particular area is filled with smoke or is insufficiently lighted. Drills are conducted on a quarterly basis and include the simulated use of equipment in each area. Drills are pre-planned and critiqued to establish the training objective and to determine how well the objectives, including communications, have been met. PVNGS includes offsite fire department participation in drills annually. The offsite fire department is the Phoenix Fire Department.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 12 of 69)

B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
(c) To have proper coverage during all phases of operation, members of each shift crew should be trained in fire protection. Training of the plant fire brigade should be coordinated with the local fire department so that responsibilities and duties are delineated in advance. This coordination should be part of the training course and implemented into the training of the local fire department staff. Local fire departments should be educated in the operational precautions when fighting fires on nuclear power plant sites. Local fire departments should be made aware of the need for radioactive protection of personnel and the special hazards associated with a nuclear power plant site.	(c) Same	(c) PVNGS complies by providing courses in fire protection training for members of each shift crew. Training is coordinated with the offsite fire department (Phoenix Fire Department).
(d) NFPA 27, Private Fire Brigade, should be followed in organization, training, and fire drills. This standard also is applicable for the inspection and maintenance of fire-fighting equipment. Among the standards referenced in this document, the following should be utilized: NFPA 194, Standard for Screw Threads and Gaskets for Fire Hose Couplings; NFPA 196, Standard for Fire Hose; NFPA 197, Training Standard on Initial Fire Attacks; NFPA 601, Recommended Manual of Instructions and Duties for the Plant Watchman on Guard. NFPA booklets and pamphlets listed on page 27-11 of Volume 8, 1971-72, are also applicable for good training references. In addition, courses in fire prevention and fire suppression which are recognized and/or sponsored by the fire protection industry should be utilized.	(d) Same	(d) PVNGS complies. The following documents are utilized where applicable: NFPA 601 (1975), Recommended Manual of Instructions and Duties for the Plant Watchman on Guard; NFPA 1001 (1987), Firefighter Professional Qualifications Level I; NFPA 1201 (1989), Developing Fire Protection Services for the Public; NFPA 1410 (1988), Training Standard on Initial Fire Attack; NFPA 1961 (1987), Fire Hose; NFPA 1963 (1985), Screw Threads and Gaskets for Fire Hose Connections. Courses in fire prevention and fire suppression which are recognized and/or sponsored by the fire protection industry are utilized as appropriate.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 13 of 69)

C. QUALITY ASSURANCE PROGRAM

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
Quality assurance (QA) programs of applicants and contractors should be developed and implemented to assure that the requirements for design, procurement, installation, and testing and administrative controls for the fire protection program for safety-related areas as defined in this Branch Position are satisfied. The program should be under the management control of the QA organization. The QA program criteria that applies to the fire protection program should include the following: 1. Design Control and Procurement Document Control Measures should be established to assure that all design-related guidelines of the Branch Technical Position are included in design and procurement documents and that deviations therefrom are controlled. 2. Instructions, Procedures, and Drawings Instructions, tests, administrative controls, fire drills, and training that govern the fire protection program should be prescribed by documented instructions, procedures, or drawings and should be accomplished in accordance with these documents. 3. Control of Purchased Material, Equipment, and Services Measures should be established to assure that purchased material, equipment, and services conform to the procurement documents.	Same	Implementation of the quality assurance program for fire protection is consistent with NRC Branch Technical Position APCSB 9.5-1, Appendix A, Section C, "Quality Assurance Program." Fire protection features required to protect safety-related structures, systems, and components are within the scope of the PVNGS Quality Assurance Program for the operational phase. APS implements the fire protection QA program through approved procedures, instructions, and drawings in accordance with the requirements of the PVNGS Operations Quality Assurance Program Description.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 14 of 69)

C. QUALITY ASSURANCE PROGRAM

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
4. Inspection A program for independent inspection of activities affecting fire protection should be established and executed by, or for, the organization performing the activity to verify conformance with documented installation drawings and test procedures for accomplishing the activities. 5. Test and Test Control A test program should be established and implemented to assure that testing is performed and verified by inspection and audit to demonstrate conformance with design and system readiness requirements. The tests should be performed in accordance with written test procedures; test results should be properly evaluated and acted upon. 6. Inspection, Test, and Operation Status Measures should be established to provide for the identification of items that have satisfactorily passed required tests and inspections.		

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 15 of 69)

C. QUALITY ASSURANCE PROGRAM

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
7. Nonconforming Items Measures should be established to control items that do not conform to specified requirements to prevent inadvertent use of installation.		
8. Corrective Action Measures should be established to assure that conditions adverse to fire protection, such as failures, malfunctions, deficiencies, deviations, defective components uncontrolled combustible material and non-conformances are promptly identified, reported, and corrected.		
9. Records Records should be prepared and maintained to furnish evidence that the criteria enumerated above are being met for activities affecting the fire protection program.		
10. Audits Audits should be conducted and documented to verify compliance with the fire protection program including design and procurement documents, instructions, procedures and drawings, and inspection and test activities.		

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 16 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Building Design	1. Building Design	1. Building Design
(a) Plant layouts should be arranged to:		(a) Plant layouts:
(1) Isolate safety-related systems from unacceptable fire hazards, and	(1) Same	(1) Safety-related systems are isolated from unacceptable fire hazards. For detailed descriptions of the protection and isolation of safety-related systems, see section 9B.2.
(2) Separate redundant safety-related systems from each other so that both are not subject to damage from a single fire hazard.	(2) Alternatives: (a) Redundant safety related systems that are subject to damage from a single fire hazard should be protected by a combination of fire retardant coatings and fire suppression systems, or (b) a separate system to perform the safety function should be provided.	(2) Redundant safety-related equipment required to shut down the unit per the design bases of section A.2 of this table are separated per the requirements of 10CFR50, Appendix R, with the exception of deviations as noted in appendix 9B.
(b) In order to accomplish 1.(a) above, safety-related systems should be identified throughout the plant. Therefore, a detailed fire hazard analysis should be made. The fire hazards analysis should be reviewed and updated as necessary.	(b) Same - Additional fire hazards analysis should be done after any plant modification.	(b) PVNGS complies and the detailed fire hazards analysis is provided by section 9B.2. The fire hazards analysis identifies safety-related systems and fire hazards. The fire hazards analysis is reviewed and updated after plant modification as necessary.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 17 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Building Design (Continued) (c) For multiple reactor sites, cable spreading rooms should not be shared between reactors. Each cable spreading room should be separated from other areas of the plant by barriers (walls and floors) having a minimum fire resistance of 3 hours. Cabling for redundant safety divisions should be separated by walls having 3-hour fire barriers.	1. Building Design (Cont.) (c) Alternative guidance for constructed plants is shown in section F.3 of this table.	1. Building Design (Continued) (c) Cable spreading rooms are not shared between reactors. PVNGS complies by providing two separate cable spreading rooms for each reactor. The cables in each room are protected by a preaction sprinkler system, and are separated from other areas of the plant by 3-hour rate barriers (walls and floors) except as follows: Lower cable spreading room (Zone 14, control building, elevation 120 feet 0 inch) • A portion of the south exterior wall is of heavy concrete construction. The wall is not required to separate redundant shutdown related systems, and as such it is deemed not necessary to qualify it as a rated barrier. • Common walls with HVAC chases and a stairwell are 2-hour rated. There are no combustibles in the HVAC chases nor the stairwell, and the combustible (fire) loading of the lower cable spreading room is moderate. Therefore, a 2-hour fire resistance rating is considered adequate. • Common walls with the Halon protected communication and inverter rooms (Zones 12 and 13) are 1-hour rated. All three fire zones have a suppression system and smoke detectors for both suppression system actuation as well as early warning. The combustible (fire) loading in Zone 12 is moderate and in Zone 13 is low. 1-hour rated fire walls separating the three fire zones will provide the necessary protection. Upper cable spreading room (Zone 20, control building, elevation 160 feet 0 inch) • A portion of the south exterior wall is of heavy concrete construction. The wall is not required to separate redundant shutdown related systems, and as such it is not deemed necessary to qualify it as a rated barrier. The north exterior wall is of heavy concrete construction. The wall is not required to separate redundant shutdown related systems, and as such it is not deemed necessary to qualify it as a rated barrier.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 18 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (Continued)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Building Design (Continued)	1. Building Design (Continued)	1. Building Design (Continued) • Common walls with HVAC chases and a stairwell are 2-hour rated. There are no combustibles in the HVAC chases nor the stairwell, and the combustible (fire) loading of the upper cable spreading room is moderate. Therefore, a 2-hour fire resistance rating is considered adequate. • Common walls with the normal smoke exhaust room are 2-hour rated. The combustible (fire) loading in this room is low. Therefore, a 2-hour fire resistance rating is considered adequate. • The ceiling, which is the roof of the control building, is nonrated and of heavy concrete construction. There are no penetrations in the ceiling of the upper cable spreading room and the barrier is not required to separate redundant shutdown related systems, and as such a fire resistance rating is not required.
(d) Interior wall and structural components, thermal insulation materials, and radiation shielding materials and sound-proofing should be noncombustible. Interior finishes should be noncombustible or listed by a nationally recognized testing laboratory, such as Factory Mutual or Underwriter's Laboratory, Inc. for flame spread, smoke, and fuel contribution of 25 or less in its use configuration (ASTM E84 test, Surface Burning Characteristics of Burning Materials).	(d) Same	(d) PVNGS complies except that surfacing is considered noncombustible when it is not over 1/8 inch thick, it has a spread rating not higher than 50 when measured using ASTM E84 test Surface Burning Characteristics of Building Materials or consists of surface coatings or paint and it has a structural base of noncombustible material. (See Appendix 9A response to Question 9A.68.) • Interior walls and structural components, thermal insulation materials, and radiation shielding materials and sound-proofing are noncombustible. • Interior finishes are listed by Underwriter's Laboratory Inc. for flame spread, smoke, and fuel contribution of 25 or less in its use configuration (ASTM E84 test), except for paint.
(e) Metal deck roof construction should be noncombustible (see the building materials directory of the Underwriter's Laboratory, Inc.) or listed as Class 1 by Factory Mutual System Approval Guide.	(e) Same. Where combustible material is used in metal deck roofing design, acceptable alternatives are (1) replace combustibles with noncombustible materials, (2) provide an automatic sprinkler system, or (3) provide ability to cover roof exterior and interior with adequate water volume and pressure.	(e) PVNGS complies by employing noncombustible buildup roof construction which meets the requirements of the Underwriter's Laboratory Class A rating.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 19 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (Continued)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Building Design (Continued) (f) Suspended ceilings and their supports should be noncombustible construction. Concealed spaces should be devoid of combustibles.	1. Building Design (Continued) (f) Same. Adequate fire detection and suppression systems should be provided where full implementation is not practicable.	1. Building Design (Continued) (f) PVNGS complies. Suspended ceilings and their supports are noncombustible. Concealed spaces are devoid of combustibles except for the following: • Control room (Zone 17, control building, elevation 140 feet 0 inch). Cable trays are routed above the suspended ceiling. Ionization smoke detectors are provided for early warning in the cable tray area above the suspended ceiling. (See appendix 9A response to Question 9A.82.) • The raised platform in the control room is a concealed space. The cables routed below the raised floor are all non-safety related and classified as low-level signal instrumentation and control cables. The cables below the platform ternminate in the platform workstations. The cables do not control plant equipment. The cables are IEEE 383 or equivalent qualified. Fire detection is not provided in the raised platform. The control room is continuously manned location. There is no ignition source or other combustible material installed below the raised platform. The raised platform is provided with floor openings and louvered sides. This will allow any potential smoke to be detected by the control room personnel. The floor openings and louvers will allow for control room personnel to apply CO2 to the underside of the platform. • Computer room (Zone 16, control building, elevation 140 feet 0 inch). Ribbon cable between two computer cabinets is routed above the suspended ceiling utilizing access to the top of each cabinet. VESDA smoke detection tubing (CPVC) is routed above suspended ceiling in Unit 1 Room J-307 Fire detection and manual suppression is provided as detailed in section 9B.2. • Auxiliary building (elevation 140 feet 0 inch). Acetylene, helium, nitrogen, hydrogen, methane, (P-10 gas), and oxygen piping is routed above the suspended ceiling from the cylinder storage area (Zones 57B and 57P) to the hot laboratory (Zone 57A), RP Island (Zone 57J), cold laboratory (Zone 57K), and counting room (Zone 57D). In addition, cable trays are routed above the suspended ceiling. Fire detection is provided as indicated in section 9B.2. (See appendix 9A response to Question 9A.132.) • Corridor building (elevation 140 feet 0 inch). Cable trays are routed above the suspended ceiling. Fire detection is not provided in the corridor building. Damage to any cables or equipment located in this building will have no adverse effect on the ability to achieve and maintain safe shutdown.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Building Design (Continued)	1. Building Design (Continued)	1. Building Design (Continued)
(g) High-voltage, high-amperage transformers installed inside buildings containing safety-related systems should be of the dry type or insulated and cooled with noncombustible liquid.	(g) Same. Safety-related systems that are exposed to flammable oil filled transformers should be protected from the effects of a fire by: • replacing with dry transformers or transformers that are insulated and cooled with noncombustible liquid; or • enclosing the transformer with a three-hour fire barrier and installing automatic water spray protection.	(g) PVNGS complies by employing dry type high voltage-high amperage transformers inside buildings containing safety-related systems.
(h) Buildings containing safety-related systems should be protected from exposure or spill fires involving oil filled transformers by: • locating such transformers at least 50 feet distant; or • ensuring that such building walls within 50 feet of oil filled transformers are without openings and have a fire resistance rating of at least 3 hours.	(h) Buildings containing safety-related systems, having openings in exterior walls closer than 50 feet to flammable oil filled transformers should be protected from the effects of a fire by: • closing of the opening to have fire resistance equal to 3 hours, • constructing a 3-hour fire barrier between the transformers and the wall openings; or	(h) PVNGS complies by locating all oil filled transformers at least 50 feet from any building containing safety-related systems with the exception of the west ESF transformer, which is located approximately 48 feet from the 3-hour-rated auxiliary building exterior wall.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 21 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Building Design (Continued)	1. Building Design (Continued) • closing the opening and providing the capability to maintain a water curtain in case of a fire.	1. Building Design (Continued)
(i) Floor drains, sized to remove expected firefighting water flow should be provided in those areas where fixed water fire suppression systems are installed Drains should also be provided in other areas where hand hose lines may be used if such firefighting water could cause unacceptable damage to equipment in the area. Equipment should be installed on pedestals, or curbs should be provided as required to contain water and direct it to floor drains. (See NFPA 92M, Waterproofing and Draining of Floors.) Drains in areas containing combustible liquids should have provisions for preventing the spread of the fire throughout the drain system. Water drainage from areas that may contain radioactivity should be sampled and analyzed before discharge to the environment.	(i) Same. In operating plants or plants under construction, if accumulation of water from the operation of new fire suppression systems does not create unacceptable consequences, drains need not be installed.	(i) Failure (clogging) of the floor drain system during firefighting activities will not create unacceptable consequences nor prevent the ability to achieve safe shutdown of the plant. PVNGS has floor drains for areas having fixed sprinkler and spray systems. Drains are also provided in areas where hand hoses are the primary source of fire protection, except for the control room (Zone 17) where portable CO_2 and pressurized water fire extinguishers are provided for fire fighting. Floor drain systems, 4 inches or larger, with some degree of redundancy and separation are provided. All equipment is installed on pedestals with the exception of electrical switchgear and control room equipment. The drain lines for the turbine-generator lube oil storage room and the diesel fuel oil day tank rooms are equipped with shutoff valves to prevent the spread of fire through the drain system. Potentially radioactive drains from the auxiliary, containment, fuel, and radwaste buildings are routed to the liquid radwaste system (LRS) which is described in section 11.2. Evaporative losses from the liquid waste systems are filtered and monitored by the plant ventilation systems prior to discharge to the plant vent. Radioactive wastes unsuited for plant recycle are shipped offsite in accordance with NRC and DOT regulations. The radioactivity of the solid radwaste is monitored prior to disposal.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A
OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 22 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Building Design (Continued) (i) Floors, walls, and ceilings enclosing separate fire areas should have minimum fire rating of 3 hours. Penetrations in these fire barriers, including conduits and piping, should be sealed or closed to provide a fire resistance rating at least equal to that of the fire barrier itself. Door openings should be protected with equivalent rated doors, frames, and hardware that have been tested and approved by a nationally recognized laboratory. Such doors should be normally closed and locked or alarmed with alarm and annunciation in the control room. Penetrations for ventilation system should be protected by a standard fire door damper where required. (Refer to NFPA 80, Fire Doors and Windows.)	1. Building Design (Continued) (i) Same. The fire hazard in each area should be evaluated to determine barrier requirements. If barrier fire resistance cannot be made adequate, fire detection and suppression should be provided, such as: • water curtain in case of fire, • flame-retardant coatings, • additional fire barriers	1. Building Design (Continued) (i) Fire hazards in each safety-related fire zone have been evaluated to determine fire barrier requirements. Where this analysis does not substantiate a need for a 3-hour rated barrier, 2-hour, 1-hour, or nonrated construction separates adjacent fire zones. See section 9B.2 and fire barriers depicted in engineering drawings 13-A-ZYD-029, 031, 030, 024, 026, 022 and 021. Each fire area may consist of one or more fire zones. For separation of the fire areas, see Section 9B.2 and figures 9B-1 through 9B-6 and engineering drawing 13-P-00B-005. In general, exterior walls, basements, and roofs on the power buildings are not rated but meet the following requirements: (1) They are not required to separate a safe shutdown related train inside the fire area from a significant fire hazard outside the fire areas. (2) They do not separate safety-related areas from nonsafety-related areas that present a significant fire threat to the safety-related areas. Additionally, all stairwells in safety-related areas are protected by barriers of 2-hour fire resistance rating in accordance with NFPA 101 (1976). Also, cable chases in the control building are separated from other parts of the building by fire barriers of 3-hour fire resistance rating. For all rated barriers in safety-related areas, the penetrations and doors, including ventilation systems, at a minimum, will carry a rating appropriate to that of the barrier itself. Three-hour barriers use a 3-hour Class A door; 2-hour barriers use a 1-1/2 hour Class B door; 1-hour barriers use a 3/4 hour class C door. A complete description of each zone and the barriers, detection, and suppression provided is contained in section 9B.2. (See appendix 9A response to Questions 9A.68, 9A.73, 9A.84, 9A.106, and 9A.121.)

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A
OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 23 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Building Design (Continued)	1. Building Design (Continued)	1. Building Design (Continued) PVNGS complies by locking and alarming fire-rated doors that are designated as part of the plant security system. Other fire-rated doors that are not part of the plant security system are normally closed, but not locked closed. Reliance has been placed upon administrative procedures to deep all fire doors in their normally closed position. Duct penetrations for ventilation through fire-rated walls or floors are equipped with fire-rated dampers equal to or greater than the rating of the wall or floor penetrated. NFPA 80 (1975) has been referred to as necessary. (See Appendix 9A response to Question 9A.68)
2. Control of Combustibles (a) Safety-related systems should be isolated or separated from combustible materials. When this is not possible because of the nature of the safety system or the combustible material, special protection should be provided to prevent a fire from defeating the safety system function. Such protection may involve a combination of automatic fire suppression and construction capable of withstanding and containing a fire that consumes all combustibles present. Examples of such combustible materials that may not be separable from the remainder of its systems are: (1) Emergency diesel generator fuel oil day tanks (2) Turbine-generator oil and hydraulic control fluid systems (3) Reactor coolant pump lube oil system		2. Control of Combustibles (a) For the diesel generator system, PVNGS complies by providing separate enclosures for the diesel generator day tanks, each with 3-hour rated barriers. (See appendix 9A response Question 9A.86.) For the turbine-generator lube oil storage and conditioning system, a separate 2-hour rated enclosure with automatic deluge system is provided. (It should be noted that the turbine-generator is not considered a "safe shutdown" or "safety-related" system.) Also, the turbine-generator lube oil storage is not a hazard to safe shutdown equipment. For hydraulic control fluid systems, no provisions are made for separation, as this fluid has a high auto-ignition point of 1150F. For safety-related systems within the containment, a reactor coolant pump oil collection system has been provided to prevent a fire from defeating the safety system functions. (See Appendix 9A responses to Question 9A.98 and 9A.126) For other safety-related systems where it is not possible to isolate the combustibles from the equipment, the fire hazards analysis in section 9B.2 has shown that: • A postulated fire will not prevent safe shutdown. (See Appendix 9A response to Question 9A.73.)

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 24 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Control of Combustibles	2. Control of Combustibles	2. Control of Combustibles
(b) Bulk gas storage (either compressed or cryogenic) should not be permitted inside structures housing safety-related equipment. Storage of flammable gas, such as hydrogen, should be located outdoors or in separate detached buildings so that a fire or explosion will not adversely affect any safety-related systems or equipment. (Refer to NFPA 50A, Gaseous Hydrogen Systems.) Care should be taken to locate high-pressure gas storage containers with the long axis parallel to building walls. This will minimize the possibility of wall penetration in the event of a container failure. Use of compressed gases (especially flammable and fuel gases) inside buildings should be controlled. (Refer to NFPA 6, Industrial Fire Loss Prevention.)	(b) Same	(b) NFPA 50A (1973) was used as guidance in developing the PVNGS bulk gas storage control and systems. Bulk gas storage (either compressed or cryogenic) is located outside of buildings housing safety-related equipment. The bulk gas storage of hydrogen is located outdoors so that a fire or explosion will not adversely affect any safety-related systems or equipment. PVNGS complies with proper orientation of all high-pressure gas storage containers and by controlling the usage of compressed gases inside buildings, using the guidance of NFPA 6 (1974).
(c) The use of plastic materials should be minimized. In particular, halogenated plastics such as polyvinyl chloride (PVC) and neoprene should be used only when substitute noncombustible materials are not available. All plastic materials, including flame and fire-retardant materials, will burn with an intensity and Btu	(c) Same	(c) PVNGS complies by minimizing the use of smoke generating halogenated plastic (e.g., PVC) materials. Total usage of halogenated plastics (PVC) materials within power block buildings is limited. Applications of PVC are as follows: • Approximately 300 feet of 2-inch and 3-inch diameter PVC are used in the control building, elevation 100 feet 0 inch and below as vent and drain lines. (See appendix 9A response to Question 9A.123). • Approximately 50 feet of 1- and 2-inch diameter PVC is used in each radwaste building at elevation 100 feet 0 inch as a fill and drain line from a chemical addition tank and skid.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 25 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Control of Combustibles (Continued) production in a range similar to that of ordinary hydrocarbons. When burning, they produce heavy smoke that obscures visibility and can plug air filters, especially charcoal and HEPA. The halogenated plastics also release free chlorine and hydrogen chloride when burning which are toxic to humans and corrosive to equipment.	2. Control of Combustibles (Continued)	2. Control of Combustibles (Continued) • Approximately 25 feet of 0.75 inch diameter CPVC is used as smoke detection sample piping for VESDA detector in Unit 1 Computer Room Storage Closet (J-307). • PVC conduits are used in the intake structure at the cooling towers and in the communications room in the Unit 3 turbine building. • PVC jacketed cable is found in some vendor panels and field installed cable. (Reference Table 9B.3-1, Section D.3.(g) for additional information.) • PVC jacket on flexible conduits. • An Electro-Static Dissipating (ESD) carpet material is installed on the raised platform and on the vinyl resilient flooring in the control room. The backing of the ESD carpet tiles are made of a PVC base material. It is identified as static dissipative PVC with conductive filler. The carpet properties are: critical radiant flux, $\geq$0.45 w/cm^2 (ASTM E-648) as required by UFSAR section 9.5.1, and smoke density, <450 (ASTM E-662). • PVC moisture eliminators in the Unit 1 Fuel Building Air Washers located on the roof of the Unit 1 Auxiliary Building (560 lbs. total). Other applications of plastics in the power block are: • One 260-gallon polypropylene tank for chemical addition located in each radwaste building at elevation 100 feet 0 inch (Zone 59). • Four safety-related battery rooms containing plastic battery casings in each control building at elevation 100 feet 0 inch (Zones 8A, 8B, 9A, and 9B - battery rooms). • The emergency lighting has plastic battery casing. • The security UPS has plastic battery casing. • Identification labels and equipment tags. • One Habitation Enclosure (8’ x 10’ x 6’6” H) in each Unit Turbine Building composed of all steel construction, steel sidieng and roof with various insulation materials (fiberglass, polyurethane foam and polyisocyanurate foam and drywall finish. Internal flooring consist of polyurethane foam insulation, vinyl tile and cove molding. A fire sprinkler is installed in each enclosure placed inside the Turbine Building.
(d) Storage of flammable liquids should, as a minimum, comply with the requirements of NFPA 30, Flammable and Combustible Liquids Code.	(d) Same	(d) PVNGS utilizes NFPA 30 (1976) as guidance in the storage of flammable liquids.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 26 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Electric Cable Construction, Cable Trays, and Cable Penetrations	3. Electric Cable Construction, Cable Trays, and Cable Penetrations	3. Electric Cable Construction, Cable Trays, and Cable Penetrations
(a) Only noncombustible materials should be used for cable tray construction.	(a) Same	(a) PVNGS complies by using only metal cable trays.
(b) See section F.3 of this table for fire protection guidelines for cable spreading rooms.	(b) Same	(b) (See section F.3 of this table for PVNGS position.)
(c) Automatic water sprinkler systems should be provided for cable trays outside the cable spreading room. Cables should be designed to allow wetting down with the deluge water without electrical faulting. Manual hose stations and portable hand extinguishers should be provided as backup. Safety-related equipment in the vicinity of such cable trays, that does not itself require water fire protection, but is subject to unacceptable damage from sprinkler water discharge, should be protected from sprinkler system operation of malfunction.	(c) Same. When safety-related cables do not satisfy the provisions of Regulatory Guide 1.75, all exposed cables should be covered with an approved fire-retardant coating and a fixed automatic water fire suppression system should be provided.	(c) PVNGS provides automatic preaction sprinkler systems in the auxiliary building areas which have significant cable concentrations. These protected areas are in the auxiliary building corridors at the 100 feet 0 inch and 120 feet 0 inch elevations and in the auxiliary building cable penetration rooms at the 100 feet 0 inch, 120 feet 0 inch elevations. Cable trays in the containment building are monitored by line type thermal detectors and ionization detectors. The detectors will alarm and annunciate in the control room and alarm locally. Manual hose stations and portable hand extinguishers are provided in fire zones as indicated in section 9B.2. Cables will allow wetting without faulting. Safety-related equipment is protected from sprinkler system malfunction by the use of preaction systems which prohibit inadvertent discharge (see section A.5 of this table). Manual hose stations are provided as indicated in section 9B.2. Safety-related cables that do not satisfy the provisions of Regulatory Guide 1.75 are provided with metal covers or protective envelopes. (See appendix 9A responses to Questions 9A.92, 9A.94, and 9A.102.)
(d) Cable and cable tray penetration of fire barriers (vertical and horizontal) should be sealed to give protection at least equivalent to that fire barrier. The design of fire barriers for horizontal and vertical cable trays should, as a minimum, meet the requirements of ASTM E119, Fire Test of Building Construction and Materials, including the hose stream test.	(d) Same. Where installed penetration seals are deficient with respect to fire resistance, these seals may be protected by covering both sides with an approved fire-retardant material. The adequacy of using such material should be demonstrated by suitable testing.	(d) PVNGS complies. Cable tray penetrations of rated fire barriers are sealed to provide a fire barrier rating at least equal to the barrier. (See appendix 9A response to Question 9A.110.)

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 27 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Electric Cable Construction, Cable Trays, and Cable Penetrations (Continued)	3. Electric Cable Construction, Cable Trays, and Cable Penetrations (Continued)	3. Electric Cable Construction, Cable Trays, and Cable Penetrations (Continued)
(e) Fire breaks should be provided as deemed necessary by the fire hazards analysis. Flame or flame-retardant coatings may be used as a fire break for grouped electrical cables to limit spread of fire in cable ventings. (Possible cable derating owing to use of such coating materials must be considered during design.)	(e) Same	(e) For cable trays which pass through rated walls, floors or ceilings, fire barriers that equal or exceed the rating of the wall or floor penetrated are provided. (See appendix 9A response to Question 9A.84.) Where PVNGS used IEEE 383 cable rated at 210,000 BTU/hr during construction, its regulatory commitment to cable fire retardancy is IEEE 383 at 70,000 BTU/hr. As such, PVNGS now procures power block cable to IEEE 383 fire retardancy requirements, other nationally recognized standards (e.g., UL 1581 Vertical Tray Flame Test, UL 910, or UL 1666) which have been evaluated to meet or exceed IEEE 383 fire retardancy requirements, or other criteria (e.g., new standards) evaluated by Design (Electrical) Engineering for fire retardant equivalency. There are 27 cables installed at PVNGS that do not meet the IEEE 383 flame test. These 27 cables have been evaluated, for both electrical and fire protection properties, and "Accepted-As-Is" by Material Engineering Evaluation (MEE) 02480. Safety-related areas outside containment which have significant concentrations of cable are provided with automatic water suppression systems. The above active and passive protection features will minimize the spread of fire in cable trays within a fire zone. No additional "fire breaks" are deemed necessary by the Fire Hazards Analysis nor by current NRC guidelines.
(f) Electric cable constructions should as a minimum pass the current IEEE 383 flame test. (This does not imply that cables passing this test will not require additional fire protection.)	(f) Same. For cable installation in operating plants and plants under construction that do not meet the IEEE 383 flame test requirements, all cables must be covered with an approved flame-retardant coating and properly derated.	(f) PVNGS meets or exceeds the requirement of IEEE-383. There are 27 cables installed at PVNGS that do not meet the IEEE 383 flame test. These 27 cables have been evaluated, for both electrical and fire protection properties, and "Accepted-As-Is" by Material Engineering Evaluation (MEE) 02480. During construction most scheduled cable construction was required to pass IEEE 383 (1974) requirements at 210,000 BTU/hr. Both Class 1E and non-Class 1E cable is now required to meet the standard's 70,000 BTU/hr requirement, other nationally recognized standards which have been evaluated to meet or exceed IEEE 383 requirements, or other criteria (e.g., new standards) evaluated by Design (Electrical) Engineering for fire retardant equivalency.
(g) To the extent practical, cable construction that does not give off corrosive gases while burning should be used.	(g) Applicable to new cable installations.	(g) PVNGS complies to the extent practical by providing cable construction that does not give off significant gases while burning. This is accomplished by minimizing the release of free chlorine and hydrogen chloride from power block cables. This is accomplished by restricting the use of PVC or PVC jacketed cable which meet or exceed the smoke generating requirements of UL 910 or UL 1685, or of cables which have been evaluated by Design (Electrical) Engineering for fire protection design applicability.
(h) Cable trays, raceways, conduit, trenches, or culverts should be used only for cables. Miscellaneous storage should not be permitted, nor should piping for flammable or combustible liquids or gases be installed in these areas.	(h) Same. Installed equipment in cable tunnels or culvert need not be removed if they present no hazard to the cable runs as determined by the fire hazards analysis.	(h) Conduit is run through the essential pipe tunnel and the condensate tunnel. Installed water piping in the pipe tunnels does not present a hazard to the conduit in those tunnels.
(i) The design of cable tunnels, culverts, and spreading rooms should provide for automatic or manual smoke venting as required to facilitate manual firefighting capability.	(i) Same	(i) PVNGS complies by providing for manual smoke venting for cable spreading rooms. PVNGS does not utilize any underground cable tunnels or cable culverts for safety-related cabling. However, safety-related conduits run through the condensate tunnel. Manual smoke venting is provided.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 28 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Electric Cable Construction, Cable Trays, and Cable Penetrations (Continued)	3. Electric Cable Construction, Cable Trays, and Cable Penetrations (Continued)	3. Electric Cable Construction, Cable Trays, and Cable Penetrations (Continued)
(j) Cables in the control room should be kept to the minimum necessary for operation of the control room. All cables entering the control room should terminate there. Cables should not be installed in floor trenches or culverts in the control room.	(j) Same. Existing cable installed in concealed floor and ceiling spaces should be protected with an automatic total flooding Halon system.	(j) PVNGS complies. The raised platform in the control room is a concealed space. The cables below the platform terminate in the platform workstations. The cables below the platform are non-safety related and are IEEE 383 or equivalent qualified. There is no ignition source or other combustible material installed below the raised platform. The control room is continuously manned location. Fire detection is not provided in the raised platform. The raised platform is provided with floor openings and louvered sides. This will allow any potential smoke to be detected by the control room personnel. The floor openings and louvers will allow for control room personnel to apply CO^2 to the underside of the platform. Cable trays are routed above and vertical raceways penetrate the corners of the suspended ceiling in the control room. Ionization smoke detectors are installed above the suspended ceiling for early warning and also below the suspended ceiling (see sections D.1.f and F.2 of this table). Fire suppression capability is provided by hose stations and portable fire extinguishers. All cables that enter the control room are terminated in the control room. No cabling is routed through the control room from one area to another. • Installation of an automatic total flooding Halon system is not deemed necessary due to the fact that the control room is manned all the time, the combustible (fire) loading is low and adequate fire suppression and detection is provided. • See appendix 9A response to Question 9A.82 and also section D.1(f) of this table.
4. Ventilation	4. Ventilation	4. Ventilation
(a) The products of combustion that need to be removed from a specific fire area should be evaluated to determine how they will be controlled. Smoke and corrosive gases should generally be automatically discharged directly outside to a safe location. Smoke and gases containing radioactive materials should be monitored in the fire area to determine if release to the environment is within the permissible limits of the plant Technical Specifications.	(a) Same. The products of combustion which need to be removed from a specific fire area should be evaluated to determine how they will be controlled.	(a) The products of combustion are removed manually using portable smoke removal equipment. See responses to Questions 9A.70, 9A.79, 9A.80, and 9A.96.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 29 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
(b) Any ventilation system designed to exhaust smoke or corrosive gases should be evaluated to ensure that inadvertent operation or signal failures will not violate the controlled areas of the plant design. This requirement includes containment functions for protection of the public and maintaining habitability for operations personnel.	(b) Same	(b) PVNGS compliance is described in detail in the appendix 9A response to Question 9A.70 (also see section D.4.(a) of this table.) The control building has a common smoke exhaust system which is not credited for removing smoke. Portable smoke removal equipment will be used to exhaust smoke to the outside. The existing smoke removal system can be used to exhaust smoke, if available. The existing smoke removal system is manually controlled from the control room. The existing smoke removal system has safety class isolation dampers to isolate the system during emergency conditions. Therefore, inadvertent operation or signal failure will not violate the controlled areas of the control building. Also, smoke intrusion into the outside air intake of the control building is monitored and alarmed in the control room. The containment, auxiliary, fuel, and radwaste buildings are continuously monitored for radioactivity and are equipped with isolation dampers. With the exception of the containment building and large open areas of the fuel building, the smoke from safety-related buildings of the plant is removed manually by use of portable smoke removal equipment. Normal plant ventilation system, if available, may also be used under manual control to remove smoke. Only portable equipment, however, is relied on for smoke removal capability. Smoke is vented manually from the affected fire zone to outside. Inadvertent operation or a single failure will not violate the controlled areas of the plant.
(c) The power supply and controls for mechanical ventilation systems should be run outside the fire areas served by the system.	(c) Same	(c) PVNGS does not meet this requirement with respect to the normal ventilation systems. However, smoke ejectors will be utilized in the event of fire. The power supply and controls for the essential air cooling units are run outside the fire zones served by the system.
(d) Fire suppression systems should be installed to protect charcoal filters in accordance with Regulatory Guide 1.52, Design Testing and Maintenance Criteria for Atmospheric Cleanup Air Filtration.	(d) Same	(d) High temperature alarms will alert operator in the control room. All charcoal filters are provided with internal spray nozzles with an outside connection to facilitate manual firefighting with hose attachments. The internal spray nozzles are not considered part of the required fire protection system. Compliance to the Regulatory Guide 1.52, Section C.3.k, is not required due to the fact that adsorbent auto-ignition will not result from radioactivity-induced heat in the adsorbent. The temperature will not exceed 200F (see section 1.8).
(e) The fresh air supply intakes to areas containing safety-related equipment or systems should be located remote from the exhaust air outlets and smoke vents of other fire areas to minimize the possibility of contaminating the intake air with the products of combustion.	(e) Same	(e) PVNGS complies by locating fresh air supply intakes of the following buildings remote from the exhaust air outlets – containment, control, auxiliary, diesel generator, fuel, radwaste, and turbine buildings.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 30 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
4. Ventilation (Continued) (f) Stairwells should be designed to minimize smoke infiltration during a fire. Staircases should serve as escape routes and access routes for fire fighting. Fire exit routes should be clearly marked. Stairwells, elevators, and chutes should be enclosed in masonry towers with minimum fire rating of 3 hours and automatic fire doors at least equal to the enclosure construction, at each opening into the building. Elevators should not be used during fire emergencies.	4. Ventilation (Continued) (f) Same. Where stairwells or elevators cannot be enclosed in 3-hour fire-rated barrier with equivalent fire doors, escape and access routes should be established by prefire plan and practiced in drills by operating and fire brigade personnel.	4. Ventilation (Continued) (f) Stairwells with fire-rated enclosures are designed to minimize smoke infiltration during a fire by providing rated fire doors with door closure mechanisms. Staircases serve as escape routes and access routes for fire-fighting. All fire exits are clearly marked. PVNGS stairwells have 2-hour rated enclosures with Class B doors. PVNGS provides multiple access/egress points for all areas, except the following, to facilitate alternate routes or either access or escape. • The diesel generator shall have a centrally located stairwell with 2 and 3-hour rated walls and Class A doors separating Train A and Train B. Access to the diesel generator building is available through the control building at elevations 100 feet 0 inch and 120 feet 0 inch. • The fuel building has one stairwell, at the southeast end of the building, with 2-hour rated walls on three sides and one Class B door at each level. The wall toward the auxiliary building is 3-hour rated. Access to the safety-related area, at elevation 100 feet 0 inch, is available through the auxiliary building or from the western end of the fuel building. • The radwaste building has one stairwell, at the southeast end of the building with 2-hour rated walls on three sides with Class B doors. The wall toward the control building is 3-hour rated. Access to the radwaste building is available through the west end of the building at elevation 100 feet 0 inch or through the auxiliary building at elevation 120 feet 0 inch and 140 feet 0 inch. There are no safety-related systems in the radwaste building. The stairwell in the corridor building is 1-hour rated. The elevator shaft in the corridor building is not rated. The elevator shaft near the turbine building is not an integral part of any building and, therefore, is not rated. In addition, elevators are not to be used for exiting during fire emergencies.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 31 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
4. Ventilation (Continued)	4. Ventilation (Continued)	4. Ventilation (Continued)
(g) Smoke and heat vents may be useful in specific areas such as cable spreading rooms and diesel fuel oil storage areas and switchgear rooms. When natural-convection ventilation is used, a minimum ratio of 1 square foot of venting areas per 200 square feet of floor area should be provided. If forced convection ventilation is used, 300 cubic feet per minute should be provided for every 200 square feet of floor area. See NFPA No. 204 for additional guidance on smoke control.	(g) Same	(g) PVNGS will use portable smoke removal equipment to remove smoke from upper and lower cable spreading rooms in the control building. The existing portable smoke ejectors will be used to remove smoke from the cable spreading rooms. No credit is taken for existing smoke removal systems in the control building as it may not be available. The portable smoke removal equipment does not meet the stated 300 cfm/200 ft^2 criteria. Standard NFPA 204M (1985) does not have specific reference to 300 cubic feet per minute per 200 square feet of floor area. The standard provides guidance for the venting of the buildings and is geared towards non-spinklered, single-story buildings. The standard discusses its reservation about the combined use of vents/sprinklers in the building and raises a concern that automatic roof venting may be detrimental to the performance of automatic sprinklers. As the cable spreading rooms are provided with fire-action sprinkler systems and the switchgear rooms are provided with CO_2 flood system, the recommended guidance is not used. Instead of recommended guidance, existing portable smoke removal equipment capacity is used. The smoke and heat removal from the diesel fuel oil storage area, in the diesel generator building, will be through the use of portable smoke removal equipment. Normal or essential ventilation systems may also be used if available. For the diesel fuel oil storage area, portable smoke removal equipment capacity meets the recommended ventilation of 300 cfm/200 ft^2. Only portable equipment, however, is relied on for smoke removal capability. See Appendix 9A response to Question 9A.86. Natural-convection ventilation is not used in any power block building.
(h) Self-contained breathing apparatus, using full face positive pressure masks, approved by NIOSH (National Institute for Occupational Safety and Health - approval formerly given by the U.S. Bureau of Mines) should be provided for fire brigade, damage control and control room personnel. Control room personnel may be furnished breathing air by a manifold system piped from a storage reservoir if practical. Service or operating life should be a minimum of 1/2 hour for the self-contained units.	(h) Same	(h) PVNGS complies. Only "bottled air" will be used with full face positive pressure masks approved by NIOSH. • Fire department and control room personnel are provided with self-contained breathing apparatus. • The service life of the self-contained breathing apparatus is a minimum of 1/2 hour.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 32 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
4. Ventilation (Continued)	4. Ventilation (Continued)	4. Ventilation (Continued)
At least two extra air bottles should be located onsite for each self-contained breathing unit. In addition, an onsite 6-hour supply of reserve air should be provided and arranged to permit quick and complete replenishment of exhausted supply air bottles as they are returned. If compressors are used as a source of breathing air, only units approved for breathing air should be used. Special care must be taken to locate the compressor in areas free of dust and contaminants.		PVNGS complies by using only "bottled air" for self-contained breathing units. An additional 1-hour air supply is provided for each self-contained breathing unit. Additionally, a minimum 6-hour supply of reserve air is provided and arranged to permit quick and complete replenishment of exhausted air supply bottles.
(i) Where total flooding gas extinguishing systems are used, area intake and exhaust ventilation dampers should close upon initiation of gas flow to maintain necessary gas concentration. (See NFPA 12, Carbon Dioxide Systems, and 12A, Halon 1301 Systems.)	(i) Same	(i) Electrothermally actuated dampers are provided for CO_2 total flooding systems in the ESF switchgear room and the battery rooms. Electrothermally actuated dampers are provided for the Halon 1301 total flooding system in the communication, computer, and inverter rooms. With the exception of the battery room exhaust dampers, which are on a time delay to prevent overpressurization, for both total flooding gas extinguishing systems, the intake and exhaust dampers close upon initiation of gas flow to maintain the necessary gas concentration. (Also see sections E.4 and E.5 of this table.) See appendix 9A response to Question 9A.83.
5. Lighting and Communication	5. Lighting and Communication	5. Lighting and Communication
Lighting and two-way voice communication are vital to safe shutdown and emergency response in the event of fire. Suitable fixed and portable emergency lighting and communication devices should be provided to satisfy the following requirements:	Same	Lighting is provided. See subsection 9.5.3 and Appendix 9A response to Question 9A.125. Two-way voice communications are provided. See appendix 9A response to Question 9A.76.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
5. Lighting and Communication (Cont)	5. Lighting and Communication (Cont)	5. Lighting and Communication (Continued)
(a) Fixed emergency lighting should consist of sealed beam units with individual 8-hour minimum battery power supplies.		(a) Fixed emergency lighting with 8-hour battery backed power supplies are provided in all areas needed for the local manual operation of safe shutdown equipment and in access and egress routes, thereto. Exceptions to this are described in 5(b). Emergency lighting for personnel egress from other plant areas is provided by 1-1/2 hour battery units. See section 9.5.3.2.1 for specific locations containing 8-hour emergency lighting.
(b) Suitable sealed beam battery powered portable hand lights should be provided for mergency use.		(b) Sealed beam battery-powered portable lanterns will be readily available to the operators for the following: when access/egress or manual actions are required in the yard area (i.e., condensate storage tank pumphouse, reactor make-up water tank, alternate entrances to the diesel generator building); and when actions are necessary beyond 8 hours or to serve as a compensatory measure for nonfunctional emergency lights.
(c) Fixed emergency communication should use voice-powered head sets at preselected stations.		(c) Fixed emergency voice-powered headsets are provided at preselected stations. See section 9B.2 for specific zones containing voice-powered headset phone jacks.
(d) Fixed repeaters installed to permit use of portable radio communication units should be protected rom exposure to fire damage.		(d) The room which houses the repeaters and other major components of the plant two-way radio system is protected by a wet pipe sprinkler system and a remotely-monitored smoke detector. The redundant ac power feeds for the radio system are from independent MCCs in different fire zones. The power cables maintain separate routings and do not both pass through the same fire zone. The interior antenna system for the radio system is fault tolerant. Loss of the antennas and antenna cables in one fire zone will not significantly impact radio system performance in other fire zones. See also the response to Question 9A.129 in UFSAR Appendix 9A.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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E. FIRE DETECTION AND SUPPRESSION

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Fire Detection	1. Fire Detection	1. Fire Detection
(a) Fire detection systems should as a minimum comply with NFPA 72D, Standard for the Installation, Maintenance and Use of Proprietary Protective Signaling Systems.	Same. Deviations from the requirements of NFPA 72D should be identified and justified.	(a) NFPA 72D (1975) was used as guidance in the design of the fire detection systems as described in the appendix 9A responses to Questions 9A.71, 9A.113, and 9A.128.
(b) Fire detection system should give audible and visual alarm and annunciation in the control room. Local audible alarms should also sound at the location of the fire.		(b) PVNGS complies by providing audible and visual alarm in the control room. Control room annunciation is provided by means of a visual display, which will display a printout description of any encountered alarm condition. Local audible alarms are provided in the areas of the fire.
(c) Fire alarms should be distinctive and unique. They should not be capable of being confused with any other plant system alarms.		(c) PVNGS complies. All signals from the fire protection system are received at the central alarm station (CAS) host computer. The fire alarm signal is then transmitted from CAS to each units' control room and annunciated at the fire protection display. The fire protection alarm signals received in the control rooms are distinctive and unique from all other trouble and alarm signals. A backup annunciator is available at the Fire Department if needed. See appendix 9A response to Question 9A.114.
(d) Fire detection and actuation systems should be connected to the plant emergency power supply.		(d) Fire detection and suppression systems for PVNGS have two sources of ac power. If failure of the primary source occurs, switching to the secondary power source will be automatic. The primary source of power is from the emergency lighting panels, with an UPS as a secondary source. However, the only power source under the fire protection quality assurance program is the local battery backups.

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COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Fire Protection Water Supply Systems (a) An underground yard fire main loop should be installed to furnish anticipated fire water requirements. NFPA 24, Standard for Outside Protection, gives neccessary guidance for such installation. It references other design codes and standards developed by such organizations as the American National Standards Institute (ANSI) and the American Water Works Association (AWWA). Lined steel or cast iron pipe should be used to reduce internal tuberculation. Such tuberculation deposits in an unlined pipe over a period of years can significantly reduce	2. Fire Protection Water Supply Systems (a) Same. Visible location marking signs for underground valves is acceptable. Alternative valve position indicators should also be provided.	2. Fire Protection Water Supply Systems (a) PVNGS complies by installing underground yard main loop for the fire water requirements using the guidance of NFPA 24 (1973) and NFPA 24 (1995). A combination of cement mortar-lined (ductile) case iron pipe and reinforced fiberglass pipe is used for the underground yard main loop. Portions of the underground yard main loop piping which are cement mortar-lined (ductile) cast iron pipe follow the guidance of NFPA 24 (1973). Those portions which are reinforced fiberglass pipe follow the guidance of NFPA 24 (1995). The reinforced fiberglass piping is intended to meet all of the requirements of the cement mortar-lined (ductile) specific cast iron pipe (e.g., structural integrity, pressure boundary integrity, hydraulic performance and minimization of internal tuberculation) with the exception of those requirements that are uniquely related to the selection of the specific underground piping material. Cement-lined, cast iron pipe is used for the underground yard main loop. Flushing of the fire protection water system piping is performed using the guidance of NFPA 24 (1973). Post indicator valves are installed to isolate portions of the yard fire main for maintenance or repair without shutting off the entire system. Post-indicator valves that do not have above grade post-indicators, are provided with position indicators located below grade and access covers to allow verification of valve position and are intended to comply with the requirements of NFPA 24 (1995).

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COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 36 of 69)

E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Fire Protection Water Supply Systems (Cont)	2. Fire Protection Water Supply Systems (Cont)	2. Fire Protection Water Supply Systems (Continued)
water flow through the combination of increased friction and reduced pipe diameter. Means for treating and flushing the systems should be provided. Approved visually indicating sectional control valves, such as post-indicator valves, should be provided to isolate portions of the main for maintenance or repair without shutting off the entire system.		
The fire main system piping should be separate from service or sanitary water system piping.	For operating plants, fire main system piping that can be isolated from service or sanitary water system piping is acceptable.	PVNGS complies by utilizing separate piping for fire protection and domestic water.
(b) A common yard fire main loop may serve multiunit nuclear power plant sites, if cross-connected between units. Sectional control valves should permit maintaining independence of the individual loop around each unit. For such installations, common water supplies may also be utilized. The water supply should be sized for the largest single expected flow. For multiple reactor sites with widely separated plants (approaching 1 mile or more), separate yard fire main loops should be used.	(b) Same. Sectionalized systems are acceptable.	(b) PVNGS complies by utilizing a cross-connected yard main loop with appropriate sectional control valves to serve all three units, which are approximately 500 feet apart from each other. The flow capacity is sized for the largest expected flow for any one unit (see section E.(2).(e) of this table.) All units can be supplied considering a single failure in any part of the loop.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 37 of 69)

D. GENERAL GUIDELINES FOR PLANT PROTECTION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Fire Protection Water Supply Systems (Continued) (c) If pumps are required to meet system pressure or flow requirements, a sufficient number of pumps should be provided so that 100% capacity will be available with one pump inactive (e.g., three 50% pumps or two 100% pumps). The connection to the yard fire main loop from each fire pump should be widely separated, preferably located on opposite sides of the plant. Each pump should have its own driver with independent power supplies and control. At least one pump (if not powered from the emergency diesels) should be driven by nonelectrical means, preferably diesel engine. Pumps and drivers should be located in rooms separated from the remaining pumps and equipment by a minimum 3-hour fire wall. Alarms indicating pump running, driver availability, or failure to start should be provided in the control room.	2. Fire Protection Water Supply Systems (Continued) (c) Same	2. Fire Protection Water Supply Systems (Continued) (c) PVNGS has three fire pumps capable of supplying 1500 ± 10% (1,350 minimum) gallons per minute each at 125 psi. Two are diesel-driven and one has an electric motor driver. With one pump inactive, adequate capacity is available for all plant areas. With two pumps inactive, adequate capacity (1,350 gpm) is available for all safety related areas. Minimum pumping capacity of 1,350 gpm is based on 500 gallons per minute for manual hose streams plus the hydraulically calculated demand for the largest safety-related area sprinkler or deluge system. Each fire pump is separately connected to the yard fire main loop. Each fire pump is provided with its own driver, with independent power supplies and control. Pumps and drivers are located in rooms separated from the remaining pumps and equipment by 2-hour walls. Wet pipe sprinkler systems are provided in the two diesel-driven pump rooms. The following alarms are provided in the control room for the diesel-driven pumps. • Engine running [Class A signal] • Controller switch to "off" or "manual" position [Class A signal] • Controller trouble [Class B signal] common for - Loss of battery charger - Failure of engine to start automatically - Shutdown from overspeed - Low oil pressure - High engine jacket water temperature - Battery failure - Fuel oil day tank low level The following alarms are provided in the control room for the motor-driven pump. • Motor running [Class A signal] • Loss of the line power on line side of motor starter in any phase [Class A signal]

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COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A
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E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Fire Protection Water Supply Systems (Cont) Details of the fire pump installation should as a minimum conform to NFPA 20, Standard for the Installation of Centrifugal Fire Pumps.	2. Fire Protection Water Supply Systems (Cont)	2. Fire Protection Water Supply Systems (Continued) NFPA 20 (1976) was used as a guide for the fire pump installation. Diesel fire pump skid components (pump, diesel engine and controller) installed in 2005, were installed using the guidance of NFPA 20, 2003. Exceptions include the following: • NFPA 20 (1976), Section 8-4.2: A guard or protection pipe is not installed for all exposed fuel lines. The diesel fuel supply tanks are located near the fire pumphouse with approximately 6 feet of exposed piping between the aboveground fuel tank and the fire pumphouse. • NFPA 20 (1976), Section 8-4.5: Diesel fuel supply tanks of steel construction are located aboveground, outside the fire pumphouse, in concrete dikes. These dikes are not considered part of the required fire protection system. The tanks and fuel piping are exposed. Freeze protection is provided by insulating the fuel piping and by using No. 2 diesel fuel specifications with appropriate winterized properties. See appendix 9A response to Question 9A.72. • NFPA 25 (2002), Section 8.3.1: The fire protection diesel driven pumps are started once per month and run for not less than 60 minutes to ensure normal operating temperatures are attained and diesels run smoothly. This change is consistent with prior technical specification commitments on the fire protection system that allowed the diesels to start from ambient conditions and operate for at least 30 minutes on recirculation flow at least once per 31 days.
(d) Two separate reliable water supplies should be provided. If tanks are used, two 100% (minimum of 300,000 gallons each) system capacity tanks should be installed. They should be so interconnected that pumps can take suction from either or both. However, a leak in one tank or its piping should not cause both tanks to drain. The main plant fire water supply capacity should be capable of refilling either tank in a minimum of 8 hours. Common tanks are permitted for fire and sanitary or service water storage. When this is done, however, minimum fire water storage requirements should be dedicated by means of a vertical standpipe for other water services.	(d) Same	(d) Two separate, reliable water supply tanks are provided. Each tank has a capacity of 500,000 gallons. Of the 500,000 gallons stored within each tank, 300,000 gallons are dedicated for fire protection. The remaining 200,000 gallons are available for other uses by means of suction piping that penetrates each tank above the 300,000-gallon level. Both tanks are interconnected and the pumps can take suction from either or both. A significant leak in one tank or its piping will initiate a low level alarm alerting operators in the Unit 1 Control Room.

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COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A
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E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Fire Protection Water Supply Systems (Cont)	2. Fire Protection Water Supply Systems (Cont)	2. Fire Protection Water Supply Systems (Continued) This design feature will ensure timely operator action to isolate the tank or the pipe section from where the leak is occurring. The main plant water supply pumps are normally capable of refilling either tank in 8 hours but are not considered part of the required fire protection system.
(e) The fire water supply (total capacity and flowrate) should be calculated on the basis of the largest expected flowrate for a period of 2 hours, but not less than 300,000 gallons. This flowrate should be based (conservatively) on 1000 gpm for manual hose streams plus the greater of: (1) all sprinkler heads opened and flowing in the largest designed fire area; or (2) the largest open head deluge system(s) operating.	(e) Same	(e) PVNGS complies. Underground fire protection water lines are sized to accommodate the largest plant site fire protection water demand for automatic systems plus simultaneous flow of 1000 gpm for hose streams for the turbine building and 500 gpm for other areas of the power block. To achieve the maximum line flowrate for the turbine building (non-safety-related area) for 2 hours, the multiple use water supply in the tank will supplement the fire protection supply. Each tank has a nominal volume of 500,000 gallons. The fire protection water supply (lower 3/5 of the storage tanks) is combined with the multiple use water supply (upper 2/5) for a maximum total of 1,000,000 gallons. The reserved fire water capacity is a total of 600,000 gallons, 300,000 gallons minimum per tank for two tanks. The minimum reserved fire water capacity of 300,000 gallons is greater than the calculated largest expected safety-related area sprinkler flowrate for a period of 2 hours plus an allowance for manual hose streams of 500 gpm (reference Safety Evaluation Report, NUREG-0857,Item 9.5.1.2, page 9-31).
(f) Lakes or fresh water ponds of sufficient size may qualify as sole source of water for fire protection, but require at least two intakes to the pump supply. When a common water supply is permitted for fire protection and the ultimate heat sink, the following conditions should also be satisfied: (1) The additional fire protection water requirements are designed into the total storage capacity; and		(f) Not applicable to PVNGS

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COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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E. FIRE DETECTION AND SUPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Fire Protection Water Supply Systems (Cont) (2) Failure of the fire protection system should not degrade the function of the ultimate heat sink.	2. Fire Protection Water Supply Systems (Cont)	2. Fire Protection Water Supply Systems (Continued)
(g) Outside manual hose installation should be sufficient to reach any location with an effective hose stream. To accomplish this hydrants should be installed approximately every 250 feet on the yard main system. The lateral to each hydrant from the yard main should be controlled by a visually indicating or key-operated (curb) valve. A hose house, equipped with hose and combination nozzle, and other auxiliary equipment recommended in NFPA 25, Outside Protection, should be provided as needed but at least every 1000 feet. Threads compatible with those used by local fire departments should be provided on all hydrants, hose couplings, and standpipe risers.	(g) Same	(g) PVNGS complies with exceptions noted. • The lateral to each hydrant from the yard main is controlled by key-operated (curb) valve. • The PVNGS Fire Department has emergency response vehicle(s) which carry an assortment of hose, nozzles and auxiliary equipment in lieu of hose houses which can reach any location about the power block with an effective hose stream. • National standard hose thread is provided on all hydrants, hose couplings and standpipe risers. Local fire departments carry adapters to allow use of national standard thread.

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COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Water Sprinklers and Hose Standpipe Systems (a) Each automatic sprinkler system and manual hose station standpipe should have an independent connection to the plant underground water main. Headers fed from each end are permitted inside buildings to supply multiple sprinkler and standpipe systems. When provided, such headers are considered an extension of the yard main system. The header arrangement should be such that no single failure can impair both the primary and backup fire protection system.	3. Water Sprinklers and Hose Standpipe Systems (a) Same	3. Water Sprinklers and Hose Standpipe Systems (a) PVNGS complies by providing headers that are fed from each end for the control, auxiliary, and turbine buildings. These headers serve multiple sprinkler systems and also the hose rack/reel stations for each respective building, and no single failure will result in any of the following situations: • For the auxiliary and control buildings, primary water spray systems and all hose stations for any specific fire zone impaired at once. • For the turbine building, primary sprinkler system and backup hose stations impaired at once. • For the diesel generator building, no single failure can impair both trains or both primary and backup fire protection system. Separate headers from the control building feed the automatic preaction sprinkler systems. Each diesel generator train is fed separately. The hose stations, connected to each header, are located in the control building. • For the main steam support structure, no single failure can impair both the primary and backup suppression capability. The backup hose streams are available from hydrant on the yard main and hose station No. 63 in the turbine building adjacent to the main steam support structure. (See appendix 9A response to Question 9A.100.) In the fuel building, sprinkler system and manual hose stations are fed from a single header connected to the plant underground yard main. In the containment building, all of the hose stations and the sprinklers for the charcoal filters are fed from a single header from the auxiliary building. The supply header piping is Seismic Category I. (See appendix 9A response to Question 9A.97.)

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COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 42 of 69)

E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Water Sprinklers and Hose Standpipe Systems (Continued) Each sprinkler and standpipe system should be equipped with outside screw and yoke (OS&Y) gate valve, or other approved shut off valve, and water flow alarm. Safety-related equipment hat does not itself require sprinkler water fire protection, but is subject to unacceptable damage if wetted by sprinkler water discharge should be protected by water shields or baffles.	3. Water Sprinklers and Hose Standpipe Systems (Continued)	3. Water Sprinklers and Hose Standpipe Systems (Continued) Each sprinkler and standpipe system is equipped with an OS&Y gate valve or approved shut off valve. Water flow alarms are provided for the sprinkler systems. See section A.5 of this table for discussion of inadvertent operation of fire suppression systems not incapacitating safety-related systems.
(b) All valves in the fire water systems should be electrically supervised. The electrical supervision signal should indicate in the control room and other appropriate command locations in the plant (see NFPA 26, Supervision of Valves.)	(b) Same. When electrical supervision of fire protection valves is not practicable, an adequate management supervision program should be provided. Such a program should include locking valves open with strict key control; tamper proof seals; and periodic, visual check of all valves.	(b) All valves controlling (isolating) Automatic Fire Protection Water Suppression Systems, and all sectional and header isolation valves, are locked in their proper position, and are supervised by inspection, per NFPA 13, 1976, section 3.13. Additionally: Supervision of the following valves is provided by inspection. • Valves located on laterals from the yard main to each hydrant. These are key-operated (curb) valves, normally open, and cannot be closed without the key. • All post-indicator valves which are locked open. • The header isolation valves for standpipes and hose stations. • Valves for the automatic water sprinkler heads over two missile doors.

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COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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E. FIRE DETECTION AND SUPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Water Sprinklers and Hose Standpipe Systems (Continued) (c) Automatic sprinkler systems should as a minimum conform to requirements of appropriate standards such as NFPA 13, Standard for the Installation of Sprinkler Systems, and NFPA 15, Standard for Water Spray Fixed Systems.	3. Water Sprinklers and Hose Standpipe Systems (Continued) (c) Same	3. Sprinklers and Hose Standpipe Systems (Continued) (c) PVNGS uses as guidance NFPA 13 (1976), Standard for the Installation of Sprinklers, and NFPA 15 (1973), Standard for Water Spray Fixed Systems, as follows: • In the auxiliary, control, fuel, radwaste, and turbine buildings and also in the main steam support structure the spacing, location, and position of the sprinklers are dictated by the type of construction. The ceilings in all these buildings are of noncombustible construction and the beam epth exceeds that which is indicated in NFPA 13 (1976). NFPA guidance is provided only for those buildings with beams of less than 18 inches in depth. The actual sprinkler spacing as measured from ceiling or beam is more than the spacing recommended in NFPA 13 (1976) Section 4.3.4. However, in order to protect the structural steel, sprinklers have been provided in bays formed by beams. These sprinklers are located 16 inches to 22 inches from the ceiling. Conformance to the applicable NFPA standards required per Section 4020 of NFPA 15 (1973) is addressed separately in this report. • See E.(3).(b) for conformance to NFPA 26 (1976) • See E.(3).(d) for conformance to NFPA 14 (1976) • See E.(2).(a) and E.(2).(g) for conformance to NFPA 24 (1973) • See E.(2).(c) for conformance to NFPA 20 (1976) • See E.(1).(a) for conformance to NFPA 72D (1975)

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E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
(d) Interior manual hose installation shall be able to reach any location with at least one effective hose stream. To accomplish this, standpipes with hose connections, equipped with a maximum of 75 feet of 1-1/2-inch woven jacket-lined fire hose and suitable nozzles should be provided in all buildings, including containment, on all floors and should be spaced at not more than 100-foot intervals. Individual standpipes should be of at least 4-inch diameter for multiple hose connections and 2-1/2-inch diameter for single hose connections. These systems should follow the requirements of NFPA 14, Standpipe and Hose Systems, for sizing, spacing, and pipe support requirements.	(d) Interior manual hose installation should be able to reach any location with at least one effective hose stream. To accomplish this, standpipes with hose connections, equipped with a maximum of 75 feet of 1-1/2 inch woven jacket-lined fire hose and suitable nozzles, should be provided in all buildings, including containment, on all floors and should be spaced at not more than 100-foot intervals. Individual standpipes should be of at least 4-inch diameter for multiple hose connections and 2-1/2-inch diameter for single hose connections. These systems should follow the requirements of NFPA No. 14 for sizing, spacing, and pipe support requirements (NELPIA).	(d) PVNGS complies except that: • As indicted in section 9B.2, hose lengths of 75 feet, 100 feet, 125 feet, and 150 feet are used (see appendix 9A responses to Questions 9A.65 and 9A.115). • The following multiple hose connections are fed from a common 2-1/2-inch standpipe: Radwaste building: • Hose station No. 54 (elevation 120 feet 0 inch) and No. 56 (elevation 140 feet 0 inch) • Hose station No. 55 (elevation 120 feet 0 inch) and No. 57 (elevation 140 feet 0 inch) Turbine building: • Hose stations No. 79 and No. 101. Both hose stations are located close to each other at elevation 176 feet 0 inch

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Water Sprinklers and Hose Standpipe Systems (Continued) Hose stations should be located outside entrances to normally unoccupied areas and inside normally occupied areas. Standpipes serving hose stations in areas housing safety-related equipment should have shutoff valves and pressure-reducing devices (if applicable) outside the area. Provisions should be made to supply water at least to standpipes and hose connections for manual firefighting in areas within hose reach of equipment required for safe plant shutdown in the event of an SSE. The standpipe system serving such hose stations should be analyzed for SSE loading and should be provided with supports to assure system pressure integrity. The piping and valves for the portion of hose standpipe system affected by this functional requirement should at least satisfy ANSI Standard B31.1, Power Piping. The water supply for this condition may be obtained by manual operator actuation of valve(s) in a connection to the hose standpipe header from a normal Seismic Category I water system such as essential service water system. The cross-connection should be (a) capable of providing flow to at least two hose stations (approximately 75 gpm/hose station), and (b) designed to the same standards as the Seismic Category I water system; it should not degrade the performance of the Seismic Category I water system.	3. Water Sprinklers and Hose Standpipe Systems (Continued) Hose stations should be located outside entrances to normally unoccupied areas and inside normally occupied areas. Standpipes serving hose stations in areas housing safety-related equipment should have shutoff valves and pressure-reducing devices (if applicable) outside the area.	3. Water Sprinklers and Hose Standpipe Systems (Continued) Hose stations are provided at the entrances to fire zones as detailed in section 9B.2. PVNGS provides shutoff valves for standpipes and pressure reducing devices for hose stations in areas housing safety related equipment. The shutoff valves are located outside the zones, except for those zones noted in Table E.3.(d)-3. Table E.3.(d)-3 STANDPIPES SERVING HOSE STATIONS WITH SHUTOFF VALVES LOCATED INSIDE THE SAME FIRE ZONE

Fire Zone	Location	Safety-Related Equipment Within Zone/Justification
42D	Auxiliary building, El: 100 feet 0 inch	Train A cables and conduit/hose streams from nearby hose stations available. Redundant train available.
42C	Auxiliary building, El: 100 feet 0 inch	Train A and B cables and conduit/hose streams from nearby hose stations available. Redundant train available.
52D	Auxiliary building, El: 120 feet 0 inch	Train B conduit. Redundant train available.
66B	Containment building, El: 80 feet 0 inch through 140 feet 0 inch	Cables, control instrumentation, and piping/hose streams from nearby hose stations available. Redundant train available. Line type thermal detectors, installed in cable trays.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 46 of 69)

E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Water Sprinklers and Hose Standpipe Systems (Continued)	3. Water Sprinklers and Hose Standpipe Systems (Continued)	3. Water Sprinklers and Hose Standpipe Systems (Continued)
(e) The proper type of hose nozzles to be supplied to each area should be based on the fire hazard analysis. The usual combination spray/straight-stream nozzle may cause unacceptable mechanical damage (for example, the delicate electronic equipment in the control room) and be unsuitable. Electrically safe nozzles should be provided at locations where electrical equipment or cabling is located.	(e) Same	(e) PVNGS selects the proper types of hose nozzles based upon the fire hazards analysis. See Section 9B.2 for details. Electrically safe nozzles are used in areas where electrical equipment or cabling is located.
(f) Certain fires such as those involving flammable liquids respond well to foam suppression. Consideration should be given to use of any of the available foams for such specialized protection application. These include the more common chemical and mechanical low expansion foams, high expansion foam, and the relatively new aqueous film forming foam (AFFF).	(f) Same	(f) Special extinguishing agents are available for use by the fire department as required.
4. Halon Suppression Systems The use of Halon fire extinguishing agents should as a minimum comply with the requirements of NFPA 12A and 12B, Halogenated Fire Extinguishing Agent Systems - Halon 1301 and Halon 1211. Only UL or FM approved agents should be used. In addition to the guidelines of NFPA 12A and 12B, preventative maintenance and testing of the systems, including check weighting of the Halon cylinders should be done at least quarterly.	4. Halon Suppression Systems Same	4. Halon Suppression Systems PVNGS complies by utilizing "Halogenated Fire Extinguishing Agent System - Halon 1301." NFPA 12A (1973) was used as a guide for the installation of Halon 1301 systems. PVNGS verifies the liquid quantity in, or weight of the Halon in the cylinders at least every 6 months.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 47 of 69)
E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
4. Halon Suppression Systems (Continued)	4. Halon Suppression Systems (Cont.)	4. Halon Suppression Systems (Continued)
Particular consideration should also be given to:		The PVNGS design reflects these considerations:
(a) minimum required Halon concentration and soak time		(a) The minimum/maximum Halon concentration range used is 5% to 7% by volume in occupied hazard areas, and 5% to 10% by volume in unoccupied areas or areas evacuable within 1 minute as provided by NFPA Pamphlet 12A (1984), Section 2-1.1.3.
(b) toxicity of Halon		(b) The Halon concentration used is below the limits specified in NFPA 12A (1973). A 20-second time delay before system actuation is provided for evacuation of personnel.
(c) toxicity and corrosive characteristics of thermal decomposition products of Halon		(c) The low concentration of Halon 1301 with rapid extinguishment (less than 10 seconds) is provided to minimize production of thermal decomposition product.
5. Carbon Dioxide Suppression Systems	5. Carbon Dioxide Suppression Systems	5. Carbon Dioxide Suppression Systems
The use of carbon dioxide extinguishing systems should as a minimum comply with the requirements of NFPA 12, Carbon Dioxide Extinguishing Systems.	Same	NFPA 12 (1973) was used as a guide for the installation of carbon dioxide extinguishing systems.
Particular consideration should also be given to:		The PVNGS design reflects these considerations;
(a) minimum required CO_2 concentration and soak time;		(a) Design CO_2 concentration of 50% is used with a flooding factor of 0.083 lb CO_2/ft^3. (Section 2421, NFPA 12, 1973). Extended discharge protection of approximately 18 minutes is provided for the ESF switchgear rooms.
(b) toxicity of CO_2;		(b) Odorizing equipment is provided to alert personnel of system operation. Actuation of CO_2 to each protected area is delayed to allow evacuation of personnel. The actuation time delay is area - specific and based on the anticipated time to allow personnel egress. The time delay setpoint is adjustable and is controlled by plant procedures.
(c) possibility of secondary thermal shock (cooling) damage;		(c) Discharge nozzles are located away from equipment to avoid possibility of thermal shock damage.
(d) offsetting requirements for venting during CO_2 injection to prevent overpressurization versus sealing to prevent loss of agent.		(d) Damper is provided with time delay relay to prevent over-pressurization during CO_2 injection in the battery rooms, door cracks in the ESF switchgear rooms are utilized to prevent overpressurization.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 48 of 69)

E. FIRE DETECTION AND SUPPRESSION (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
5. Carbon Dioxide Suppression Systems (Continued)	5. Carbon Dioxide Suppression Systems (Continued)	5. Carbon Dioxide Suppression Systems (Continued)
(e) design requirements from overpressurization; and		(e) Provided as indicated above.
(f) possibility and probability of CO_2 systems being out-of-service because of personnel safety consideration. CO_2 systems are disarmed whenever people are present in an area so protected. Areas entered frequently (even though duration time for any visit is short) have often been found with CO_2 systems shut off.	(f) Same	(f) The status of the CO_2 suppression syst4em is monitored in the control room. When the CO_2 system is disarmed, this condition is annunciated in the control room except for the CO_2 manual valves which are locked/sealed open and administratively controlled.
6. Portable Extinguishers Fire extinguishers should be provided in accordance with guide lines of NFPA 10 and 10A, Portable Fire Extinguishers Installation, Maintenance and Use. Dry chemical extinguishers should be installed with due consideration given to cleanup problems after use and possible adverse effects on equipment installed in the area.	6. Portable Extinguishers Same	6. Portable Extinguishers PVNGS complies by providing portable extinguishers using the guidelines of NFPA 10 (1975). Listed below are zones where the travel distance between extinguishers exceeds the maximum travel distance of 75 feet required per Section 3.2 of NFPA 10 (1975). Zones 37A and 37B; Train A and B corridor zones, El: 70 feet 0 inch, auxiliary building Zones 39A and 39B: Train A and B pipeways, El: 88 feet 0 inch, auxiliary building

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 49 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Primary and Secondary Containment	1. Primary and Secondary Containment	1. Primary and Secondary Containment
(a) Normal Operation Fire protection requirements for primary and secondary containment areas should be provided on the basis of specific identified hazards. For example:	(a) Normal Operation Same except as noted.	(a) Normal Operation PVNGS complies with the fire protection requirements for the specific identified hazards for the primary containment areas. See section 9B.2. See F.1.(b) for portable fire extinguishers. Note: There are no secondary containment areas in PVNGS.
• Lubricating oil or hydraulic fluid system for the primary coolant pumps		• PVNGS complies by providing a design for the reactor coolant pumps which channels lube oil leakage away from the hot surfaces of the pump to an oil collection tank. See appendix 9A response to Question 9A.126.
• Cable tray arrangements and cable penetrations		• Cable tray arrangements and cable penetrations are protected. Line type temperature detectors as well as ionization smoke detectors are provided for early warning. Class A wiring is provided. The high temperature alarm is annunciated in the control room. Cable trays are also accessible from manual hose stations. PVNGS meets 10CFR50, Appendix R, Section III.G.2, separation criteria with the exception of the deviations called out in section 9B.2 of this report and the appendix 9A response to Question 9A.130.
• Charcoal filters		• For the fire protection provided for the charcoal filters, see section D.4(d) of this table.
Because of the general inaccessibility of these areas during normal plant operations, protection should be provided by automatic fixed systems. Automatic sprinklers should be installed for those hazards identified as requiring fixed suppression.	Fire suppression systems should be provided based on the fire hazards analysis. Fixed fire suppression capability should be provided for hazards that could jeopardize safe plant shutdown. Automatic sprinklers are preferred. An acceptable alternate is automatic gas (Halon or CO_2) for hazards identified as requiring fixed suppression protection.	PVNGS does not provide any automatic fixed suppression system within the containment based on the results of the fire hazards analysis in section 9B.2. The analysis has shown that any postulated fire occurring within the PVNGS containment will not restrict the capability of safe shutdown systems to accomplish a safe shutdown of the reactor.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Primary and Secondary Containment (Continued)	1. Primary and Secondary Containment (continued)	1. Primary and Secondary Containment (continued)
Operation of the fire protection systems should not compromise integrity of the containment or the other safety-related systems. Fire protection activities in the containment areas should function in conjunction with total containment requirements such as control of contaminated liquid and gaseous release and ventilation.	An enclosure may be required to confine the agent if a gas system is used. Such enclosure should not adversely affect safe shutdown, or other operating equipment in containment.	PVNGS does not utilize any fixed gas fire suppression systems within the containment building. Fire protection systems will not compromise the integrity of the containment or of the other safety-related systems. Fire protection activities will function in conjunction with total containment requirements such as the control of contaminated liquid and gaseous release and ventilation.
Fire detection systems should alarm and annunciate in the control room. The type of detection used and the location of the detectors should be most suitable to the particular type of fire that could be expected from the identified hazard. A primary containment general area fire detection capability should be provided as backup for the above described hazard detection. To accomplish this, suitable smoke detection (e.g., visual obscuration, light scattering, and particle counting) should be installed in the air recirculation system ahead of any filters.		Fire detection systems will alarm and annunciate in the control room. Line-type temperature detectors are installed on the cable trays, thermal detectors in the HVAC charcoal filters, and ionization detectors near the reactor coolant pumps. Primary general area fire detection capability is provided by ionization detectors as backup to the specific hazard detection identified above. Therefore, smoke detection ahead of the air filters is not provided. Special fire protection requirements during refueling and maintenance operations are addressed in section F.1.(b) of this table.
Automatic fire suppression capability need not be provided in the primary containment atmospheres that are inerted during normal operation. However, special fire protection requirements during refueling and maintenance operations should be satisfied as provided below.	Automatic fire suppression capability need not be provided in the primary containment atmospheres that are inerted during normal operation. However, special fire protection requirements during refueling and maintenance operations should be satisfied as provided below.	

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 51 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Primary and Secondary Containment (continued)	1. Primary and Secondary Containment (continued)	1. Primary and Secondary Containment (continued)
(b) Refueling and Maintenance	(b) Refueling and Maintenance	(b) Refueling and Maintenance
Refueling and maintenance operations in containment may introduce additional hazards such as contamination control materials, decontamination supplies, wood planking, temporary wiring, welding, and flame cutting (with portable compressed fuel gas supply). Possible fires would not necessarily be in the vicinity of fixed detection and suppression systems.	Same	
Management procedures and controls necessary to assure adequate fire protection are discussed in section 3a.		PVNGS complies, as described in section 3a of this table.
In addition, manual firefighting capability should be permanently installed in containment. Standpipes with hose stations, and portable fire extinguishers, should be installed at strategic locations throughout containment for any required manual firefighting operations.	Equivalent protection from portable systems should be provided if it is impractical to install standpipes with hose stations.	PVNGS complies by providing permanent hose stations within the containment building. Portable fire extinguishers are provided within the containment building during outages (modes 5 and 6). They are removed during operation (modes 1-4) to prevent potential adverse effects from radiation, heat, and other plant accidents and to permit periodic inspections.
Adequate self-contained breathing apparatus should be provided near the containment entrances for firefighting and damage control personnel. These units should be independent of any breathing apparatus or air supply systems provided for general plant activities.		PVNGS complies by providing the plant fire department with self-contained breathing apparatus for use as required.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Control Room	2. Control Room	2. Control Room
The control room is essential to safe reactor operation. It must be protected against disabling fire damage and should be separated from other areas of the plant by floors, walls, and roofs having minimum fire resistance ratings of 3 hours. Control room cabinets and consoles are subject to damage from two distinct fire hazards: (a) Fire originating within cabinet or console; and (b) Exposure fire involving combustibles in the general room area.	Same	PVNGS complies by providing 3-hour rated walls, floor, and ceiling for the control room complex except for the following: (i) The southeast exterior wall of the control room is non-rated. It is not required to separate redundant shutdown systems. (ii) The common walls to the three HVAC chases, located at three corners of the control room, are 2-hour rated. There are no combustibles in the HVAC chases and the combustible (fire) loading of the control room is low. (iii) The common walls between the control room and computer room are 2-hour rated. The computer room has a Halon suppression system. (See appendix 9A responses to Questions 9A.109 and 9A.118.)
Manual firefighting capability should be provided for both hazards. Hose stations and portable water and Halon extinguishers should be located in the control room to eliminate the need for operators to leave the control room. An additional hose piping shutoff valve and pressure-reducing device should be installed outside the control room. Hose stations adjacent to the control room with portable extinguishers in the control room acceptable.	Hose stations adjacent to the control room with extinguishers in the control room are acceptable.	PVNGS complies by providing a hose station adjacent to each entrance to the control room plus portable CO_2 and pressurized water fire extinguishers inside the control room. Portable Halon extinguishers are utilized in the computer room. The hose piping shutoff valves are installed outside the control room.
Nozzles that are compatible with the hazards and equipment in the control room should be provided for the manual hose station. The nozzles chosen should satisfy actual firefighting needs, satisfy electrical safety and minimize physical damage to electrical equipment from hose stream impingement.		PVNGS complies by providing Class C nozzles on the hose stations to satisfy electrical safety and minimize physical damage to electrical equipment from hose stream impingement.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
2. Control Room (continued)	2. Control Room (continued)	2. Control Room (continued)
Fire detection in the control room cabinets and consoles should be provided by smoke and heat detectors in each fire area. Alarm and annunciation should be provided in the control room. Fire alarms in other parts of the plant should also be alarmed and annunciated in the control room.		PVNGS complies by providing smoke detectors in the ventilation stream above each cabinet. Area smoke detectors are provided for the entire control room. All fire alarms in the plant are annunciated in the control room. The PVNGS design does not utilize smoke detectors inside control room cabinets.
Breathing apparatus for control room operators should be readily available. Control room floors, ceiling, supporting structure, and walls, including penetrations and doors, should be designed to a minimum fire rating of 3 hours. All penetration seals should be airtight.		PVNGS complies by providing readily available breathing apparatus for the control room personnel. The fire rating of the control room is described at the start of this section. Penetration seals are airtight.
The control room ventilation intake should be provided with smoke detection capability to automatically alarm locally and isolate the control room ventilation system to protect operators by preventing smoke from entering the control room. Manually operated venting of the control room should be available so that operators have the option of venting for visibility.	Manually operated ventilation systems are acceptable.	Smoke detectors are installed to provide area wide coverage in the control room and to alarm if smoke is detected. • Smoke detection is provided in the combined control building/control room ventilation intake shaft. • If smoke enters the control room, the Control Room Ventilation Isolation Actuation Signal (CRVIAS) will be manually initiated to protect the operators. • PVNGS complies with manually operated smoke removal ventilation system.
Cables should not be located in concealed floor and ceiling spaces. All cables that enter the control room should terminate in the control room. That is, no cabling should be simply routed through the control room from one area to another.	If such concealed spaces are used, however, they should have fixed automatic total flooding Halon protection	Cables to the control room operator workstations are routed below the raised platform. Some cable trays are routed above the suspended ceiling. See response to section D.1(f) of this table. All cables that enter the control room are terminated in the control room. No cabling is routed through the control room from one area to another.
Safety-related equipment should be mounted on pedestals or the control room should have curbs and drains to direct water away from such equipment. Such drains should be provided with means for closing to maintain integrity of the control room in the event of other accidents requiring control room isolation.	Not applicable.	Not applicable. Note: For information concerning mounting of control room equipment, see section D.1.(i) of this table.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Cable Spreading Room The primary fire suppression in the cable spreading room should be an automatic water system such as closed head sprinklers, open head deluge, or open directional spray nozzles. Deluge and open spray systems should have provisions for manual operation at a remote station; however, there should be provisions to preclude inadvertent operation. Location of sprinkler heads or spray nozzles should consider cable tray sizing and arrangements to assure adequate water coverage. Cables should be designed to allow wetting down with deluge water without electrical faulting. Open head deluge and open directional spray systems should be zoned so that a single failure will not deprive the entire area of automatic fire suppression capability. The use of foam is acceptable, provided it is of a type capable of being delivered by a sprinkler or deluge system, such as an AFFF. An automatic water suppression system with manual hoses and portable extinguisher backup is acceptable, provided: (a) At least two remote and separate entrances are provided to the room for access by fire brigade personnel: and (b) Aisle separation provided between tray stacks should be at least 3 feet wide and 8 feet high.	3. Cable Spreading Room (a) The preferred acceptable methods are: 1. Automatic water system such as closed head sprinklers, open head deluge, or open directional spray nozzles. Deluge and open spray systems should have provisions for manual operation at a remote station; however, there should also be provisions to preclude inadvertent operation. Location of sprinkler heads or spray nozzles should consider cable tray sizing and arrangements to assure adequate water coverage. Cables should be designed to allow wetting down with deluge water without electrical faulting. Open head deluge and open directional spray systems should be zoned so that a single failure will not deprive the entire area of automatic fire suppression capability. The use of foam is acceptable, provided it is of a type capable of being delivered by a sprinkler or deluge system, such as an AFFF.	3. Cable Spreading Room (a)1. PVNGS complies by utilizing automatic preaction sprinkler systems with closed head directional spray. In order to prevent a single failure from depriving the entire area of automatic protection, each cable spreading room is divided into zones and each zone is protected by a separate preaction system. The upper cable spreading room (elevation 160 feet 0 inch) is divided into five zones and the lower cable spreading room (elevation 120 feet 0 inch) is divided into six zones. Cables are designed to allow wetting without faulting.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 55 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Cable Spreading Room (continued)	3. Cable Spreading Room (continued)	3. Cable Spreading Room (continued)
	(2) Manual hoses and portable extinguishers should be provided as backup.	(2) PVNGS complies by providing hose stations and portable CO_2 fire extinguishers as backup.
	(3) Each cable spreading room of each unit should have divisional cable separation, and be separated from the other and the rest of the plant by a minimum 3-hour rated fire wall (refer to NFPA 251 or ASTM E119 for fire test resistance rating).	(3) PVNGS complies by providing a design as described in section D.1.(c) of this table.
Drains to remove firefighting water should be provided with adequate seals when gas extinguishing systems are also installed. Redundant safety-related cable division should be separated by walls with a 3-hour fire rating.	(4) At least two remote and separate entrances are provided to the room for access by fire brigade personnel; and	(4) PVNGS complies by providing two remote and separate entrances for access by fire department personnel.
	(5) Aisle separation provided between tray stacks should be at least 3 feet wide and 8 feet high.	(5) Two cable spreading rooms are provided for divisional separation, one for train A and one for train B. PVNGS also complies with the intent of "aisle separation" within each cable spreading room, but actual separation is 2 feet 6 inches wide by 7 feet 6 inches high.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Cable Spreading Room (continued)	3. Cable Spreading Room (continued) (b) For cable spreading rooms that do not provide divisional cable separation of a(3), in addition to meeting a(1), (2), (4), and (5) above, the following should also be provided: (1) Divisional cable separation should meet the guidelines of Regulatory Guide 1.75, Physical Independence of Electric Systems. (2) All cabling should be covered with a suitable fire-retardant coating. (3) As an alternate to a(1) above, automatically initiated gas systems (Halon or CO_2) may be used for primary fire suppression, provided a fixed water system is used as a backup. (4) Plants that cannot meet the guidelines of Regulatory Guide 1.75, in addition to meeting a(1), (2), (4), and (5) above, an auxiliary shutdown system with all abling independent of the cable spreading room should be provided.	3. Cable Spreading Room (continued) (b) Not applicable to PVNGS, as divisional separation is provided.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
3. Cable Spreading Room (Continued)	3. Cable Spreading Room (Continued)	3. Cable Spreading Room (Continued)
Alternately, gas systems (Halon or CO_2) may be used for primary fire suppression if they are backed up by an installed water spray system and hose stations and portable extinguishers immediately outside the room and if the access requirements stated above are met.		Not applicable to PVNGS; preaction system is provided as primary system.
Electric cable construction should, as a minimum, pass the flame test in IEEE-383, IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices and Connections for Nuclear Power Generating Stations.		Electric cable construction is discussed in section D.3.(f) of this table.
For multiple-reactor unit sites, cable spreading rooms should not be shared between reactors. Each cable spreading room of each unit should have divisional cable separation as stated above and be separated from the other and the rest of the plant by a wall with a minimum fire rating of 3 hours. (See NFPA 251, Fire Tests, Building Construction and Materials, or ASTM E119, Fire Test of Building Construction and Materials, for fire test resistance rating.)		PVNGS complies by providing two separate cable spreading rooms for each reactor. The cable spreading rooms of each unit have divisional cable separation, as described in section D.1.(c) of this table.
The ventilation system to the cable spreading room should be designed to isolate the area upon actuation of any gas extinguishing system in the area. In addition, smoke venting of the cable spreading room may be desirable. Such smoke venting systems should be controlled automatically by the fire detection or suppression system as appropriate. Capability for remote manual control should also be provided.		PVNGS does not utilize gas extinguishing systems for the cable spreading rooms. Smoke venting for the cable spreading rooms is manually operated from the control room.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 58 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
4. Plant Computer Room Safety-related computers should be separated from other areas of the plant by barriers having a minimum 3-hour fire-resistant rating. Automatic fire detection should be provided to alarm and annunciate in the control room and alarm locally. Manual hose stations and portable water and Halon fire extinguishers should be provided.	4. Plant Computer Room Same	4. Plant Computer Room PVNGS computers are not safety-related. The computer room is separated from the control room by 2-hour rated barriers. The computer room is provided with a fixed Halon total flooding system. Detectors are provided for early warning and alarm locally.
5. Switchgear Rooms Switchgear rooms should be separated from the remainder of the plant by minimum 3-hour rated fire barriers, if practicable. Automatic fire detection should alarm and annunciate in the control room and alarm locally. Fire hose stations and portable extinguishers should be readily available.	5. Switchgear Rooms Switchgear rooms should be separated from the remainder of the plant by minimum 3-hour rated fire barriers to the extent practicable. Automatic fire detection should alarm and annunciate in the control room and alarm locally. Fire hose stations and portable extinguishers should be readily available.	5. Switchgear Rooms PVNGS safety-related switchgear rooms are separated primarily by 3-hour rated fire barriers, but some portions are 2-hour and 1-hour rated. The floors and ceilings are 3-hour rated. The train A and train B switchgear are located in separate fire zones and areas. (For details of barriers provided refer to section 9B.2.) The basis for this exception is that the PVNGS switchgear rooms are equipped with fixed CO_2 total flooding systems in addition to the fixed water hose stations and portable extinguishers, and by the fact that the fire hazards analysis has shown the combustible (fire) loading for this area to be low such that the existing barriers will contain a postulated fire.
Acceptable protection for cables that pass through the switchgear room is automatic water or gas agent suppression. Such automatic suppression must consider preventing unacceptable damage to electrical equipment and possible necessary containment of agent following discharge.	Acceptable protection for cables that pass through the switchgear room is automatic water or gas agent suppression. Such automatic suppression must consider preventing unacceptable damage to electrical equipment and possible necessary containment of agent following discharge.	PVNGS complies by providing fixed CO_2 total flooding systems for the ESF switchgear rooms. (See appendix 9A response to Question 9A.83.) The nozzles are located away from the electrical equipment in order to prevent unacceptable damage. The HVAC dampers will automatically close, following CO_2 discharge, to contain the agent.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 59 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
6. Remote Safety-Related Panels	6. Remote Safety-Related Panels	6. Remote Safety-Related Panels
The general area housing remote safety-related panels should be provided with automatic fire detectors that alarm locally and alarm and annunciate in the control room. Combustible materials should be controlled and limited to those required for operation. Portable extinguishers and manual hose stations should be provided.	Same	PVNGS complies. Automatic fire detectors are provided to alarm locally and to alarm and annunciate in the control room. Portable extinguishers and manual hose stations are available within the same fire area. Combustible materials are controlled and limited to those required for operation.
7. Station Battery Rooms	7. Station Battery Rooms	7. Station Battery Rooms
Battery rooms should be protected against fire explosions. Battery rooms should be separated from each other and other areas of the plant by barriers having a minimum fire rating of 3 hours inclusive of all penetrations and openings. (See NFPA 69, Standard on Explosion Prevention Systems.) Ventilation systems in the battery rooms should be capable of maintaining the hydrogen concentration well below 2 vol. % hydrogen concentration. Standpipe and hose and portable extinguishers should be provided.	Same	PVNGS complies by providing barriers having 3-hour fire ratings. In addition the battery rooms have CO_2 total flooding systems. The ventilation system is capable of maintaining the hydrogen concentration below 2 vol. %. Hose stations and portable extinguishers are located within the same fire area.
Alternatives:		Alternatives:
(a) Provide a total fire-rated barrier enclosure of the battery room complex that exceeds the fire load contained in the room.		Not applicable; PVNGS meets requirements above.
(b) Reduce the fire load to be within the fire barrier capability of 1-1/2 hours.		
OR		
(c) Provide a remote manual actuated sprinkler system in each room and provide the 1-1/2 hour fire barrier separation.		

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 60 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
8. Turbine Lubrication and Control Oil Storage and Use Areas	8. Turbine Lubrication and Control Oil Storage and Use Areas	8. Turbine Lubrication and Control Oil Storage and Use Areas
A blank fire wall having a minimum resistance rating of 3 hours should separate all areas containing safety-related system and equipment from the turbine oil system.	Same. When a blank wall is not present, open head deluge protection should be provided for the turbine oil hazards and automatic open head water curtain protection should be provided for wall openings.	PVNGS has 2-hour fire barriers that separate the turbine lube oils reservoir from the rest of the turbine building. None of the equipment located in the turbine building is safety-related. The lube oil room is protected by an open head deluge system. The turbine building at elevations 100 feet and 140 feet are protected by a complete automatic wet pipe sprinkler system.
9. Diesel Generator Areas	9. Diesel Generator Areas	9. Diesel Generator Areas
Diesel generators should be separated from each other and other areas of the plant by fire barriers having a minimum fire resistance rating of 3 hours.	Same	PVNGS complies. The diesel generators are separated from each other and other areas of the plant by barriers having a fire resistance rating of 3 hours.
Automatic fire suppression such as AFFF foam or sprinklers should be installed to combat any diesel generator or lubricating oil fires. Automatic fire detection should be provided to alarm and annunciate in the control room and alarm locally. Drainage for firefighting water and means for local manual venting of smoke should be provided.		PVNGS complies by providing an automatic preaction sprinkler system for each diesel generator area. Ultraviolet and thermal detectors are installed for early warning and for system actuation. Drainage for firefighting water and means for local manual venting are provided. Automatic fire detection provided to alarm and annunciate in the control room and alarms locally.
Day tanks with total capacity up to 1100 gallons are permitted in the diesel generator area under the following conditions: (a) The day tank is located in a separate enclosure, with a minimum fire resistance rating of 3 hours, including doors or penetrations. These enclosures should be capable of containing the entire contents of the day tanks. The enclosure should be ventilated to avoid accumulation to oil fumes.	When day tanks cannot be separated from the diesel generator, one of the following should be provided for the diesel generator area. (a) Automatic open head deluge or open head spray nozzle system(s).	A fuel oil day tank of 1100 gallon nominal capacity is installed in each diesel generator area. Three-hour enclosures are provided for each of the day tanks. The enclosures are sized to contain the entire contents of the day tanks. (See appendix 9A response to Questions 9A.86.) The enclosures are protected by an automatic preaction sprinkler system. Thermal detectors are installed for early warning and system actuation. The enclosures are ventilated to avoid accumulation of oil fumes.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 61 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
9. Diesel Generator Areas (continued) (b) The enclosure should be protected by automatic fire suppression systems such as AFFF or sprinklers.	9. Diesel Generator Areas (continued) (b) Automatic closed head sprinklers (c) Automatic AFF that is delivered by a sprinkler deluge or spray system (d) Automatic gas system (Halon or CO_2) may be used in lieu of foam or sprinklers to combat diesel generator and/or lubricating oil fires.	9. Diesel Generators Areas (continued)
10. Diesel Fuel Oil Storage Areas Diesel fuel oil tanks with a capacity greater than 1100 gallon should not be located inside the buildings containing safety-related equipment. They should be located at least 50 feet from any building containing safety related equipment, or if located within 50 feet, they should be housed in a separate building with construction having a minimum fire resistance rating of 3 hours. Buried tanks are considered as meeting the 3-hour fire resistance requirements. See NFPA 30, Flammable and Combustible Liquids Code, for additional guidance. When located in a separate building the tank should be protected by an automatic fire suppression system such as AFFF or sprinklers.	10. Diesel Fuel Oil Storage Areas Same	10. Diesel Fuel Oil Storage Areas PVNGS complies by providing an underground location for the diesel fuel oil storage tanks with capacities that are larger than 1100 gallons. The underground tanks are located more than 50 feet from any building containing safety-related equipment, except for the diesel generator building which is separated from the buried tanks by approximately 31 feet.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 62 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
10. Diesel Fuel Oil Storage Areas (continued)	10. Diesel Fuel Oil Storage Areas (continued)	10. Diesel Fuel Oil Storage Areas (continued)
Tanks, unless buried, should not be located directly above or below safety-related systems or equipment regardless of the firm rating of separating floors or ceilings.		
	In operating plants where tanks are located directly above or below the diesel generators and cannot reasonably be moved, separating floors and main structural members should, as a minimum, have fire resistance rating of 3 hours. Floors should be liquid tight to prevent leaking of possible oil spills from one level to another. Drains should be provided to remove possible oil spills and fire-fighting water to a safe location. One of the following acceptable methods of fire protection should also be provided: (a) Automatic open head deluge or open head spray nozzle system(s) (b) Automatic closed head sprinklers; or (c) Automatic AFFF that is delivered by a sprinkler system or spray system	PVNGS complies by providing 3-hour rated enclosures for the day tanks that are located directly above diesel generators, and day tank floors that are liquid tight with drains designed to remove oil and fire water to a safe location. The enclosures are adequately vented. The enclosures are protected by automatic preaction sprinkler systems.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A
OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 63 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
11. Safety-Related Pumps Pumphouses and rooms housing safety-related pumps or other safety-related equipment should be separated from other areas of the plant by fire barriers having at least 3-hour ratings. These rooms should be protected by automatic sprinkler protection unless a fire hazards analysis can demonstrate that a fire will not endanger other safety-related equipment required for safe plant shutdown. Early warning fire detection should be installed with alarm and annunciation locally and in the control room. Local hose stations and portable extinguishers should also be provided.	11. Safety-Related Pumps Pumphouses and rooms housing safety-related pumps should be protected by automatic sprinkler protection unless a fire hazards analysis can demonstrate that a fire will not endanger other safety-related equipment required for safe plant shutdown. Early warning fire detection should be installed with alarm and annunciation locally and in the control room. Local hose stations and portable extinguishers should also be provided.	11. Safety-Related Pumps PVNGS complies by demonstrating in the fire hazards analysis that a fire in any safety-related pump room will not endanger other safety-related equipment required for safe plant shutdown. The analyses for areas that contain safety-related pumps are included in section 9B.2 (see Zones 1, 2, 28, 30A, 30B, 31A, 31B, 32A, 32B, 34A, 34B, 46A, 46B, 46E, 72, 73, 51B, 63A, 63B, 78, 83, 84). An early warning fire detection system is installed in all zones listed above except Zone 78. The detection will alarm locally and alarm and annunciate in the control room. Automatic preaction water suppression systems are installed over the pumps in Zones 30A, 30B, 31A, 31B, 32A, 32B, 46A, 46B, 46E, and 72. Local hose stations and portable extinguishers are available at, or near, the areas that contain safety-related pumps (zones indicated above) except: Zone 78: Diesel fuel oil transfer pumps Zone 83: Condensate transfer pumps Zone 84: Essential spray pond pumps The above three zones are in the outside area and the PVNGS Fire Department has emergency response vehicle(s) which carry an assortment of hose, nozzles, and auxiliary equipment in lieu of hose houses. The diesel fuel oil transfer pumps (Zone 78) are located within the tanks and the tanks are installed underground. The condensate transfer pumps (Zone 83) are separated from each other by a nonrated reinforced concrete partition wall. The wall is of full height but not the full width of the building. It does, however, provide a radiant heat barrier between the pumps. The combustible (fire) loading in this zone is low and ionization detectors are provided with alarm and annunciation in the control room. (Refer to section 9B.2.9.1.8, Deviations from 10CFR50, Appendix R.) The essential spray pond pumps (Zone 84) are separated from each other by a nonrated reinforced concrete wall. The combustible (fire) loading in this zone is low and ionization detectors are provided with alarm and annunciation in the control room.
Equipment pedestals or curbs and drains should be provided to remove and direct water away from safety-related equipment.		Equipment pedestals and drains are provided to remove and direct water away from the equipment.
Provision should be made for manual control of the ventilation system to facilitate smoke removal if required for manual firefighting operation.		Manual control of ventilation system has been provided as discussed in section D.4 of this table.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 64 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
12. New Fuel Area Hand portable extinguishers should be located within this area. Also, local hose stations should be located outside but within hose reach of this area. Automatic fire detection should alarm and annunciate in the control room and alarm locally. Combustibles should be limited to a minimum in the new fuel area. The storage area should be provided with a drainage system to preclude accumulation of water. The storage configuration of new fuel should always be so maintained as to preclude criticality for any water density that might occur during fire water application.	12. New Fuel Area Same	12. New Fuel Area PVNGS complies by providing portable CO_2 extinguishers. A hose station is located within reach of this area. Ionization detectors are provided to alarm and annunciate in the control room and alarm locally. Drains are provided to preclude accumulation of water. The hose station in the new fuel fire zone is equipped with a Class A-B-C nozzle. The storage configuration of new fuel is such as to preclude criticality for any water density that might occur during fire water application. (See section 9.1.)
13. Spent Fuel Pool Area Protection for the spent fuel pool area should be provided by local hose stations and portable extinguishers. Automatic fire detection should be the control room and to alarm locally.	13. Spent Fuel Pool Area Same	13. Spent Fuel Pool Area PVNGS complies. A local hose station and a portable CO_2 extinguisher are provided. Automatic smoke detection system is provided in the area to alarm and annunciate in the control room and to alarm locally. Detectors are not provided directly over the spent fuel pool.
14. Radwaste Building The radwaste building should be separated from other areas of the plant by fire barriers having at least 3-hour ratings. Automatic sprinklers should be used in all areas where combustible materials are located. Automatic fire detection should be provided to annunciate and alarm in the control room and alarm locally. During a fire, the ventilation systems in these areas should be capable of being isolated. Water should drain to liquid radwaste building sumps.	14. Radwaste Building Same	14. Radwaste Building PVNGS complies by separating the radwaste building from the adjacent control and auxiliary buildings by fire barriers of 3-hour rating. Door A204, between the auxiliary building and the radwaste building, is protected by sprinklers located on both sides of the door. (See appendix 9A response to Question 9A.106.) A wet pipe sprinkler system has been provided in the waste compacting area (Zone 5B; section 9B.2). Automatic fire detection is provided to alarm and annunciate in the control room and alarm locally. Fire zones provided with ionization detectors are identified in section 9B.2.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 65 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
14. Radwaste Building (Continued) Accept alternative fire protection is automatic fire detection to alarm and annunciate in the control room, in addition to manual hose stations and portable extinguishers consisting of hand-held and large-wheeled units.	14. Radwaste Building (Continued)	14. Radwaste Building (Continued) Manual hose stations and portable extinguishers are provided. All drains are routed to the radwaste building sump except for the auxiliary drain from the shutdown cooling heat exchanger. The radwaste building ventilation systems are capable of being isolated during fire.
15. Decontamination Areas The decontamination areas should be protected by automatic sprinklers if flammable liquids are stored. Automatic fire detection should be provided to annunciate and alarm in the control room and alarm locally. The ventilation system should be capable of being isolated. Local hose stations and hand portable extinguishers should be provided as backup to the sprinkler system.	15. Decontamination Areas Same	15. Decontamination Areas The decontamination areas are as follows: • Personnel decontamination area - auxiliary building, elevation 140 feet, Zone 57F • Tool room and supply storage area - radwaste building, elevation 100 feet, Zone 60E • Decontamination and laundry facility area, elevation 100 feet, Zones 91A, 91B, 91C, and 91D. No flammable liquid storage is planned in Zones 57F and 60E. The decontamination and laundry facility area is located outside and is physically separated by more than 30 feet and by walls of heavy concrete construction from the radwaste building. Ionization detectors are provided in Zones 57F and 60E. Wet pipe sprinklers are provided in Zone 57H. The decontamination and laundry facility area are not provided with a detection system. It is not deemed necessary due to the physical separation from safety related structures. Portable extinguishers are provided in the decontamination and laundry facility area and the area is readily accessible for manual fire fighting. Ventilation isolation capability is provided.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 66 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
16. Safety-Related Water Tanks Storage tanks that supply water for safe shutdown should be protected from the effects of fire. Local hose stations and portable extinguishers should be provided. Portable extinguishers should be located in nearby hose houses. Combustible materials should not be stored next to outdoor tanks. A minimum of 50 feet of separation should be provided between outdoor tanks and combustible materials where feasible.	16. Safety-Related Water Tanks Same	16. Safety-Related Water Tanks Water for safe shutdown is supplied from the following tanks and reservoirs: (a) Condensate storage tank - Zone 83 (b) Refueling water storage tank - Zone 81 (c) Spray pond - Zone 84A and 84B PVNGS complies by protecting the above tanks and reservoir from the effects of fire, however: • Due to the low in situ combustibles in the above three fire zones, portable extinguishers are not provided. The nearby hydrants are available for firefighting. • Local standpipe hose stations are not provided due to the outdoor location. • The refueling water tank is located adjacent to the fuel building. The exterior wall of the fuel building, near the refueling tank, is of reinforced concrete and the area inside the building is protected by wet pipe sprinklers.
17. Cooling Towers Cooling towers should be of non-combustible construction or so located that a fire will not adversely affect any safety-related systems or equipment. Cooling towers should be of noncombustible construction when the basins are used for ultimate heat sink or for the fire protection water supply.	17. Cooling Towers Same. Cooling towers of combustible construction, so located that a fire in them could adversely affect safety-related systems or equipment, should be protected with an open head deluge system installation with hydrants and hose houses strategically located.	17. Cooling Towers A fire at the cooling towers will not adversely affect any safety-related systems or equipment.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 67 of 69)

F. GUIDELINES FOR SPECIFIC PLANT AREAS (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
18. Miscellaneous Areas Miscellaneous areas such as records storage areas, shops, warehouses, and auxiliary boiler rooms should be so located that a fire or effects of a fire, including smoke, will not adversely affect any safety-related systems or equipment. Fuel oil tanks for auxiliary boilers should be buried or provided with dikes to contain the entire tank contents.	18. Miscellaneous Areas Same	18. Miscellaneous Areas PVNGS considers that any exposure fire in these miscellaneous areas will not affect safety-related equipment or systems. A fire hazards analysis has been performed on fire areas in or adjacent to safety-related equipment. This includes the records storage area (adjacent to the computer room (Zone 16)) and the shop area (Zone 60E). The auxiliary boiler area (Zone 85A) and the warehouse areas are not located at or adjacent to safety-related equipment. The fuel oil tanks that supplied the now abandoned auxiliary boiler are remote from the power block and safety-related equipment. In addition, any exposure fire in the dry active waste processing system (DAWPS) facility is not considered to affect safety-related, safe-shutdown, or result in a significant radiological release due to administrative control of the contents of this facility.

Table 9B.3-1

COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF NRC BRANCH TECHNICAL POSITION APCSB 9.5-1 (Sheet 68 of 69)

G. SPECIAL PROTECTION GUIDELINES

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
1. Welding and Cutting, Acetylene - Oxygen Fuel Gas Systems This equipment is used in various areas throughout the plant. Storage locations should be chosen to permit fire protection by automatic sprinkler systems. Local hose stations and portable equipment should be provided as backup. The requirements of NFPA 51 and 51B are applicable to these hazards. A permit system should be required to utilize this equipment. (Also refer to 2f herein.)	1. Welding and Cutting, Acetylene - Oxygen Fuel Gas Systems Same	1. Welding and Cutting, Acetylene - Oxygen Fuel Gas Systems NFPA 51 (1974) and NFPA 51B (1976) are used as guidelines for handling of these processes. A permit system is in place to use this equipment. Reserve inventory of acetylene-Oxygen is stored at the chemical storage facility, near the WRF, and on the south side of Unit 3 Ops Support Building, welding shop. Both locations utilize outdoor storage. Control of Oxy-Acetylene use within structures is in accordance with the permit system and site procedures and/or the safety manual.
2. Storage Areas for Dry Ion Exchange Resins Dry ion exchange resins should not be stored near essential safety-related systems. Dry unused resins should be protected by automatic wet pipe sprinkler installations. Detection by smoke and heat detectors should alarm and annunciate in the control room and alarm locally. Local hose sta tions and portable extinguishers should provide backup for these areas. Storage areas of dry resin should have curbs and drains. (Refer to NFPA 92M, Waterproofing and Draining of Floors.)	2. Storage Areas for Dry Ion Same	2. Storage Areas for Dry Ion Exchange Resins Dry ion exchange resins are stored in the warehouse which is approximately 400 feet from Unit 2 power block areas and is, therefore, remote from essential safety-related system. Automatic wet pipe sprinkler protection is provided in the warehouse as well as hose stations and portable extinguishers. Detection by smoke and heat detectors is not provided.
3. Hazardous Chemicals Hazardous chemicals should be stored and protected in accordance with the recommendations of NFPA 49, Hazardous Chemicals Data. Chemicals storage areas should be well ventilated and protected against flooding conditions since some chemicals may react with water to produce ignition.	3. Hazardous Chemicals	3. Hazardous Chemicals For the storage of hazardous chemicals, the recommendations of NFPA 49 (1975) are used as guidance.

Table 9B.3-1
COMPARISON OF PALO VERDE NUCLEAR GENERATING STATION TO APPENDIX A OF
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G. SPECIAL PROTECTION GUIDELINES (CONTINUED)

APPLICATION DOCKETED BUT CONSTRUCTION PERMIT NOT RECEIVED AS OF 7/1/76	PLANTS UNDER CONSTRUCTION AND OPERATING PLANTS	PVNGS POSITION AND BASIS FOR NONCOMPLIANCE ITEMS
4. Materials Containing Radioactivity Materials that collect and contain radioactivity such as spent ion exchange resins, charcoal filters, and HEPA filters should be stored in closed metal tanks or containers that are located in areas free from ignition sources or combustibles. These materials should be protected from exposure to fires in adjacent areas as well. Consideration should be given to requirements for removal of isotopic decay heat from entrained radioactive materials.	4. Materials Containing Same	4. Materials Containing Radioactivity Materials that contain radioactivity are collected in the radwaste systems and stored in 55-gallon drums at 100-foot elevation of the radwaste building. Spent resins are temporarily stored in a steel tank at the 110-foot elevation of the radwaste building. Spent charcoal filters are directly processed through the radwaste system. HEPA filter waste is sent through the baler system and then placed in the drums. PVNGS complies with the protection of drum storage area Zone 58, and the spent resin tanks, Zone 62. (See section 9B.2.) At PVNGS the level of radiation in the entrained radioactive materials is not high enough to generate heat due to isotropic decay.

CHAPTER 10

STEAM AND POWER CONVERSION SYSTEM

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FIGURES

10. STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion systems for each unit at PVNGS are identical. Therefore, the summary description provided in this section is on a per-unit basis.

10.1.1 DESIGN BASES

The steam and power conversion system is designed to remove heat energy from the reactor coolant in two steam generators and to convert it to electric power via the turbine-generator. The main condenser transfers heat that is not utilized in the cycle to the circulating water system and deaerates the condensate. The closed regenerative turbine cycle heats the condensate and returns it as feedwater to the steam generators.

A full-flow condensate demineralizer system is available to maintain feedwater quality. A blowdown system operates to maintain steam generator water chemistry. The condenser air removal system provides a filter and charcoal adsorber and is monitored for radioactive contamination. The Seismic Category I redundant auxiliary feedwater pumps, one motor-driven and one steam turbine-driven, provide feedwater during loss of offsite power and during design basis accident conditions. A non-Seismic Category I, motor-driven auxiliary feedwater pump provides feedwater for startup, hot standby, and normal shutdown.

10.1.2 SYSTEM DESCRIPTION

Components of the steam and power conversion system are of types that have been extensively used in fossil fuel plants and in other nuclear power plants. Instruments, controls, and protective devices are provided to ensure reliable and safe operation, as described in paragraph 10.2.2.3.

A system flow diagram is shown in figure 10.1-1. A summary of design basis information and performance specifications is given in table 10.1-1. Also, the cycle heat balances, at turbine rated (guaranteed) power and at stretch power (valves wide open-VWO), are shown on figures 10.1-2 and 10.1-3, respectively, and are summarized in table 10.2-2. Safety-related components include the main steam isolation valves, the atmospheric steam dump valves, the feedwater isolation valves, the Seismic Category I portion of the auxiliary feedwater system, and the main steam safety valves. The steam and power conversion system provides steam for the feedwater pump turbines, the turbine gland sealing system, condensate and feedwater heating, and main turbine reheat steam as required.

The condenser air removal system is described in subsection 10.4.2. The condensate cleanup system is described in subsection 10.4.6. The auxiliary feedwater system is described in subsection 10.4.9.

10.1.3 SAFETY-RELATED FEATURES

10.1.3.1 Loss of External Electrical Load and/or Turbine Trip

Upon loss of load the turbine control system provides for fast closing of turbine valves. Depending on the magnitude of the

load reduction, a turbine bypass system will dump excess steam into the condenser and, if required, to atmosphere. If the load reduction is large, i.e., greater than approximately 55% of full load, an automatic reactor power cutback will be initiated provided the turbine power level is greater than 75%. The turbine control and bypass equipment is not safety grade.

In the event the condenser is not available to receive steam, ASME Code safety and atmospheric dump valves are provided on the main steam piping.

The atmospheric dump valves are remotely operated from the control room and can be modulated to control the steam flow.

The power/load unbalance circuit is capable of controlling the speed of the turbine generator upon full load rejection so as to not exceed 110% of rated turbine speed. After a power/load unbalance circuit actuation, a positive turbine trip occurs with no subsequent re-opening of the control valves and intercept valves.

10.1.3.2 Overpressure Protection

Safety valves are provided on the main steam lines in accordance with the ASME Boiler and Pressure Vessel Code, Section III. The pressure relief capacity of all safety valves is such that the flow capacity is equal to 19 x 10^6 lb/hr (105% of maximum calculated steam generator stretch power mass flow, 18.0 x 10^6 lb/hr) at setpoint pressure.

Table 10.1-1

STEAM AND POWER CONVERSION SYSTEM DESIGN AND PERFORMANCE SPECIFICATIONS (Sheet 1 of 4)

Design and Performance Characteristics	Original Design Value(1)	Power Uprate/Rotor Replacement Value(2)
Main steam system minimum required design pressure/temperature, psia/F	1270/575	1270/575
Main steam system operating pressure/temperature, at 100% power, psia/F (at guar. load 3817/3990 MWt)	1070/552.9	1012/546.1
Main steam system operating pressure/temperature, at 100% power, psia/F (VWO)	1000/544.6	1007/545.4
Main steam flow, guar./VWO, 10^6 lb/h	17.2/18.1	17.96/18.36
Main turbine throttle flow, guar./VWO, 10^6 lb/h	15.9/17.05	16.87/17.28
Main condenser pressure, in.Hg abs	3.5	3.5
Feedwater temperature, guar./VWO, F	442.5/449.5	448.5/450.9
Main turbine-generator output, guar./VWO, MWe	1304/1375	1411/1443
Guaranteed generator rating, MVA	1559.1	1559.1
No./normal capacity/runout capacity at 65% of each feedwater pump, lb/hr x 10^6 at VWO	2/9.2/11.3	2/9.2/11.3
No./design capacity/runout capacity of each condensate pump, lb/hr x 10^6	3/4.4/6.2	3/4.4/6.2
Turbine gland seal system, normal flow air/steam, lb/h	2855/9025	2855/9025
Steam generator blowdown system, flowrate, normal/abnormal/high rate	0.2%/1%/8% of maximum steam rate	0.2%/1%/8% of maximum steam rate

Table 10.1-1

STEAM AND POWER CONVERSION SYSTEM DESIGN AND

PERFORMANCE SPECIFICATIONS (Sheet 2 of 4)

System Component	Performance Characteristics
Main steam system (section 10.3)	
Main steam piping	From each steam generator up to and including the main steam isolation valves: ASME III, Code Class 2. (design pressure 1255 psig, design temperature 600F, Seismic Category I) Balance of the main steam piping: ANSI B31.1
Main steam isolation valves (one per steam line)	Maximum closing time 4.6 seconds after receipt of signal. ASME III, Code Class 2 valves. (design pressure 1270 psia, design temperature 575F, Seismic Category I)
Main steam safety valves (five per steam line)	Required flow capacity equal to 19 x 10^6 lb/hr (105% of the maximum calculated steam generator stretch power flow 18.0 x 10^6 lb/hr) at setpoint pressure: ASME III, Code Class 2 valves. (design pressure 1375 psig, design temperature 575F, Seismic Category I) (See CESSAR Table 5.4.13-2).
Atmospheric dump valves (one per steam line)	Required flow capacity equal to 950,000 lb/hr (min): ASME III, Code Class 2 valves. (design pressure 1333 psia, design temperature 575F, Seismic Category I)
Turbine bypass system (subsection 10.4.4)	
Bypass valves downstream of main steam isolation valves (six piped to condenser, two piped to atmosphere)	Flow capacity equal to at least 55% of design steam flow: Piping ANSI B31.1 (design pressure 1255 psig, design temperature 600F, non-Seismic Category I)

Table 10.1-1

STEAM AND POWER CONVERSION SYSTEM DESIGN AND

PERFORMANCE SPECIFICATIONS (Sheet 3 of 4)

System Component	Performance Characteristics
Condenser	See subsection 10.4.1
Condenser air removal system	See subsection 10.4.2
Circulating water system	See subsection 10.4.5
Turbine gland seal system	See subsection 10.4.3
Condensate and main feedwater system (subsection 10.4.7)	Piping in main steam support structure (MSSS) to upstream economizer feedwater isolation valves - ASME III, Code Class 2. Design pressure 1875 psig, 450F downcomer feedwater piping to upstream isolation valve – ANSI B31.1, design pressure - 1600 psig, design temperature - 450F. From downstream feedwater isolation valves to steam generators – ASME III, Code Class 2. Design pressure 1255 psig, 600F, Seismic Category I. Balance of system piping: ANSI B31.1
Auxiliary feedwater system (subsection 10.4.9)	See subsection 10.4.9.

Table 10.1-1

STEAM AND POWER CONVERSION SYSTEM DESIGN AND PERFORMANCE SPECIFICATIONS (Sheet 4 of 4)

System Component	Performance Characteristics
	All piping from the condensate storage tank to the Seismic Category I auxiliary feedwater pumps and containment isolation valves is ASME III, Code Class 3; piping from and including the isolation valves to the steam generators is ASME III, Code Class 2, design pressure 1255 psig, design temperature 600F, Seismic Category I All piping associated with the non-Seismic Category I motor-driven auxiliary feedwater pump, excluding upstream of the condensate tank isolation valve and downstream of the containment isolation valves, is ANSI B31.1 Code for pressure piping.
Secondary chemistry control system (subsection 10.4.6)	Full flow condensate demineralization. Continuous hydrazine additions for oxygen scavenging and continuous ammonia additions for pH control. Continuous monitoring of significant chemical parameters. Steam generator blowdown at a rate up to 8% of the maximum steaming rate

<u>NOTE 1</u>: The parameters listed in Table 10.1-1 for Original Design are nominal parameters obtained from GE Heat Balance 449HB673 (13-M400-0301-00029) and Specification 13-MM-0004/010 for the original rated performance at 3800 MWt and VWO conditions of the plant secondary system, respectively. The Heat Balance and specification are applicable for original operation, stretch power to 3876 MWe and T_{hot} Reduction. For the actual design parameters and predicted performance at various power levels see calculation 13-MC-MT-0200.

<u>NOTE 2</u>: The parameters listed in Table 10.1-1 for Power Uprate are nominal parameters obtained from GE Thermal Kit 91LR0297 (13-M400-0303-01058) to determine the effect of Replacement Steam Generators, Power Uprate to 3990 MWt and Low Pressure Turbine Rotor Replacement on the plant secondary system. For the actual design parameters and predicted performance at various power levels see calculation 13-MC-MT-0200.

10.1.3.3 Loss of Normal Electric Power

The auxiliary feedwater system is designed to provide feedwater to the steam generators for the removal of decay heat when the feedwater pumps are not available following a loss of normal electric power. In the event of reactor trip with loss of offsite power, two Seismic Category I auxiliary feedwater pumps, one motor-driven and one steam turbine-driven, are available to provide feedwater to the steam generators. The motor-driven pump and its associated isolation valves receive power from a separate standby diesel generator bus. In addition, the steam turbine-driven auxiliary feedwater pump with dc powered controls is available. Refer to subsection 10.4.9.

10.1.4 TESTS AND INSPECTIONS

Pumps and controls are given preoperational tests. Functional operational checks are made on essential valves, control systems, and protective equipment.

10.1.5 INSTRUMENTATION APPLICATIONS

Operating instrumentation is provided to permit the operators to monitor equipment and plant performance. Equipment, instruments, and controls are inspected regularly and are monitored during operation to ensure proper functioning of systems.

Checking and recalibration of instruments and controls continue during operating periods as well as during standby and shutdown periods.

10.2 TURBINE-GENERATOR

The function of the turbine-generator is to convert thermal energy into electric power.

10.2.1 DESIGN BASES

10.2.1.1 Safety Design Bases

The turbine-generator serves no safety function and has no safety design bases.

10.2.1.2 Power Generation Design Bases

The following is a list of the principal design bases:

A. The turbine-generator load change characteristics are compatible with the restrictions imposed by or on the nuclear steam supply system (NSSS). The NSSS is capable of accepting a step load change of 10% and ramp load change of 5% per minute over the load range of 15 to 100%. These load change rates can be accomplished without the operation of the turbine bypass system (TBS) described in subsection 10.4.4. With operation of the TBS, the reactor can accept step load rejections of up to 55% of the rated power of 3817 MWt without causing a reactor trip by bypassing steam to the condenser and, if required, to atmosphere. With the reactor power cutback system and TBS, the reactor can accept a step load rejection of 100% without causing a reactor trip. However, the steam bypass control system (SBCS) and reactor power cutback system (RPCS) are not capable of handling step load rejections for turbine power level between 57% and 75% due to limitations on condenser pressure.

B. The turbine-generator is designed to trip automatically under abnormal conditions as designated in paragraph 10.2.2.4.

C. The turbine-generator is intended to operate base loaded.

10.2.1.3 Codes and Standards

System components are designed in accordance with the requirements of ANSI B31.1.0 Code for pressure piping, TEMA and HEI standards for heat exchangers, NEMA standards, IEEE standards, Hydraulic Institute standards, and regulations of the National Board of Fire Underwriters.

10.2.2 DESCRIPTION

The General Electric turbine-generator (engineering drawings 01, 02, 03-M-MTP-001, -002 and -003) is designated TC6F-43 and consists of turbines, a generator, moisture separator-reheaters, exciter, controls, and auxiliary subsystems. The major design parameters of the turbine-generator are presented in tables 10.2-1 and 10.2-2. Details of system components are presented in this section. The location of the turbine-generator is shown in engineering drawings 13-P-OOB-002 through -011.

10.2.2.1 Turbine-Generator Description

The turbine is an 1800 revolutions per minute, tandem-compound, six-flow, reheat unit with 43-inch, last-stage buckets (blades). The turbine includes one double-flow, high-pressure turbine; three double-flow, low-pressure turbines; and four

moisture separator-reheaters with two stages of reheating. The direct-driven generator is conductor-cooled and rated at 1559.1 MVA at 24 kV, three phase, 60 Hz. Other related system components include a complete turbine-generator bearing lubrication oil system, an electrohydraulic control (EHC) system with supervisory instrumentation, a turbine gland sealing system (refer to subsection 10.4.3), overspeed protective devices, turning gear, a generator hydrogen and seal oil system, a stator cooling system, an exciter cooler (for those units where DMWO 3286783 has been implemented, the exciter cooler has been removed), a rectifier section, and a voltage adjuster.

Table 10.2-1
TURBINE-GENERATOR DESIGN DATA

Supplier	General Electric
Unit designation	TC6F-43" LSB
Last-stage bucket length, in.	43
Design condenser backpressure (average for three shells), in. Hg abs	3.50
Stages of reheating	2
Stages of feedwater heating	7
Rotational speed, r/min	1,800
Guaranteed generator rating, MVA	1,559.1
Generator voltage, kV	24
Power factor	0.9
Short circuit ratio	0.5

10.2.2.2 Turbine-Generator Cycle Description

Steam from the main steam system enters the high-pressure turbine through four stop and governing control valves. Crossties are provided both upstream and downstream of the stop valves to provide pressure equalization with one or more stop valves closed. A portion of the main steam is used for second-stage reheat of the steam supply to the low-pressure turbines.

There are two steam extraction points in the high-pressure turbine. Steam from the first (higher pressure) extraction point is used for seventh-point feedwater heating and first-stage reheat of the two-stage reheater. Steam from the second

Table 10.2-2
TURBINE-GENERATOR PERFORMANCE DATA

Parameter	Guaranteed Load [(a)(b)] Original/Pur & Rotor Replacement	Valves Wide Open [(a)(b)] Original/Pur & Rotor Replacement
NSSS thermal output, MWt	3,911/4,013	4,030/4,030
Steam generator outlet pressure, psia	1,020/1,030	1,010/1,025
Throttle pressure, psia	1,002/1,012	993/1,007
Throttle temperature, °F	544.8/546.1	543.7/545.4
Main steam flow, 10^6 lb/h	17.5/17.96	18.1/18.36
Gross electrical output, MWe	1,333/1,411	1,375/1,443

a. For turbine-generator design purposes only.

b. The parameters listed for Original Design are nominal parameters obtained from GE Heat Balance for the original rated performance and Valves Wide Open conditions of the plant secondary system. This data is applicable for original operation at 3800 MWt, stretch power to 3876 MWe and T_{hot} reduction. The parameters listed for Power Uprate (PUR) are nominal secondary system parameters based upon implementation of Replacement Steam Generators, Power Uprate to 3990 MWt and Low Pressure Turbine Rotor Replacement.

extraction point is used for sixth-point feedwater heating. (Refer to subsection 10.4.7 for discussion of the condensate and feedwater system.) After expansion in the high-pressure turbine, the steam flows through the moisture separator-reheaters to remove entrained moisture and to superheat the steam, thus improving cycle efficiency. A portion of the cold reheat steam is used for fifth-point feedwater heating. (Feedwater heaters are numbered sequentially in order of increasing extraction pressure.)

Hot reheat steam leaving the moisture separator-reheaters is used to power the feedwater pump turbine. Hot reheat steam also is distributed equally to the three low-pressure turbines through combined reheat stop and intercept valves. In each low-pressure turbine, there are four steam extraction points for the remaining four stages of feedwater heating (one heater train per low-pressure turbine). After expansion in the low-pressure turbines, the steam is discharged to the main condensers.

In addition to the external moisture separators, the last three low-pressure turbine stages are designed to remove any condensed moisture and drain it to the next lowest extraction. The moisture from the external moisture separators is drained to moisture separator drain tanks and from there to the high-pressure heater drain tank and subsequently is pumped into the feedwater system. Similarly, the condensate in the reheaters is drained to the heater drain tank and is pumped into the feedwater system.

10.2.2.3 Automatic Controls

Automatic controls provide control of turbine speed and acceleration through the entire speed range, with several discrete speed and acceleration rate settings. The automatic control system includes control of load and loading rate from no load to full load, with continuous load adjustments and discrete loading rates. Should it become necessary to remove the generating unit from the primary automatic controls, the standby manual control of speed and load takes over, thus allowing continued operation of the turbine generator.

10.2.2.3.1 Electrohydraulic Control Systems

The turbine-generator is equipped with an EHC system that combines the principles of solid-state electronics and high-pressure hydraulics to control steam flow through the turbine. The control system has three major subsystems: speed control unit, load control unit, and valve flow control units.

10.2.2.3.1.1 Speed Control Unit. The speed control unit produces the speed error signal for input to the load control unit. This error signal is determined by comparing the desired speed with the actual speed of the turbine at steady-state conditions, or the desired acceleration with the actual acceleration during startup. Because of the importance in safeguarding against overspeed, the speed control unit has two redundant channels. If the primary channel fails, the backup channel takes over automatically. If both channels should fail, the turbine-generator will trip.

The above two speed channels generate three error signals during the period between turbine roll and synchronization. Two of these error signals are from a deviation between the actual speed as measured by the primary and backup speed sensors and a reference speed. The third error signal is a deviation between the actual acceleration as measured by the primary and backup speed sensors and a reference acceleration. These signals combine with signals from the load control unit to generate a flow reference signal to the control valves and intercept valves.

10.2.2.3.1.2 Load Control Unit. The load control unit develops flow reference signals that are used to proportion the steam flow to the control valves and intercept valves. Signal outputs are based on a proper combination of the speed error signals and load reference signals. The generator does not strictly follow load, but is controlled through a ramped, predetermined straight-line function. Power/load imbalance is discussed in paragraph 10.2.2.3.1.4.

10.2.2.3.1.3 Valve Flow Control Units. The valve flow control unit regulates the steam flows as directed by the load control unit. Compensation circuits are introduced to ensure linear steam flow response with respect to steam flow reference signals. The bypass valve in the No. 2 main stop valve, control valves, and the intercept valves each have a control loop which consists of electronic circuitry, an electrohydraulic servo valve, a hydraulic actuator, and a linear position transducer. By use of valve position feedback control, the valve control units position the bypass valve in

the No. 2 main stop valve, the control valves, and the intercept valves according to the flow demand signal from the load control unit, the standby control unit, or directly from the control panel (valve test).

Only the No. 2 main stop valve has an internal bypass valve. The control loop operates the internal bypass valve and is used only for prewarming the turbine.

The flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four governing control valves. Each stop valve is controlled by an electrohydraulic actuator so that the stop valve is either fully open or fully closed. The function of the stop valves is to shut off the flow of steam to the turbine, when required. The stop valves are closed within 0.2 second or less when steam pressure is present, and are closed in 0.3 second or less when no steam pressure is present, by actuation of the emergency trip system devices. These devices are independent of the electronic flow control unit (see paragraph 10.2.2.3.1.5).

The turbine control valves are positioned by electrohydraulic servo-actuators in response to signals from their respective flow control unit. The flow control unit signal positions the control valves for long range speed control through the normal turbine operating range and for load control after the turbine-generator unit is synchronized.

The combined reheat valves located in the hot reheat lines are stop and intercept valves in one casing and control steam flow to the low-pressure turbines. During normal operation of the turbine, the stop and intercept valves are wide open. The

intercept valve flow control unit positions the valve during startup and normal operations and closes the valve rapidly on loss of turbine load. The reheat stop valves close completely on turbine overspeed and trip.

10.2.2.3.1.4 Power/Load Unbalance. Associated with the load control unit is a rate sensitive power/load unbalance circuit whose purpose is to initiate control valve fast closing action under load rejection conditions that might lead to rapid rotor acceleration and consequent overspeed.

Valve action will occur when the power exceeds the load by at least 40% and generator current is lost in a time span of 35 ms or less with an additional 150 ms time delay. Cold reheat pressure is used as a measure of power, and generator current is used as a measure of load to provide discrimination between loss of load incidents and occurrences of electric system faults.

The power/load unbalance circuitry includes an approximate 150 ms time delay between the detection of a power/load unbalance condition and actuation of turbine control. This time delay will allow the turbine control to ride out transient electrical transmission network disturbances. The 150 ms delay is based on a three-phase bolted fault at the Palo Verde 525 kv switchyard as a worst case scenario.

Following the detection of a power/load unbalance condition and the 150 ms time delay, all control valves are closed in 0.2 second or less when steam pressure is present, and are closed in 0.3 second or less when no steam pressure is present, by a fast acting solenoid for each control valve. Simultaneously,

the load reference signal is grounded and the load reference motor begins to run back toward the no-load flow point. Should the condition disappear quickly, the power/load unbalance circuit will reset automatically, and the load reference signal will be reestablished near its value prior to the loss of load. Should the condition persist and the load does not return within approximately 45 seconds, the load reference runback will be completed. The power/load unbalance circuit will clear automatically when the cold reheat pressure drops below 40%. However, after a power/load unbalance circuit actuation, a positive turbine trip occurs with no subsequent re-opening of the control valves and intercept valves.

10.2.2.3.1.5 Overspeed Protection. Two means of overspeed trip protection are provided; a mechanical overspeed trip (OST) and a backup overspeed trip (BOST). The OST is a conventional eccentric ring that actuates a trip latch to operate a pilot valve that operates the mechanical trip valve. The mechanical trip valve releases the hydraulic fluid pressure in the steam valve actuator, allowing the springs to close the steam valves.

The OST trip is set at 110% (+1%/-2.5%) of rated turbine speed. (Refer to protection system block diagram, figure 10.2-2.)

The BOST is an electric trip normally set to operate at a slightly higher speed than the OST. Three independent BOSTs are provided by magnetic pickups from toothed wheels on the turbine shaft. The signals are amplified through electronic circuitry and are compared to trip speed reference voltage signals. Exceeding the trip speed will cause each BOST voltage to energize its master trip relay. The master trip relays,

through a two-out-of-three logic, deenergize both pilot solenoids of the master (electric) trip solenoid valve. This releases the hydraulic fluid pressure in the steam valve actuators, causing the turbine main valves to close. The overspeed trip logic is shown in figure 10.2-1.

The BOST electric trip also results in a "cross trip" by actuating, also through two-out-of-three relay logic, the mechanical trip, the mechanical trip solenoid, and the trip latch system described above. The BOST trip is set at 111% of rated turbine speed.

When in the standby mode, the automatic speed control and load control subsystems are out of service. If it is necessary to operate the turbine in the standby mode, added overspeed protection is provided by automatically lowering the setpoint of the backup overspeed governor to 105% of rated turbine speed. The mechanical governor then becomes the backup governor since its trip setpoint remains at 110% (+1%/-2.5%) of rated speed. (See table 10.2-3 for turbine overspeed sensors and trip signals.) Each of the two means of overspeed tripping may be independently tested online at any desired load. During these tests, overspeed protection will be provided by the device not being tested.

Finally, because the turbine-generator overspeed protection system is not a safety system (other than for equipment protection), a single failure analysis per IEEE-279 is not required.

Table 10.2-3
TURBINE OVERSPEED SENSORS AND TRIP SETPOINTS (Sheet 1 of 2)

Sensors	Type	Function	Setpoints in Percent of Turbine Rated Speed			
			HP Stop Valve	HP Throttle Valve	LP Stop Valve	LP Intercept Valve
MTNST-160	Magnetic pickup	Normal speed control and overspeed protection	None	100	None	102
MTNST-161	Magnetic pickup	Normal speed control and overspeed protection	None	100	None	102
MTNZS-145	Mechanical eccentric ring	Emergency overspeed protection	110	110	110	110
MTNST-162	Magnetic pickup	Backup emerg. over-speed protection (2/3 logic)	111	111	111	111
MTNST-163	Magnetic pick up	Backup emerg. over-speed protection (2/3 logic)	111	111	111	111
MTNST-164	Magnetic pickup	Backup emerg. over-speed protection (2/3 logic)	111	111	111	111
MTNST-165	Magnetic pick up	Backup emerg. over-speed protection (2/3 logic)	111	111	111	111
MTNST-169	Magnetic pickup	Backup emerg. over-speed protection (2/3 logic)	111	111	111	111

Table 10.2-3
TURBINE OVERSPEED SENSORS AND TRIP SETPOINTS (Sheet 2 of 2)

Sensors	Type	Function	Setpoints in Percent of Turbine Rated Speed			
			HP Stop Valve	HP Throttle Valve	LP Stop Valve	LP Intercept Valve
MTNPT-9	Cold RH press trans-mitter	Power/load unbalance turbine power	None	100	None	102
1 PUE-A004(a)	KW trans-ducer	Power/load unbalance anticipatory O/S protection	None	(b)	None	(b)

a. Turbine supplier identification number.

b. Control valves and intercept valves all close in 0.2 second or less following a 150 ms delay when power/load unbalance detects loss of generator load. This could occur before turbine speed starts to increase. This is not a trip.

10.2.2.4 Turbine Protective Trips

Turbine protective trips are independent of the electronic control system and, when initiated, cause tripping of all turbine stop and control valves. The protective trips are:

- Overspeed trip (mechanical): 110% (+1%/-2.5%) of normal
- Backup overspeed trip (electrical): 111% of normal
- Low vacuum trip
- Excessive thrust bearing wear trip
- Electric solenoid trip actuated by:
  - Reactor trip
  - Generator trip
  - Manual trip from control room
- Excessive vibration trip
- Manual trip handle located at the turbine front standard
- High exhaust hood temperature trip
- Moisture separator drain system high level trip
- Prolonged loss of stator coolant trip
- Low hydraulic fluid pressure trip
- Loss of both speed signals or backup overspeed trip
- Low bearing oil pressure trip
- Loss of main shaft oil pump discharge pressure trip

The EHC system employs five electric and one mechanical speed inputs. Signals are redundantly processed in both electronic and hydraulic logic channels. Valve opening actuation is provided by a 1600 psig hydraulic system that is totally independent of the bearing lubrication system. Valve closing actuation is provided by springs and steam forces upon the reduction or relief of fluid pressure. The system is designed so that loss of fluid pressure for any reason leads to valve closing and consequent shutdown.

To help prevent turbine overspeed, a sequential tripping system isolates all steam to the high-pressure turbine and low-pressure turbines, and must detect no load on the generator before the main generator breaker is opened. (See figure 10.2-3.) This system provides for an orderly shutdown from a single tripping signal and prevents a rapid rise in speed that would occur if the generator breaker were opened before the turbine valves closed. All turbine protective trips are done by sequential tripping logic including the manual trip from the control room or by the trip handle at the turbine front standard. In a sequential trip, the interval between the closure of the turbine valves and the opening of the generator breaker is at least 3 seconds. Refer to calculation 13-EC-MA-232. In some electrical faults which would do serious damage to the generator, sequential tripping is not permissible. In these cases the generator and turbine are tripped simultaneously.

It is possible for the operator, in an emergency, to open the main generator breaker from the control room switch instead of using the turbine trip button. This action at or near full

load, coupled with transient steam conditions from the steam generator, could cause serious turbine damage and excessive overspeed. To help prevent the above, the operator is required to hold a breaker bypass switch in "trip" as a permissive before operating the main breaker switch to trip the generator. Limit switches on the main stop valves, control valves, reheat stop valves, and intercept valves are used in the sequential tripping logic. A reverse power relay is used to detect reverse current flow for the no load condition on the generator. A time delay, which is adjustable in the reverse power relay, is credited for a portion of the 3 second interval between a turbine trip and the loss of power to the RCPs assumed in certain accident analyses. Refer to section 8.3.4 and table 15.0-0. In a sequential trip, the unit auxiliary transformer continues to supply power to the non-Class 1E distribution system during the relay timeout period. Refer to section 8.3.5 and calculation 13-EC-MA-232.

All steam valves are arranged in series pairs such as a main stop valve and associated control valve or a reheat stop and associated intercept valve. There are four pairs of valves for the high-pressure turbine and two pair of valves for each low-pressure turbine making a total of ten pairs of steam admission valves. Each stop valve, control valve, and intercept valve (20 total) is actuated by either of two overspeed trip systems. Four control valves on the high-pressure turbine and one intercept valve on each low-pressure turbine is modulated by the speed governing system. Closure of either valve in a pair stops the steam flow from that source and therefore a single valve failure would not disable the

turbine overspeed trip from functioning. The backup overspeed trip and the trip caused by loss of the primary and backup speed signals are initiated by the 24 volt dc trip logic shown on figure 10.2-2.

The 24 volt trip system is used for turbine vital trips which includes the backup overspeed trip. A 125 volt dc trip system is also used for trips from related equipment and several turbine protective trips. As further protection, there is a "cross trip" logic employed which allows all trips originating in the 24 volt dc logic to initiate a trip by the 125 volt dc system. Conversely all trips originating in the 125 volt dc logic will initiate a trip in the 24 volt dc system. The output trip signals from these two voltage levels energize separate and individual solenoid valves which, in turn, dump the pressure off the high-pressure fluid connected to all the turbine steam admission valves.

10.2.2.5 Other Protective Systems

In addition to the previously mentioned devices, other protective features of the turbine and steam system are:

A. Safety valves on the moisture separator-reheater to protect the high-pressure turbine cylinder from overpressure in the event of a turbine trip

B. With the exception of the last two low-pressure heaters, each steam extraction line is equipped with a nonreturn valve to protect the turbine from overspeed due to reverse flow in case of a turbine trip. Each nonreturn valve will be exercised once per week using a

hand air test valve which is located at the nonreturn valve. Movement of the nonreturn valve shaft and counter weight extension will be noted during testing.

C. Exhaust casing rupture diaphragms to protect the low-pressure turbine cylinders from overpressure in case of loss of condenser vacuum.

10.2.2.6 Plant Loading and Load Following

The turbine-generator is intended to be base loaded, but is designed to match or exceed the transient load following capabilities of the NSSS. The reactor regulating system (RRS) automatically adjusts reactor power to follow turbine load transients. The RRS senses turbine first-stage pressure as a linear indication of load and generates signals that regulate control element assembly (CEA) drive direction and speed. As a combined unit consisting of turbine-generator and reactor, the system accepts step load changes of $\pm 10\%$ and ramp load changes of $\pm 5\%$/min over the range of 15 to 100% full power. It also accepts, with the aid of the turbine bypass system, a load rejection of approximately 55% of full load power without reactor trip. For load rejections greater than approximately 55% of full load, reactor power is cut back as described in subsection 10.4.4, and steam is dumped to the condenser as needed. In the event of complete loss of load, the system automatically runs back to house load. If the condenser is not available, concurrent with a load rejection, the reactor is tripped.

The turbine control system is designed to provide protection to the turbine by tripping the turbine for certain predetermined

conditions as discussed in paragraph 10.2.2.3. The turbine is tripped upon reactor trip. The reactor protective system provides two separate signals of reactor trip to the turbine control system.

10.2.2.7 Inspection and Testing Requirements

Major system components are readily accessible for inspection and are available for testing during normal plant operation. Controls and protective devices associated with each turbine-generator component will be tested on a regularly scheduled basis. Various turbine trips will be tested in sequence prior to unit startup.

The schedules for testing and inspection of the various system components are developed as part of the plant operating procedures presented in section 13.5.

10.2.3 TURBINE DISK INTEGRITY

10.2.3.1 Materials Selection

The originally installed General Electric turbine wheels and rotors are made from vacuum melted or vacuum degassed Ni-Cr-Mo-V alloy steel by processes that minimize flaw occurrence and provide adequate fracture toughness. Tramp elements are controlled to the lowest practical concentrations consistent with good scrap selection and melting practices, and consistent with obtaining adequate initial and long life fracture toughness for the environment in which the parts operate. The turbine wheel and rotor materials have the lowest fracture appearance transition temperatures (FATT) and highest

Charpy V-notch energies obtainable, on a consistent basis, from water quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Since actual levels of FATT and Charpy V-notch energy vary depending upon the size of the part and the location within the part, etc., these variations will be taken into account in accepting specific forgings for use in turbines for nuclear application. Charpy tests essentially in accordance with Specification ASTM A370 are included.

The replacement General Electric Low Pressure Rotors are manufactured as a monoblock forging and do not have shrunk on wheels to preclude brittle failure at the wheel bore region. The monoblock forging material chemistry is optimally balanced to achieve high hardenability, good fracture toughness at the required tensile strength, low tramp elements to minimize temper embrittlement and low sulfur to minimize harmful segregation. This material is similar to ASTM 470 Class 6 but with more restrictive quality requirements.

The rotor forging is semi-machined to provide suitable surface for a periphery ultrasonic inspection. After final heat treatment a series of NDT testing is performed to ensure rotor structural integrity. Specimen testing of the rotors is performed to assure the rotors meet the supplier’s material specifications. Charpy tests essentially in accordance with Specifications ASTM A370 and ASTM A470 are included. A copy of all these test records and inspections for each rotor are submitted by GE and included in SDR log 13-M400-0303-1036.[1]

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described in paragraph 10.2.3.1 to produce a balance of adequate material strength and toughness to ensure safety while simultaneously providing high reliability, availability, and efficiency during operation. For the original General Electric turbines, bore stress calculations include components due to centrifugal loads, interference fit, and thermal gradients where applicable. The ratio of material fracture toughness, K_{IC} (as derived from material tests on each wheel or rotor) to the maximum tangential stress for wheels and rotors at speeds from normal to 115% of rated speed[a] will be at least $2\sqrt{\text{inches}}$. Adequate material fracture toughness needed to maintain this ratio is assured by destructive tests on material taken from the wheel or rotor using correlation methods which are more conservative than that presented in reference 1.

Turbine operating procedures are employed to preclude brittle fracture at startup by ensuring that the metal temperature of wheels and rotors (a) is adequately above the FATT, and (b) as defined above is sufficient to maintain the fracture toughness to tangential stress ratio at or above $2\sqrt{\text{inches}}$. For original General Electric turbines details of these startup procedures are contained in reference 2.

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a. The highest anticipated speed resulting from a loss of load is 110%.

10.2.3.3 High-Temperature Properties

The operating temperatures of the high-pressure rotor in turbines operating with light-water reactors are below the creep rupture range. Creep rupture is, therefore, not considered to be a significant factor in assuring rotor integrity over the lifetime of the turbine. Basic data is obtained from laboratory creep rupture tests.

10.2.3.4 Turbine Disk Design

The original General Electric turbine assembly is designed to withstand normal conditions and anticipated transients including those resulting in turbine trip without loss of structural integrity. The design of the turbine assembly meets the following criteria:

A. The maximum tangential stress in wheels and rotors resulting from centrifugal forces, interference fit, and thermal gradients does not exceed 0.75 of the yield strength of the materials at 115% of rated speed.

B. Turbine shaft bearings are designed to retain their structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

C. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20% overspeed are controlled in the design and operation so as to cause no distress to the unit during operation.

GE, in the course of designing the new turbine for Palo Verde #1, 2 and 3, has evaluated tensile stresses in rotating

components. All of the rotating components have sufficient margin to tensile strength at design component temperatures to support operating speeds well in excess of 120% of normal. For example, the overspeed capability of the un-bucketed HP and LP rotors is over 200%. The most limiting components, per design, for the bucketed rotors are the LP L-0 buckets which have a minimum overspeed capability of 170%. The design of some of the most critical parts of the monoblock rotor assembly meet the following criteria:

A. The new monoblock rotors utilize tangential entry “pinetree” dovetails to attach the first five stages of buckets and radial entry “finger” dovetails to attach the last two stages. The wheel tangential entry dovetails are shot peened to introduce a compressive stress layer for protection against Stress Corrosion Cracking (SCC). In addition, the critical areas that are susceptible to SCC are designed such that the peak stresses do not exceed 55 percent of the material yield strength.

B. Turbine shaft bearings are designed to retain their structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

C. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20% overspeed are controlled in the design and operation so as to cause no distress to the unit during operation.

10.2.3.5 Preservice Inspection

The preservice inspection program is as follows:

A. The original wheel and rotor forgings and the new monoblock forgings are rough machined with minimum stock allowance prior to heat treatment.

B. Each original rotor and wheel forging and new monoblock forging is subjected to a 100% volumetric (ultrasonic) examination. Each finish-machined original rotor and wheel and new monoblock forging is subjected to a surface magnetic particle and visual examination. Results of the above examination will be evaluated by use of General Electric acceptance criteria. These criteria are most restrictive than those specified for Class 1 components in the ASME Boiler and Pressure Vessel Code, Sections III and V, and include the requirement that subsurface sonic indications are either removed or evaluated to assure that they do not grow to a size which compromises the integrity of the unit during the service life of the unit.

C. Finish-machined surfaces are subjected to a magnetic particle examination. No magnetic particle flaw indications are permissible in bores, holes, keyways, and other highly stressed regions.

D. Each fully bucketed turbine rotor assembly is spin tested at or above the maximum speed anticipated following a load rejection from full load.

10.2.3.6 Inservice Inspection

The inservice inspection program for the turbine assembly and valves includes the following:

A. Disassembly of the turbine is conducted during selected plant shutdowns. Inspection of parts that are normally inaccessible when the turbine is assembled for operation, such as couplings, coupling bolts, turbine shafts, low-pressure turbine buckets, low-pressure wheels, and high-pressure rotors, is conducted. This inspection consists of visual, surface, and volumetric examinations.

B. Dismantle at least one main steam stop valve, one main steam control valve, one reheat stop valve, and one reheat intercept valve during selected refueling or maintenance shutdowns, and conduct a visual and surface examination of valve seats, wheels, and stems. If unacceptable flaws or excessive corrosion are found in a valve, other valves of its type are inspected. Valve bushings are inspected and cleaned, and bore diameters are checked for proper clearance.

C. Main steam stop, control, reheat stop, and intercept valves will be exercised at least once per quarter by closing each valve and observing by direct observation that it moves smoothly to a fully closed position.

D. Extraction steam valves will be exercised once per week using a hand air test valve which is located at the nonreturn valve. Movement of the nonreturn valve shaft

and counterweight extension will be noted during testing.

10.2.4 EVALUATION

10.2.4.1 Power Generation

Components of the turbine-generator are conventional and are types that have been extensively used in other nuclear power plants. Instruments, controls, and protective devices are provided to ensure reliable and safe operation. Redundant, fast actuating controls are installed to prevent any damage resulting from overspeed and/or full load rejection. The control system ensures turbine trip upon reactor trip. Automatic low-pressure exhaust hood water sprays prevent excessive hood temperatures. Exhaust casing rupture diaphragms prevent low-pressure cylinder overpressure in the event of loss of condenser vacuum.

Since the steam generated in the steam generators is not normally radioactive, no radiation shielding is provided for the turbine-generator and associated components. Thus, radiological considerations do not affect access to system components during normal conditions. In the event of a primary-to-secondary system leak due to a steam generator tube leak, it is possible for the main steam to become radioactively contaminated. Discussions of the radiological aspects of primary-to-secondary leakage are presented in chapters 11 and 12.

10.2.4.2 CESSAR Interface Evaluation

Refer to subsections 5.1.5 and 7.2.4.

10.2.5 INSTRUMENTATION APPLICATIONS

The turbine-generator is provided with a full complement of turbine supervisory instruments mounted in the control room, complete with sensors and/or transmitters mounted on the associated equipment, which indicate and record the following:

- Speed
- Stop valve position
- Control valve position
- Intercept valve position
- Temperatures as required for controlled starting, including:
  - Steam chest
  - Nozzle bowl
  - First-stage steam and drain
  - High-pressure casing drain
  - High-pressure exhaust
  - First-stage reheater outlet
  - Second-stage reheater outlet
- Casing expansion
- Casing and shaft differential expansion

- Vibration at each bearing
- Shaft eccentricity
- Bearing oil drain, shaft bearing sleeve, and thrust bearing plate temperatures
- Shaft axial position

Control room alarms are provided to warn the operators of the following abnormal conditions:

- High vibration
- High eccentricity
- High differential expansion
- High bearing temperature
- High exhaust hood temperature alarm
- Turbine trip (for each independent redundant channel)
- Low vacuum
- Thrust bearing wear
- Low bearing oil pressure
- Low steam seal pressure
- High gland seal condenser pressure (or low vacuum)
- Overspeed trip (for each independent redundant channel)
- High-low level in moisture separator drain tank

Local and control room indication of the following miscellaneous parameters are provided:

- Main steam chest pressure
- Steam seal header pressure
- Gland seal condenser vacuum
- Bearing oil header pressure
- Hydraulic header pressure
- Crossover pressure
- Moisture separator drain tank level (local only)
- First-stage pressure
- High-pressure turbine exhaust pressure
- Extraction steam pressure, each extraction point (via computer)
- Exhaust hood spray water flow
- Exhaust hood temperature, each exhaust

Instrumentation and controls are provided in the control room for the generator equipment as follows:

A. Generator supervisory instruments with sensors and/or transmitters mounted on the associated equipment, indicating or recording the following:

   1. Multiple generator stator winding temperatures. The detectors are built into the generator, fully protected from the cooling medium, and suitably distributed around the circumference in positions having the highest temperature.

2. Multiple stator winding cooling coil outlet temperature detectors

3. Stator coolant inlet and discharge temperatures

4. Hydrogen cooler inlet gas temperature (two detectors at each point)

5. Field temperature

6. Hydrogen gas pressure

7. Hydrogen gas purity

8. Generator winding over temperature.

B. Alarms are provided for high stator, hydrogen, stator coil coolant, and field temperature. An alarm is provided from a core monitoring system to indicate a local core overheating condition.

10.2.6 REFERENCES

1. Begley, J. A., and Logsdon, W. A., Westinghouse Scientific Paper 71-1E7-MSLRF-P1.

2. Spender, R. C., and Timo, D. F., Starting and Loading of Turbines, General Electric Company, presented at the 36th Annual Meeting of the American Power Conference, Chicago, Illinois, April 29-May 1, 1974.

3. Turbine Generator Final Report 105% core Thermal Uprate Study, SDR log 13-M400-0303-01036.

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10.3 MAIN STEAM SUPPLY SYSTEM

The function of the main steam supply system is to deliver steam from the steam generators to the high-pressure turbine over a range of flows and pressures covering the entire operating range from system warmup to valves-wide-open (VWO) conditions. The system also provides steam to the moisture separator/reheaters, the feedwater pump turbines, the auxiliary steam system, and the steam seal system for the main and the feedwater pump turbines.

Under certain conditions the Auxiliary Steam condensate cross connection header may be connected to the Secondary Chemistry Condensate Cleanup System in order to transfer water from the steam generators to the Chemical Waste Neutralization Tanks. This capability is discussed further in Section 10.4.6.

10.3.1 DESIGN BASES

10.3.1.1 Safety Design Bases

Pertinent safety design bases are as follows:

A. Safety Design Basis One

   The system provides a means of dissipating heat generated in the nuclear steam supply system (NSSS) during normal power operation, plant startup, hot shutdown, hot standby, and cooldown, even if the main condenser is unavailable. Atmospheric dump valves are provided to allow cooldown of the steam generator when the condenser is not available.

B. Safety Design Basis Two

The system is provided with automatically operated isolation valves on the main steam lines. These valves are located outside of and as close as possible to the containment in accordance with the requirements of Criterion 57 of 10CFR50.

C. Safety Design Basis Three

The system, from the secondary side of the steam generators and up to and including the main steam isolation valves (MSIVs) and the main steam isolation valve bypass valves, is designed to withstand the effects of a safe shutdown earthquake (SSE). The safety-related portions of the system are capable of withstanding the effects of natural phenomena.

D. Safety Design Basis Four

Main steam system components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, testing, and postulated accidents, including loss-of-coolant accidents (LOCAs), in accordance with 10CFR50, Appendix A, General Design Criterion 4.

E. Safety Design Basis Five

The main steam piping and supports are designed so that a single failure in the main steam system will have no contributory effects on:

- Initiation of a LOCA

- Integrity of other steam lines
- The capability of the engineered safety features system to effect a safe reactor shutdown
- Transmission of excessive loading to the containment pressure boundary

F. Safety Design Basis Six

The portion of the main steam system that is constructed in accordance with ASME Section III, Class 2, requirements is provided with access to welds and removable insulation as required for inservice inspection in accordance with ASME Section XI, Rules for Inservice Inspection of Nuclear Reactor Coolant Systems.

G. Safety Design Basis Seven

Flow restrictors are installed in the steam generator steam nozzles to limit flow in the event of a main steam line break.

H. Safety Design Basis Eight

Provide steam to the auxiliary feedwater pump turbine.

10.3.1.2 Power Generation Design Basis

The main steam supply system delivers the steam from the steam generators to the high-pressure turbine for a range of flows and pressure varying from system warmup to maximum operating conditions. It also provides steam to the moisture separator reheater, the feedwater pump turbines, the auxiliary steam system, and the turbine gland steam seal system.

10.3.1.3 Environmental Design Bases

Refer to section 3.11 and CESSAR Section 3.11 for a discussion of environmental design bases.

10.3.1.4 Codes and Standards

The main steam supply is designed in accordance with the codes and standards identified in table 3.2-1.

10.3.1.5 CESSAR Interface Requirements

Refer to subsection 5.1.4.

10.3.2 DESCRIPTION

10.3.2.1 General Description

The main steam supply system, shown in engineering drawings 01, 02, 03-M-SGP-002 and -001, includes the following major components:

- Main steam piping from the steam generator nozzles to the main turbine stop valves
- One main steam isolation valve per main steam line
- Main steam safety valves, 5 per main steam line
- Atmospheric dump valves, 1 per main steam line

Table 10.3-1 lists the design data covering the major components of the main steam supply system.

10.3.2.2 Component Description

10.3.2.2.1 Main Steam Piping

The main steam lines deliver the required steam flow from the secondary side of the two steam generators to the high-pressure turbine; while brunch lines deliver steam to the moisture separator/reheater, feedwater pump turbines, steam seal system, and the auxiliary steam system. Each of the main steam lines from the steam generators is anchored at the containment wall and has sufficient flexibility to accommodate thermal expansion. Design of the attachment of the main steam piping to the steam generators includes design considerations that incorporate the allowable nozzle loading moments and stresses for both steam generators operating, or with one of them out of service. The design of all piping and supports considers all static and dynamic loadings, stresses, and moments arising from normal operation, pressure transients, or pipe rupture. The design of Seismic Category I piping and supports considers the loads discussed in subsection 3.9.3.

Each main steam line contains five spring-loaded safety valves, one atmospheric dump valve, and one isolation valve. All of these valves are located outside the containment and are installed as close as possible to the containment wall. Containment penetrations are discussed in subsection 6.2.4.

Turbine bypass valves are provided between the main steam isolation valves and turbine generator stop valves as discussed under the turbine bypass system (refer to subsection 10.4.4). Connections are provided for nitrogen pressurization of the steam generators. Also, sample connections are provided

downstream of the steam generator nozzles for determination of steam quality. Branch piping provides steam to moisture separator reheaters, main and feedwater pump turbine gland steam sealing systems, the feedwater pump turbines, the auxiliary feedwater pump turbine, and the bypass steam to the condenser and to atmosphere.

The main steam lines are designed to permit preoperational cleaning to remove foreign material and rust. The design is such as to prevent entry of foreign material into either the steam generators or turbine-generator. The main steam piping drops several feet immediately downstream of the steam generators prior to being routed to the turbine stop valves. The lines are sloped in the direction of the turbine, and drains are provided at all low points to provide for flushing and drainage.

Pertinent design parameters for the main steam piping out to the main steam isolation valve are presented in table 10.3-2.

The main steam piping out to the first isolation valve is inspected and tested in accordance with ASME Code, Sections III and XI. ANSI B31.1 piping is inspected and tested in accordance with Paragraphs 136 and 137 of ANSI B31.1.

Table 10.3-1
MAIN STEAM SUPPLY SYSTEM DESIGN DATA
(Sheet 1 of 2)

Component	Parameter
Main steam piping	
Steam flow at Rated power (Reactor Power of 3800 MWt), 10^6 lb/hr	17.2
at rated Power (Reactor Power of 3990 MWt), 10^6 lb/hr	17.96
at VWO power, (Reactor Power of 3800 MWt), 10^6 lb/hr	18.1
at VWO power, (Reactor Power of 3990 MWt), 10^6 lb/hr	18.45
Number of main steam lines	4
Pipe size, OD in.	28
Design pressure, psig	1255
Design temperature, °F	600
Pipe material	ASME SA-155 grade KCF 70, class I carbon steel (Discontinued in 1978) Replaced with ASME SA-672 grade C 70, class 21 carbon steel
Pressure drop from steam generator to stop valve at VWO, psi	39
at Rated Power (Reactor Power of 3880 MWt), psi	33
at Rated Power (Reactor Power of 3990 MWt), psi	19.8
at Turbine Guarantee, psi	33
Main steam isolation valves	
Number per main steam line	1
Total number required	4
Atmospheric dump valves	
Number per main steam line	1
Total number required	4
Design relieving capacity per valve 100% open, lb/h (at 1000 psia)	1.47×10^6
Controllable capacity per valve, lb/h (at 1170 psia)	63,000
Main steam safety valves	
Number per main steam line	5
Total number required	20

Table 10.3-1

MAIN STEAM SUPPLY SYSTEM DESIGN DATA
(Sheet 2 of 2)

Component			Parameter
Main steam safety valves (Cont.)			
Set pressure, psig			
No. 1			1250
No. 2			1290
No. 3			1315
No. 4			1315
No. 5			1315
Orifice size, in^2			
No. 1			16.0
No. 2			16.0
No. 3			16.0
No. 4			16.0
No. 5			16.0
Inlet/Outlet size, in./in.			
No. 1			6 x 10
No. 2			6 x 10
No. 3			6 x 10
No. 4			6 x 10
No. 5			6 x 10
Minimum rated relieving capacity, per valve, at 3% accumulation, 10^5 lb/h: VALVE NUMBER			
	S/G No. 1	S/G No. 2	Parameter
a.	SGE PSV 572	SGE PSV 554	9.415
b.	SGE PSV 579	SGE PSV 561	9.415
c.	SGE PSV 573	SGE PSV 555	9.713
d.	SGE PSV 578	SGE PSV 560	9.713
e.	SGE PSV 574	SGE PSV 556	9.899
f.	SGE PSV 575	SGE PSV 557	9.899
g.	SGE PSV 576	SGE PSV 558	9.899
h.	SGE PSV 577	SGE PSV 559	9.899
i.	SGE PSV 691	SGE PSV 694	9.899
j.	SGE PSV 692	SGE PSV 695	9.899
Total (20 valves), 10^6 lb/h			19.53
Total maximum actual relieving capacity (20 valves), 10^6 lb/h			22.258

[Editing Note: The truncated "parameter" value bounds the CTS Value]

10.3.2.2.2 Main Steam Isolation Valves

Each of the main steam lines is equipped with one quick acting main steam isolation valve (MSIV). Each valve has an actuation time of 4.6 seconds or less and operates automatically in the event of rupture in the main steam piping or associated components either upstream or downstream of the MSIV. They prevent blowdown of more than one steam generator (assuming a single active failure of an MSIV to close coincident with rupture) based on the MSIV's ability to close against maximum design differential pressure in either direction. The valves are designed to close upon loss of electric power. Once isolation is initiated, in response to a main steam isolation signal (MSIS), the valves continue to close and cannot be opened until the initiating MSIS is reset or overridden manually by the operator in the control room.

Table 10.3-2

MAIN STEAM ISOLATION VALVE EXPECTED LEAKAGE

Differential Pressure (psi)	Pressurized (Upstream/Downstream)	Seat Leakage
1400	Downstream (after steam line break)	0.1% VWO steam flow
1400	Upstream (after steam line break)	0.001% VWO steam flow

Each valve has two physically separate and electrically independent solenoid actuators in order to provide redundant means of valve operation. Refer to table 10.3-2 for valve leakage.

The main steam isolation valves are installed in the straight piping runs outside the containment. Table 10.3-3 tabulates all flow paths that branch off the main steam lines between the MSIVs and the turbine stop valves and provides information, including valve positions, to determine performance in the event of steam line break upstream of the MSIV. For those valves which remain open, the total steam flow through these valves is approximately 251,200 lbm/hr. The auxiliary feedwater pump (AFW) delivers at least 316,000 lbm/hr (650 gpm @ 180F.), to the intact steam generator at 1270 psia. Therefore, in the event of a postulated MSLB on one steam generator, and one MSIV failure to close on the intact steam generator, an auxiliary feedwater pump can provide sufficient make-up to the intact steam generator. The maximum stress level does not exceed the criteria specified in subsection 3.9.3. As noted in UFSAR Sections 15.1.5 and 15.1.6, however, the single failure of a HPSI pump to start on demand is more limiting for postulated MSLBs, than the single failure of an MSIV to close.

A mechanistic main steam line pipe rupture is not postulated to occur between the containment penetrations and the MSIVs nor between the MSIVs and the double concrete wall (designed as a pipe whip restraint) downstream from the MSIVs. However, the main steam support structure and safety-related equipment within are designed to withstand the temperature and pressure effects of a single area pipe break.

The bending moment resulting from a main steam line rupture downstream of the pipe whip restraint is absorbed by the pipe whip restraint and the MSIV nozzle has no bending moment transmitted to it.

Table 10.3-3

FLOW PATHS ORIGINATING AT MAIN STEAM LINES (Sheet 1 of 2)

System Identification	Max. Steam Flow (LB/HR)	Type of Shut-off Valves	Size of Valve	Quality of Valve	Design Code of Valve	Closure Time of Valve (Seconds)	Actuation Mechanism	Motive or Power Source	Closure Signal (Sensor)	Quality of Power Source	Quality of Air Supply	Positive Status of Valve After MSIV Isolation	Comment
SG-V093 (or AS-V004)	82,600	Gate (Gate)	6"	Non-Q	ANSI B31.1	15	Manual	N/A	N/A	N/A	N/A	Open	
SG-V094 (or AS-V012)	82,600	Gate (Gate)	6"	Non-Q	ANSI B31.1	15	Manual	N/A	N/A	N/A	N/A	Open	Aux. steam supply to control valves PV-5A/B,PV-6 (13-M-ASP-001) (13-M-SGP-001)
SG-V095 (or AS-V013)	50,000	Globe (Gate)	3"	Non-Q	ANSI B31.1	10	Manual	N/A	N/A	N/A	N/A	Open	
MT-UV-1004 (or UV-1005)	4.25×10^6	Globe	28"	Non-Q	ANSI B31.1	0.2	Hydraulic	Trip of turbine speed control system (actu-ated on MSIS parameters)	MSIS Actuation Signal (Low S/G Pressure)	Non-IE	N/A	Closed	
MT-UV-1006 (or UV-1007)	4.25×10^6	Globe	28"	Non-Q	ANSI B31.1	0.2	Hydraulic	Trip of turbine speed control system (actu-ated on MSIS parameters)	MSIS Actuation Signal (Low S/G Pressure)	Non-IE	N/A	Closed	Main steam supply to main turbine (13-M-MTP-001)
MT-UV-1002 (or UV-1001)	4.25×10^6	Globe	28"	Non-Q	ANSI B31.1	0.2	Hydraulic	Trip of turbine speed control system (actu-ated on MSIS parameters)	MSIS Actuation Signal (Low S/G Pressure)	Non-IE	N/A	Closed	
MT-UV-1000 (or UV-1003)	4.25×10^6	Globe	28"	Non-Q	ANSI B31.1	0.2	Hydraulic	Trip of turbine speed control system (actu-ated on MSIS parameters)	MSIS Actuation Signal (Low S/G Pressure)	Non-IE	N/A	Closed	
SG-UV-031	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	Non-IE	N/A	Non-IE	N/A	Closed	
SG-UV-032	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	480V	N/A	Non-IE	N/A	Closed	
SG-UV-033	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	3 Phase	N/A	Non-IE	N/A	Closed	
SG-UV-034	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	60 Cycle	N/A	Non-IE	N/A	Closed	Bleed off line between MSIV's and turbine stop valves closes on turbine trip (normally closed MOVs) (13-M-SGP-001)
SG-UV-035	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	Non-IE	N/A	Non-IE	N/A	Closed	
SG-UV-036	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	480V	N/A	Non-IE	N/A	Closed	
SG-UV-037	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	3 Phase	N/A	Non-IE	N/A	Closed	
SG-UV-038	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	60 Cycle	N/A	Non-IE	N/A	Closed	

Table 10.3-3

FLOW PATHS ORIGINATING AT MAIN STEAM LINES (Sheet 2 of 2)

System Identification	Max. Steam Flow (LB/HR)	Type of Shut-off Valves	Size of Valve	Quality of Valve	Design Code of Valve	Closure Time of Valve (Seconds)	Actuation Mechanism	Motive or Power Source	Closure Signal (Sensor)	Quality of Power Source	Quality of Air Supply	Positive Status of Valve After MSIV Isolation	Comment
SG-PV-1007	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	Main steam blow-down at atmos vent restrictor (13-M-SGP-001)
SG-PV-1008	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
SG-PV-1002	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
SG-PV-1001	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic		Solenoid permissive to open (Non-ie 120V dc)	Non-IE	ANSI B31.1	Closed	
SG-PV-1003	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic	Instrument Air	SGBD permissive signal logic (Non-IE 120V ac	Non-IE	ANSI B31.1	Closed	
SG-PV-1004	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	Main steam blow down to condenser (13-M-SGP-001)
SG-PV-1005	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
SG-PV-1006	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
FT-HV-65	120,000	Globe	5"	Non-Q	ANSI B31.1	0.3	Hydraulic			Non-IE	N/A	Closed	
(or HV-67)	120,000	Globe	5"	Non-Q	ANSI B31.1	0.3	Hydraulic	MFW Pump Turgine Speed Control System	MFW pump trip logic (MSIS) [(a)]	Non-IE	N/A	Closed	
FT-HV-66	120,000	Globe	5"	Non-Q	ANSI B31.1	0.3	Hydraulic			Non-IE	N/A	Closed	Main steam supply to MFW pump turbine
(or HV-68)	120,000	Globe	5"	Non-Q	ANSI B31.1	0.3	Hydraulic			Non-IE	N/A	Closed	
MT-UV-328B	262,500	Globe	10"	Non-Q	ANSI B31.1	75	Motor		Load sensing logic on main turbine, (i.e., pressure switch PSL 512)	Non-IE	N/A	Closed	
MT-UV-328A	262,500	Globe	10"	Non-Q	ANSI B31.1	75	Motor	Electrical (Non-IE, 480V 3 phase 60 cycle		Non-IE	N/A	Closed	
MT-UV-328D	262,500	Globe	10"	Non-Q	ANSI B31.1	75	Motor			Non-IE	N/A	Closed	Main steam supply to moisture separator reheater
MT-UV-328C	262,500	Globe	10"	Non-Q	ANSI B31.1	75	Motor		Control room hand switch	Non-IE	N/A	Closed	
GS-HV-005	36,000	Gate	4"	Non-Q	ANSI B31.1	10	Motor	Electrical (Non-IE, 480V 3 phase 60 cycle		Non-IE	N/A	Open (closed by plant operator)	Main steam supply to gland seal

The steady-state discharge thrust load from such a break does not cause nozzle bending or torsion. Axial thrust is resisted and balanced at the penetration.

The bending and axial loads resulting from a postulated main steam line break inside the containment are absorbed by the containment penetration which is designed to withstand pipe collapsing moments and axial thrust.

The operability of the MSIVs is thus unaffected by the above postulated main steam line breaks.

The MSIVs are designed, manufactured, inspected, tested, and certified in accordance with the requirements of the ASME Code, Section III.

The supplier of the MSIVs has designed the valve body to the specified design pressure and temperature and designed the disc, piston, cylinder, connecting shaft, and all other valve and operational components subject to the closing and opening loads within the specified operational time limits to the design differential pressure (in either direction). Disc load and disc assembly inertia load are safely transferred to the valve body.

Total load combinations and stress limits (including pressure load and disc assembly inertia load acting on the valve seat) meet the requirements of table 3.9-3.

The maximum disc stress due to differential pressure and the inertia load due to the moving disc assembly do not exceed 75% of the yield strength in bending and 50% of the yield strength in shear of the disc material at the operating temperature.

The MSIVs are qualified for operability in conformance to paragraph 3.9.3.2.1.2.

10.3.2.2.3 Main Steam Safety Valves

Each main steam line is provided with five ASME Code, spring loaded safety valves located upstream of the main steam isolation valves but outside the containment. The total relieving capacity of these valves is divided equally between the main steam lines and is sufficient to pass the steam flow equivalent to 105% of the plant's maximum steam flow. Design data for the main steam safety valves are included in table 10.3-1. The safety valve pressure accumulation does not exceed 3% and the maximum pressure while relieving is below the maximum allowable of 10% above the steam generator design pressure, in accordance with Article NC-7000 of ASME Section III, Nuclear Power Plant Components Code. The design pressure-temperature rating of the main steam piping is 1270 psia and 600F, which are more conservative than the design conditions for the steam generator secondary side.

10.3.2.2.4 Atmospheric Dump Valves

Atmospheric dump valves, one per main steam line, are provided to allow cooldown of the steam generators when the main steam isolation valves are closed, or when the main condenser is not available as a heat sink. Each atmospheric dump valve is sized to hold the plant at hot standby while dissipating core decay heat or to allow a flow of sufficient steam to maintain a controlled reactor cooldown rate. No automatic control capability is required or provided. Refer to section 7.4 for

discussion of the control of the atmospheric dump valves. A nitrogen accumulator is provided for each valve. The accumulator is designed to Seismic Category I standards and is sized for 4 hours at hot standby plus 9.3 hours of operation to reach cold shutdown[(1)] under natural circulation conditions in the event of failure of the normal control air system, with a minimum nitrogen accumulator pressure of 615 psig indicated. Refer to subsection 9.3.6 for a discussion of the nitrogen supply for the atmospheric dump valve accumulators.

10.3.2.3 Radiological Considerations

Because the steam from the steam generator is not normally radioactive, no radiation shielding is required for the main steam system and associated components. Thus, radiological considerations will not affect access to system components during normal conditions. In the event of a primary-to-secondary system leak caused by a steam generator tube leak, it is possible for the steam to become radioactively contaminated. Discussions of the radiological aspects of primary-to-secondary leakage are presented in chapters 11 and 12.

10.3.3 EVALUATION

Table 10.3-4 covers the failure mode and effects analysis of the main steam supply system.

10.3.3.1 Safety Evaluation

Safety evaluations are numbered to correspond to the safety design bases and are as follows:

A. Safety Evaluation One

Under the following conditions, with the steam generators in service, the power-operated atmospheric dump valves are used to dissipate reactor coolant system energy and core decay heat into the atmosphere:

1. When the turbine generator or main condenser is not in service
2. When the plant is being started up or shut down
3. During core physics testing
4. Following a turbine-generator trip on loss of main condenser vacuum
5. Loss of electric power to plant auxiliaries

Controlled cooldown can be accomplished by use of the dump valves.

B. Safety Evaluation Two

Isolation valves are included in the system design. These valves are described in paragraph 10.3.2.2.2 and their performance under the accident conditions is discussed in chapter 15.

C. Safety Evaluation Three

The main steam system is designed in accordance with seismic criteria set forth in chapter 3. The design of the main steam system with respect to natural phenomena is also discussed in chapter 3.

Table 10.3-4

MAIN STEAM SYSTEM FAILURE MODE AND EFFECTS ANALYSIS (Sheet 1 of 3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision
1	Main steam isolation valve	a) Fails open	Solenoid failure	None, redundant solenoid will close valve	Valve Position Indicator, S. G. Pressure and Level Indicators, and steam line flow recorders	Each MSIV has redundant trip circuits, solenoid valves, accumulators, and position indicators.
		b) Fails closed	Actuator failure	Decrease in steam flow to the turbine generators, about 25%	Valve Position Indicator and steam line flow recorders	None
2	MSIV bypass valve	a) Fails closed	Mechanical binding Pneumatic operator failure	Main steam isolation valves can't be opened if there is a pressure drop across them	Valve position indication in control room	Either of two valves can be used to equalize pressure in all four steam lines.
		b) Fails open	Mechanical binding	None, if MSIV is open. If MSIV is shut, then bleedoff of steam generator	Valve position indication in control room	Affects only one steam generator.

Table 10.3-4

MAIN STEAM SYSTEM FAILURE MODE AND EFFECTS ANALYSIS (Sheet 2 of 3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision
3	Valve, atm dump	a) Fails closed	Failure of seals or air supply	No effect unless coupled with some other failure	Valve position indication in control room	Backup nitrogen supply. Also, other steam generator atmospheric dump valves provide full capability for steam release
		b) Fails open	Mechanical binding	About 16% of one steam generator's steam output would be dumped to atmosphere. A stuck open ADV will result in both a reactor trip and a MSIS.	Noise level increase, and a decrease in steam generator pressure indicated in control room	Blowdown of only one steam generator
4	Main feedwater isolation valve	a) Fails open	Mechanical binding	No effect	Periodic tests	Two valves in series in each line are available for isolation. Auxiliary feed flow is available via alternate path
		b) Fails closed	Operator failure	Loss of 90% of flow to one section of the steam generator. Decrease in steam generator efficiency	Low flow indicated on flow indicator	Feed to steam generator still available to other sections

Table 10.3-4

MAIN STEAM SYSTEM FAILURE MODE AND EFFECTS ANALYSIS (Sheet 3 of 3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failure	Methods of Detection	Inherent Compensating provision
5	Main feedwater check valve	a) Fails closed	Mechanical binding	No flow to one portion of the economizer in one steam generator. Decrease in efficiency of the steam generator	Flow indicator in control room	Steam generator feed still available to other sections Feedwater control system will automatically compensate
		b) Fails open	Mechanical binding	No effect unless coupled with some other failure	Periodic test	Closing of containment isolation valve
6	Auxiliary feedwater check valve	a) Fails closed	Mechanical binding	Temporary low feedwater flow to one steam generator	Low flow indication in control room	Alternate flow paths available. Feedwater control system compensates automatically
		b) Fails open	Mechanical binding	No effect unless coupled with some other failure	Periodic test	None required

D. Safety Evaluation Four

All safety-related components in the main steam system are designed to perform their intended function in the normal and accident temperature, pressure, humidity, chemical, and radiation environment in which they will operate. Environmental design bases and qualifications are discussed in section 3.11.

E. Safety Evaluation Five

The main steam lines are routed from the containment to the turbine building with separations provided so that the failure of steam lines or components associated with one steam generator cannot damage the main steam lines, the isolation valves, and atmospheric dump valves associated with the other steam generator, or damage any component required to effect a safe reactor shutdown. Refer to sections 3.5 and 3.6 for the discussion of missile and pipe rupture effects.

F. Safety Evaluation Six

Removable insulation and access to welds, in accordance with ASME Section XI requirements, are provided in the main steam supply system.

G. Safety Evaluation Seven

Each steam generator steam outlet nozzle is equipped with a flow limiting device to limit steam flow in the event of a downstream pipe break. Refer to CESSAR Section 5.4.4 for a description of the flow limiting device.

H. Safety Evaluation Eight

A branch connection upstream of the MSIVs from each steam generator provides steam to operate the auxiliary feedwater pump turbine. Refer to subsection 10.4.9.

10.3.3.2 CESSAR Interface Evaluation

Refer to subsection 5.1.5.

10.3.4 INSPECTION AND TESTING REQUIREMENTS

Refer to section 14.2 for preoperational testing requirements. Refer to section 3.9 and to the Technical Specifications for inservice testing and inspection requirements.

10.3.5 WATER CHEMISTRY (PWR)

10.3.5.1 Chemistry Control Basis

Steam generator secondary side water chemistry control is accomplished by:

A. Close control of the feedwater to limit the amount of impurities which can be introduced into the steam generator;

B. Blowdown of the steam generator to reduce the concentrating effects of the steam generator;

C. Chemical addition to establish and maintain an environment which minimizes system corrosion;

D. Preoperational cleaning of the feedwater system;

E. Minimizing feedwater oxygen content prior to entry into the steam generator.

Chemistry limits for secondary steam generator water and feedwater are established in accordance with EPRI PWR Secondary Water Chemistry Guidelines as endorsed by NEI 97-06, Steam Generator Program Guidelines. The EPRI guidelines and their bases represent the industry best practice, as developed from evaluation of the most recent experimental data and plant operating experience. Exceptions are fully evaluated and documented prior to implementation.

Secondary water chemistry is based on all volatile treatment to maintain system pH, ensure a reducing environment, and to scavenge dissolved oxygen present in the feedwater. Boric acid may be added to minimize SCC of the steam generator tubes.

A neutralizing amine such as ammonia, ethanolamine (ETA) and/or dimethylamine (DMA) is added to establish and maintain alkaline conditions in the feed train.

A reducing agent/oxygen scavenger, such as hydrazine is added to establish a reducing environment and to scavenge dissolved oxygen present in the feedwater. The reducing agent/oxygen scavenger also tends to promote the formation of a protective oxide layer on metal surfaces by keeping these layers in a reduced chemical state (lower electrochemical potential).

Both the pH agent and the reducing agent/oxygen scavenger can be injected continuously downstream of the condensate polishing demineralizers or in the extraction steam lines. These chemicals are added for chemistry control, and can also be added to the upper steam generator feed line when necessary.

Molar Ratio chemistry is monitored and may be controlled to provide additional assurance that aggressive species are not

concentrated above their respective molar concentration ratio (anion to cation ratio). Ammonium chloride injection may be utilized as a method to control Molar Ratio within a prescribed band.

Implementation of Boric Acid Treatment per NSSS Vendor recommendations and EPRI BAT Application guidelines is site specific and is controlled by the station chemistry control program. Boron is maintained at very low concentrations in wet layup to minimize excessive use of pH control agent.

pH is dependent on the pH agent used, the implementation of Boric Acid Treatment (BAT), which may be used to mitigate IGA/SCC of steam generator tubes (alloy 690 tubes, and the use of condensate polishing demineralizes. Alternate amine pH agents can be utilized to provide better pH control at the normal operating temperature of PWR steam generators. Implementation of BAT will require adjustment in the pH and boron specifications.

The normal chemistry conditions can be maintained by any plant operating with little or no condenser leakage. The steam generator limits permit operations with minor system fault conditions until the affected component can be isolated and/or repaired.

Secondary water chemistry monitoring is described in section 9.3.2.

Procedures will require prompt corrective action for out of specification secondary water chemistry conditions.

If condenser leakage is indicated, leak isolation procedures are instituted.

The abnormal limits permit operation with minor system fault conditions until the affected component can be isolated and/or repaired. If the abnormal limits are exceeded, plant shutdown procedures are considered.

Sampling of the steam generator water is done on a continuous basis; parameters monitored include pH, conductivity and radiation.

Out of specification chemical conditions are alarmed in the auxiliary building chemistry laboratory, with a common system trouble alarm in the control room.

In addition, recording and management of secondary water chemistry data will be covered by administrative procedures. These procedures will include the following requirements:

A. The composition, quantities, and addition rates of additives shall be recorded initially and thereafter whenever a change is made;

B. The electrical conductivity and the pH of the bulk steam generator water and feedwater shall be measured continuously (with provision for alternate sampling methods in case of equipment failure);

C. The electrical conductivity and sodium ion concentration of the condensate is measured continuously. An administrative procedure will specify responsibilities for interpretation of secondary water chemistry data, initiation of corrective action, maintaining secondary water chemistry conditions within specifications, and taking such action as is needed to correct out of specification or off control point conditions. The

Shift Manager is responsible for initiating corrective action for out of specification chemical parameters. The Shift Manager is advised in these corrective actions by the senior chemistry technician. Chemistry data sheets and reports are reviewed on a routine basis by unit chemistry management. Procedures will provide guidance for correcting out of specification and off control point conditions and will require prompt action to correct out of specification conditions.

Procedures for secondary water chemistry control and monitoring were available onsite for NRC review 60 days prior to filling the secondary side of a steam generator.

10.3.5.2 Corrosion Control Effectiveness

Alkaline conditions in the feedtrain and the steam generator reduce general corrosion at elevated temperatures and tend to decrease the release of soluble corrosion products from metal surfaces. These conditions promote the formation of a protective metal oxide film and thus reduce the corrosion products released into the steam generator.

The reducing agent/oxygen scavenger also promotes the formation of a metal oxide film by the reduction of ferric oxide to magnetite. Ferric oxide may be loosened from the metal surfaces and be transported by the feedwater. Magnetite, however, provides an adherent protective layer on carbon steel surfaces. The reducing agent/oxygen scavenger also promotes the formation of protective metal oxide layers on copper surfaces.

The removal of oxygen from the secondary waters is also essential in reducing steam generator corrosion mechanisms. Low levels of oxygen dissolved in water causes general corrosion that can result in pitting of ferrous metals, particularly carbon steel. Oxygen is removed from the steam cycle condensate in the main condenser deaerating section. Additional oxygen protection is obtained by chemical injection of a reducing agent/oxygen scavenger into the condensate stream. Maintaining a residual level of the reducing agent/oxygen scavenger in the feedwater ensures that any dissolved oxygen not removed by the main condenser is scavenged before it can enter the steam generator.

The presence of free hydroxide (OH^-) can cause rapid corrosion (caustic stress corrosion) if it is allowed to concentrate in a local area. Free hydroxide is avoided by maintaining proper pH control, and by minimizing impurity ingress in the steam generator.

Zero solids treatment is a control technique whereby both soluble and insoluble solids are excluded from the steam generator. This is accomplished by maintaining strict surveillance over the possible sources of feed train contamination (e.g.,: Main Condenser cooling water leakage, air in leakage and subsequent corrosion product generation in the Low Pressure Drain System, etc.). Solids (with the exception of boric acid, if used) are also excluded, as discussed above, by injecting only volatile chemicals to establish conditions which reduce corrosion and, therefore, reduce the transport of corrosion products into the steam generator. Reduction of

solids in the steam generator can also be accomplished through the use of full flow condensate demineralization.

In addition to minimizing the sources of contaminants entering the steam generator, continuous blowdown of one and/or both steam generators is employed to minimize their concentration. These systems are discussed in Section 10.4.6. With the low solid levels which result from employing the above procedures, the accumulation of scale and deposits on steam generator heat transfer surfaces and internals is limited. Scale and deposit formations can alter the thermal hydraulic performance in local regions to such an extent that they create a mechanism which allows impurities to concentrate to high levels, and thus could possibly cause corrosion. Therefore, by limiting the ingress of solids into the steam generator, the effect of this type of corrosion is reduced.

Because they are volatile, the chemical additives will not concentrate in the steam generator, and do not represent chemical impurities which can themselves cause corrosion.

10.3.5.3 Chemistry Control Effects on Iodine Partitioning

The partition factor assumed for the condenser vacuum pump outlet is discussed in subsection 11.1.8.

10.3.6 STEAM AND FEEDWATER SYSTEM MATERIALS

10.3.6.1 Fracture Toughness

The materials are in compliance with the ASME Boiler and Pressure Vessel Code, Sections II and III, 1974 Edition through the Winter, 1975 Addenda. The fracture toughness properties

meet the requirements of the Code, Section III, Paragraphs NB-2300, NC-2300, and ND-2300.

10.3.6.2 Material Selection and Fabrication

All pipe, flanges, fittings, valves, and other piping material conform to the latest referenced ASME, ASTM, ANSI, or MSS-SP code, including addenda and supplements.

The following code requirements apply:

	Stainless Steel	Carbon Steel
sPipe	ANSI B36.19	ANSI B36.10
Fittings	ANSI B16.9, B16.11 or B16.28	ANSI B16.9, B16.11 or B16.28
Flanges	ANSI B16.5	ANSI B16.5

The following ASME material specifications apply specifically:

ASME SA-155 GR KCF 70 Class 1 (impact tested) (Discontinued in 1978)

ASME SA-672 GR C 70 Class 21 (impact tested)

ASME SA-106 GR C (impact tested)

ASME SA-106 GR B

ASME SA-234 GR WP-22

ASME SA-234 GR WPB

ASME SA-234 GR WPBW (manufactured from ASME SA-516 GR 70 plate)

ASME SA-234 GR WPC (impact tested)

ASME SA-105

ASME SA-182

ASME SA-193 GR B7

ASME SA-194 GR 2H

ASME SA-333 GR 6 (impact tested)

ASME SA-335 GR P22

ASME SA-420 GR WPL6 (impact tested)

ASME SA-420 WPL6-W (manufactured from ASME SA-516 GR 70 plate) (impact tested)

ASME SA-350 LF 2 (impact tested)

ASME SA-403

ASME SA-312

ASME SA-376

For austenitic stainless steel components, consistency with the recommendations of Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel; Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel; and Regulatory Guide 1.31, Control of Ferrite Content in Metal, is discussed in section 1.8.

For cleaning and handling of Class 1, 2, and 3 components, the recommendations of Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants, and ANSI-N45.2.1-73, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Plants, are followed as discussed in section 1.8.

With regard to preheat temperatures used for welding of Class 1, 2, and 3 low-alloy steel, the recommendations of Regulatory Guide 1.50, Control of Preheat Temperatures for Welding of Low-Alloy Steel, were followed.

All piping of the main steam system with pipe sizes larger than 2-1/2 inches is grit blasted.

Materials for use in Class 1, 2, and 3 components have been specified to conform to Appendix I of Section III of the Code and to Parts A, B, and C of Section II of the Code. Regulatory Guide 1.85, Code Case Acceptability ASME Section III Materials, has been used in conjunction with the above specifications.

For a discussion of conformance to Regulatory Guide 1.71, Welder Qualification for Areas of Limited Accessibility, refer to section 1.8.

10.3.7 REFERENCES

1. Scherer, A. E., Director, Nuclear Licensing, Combustion Engineering, letter to Eisenhut, D. G., Director, Division of Licensing, USNRC, August 12, 1983 (LD-83-074).

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10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

The main condenser is designed to condense and deaerate exhaust steam from the turbine generator and the feedwater pump turbines.

10.4.1.1 Design Bases

10.4.1.1.1 Safety Design Bases

The main condenser has no safety function.

10.4.1.1.2 Power Generation Design Bases

Power generation design bases are as follows:

A. Power Generation Design Basis One

   The main condenser provides a heat sink for the exhaust steam from the turbine-generator and the feedwater pump turbines, as well as for turbine bypass steam and other cycle flows.

B. Power Generation Design Basis Two

   The main condenser provides hotwell storage for surge capability and retention of condensate in the event of a condenser tube leak.

C. Power Generation Design Basis Three

   The main condenser provides required deaeration of the condensate.

D. Power Generation Design Basis Four

The main condenser is designed to minimize air inleakage into the steam thermal cycle.

E. Power Generation Design Basis Five

The chemistry of the condensate and feedwater is maintained by the secondary chemical system under all normal operating and allowable upset or abnormal conditions.

10.4.1.1.3 Codes and Standards

The main condenser is designed in accordance with the applicable codes and standards identified in table 3.2-1.

10.4.1.2 System Description

The main condenser is a multi-pressure, three-shell, single-pass, deaerating type of surface condenser with divided waterboxes. The condenser is floor supported and is located beneath the low-pressure turbines. Expansion joints are provided between each turbine exhaust opening and steam inlet connection of the condenser shells. Main condenser design data are given in table 10.4-1. During normal operation, exhaust steam from the low-pressure turbines is directed downward into the condenser shells through exhaust openings in the bottom of turbine casings and is condensed. The condenser also receives vents and drains from feedwater heaters, miscellaneous equipment, valves, and piping. During transient conditions, the main condenser serves as a heat sink for feedwater heater

and drain tank high-level dumps and for the turbine bypass steam. The main condenser is designed to accept up to 41% of the rated steam flow through the turbine bypass system described in subsection 10.4.4. The bypassed steam flow is distributed between the three condenser shells. These conditions are accommodated without increasing the condenser backpressure to the turbine trip setpoint or exceeding the allowable turbine exhaust temperature. Provision is made to reduce the bypass steam pressure before exhausting into the condenser distribution manifold. Special considerations were given to the design of the condenser to avoid steam impinging on the tubes. The condenser has titanium tubes conforming to ASTM B388 which eliminate corrosion/erosion problems.

The condenser is cooled by the circulating water system that removes the heat rejected to the condenser. The use of divided water boxes, lined with repairable protective coating to minimize corrosion/erosion, on each shell permits isolation of one-half of the total circulating water flow through each shell. This permits access to the isolated water box on each shell for repair and/or inspection while one-half of the circulating water flows through the other water box. The circulating water system is described in subsection 10.4.5. The condenser hotwells provide 100,000 gallons of water storage, equivalent to that required for 4 minutes of operation at valves wide open load. The hotwells of each of the condenser shells are interconnected. In addition to struts and braces, the first, second, third, and fourth point low-pressure

feedwater heaters are installed in the steam dome of each condenser shell.

In the event that a condenser hotwell ruptures, the flooding will not jeopardize the safe shutdown of the plant. At no time would the water enter the auxiliary building, control building, or diesel generator building. The only access to any of these buildings from the turbine building is sufficiently above the turbine building basemat elevation. Since there is no safety-related equipment in the turbine building, none could be affected.

Air and noncondensable gases contained in the turbine exhaust steam are collected in the condenser and passed through the air removal section. Here, the noncondensable gases are removed by the condenser air removal system described in subsection 10.4.2. The maximum total condenser air inleakage is 60 standard cubic feet per minute, as calculated in accordance with Heat Exchange Institute Standard. Buildup of noncondensable gases is precluded since the air removal system is in continuous operation. The condenser reduces oxygen concentration in the condensate to 5 ppm or less by deaeration while the final oxygen content is reduced to 0.01 ppm or less by hydrazine injection at the discharge side of the condensate polishing system. The hydrazine injection system is discussed in subsection 10.4.6.

Table 10.4-1
MAIN CONDENSER DESIGN DATA (Sheet 1 of 2)

Design Factor	Value
Exhaust steam to condenser at VWO load, (Reactor Power of 3800 MWt/3990 MWt), lb/h	9,303,000/ 9,361,830
Total condensate outflow, (Reactor Power of 3800 MWt/3990 MWt), lb/h	12,864,000/ 12,752,876
Total condenser duty, Btu/h	9.04×10^9
Maximum expected condenser operating pressure, in.Hg abs	5.0
Condenser high operating pressure alarm, in.Hg abs	5.5
Condenser loss of vacuum setpoint for bypass valves to close, in.Hg abs	5.5
Turbine trip vacuum setpoint, in.Hg abs	7.5
Circulating water design flow to condenser gal/min	560,000
Physical Characteristics	**Value**
No. of condenser tubes	76,278
Condenser tube material	Titanium
Total heat transfer surface, ft^2	1,122,860
Overall dimensions	
High pressure (HP)	90'-4" L; 30'-11" W; 67'-2" H
Intermediate pressure (IP)	87'-10" L; 30"-11" W; 67'-2" H
Low pressure (LP)	87'-10" H; 30'-11" W; 67'-2" H
No. of passes	One
Total hotwell capacity	100,000 gal

Table 10.4-1
MAIN CONDENSER DESIGN DATA (Sheet 2 of 2)

Physical Characteristics	Value
Special design features	3 pressure deaerating type condenser
Minimum heat transfer, Btu/h°F sq ft	
High-pressure stage	533
Intermediate pressure stage	546
Low-pressure stage	560
Steam flow from main turbine	
Guaranteed power, (Reactor Power of 3800 MWt/3990 MWt)lb/h	9,002,000 9,191,086
Vwo power, (Reactor Power of 3800 MWt/3990 MWt)lb/h	9,303,000 9,361,830
Circulating water temp., °F (Typical)	
Normal	87.3
Maximum	94.0
Exhaust steam temperature, °F	
Normal	
Without bypass flow	127
With bypass flow	133.8
Maximum	
Without bypass flow	131
With bypass flow	133.8
Condensate oxygen content cc/liter (at normal circulating water temp.)	
Above 24% load	0.005
Below 24% load (circulating water flow is divided)	>0.005

The internal steam dump fittings for the turbine bypass steam consist of double pressure reduction critical flow orifices. The steam exits in a horizontal direction away from both the turbine and the condenser tubes. In addition, the condenser tubes are protected from high temperature drains by austenitic stainless steel baffles that direct the flow away from the condenser tubes.

Loss of main condenser vacuum, as evidenced by the condenser pressure reaching or exceeding the setpoint of 7.5 in.Hg abs, trips the turbine. However, a standby vacuum pump having 100% capacity for one condenser shell is provided to prevent loss of vacuum. The pump is on automatic control to assist or take over the service of the operating pump. If the turbine is tripped because of high backpressure, the steam bypass valves close to prevent additional steam from entering the condenser.

Two of the eight bypass valves are directed to atmosphere and open only on high condenser pressure.

Rupture diaphragms on the main turbine exhaust hood are provided to protect the condenser and turbine exhaust hoods against overpressure. Exhaust hood overheating protection is provided by an exhaust hood spray system that uses condensate from the condensate pumps.

In the event of primary-to-secondary tube leakage, radioactive contaminants are present in the steam generator. Radioactive concentrations in the hotwell are given in section 11.1. During normal operation, there is no gaseous hydrogen going to the main condenser. In the event of a steam generator tube

leak, minute quantities of gaseous hydrogen are carried over to the main condenser. As noted in subsection 10.4.2, the condenser air removal system removes the hydrogen.

The reactor coolant system (RCS) is independent of the condenser circulating water system and the condensate and feedwater systems; therefore, the influence of condenser control functions on RCS operation is negligible. Minute changes in reactor power level occur as a result of changes in main turbine cycle efficiency caused by variations in condenser vacuum. However, these reactor power level variations are slight and are limited by the reactor regulating system. Each occurrence that leads to a loss of function of the condenser is accompanied by a loss of condenser vacuum, which is analyzed in section 15.2.

The operating chemistry limits for condensate and feedwater are discussed in section 10.3.5. Excessive leakage of coolant from the circulating water system into the condensate causes the condensate demineralizer to be placed in service. This system is also used to maintain water chemistry during startup, shutdown, and other conditions requiring the polishing of the condensate to maintain the required chemistry. The secondary chemistry control system, which controls and monitors the condensate chemistry, is discussed in subsection 10.4.6.

10.4.1.3 Safety Evaluation

The main condenser serves no safety function and has no safety design bases.

10.4.1.4 Tests and Inspections

Acceptance testing of the main condenser will be performed in accordance with section 14.2.

The condenser shells, hotwells, and waterboxes are provided with access openings to permit inspection and/or repairs.

During unit outages, the condenser shells can be completely filled with water and tested by the fluorescent tracer method for leaks in accordance with ASME Power Test Code 19.21, before returning the condenser to operation.

10.4.1.5 Instrument Application

Hotwell level and pressure indications are provided locally and associated alarms are provided in the control room for each condenser shell. The condenser hotwell in each shell contains conductivity cells to provide a means of detecting and locating condenser tube leaks. Rejection of hotwell condensate to the condensate tank is blocked automatically upon an indication of high hotwell cation conductivity. This feature prevents transfer of impurities into the condensate tank in the event of a condenser tube leakage. The condensate level in the main condenser hotwell is maintained within proper limits by automatically transferring condensate to or from the condensate tank. Condensate temperature is measured in the suction lines of the condensate pumps. Turbine exhaust hood temperature is monitored and automatically controlled by use of the water sprays. A high condenser backpressure alarm also is provided.

Turbine trip is activated on loss of main condenser vacuum when condenser pressure reaches or exceeds the setpoint. Monitoring of circulating water temperature, pressure, and differential pressure from waterbox to waterbox is provided.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

The main condenser evacuation system for PVNGS is the condenser air removal system (CARS) which establishes and maintains vacuum in the shell side of the condenser and provides for continuous removal of air and noncondensable gases from the condenser during normal power operation and plant startup.

10.4.2.1 Design Bases

10.4.2.1.1 Safety Design Bases

The CARS has no safety function.

10.4.2.1.2 Power Generation Design Bases

Applicable power generation design bases are as follows:

A. Power Generation Design Basis One

   The CARS is designed to remove air and noncondensable gases from the condenser and turbine gland sealing system and exhaust them to the atmosphere via the plant vent or through the effluent filtration system to atmosphere via the plant vent when radioactivity is detected.

B. Power Generation Design Basis Two

The CARS establishes and maintains vacuum in the condenser during startup and normal operation.

10.4.2.1.3 Codes and Standards

The CARS is designed in accordance with the codes and standards identified in table 3.2-1.

10.4.2.2 System Description

The CARS, shown schematically in engineering drawings 01, 02, 03-M-ARP-001, consists of four two-stage mechanical vacuum pumps, a moisture separator, post-filter, charcoal bed adsorber, blower, and associated valves and piping. The design parameters of the system are shown in table 10.4-2.

Operation of the vacuum pumps is initiated from the main control room. These pumps establish a vacuum of approximately 5 inches Hg abs, prior to buildup of steam generator pressure during plant startup.

During normal plant operation, three mechanical vacuum pumps evacuate air and noncondensables from the condenser.

Noncondensable gases, air, and water vapor are drawn from the three condenser shells to the vacuum pumps. The air and noncondensables from the vacuum pumps are directed to the filtration system whenever radioactivity is detected and prior to discharge to the plant vent stack.

Table 10.4-2
CONDENSER AIR REMOVAL AND TREATMENT SYSTEM
DESIGN DATA

Design Factor	Value
Vacuum pumps	
Design air removal capacity, std ft^3/min	180
Number	4
Capacity, each pump, std ft^3/min	60
High efficiency particulate air filters	
Number	1
Design Noncondensable gas flow, std ft^3/min[(a)]	1,664
Charcoal bed adsorber	
Number	1
Vessel material	Carbon Steel
Bed depth, in.	2
Design temperature, °F	165
Design Noncondensable gas flow, std ft^3/min[(a)]	1,664

a. Includes noncondensable gas flow from turbine gland steam seal exhausters.

b. All values shown in the table that have units of std ft^3/min are based on standard temperature and pressure conditions of 60°F and 14.7 psia, respectively.

If the steam generators develop a primary to secondary leak, the CARS effluents will contain radioactive nuclides. A radiological evaluation of the discharge from the CARS and the basis for this evaluation are discussed in section 11.3. The

average and maximum steam generator tube leaks are given in section 11.1. The CARS effluents, after passing through the moisture separators, are treated in the effluent treatment system. The post-filter removes particulate radioactivity.

The charcoal adsorber removes iodine. Effluents from the treatment system are monitored for radioactivity by plant vent monitors before being released to the atmosphere via the plant vent stack. The effluent treatment system also treats effluent from the turbine gland sealing system (TGSS).

As long as the CARS is functional, its operation does not affect the RCS. Should the CARS fail completely, a gradual reduction in condenser vacuum would result from the buildup of noncondensable gases. The reduction in vacuum would cause a lowering of turbine cycle efficiency that requires an increase in reactor power to maintain the demanded electric power generation level. The reactor power is limited by the reactor regulating system as described in section 7.7. If the CARS remains nonfunctional, condenser vacuum decreases to the turbine trip setpoint and a turbine trip is initiated. Loss of condenser vacuum is discussed in section 15.2.

10.4.2.3 Safety Evaluation

The CARS has no safety function.

10.4.2.4 Tests and Inspections

Tests and inspections of the equipment and piping are performed in accordance with applicable codes and standards prior to

operation. CARS standby equipment is cycled periodically to ensure availability. Periodic inservice tests and inspections of the CARS are performed in conjunction with the scheduled maintenance outages.

10.4.2.5 Instrumentation Applications

Radioactivity of the effluent from the CARS is indicated and monitored in the main control room. In addition, high activity levels are alarmed.

10.4.3 TURBINE GLAND SEALING SYSTEM

The TGSS prevents air leakage into and steam leakage out of the main turbine and feedwater pump turbines.

10.4.3.1 Design Bases

10.4.3.1.1 Safety Design Bases

The TGSS has no safety function.

10.4.3.1.2 Power Generation Design Bases

Power generation design bases applicable to this system are as follows:

A. Power Generation Design Basis One

   The TGSS prevents air leakage into, and steam leakage out of, the turbine through the turbine shaft glands and through various steam valve stems.

B. Power Generation Design Basis Two

The TGSS returns the air-steam mixture to the turbine gland steam packing exhauster (GSC), condenses the steam, returns the drains to the main condenser, and exhausts the noncondensable gases to the atmosphere, via the effluent filtration system whenever radioactivity is detected.

10.4.3.1.3 Codes and Standards

The TGSS is designed in accordance with the applicable codes and standards identified in table 3.2-1.

10.4.3.2 System Description

The TGSS, shown schematically in engineering drawings 01, 02, 03-M-GSP-001, consists of steam seal supply and exhaust headers, gland steam regulators (GSRs), gland steam packing exhauster, steam packing exhauster drain tank, and the associated piping and valves. For the system to function satisfactorily from startup to full load, a fixed positive pressure in the steam seal supply header and a fixed vacuum in the outer ends of all the turbine glands (refer to table 10.4-3) must be maintained at all loads.

The steam discharge ends of all glands are routed to the GSC that is maintained at a slight vacuum by the redundant motor-driven blowers. The GSC is a shell and tube heat exchanger. Water supplied from the turbine cooling water system is used to condense the steam from the mixture of air and steam drawn from

the shaft packings. Drains from the GSC are returned to the main condenser, and the noncondensables are discharged to the atmosphere via the effluent filtration system of the MCES.

PVNGS operates with Auxiliary Steam as the preferred source to provide added protection to the main condenser in case of a main steam isolation signal. As the turbine is brought up to load, steam leakage from the high-pressure packings enters the steam-seal header becoming a steam source to the gland steam header. At higher loads, when more steam is leaking from the HP packings than is required by vacuum packings, the excess steam is discharged to the main condenser.

Table 10.4-3
TURBINE GLAND SEALING SYSTEM

Design Data	Value
Pressure in steam-seal header, psig	3 to 5
Vacuum in gland steam packing exhauster, in.WG	10 to 20
Number of gland steam packing exhausters	1
Number of blowers mounted on gland steam packing exhausters	2

In case of a malfunction of the GSR, a motor-operated bypass valve is opened and manually controlled to maintain steam-seal header pressure. Vacuum in the GSC can be maintained with one or both blowers in operation. Loss of both blowers may cause sufficient steam to blow through the seals into the turbine area and thus necessitate shutdown of the turbine. The radiological evaluation for the turbine gland sealing system is included in section 11.3. Relief valves on the steam-seal

header prevent excessive steam seal pressure. The valves are vented to atmosphere. The potential effects of high-energy pipe breaks are covered in section 3.6.

10.4.3.3 Safety Evaluation

The TGSS has no safety function.

10.4.3.4 Tests and Inspection

Tests and inspection on the TGSS equipment are performed in accordance with applicable codes and standards.

10.4.3.5 Instrumentation Applications

Local and control room displays consist of indicating and alarm devices of steam seal header pressure, temperature, and flow.

10.4.4 TURBINE BYPASS SYSTEM

The turbine bypass system removes heat from the NSSS and transfers it to the condenser or atmosphere following load rejections and during plant cooldown, plant startup, and hot standby.

For a discussion of environmental conditions for equipment qualification, refer to section 3.11.

10.4.4.1 Design Bases

10.4.4.1.1 Safety Design Bases

The turbine bypass system has no safety function.

10.4.4.1.2 Power Generation Design Bases

Power generation design bases applicable to the turbine bypass system are as follows:

A. Power Generation Design Basis One

Operate in conjunction with the reactor power cutback system (refer to CESSAR Section 7.7.l.l.6) to prevent reactor trip or opening of the pressurizer or main steam safety valves following load rejections provided the condenser is available.

B. Power Generation Design Basis Two

Remove heat from the NSSS and reject it to the condenser or atmosphere during plant cooldown, plant startup, and hot standby conditions.

C. Power Generation Design Basis Three

Control NSSS thermal conditions to prevent the opening of safety valves following a unit trip.

D. Power Generation Design Basis Four

Control NSSS thermal conditions when it is desirable to have reactor power greater than turbine power, e.g., during turbine synchronization.

E. Power Generation Design Basis Five

Provide pressure-limiting control during the loss of one out of two feedwater pumps.

F. Power Generation Design Basis Six

Provide a CEA automatic motion inhibit (AMI) signal when turbine power and reactor power fall below selected thresholds; provide AMI signal below 15% reactor power to block automatic control of the reactor below this power level.

G. Power Generation Design Basis Seven

Provide a means for manual control of RCS temperature during NSSS heatup or cooldown.

H. Power Generation Design Basis Eight

Provide for operation of the turbine bypass valves in a manner that minimizes valve wear and maintains controllability.

I. Power Generation Design Basis Nine

Provide for the operation of the turbine bypass valves in a manner to maximize thermal efficiency of the condenser.

J. Power Generation Design Basis Ten

Include redundancy in the design so that neither a single component failure nor a single operator error result in excess steam releases.

K. Power Generation Design Basis Eleven

Provide a condenser interlock which will block turbine bypass flow when unit condenser pressure exceeds a preset limit.

10.4.4.1.3 Codes and Standards

All components of the turbine bypass system are designed and constructed in accordance with the applicable codes and standards identified in section 3.2.

10.4.4.2 System Description

The turbine bypass system is shown schematically in figure 10.4-1.

The turbine bypass system consists of eight air-operated globe valves and associated instruments and controls. These valves branch from each main steam line downstream of the main steam isolation valve.

Six of these valves direct steam to the condenser and the remaining two vent directly to the atmosphere.

The valves are designed to quick open within approximately 1 second and quick close within approximately 5 seconds or modulate full open or closed within approximately 15 seconds. The valves are equipped with remote-operated handwheels to permit manual operation at the valve location.

The two valves which exhaust to the atmosphere are the last to open and the first to close during load rejections, thus minimizing the quantity of steam discharged to the environment. The valves and piping for the system are located in the turbine building.

The valves in the turbine bypass system are designed to fail closed to prevent uncontrolled bypass of steam. Should the

bypass valves fail to open on command, the main steam safety valves provide main steam line overpressure protection, and the power-operated atmospheric dump valves provide a means for controlled cooldown of the reactor. The main steam safety valves and power-operated atmospheric dump valves are described in paragraph 10.3.2.2.

In the event of a turbine trip, the amounts of radioactivity released and the resultant offsite doses are those stated in section 15.2. The main steam safety valves and power-operated atmospheric dump valves are used to control the load transient, if the bypass valves are disabled. Because the ASME Code safety valves provide the ultimate overpressure protection for the steam generators, the turbine bypass system is defined as a control system and is designed without consideration for the special requirements applicable to protection systems. Failure of this system will have no detrimental effects on the RCS.

The turbine bypass system removes heat from the NSSS following load rejections and during startup, plant cooldowns, and hot standby. The system removes heat by modulating bypass steam flow. The modulation of the bypass steam is performed by the turbine bypass valves, which receive signals from the steam bypass control system. Refer to section 7.7 for a discussion of the steam bypass control system.

The turbine bypass system provides a design steam dump capacity of at least 55% of the rated main steam flow. This amount of bypass steam capacity in conjunction with the reactor power cutback feature of the steam bypass control system will

dissipate enough energy from the NSSS to permit load rejection of any magnitude without lifting the main steam or pressurizer safety valves or tripping the reactor provided the condenser remains available. The effects of postulated system piping failure on safety-related equipment are given in section 3.6.

10.4.4.3 Tests and Inspections

A. Prior to initial operation, the complete turbine bypass system receives a field hydrostatic test and inspection in accordance with ANSI B31.1.

B. The turbine bypass system is tested under the requirements of the preventative maintenance program on a minimum frequency of every 18 months.

10.4.4.4 Instrumentation Applications

The control system for the turbine bypass system is discussed in CESSAR Section 7.7.

10.4.4.5 CESSAR Interface Requirements

Refer to subsection 5.1.4.

10.4.4.6 CESSAR Interface Evaluation

Refer to subsection 5.1.5.

10.4.5 CIRCULATING WATER SYSTEM

The circulating water system (CWS) removes heat from the main condensers and rejects it to the atmosphere using the plant cooling towers.

10.4.5.1 Design Bases

10.4.5.1.1 Safety Design Bases

The CWS has no safety function.

10.4.5.1.2 Power Generation Design Bases

The power generation design bases are as follows:

A. Power Generation Design Basis One

The circulating water receives the heat rejected by the turbine cycle.

B. Power Generation Design Basis Two

The plant cooling towers in the CWS dissipate waste heat from the turbine thermal cycle and from the plant cooling water system. The plant cooling water system is discussed in subsection 9.2.10.

10.4.5.1.3 Codes and Standards

The CWS is designed in accordance with codes and standards specified in table 3.2-1.

10.4.5.2 System Description

The CWS consists of the main condenser, cooling towers, circulating water pumps, a chemical injection system, and a makeup and blowdown system. The CWS is shown schematically in engineering drawings 01, 02, 03-M-CWP-001. Table 10.4-4 lists design data of the major components in the system.

The circulating water pumps are motor-driven, vertical, wetpit type, each rated at 25% capacity. The total design flow rate is 560,000 gallons per minute. These pumps take suction from the intake structure of the CWS and pump the circulating water through the main condensers. The CWS cooling water is returned from the main condensers through a common line to the cooling towers. The system is designed with cross-connected discharge piping from the circulating water pumps. The pump discharge lines are equipped with butterfly valves that permit any circulating water pump to be isolated individually.

Each circulating water path is provided with a butterfly valve at the low-pressure shell inlet and at the high-pressure shell outlet. In case of a condenser tube leak in any water box, the system will remain functional at reduced capacity.

The main condenser is discussed in subsection 10.4.1.

The cooling towers are designed for an ambient wet bulb temperature that will not be exceeded more than 5% of the time during the year. The design cooling range, design approach to ambient wet bulb temperature, and the unit data of the towers are shown in table 10.4-4.

In the event of flooding due to a failure in the portion of the circulating water system in the yard area (such as cooling towers, intake structure, buried pipe), the yard is graded in a direction to provide drainage of the water away from the power block and spray ponds. Therefore, the safe shutdown capability will not be compromised by flooding of the yard area.

A postulated failure in the circulating water system in the turbine building would flood the turbine building floor. The water would flow out of the building doors and side panels. The condenser area sumps and the oily waste sump would be filled to overflowing, but they are not safety-related. The condensate demineralizer sump, which is a sealed sump, would not be affected.

Assuming that 684,000 gallons per minute are available at the riser butterfly valve and considering the closing characteristics of the valve, it has been determined that 520,200 gallons would escape through the rupture with a valve closing time of 60 seconds. This amount of water would tend to flood the turbine building floor; however, as previously stated, the water would flow out of and away from the building. There are no passageways, pipe chases, cableways, or any other flow paths joining the turbine building floor. There are no essential electrical systems in the turbine building floor. These conclusions are based on the following conditions:

A. Low-pressure alarms in the circulating pumps discharge line will alert the operators.

Table 10.4-4
CIRCULATING WATER SYSTEM DESIGN DATA
FOR ONE TURBINE UNIT

Design Factor	Values
Circulating water pumps	
Number	4
Type	Vertical, wet-pit
Capacity each, gal/min	140,000
Head, ft (TDH)	103
Cooling tower	
Number	3 Round, mechanical draft
Design ambient temperatures	
Wet bulb temperature, °F	75
Dry bulb temperature, °F	116
Design range, °F	31.5
Design approach, °F	12.3
Unit tower data, VWO	
Makeup flow, gal/min	19,651
Blowdown flow, gal/min	1,284
Evaporation, gal/min	18,341
Drift, gal/min	26
Cooling tower circulating water flow, gal/min	587,000
Total turbine plant heat load, Btu/h	9.1×10^9
Chlorination facilities	
Chlorine injection rate (yearly average), lb/d	3,490 average

B. Each pump is capable of delivering 171,000 gallons per minute at maximum runout conditions.

C. The circulating water line crosstie is initially open.

D. Valve closing time is 60 seconds.

It is estimated that the operator action time to shut the valves and stop the circulating water pumps would be 20 seconds based on multiple indications of low circulating water pump discharge pressure and high condenser pressure. At 80 seconds, 748,200 gallons of water would have escaped. If the operator should fail to act, then the water would continue to flow out of the turbine building through doors and sidings at grade level 100 feet.

In the event of a failure of the circulating water system in the turbine building, at no time would the water enter the auxiliary building, control building, main steam support structure, or diesel generator building. Finish grade of 0.5% is established to permit flood water from a break in the circulating water system to spread and flow away from safety-related structures (reference Bechtel drawings 01-C-ZVC-400 through 01-C-ZVC-407). This flow pattern occurs whether the break is in the yard area or within the turbine building. The at-grade door sills in the auxiliary building and main steam support structure (MSSS) are sufficiently above expected water levels resulting from any postulated flooding source. An opening in the MSSS at the 81-foot elevation (a stairwell from the roof of the condensate tunnel) will have a waterproof door installed.

A makeup system is provided to replace water losses due to evaporation, blowdown, and drift from the unit cooling towers. Makeup water for the CWS is pumped from the water storage reservoirs to the CWS pump intake structure as required. Plant water requirements are covered in paragraph 2.4.11.5.

Salinity buildup in the CWS is controlled by blowing down to the evaporation ponds. Blowdown is taken from the circulating water system condenser discharge. Periodic samples are analyzed for dissolved solids, pH, temperature, and radioactivity.

The CWS is designed to prevent any injection of radioactive material into the circulating water. Circulating water passing through the main condenser is at a higher pressure than the steam on the condensing side. Therefore, any leakage, such as from the main condenser tubes, will be from the circulating water into the shell side of the main condenser.

Chemical injection systems add chlorine as sodium hypochlorite, sulfuric acid, and dispersant. The hypochlorite is used to control biological growth and the sulfuric acid adjusts pH in order to minimize corrosion and scaling from calcium carbonate. A flow diagram of the chemical injection system is shown in engineering drawings 01, 02, 03-M-CWP-001.

Sodium hypochlorite is received into storage from a chemical production system for chlorination. Upon initiation of a timed cycle, hypochlorite is fed to each unit CWS for biological control. The hypochlorite system serves all units, and

includes, at each unit, adjustable program control with a residual chlorine analyzer.

In addition to chlorination, a non-oxidizing biocide is used for control of aerobic slime forming bacteria and anaerobic corrosive bacteria, which are relatively unaffected by chlorine alone. The biocide is one which will hydrolyze to less toxic components with time.

10.4.5.3 Tests and Inspections

All active components of the system are accessible for inspection during station operation. Performance, hydrostatic, and leakage tests are conducted on the CWS butterfly valves in accordance with applicable codes and standards.

10.4.5.4 Instrumentation Application

Temperature and pressure in the CWS lines are measured at the main condensers. In addition, level alarms are provided at the CWS pump intake structure and high discharge pressure is alarmed in the control room.

10.4.6 CONDENSATE CLEANUP SYSTEM

Condensate cleanup is performed by the secondary chemistry control system (SCCS) which is an integrated system comprised of the condensate demineralization and blowdown processing subsystem and the chemical monitoring and addition subsystem.

These two subsystems, operating concurrently, provide the capability to maintain the proper operating chemistry of the

condensate feedwater and steam generator secondary side water. The SCCS is shown schematically in engineering drawings 01, 02, 03-M-SCP-002, -003, -001 and -004.

An interconnection exists between Secondary Chemistry (SC) and Auxiliary Steam (AS) condensate piping which permits the condensate cross connection header (APASNL107) to transfer warm (212 °F or less) condensate drained from the steam generators of a unit in operational mode 5 (when the primary system pressure is less than or equal to the secondary system pressure), mode 6, or defueled, to either or both of the other unit's Chemical Waste Neutralization Tanks for disposal or processing. The following conditions and restrictions apply to the use of this interconnection.

1. The unit discharging secondary coolant is in either Mode 5 and the primary system pressure is less than or equal to the secondary system pressure, or Mode 6, or in a defueled operating condition.

2. The specific activity of the secondary coolant in both the discharging and the receiving units is less than or equal to PVNGS Technical Specification LCO 3.7.16.

3. Radiological surveys and controls of ASNL107 will be performed as directed by the Radiation Protection Program.

4. Prior to transferring water, radiological conditions in the secondary system will be evaluated to ensure the transfer will not have a significant impact on operations in the receiving unit.

5. ASNL107 should be flushed after the draining of the steam generators to minimize the potential build-up of non-soluble particulates in the line. The flush may be waived if an evaluation of the radiological conditions determines it is not required.

6. Administrative controls (such as procedures) shall be in place to isolated the flow in the event of a large leak or pipe rupture.

7. Since flow rate from this modification may approach TDS sump pump capacity, monitor the sump as needed to ensure that is does not overflow.

8. During Operational Modes 1 through 4, valves 13PSCNV955 and 13PSCNV956 are to be verified closed and locked if not in use.

9. After use of pipe 13PSCNL479 and closure of 13PSCNV955 and 13PSCNV956, 13PSCNL479 must be drained.

10.4.6.1 Design Bases

The condensate cleanup system has no safety function.

10.4.6.1.1 Condensate Demineralization and Blowdown Processing Design Bases

The following design bases apply to the condensate demineralization and blowdown processing subsystem:

A. Maintain the purity and chemistry of the condensate, feedwater, and steam generator secondary side water.

When feeding the steam generators, the chemistry of the main feed train shall be in accordance with subsection 10.3.5.

B. Be capable of continuously purifying the full condensate flow. Full flow condensate demineralization systems shall be capable of continuous operation with 1 ppm total dissolved solids in the influent.

C. Continuously purify and recycle the steam generator blowdown. Blowdown flow for each steam generator may be used to maintain the steam generator chemistry within the limits outlined in subsection 10.3.5.

D. In order to minimize the consequences of a blowdown line rupture, each steam generator shall be equipped with an independent blowdown line.

10.4.6.1.2 Chemical Monitoring and Addition Design Bases

The following design bases apply to the chemical monitoring and addition subsystem:

A. Continuously monitor significant secondary side chemical parameters and alarm any fault conditions.

B. Continuously add volatile chemicals to the secondary side water to maintain pH and oxygen levels within the specified limits.

C. Inject boric acid into the secondary system as needed to mitigate denting and intergrannular attack/stress corrosion cracking (IGA/SCC) in the SGs.

D. Add chemicals to the feed train and steam generators prior to wet layup to minimize corrosion during long outages.

10.4.6.2 System Description and Operation

10.4.6.2.1 Condensate Demineralization

A full flow condensate demineralization subsystem capable of continuous service maintains feedwater purity during startup and periods of condenser leakage. In the condensate demineralizers, dissolved solids are removed by ion exchange, and suspended solids are removed by filtration.

The Condensate demineralization subsystem is comprised of six mixed bed ion exchangers in the hydrogen-hydroxide form. The demineralizers are normally in standby unless condenser leakage dictates that they be in service. If full flow service is needed, five of the demineralizers are required to be in service to support full power (approximately 26,000 gallons per minute), leaving one vessel in standby where it is available when one of the other beds becomes exhausted. This extra vessel allows the system to remain in continuous operation without reducing the process capability. The effluent from each condensate demineralizer is continuously monitored for conductivity and specific ions. This will assure that the

quality of the effluent is within the specified limits for feedwater (subsection 10.3.5).

The condensate demineralizer subsystem is designed to have sufficient capacity to continuously process condensate contaminated by small condenser leaks, and will permit an orderly shutdown if a larger leak occurs. The size of the leak that is able to be tolerated will depend partly on the pH at which the secondary system is being maintained. It takes approximately 24 hours to perform a regeneration of both the cation and anion resin. The secondary pH may be lowered slightly to allow sufficient time to perform full regenerations if the condenser leakrate exceeds the capacity of the resin to maintain acceptable effluent chemistry.

The operation of the CDS during plant startup is described in paragraph 10.4.6.2.5.

In order to ensure that a condensate demineralizer is always on standby, and to minimize the possibility of introducing regenerant chemicals into the feed train, the exhausted resin from the condensate demineralizers is externally regenerated.

Resin regeneration is performed in one of the two modes:

- Full regeneration, including backwash, anion resin chemical regeneration, and cation resin chemical regeneration
- Partial regeneration, including backwash and cation resin chemical regeneration.

Wastes produced by resin regeneration are minimized by reusing those which are acceptably low in TDS. Low TDS rinse water is

recycled to the condenser hotwell. Low TDS regenerant waste is recycled to the circulating water system for use in condenser cooling. Condensate polisher Pre-Service Rinse water can be diverted directly to the Retention Tank for ultimate onsite disposal. High TDS regenerant waste is unacceptable for reuse and is processed through the chemical waste system. From here the waste is sent either to the retention tank for ultimate onsite disposal or, if radioactivity exceeds the release limits stated in the Offsite Dose Calculation Manual (ODCM), to the liquid radwaste system for further processing and eventual recycle.

10.4.6.2.2 Steam Generator Blowdown Processing

Steam generator blowdown controls the concentration of impurities in the steam generator secondary side water. Each steam generator will be equipped with its own blowdown processing line with the capability of blowing down either the primary inlet or primary outlet regions of the steam generator. In addition to a hot leg blowdown line, the steam generators are also equipped with a blowdown line that allows blowdown from the downcomer region, and an additional downcomber blowdown line.

The blowdown will be directed into a flash tank operating at 225 psig where the flashed steam is returned to the cycle via the heater drain tanks. The liquid portion then flows to a heat exchanger where it is cooled by condensate to 140F (Blowdown Demineralizer in use) or 165F (Blowdown Demineralizer bypassed). It is then directed through a blowdown filter where

the major portion of the suspended solids are removed. It can also be directed to the retention tank for ultimate onsite disposal. After filtration, the blowdown fluid is processed by the blowdown demineralizer or directed straight to the condenser hotwell (Blowdown Demineralizer bypassed).

In the event of malfunction of the blowdown processing equipment, the flow can be directed to the condenser, thus maintaining the steam generator chemistry. During this mode of operation, the condensate polishing demineralizers would be placed in service.

10.4.6.2.3 Chemical Monitoring

The chemical monitoring subsystem is designed to provide continuous indication of significant chemical parameters in the secondary system and to alert the operator of faulty chemistry or equipment malfunction. Continuous online samples are taken from each section of the main condenser, the condensate demineralizer system inlet and outlet, the main feed lines, and the steam generator blowdown lines or downcomer sample, feedwater lines, and circulating water lines.
Samples taken from each section of the main condenser are analyzed for sodium ion concentration and intensified conductivity. Besides providing indications of condenser tube leakage, these monitors can be used in locating the section of the condenser that is leaking.

Upon indication of a condenser tube leak by the sampling system, the condensate polishing demineralizer may be placed

into service and the polishing demineralizer bypass valve closed. The condensate polishers will handle a maximum circulating water inleakage of 1 gallon per minute on a continuous basis. If this leakage is exceeded, the affected condenser hotwell half may be isolated by motor-operated valves in the condensate pump suction and discharge lines. The remaining condenser hotwell storage and the makeup rate will provide enough condensate for reduction to 50% power by utilizing a 10% step and then a 5% per minute ramp down to a 50% power level. The respective circulating water path is isolated and the condenser half is drained. The leaking tubes can be plugged and the contaminated hotwell can be pumped out by one condensate pump to the condenser circulating water outlet.

Leakage from the condensate demineralizers will allow contaminants to enter the steam generators (SGs). To detect for this possibility, the condensate demineralizers' influent and effluent will be monitored. Sodium, specific conductivity, cation conductivity, sulfates, and chlorides will be measured on the demineralizer effluent.

Hydrazine monitors are used to measure the hydrazine content in the main feed lines.

The main feed lines will be analyzed for pH, and samples taken from the steam generator blowdown lines are monitored for pH, conductivity, and radiation. Continuous pH measurements will ensure that the specified alkaline conditions exist in the system. This will ensure an alkaline environment which

minimizes corrosion. Conductivity measurements on the steam generator blowdown will verify that dissolved solids are not concentrating in the steam generators. A steam generator sample is measured for radioactivity in order to detect primary to secondary leakage.

10.4.6.2.4 Chemical Addition

The function of the chemical addition subsystem is to establish and maintain the proper chemistry within the condensate, feedwater, and steam generator secondary side water. During normal operation, volatile chemicals are added to the feed train downstream of the condensate demineralizers. These additives serve to control the pH, establish a reducing environment, and to scavenge any dissolved oxygen. In addition, the chemical addition subsystem is also used to provide the proper chemical environment during wet layup.

Since these additives are volatile, they will not concentrate in the steam generators. This characteristic is desirable for several reasons. First, the concentration of solids in the steam generators will be minimized. This will lessen the dangers associated with solids attack of Inconel 690. In addition, the volatile nature of these additives will allow for some corrosion protection throughout the steam system. This is especially important in protecting the large metal surface areas of the feedwater heater shells.

A pH controlling additive, usually ammonia, is used to raise the feedwater pH to within normal limits. This pH range is effective in slowing the corrosion rate of carbon steel.

Continuous ammonia additions are required during operations because the volatile ammonia will be scrubbed from the condensing steam in the air removal section of the main condenser or be removed by the condensate demineralizers if it redissolves in the condensate.

An inventory of a reducing agent/oxygen scavenger, usually hydrazine, is maintained in the feed train as a means of scavenging dissolved oxygen and to ensure a reducing environment is maintained in the steam generators. Hydrazine also contributes to the formation of an adherent metal oxide film on system surfaces that reduces corrosion product release. Ammonia is a by-product of Hydrazine once it volatilizes.

Boric acid, a non-volatile chemical, may be injected into the secondary system for mitigating denting and Intergranular Attack/Stress Corrosion Cracking (IGA/SCC) in the steam generator. Boric acid reduces pH in the steam generator crevices by reacting with sodium hydroxide (NaOH) to form a borate complex. Also, boric acid dilutes the hydroxide (OH^-) concentration, thereby lowering the chemical activity and reducing the probability that OH^- is present at the actively corroding grain boundary of the steam generator crevices. The small affect that boric acid has on lowering the secondary plant pH can be offset by increasing the pH controlling chemical additive.

Chemical additions necessary for wet layup will be accomplished through the use of the auxiliary feedwater system. The chemical additions will be made at the suction of the non-Seismic Category I auxiliary feed pump. This will ensure that each steam generator receives adequate protection during long outages.

Chemical additions are typically made by metering pumps. The ammonia addition subsystem consists of three positive displacement pumps which inject into the steam generator main feedwater, demineralized condensate, blowdown condensate, or auxiliary feedwater. All three can be aligned to take ammonia from two ammonia tanks.

The hydrazine addition subsystem consists of three positive displacement pumps. Any of the three pumps can be aligned to pump from two hydrazine tanks to any of the hydrazine injection points. The hydrazine pumps inject into the steam generator main feedwater, extraction steam lines to high-pressure feedwater heaters, demineralized condensate, blowdown condensate, or auxiliary feedwater. Hydrazine can be transferred into the ammonia tanks for injection via the ammonia addition system.

10.4.6.2.5 System Operation During Plant Startup

While the secondary plant is in a cold shutdown condition, it is possible for air to enter the system. Use of nitrogen blankets and a reducing agent/oxygen scavenger, such as hydrazine will minimize, but not eliminate, the corrosion of

metal surfaces. This corrosion results in loose oxide layers being formed on the surfaces of the feed train. Before returning to power, it is necessary to reduce the concentration of the reducing agent/oxygen scavenger in the secondary system, remove the corrosion products generated during layup, and reduce the dissolved oxygen concentration to within the normal operating specifications.

Reduction in the reducing agent/oxygen scavenger concentration is accomplished by draining the steam generators and refilling them with auxiliary feedwater containing the correct hydrazine concentration. In addition, the draining of the steam generators serves to remove any suspended solids which might be present in the generators.

Once the steam generators have been refilled with water, the primary plant temperature will be raised and the steam generators warmed up.

Next, feed train recirculation is started by initiating flow through the presteam generator cleanup line.

The concentration of suspended solids is reduced by draining a portion of the circulating flow prior to entering the hotwell or by circulating through the condensate demineralizers. Make-up at a rate of approximately 500 gallons per minute is supplied from the condensate storage tank.

Oxygen will be removed from the recirculating feedwater by using the vacuum that has been established in the main condenser. Since the feedwater has been heated to 175F, a

condenser vacuum to 6 inches of Hg (abs) is sufficient to remove dissolved oxygen from the feedwater.

Once main feed has been initiated, the reactor power can be increased.

10.4.6.3 Safety Evaluation

The secondary chemistry control system serves no safety-related functions. Therefore, no safety evaluation is performed. Each of the steam generator blowdown lines is equipped with two remotely operated containment isolation valves that automatically close on a main steam isolation signal (MSIS), auxiliary feedwater actuation signal (AFAS), or safety injection actuation signal (SIAS).

The sample lines from the steam generator blowdown lines are each equipped with two remotely operated containment isolation valves which automatically close on an AFAS, MSIS, or SIAS.

10.4.6.4 Tests and Inspections

Preoperational testing will include a test of the system instrumentation. Automatic control features will be tested to ensure proper operation. Piping, valves, and components will be checked for proper installation. Pumps will be tested for head and capacity. Valves will be operated and checked for function. The system will be operated automatically to ensure that the system will function as designed. Heat exchangers will be checked for proper performance and flow rates adjusted where necessary to establish proper conditions.

During normal plant operations, testing, inspection, and calibration will be conducted on a regular schedule to ensure proper system operation. Data taken during operating periods will be used to evaluate the performance of the secondary chemistry control system.

10.4.6.5 Instrumentation Requirements

Flow and conductivity of the demineralized condensate are continuously recorded.

Local instrumentation is provided for the demineralizer regeneration system including temperature control of the dilute caustic and level control of acid and rinse tanks.

Conductivity of the demineralized condensate is recorded continuously. Local conductivity indication is provided for the resin regenerant solutions and rinses.

Local instrumentation is provided for the chemical addition and monitoring subsystem. The sampling instruments are protected from a high temperature sample by a bypass valve operated by a temperature controller.

10.4.7 CONDENSATE AND FEEDWATER SYSTEM

The condensate and feedwater system provides heated feedwater to the steam generators. The system has the capability of maintaining the proper feedwater inventory in the steam generator during startup and normal operation.

10.4.7.1 Design Bases

10.4.7.1.1 Safety Design Bases

Pertinent safety design bases are as follows:

A. Safety Design Basis One

   The feedwater lines are designed so that failure in this piping will have minimal effects on the reactor coolant pressure boundary (RCPB).

B. Safety Design Basis Two

   The feedwater lines are designed so that the failure of any feedwater supply piping will not prevent safe shutdown of the reactor.

C. Safety Design Basis Three

   The containment feedwater isolation valves and piping from the valves to the steam generator nozzles are designed to withstand the effects of a safe shutdown earthquake (SSE).

D. Safety Design Basis Four

   Components and piping shall be designed, protected from, or located to protect against the effects of high and moderate energy pipe rupture, whip, and jet impingement.

E. Safety Design Basis Five

   This system will be designed such that adverse environmental conditions such as tornados, floods, and earthquakes will not impair its safety function.

F. Safety Design Basis Six

The loss of offsite power to the system will not prevent the safe shutdown of the reactor.

10.4.7.1.2 Power Generation Design Bases

Power generation design bases applicable to this system are as follows:

A. Power Generation Design Basis One

The condensate and feedwater system is designed to provide feedwater to the steam generator at the required temperature and pressure during all phases of operation.

B. Power Generation Design Basis Two

Extraction lines and feedwater heaters are designed to minimize the possibility of water slug induction to the main turbine and to limit main turbine overspeed due to entrained energy in the extraction system.

10.4.7.1.3 Codes and Standards

Components of the condensate and feedwater systems are designed and constructed in accordance with the applicable codes and standards identified in table 3.2-1.

10.4.7.2 System Description

The condensate and feedwater system is shown schematically on engineering drawings 01, 02, 03-M-CDP-001, -002, -003, -004 and 01, 02, 03-M-FWP-001. The condensate and feedwater system

supplies the steam generators with heated feedwater in a closed steam cycle using regenerative feedwater heating. The main turbine cycle heat balance at guaranteed load is given in section 10.1. Extraction steam is covered in subsection 10.2.2.

The main condenser hotwells receive condensate makeup from the condensate tank. Refer to subsection 9.2.6 for a discussion of the condensate storage system.

The main portion of the feedwater flow is deaerated condensate pumped from the main condenser hotwells by the condensate pumps.

This stream passes in sequence through the condensate cleanup system; the three trains of low-pressure heaters, each train consisting of No. 1, No. 2, No. 3, and No. 4 low-pressure heaters; the steam generator feedwater pumps; the two trains of high-pressure heaters, each train consisting of No. 5, No. 6, and No. 7 high-pressure heaters; control and isolation valves; and on into the two steam generators of the NSSS. The balance of the feedwater flow is provided by the drains from the moisture separator reheaters and No. 7, No. 6, and No. 5 heaters that are collected into a drain tank and pumped into the feedwater pump suction stream by the heater drain pumps.

To allow feedwater and condensate system startup recirculation, a cleanup system called "long path recirculation" is provided. This system allows condensate from the hotwell to be pumped by a condensate pump through all major feedwater/condensate piping and components up to the economizer crosstie line. From this

point the recirculation flow is returned to the hotwell. The system is sized to allow a flow velocity of up to 2 ft/sec in the largest portion of the main flow path, thereby ensuring shearing and entrainment of pipe scale and other system impurities. A drain connection is provided upstream of the return nozzle to the hotwell.

Transients within the condensate and feedwater system that affect the final feedwater temperature or flow have a direct effect on the RCS. Occurrences that produce an increase in feedwater flow or a decrease in feedwater temperature result in excessive heat removal from the RCS, which is compensated for by control system action as described in section 7.7. These occurrences are considered in section 15.1 in conjunction with the failure of compensatory control actions, and are shown to be safely terminated by the reactor protective system. Events that produce the opposite effect; i.e., decreased feedwater flow or increased feedwater temperature, result in reduced heat transfer in the steam generators. Normally, automatic control system action is available to adjust feedwater flow and reactor power to prevent excess energy accumulation in the RCS, and the increasing reactor coolant temperature provides a negative reactivity feedback that tends to reduce reactor power. In the absence of control action, the high outlet temperature and high-pressure trips of the reactor protective system are available to assure reactor safety. Loss of all feedwater, the most severe transient of this type, is examined in section 15.2.

Nitrogen accumulators are provided on the feedwater control and isolation valves in the feedwater line to the steam generator downcomer nozzle. These accumulators allow the operator to remotely operate these valves without normal instrument air. In conjunction with the non-Seismic Category I auxiliary feedwater pump described in subsection 10.4.9, this provides a third flow path for auxiliary feedwater to the steam generators. This use of the non-essential AFS train is provided to improve the overall availability of the AFS system and is not required for Chapters 6 and 15 accident mitigation.

10.4.7.2.1 Component Description

Refer to table 10.4-5 for design data.

10.4.7.2.1.1 Condensate Pumps. The condensate pumps are motor-driven, of the vertical mixed-flow type, and operate in parallel. Valving is provided to allow removal of individual pumps and maintain system functionality.

10.4.7.2.1.2 Condensate Cleanup System. Refer to subsection 10.4.6 for a discussion of the condensate cleanup system.

Table 10.4-5
MAIN FEEDWATER/CONDENSATE SYSTEM REQUIREMENTS
FOR MAJOR COMPONENTS DESIGN DATA

Equipment	Number	Capacity
Condensate pumps	3	50%[b]
No. 1 to No. 4 feedwater heaters	4/train 3 trains	33%/train
Steam generator feedwater pumps	2	65%
No. 5, No. 6, and No. 7 HP feedwater heaters	3/train 2 trains	50%/train [a]
Heater drain tank	1/train 2 trains	50%/train
Heater drain pumps	1/train 2 trains	50%/train

a. Approximately 40%/train and 20% bypass in feedwater temperature reduction mode of full power operation.

b. Capacity listed is a nominal initial sizing value. Three Condensate pumps may be required to support plant operation at 100% power as described in site procedures.

10.4.7.2.1.3 Low-Pressure Feedwater Heaters. The low-pressure heaters are of the closed type and are installed in the main condenser necks. Low-pressure feedwater heaters have integral drain coolers. The No. 4 drains to No. 3 heater, No. 3 drains to No. 2, and No. 2 drains to No. 1 and from there to the main condenser. The condensate, after passing from the main condenser through the low-pressure heaters (three trains), is routed to a header and fed to the steam generator feedwater pumps.

Low-pressure feedwater heaters have main condenser drain lines to allow direct discharge to the main condenser.

10.4.7.2.1.4 Feedwater Pumps. The feedwater pumps operate in parallel and discharge to the high-pressure feedwater

heaters. The pumps take suction from the No. 4 low-pressure feedwater heaters of the three parallel low-pressure heater trains and discharge through the two parallel trains of high-pressure feedwater heaters. Each pump is turbine-driven with independent variable speed control units. Steam for the turbines is supplied from the main steam header at low loads, and from the hot reheat line during normal operation.

Isolation valves are provided to allow each steam generator feedwater pump to be individually removed from service, while continuing operations at reduced capacity with the parallel pump.

10.4.7.2.1.5 High-Pressure Feedwater Heaters. The feedwater system contains two parallel trains of high-pressure feedwater heaters. High-pressure feedwater heaters Nos. 6 and 7 are provided with integral drain coolers. High-pressure heater No. 7 drains to high-pressure heater No. 6. High-pressure heaters Nos. 6 and 5 drain to the high-pressure heater train drain tank.

Isolation valves and bypasses are provided to allow each train of high-pressure heaters to be removed from service. System functionality is maintained with the remaining train. The bypass line may also be used in conjunction with flow through both heater trains when operating the plant in the feedwater temperature reduction mode of full power operation.

Provisions are made in heater drain lines to allow direct discharge to the main condenser.

10.4.7.2.1.6 Heater Drain Tank. A single heater drain tank for each high-pressure heater train receives the drains from the shells of high-pressure feedwater heater Nos. 5 and 6 and moisture separator reheater drain tank and provides reservoir capacity for drain pumping into the feed pump suction header. Each high-pressure heater train drain tank is installed beneath the No. 5 feedwater heater so that high-pressure heaters drain freely. The drain level is maintained within the train drain tank by a level controller in conjunction with the heater drain pump discharge flow control valve.

The high-pressure heater train drain tank is provided with an alternate drain line to the main condenser for automatic dumping upon high level. The alternate drain line also is used during startup and shutdown when it is desirable to bypass the drain pumping for feedwater quality purposes.

10.4.7.2.1.7 Heater Drain Pumps. The high-pressure heater drain pumps operate in parallel, each taking suction from its high-pressure heater train drain tank and discharging to the suction header of the feedwater pumps. Each high-pressure heater drain tank pump is a motor-driven, multistage, centrifugal pump located below the heater drain tank and is designed for the available suction conditions.

10.4.7.2.1.8 Pump Recirculation Systems. Minimum flow control systems are provided to allow all pumps in the main condensate and feedwater trains to operate at a sufficient rate to prevent damage.

10.4.7.2.1.9 Containment Feedwater Line Isolation Valves. The containment feedwater isolation valves discussed in subsection 6.2.4 are designed to isolate the feedwater system from the steam generator in the event of a steam line break, feedwater line break, or loss-of-coolant accident (LOCA). This isolation precludes any possibility of radioactivity release from the containment due to a condensate or feedwater pipe break. The isolation valves in the feedwater line to the steam generator downcomer nozzle are provided with nitrogen accumulator to allow manual remote control with a loss of offsite power to supply auxiliary feedwater to the steam generators from the non-Seismic Category I auxiliary feedwater pump described in subsection 10.4.9. Note that the backup nitrogen accumulator for the feedwater control and isolation valves was not credited during a normal loss of offsite power event.

10.4.7.2.2 System Operation

10.4.7.2.2.1 Prestartup Feedwater Cleanup Procedure. The condensate pumps circulate condensate from the condenser hot-wells, through the condensate cleanup system, through all feedwater heater trains through the recirculation valve, and back to the hotwell. This procedure is repeated until the condensate cleanup system has yielded feedwater quality equivalent to that specified in section 10.3.5.

10.4.7.2.2.2 Power Generation Operation. Feedwater is supplied to the steam generator from the steam generator

feedwater pumps. Feedwater flow is controlled through the main feedwater control valves that establish steam generator feedwater balancing in conjunction with the variable speed feedwater pump turbine drives. The feedwater system may be operated either with the high pressure feedwater bypass valve open or closed in conjunction with both feedwater heater trains being in service. When the plant is operated at the licensed reactor power with the bypass valve closed, additional plant thermal efficiencies are achieved. When the plant is operated at the licensed reactor power with the bypass valve open in the feedwater temperature reduction mode, both plant thermal efficiencies and steam generator thermal stresses are reduced. Extended operation in either configuration is within the system and plant design and licensing basis.

10.4.7.3 Safety Evaluation

Safety evaluations, numbered to correspond to the safety design bases, are as follows:

A. Safety Evaluation One

The main feedwater lines are restrained or are separated to the extent necessary to prevent damage to the RCPB in the event of a feedwater pipe rupture. Refer to section 3.6 for additional discussion on this subject.

B. Safety Evaluation Two

Main feedwater lines are designed and routed so that a failure will not prevent a safe shutdown of the

reactor. Refer to section 3.6 for information on this subject.

C. Safety Evaluation Three

The containment feedwater isolation valves and piping between them and the steam generators are designed to meet Seismic Category I criteria in accordance with requirements given in sections 3.7 and 3.9.

D. Safety Evaluation Four

Components and piping are designed to protect against the effects of high and moderate energy pipe rupture as discussed in section 3.6.

E. Safety Evaluation Five

Adverse environmental conditions do not impair the safety function of this system. Wind and tornado loadings are discussed in section 3.3. Flood design is covered in section 3.4. Seismic design is discussed in section 3.7.

F. Safety Evaluation Six

The loss of offsite power does not prevent the safe shutdown of the reactor as discussed in sections 7.4 and 8.3.

10.4.7.4 Tests and Inspections

ASME Code, Section III, Class 2, piping is inspected and tested in accordance with ASME Code, Sections III and XI and the ASME OM Code. ANSI B31.1.0 piping is inspected and tested in

accordance with Paragraphs 136 and 137. ASME Code, Section III, Class 2, valves are periodically inservice-tested for exercising and leakage in accordance with ASME OM Code. Isolation valves, vent and drain valves, and test connections required in the system to effect these tests are included in engineering drawings 01, 02, 03-M-CDP-001, -002, -003, -004 and 01, 02, 03-M-FWP-001.

Each feedwater heater, heater drain tank, pump, and valve is shop-tested by hydrostatic pressure tests performed in accordance with applicable codes. Tube joints of feedwater heaters are shop leak-tested. Prior to initial operation, the completed condensate and feedwater system receives a field hydrostatic test and inspection in accordance with the applicable code. Periodic tests and inspections of the system are performed in conjunction with scheduled maintenance outages. In addition, PVNGS agrees to perform a steam generated feedwater water hammer test in accordance with NUREG/CR-1606. PVNGS will perform the test according to a standard operating procedure (SOP). PVNGS will run the plant at approximately 15% of full power by using feedwater through the downcomer nozzle. The feedwater will then be switched from the downcomer nozzle to the economizer nozzle and the following transient will be observed and recorded. Inservice inspections are not required unless there is an indication of malfunction somewhere in the system.

10.4.7.5 Instrumentation Applications

Feedwater flow control instrumentation measures the feedwater flowrate from the condensate and feedwater system. This flow measurement, transmitted to the feedwater control system, regulates the feedwater flow to the steam generators to meet system demands. Refer to section 7.7 for a description of the feedwater control system.

Instrumentation and controls are provided for regulating minimum pump flowrates for the condensate pumps, high-pressure heater drain pumps, and steam generator feedwater pumps.

Sampling means are provided for monitoring the quality of the final feedwater, as described in subsection 10.4.6.

In the feedwater heating portion of the system, temperature measurements are provided for each stage of heating. These measurements include the temperature into and out of each feedwater heater for the water side and out of each heater for the steam side of the system except that steam temperature is determined by its saturation pressure in feedwater heater Nos. 1, 2, 3, and 4. Steam pressure measurements are provided at each feedwater heater. Liquid pressure measurements are provided at appropriate locations throughout the system.

Instrumentation and controls are provided to maintain the proper condensate level in the feedwater heater or heater drain tank. High level alarm and automatic dump action on high level also are provided.

Appropriate instrumentation displays and alarms are provided in the control room.

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM

The steam generator blowdown system is an integral part of the secondary chemistry control system of the condensate cleanup system, and is discussed in subsection 10.4.6.

10.4.8.1 CESSAR Interface Requirements

Refer to subsection 5.1.4.

10.4.8.2 CESSAR Interface Evaluations

Refer to subsection 5.1.5.

10.4.9 AUXILIARY FEEDWATER SYSTEM

The auxiliary feedwater system (AFS) is designed to provide steam generator feedwater during startup, hot standby, normal shutdown, and emergency conditions.

The AFS reliability analysis (formally appendix 10B) has been archived as historical information only in PVNGS engineering calculation 13-NC-AF-200, "Auxiliary Feedwater System (AFS) Reliability Analysis." Refer to appendix 5A, Question 5A.17, for additional discussion.

10.4.9.1 Design Bases

10.4.9.1.1 Safety Design Bases

The following safety design bases are applicable to the essential portions of the AFS only:

A. Safety Design Basis One

The AFS shall provide feedwater for the removal of decay heat from the RCS following reactor shutdown from any power level until such time as cooling by the shutdown cooling system may be initiated.

B. Safety Design Basis Two

One motor-driven AFS pump and one steam turbine-driven AFS pump and associated valves and piping shall be designed to Seismic Category I requirements. In addition, the isolation valves and piping connections to this Seismic Category I piping shall be designed to Seismic Category I requirements.

C. Safety Design Basis Three

The turbine-driven Seismic Category I AFS pump shall be available in the event of a loss of all ac power.

D. Safety Design Basis Four

The Seismic Category I motor-driven AFS pump and its associated power-operated valves shall be connected to one onsite (diesel generator) power bus as discussed in subsection 8.3.1. In addition, the turbine-driven AFS pump's turbine control system and its associated

power-driven valves are connected to the dc power system as discussed in subsection 8.3.2.

E. Safety Design Basis Five

Redundancy shall be provided throughout the AFS and supporting systems to ensure the supply of feedwater to either or both steam generators in the event of an accident plus one active failure.

F. Safety Design Basis Six

The AFS shall be designed to maintain water level in the steam generators under the following operating modes and accident conditions:

1. Reactor coolant system cooldown at a maximum rate of 75F per hour from hot standby to a temperature of 350F with a loss of offsite power and normal onsite power.
2. Hot standby for 8 hours with a loss of offsite power and normal onsite power.
3. Reactor coolant system cooldown using the intact steam generator following a main steam line break or main feedwater line break inside the containment with a loss of offsite power and normal onsite power.

G. Safety Design Basis Seven

Each of the two Seismic Category I AFS pumps shall be designed to provide 100% of the required flow (see Table 10.4-6) for decay heat removal. The head

generated by each pump is sufficient to deliver feedwater into the steam generators at 1270 psia or equivalent at the entrance of the steam generators.

H. Safety Design Basis Eight

In the unlikely event that the control room must be evacuated, the AFS shall be capable of being operated for shutdown from a remote shutdown station.

I. Safety Design Basis Nine

The Seismic Category I, motor-driven AFS pump shall be located in a separate room designed to Seismic Category I requirements in the main steam support structure. The Seismic Category I, steam turbine-driven AFS pump shall also be located in a separate room designed to Seismic Category I requirements in the main steam support structure.

J. Safety Design Basis Ten

The components, including piping for each AFS pump safety train, shall be separated from each other and are either enclosed by a Seismic Category I structure or installed underground.

K. Safety Design Basis Eleven

The combination of motor-driven and steam turbine-driven pumps shall provide diversity of power sources to assure delivery of feedwater under an emergency condition.

L. Safety Design Basis Twelve

All components and piping shall be designed, protected from, or located to protect against the effects of high and moderate energy pipe rupture, pipe whip, and jet impingement.

M. Safety Design Basis Thirteen

This system shall be designed such that adverse environmental conditions such as tornados, floods, and earthquakes will not impair its safety function.

10.4.9.1.2 Power Generation Design Basis

The non-Seismic Category I, motor-driven AFS pump is used as the feedwater pump during startup, hot standby, and normal shutdown conditions.

10.4.9.1.3 CESSAR Interface Requirements

Refer to subsection 5.1.4.

10.4.9.1.4 CESSAR Interface Evaluation

Refer to subsection 5.1.5.

10.4.9.1.5 Codes and Standards

The AFS is designed to codes and standards identified in table 3.2-1.

10.4.9.1.6 Reliability/Availability Bases

The bases contained within this section represent the major design features of the non-essential AFS train which were added to improve the original AFS design from a reliability/availability perspective or are major assumptions which have been credited in performing risk related analyses for PVNGS. These bases reflect the most relevant features of the non-essential AFS train design from a reliability/availability perspective and are not intended to be all encompassing. The PVNGS Individual Plant Examination (IPE) provides a complete description of the reliability/availability assessments that were completed for the AFS. The following bases are only applicable to the non-essential AFS trains:

A. Reliability/Availability Bases One

The non-essential AFS train is not required to perform a safety function for the mitigation of the design basis accidents presented in Chapters 6 and 15. The emergency operating procedures provide instructions for using the non-essential AFS train, if available, in addition to the essential AFS trains as a defense-in-depth measure that assists in mitigating plant events. The non-essential AFS train is not required to mitigate accidents, but provides additional reliability/availability to the AFS. Risk related analyses shall consider operator actions (including human errors) in assessing the reliability or availability of the AFS.

B. Reliability/Availability Bases Two

The following bases have been credited in the risk assessments performed on the non-essential portion of the AFS as part of the IPE:

1. The non-Seismic Category I AFS pump minimum flow recirculation path back to the condensate storage tank does not need to be isolated to meet the IPE performance as described in Table 10.4-6, note c. In addition, the IPE does not require the flow path to remain open in situations where the minimum flow requirements for the pump are met with the minimum flow path isolated.

2. Periodic full-flow testing of the non-Seismic Category I AFS pump is not required.

3. The downcomer feedwater isolation valves are designed to fail open on a loss of power.

4. The backup nitrogen accumulator for the downcomer feedwater control and isolation valves was not credited during a normal loss of offsite power event.

5. The AFS flow to the steam generators is controlled in accordance with the standard post trip actions as defined in the emergency operating procedures (see Table 10.4-6, note c, for IPE credited performance for the AFS pumps).

C. Reliability/Availability Bases Three

The AFS overall reliability is enhanced by including the non-essential AFS pump in each unit's Technical Specifications.

D. Reliability/Availability Bases Four

The non-Seismic Category I motor driven AFS pump and associated power-operated valves shall have the capability to be powered by the Train A diesel generator when connected by manual action to the load group 1 bus as described in Section 8.3.1. The non-Seismic Category I motor driven AFS pump may be controlled from the main control room.

E. Reliability/Availability Bases Five

The non-Seismic Category I motor driven AFS pump is located within the Turbine Building. This structure and the non-essential AFS train components contained within this structure are not designed to withstand adverse environmental conditions resulting from earthquakes, tornadoes, floods or hazards for which the essential AFS trains are required to be designed to withstand.

Should a seismic even occur when the nonseismic auxiliary feedwater pump is in service, the operator can take the necessary action to locally close one of the suction line valves should the line fail. This action will be taken with sufficient time to prevent a significant loss of water from the condensate storage tank.

F. Reliability/Availability Bases Six

The design and performance requirements for the non-Seismic Category I motor driven AFS pump are provided in Table 10.4-6.

10.4.9.2 System Description

10.4.9.2.1 General Description

The AFS consists of one Seismic Category I, motor-driven AFS pump; one Seismic Category I, steam turbine-driven AFS pump; and one non-Seismic Category I, motor-driven AFS pump, associated piping, controls, and instrumentation. Engineering drawings 01, 02, 03-M-AFP-001 show the piping and instrumentation diagram of the system.

The primary source of auxiliary feedwater is the condensate storage tank. The condensate storage tank provides a reserve capacity (see Table 9.2-21) for the AFS during emergency shutdown conditions. This provides an orderly RCS cooldown to shutdown cooling initiation conditions as addressed in safety design basis six of paragraph 10.4.9.1.1 and provides sufficient feedwater to maintain the plant as hot standby for 8 hours.

Both motor-driven auxiliary feedwater pumps and their motor-operated valves can receive power from both onsite and offsite power sources. In the event of a loss of offsite power, power is supplied to these motor-driven pumps by their standby diesel generators. The Seismic Category I, motor-driven pump and its motor-operated valves are connected to the train B power source by automatic initiation or by operator action. The non-Seismic

Category I pump and its valves can be connected to the train A power source by operator action only. The two Seismic Category I auxiliary feedwater pumps are separated by a physical barrier. Piping and components for the Seismic Category I pumps are located, separated, or protected to preclude damage from any missile effects.

The turbine-driven AFS pump is supplied with steam from the main steam lines of either steam generator upstream of the main steam isolation valves. The turbine controls and associated valves are powered from the dc bus.

10.4.9.2.2 Component Description

Principal components are listed in table 10.4-6.

10.4.9.2.3 System Operation

For emergency operation, normal flow is from the condensate tank to either the Seismic Category I, motor-driven AFS pump or to the steam turbine-driven, Seismic Category I AFS pump which are located in the main steam support structure. An alternate supply of water is provided by cross-connections to the reactor makeup tank.

A minimum flow recirculation system is provided on each pump discharge with recirculation to the condensate tank and supports pump testing. Each pump can supply either steam generator with feedwater.

One auxiliary feedwater path to the steam generators is provided for the non-Seismic Category I, motor-driven auxiliary

feedwater pump through the feedwater header, with manual operation of feedwater valves possible during emergency operation. This feature of the non-essential AFS train is provided to improve the overall availability of the AFS system and is not required for Chapters 6 and 15 accident mitigation.

The two Seismic Category I auxiliary feedwater pumps only provide flow to the downcomer feedwater nozzles on each steam generator. Either Seismic Category I auxiliary feedwater pump

Table 10.4-6
AUXILIARY FEEDWATER SYSTEM DESIGN DATA

Design Factor	Value	Notes
Auxiliary feedwater pumps		
Quantity		
Motor-driven, non-Seismic Category I	1	
Motor-driven, Seismic Category I	1	
Steam turbine-driven, Seismic Category I	1	
Flow, Seismic Category I, gal/min, net	750	a, b
Miniflow, Seismic Category I, gal/min, maximum	260	b
Flow, non-Seismic Category I, gal/min, net	710	a, c
Miniflow, non-Seismic Category I, gal/min, maximum	300	c
Head, ft - Seismic Category I at 750 gal/min plus 260 gal/min miniflow	3,280	b
Head, ft - non-Seismic Category I at 710 gal/min plus 300 gal/min miniflow	2,960	c

a. Net flow delivered to steam generators.

b. The values shown are for the design performance specifications of the auxiliary feedwater pumps. The safety analysis credits delivery of 650 gpm at a steam generator pressure of 1270 psia or equivalent at the steam generator entrance for design basis accidents.

c. The values shown in this Table are based on the design performance specifications for the non-Seismic Category I AFS pump. The power generation design bases for this pump assumes a minimum performance of 650 gpm delivered to the steam generator(s) at a design no load pressure of 1170 psia. The IPE credits a AFS flow of approximately 500 gpm to the steam generator(s) when steam generator conditions are maintained in accordance with the standard post trip actions as defined in the emergency operating procedures.

can supply the necessary feedwater for reactor decay heat removal and reactor cooldown to 350F.

At a reactor coolant temperature of 350F, the shutdown cooling system is placed in operation.

A minimum flow path is provided for each pump. Approximately 26% of the Seismic Category I pump capacity and 30% of the non-Seismic Category I pump capacity is recirculated back to the condensate tank whenever a pump is operating. The minimum flow line is provided to prevent pump overheating in the event the pump discharge line is isolated.

The Seismic Category I pump motor driver is powered from a separate engineered safety features (ESF) bus which is powered by the load group 2 diesel generator. The Seismic Category I, steam turbine-driven pump's associated valving is powered from the dc bus as discussed in subsection 8.3.2. The turbine for this pump is supplied with steam from either of the steam generators. The turbine controls are powered from the dc bus.

Auxiliary feedwater control for the essential trains is normally from the control room, but instrumentation is provided for operation from the remote shutdown panel in the unlikely event that the control room must be evacuated.

Signals from the auxiliary feedwater actuation signal (AFAS) start the Seismic Category I, motor-driven auxiliary feedwater pump and the Seismic Category I, steam turbine-driven auxiliary feedwater pump, shut all steam generators' blowdown and blowdown sample isolation valves, and open the associated isolation valves to the downcomer nozzles of the intact steam

generator(s). The non-Seismic Category I, motor-driven pump is started manually and its associated valves are opened manually from the control room.

Assuming a pipe break in either steam generator lower feedwater supply line in the containment, a single electrical failure will not prevent the system from accomplishing its function. Either Seismic Category I pump can supply the flow required for safe shutdown. Table 10.4-7 lists the Seismic Category I valves in the AFS.

10.4.9.3 Safety Evaluation

Safety evaluations, numbered to correspond to the safety design bases, are as follows:

A. Safety Evaluation One

The AFS, in conjunction with the condensate tank described in subsection 9.2.6, provides a means of pumping feedwater to maintain the plant at hot standby for 8 hours, with a subsequent cooldown at a maximum rate of 75F per hour to a reactor coolant temperature of 350F.

B. Safety Evaluation Two

The two Seismic Category I AFS pumps and their associated valves and piping are designed to Seismic Category I requirements. The isolation valves and piping connections to the Seismic Category I piping are also designed to Seismic Category I requirements.

C. Safety Evaluation Three

During normal operation, the two Seismic Category I AFS pumps are each available in the event of loss of off-site power and normal onsite power.

D. Safety Evaluation Four

The Seismic Category I, motor-driven AFS pump and its associated line valves are connected to the load group 2 onsite power bus as discussed in subsection 8.3.1. The turbine-driven AFS pump control system and the associated line valves are connected to the dc power system as discussed in subsection 8.3.2.

E. Safety Evaluation Five

Redundancy is provided throughout the AFS and associated systems to ensure the supply of feedwater to either or both steam generators in the event of an accident plus one active failure. Table 10.4-8 presents a single failure analysis for the AFS.

F. Safety Evaluation Six

The AFS is designed to maintain an adequate water level in the steam generators under the following operating modes and accident conditions:

1. Reactor cooldown at a maximum administratively controlled rate of 75F per hour from hot standby to 350F with a loss of offsite power and normal onsite power.

Table 10.4-7
SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE AUXILIARY FEEDWATER SYSTEM[(a)] (Sheet 1 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actu-ator Type	Valve Classifi-cation[(b)]
V002	Main steam to AFW PP A turbine isolation valve	Gate	6	None	N
V005	AFW PP A suction check valve from reactor makeup water tank	Check	8	None	A
V006	AFW PP A suction isolation valve from condensate storage tank	Gate	8	None	N
V007	AFW PP A suction check valve from condensate storage tank	Check	8	None	A
V009	AFW PP B suction check valve from reactor makeup water tank	Check	8	None	A
V015	AFW PP A discharge check valve after recirculation	Check	6	None	A
V016	AFW PP A discharge isolation valve after recirculation	Gate	6	None	N
V017	AFW PP A miniflow recirculation	Gate	3	None	N
V021	AFW PP B suction isolation valve from condensate storage tank	Gate	8	None	N

Table 10.4-7

SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE AUXILIARY FEEDWATER SYSTEM[a] (Sheet 2 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actu-ator Type	Valve Classifi-cation[b]
V022	AFW PP B suction check valve from condensate storage tank	Check	8	None	A
V024	AFW PP B discharge check valve after recirculation line	Check	6	None	A
V025	AFW PP B discharge isolation valve (manual)	Gate	6	None	N
V026	AFW PP B miniflow recirculation valve	Gate	3	None	N
V028	AFW PP B suction isolation valve from reactor makeup water tank	Gate	8	None	N
HV30	AFW regulating valve PP B to SG 1	Globe	6	Motor	A
HV31	AFW regulating valve PP B to SG 2	Globe	6	Motor	A
HV32	AFW regulating valve PP A to SG 1	Globe	6	Motor	A
HV33	AFW regulating valve PP A to SG 2	Globe	6	Motor	A
UV34	AFW isolation valve PP B to SG 1	Gate	6	Motor	A
UV35	AFW isolation valve PP B to SG 2	Gate	6	Motor	A
UV36	AFW isolation valve PP A to SG 1	Gate	6	Motor	A

Table 10.4-7

SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE AUXILIARY FEEDWATER SYSTEM[(a)] (Sheet 3 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actu-ator Type	Valve Classifi-cation[(b)]
UV37	AFW isolation valve PP A to SG 2	Gate	6	Motor	A
HV54	AFW turbine steam trip and throttle valve	Globe	4	Motor	A
V055	AFW turbine auxiliary steam isolation valve	Gate	4	None	N
V058	AFW PP A reactor makeup water tank isolation valve	Gate	8	None	N
V077[(c)]	AFW PP A recirculation isolation valve to condensate tank	Gate	6	None	N
V078[(c)]	AFW PP B recirculation isolation valve to condensate tank	Gate	6	None	N
V079	AFW check valve to SG 1 FW header (in-containment)	Check	6	None	A
V080	AFW check valve to SG 2 FW header (in-containment)	Check	6	None	A
V096	Auxiliary steam check valve to AFW turbine	Check	4	None	N

Table 10.4-7

SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE AUXILIARY FEEDWATER SYSTEM[a] (Sheet 4 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actuator Type	Valve Classification[b]
V137	AFW PP A discharge check valve before recirculation	Check	6	None	A
V138	AFW PP B discharge check valve before recirculation	Check	6	None	A
UV134[d]	SG 1 steam supply to AFW PP turbine	Gate	6	Motor	A
UV138[d]	SG 1 steam supply to AFW PP turbine	Gate	6	Motor	A
UV134A[d]	SG 1 steam bypass to AFW PP turbine	Globe	1.5	Motor	A
UV138A[d]	SG 2 steam bypass to AFW PP turbine	Globe	1.5	Motor	A
V234[d]	SG 1 steam bypass line isolation valve for UV134A	Globe	2[f]	None	N
V238[d]	SG 2 steam bypass line isolation valve for UV138A	Globe	2[f]	None	N
V885[d]	SG 1 steam bypass isolation valve to AFW PP turbine	Globe	2	None	N
V886[d]	SG 2 steam bypass isolation valve to AFW PP turbine	Globe	2	None	N
V887[d]	SG 1 steam bypass check valve to AFW PP turbine	Check	2	None	A
V888[d]	SG 2 steam bypass check valve to AFW PP turbine	Check	2	None	A

Table 10.4-7

SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE

AUXILIARY FEEDWATER SYSTEM[a] (Sheet 5 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actuator Type	Valve Classification[b]
V889[d]	Steam bypass to AFW PP turbine isolation valve	Globe	2	None	N
V043[d]	SG 1 steam check valve to AFW PP turbine	Check	6	None	A
V044[d]	SG 2 steam check valve to AFW PP turbine	Check	6	None	A
V994[e]	SG 2 FW recirculation isolation valve	Gate	4	None	N
V995[e]	SG 2 FW recirculation isolation valve	Gate	4	None	N
V996[e]	SG 1 FW recirculation isolation valve	Gate	4	None	N
V997[e]	SG 1 FW recirculation isolation valve	Gate	4	None	N

a. Seismic Category I valves listed below are omitted from the list:

- Instrument isolation valves
- Vent valves
- Drain valves
- AFW PP turbine cooling subsystem valves
- AFW PP bearing cooling and gland seal injection subsystem valves
- Makeup (primary, alternate and suction) Isolation Valves. Effective for Units where DMWO 4345882 has been implemented.

b. A = active; N = nonactive; Note that "A" and "N" are related to the component's movement during performance of its safety function and not to the application of single failure criteria.

c. Valves in AFW system shown in condensate transfer and storage system (CT)

d. Valves in AFW system shown in main steam system (SG)

e. Valves isolate downcomer feedwater (an AFW flow path) from recirculation lines.

f. Valve size in Unit 2 is 1½ inches

Table 10.4-8

SINGLE FAILURE MODE ANALYSIS--AUXILIARY FEEDWATER SYSTEM (Sheet 1 of 3)

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Isolation valve to reactor makeup water tank	Fails closed/ mechanical failure or inadvertent misposition	Loss of secondary source of water for the auxiliary feedwater pumps	Valve stem position	Redundant lines from condensate tank	
	Fails open/ mechanical failure or inadvertent misposition	None	Valve stem position		Valve is normally closed.
Check valves from reactor makeup water tank	Fails closed/corrosion	None	None	Redundant lines available to condensate tank	Only used in case condensate tank not available.
	Fails open/ contamination	None	None		
Isolation valves to condensate tank	Fails closed/ mechanical binding	None	Handle position	Redundant line available from condensate tank	Valve is normally locked open.
	Fails open/locking mechanism jams	None	Handle position	None	Valve is locked open.
Check valves from condensate tank	Fails closed/corrosion	None	None	Redundant line available from condensate tank	
	Fails open/ contamination	None	None		
Auxiliary feedwater pump (Seismic Category I)	Fails to pump/ mechanical electrical failure	No effect on system performance	Low pressure indication from pump	Redundant 100% capacity Seismic Category I auxiliary feedwater pump available. A 100% capacity non-Seismic Category I pump is also available	

Table 10.4-8

SINGLE FAILURE MODE ANALYSIS--AUXILIARY FEEDWATER SYSTEM (Sheet 2 of 3)

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Pump discharge check valves	Fails closed/ corrosion	Loss of one auxiliary feedwater pump	High-pressure indication from pump	Redundant 100% capacity auxiliary feedwater pump available.	
	Fails open/ contamination	No effect other than causing trouble if maintenance of valve is required while system is operating.	None		
Discharge valves, auxiliary feedwater pumps	Fails open/ mechanical or electrical failure	None	Handle position		Valve is normally locked open
	Fails closed/ mechanical binding	Effective loss of one auxiliary feedwater pump	Handle position	Redundant 100% capacity auxiliary feedwater pump	Valve is normally locked open
Isolation valves to feedwater header	Fails open/ mechanical or electrical failure	Loss of double isolation between the main feedwater supply and auxiliary feedwater supply to one steam generator	Valve position indicator in control room	Redundant valves	
	Fails closed/ mechanical or electrical failure	Slight decrease in flexibility of feedwater system	Valve position indicator in control room	None required	
Check valves to feedwater header	Fails open/ contamination	No serious effect	Periodic test	None required	
	Fails closed/ corrosion	Slight decrease in flexibility of feedwater system	Periodic test	None requried	
Overpressure Relief Valves for Outboard AF Containment Isolation Valves	Fails open/ mechanical failure	Slight decrease in amount of water delivered to Steam Generator(s)	Periodic test	Both auxiliary feedwater pumps remain available such that their total combined Technical Specification required flow is met.	
	Fails closed/ mechanical failure or corrosion	Effective loss of one auxiliary feedwater pump	Periodic test	Redundant 100% capacity auxiliary feedwater pump	
FW recirculation isolation valve[(a)]	Fails open/inadvertent position	None	Handle position	Redundant valve	Valves are locked closed and administratively controlled

a. Valves isolate downcomer feedwater (an AFW flow path) from recirculation lines.

Table 10.4-8

SINGLE FAILURE MODE ANALYSIS--AUXILIARY FEEDWATER SYSTEM (Sheet 3 of 3)

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
SG Primary and Alternate Makeup Valves	Fails closed/ corrosion	No effect on system	Operator	None Required	Redundant isolation valves provided. Inboard valve is locked closed.
(Effective for Units where DMWO 4345882 has been implemented.)	Fails open/operator error	No effect on system	Operator	None Required	
SG Alternate Suction Isolation Valve	Fails closed	No effect on system	Operator	None Required	Multiple failures required to affect B Train Auxiliary Feedwater Pump
(Effective for Units where DMWO 4345882 has been implemented.)	Fails open	Effective loss of one Auxiliary Feedwater Pump	Periodic Test	Valve is locked closed	

2. Hot standby for 8 hours with a loss of offsite power and normal onsite power.

3. Reactor coolant system cooldown using the intact steam generator following a main steam line break or main feedwater line break inside the containment with a loss of offsite power and normal onsite power.

Only the Seismic Category I pumps are started on an AFAS. The Seismic Category I AFS pumps are not routinely used for normal plant operations. The non-Seismic Category I AFS pump is utilized for startup, hot standby and normal shutdown of the plant.

G. Safety Evaluation Seven

Each of the essential AFS pumps is capable of delivering 650 net gallons per minute at 1270 psia or equivalent at the entrance of the steam generator.

H. Safety Evaluation Eight

The AFS can be operated from either the control room or from a remote shutdown station.

I. Safety Evaluation Nine

Each Seismic Category I AFS pump is installed in a separate room designed to Seismic Category I requirements. These rooms are in the main steam support structure.

J. Safety Evaluation Ten

The components and piping for each Seismic Category I AFS pump train are separated from each other in that no credible hazard within either train pump room can affect both trains. Where complete physical separation is not met as a result of design constraints, separation criteria are satisfied because sufficient protection is provided to assure an inherently reliable and safe design configuration which ensures essential AFS train redundancy. The components and piping of both Seismic Category I AFS trains are either enclosed by a Seismic Category I structure or are installed underground.

K. Safety Evaluation Eleven

The combination of the one Seismic Category I, motor-driven pump and the one Seismic Category I, steam turbine-driven pump utilizes a diversity of power sources to assure delivery of feedwater under emergency conditions.

L. Safety Evaluation Twelve

All components and piping are designed to protect against the effects of high and moderate energy pipe ruptures as discussed in section 3.6.

M. Safety Evaluation Thirteen

Adverse environmental conditions will not impair the safety function of this system. Wind and tornado loadings are discussed in section 3.3. Flood design is

covered in section 3.4. Seismic design is discussed in section 3.7.

10.4.9.4 Inspection and Testing Requirements

The system is capable of being tested while the plant is in normal operation. Each of the essential and non-essential AFS pumps is provided with a minimum flow recirculation line back to the condensate storage tank. This line ensures that the minimum flow requirements for each pump are met and allows for periodic testing required by the applicable codes that are identified in Section 3.9.6. This design allows the AFS to be operationally tested up to the steam generator auxiliary feedwater isolation valves. Full flow testing of the essential AFS pumps is performed in accordance with the Technical Specifications. These tests ensure the operability of the essential AFS by taking a supply from the condensate storage tank and injecting auxiliary feedwater into the steam generators. Successful performance of these full flow tests ensure that the essential AFS meets the minimum performance requirements credited in the safety analyses (Table 10.4-6, note b) for Chapter 6 and 15 events. Full flow testing of the non-essential AFS pump is not required to be performed since this pump is not credited in the safety analyses for Chapter 6 and 15 events.

Power Operated Containment isolation valves can be tested by either remote or local operation during normal plant operation.

The system is inspected as required by the applicable codes as identified in table 3.2-1.

Temperature monitoring of both the Seismic Category I and Non-Seismic Category I Auxiliary Feedwater pump is conducted in accordance with the recommendations of Generic Letter 88-03, Steam Binding of Auxiliary Feedwater Pumps.

10.4.9.5 Instrumentation Requirements

Instrumentation and controls are provided as described in paragraph 10.4.9.3. Control room instrumentation includes auxiliary feedwater flow and pump discharge pressure, steam generator level, control hand switches, and position indication for all power-operated valves, and auxiliary feedwater pump, turbine speed control, and indication.

Control logic for the AFS is addressed in section 7.3.

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APPENDIX 10A

RESPONSES TO NRC REQUESTS FOR INFORMATION

CONTENTS

CONTENTS (cont)

APPENDIX 10A

QUESTION 10A.1 (NRC Question 430.37) (10.1)

Provide a general discussion of the criteria and bases of the various steam and condensate instrumentation systems in section 10.1 of the FSAR. The FSAR should differentiate between normal operation instrumentation and required safety instrumentation.

RESPONSE: The response is given in subsection 10.1.3 and amended paragraph 10.4.9.5.

QUESTION 10A.2 (NRC Question 430.38) (10.2)

Expand your discussion of the turbine speed control and over-speed protection system. Provide additional explanation of the turbine and generator electrical load following capability for the turbine speed control system with the aid of system schematics (including turbine control and extraction steam valves to the heaters). Tabulate the individual speed control protection devices (normal emergency and backup), the design speed (or range of speed) at which each device begins operation to perform its protective function (in terms of percent of normal turbine operating speed). In order to evaluate the adequacy of the control and overspeed protection system provide schematics and include identifying numbers to valves and mechanisms (mechanical and electrical) on the schematics. Describe in detail, with references to the identifying numbers, and sequence of events in the turbine trip including response times, and show that the turbine stabilizes. Provide the results of a failure mode and effects analysis for the overspeed protection systems. Show that a single steam

valve failure cannot disable the turbine overspeed trip from functioning. (SRP 10.2, Part III, Items 1, 2, 3, and 4).

RESPONSE: Expanded discussion of turbine speed control and overspeed protection system is given in amended subsection 10.2.2 and table 10.2-3.

QUESTION 10A.3 (NRC Question 430.39) (10.2)

The FSAR discusses the main steam stop and control, and reheat stop and intercept valves. Show that a single failure of any of the above valves cannot disable the turbine overspeed trip functions. (SRP 10.2, Part III, Item 3).

RESPONSE: The turbine overspeed protection system is an equipment protection system and is not required for plant safety.

Nevertheless, as described below and in section 10.2, the turbine overspeed protection system provides a highly reliable system to trip the turbine in the event of a turbine overspeed condition.

The function of the turbine overspeed trip sensors is to provide signals to the turbine trip system which, in turn, actuates the solenoid valves in the emergency trip systems. The emergency trip actuates the disk dump valve for each stop, control, reheat stop, and intercept valve to depressurize hydraulic fluid in trip system. This allows spring to close the valves to terminate the flow of steam to the turbine.

Each of the main steam and reheat lines supplying steam to the high-pressure and low-pressure cylinders of the turbine has two valves (stop and control) in series. Failure of one valve to close will not prevent tripping the turbine since the second valve in the same line will close, thus terminating the flow of steam to the turbine.

(Figure 10.1-1, sheet 1, indicates the approximate location of the turbine main steam stop, control, reheat stop, and intercept valves.)

QUESTION 10A.4 (NRC Question 430.40) (10.2)

Expand your discussion of the inservice inspection program for throttle-stop, control, reheat stop, and interceptor steam valves to include inspection times and the capability for testing essential components during turbine generator system operation. (SRP 10.2, Part III, Items 5 and 6).

RESPONSE: The response is given in amended paragraph 10.2.3.6.

QUESTION 10A.5 (NRC Question 430.41) (10.2)

Discuss the effects of a high and moderate energy piping failure or failure of the connection from the low pressure turbine to condenser on nearby safety-related equipment or systems. Discuss what protection will be provided the turbine overspeed control system equipment, electrical wiring, and hydraulic lines from the effects of a high or moderate energy pipe failure so that the turbine overspeed protection system

will not be damaged to preclude its safety function. (SRP 10.2 Part III, Item 8).

RESPONSE: High and moderate energy piping failure within the turbine building, or failure of the connection between the low-pressure turbine to the condenser will not adversely affect plant safety since there is no safety-related equipment located within the turbine building. Further response is given in paragraph 3.6.1.2. The turbine overspeed protection system is for equipment protection only.

Nevertheless, the turbine overspeed protection system provides a highly reliable system to trip the turbine in event of a turbine overspeed condition. Aside from providing two redundant channels of speed control, two additional means of overspeed protection are provided as discussed in paragraph 10.2.2.3.1.5. Because of the redundancy in the mode of operation and the physical separation of components, a high or moderate energy pipe failure will not preclude protective function of the turbine overspeed control system.

<u>QUESTION 10A.6</u> (NRC Question 430.42) (10.2)

In paragraph 10.2.3.6 you discuss inservice inspection and exercising of the main steam turbine stop and control and reheater stop and intercept valves. You do not discuss the inservice inspection, testing and exercising of the extraction steam valves. Provide a detail description of: 1) the extraction steam valves, and 2) your inservice inspection and testing program for these valves. Also provide the time

interval between periodic valve exercising to assure the extraction steam valves will close on turbine trip.

RESPONSE: The extraction steam valves are described in amended paragraph 10.2.2.5.

<u>QUESTION 10A.7</u> (NRC Question 430.43) (10.2)

Describe with the aid of drawings, the bulk hydrogen storage facility including its location and distribution system. Include the protective measures considered in the design to prevent fires and explosions during operations such as filling and purging the generator, as well as during normal operations.

RESPONSE: The following drawings (sent under separate cover) show the location of the bulk hydrogen storage facilities and the hydrogen distribution system:

- 13-P-ZYA-958, Rev. 0
- 01-C-ZVC-305, Rev. 7
- 01-C-CVC-306, Rev. 7
- 13-P-GAF-201, Rev. 4
- 13-P-GAF-401, Rev. 2
- 13-P-ZYA-015, Rev. 6
- 13-M-GAP-001, Rev. 4
- 13-M-GAP-002, Rev. 2
- 13-M-GHP-001, Rev. 4
- 13-M-CHP-002, Rev. 6
- 13-P-CHF-218, Rev. 5

Further response is given in paragraph 9.3.6.2.2.

APPENDIX 10A

<u>QUESTION 10A.8</u> (NRC Question 430.44) (10.2)

Paragraph 10.2.1.3 references the CESSAR turbine generator interface requirements of subsections 5.1.4 and 7.2.3 The CESSAR FSAR sections 5.1.4 and 7.2.3 do not contain any turbine generator interface requirements. Clarify this inconsistency, provide the CESSAR interface requirements and an evaluation of how you are meeting those requirements.

RESPONSE: The response is given in amended paragraph 10.2.1.3.

<u>QUESTION 10A.9</u> (NRC Question 430.45) (10.3)

As explained in issue No. 1 of NUREG-0138, credit is taken for all valves downstream of the main steam isolation valve (MSIV) to limit blowdown of a second steam generator in the event of a steam line break upstream of the MSIV. In order to confirm satisfactory performance following such a steam line break provide a tabulation and descriptive text (as appropriate) in the FSAR of all flow paths that branch off the main steam lines between the MSIVs and the turbine stop valves. For each flow path originating at the main steam lines, provide the following information:

a) System identification

b) Maximum steam flow in pounds per hour

c) Type of shutoff valve(s)

d) Size of valve(s)

e) Quality of the valve(s)

f) Design code of the valve(s)

g) Closure time of the valve(s)

h) Actuation mechanism of the valve(s) (i.e., solenoid-operated, motor-operated, air-operated diaphragm valve, etc.)

i) Motive or power source for the valve actuating mechanism

In the event of the postulated accident, termination of steam flow from all systems identified above, except those that can be used for mitigation of the accident, is required to bring the reactor to a safe cold shutdown. For these systems describe what design features have been incorporated to assure closure of the steam shutoff valve(s). Describe what operator actions (if any) are required.

If the systems that can be used for mitigation of the accident are not available or decision is made to use other means to shut down the reactor describe how these systems are secured to assure positive steam shutoff. Describe what operator actions (if any) are required.

If any of the requested information is presently included in the FSAR text, provide only the references where the information may be found.

RESPONSE: NUREG-0138 page 1-9 states that the probability of occurrence of the above scenario is quite low. Page 1-10 states that the scenario is not analyzed by the staff and need not be considered as a design basis accident. This

scenario should, therefore, not be a design basis accident for Palo Verde Units 1, 2, and 3.

Refer to the following P&IDs:

- 13-M-SGP-001
- 13-M-SGP-002
- 13-M-FTP-001
- 13-M-CDP-001
- 13-M-MTP-001
- 13-M-MTP-002
- 13-M-ASP-001
- 13-M-GSP-001

Further response is given in paragraph 10.3.2.2.2.

QUESTION 10A.10 (NRC Question 430.46) (10.4.1)

Provide a tabulation in your FSAR showing the physical characteristics and performance requirements of the main condensers. In your tabulation include such items as: 1) the number of condenser tubes, material and total heat transfer surface, 2) overall dimensions of the condenser, 3) number of passes, 4) hot well capacity, 5) special design features, 6) minimum heat transfer, 7) normal and maximum steam flows, 8) normal and maximum cooling water temperature, 9) normal and maximum exhaust steam temperature with no turbine bypass flow and with maximum turbine bypass flow, 10) limiting oxygen

content in the condensate in cc per liter, and 11) other pertinent data. (SRP 10.4.1, Part III, Item 1).

RESPONSE: The response is given in amended paragraph 10.4.2.2 (table 10.4-1).

QUESTION 10A.11 (NRC Question 430.47) (10.4.1)

Discuss the measures taken; 1) to prevent loss of vacuum, and 2) to prevent corrosion/erosion of condenser tubes and components. (SRP 10.4.1, Part III, Item 1).

RESPONSE: The response is given in paragraph 10.4.1.2.

QUESTION 10A.12 (NRC Question 430.48) (10.4.1)

Indicate and describe the means of detecting and controlling radioactive leakage into and out of the condenser and the means for processing excessive amounts.
(SRP 10.4.1, Part III, Item 2).

RESPONSE: The response is given in paragraphs 10.4.5.2, 11.3.3.4, and 11.5.2.1.3.2, and subsection 10.4.6.

QUESTION 10A.13 (NRC Question 430.49) (10.4.1)

Discuss the measures taken for detecting, controlling and correcting condenser cooling water leakage into the condensate stream. (SRP 10.4.1, Part III, Item 2)

RESPONSE: The response is given in amended paragraph 10.4.6.2.3.

APPENDIX 10A

<u>QUESTION 10A.14</u> (NRC Question 430.50) (10.4.1)

In paragraph 10.4.1.4 you have discussed tests and initial field inspection but not the frequency and extent of inservice inspection of the main condenser. Provide this information in the FSAR (SRP 10.4.1, Part II).

RESPONSE: The response is given in amended paragraph 10.4.1.4.

<u>QUESTION 10A.15</u> (NRC Question 430.51) (10.4.1)

Indicate what design provisions have been made to preclude failures of condenser tubes or components from turbine bypass blowdown or other high temperature drains into the condenser shell (SRP 10.4.1, Part III, Item 3).

RESPONSE: The condenser and its tubes are protected from turbine bypass blowdown steam flow by a manifold having two stages of pressure reduction orifices that direct the steam flow away from the condenser tubes.

Further response is given in paragraph 10.4.1.2.

<u>QUESTION 10A.16</u> (NRC Question 430.52 (10.4.1)

Discuss the effect of loss of main condenser vacuum on the operation of the main steam isolation valves (SRP 10.4.1, Part III, item 3).

RESPONSE: As discussed in subsection 10.4.1, the main condenser has no safety function. However, the main steam

isolation valves will shut indirectly because of loss of main condenser vacuum as explained in paragraph 15.2.2.1.

QUESTION 10A.17 (NRC Question 430.53) (10.4.4)

Provide additional description (with the aid of drawings) of the turbine bypass valves and associated instrumentation and controls. In your discussion include the number, size, principle of operation, construction, setpoints, and capacity of each valve and the malfunctions and/or modes of failure considered in the design of the turbine bypass system. (SRP 10.4.4, Part III, Item 1.)

RESPONSE: The response is given in subsection 10.4.4 and section 7.7, figure 10.4-1, CESSAR Sections 10.4.4 and 7.7.1.1.5, and CESSAR Figure 7.7-6.

QUESTION 10A.18 (NRC Question 430.54) (10.4.4)

Provide the results of an analysis indicating that failure of the turbine bypass system high energy line will not have an adverse effect or preclude operation of the turbine speed control system or any safety-related components or systems located close to the turbine bypass system. (SRP 10.4.4, Part III, Item 4).

RESPONSE: See response to Question 10A.5 (NRC Question 430.41.)

QUESTION 10A.19 (NRC Question 430.55) (10.4.4)

In paragraph 10.4.4.4 you have discussed tests and initial field inspection but not the frequency and extent of inservice

testing and inspection of the turbine bypass system. Provide this information in the FSAR. (SRP 10.4.4, Part II).

RESPONSE: The response is given in amended paragraph 10.4.4.3, listing B.

QUESTION 10A.20 (NRC Question 430.56) (10.4.4)

Subsection 10.4.4 of your FSAR refers to Section 10.4.4 of CESSAR for additional discussion of the turbine bypass system. Your turbine bypass system differs from the one discussed in CESSAR, in that two of your bypass valves dump to atmosphere while in CESSAR they do not. Provide a discussion to show that your system meets the 11 design bases stated in Section 10.4.4.1 of CESSAR.

RESPONSE: The response is given in amended subsection 10.4.4.

QUESTION 10A.21 (NRC Question 282.2) (10.3.5)

Provide the steam generator secondary water chemistry control and monitoring program, addressing the following:

1. Sampling schedule for the critical parameters and of control points for these parameters for each mode of operation: normal operation, hot startup, cold startup, hot shutdown, cold wet layup;

2. Procedures used to measure the values of the critical parameters;

3. Process sampling points;

4. Procedure for the recording and management of data;

5. Procedures defining corrective actions[a] for off-control point chemistry conditions; and

6. The procedure identifying (a) the authority responsible for the interpretation of the data and (b) the sequence and timing of administrative events required to initiate corrective action.

Verify that the steam generator secondary water chemistry control program incorporates technical recommendations of the NSSS. Any significant deviations from NSSS recommendations should be noted and justified technically.

In addition to the secondary water chemistry monitoring and control program, we require monitoring of the steam condensate at the effluent of the condensate pump. The monitoring of the condensate is for the purpose of detecting condenser leakage.

RESPONSE: (Item numbers correspond to those of the question.)

1. The response is given in paragraph 10.3.5.1.

2. Procedures for measuring the values of critical parameters will reflect C-E technical recommendations or exceptions will be technically justified in subsection 10.3.5.

   The following industry procedures reflect the most recent C-E technical recommendations for measuring the respective parameters.

---

a. Branch Technical Position MTEB 5-3 describes the acceptable means for monitoring secondary side water chemistry in PWR steam generators, including corrective actions for off- control point chemistry conditions. However, the staff is amenable to alternatives, particularly to Branch Technical Position B.3.b(9) of MTEB 5-3 (96-hour time limit to repair or plug confirmed condenser tube leaks).

Parameter	Procedure
pH	ASTM, Part 31, Procedure D1293, Method B
Conductivity	ASTM, Part 31, Procedure D1125, Method B
Suspended Solids	Standard Methods, Procedure 208D or ASTM, Part 31, Procedure D1888
Silica	ASTM, Part 31, D859, Method B

3. Process sampling points are listed in paragraph 10.4.6.2.3.

4. The response is given in paragraph 10.3.5.1.

5. The response is given in paragraph 10.3.5.1.

6. The response is given in paragraph 10.3.5.1.

   The steam generator secondary water chemistry control program is described in paragraph 10.3.5.1, which reflects C-E's technical recommendations. Technical recommendations are met by the existing design. There are no significant deviations from NSSS steam generator chemistry recommendations.

   Paragraph 10.4.6.2.3 describes the method of continuously monitoring for indication of condenser leaks, which is to continuously monitor each section of the condenser hotwell, instead of monitoring condenser pump discharge.

QUESTION 10A.22 (NRC Question 410.25) (10.3)

In order to prevent blowdown of more than one steam generator, verify that the main steam isolation valves are designed to stop full main steam flow at the maximum design differential pressure in both directions in the event of a main steam line break in one steam line upstream of an MSIV and corresponding single failure (to close) in an MSIV to the other steam generator.

RESPONSE: The response is given in subsection 10.3.2.2.2.

QUESTION 10A.23 (NRC Question 410.26) (10.4.5)

The evaluation of potential flooding of essential plant areas as a result of a circulating water system failure indicates that the water level would eventually reach plant grade at which point the water leaves the turbine building. Verify that this water cannot enter safety-related structures through openings at grade or describe the protection provided for safety-related equipment from such an occurrence.

RESPONSE: The response is given in paragraph 10.4.5.2.

QUESTION 10A.24 (NRC Question 410.27) (10.4.7)

It is our position that you commit to perform a steam generator/feedwater water hammer test in accordance with the guidance for preheat type steam generators as identified in NUREG/CR-1606, "An Evaluation of Condensation-Induced Water Hammer in Preheat Steam Generators." The following procedure should be followed:

"Run the plant at approximately 15% of full power by using feedwater through the downcomer nozzle at the lowest feedwater temperature that the plant Standard Operating Procedure (SOP) allows. Switch the feedwater at that temperature from the downcomer nozzle to the economizer nozzle by following the SOP. Observe and record the transient that follows."

RESPONSE: The response is given in paragraph 10.4.7.4.

APPENDIX 10B

(DELETED)

CHAPTER 11

RADIOACTIVE WASTE MANAGEMENT

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11. RADIOACTIVE WASTE MANAGEMENT

11.1 SOURCE TERMS

11.1.1 FISSION PRODUCTS

11.1.1.1 Maximum (Design Basis) Fission Product Activities in Reactor Coolant

Maximum fission product activities are used as design basis source terms for shielding and facilities design and for calculating the consequences of postulated accidents. The isotopes chosen for consideration in the maximum case are those which are significant for design purposes by reason of a combination of energy, half-life or abundance.

The mathematical model used to determine the concentration of nuclides in the Reactor Coolant System involves a group of linear, first order differential equations. These equations are obtained by applying a mass balance for production and removal for the fuel pellet region as well as the coolant region. In the fuel pellet region, the mass balance includes fission product production by direct fission yield, by parent fission product decay and by neutron activation; while the removal includes decay, neutron activation and escape to the coolant. In the coolant region the analysis includes the fission product production by escape from the fuel through defective fuel rod cladding, parent decay in the coolant and neutron activation of coolant fission products. Removal is by decay, by coolant purification, by feed and bleed operations (for fuel burnup), by leakage and other feed and bleed operations such as startups and shutdowns as well as load follow operation.

The expression derived to determine the fission product inventory in the fuel pellet region is;

$$\frac{dN_{p,i}}{dt} = (F)(Y_i)(P) + (f_{i-1}\lambda_{i-1})N_{p,i-1} + \sigma\varphi N_{p,j} - (\lambda_i + v_i + \sigma_i\varphi)N_{p,i} \qquad (1)$$

The expression derived to determine the fission product inventory in the reactor coolant region is;

$$\frac{dN_{c,i}}{dt} = (D)(v_i)\left(N_{p,i}\right) + (f_{i-1}\lambda_{i-1})N_{c,i-1} + \left(\sigma_j\varphi CVR\right)N_{c,j}$$

$$-\left(\lambda_i + \frac{\dot{Q}}{W}\eta_i + \frac{(1-\eta_i)\dot{C}}{C_o-\dot{C}t} + \frac{L}{W}\right)N_{c,i} \qquad (2)$$

where the variables are identified as –

N = Population, atoms
F = Average fission rate, fissions/Mwt – sec
Y = U-235 fission yield of nuclide, fraction (Reference 1)
P = Core power, Mwt
λ = Decay constant, sec^{-1} (Reference 2)
σ = Microscopic capture cross section cm^2 (Reference 3)
φ = Thermal neutron flux, neutron/cm^2 –sec
v = Escape rate coefficient, sec^{-1}
f = Branching fraction
t = Time, seconds
D = Defective fuel cladding, fraction
CVR = Core coolant volume to reactor coolant volume ratio, fraction
$\dot{Q}$ = CVCS purification flow rate during power operation, lbm/sec
W = Reactor Coolant System mass during power operation, lbm
η = Resin efficiency of CVCS ion exchanger and gas stripper efficiency (subscripted for a particular nuclide)
C_o = Beginning of core life boron concentration, ppm
C = Boron concentration reduction rate because of feed and bleed, ppm/sec
L = Leakage or other feed and bleed from the reactor coolant, lbm/sec

and where the subscripts are identified as –

i = i^{th} nuclide
i-l = precursor to i^{th} nuclide for decay
j = precursor to i^{th} nuclide for neutron activation
p = pellet region
c = coolant region

It should be noted that this model does not involve the fuel plenum and gap region. Instead, escape rate coefficients are used to represent the overall release from the fuel pellets to the coolant. The escape rate coefficients are consistent with escape rate coefficients provided in the 1976 version of NUREG-0017 (Reference 4).

Shown in Table 11.1-1A are the values of parameters used to calculate the reactor coolant fission product activities.

The maximum activities are presented in Table 11.1-1B and are defined in Table 11.1-1A.

11.1.1.2 Normal Operating Source Terms Including Anticipated Operational Occurrences

The data in Table 11.1-1C represent the expected normal fission product activities for the plant with no gas stripping. The activities for this case are based on ANSI Standard N237 (Reference 6) and are intended for use in evaluating only normal operations including anticipated operational occurrences.

Table 11.1-1A
(Sheet 1 of 2)
BASIS FOR REACTOR COOLANT FISSION PRODUCT ACTIVITIES

PARAMETER	MAXIMUM	NORMAL(1)
Core Power Level (Mwt)	4200	4000
Duration of Reactor Operation (core cycles)	5	-
Equilibrium Fuel Cycle (Equivalent Full Power Days)	550	-
Average Thermal Fission Rate (Fission/MW-second)	3.10E+16	-
Thermal Neutron Flux – average (n/cm^2-second)	4.61E+13	-
Fraction of Failed Fuel	0.01	-
Primary Coolant Mass including pressurizer and CVCS (Pounds)	645,421	645,421
Core Coolant Volume to Reactor Coolant Volume Ratio	0.0655	-
Purification Flow (gallons/minute)	72	72
Purification Flow, yearly average for – boron control (gpm)	-	0.725
Boron Concentration Reduction Rate (ppm/second)	2.31E-05	-
Beginnings of Life Boron Concentration (ppm)	2,100	-
Ion Exchanger and Gas Stripper Removal Efficiency		
CVCS Purification Ion Exchanger		
Noble gas, tritium	0	0
Cs, Rb	0.5	0.5
All other	0.9	0.9
CVCS Lithium Removal Ion Exchanger(2)		
Noble gas, tritium	0	0
All others	0.9	0.9
CVCS Gas Stripper Removal Efficiency		
Noble gas	0.999	-
All others	0	-
CVCS Gas Stripper Operation	None	None

Table 11.1-1A
(Sheet 2 of 2)
BASIS FOR REACTOR COOLANT FISSION PRODUCT ACTIVITIES

PARAMETER	MAXIMUM	NORMAL(1)
Fission Product Escape Rate Coefficients(3) (sec^{-1})		
Noble Gasses	6.5E-08	-
I, Br, Rb, Cs	1.3E-08	-
Mo	2.0E-09	-
Te	1.0E-09	-
Sr, Ba	1.0E-11	-
All others	1.6E-12	-

Notes:

(1) Average conditions including anticipated operational occurrences.

(2) Nuclides are also removed from the letdown flow via the CVCS Lithium Removal Ion Exchanger. This ion exchanger is used in series with the CVCS Purification Ion Exchanger during approximately 20 percent of the core cycle.

(3) Values listed are those utilized in determining maximum reactor coolant concentrations (designated as variable v_i in Section 11.1.1.1). Reactor coolant radionuclide concentrations for normal (expected) cases are calculated in accordance with NUREG-0017 and Standard ANS/ANSI-N237.

SOURCE TERMS

Table 11.1-1B
MAXIMUM ACTIVITIES IN THE REACTOR COOLANT DUE TO CONTINUOUS OPERATION AT MAXIMUM POWER WITH ONE PERCENT FAILED FUEL

Nuclide	Specific Activity @70°F, µci/cc*	Nuclide	Specific Activity @70°F, µci/cc*
Noble Gasses		Other Nuclides	
Kr-85m	1.3E+00	Sr-89	4.0E-03
Kr-85	6.1E+00	Sr-90	1.9E-04
Kr-87	1.0E+00	Sr-91	6.0E-03
Kr-88	2.8E+00	Y-90	5.4E-05
Xe-131m	5.9E+00	Y-91	5.8E-04
Xe-133	3.6E+02	Zr-95	6.3E-04
Xe-135	7.7E+00	Mo-99	3.5E-01
Xe-138	6.3E-01	Ru-103	2.2E-04
		Ru-106	8.9E-05
Halogens		Te-129	7.9E-03
		Te-132	2.4E-01
Br-84	2.4E-02	Te-134	2.8E-02
I-129	3.7E-08	Ba-140	4.9E-03
I-131	3.0E+00	La-140	1.7E-03
I-132	8.3E-01	Ce-144	5.2E-04
I-133	4.4E+00	Pr-143	6.6E-04
I-134	5.2E-01		
I-135	2.5E+00		
		Reactor Coolant Activated Corrosion Products	
Cs, Rb			
Rb-88	2.9E+00	Cr-51	3.1E-03
Rb-89	1.5E-01	Mn-54	1.6E-03
Cs-134	2.9E-01	Fe-55	1.2E-03
Cs-136	5.8E-02	Fe-59	3.0E-04
Cs-137	4.4E-01	Co-58	4.6E-03
Cs-138	9.0E-01	Co-60	5.3E-04

Table 11.1-1C
REACTOR COOLANT SYSTEM ACTIVITIES DURING NORMAL OPERATIONS INCLUDING ANTICIPATED OPERATIONAL OCCURRENCES

Nuclide	Specific Activity @70°F, µci/cc*
Noble Gasses	
Kr-83m	2.12E-02
Kr-85m	1.11E-01
Kr-85	2.42E-01
Kr-87	6.05E-02
Kr-88	2.02E-01
Kr-89	5.04E-03
Xe-131m	1.23E-01
Xe-133m	2.27E-01
Xe-133	1.91E+01
Xe-135m	1.31E-02
Xe-135	3.54E-01
Xe-137	9.06E-03
Xe-138	4.43E-02
Halogens	
Br-83	4.98E-03
Br-84	2.64E-03
Br-85	3.02E-04
I-130	2.32E-03
I-131	3.24E-01
I-132	1.04E-01
I-133	4.29E-01
I-134	4.79E-02
I-135	2.04E-01
Cs, Rb	
Rb-86	6.07E-05
Rb-88	2.00E-01
Cs-134	1.76E-02
Cs-136	9.33E-03
Cs-137	1.27E-02

Nuclide	Specific Activity @70°F, µci/cc*
Other Nuclides	
Sr-89	3.85E-04
Sr-90	1.10E-05
Sr-91	6.81E-04
Y-90	1.30E-06
Y-91	7.05E-05
Y-91m	3.65E-04
Y-93	3.57E-05
Zr-95	6.61E-05
Nb-95	5.50E-05
Mo-99	9.13E-02
Tc-99m	4.98E-02
Ru-103	4.95E-05
Ru-106	1.10E-05
Rh-103m	4.56E-05
Rh-106	1.01E-05
Te-125m	3.19E-05
Te-127m	3.08E-04
Te-127	8.90E-04
Te-129m	1.54E-03
Te-129	1.62E-03
Te-131m	2.68E-03
Te-131	1.11E-03
Te-132	2.94E-02
Ba-137m	1.61E-02
Ba-140	2.42E-04
La-140	1.62E-04
Ce-141	7.70E-05
Ce-143	4.30E-05
Ce-144	3.64E-05
Pr-143	5.49E-05
Pr-144	3.33E-05
Np-239	1.30E-03
Reactor Coolant Activated Corrosion Products	
Cr-51	2.09E-03
Mn-54	3.42E-04
Fe-55	1.76E-03
Fe-59	1.10E-03
Co-58	1.76E-02
Co-60	2.20E-03

11.1.2 DEPOSITED CRUD ACTIVITIES

The activity of radioactive crud and its thickness on primary system surfaces have been evaluated using measured data from various operating pressurized water reactors.

Even though these reactors have different water chemistries and different materials in contact with the primary coolant, their crud activity (dpm/mg-crud), crud film thicknesses and dose rates due to this crud are remarkably similar. The half-lives, reactions and gamma decay energies for each of the long-lived isotopes in the radioactive crud are as shown in Table 11.1-1D. The long-lived isotopes are those significant isotopes remaining after 48 hours decay.

The radioactive crud originates on in-core and out-of-core surfaces. The crud plates out on the in-core surfaces and re-erodes after a short irradiation period. This irradiation period or core residence time for each isotope is determined by the following equations. (See Appendix 11B for the derivation of the core residence time equations):

Circulating Crud:

$$T_{res} = -\frac{1}{\lambda} ln\left(1 - \frac{A_i A_T 16.67}{\sum_i \varphi A_c}\right), sec \qquad (1)$$

Deposited Crud:

$$T_{res} = -\frac{1}{\lambda} ln\left(1 - \frac{A_j 16.67}{\sum_i \varphi}\right), sec, \qquad (2)$$

Where: A_i, A_j are the crud activities for each isotope (dpm/mg-crud),

A_T is the total primary system area (cm^2),

$\sum_i \varphi$ is the activation rae (d/g-sec), and

A_c is the core surface area (cm^2)

The activation cross-section $\sum_i$ is as follows:

$$\Sigma_i = \frac{(a/o)_i (w/o)_i N_o \sigma_i}{[A]_i}, cm^2/g \qquad (3)$$

Where: $(a/o)_i$ is the isotopic abundance,

$(w/o)_i$ is the elemental abundance in the crud or the element abundance in the base metal,

N_o is Avagadro number (0.6023×10^{24} a/g-mole),

$[A]_i$ is the atomic weight of isotope (i), and

σ_i is the microscopic cross-section (barns).

Circulating crud is taken to be all crud in the reactor coolant. Deposited crud is taken to be all crud which plates out on in-core surfaces.

The measured average and maximum crud activities (dpm/mg-crud) as taken from References 5 and 7 through 19 for those reactors considered in the determination of the core residence times are as shown in Table 11.1-1E. The average and maximum core residence times as determined by the above expressions, the activation rates in Table 11.1-1F and the system parameters in Table 11.1-1G are as shown in Table 11.1-1H. As all the Fe-59 residence times are long, its activity (A_i) is assumed saturated. The averages (T_{res}) of the maximum residence times are also given in Table 11.1-1H.

The calculated crud activities (A_i) are determined utilizing the averages (T_{res}) of the maximum core residence times, the system parameters in Table 11.1-1I and the following equation:

$$A_i = \Sigma_i \varphi \left(1 - e^{-\lambda_i T_{res}}\right) \frac{A_c}{A_T} (0.06), dpm/mg - crud \qquad (4)$$

As the averages (T_{res}) of the maximum residence times are used and in general these (T_{res}) are a factor of 2 to 4 higher than a straight average residence time, the resulting calculated crud activities will be conservative. These calculated crud activities of the long-lived isotopes are as shown in Table 11.1-1J. These calculated crud activities are applied to both the circulating crud and out of core deposited curd. Using the average crud level in the reactor coolant (75ppb) of those operating reactors shown in Table 11.1-1E and the calculated crud activities (dpm/mg-crud) as shown in Table 11.1-1J, the average isotopic activities in the primary coolant are determined by the following expression:

$$A = \frac{A_i}{60} (75x10^{-9}) \rho (2.7x10^{-5}) 1x10^3, \mu ci/cm^3 \qquad (5)$$

where ρ is density of water (g/cc) and 1000 is mg/g.

The average calculated activities in the primary coolant using the above expression are shown in Table 11.1-1K. The maximum coolant activities can be higher due to "crud bursts" during shutdowns or changes in power. However, these "bursts" occur over short periods of time, and therefore, the average values are more reasonable to use for long term operation.

The equilibrium thickness of radioactive crud film (mg-crud/cm^2) has been determined by two methods:

1. The direct measurement of the film during maintenance and/or tests in operating reactors.
2. Calculating crud film thickness from measured dose rates and specific activities (dpm/mg-crud) of deposited crud.

The quilibrium crud film thicknesses for various Reactor Coolant System areas are as shown in Table 11.1-1L.

The calculated crud activities in this section are reasonable values and together with measured plateout thicknesses match measured shutdown dose rates around various equipment associated with operating reactors. However, both the crud levels and plateout thicknesses do have rather wide variations as shown in Table 11.1-1E for operating reactors and many combinations of activities and plateout thicknesses could reproduce the measured shutdown dose rates. It is for this reason that the crud activities are periodically reviewed as more measured crud activities, plateout thicknesses and dose rates become available.

The conservative evaluation of the above operating data yields circulating crud concentrations (Table 11.1-1K) which are generally consistent with those from NUREG-0017 and ANSI N237. ANSI standard N237 is used for evaluating normal operations including anticipated operational occurrences. Values from NUREG-0017 for circulating crud are used as design source terms. Average reactor coolant crud activities calculated in this section are for a 3817 MWt plant.

Reactor coolant radioactive crud specific activities provided in NUREG-0017 and ANSI 237 are based on operating information obtained from reference plants. The majority of the information is late 1970s vintage. Since the late 1970s, reactor coolant water chemistry control methodologies (e.g., pH control) and use/replacement of materials (exposed to reactor coolant) with materials less likely to generate

radioactive crud have substantially reduced the presence of radiologically significant crud in reactor coolant e.g., Co-60. This is supported by conference presentations. Reduction of radioactive crud concentrations in reactor coolant since the late 1970s and early 1980s provides support for using activated crud values from NUREG-0017 and ANSI 237.

The information provided in this section is considered to be historical. Design and expected source terms for Palo Verde are presented in Tables 11.1-1B and 11.1-1C.

Table 11.1-1D

LONG-LIVED ISOTOPES IN CRUD

Isotope	$T_{1/2}$	λ_i, d^{-1}	Parent	Reaction	γ/dis	E(mev)
^{60}Co	5.26Y	3.6(-4)	^{59}CO	n,γ	2.00	1.25
^{58}Co	71.4d	9.73(-3)	^{58}Ni	n,p	1.00	0.81
^{54}Mn	313d	2.21(-3)	^{54}Fe	n,p	1.00	0.84
^{51}Cr	27.8d	2.49(-2)	^{50}Cr	n,γ	0.10	0.32
^{59}Fe	45d	1.54(-2)	^{58}Fe	n,γ	1.00	1.18
^{95}Zr	65.5d	1.06(-2)	^{94}Zr	n,γ	2.00	0.75

Table 11.1-1E
MEASURED RADIOACTIVE CRUD ACTIVITY (dpm/mg-crud)

Reactor		^{60}Co	^{58}Co	^{54}Mn	^{51}Cr	^{59}Fe	^{181}Hf	^{95}Zr	^{64}Cu	Crud ppb	Ref
Conn-Yankee,[a]											
	Ave.	9.1(+6)[c]	9.9(+7)	2.3(+6)	1.3(+7)	2.8(+6)	----	----	----	85	7
	Max.	2.5(+7)	4.0(+8)	1.2(+7)	3.6(+7)	1.5(+7)	----	----	----	4000	
San Onofre,[a]											
	Ave.	2.0(+6)	2.2(+7)	1.4(+6)	3.1(+6)	6.7(+5)	----	----	----	90	8
	Max.	2.0(+7)	1.2(+8)	4.2(+6)	2.0(+7)	3.8(+6)	----	----	----	400	
Yankee Rowe,[a]											
	Ave.	6.7(+6)	3.3(+7)	4.5(+6)	1.7(+7)	5.5(+6)	----	6.6(+5)	----	70	9, 13
	Max.	2.1(+7)	1.2(+8)	1.9(+7)	1.4(+8)	1.8(+7)	----	1.8(+6)	----	--	
Saxton,[b]											
	Ave.	4.3(+6)	2.7(+7)	3.9(+6)	9.0(+7)	1.2(+6)	----	----	----	55	10, 11
	Max.	2.2(+7)	1.5(+8)	1.4(+7)	1.1(+8)	6.0(+6)	----	----	----	250	12, 13
Shippingport,[a]											
	Ave.	2.3(+7)	2.8(+6)	1.3(+6)	2.2(+6)	1.8(+6)	5.2(+6)	7.0(+5)	----	75	14, 15
	Max.	4.8(+7)	3.2(+6)	1.7(+6)	2.2(+6)	1.8(+6)	7.6(+5)	9.7(+5)	----	--	
Indian Point 1,[a]											
	Ave.	1.8(+6)	4.6(+6)	7.7(+5)	5.7(+6)	2.2(+6)	1.5(+5)	- 2.3(+5)	3.1(+9)	77	16
	Max.	2.9(+6)	9.1(+6)	2.0(+6)	8.2(+6)	3.3(+6)	----	4.2(+5)	1.2(+10)	--	
Maine-Yankee,[a]											
	Ave.	-	-	-	-	-	-	1.29(+6)	-		
	Max.	2.22(+6)	4.53(+7)	9.70(+5)	4.24(+7)	2.03(+6)	-	7.29(+6)	-	41	17
Oconee,[a]											
	Ave.	2.8(+6)	5.1(+7)	5.5(+5)	2.9(+7)	2.4(+5)	-	5.6(+6)	-	25	18
	Max.	2.3(+7)	1.9(+8)	1.1(+7)	1.5(+8)	1.7(+6)	-	8.7(+6)	-	100	19,5
Average Crud	(ppb)									68 75[d]	

(a) Circulating crud.

(b) Deposited crud on fuel rods with exception of Cr-51 (ave, max) and Fe-59 (ave.) which are circulating.

(c) Denotes power of (10).

(d) Does not include Oconee data.

Table 11.1-1F
SYSTEM PARAMETERS

Reactor	Activation Rates, $\sum_i \varphi$						
	^{60}Co	^{58}Co	^{54}Mn	^{51}Cr	^{59}Fe	^{95}Zr	A_T/A_C
Conn. Yankee[b]	1.90(+10)[a]	7.00(+10)	1.40(+9)	2.90(+10)	1.90(+8)	-	4.10
San Onofre[b]	1.90(+10)	7.00(+10)	1.40(+9)	2.90(+10)	1.90(+8)	-	4.10
Yankee Rowe	1.70(+10)	1.50(+10)	4.34(+9)	1.90(+10)	3.50(+8)	7.50(+8)	3.13
Saxton	8.00(+9)	1.00(+10)	2.95(+9)	1.30(+10)	2.40(+8)	-	5.26
Shippingport	2.30(+10)	9.90(+9)	2.90(+9)	2.90(+10)	5.20(+8)	6.80(+8)	2.44
Indian Point 1	6.6(+9)	1.3(+10)	3.7(+9)	1.1(+10)	2.0(+9)	1.4(+8)	4.53
Maine-Yankee	6.5(+9)	6.1(+10)	5.2(+8)	1.9(+10)	6.3(+7)	3.8(+8)	5.44
Oconee	1.3(+10)	1.00(+11)	3.1(+9)	9.8(+10)	9.5(+8)	3.1(+9)	4.00

(a) Denotes power of ten (10).

(b) Conn. Yankee and San Onofre fluxes and area ratios assumed the same.

Table 11.1-1G
SYSTEM PARAMETERS

Reactor	Stn Gen Tubing	Core Cladding	Thermal Flux n/cm^2-sec)	Fast Flux (n/cm^2-sec)	A_T/A_C
Conn. Yankee[b]	Inconel	S. Steel	4.0(+13)[a]	1.8(+14)	4.10
San Onofre[b]	Inconel	S. Steel	4.4(+13)	1.8(+14)	4.10
Yankee Rowe	S. Steel	Zircaloy	3.9(+13)	2.6(+14)	3.13
Saxton	S. Steel	S. Steel	1.8(+13)	1.2(+14)	5.26
Shippingport	S. Steel	Zircaloy	5.1(+13)	1.5(+14)	2.44
Indian Point 1	S. Steel	S. Steel[c]	1.5(+13)	1.5(+14)	4.53
Maine-Yankee	Inconel	Zircaloy	3.6(+13)	1.6(+14)	5.44
Oconee	Inconel	Zircaloy	3.6(+13)	1.5(+14)	4.00

(a) Denotes power of ten (10).

(b) San Onofre fluxes and area ratio assumed same as Conn. Yankee.

(c) Zircaloy box around each fuel assembly.

Table 11.1-1H
AVERAGE AND MINIMUM RESIDENCE TIMES, DAYS

Reactor		^{60}Co	^{58}Co	^{54}Mn	^{51}Cr	^{59}Fe	^{95}Zr
Conn. Yankee,	Ave.	92	10	54	1	Sat.	--
	Max.	262	51	390	4	Sat.	--
San Onofre,	Ave.	20	2	32	1	18	--
	Max.	207	13	104	2	Sat.	--
Yankee Rowe,	Ave.	58	13	25	2	111	6
	Max.	185	56	116	19	Sat.	17
Saxton,	Ave.	25	5	10	38	38	--
	Max.	136	30	38	54	Sat.	--
Shippingport,	Ave.	115	1	8	1	10	2
	Max.	246	1	11	1	10	3
Indian Point 1	Ave.	58	3	7	2	115	13
	Max.	94	6	19	2	Sat.	24
Maine-Yankee,	Ave.	-	-	-	-	-	34[b]
	Max.	87	7	84	9	Sat.	-
Oconee,	Ave.	41	3	5	1	1	12
	Max.	356	13	118	4	8	66
Ave. of Max.	(T_{res})	166	22	110	12	Sat.	29
		140[c]	23	110	13	Sat.	20

(a) ^{59}Fe isotope reaches saturation before erosion from core surfaces.

(b) Included in Zr-95 ave. Max. (T_{res}).

(c) Lower values do not include Oconee data.

Table 11.1-1I
ASSUMED SYSTEM PARAMETERS, SYSTEM 80

Parameter	Value
Thermal Flux (n/cm^2-sec)	5.50(+13)[a]
Fast Flux (n/cm^2-sec)	3.00(+14)
A_T/A_c	4.28

(a) Denotes power of ten (10).

ASSUMED ACTIVATION RATES 3817 Mwt Plant

Isotope	Activation Rate[b], $\sum_i \varphi$(d/g-sec)
^{60}Co	9.30(+9)[a]
^{58}Co	1.10(+11)
^{54}Mn	1.00(+9)
^{51}Cr	2.80(+10)
^{59}Fe	9.90(+7)
^{95}Zr	7.50(+8)

(a) Denotes power of ten (10).

(b) Activation rates are for a 3817 MWt plant. Palo Verde’s licensed power level exceeds 3817 MWt. The activation rates are included in this table as historical information.

Table 11.1-1J

LONG-LIVED CRUD ACTIVITY FOR A STANDARD 3817 MWT PLANT[b]

Isotope	Tres (days)	Half Life	Act, dpm/mg
^{60}Co	166	5.26 y	7.4(+6)[a]
^{58}Co	22	71.4 d	2.9(+8)
^{54}Mn	110	313 d	3.0(+6)
^{51}Cr	12	27.8 d	1.0(+8)
^{59}Fe	Sat.	45 d	1.4(+6)
^{95}Zr	29	65.5 d	2.7(+6)

a) Denotes power of ten (10).

b) Long-lived crud activities are for a 3817 MWt plant. Palo Verde's licensed power level exceeds 3817 MWt. The long-lived crud activities are included in this table as historical information.

Table 11.1-1K

AVERAGE CALCULATED REACTOR COOLANT CRUD ACTIVITY [a, c]

Isotope	Act, (μCi/cc)
^{60}Co	2.5(-4)[b]
^{58}Co	9.8(-3)
^{54}Mn	1.0(-4)
^{51}Cr	3.7(-3)
^{59}Fe	4.7(-5)
^{95}Zr	9.1(-5)

a) Reactor coolant temperature is 70°F. Crud level 75 ppb.

b) Denotes power of ten (10).

c) Average reactor coolant crud activities are for a 3817 MWt power plant. Palo Verde's licensed power level exceeds 3817 MWt. Average reactor coolant crud activities are included in this table as historical information. Average reactor coolant crud activities for Palo Verde, are presented in Tables 11.1-X2 and 11.1-X3.

Table 11.1-1L
EQUILIBRIUM CRUD FILM THICKNESS

Location	Thickness (mg/cm^2)
Vessel Internals, Piping SG Inlet Plenum	1.00(+0)[a]
Pressurizer	
Lower Head	6.5(-1)
Surge Line	1.20(+0)
CRDM, Vessel Head ICI Tops	3.00(-1)
SG Tubing	1.00(-1)
Regenerative HX	3.50(-1)
Letdown HX	3.00(-2)
Shutdown Cooling HX	3.00(-2)

(a) Denotes power of ten (10).

11.1.3 TRITIUM PRODUCTION IN REACTOR COOLANT

The principal sources of tritium production in a pressurized water reactor (PWR) are from ternary fission and neutron induced reactions in boron, lithium and deuterium that are present in the coolant, borated shim rods and control element assemblies (CEA). The tritium produced in the coolant contributes immediately to the overall tritium activity while the tritium produced by fission and neutron capture in the CEAs and borated shim rods contributes to the overall tritium activity via release through the cladding.

11.1.3.1 Activation Sources of Tritium

The activation reactions producing tritium are as shown in Table 11.1-1M. The tritium production from reactions 5 and 6 (B-11 and N-14 sources) is insignificant due to low cross

section and/or abundance and can be neglected. Reactions 1-4 (from B-10, lithium, and deuterium) are the major sources of tritium in the coolant, CEA's and borated shim rods.

The tritium production from the above sources is determined by the following expressions:

Tritium Formation Rate = Production Rate – Decay

$$\frac{dN}{dt} = \Sigma_a \phi - \lambda N$$

$$N = \frac{\Sigma_a \phi}{\lambda}\left(1 - e^{-\lambda t}\right), atoms/cm^3 \; at \; time \; (t)$$

$$activity \; (curies) = V \lambda N \times 2.7 \times 10^{-11} = \Sigma_a \phi \left(1 - e^{\lambda t}\right) V \times 2.7 \times 10^{-11}$$

Where $\sum_a \phi$ is the production rate (atoms/cc-sec)

t is the reactor operating period of interest

V is the effective core volume, borated shim rod volume or CEA volume (cm^3) and 2.7 x 10^{-11} converts disintegrations/sec to curies.

The parameters used in the calculation are as shown in Table 11.1-1N. Based on these parameters, the tritium produced annually from activation sources in the reactor coolant is included in Table 11.1-1O.

11.1.3.2 Tritium From Fission

The computer code ORIGEN II was run in to obtain the tritium generation as a product of fission only. The ORIGEN II data is based on a 5 w/o fuel enrichment and 105.5 MTU loading. The ORIGEN II value accounts for production from fissions of U-235 and also from Pu-239 as the U-235 is depleted. Tritium activity at reactor operation of 1-yr (365 days) is reported.

The amount of tritium that is released through fuel cladding can be indirectly determined using measured tritium levels from operating PWRs, subtracting the calculated tritium activity produced by neutron capture in the reactor coolant, and attributing the remaining tritium activity to release from the cladding of the fuel rods, borated shim rods and CEAs. Due to the large number of the fuel rods as compared to the number of borated shim rods and CEA’s within the core during operation, any amount of tritium released to the system will be principally from the fuel rods. The total amount of tritium produced per fuel cycle can be determined by summing the total tritium discharged in the gaseous, liquid and solid waste discharges of the plant and the tritium inventories in the Reactor Coolant System and other waste or refueling tanks that can contain tritium at the end of the fuel cycle of interest. This method has been used to analyze C-E operating data and data from other PWR’s. The results of the analysis are shown in Table 11.1-1P. Buildup of plutonium in the fuel with burnup was accounted for in the analysis. A release rate of 2% is used to estimate the annual tritium production in table 11.1-1O.

Table 11.1-1M
TRITIUM ACTIVATION REACTIONS

	Reaction	Threshold Energy (MeV)	Cross Section (mb)
1)	10B(n. 2a)T	1.9	4.2(+1)[a]
2)	7Li(n. na)T	3.9	3.85(+2)
3)	6Li(n. a)T	Thermal	9.5(+2)
4)	D(n. a)T	Thermal	5.5(-1)
5)	11B(n. T)9Be	10.4	Negligible
6)	14N(n. T)12C	4.3	Negligible

(a) () denotes power of ten.

Table 11.1-1N
PARAMETERS USED IN TRITIUM PRODUCTION DETERMINATION

Effective Core Volume cm^3 2.314(+7)[a]

Average Thermal Fission Rate. f/Mw-sec 3.10(+16)

Lithium Concentration. ppm

Average 2.2

Maximum 2.2

Lithium-6 Abundance. %0.1

Boron Concentration. ppm

avg=750, max=1000

Power Level

Average 3990

Maximum 4200

Fuel Release. %

Average 2

Maximum 2

(a) () denotes power of ten.

Table 11.1-1O
TRITIUM PRODUCTION IN REACTOR COOLANT
(Ci/year)

AVERAGE

Reaction	U02
D(n.¥)T	4.42
6Li (n.e)T	146
7Li (n. na)T	14.5
10B(n. 2a)T	288
Fission	353
Total	<1224

MAXIMUM

D(n.¥)T	6.16
6Li((n.a)T	204
7Li(n. na)T	17.7
10B(N. 2a)T	469
Fission	372
Total	<2347

Table 11.1-1P (Sheet 1 of 3)
TRITIUM PRODUCTION AND RELEASE AT OPERATING PWRS

Measured Production[a]	Cycle #	Ci/cycle	Total [b]Calc. Prod. (Ci/cycle) Due to Fissions	Total Calc. Prod. (Ci/cycle) Due to Capture in RCS	Percent Release From Fuel
MAINE YANKEE	1	305.3	11.720	370.0	---
(Li conc. approximately 0)	2	59.8	6.510	155.8	---
OMAHA					
(Li conc. approximately 0)	1	192.6	6.100	153.9	0.6
PALISADES					
(Li conc. approximately 0)	1	440	10.890	343.8	0.9
OBRIGHEIM, KWO					
(Li conc. assumed 2 ppm)	1	662	6,540	257.1	6.2
2		239	5,120	86.0	3.0
3		391	5,680	103.6	5.1
4		314	6,070	110.8	3.3
5		199	5,700	82.4	2.1

Table 11.1-1P (Cont'd.) (Sheet 2 of 3)
TRITIUM PRODUCTION AND RELEASE AT OPERATING PWRS

Measured Production[a]	Cycle #	Ci/cycle	Total [b]Calc. Prod. (Ci/cycle) Due to Fissions	Total Calc. Prod. (Ci/cycle) Due to Capture in RCS	Percent Release From Fuel
STADE, KKS					
(Li conc. assumed 2 ppm)	1	408	10.490	300.3	1.0
2		131	8,050	157.4	---
OCONEE					
(Li conc. 0.05 ppm)	1	325	8,050	335.7	---
GINNA					
(Li conc. assumed 2 ppm)	1[c]	1410[e]	15,570	384.1	6.6
3		449	9,830	216.2	2.4
4		105	5,260	115.7	---
POINT BEACH 1 & 2					
(Li conc. assumed 2 ppm)	1-1[d]	943	11,470	381.9	4.9
	1-2,2-1	1269	19,060	558.2	3.7

Table 11.1-1P (Cont'd.) (Sheet 3 of 3)
TRITIUM PRODUCTION AND RELEASE AT OPERATING PWRS

Measured Production[a]	Cycle #	Ci/cycle	Total [b]Calc. Prod. (Ci/cycle) Due to Fissions	Total Calc. Prod. (Ci/cycle) Due to Capture in RCS	Percent Release From Fuel
H. B. ROBINSON					
(Li conc. assumed 2 ppm)	1	777	12,090	373.1	3.3
2		604	11,980	228.2	2.6
3		247	7,050	204.4	0.6

(a) Production is total measured tritium discharges plus measured system inventories.

(b) Fission curies are based on appropriate cycle average fractional fissions of U-235. U-238 and Pu.

(c) Includes cycles 1-A, 1-B and 2.

(d) (1-1) Unit #1 - Cycle #1.

(e) 1410 Ci accounted for under tritium measurement program (Ref. 11). Only 800 Ci can be accounted for using plant discharges and inventories.

11.1.3.2.1 Tritium Liquid Concentrations

The tritium concentrations in the plant are dependent on the production rate in the reactor coolant system (Note 1); the losses due to radioactive decay, plant discharges, leakage and evaporation; and the transfer of plant water. The concentrations are based upon discharging a sufficient amount of boric acid concentrator distillate (as vapor) as necessary to maintain plant tritium airborne concentrations below 10CFR20.1-20.601 limits. A tritium balance is performed on the entire plant by simultaneously solving the following differential equations for the equilibrium case. Each equation represents the tritium activity in a major water source for tritium transfer. The model used for determining the equations is shown in figure 11.1-1.

<u>RCS</u>

$$\frac{dN}{dt} = P + \lambda_6 R + \lambda_3 M - (\lambda_1 + \lambda_D + \lambda_L + \lambda_2 + \lambda_{10})N \qquad (1)$$

<u>RMWT</u>

$$\frac{dM}{dt} = [(1 - X)\lambda_9 + \lambda_{10}]N - (\lambda_D + \lambda_3 + \lambda_5)M \qquad (2)$$

<u>SFP</u>

$$\frac{dS}{dt} = (\lambda_4 + \lambda_7)\ R - (\lambda_S + \lambda_D + \lambda_8)S \qquad (3)$$

Note (1): Current design estimates for tritium production rates are less than the licensing basis values. As a result, design tritium concentrations and releases reported in this section are less than licensing basis limits.

RWT

$$\frac{dR}{dt} = \lambda_5 M + (\lambda_2 + \lambda_{RT})N + \lambda_8 S - (\lambda_7 + \lambda_D + \lambda_4 + \lambda_6 + \lambda_R)R \qquad (4)$$

where:

RCS = reactor coolant system

RMWT = reactor makeup water tank

SFP = spent fuel pool

RWT = refueling water tank (includes refueling pool)

BAC = boric acid concentrator

N = tritium activity in the reactor coolant system (Ci)

M = tritium activity in the reactor makeup water tank (Ci)

S = tritium activity in the spent fuel pool (Ci)

R = tritium activity in the refueling water tank (or refueling pool) (Ci)

P = tritium production rate in reactor coolant (Ci/yr)

t = time (yr)

λ_L = leakage constant =

$$\frac{\text{Primary-to-secondary leakage (gal/yr)}}{\text{RCS water volume (gal)}}, \ (yr^{-1})$$

λ_D = tritium decay constant $= \dfrac{\ln 2}{\text{half} - \text{life}}, \ (yr^{-1})$

λ_6 = RWT fraction used as RCS makeup after refueling =

$$\frac{\text{Refueling pool water used as RCS makeup (gal/yr)}}{\text{RWT water volume (gal)}},$$

(yr^{-1})

λ_3 = RMWT makeup fraction to RCS =

$$\frac{\text{RMWT makeup to RCS (gal / yr)}}{\text{RMWT water volume (gal)}}, \ (yr^{-1})$$

λ_1 = RCS letdown fraction to boric acid concentrator

$$\text{(BAC)} = \frac{\text{letdown flow (gal / yr)}}{\text{RCS water volume (gal)}}, \ (yr^{-1})$$

λ_2 = RCS water fraction left after draining prior to refueling =

$$\frac{\text{RCS water available for mixing (gal / yr)}}{\text{RCS water mass (gal)}}, \ (yr^{-1})$$

X = fraction of flow sent to CVCS BAC that is discharged

from the plant (unitless)

λ_9 = RCS letdown fraction to BAC distillate =

$$\frac{\text{BAC distillate flow (gal / yr)}}{\text{RCS water volume (gal)}}, \ (yr^{-1})$$

λ_7 = RWT transfer fraction to SFP =

$$\frac{\text{fuel transfer flow (gal / yr)}}{\text{RWT water volume (gal)}}, \ (yr^{-1})$$

λ_S = SFP evaporation fraction =

$$\frac{\text{SFP evaporation rate (gal / yr)}}{\text{SFP water volume (gal)}}, \ (yr^{-1})$$

λ_4 = SFP makeup =

$$\frac{\text{SFP evaporation rate (gal / yr)}}{\text{RWT water volume (gal)}}, \ (yr^{-1})$$

λ_5 = RWT makeup =

$$\frac{\text{RWT net losses}\,(\text{gal / yr})}{\text{RMWT water volume}\,(\text{gal})},\ (\text{yr}^{-1})$$

λ_8 = SFP transfer fraction to refueling pool =

$$\frac{\text{fuel transfer flow}\,(\text{gal / yr})}{\text{SFP water volume}\,(\text{gal})},\ (\text{yr}^{-1})$$

λ_{RT} = RCS letdown fraction to RWT =

$$\frac{\text{BAC bottoms flow}\,(\text{gal / yr})}{\text{RCS water volume}\,(\text{gal})},\ (\text{yr}^{-1})$$

λ_5 = RWT evaporation fraction =

$$\frac{\text{refueling pool evaporation rate}\,(\text{gal / yr})}{\text{RWT water volume}\,(\text{gal})},\ (\text{yr}^{-1})$$

λ_{10} = RCS transfer fraction to RMWT =

$$\frac{\text{RCS processed leakage}\,(\text{gal / yr})}{\text{RCS water volume}\,(\text{gal})},\ (\text{yr}^{-1})$$

The leakage constant (λ_L) includes a primary-to-secondary leak rate of 100 pounds per day. Other leakage (λ_{10}) is assumed to be recycled to the RMWT after collection and processing by the liquid radwaste system.

The evaporation fractions (λ_S and λ_R) include year-round evaporation from the SFP and evaporation from the refueling pool during refueling only (this is the only time the refueling pool contains water).

Normal RMWT (λ_{11}) makeup is from a demineralized water source that uses nontritiated water, and is, therefore, not considered in the analysis.

Makeup to the RCS (λ_3) is from the RMWT. This is equal to the letdown flow to the BAC (λ_1) plus the leakage from the RCS ($\lambda_L + \lambda_{10}$).

The volume from the refueling pool, spent fuel pool and RCS are assumed to be instantaneously and homogeneously mixed at the start of each refueling outage.

Utilizing the above equations and the assumptions given in table 11.1-1Q, under the design basis of limiting the tritium airborne concentration to 1/2 of the 10CFR20.1-20.601 limit in the most restrictive building, the equilibrium tritium concentrations and inventories are determined. This also determines the approximate vapor discharge of boric acid concentrator distillate necessary to maintain concentration below this level, for equilibrium conditions. The annual expected distillate flow is 358,000 liquid gallons per year as vapor. The annual design distillate flow is 643,000 liquid gallons per year as vapor. Equilibrium tritium liquid concentrations and inventories for the RCS, RMWT, RWT, SFP, refueling pool, and secondary system are given in table 11.1-2.

11.1.3.2.2 Tritium Airborne Concentrations

Tritium airborne concentrations for various buildings are reported in subsection 12.2.2.

Table 11.1-1Q
ASSUMPTIONS USED IN DETERMINING TRITIUM ACTIVITIES
(Sheet 1 of 2)

No.	Assumption
1.	Equilibrium tritium production rate in reactor Coolant is: Average = 921 curies per year Maximum = 1375 curies per year
2.	Tritium activities are based on the maximum building airborne tritium concentration being 1/2 of 10CFR20.1-20.601 limits.
3.	Reactor coolant leakage is as per NUREG-0017.
4.	The tritium balance is as per figure 11.1-1.
5.	Boric acid is concentrated to 4400 ppm boron from an average RCS concentration of 750 ppm boron.
6.	Core cycle and primary coolant parameters are per Table 11.1.1A.
7.	Instantaneous mixing of the Reactor Coolant System, Refueling Pool and Spent Fuel Pool is assumed at the start of each outage.
8.	Primary-to-secondary leakage is as per NUREG 0017.
9.	Leakage from the secondary system in the turbine building is as per NUREG 0017.
10.	Primary coolant flow to the boric acid concentrator is based on 1,345,000 gal/cycle.
11.	Spent fuel pool parameters: Refueling and normal temperature = 125F Liquid volume = 311,000 gallons Surface area = 1320 square feet Air speed across SFP = 20 feet per minute
12.	Refueling pool parameters: Refueling temperature = 125F Liquid volume = 506,000 gallons Surface area = 2130 square feet Air speed across pool = 20 feet per minute
13.	Tank and RCS volumes: RMWT = 380,000 gallons RWT = 680,000 gallons RCS = 68,100 gallons

Table 11.1-1Q
ASSUMPTIONS USED IN DETERMINING TRITIUM ACTIVITIES
(Sheet 2 of 2)

No.	Assumption
14.	Containment building parameters: Air temperature = 104F Free volume = 2.6 x 10^6 cubic feet Normal purge rate = 2200 cubic feet per Refueling rate = 33,000 cubic feet per minute
15.	Fuel building parameters: Air temperature = 104F Free volume = 7.36 x 10^5 cubic feet HVAC exhaust = 42,686 cubic feet per minute
16.	Auxiliary building parameters: Air temperature = 104F Free volume = 1.37 x 10^6 cubic feet HVAC exhaust rate = 58,400 cubic feet minute
17.	Turbine building parameters: Air temperature= 104F Free volume = 7.13 x 10^6 cubic feet HVAC exhaust rate = 474,160 cubic feet per minute
18.	Secondary system volume is 2.32E+05 gallons

Table 11.1-2
TRITIUM LIQUID ACTIVITIES

System	Concentration (μCi/g)		Inventory (Ci)	
	Expected	Maximum	Expected	Maximum
Reactor coolant system (RCS)	0.37	0.41	138	152
Reactor makeup water tank (RMWT)[a]	0.13	0.02	181	26
Refueling water tank (RWT)	0.74	0.7	1900	2000
Refueling pool[b]	0.41	0.42	790	778
Spent fuel pool (SFP)	0.42	0.42	490	500
Total	--	--	3499	3456

a. Note that the inventory is smaller for the higher production rate. This is due to the increased fraction of total BAC distillate vapor necessarily discharged before reaching the RMWT to maintain a 1/2 MPC in the containment in the maximum case.

b. Refueling pool inventory is included in the RWT inventory.

11.1.3.2.3 Tritium Releases

Plant tritium activity is reduced as a result of either natural radioactive decay or airborne release through plant ventilation systems and boric acid concentrator distillate vapor. Table 11.1-3 summarizes the tritium releases per unit based on the model described in paragraph 11.1.3.2.1 for distillate vapor release, and on the model described in subsection 11.3.3 for ventilation system releases. Gaseous tritium releases by source are given in table 11.3-6.

Table 11.1-3

TRITIUM RELEASES (Ci/yr/unit)

Source	Expected Tritium Releases	Maximum Tritium Releases
Boric acid concentrator distillate vapor exhaust	501	998
HVAC systems exhaust	420	377
Total	<1224	<2347

11.1.4 NEUTRON ACTIVATION PRODUCTS

11.1.4.1 Nitrogen-16 Activity

Nitrogen-16 is produced by the $^{16}O(n,p)^{16}N$ reaction. Nitrogen-16 decays by beta emission and high energy gamma emission 78% of the time. The gamma energies are 6.13 Mev, 73% of the time and 7.10 Mev, 5% of the time. The nitrogen-16 half life is 7.13 seconds. The threshold energy for the reaction is 10.2 Mev.

The maximum nitrogen-16 activity at the pressure vessel outlet nozzle is 7.42(+06) disintegrations/cm^3-sec. This activity is applicable for stretch power conditions with the original steam generators (SG) and for power uprate conditions with replacement steam generators and is based on the following expression and reactor parameters.

$$\text{Activity (disintegrations/cm}^3\text{ - sec)} = \frac{\Sigma\varphi\left(1-e^{-\lambda\tau_c}\right)e^{-\lambda t_r}}{\left(1-e^{-\lambda t_t}\right)}$$

Where:

- $\sum\varphi$ is the reaction rate (dis/cm^3 - sec)
- t_c is the core transit time (sec),
- t_t is the total primary loop time (sec),
- t_r is the time from the active core outlet to the point of interest (sec to outlet nozzle) and
- λ is the decay constant (0.097 sec^{-1})

11.1.4.2 Carbon-14 Production

Carbon-14 is produced in the RCS by activation of O^{17} and N^{14} isotopes. The greatest amount of C^{14} is produced by the O^{17} (n,α) C^{14} reaction. A lesser amount of C^{14} is produced by the N^{14} (n, ρ) C^{14} reaction. The production of C^{14} from both sources can be calculated by using the following equation:

$$Q = N_o\ \sigma_o\ \phi\ \nu\ \rho\ t\ s$$

Where:

- N_o = atom concentration in the RCS water, (atoms gram H_2O)
- σ_o = thermal neutron cross section (cm^2)
- φ = thermal neutron flux, 4.4×10^{13} n / cm^2 - sec
- ν = effective core water volume, 2.46×10^7 cm^3
- p = coolant density, 0.64 grams/cm^3

t = full power run time for 1 cycle, 500 days (4.32×10^{7} sec)

s = 1.03×10^{-22} Ci / atom

Q = production rate, Ci / cycle

For C-14 production from O^{17} activation, $N_o = 1.24 \times 10^{19}$ atoms O^{17}/gram (H_2O) and $\sigma_o = 2.4 \times 10^{-25}$ cm^2 are used in the above equation. For carbon-14 production from N^{14} activation, $N_o = 1.07 \times 10^{18}$ atoms N^{14}/gram (H_2O) and σ_o 1.8×10^{-24} cm^2 are used in the above equation.

The production of C^{14} from these sources during one 500 day full power run time cycle will be 18.5 curies.

11.1.5 FUEL EXPERIENCE

Refer to CESSAR Section 11.1.5.

Fuel experience is discussed in Section 4.2.3.2.10. On the basis of experience, it is expected that the failed fuel fraction during normal operation will be less than 0.12 percent.

11.1.6 LEAKAGE SOURCES

Systems containing radioactive liquids or gases are potential sources of leakage to the environment. Liquid leakage is made up from such potential sources as pump seals and valve packings. Table 11.1-3A provides a listing of leakage values from valves and pumps. Leakage from systems containing potentially radioactive liquids is collected in radioactive sumps and sent to the liquid radwaste system (LRS).

Radioactive liquid leakage sources processed by the LRS are summarized in table 11.2-8.

Primary-to-secondary system leakage is expected to be less than 100 pounds per day under normal conditions. Leakage from the secondary system into the turbine building is expected to be less than 1700 pounds per hour of main steam and 5 gallons per minute of liquid from the condensate. The main steam leakage activity is assumed to become instantly airborne. Noble gases dissolved in the liquid leakage are assumed to become airborne, as they are for other buildings' liquid leakage. A partition factor (PF) of 0.0075 for iodines dissolved in plant liquid leakage is assumed for calculating airborne iodine activities. A PF of 0.1 is assumed for calculating airborne tritium activities from plant liquid leakage. A PF of 0.0001 is conservatively assumed for calculating airborne activities of other isotopes from plant liquid leakage.

A daily leakage rate of 3% of the noble gas inventory and 0.001% of the iodine inventory in the primary coolant is assumed released to containment atmosphere.

Airborne releases inside the plant are handled by the appropriate ventilation system. The containment, auxiliary, radwaste, turbine, and fuel building HVAC systems are discussed in section 9.4. Airborne activity in the plant is monitored by area monitors and airborne monitors before release from the plant. Airborne releases are discussed in subsection 11.3.3.

Means of controlling leakage from the reactor coolant pressure boundary are discussed in subsection 5.2.5.

Table 11.1-3A
LEAKAGE ASSUMPTIONS FROM C-E SUPPLIED EQUIPMENT

<u>Valves</u>	
Dish Leakage	10 cc/hr/inch Seat Diameter
Steam Leakage	10 cc/hr/inch Stem Diameter
<u>Pumps</u>	
Centrifugal	50 cc/hr
Positive displacement	1 gallon/hr
Flanges	30 cc/hr

11.1.7 FUEL POOL FISSION PRODUCT AND CORROSION PRODUCT ACTIVITIES

The fuel pool cooling and cleanup system (FPCCS) described in subsection 9.1.3 is comprised of two purification loops and one cooling loop with redundant heat exchangers. One purification loop and the cooling loop act on the spent fuel pool, and the other purification loop acts on the refueling pool. Since the loops return the flow to the respective pool from which flow was taken, the only exchange of water between the two pools is through the fuel transfer tube as a result of fuel transfer.

The primary source of activity in the pools is the reactor coolant water available for mixing with the refueling pool water upon reactor vessel head removal. Upon shutdown for refueling, the RCS is cooled down for a period of approximately 2 days until the reactor coolant temperature is less than 125F. During this time, the primary coolant is letdown through the CVCS system to degas and reduce radioactive impurities in the coolant. The gas space of the volume control tank is vented to help reduce fission gas activity and hydrogen concentration to

less than 5 cc/kg of water at STP before head removal. This letdown process, therefore, accomplishes the removal of combustible gases to safe levels and the removal of noble gases and dissolved fission and corrosion product activities. At the end of this cooldown and letdown period, the coolant above the reactor vessel flange is drained. The head is unbolted and the refueling pool is filled with 506,000 gallons of water from the refueling water tank. The remaining coolant volume of 68,100 gallons is then assumed to be instantaneously and homogeneously mixed with the water in the refueling pool and the 390,000 gallons in the spent fuel pool. After refueling, the spent fuel pool is isolated and the water in the refueling pool is returned to the refueling water tank. This series of events determines the total activity in the pools. Activities are all at a maximum at the start of refueling as it is conservatively assumed that reactor coolant water mixes with refueling pool and spent fuel pool water instantly and completely upon head removal. The maximum spent fuel pool activity level is defined as the activity that would result in the highest dose relative to the design of shielding structures. The expected and maximum refueling pool and spent fuel pool peak concentrations under the assumptions listed in table 11.1-4 are given in table 11.1-5. Equilibrium tritium concentrations given are based on the assumptions and methods presented in subsection 11.1.3.

The spent fuel pool activity contribution from stored defective fuel elements is assumed to be negligible. Due to the cooldown and letdown prior to refueling, the majority of the fission products available for release will evolve from the elements.

Table 11.1-4
ASSUMPTIONS USED IN DETERMINING REFUELING ACTIVITIES

No.	Assumption
1.	Expected case values are based on primary coolant activities given in Table 11.1-1C and maximum case values are based on primary coolant activities given in Table 11.1-1B. Specific radionuclides listed in Table 11.1.1B differ from those listed in Table 11.1.1C due to different models used to determine maximum versus expected case source terms.
2.	Water from the RCS, SFP and RWT is instantaneously homogeneously mixed upon removal of the reactor head.
3.	The spent fuel pool volume is 311,000 gallons.
4.	68,100 gallons of primary coolant are mixed with 506,000 gallons of refueling pool water and 311,000 of spent fuel pool water upon removal of the reactor head.
5.	Decontamination factors (DF) of purification equipment are: Xe,Kr,H,N / I,Br / Cs,Rb / Particulates / Others Fuel pool filter: 1 / 1 / 1 / 100 / 1 Fuel pool ion exchangers: 1 / 100 / 2 / 1 / 100
6.	Fuel pool purification train flowrate is 150 gallons per minute for both the refueling pool and the spent fuel pool.
7.	Activity losses due to evolution from the pool are negligible.
8.	Any Isotope with specific activity less than 1.0E-10 is considered to be insignificant and is not reported.

Decontamination factors (item 5):

	Xe,Kr,H,N	I,Br	Cs,Rb	Particulates	Others
Fuel pool filter	1	1	1	100	1
Fuel pool ion exchangers	1	100	2	1	100

Table 11.1-5

REFUELING ACTIVITIES[(a)(c)] (Sheet 1 of 2)

	Expected Peak Refueling Activities (µCi/gm)	Design Peak Refueling Activities (µCi/gm)
Radionuclide	Refueling and Spent Fuel Pools	Refueling and Spent Fuel Pools
Cr-51	1.650E-04	2.53E-04
Mn-54	8.788E-05	4.54E-04
Fe-55	6.160E-04	4.69E-04
Co-58	2.085E-03	5.73E-04
Fe-59	1.037E-04	2.93E-05
Co-60	8.332E-04	2.26E-04
Br-83	3.495E-04	-
Br-84	1.875E-04	1.57E-03
Br-85	2.164E-05	-
Rb-86	4.003E-06	-
Rb-88	1.429E-02	1.90E-01
Rb-89	-	9.84E-03
Sr-89	2.464E-05	2.64E-04
Y-89m	2.464E-09	2.64E-08
Sr-90	7.514E-07	1.34E-05
Y-90	1.344E-07	4.52E-06
Sr-91	4.616E-05	3.94E-04
Y-91m	2.590E-05	3.03E-05
Y-91	4.519E-06	3.85E-05
Y-93	2.413E-06	2.75E-04
Zr-95	4.237E-06	4.16E-05
Nb-95m	1.051E-07	8.86E-07
Nb-95	3.580E-06	1.90E-05
Mo-99	5.987E-03	2.29E-02
Tc-99m	3.357E-03	3.08E-04
Ru-103	3.163E-06	1.45E-05
Rh-103m	3.248E-06	1.45E-05
Ru-106	7.323E-07	6.10E-06
Rh-106	7.519E-07	6.10E-06
Te-125m	2.043E-06	-
Te-127m	1.995E-05	-
Te-127	6.074E-05	-
Te-129m	9.808E-05	1.25E-05
Te-129	1.150E-04	5.19E-04
I-130	1.567E-04	-
Te-131m	1.764E-04	9.84E-05
Te-131	7.934E-05	5.06E-04
I-131	2.072E-02	1.97E-01
Te-132	1.895E-03	1.57E-02
I-132	7.278E-03	5.44E-02
I-133	2.767E-02	2.87E-01

Table 11.1-5

REFUELING ACTIVITIES[(a)(c)] (Sheet 2 of 2)

	Expected Peak Refueling Activities (μCi/gm)	Design Peak Refueling Activities (μCi/gm)
Radionuclide	Refueling and Spent Fuel Pools	Refueling and Spent Fuel Pools
	3.397E-03	3.41E-02
Cs-134	2.689E-03	4.83E-02
I-135	1.403E-02	1.64E-01
Cs-136	6.060E-04	3.89E-03
Cs-137	2.238E-03	8.57E-02
Ba-137m	2.493E-03	8.02E-02
Ba-140	1.542E-05	3.21E-04
La-140	1.057E-05	1.12E-04
Ce-141	4.916E-06	9.88E-06
Ce-143	2.820E-06	1.84E-04
Pr-143	3.505E-06	4.33E-05
Ce-144	2.396E-06	3.55E-05

a. Specific radionuclides listed in CESSAR Table 11.1-1B differ from those listed in CESSAR Table 11.1-1C due to different models used to determine maximum versus expected case source terms.

b. A "-" indicates a radionuclide not in the source term list or is insignificant.

c. Values shown are representative of a core power of 3876 MWt with the original steam generators. For a core power of 3990 MWt with the replacement steam generators the values shown should be corrected by the ratio of core power.

11.1.8 SECONDARY SYSTEM SOURCES

The secondary system will become contaminated if steam generator tube leaks exist coincident with failed fuel. This primary-to-secondary leakage is expected to be less than 100 pounds per day. Secondary system steam and condensate leakage are listed in sections 11.3 and 11.2, respectively. Equilibrium secondary system activities in the steam generator liquid and steam, and in the main condenser hotwell, have been derived using assumed conditions of primary coolant activity, primary- to-secondary leakage, secondary system leakage, and certain secondary system process parameters, as listed in table 11.1-6.

Radionuclides will be removed from the secondary system by the following means:

- Steam generator blowdown demineralizer treatment
- Condensate polishing demineralizer treatment
- Radioactive decay
- Exhaust through the main condenser vacuum pumps
- Exhaust through the gland seal system
- Main steam leakage to the turbine building
- Condensate leakage to the turbine building sump
- Removal of nonrecyclable secondary samples

The model used to determine the secondary system activity concentrations is given in figure 11.1-2.

The set of equations developed from the model used to determine equilibrium secondary activities are:

Steam Generator Liquid Activity

$$X_L = \frac{Q\,X_p}{C_1 - \alpha K_{FT}\dfrac{B^2}{C_2} - K_{SG} R_3 - \dfrac{R_2}{DF_{PDM}}\left(K_{SG} C_4 + \dfrac{C_5 B}{C_2\,DF_{IX}} + \dfrac{K_{SG} C_3}{R_2 + \lambda M_{CON}}\right)} \tag{5}$$

Main Steam Activity

$$X_S = K_{SG}\,X_L \tag{6}$$

Main Condenser Hotwell Activity

$$X_2 = X_L\left(K_{SG} C_4 + \frac{C_5\,B}{C_2\,DF_{IX}} + \frac{K_{SG}\,C_3}{R_2 + \lambda M_{CON}}\right) \tag{7}$$

where:

$$C_1 = K_{SG} S + B + M_L \lambda$$

$$C_2 = \alpha B K_{FT} + (1 - \alpha) B + \lambda(M_{FTLIQ} + K_{FT} M_{FTVAP})$$

$$C_3 = R_5 - R_6/DF_{GSS}$$

$$C_4 = \frac{K_{AE} R_1 + R_4}{R_2 + \lambda M_{CON}}$$

$$C_5 = \frac{R_7}{R_2 + \lambda M_{CON}}$$

The parameters used in these equations are defined below:

X_P = primary coolant concentration (μCi/g)

X_L = steam generator liquid concentration (μCi/g)

X_S = main steam concentration (μCi/g)

X_2 = main condenser hotwell concentration (μCi/g)

Q = total primary-to-secondary leak rate (lbm/h)

S = main steam total flowrate (lbm/h)

B = total blowdown rate (lbm/h)

M_L = total mass of all steam generator liquid (lbm)

M_{CON} = mass of condenser hotwell (lbm)

M_{FTLIQ} = mass of blowdown flash tank liquid (lbm)

M_{FTVAP} = mass of blowdown flash tank vapor (lbm)

λ = isotopic decay constant (h^{-1})

α = mass fraction of blowdown that exits flash tank as vapor

DF_{IX} = Combined isotopic decontamination factor of blowdown demineralizers

DF_{PDM} = isotopic decontamination factor of condensate polishing demineralizers

DF_{GSS} = 1/fraction of gland seal system activity that exits system

K_{AE} = fraction of activity entering condenser that goes to hotwell

K_{SG} = steam generator internal partition coefficient

K_{FT} = flash tank internal partition coefficient

R_1 = main steam flowrate to main condenser (lbm/h)

R_2 = condensate flowrate (lbm/h)

R_3 = total extraction steam flowrate to high pressure feedwater heaters (lbm/h)

R_4 = total extraction steam flowrate to low pressure feedwater heaters (lbm/h)

R_5 = main steam flowrate to gland seal system (lbm/h)

R_6 = gland seal exhaust flowrate (lbm/h)

R_7 = blowdown flash tank condensate flowrate (lbm/h)

Assumptions used in determining the secondary system activities are listed in table 11.1-6. Expected and design basis secondary activities are given in table 11.1-7.

The equilibrium concentration of tritium expected to be present in the secondary system is 3.53E-05 μCi/cc, and is calculated based on the assumption and methods presented in subsection 11.1.3.

11.1.9 GASEOUS SOURCE TERM

As stated in Section 3.5 of the Environmental Report, there are no liquid releases from PVNGS. Therefore, the data required for the liquid source term calculation are not applicable to PVNGS. The data required for the gaseous source term calculation for PWRs using the format given in Chapter 4 of NUREG-0017, April 1976, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors" are summarized on a per unit basis as follows:

Table 11.1-6
ASSUMPTIONS USED IN DETERMINING SECONDARY SYSTEM ACTIVITIES (Sheet 1 of 2)

No.	Assumptions		
1.	Primary coolant activities are per Table 11.1-1B for the maximum case and per Table 11.1-1C for the expected case.		
	Note: Specific radionuclides listed in 11.1-1B differ from those listed in Table 11.1-1C due to different models used to determine maximum versus expected case source terms.		
2.	Primary-to-secondary leak rate is 100 pounds per day for the expected case and 1 gallon per minute at primary coolant temperature for the maximum case.		
3.	Secondary system flowrates are as follows (note that the design blowdown rate is used for the maximum activities case and the expected activities case):		
		Expected Case	Maximum Case
	Steam flowrate (lb/h)	1.79E7	1.79E7
	Total blowdown rate (lb/h)	9.0E4	9.0E4
	High-pressure extraction steam flow rate (lb/h)	5.4E6	5.4E6
	Low-pressure extraction Steam flowrate (lb/h)	2.6E6	2.6E6
	Gland steal exhauster moisture flowrate = 310 lb/h		
	Steam leakage = 1700 lb/h		
4.	Secondary system masses are:		
	Total steam generator liquid mass = 3.55E5 lbm		
	Main condenser hotwell mass = 8.52E5 lbm		
	Blowdown flash tank liquid mass = 2.89E4 lbm		

Table 11.1-6
ASSUMPTIONS USED IN DETERMINING SECONDARY SYSTEM ACTIVITIES (Sheet 2 of 2)

<table>
<tr><th>No.</th><th>Assumptions</th></tr>
<tr><td>5.</td><td>Steam generator internal partition coefficients are:
Xe, Kr, H, N-16 = 1
I, Br = 0.01
All others = 0.005</td></tr>
<tr><td>6.</td><td>Condenser air removal system partition factors are:
Xe, Kr, H, N-16 = 1
I, Br = 0.03
All others = 0</td></tr>
<tr><td>7.</td><td>Blowdown flash tank partition factors are:
Xe, Kr, H, N-16 = 1
I, Br = 0.05
All others = 0.001</td></tr>
<tr><td>8.</td><td>Blowdown demineralizer and condensate polishing demineralizer decontamination factors are:
<table>
<tr><th></th><th>Xe,Kr,H</th><th>I,Br</th><th>Cs,Rb</th><th>Particulates</th><th>Others</th></tr>
<tr><td>Condensate polishing demineralizer</td><td>1</td><td>1</td><td>1</td><td>1</td><td>1</td></tr>
<tr><td>Blowdown demineralizer</td><td>1</td><td>100[a]</td><td>1</td><td>100</td><td>100</td></tr>
</table>
For calculation of expected secondary activities, the lead blowdown demineralizer is assumed to be in operation.</td></tr>
</table>

a. No credit is conservatively assumed for lag Blowdown Demineralizers.

Table 11.1-7

SECONDARY SYSTEM ACTIVITIES (μCi/g)[Note 1]

	Maximum, μCi/gm			Expected, μCi/gm		
Nuclide	SG Liquid	Main Steam	Condenser Hotwell	SG Liquid	Main Steam	Condenser Hotwell
Kr-85m	4.66E-05	4.66E-05	9.97E-06	-	-	-
Kr-85	2.21E-04	2.21E-04	4.77E-05	1.02E-07	1.02E-07	-
Kr-87	3.51E-05	3.51E-05	7.29E-06	-	-	-
Kr-88	9.99E-05	9.99E-05	2.12E-05	-	-	-
Xe-131m	2.13E-04	2.13E-04	4.62R-05	-	-	-
Xe-133	1.30E-02	1.30E-02	2.82E-03	8.06E-06	8.06E-06	1.74E06
Xe-135	2.77E-04	2.77E-04	5.97E-05	1.49E-07	1.49E-07	-
Xe-138	1.97E-05	1.97E-05	3.50E-06	-	-	-
Br-84	1.63E-05	1.63E-07	3.09E-07	-	-	-
I-131	3.61E-01	3.61E-03	8.58E-03	7.62E-06	-	-
I-132	2.35E-03	2.35E-05	5.26E-05	1.51E-06	-	-
I-133	1.03E-01	1.03E-03	2.43E-03	9.51E-06	-	-
I-134	5.76E-04	5.76E-06	1.19E-05	4.31E-07	-	-
I-135	1.98E-02	1.98E-04	4.61E-04	3.97E-06	-	-
Rb-88	1.13E-03	5.63E-06	1.39E-05	8.25E-07	-	-
Cs-134	6.58E+00	3.29E-02	1.26E-01	4.54E-07	-	-
Cs-136	2.30E-02	1.15E-04	4.41E-04	2.39E-07	-	-
Cs-137	1.47E+02	7.36E-01	2.83E+00	3.27E-07	-	-
Y-90	4.34E-06	-	--		-	-
Y-91	1.02E-03	5.10E-06	1.96E-05	-	-	-
Mo-99	2.89E-02	1.45E-04	5.54E-04	2.10E-06	-	-
Sr-89	6.08E-03	3.04E-05	1.17E-04	-	-	-
Sr-90	6.13E-02	3.06E-04	1.18E-03	-	-	-
Sr-91	7.16E-05	3.58E-07	1.35E-06	-	-	-
Zr-95	1.21E-03	6.06E-06	2.33E-05	-	-	-
Ru-103	2.60E-04	1.30E-06	4.99E-06	-	-	-
Ru-106	9.97E-04	4.99E-06	1.92E-05	-	-	-
Te-129	1.17E-05	-	1.97E-07	-	-	-
Te-132	2.35E-02	1.18E-04	4.51E-04	6.77E-07	-	-
Ba-140	1.88E-03	9.39E-06	3.61E-05	-	-	-
La-140	8.58E-05	4.29E-07	1.64E-06	-	-	-
Ce-144	4.45E-03	2.23E-05	8.55E-05	-	-	-
Pr-143	2.69E-04	1.35E-06	5.17E-06	-	-	-
Cr-51	1.74E-03	8.71E-06	3.34E-05	-	-	-
Mn-54	3.21E-03	1.61E-05	6.17E-05	-	-	-
Fe-55	5.28E-02	2.64E-04	1.01E-03	-	-	-
Fe-59	1.47E-03	7.36E-06	2.83E-05	-	-	-
Co-58	3.75E-02	1.88E-04	7.21E-04	4.12E-07	-	-
Co-60	1.28E-01	6.38E-04	2.45E-03	-	-	-
H-3	1.48E-05	1.48E-05	3.21E-06	1.56E-07	1.56E-07	-
N-16	3.43E-04	3.43E-04	2.87E-06	3.26E-06	3.26E-06	-
Total	1.55E+02	7.90E-01	2.98E+00	3.98E-05	1.17E-05	1.74E-06

Note 1: “-“indicates that isotope is not on source term list or concentration is less than 1.0E-07 and source is insignificant.

SOURCE TERMS

A. General

1. Maximum core thermal power is 4200 MWt (Table 11.1-1A).

2. Expected tritium released is 921 Ci/yr (Bounded by value reported in Section 1.11.3) (Table 11.1-1O).

B. Primary System

1. Normal primary coolant mass is 645,421 pounds (Table 11.1-1A).

2. Average letdown rate is 72 gallons per minute (Table 11.1-1A).

3. Average purification flow is 72 gallons per minute (Table 11.1-1A).

4. Average shim bleed flow is 0.725 gallon per minute (Table 11.1-1A).

C. Secondary System

1. Two vertical U-tube steam generators with iodine and nonvolatile carryover factor of 1/400

2. Total secondary steam flow is 1.79E+07 pounds per hour.

3. Mass of liquid per steam generator is 178,000 pounds.

4. Average primary-to-secondary leakage rate is as per NUREG 0017.

5. Average steam generator blowdown rate is 4.5E+04 pounds per hour per SG. Flashed steam from the

blowdown flash tank is returned back to the system via the number 4 feedwater heaters. Two blowdown demineralizers provide a total DF of 1 for noble gases, tritium, and nitrogen, 10 for Cs and Rb, and 100 for all others.

6. If the condensate demineralizers are in service, a DF of 1 is assumed to maximize the gaseous source term.

7. A detailed description of the condensate demineralizers is given in subsection 10.4.6.

D. Liquid Waste Processing Systems

As stated above, liquid source term data is not applicable to PVNGS. Refer to section 11.2 for a discussion of processing capability and system description.

E. Gaseous Waste Processing System

Gaseous source term data is provided in subsections 11.3.1 and 11.3.2, tables 11.3-4 and 11.3-7, and engineering drawings 13-N-GRF-001 and 01, 02, 03-N-GRP-001.

F. Ventilation and Exhaust Systems

Refer to subsection 11.3.3 for ventilation and exhaust data. In addition:

1. Data regarding provisions for reducing radioactivity releases through the ventilation or exhaust systems, DFs assumed, and their bases are provided in table 11.3-7.

2. Release rates are provided in table 11.3-6.

3. Data on release points are provided in PVNGS Environmental Report - Operating License Stage, Section 3.1.3.1. However, the condenser air removal system has since been routed to the plant vent.

4. The plant vent is a 72-inch x 84-inch rectangular duct discharging vertically. The fuel building exhaust is a 60-inch circular duct discharging vertically.

5. Containment building internal circulation filtration data are provided in subsection 9.4.6 and table 11.3-7.

11.2 LIQUID WASTE MANAGEMENT SYSTEMS

The liquid waste management systems consist of the secondary chemistry control system (SCCS), fuel pool cooling and cleanup system (FPCCS), and liquid radwaste system (LRS).

The SCCS and FPCCS are discussed in subsections 10.4.6 and 9.1.3, respectively. The liquid waste management systems are not shared between units.

Radioactive laundry is typically handled by private contractors. Some radioactive laundering may be performed on site using temporary laundering equipment. Liquid waste from on-site laundry activities is routed to the liquid radwaste system for processing. Administrative controls limit on-site laundry additives to prevent generation of mixed use waste.

11.2.1 DESIGN BASES

11.2.1.1 Design Objectives

The function of the liquid waste management systems is to collect and process radioactive or potentially radioactive liquid wastes generated during plant operation.

The principal design objectives of the liquid waste management systems are:

A. To collect liquid wastes generated during plant operation which contain potentially radioactive material.

B. To provide sufficient processing capacity, redundancy, and flexibility to meet the concentration limits of

10CFR20.1-20.601 during periods of equipment downtime and during operation at design basis fuel leakage.

C. To control releases of radioactive materials within the numerical design objectives of 10CFR50, Appendix I, in maintaining releases "as-low-as-is-reasonably-achievable (ALARA)."

D. To purify the radioactive liquid wastes to enable reclaimed water to be reused in the plant.

The liquid waste systems, as designed, contain items of reasonably demonstrated technology that, when added to the system and in order of diminishing cost-benefit return, can, for a favorable cost-benefit ratio, effect reductions in dose to the population reasonably expected to be within 50 miles of the site. Section 5.2 of the Environmental Report-Operating License Stage provides a summary of the results of the cost-benefit analysis performed to demonstrate that the design of the liquid waste system meets the ALARA guidelines set forth in Appendix I to 10CFR50.

A discussion of the ability of the liquid waste systems to provide sufficient capacity, redundancy, and flexibility to control wastes in order to prevent radioactive liquid releases and minimize solidified waste is given in subsection 11.2.2.

11.2.1.2 System Design

The components of the LRS are listed in table 11.2-1. Included are equipment sizes and/or capacities, process flowrates, storage capabilities, materials of construction, and design temperatures and pressures. Applicable codes and standards of

process equipment are listed in table 11.2-2. The ability of the SCCS, FPCCS, and LRS to process surge waste volumes in excess of the design assumptions is discussed in subsection 11.2.2.

The layout of LRS components is indicated in engineering drawings 13-P-OOB-002 through -011. The seismic and quality group classifications for the LRS components and piping are provided in table 3.2-1. There are no provisions or pathways for the release of radioactive liquids directly from the LRS to the environment.

NOTE

> Liquids with activity levels less than the release limits cited in the Offsite Dose Calculation Manual (ODCM) are discharged to the onsite evaporation ponds.

Equipment design provisions have been incorporated to reduce maintenance radiation exposure, equipment downtime, liquid leakage, and gaseous releases of radioactive materials to the building atmosphere. Where practical, welded connections are used in lieu of flanged ones. Butt welds and plug valves are used where justified in the liquid waste systems to reduce crud trap formation. Redundant or backup pumps and process lines allow for flushing and maintenance of mechanical components without restricting system operation. Pumps are provided with mechanical seals to minimize leakage. Less frequent equipment maintenance is provided for by utilizing corrosion-resistant materials.

Table 11.2-1
LIQUID RADWASTE SYSTEM EQUIPMENT DESCRIPTIONS
(Sheet 1 of 6)

Tanks		
High TDS holdup tanks (T-01 A,B)		
Quantity/unit	=	2
Capacity (each)	=	30,000 gallons
Design pressure/temp	=	Atmos/150F
Operating pressure/temp	=	Atmos/80F
Material	=	304 SS
Low TDS holdup tank (T-01 C)		
Quantity/unit	=	1
Capacity (each)	=	30,000 gallons
Design pressure/temp	=	Atmos/150F
Operating pressure/temp	=	Atmos/80F
Material	=	304 SS
Chemical drain tanks (T-05 A,B)		
Quantity/unit	=	2
Capacity (each)	=	1100 gallons
Design pressure/temp	=	15 psig/250F
Operating pressure/temp	=	Atmos/80F
Material	=	304 SS
Antifoam tank (T-07)		
Quantity/unit	=	1
Capacity	=	110 gallons of anti-foaming agent
Design pressure/temp	=	Atmos/120F
Operating pressure/temp	=	Atmos/80F
Material	=	304 SS
Concentrate monitor tanks (T-03 A,B)		
Quantity/unit	=	2
Capacity (each)	=	5000 gallons
Design pressure/temp	=	15 psig/250F

Table 11.2-1
LIQUID RADWASTE SYSTEM EQUIPMENT DESCRIPTIONS
(Sheet 2 of 6)

Tanks (continued)		
Operating pressure/temp	=	Atmos/170F
Material	=	Carpenter 20 Cb-3
Caustic storage tank (T-08)		
Quantity/unit	=	1
Capacity	=	2000 gallons of caustic
Design pressure/temp	=	15 psig/120F
Operating pressure/temp	=	Atmos/120F
Material	=	ASTM A283C
Caustic batch tank (T-10)		
Quantity/unit	=	1
Capacity	=	25 gallons
Design pressure/temp	=	Atmos/250F
Operating pressure/temp	=	Atmos/100F
Material	=	ASTM A53B
Acid storage tank (T-06)		
Quantity/unit	=	1
Capacity	=	450 gallons of acid
Design pressure/temp	=	15 psig/120F
Operating pressure/temp	=	Atmos/120F
Material	=	ASTM SA-515-70
Acid batch tank (T-09)		
Quantity/unit	=	1
Capacity	=	25 gallons
Design pressure/temp	=	15 psig/250F
Operating pressure/temp	=	Atmos/80F
Material	=	ASTM A53B
Recycle monitor tanks (T-04 A,B)		
Quantity/unit	=	2

Table 11.2-1
LIQUID RADWASTE SYSTEM EQUIPMENT DESCRIPTIONS
(Sheet 3 of 6)

Tanks (continued)		
Capacity/each	=	30,000 gallons
Design pressure/temp	=	Atmos/150F
Operating pressure/temp	=	Atmos/80F
Material	=	304 SS
Pumps		
LRS holdup pumps (P-01 A,B,C)		
Quantity/unit	=	3
Type	=	Centrifugal
Capacity	=	250 gal/min
Design pressure/temp	=	275 psig/100F
Material	=	316L SS
Motor rpm/bhp	=	3600/25
Chemical drain pumps (P-02 A,B)		
Quantity/unit	=	2
Type	=	Centrifugal
Capacity	=	30 gal/min
Design pressure/temp	=	275 psig/100F
Material	=	316L SS
Motor rpm/bhp	=	3600/7.5
Antifoam pump (P-07)		
Quantity/unit	=	1
Type	=	Positive displacement
Capacity	=	57 gal/h
Design pressure/temp	=	100 psig/200F
Material	=	316 SS
Motor rpm/bhp	=	1725/0.5

Table 11.2-1
LIQUID RADWASTE SYSTEM EQUIPMENT DESCRIPTIONS
(Sheet 4 of 6)

Pumps (continued)		
Recycle monitor pump (P-03)		
Quantity/unit	=	1
Type	=	Centrifugal
Capacity	=	150 gal/min
Design pressure/temp	=	275 psig/100F
Material	=	316L SS or 316 SS
Motor rpm/bhp	=	3600/10
LRS evaporator main recycle pump (P-08)		
Quantity/unit	=	1
Type	=	Inline propeller
Capacity	=	10,500 gal/min
Design pressure/temp	=	5 psig/230F
Material	=	Carpenter 20 Cb-3
Pump rpm	=	714
Motor rpm/bhp	=	1750/75
LRS evaporator distillate pumps (P-09 A,B)		
Quantity/unit	=	2
Type	=	Centrifugal
Capacity	=	40 gal/min
Design head/temp	=	140 feet/220F
Material	=	316 SS
Motor rpm/bhp	=	3500/5
LRS evaporator concentrate pumps (P-10 A,B)		
Quantity/unit	=	2
Type	=	Centrifugal
Capacity	=	50 gal/min
Design head/temp	=	40 feet/235F
Material	=	Gould-a-loy 20
Motor rpm/bhp	=	1750/2

Table 11.2-1
LIQUID RADWASTE SYSTEM EQUIPMENT DESCRIPTIONS
(Sheet 5 of 6)

Pumps (continued)	
LRS steam condensate pump (P-11)	
Quantity/unit	= 1
Type	= Centrifugal
Capacity	= 40 gal/min
Design head/temp	= 150 feet/270F
Material	= 316 SS
Motor rpm/bhp	= 3505/5
Concentrate monitor tank pumps (P-04 A,B)	
Quantity/unit	= 2
Type	= Centrifugal
Capacity	= 130 gal/min
Design pressure/temp	= 275 psig/100F
Material	= W20
Motor rpm/bhp	= 1760/30
Filters	
LRS ion exchanger prefilters (F-01 A,B)	
Quantity/unit	= 2
Size	= 5 mm 98%, 25 mm 100%
Capacity	= 150 gal/min
Design pressure/temp	= 200 psig/250F
Operating pressure/temp	= 90 psig/80F
Material (shell)	= 304 SS
Ion exchangers	
LRS adsorption bed (D-01)	
Quantity/unit	= 1
Capacity	= 50 cubic feet of organic adsorber
Flowrate	= 130 gal/min
Design pressure/temp	= 200 psig/250F

Table 11.2-1
LIQUID RADWASTE SYSTEM EQUIPMENT DESCRIPTIONS
(Sheet 6 of 6)

Ion exchangers (continued)		
Material (shell)	=	304L SS
Operating pressure/temp	=	90 psig/125F
LRS mixed bed ion exchangers (D-02 A,B)		
Quantity/unit	=	2
Capacity	=	50 cubic feet of mixed bed resin (825 gal)
Flowrate	=	130 gal/min
Design pressure/temp	=	200 psig/250F
Material (shell)	=	304L SS
Operating pressure/temp	=	90 psig/125F
Evaporator		
LRS evaporator package		
Quantity/unit	=	1
Capacity	=	30 gal/min
Type	=	forced circulation
Design pressure/temp[a]	=	20 psig/250F
Operating pressure/temp[a]	=	1 psig/219F
Material	=	Incoloy 825 (concentrate side)
	=	304 SS (distillate side)

a. Data stated are for vapor body.

Table 11.2-2

LIQUID RADWASTE SYSTEM EQUIPMENT CODES

Equipment	Codes			
	Design and Fabrication	Materials	Welder Qualifications and Procedures	Inspection and Testing
Tanks, atmospheric or 0-15 psig (steel)	API 620 and 650	ASME Code Section II	ASME Code Section IX	API 620 and 650
Pressure Vessels	ASME Code Section VIII, Div 1	ASME Code Section II	ASME Code Section IX	ASME Code Section VIII, Div 1
Pumps	Manufacturer's[(a)] standards	Manufacturer's standards	ASME Code Section IX	Hydraulic Institute
Piping and valves	ANSI B31.1	ASTM, ASME Section II	ASME Code Section IX	ANSI B31.1
Ion Exchangers	ASME Code Section VIII, Div 1	ASME Code Section II	ASME Code Section IX	ASME Code Section VIII, Div 1
Filters and strainers	ASME Code Section VIII, Div 1	ASME Code Section II	ASME Code Section IX	ASME Code Section VIII, Div 1
Evaporators	ASME Code Section VIII, Div 1	ASME Code Section III	ASME Code Section IX	ASME Code Section VIII, Div 1

a. Manufacturer's standard for the intended service. Hydrotesting is 1.5 times the design pressure.

Provisions have also been incorporated to control the release of radioactive materials due to overflows or leakage from potentially radioactive liquid tanks. Overflow of atmospheric tanks is minimized by the installation of level instrumentation and high level alarms that are annunciated in respective control rooms to alert operators of potential overflow situations. In addition, overflow lines of indoor tanks are routed to their respective building sump whose contents are sent to the LRS for processing. Overflow protection of outdoor LRS tanks is provided by interconnecting the overflow lines of the redundant tanks and routing the common flow to a sump, as in the case of the LRS recycle monitor tanks. There are no potentially radioactive pressurized tanks in the LRS.

Table 11.2-3 provides a list of the potentially radioactive LRS atmospheric tanks and the design provisions incorporated to prevent releases by the control of tank overflow. Control of liquid releases due to tank leakage is provided for by plant design. Indoor tanks are surrounded by curbs or are in compartments provided with thresholds to contain any leakage. Radioactive leakage is directed to the same sump as the tank overflow indicated in table 11.2-3. Outdoor LRS tanks, that is, the holdup tanks and recycle monitor tanks, are surrounded by a dike capable of preventing runoff in the event of a tank overflow. As discussed in subsection 2.4.13, release of the contents of the refueling water tank to the groundwater results in concentrations at the site boundary well below the maximum permissible concentrations in water listed in 10CFR20.1-20.601, Appendix B, Table II. The specific activities and total isotopic inventories in the outdoor LRS tanks are comparable

Table 11.2-3

LRS ATMOSPHERIC RADIOACTIVE TANK OVERFLOW PROTECTION

LRS Tanks	Location	Level Monitoring	Potential Overflow Alarm	Method for Containing Overflow
LRS Tanks				
High TDS holdup tanks				
LRN-TO1 A	Outside radwaste building	Radwaste control room (LI-4)[a]	Radwaste control room (LAHL-4)	Overflow from one LRS holdup tank flows to the other holdup tanks with the ultimate overflow of all three tanks directed to the radwaste building sump
LRN-TO1 B	Outside radwaste building	Radwaste control room (LI-5)	Radwaste control room (LAHL-5)	
Low TDS holdup tank				
LRN-TO1 C	Outside radwaste building	Radwaste control room (LI-6)	Radwaste control room (LAHL-6)	See above.
Chemical drain tanks				
LRN-TO5 A	Auxiliary building (elevation 51'6")	Radwaste control room (LI-18)	Radwaste control room (LAHL-18)	Overflow from one drain tank flows to the other drain tank with the ultimate overflow of both tanks directed to the auxiliary building nonengineered safety feature sump.
LRN-TO5 B	Auxiliary building (elevation 51'6")	Radwaste control room (LI-19)	Radwaste control room (LAHL-19)	
Recycle monitor tanks				
LRN-TO4 A	Outside radwaste building	Radwaste control room (LI-66)	Radwaste control room (LAHL-67)	Overflow from one monitor tank flows to the other tank with the ultimate overflow of both tanks directed to the radwaste building sump.
LRN-TO4 B	Outside radwaste building	Radwaste control room (LI-67)	Radwaste control room (LAHL-67)	
Concentrate monitor tanks				
LRN-TO3 A	Radwaste building (elevation 100')	Radwaste control room (LI-79)	Radwaste control room (LAHL-79)	Overflow from one concentrate tank flows to the other tank with the ultimate overflow of both tanks directed to the radwaste building sump.
LRN-TO3 B	Radwaste building (elevation 100')	Radwaste control room (LI-80)	Radwaste control room (LAHL-80)	

a. Refer to engineering drawings 01, 02, 03-N-LRP-001, -002, -003.

to that in the refueling water tank. Radioactive liquid accumulating within the retention walls surrounding these outside tanks are directed to the same sump as the tank overflow indicated in table 11.2-3.

Liquid releases from the liquid waste management systems to the evaporation ponds are limited to releases of liquid with activity less than the release limits cited in the Offsite Dose Calculation Manual (ODCM). Liquid leakage from the waste systems is collected by gravity drainage in respective sumps. The contents of these sumps are pumped to the LRS holdup tanks. Liquid radioactive wastes are demineralized by ion exchange and distillation. Radioactive wastes unsuited for plant recycle are prepared for shipment in accordance with NRC and DOT regulations. Evaporative losses from the liquid waste systems are filtered and monitored by the plant ventilation systems prior to discharge to the plant vent.

11.2.2 SYSTEM DESCRIPTION

11.2.2.1 Secondary Chemistry Control System

The SCCS is described in section 10.4. High-conductivity regenerant solutions are produced as a result of blowdown demineralizer and condensate polishing demineralizer regeneration. If significant steam generator tube leaks exist coincident with failed fuel, which necessitates that the regenerants be processed by the LRS, they are processed via the high or low TDS tanks as required. The specific activities of the regenerant solutions, based on the assumptions given in table 11.2-4, are listed in table 11.2-5. Secondary chemistry

control system expected specific activities are also listed in table 11.2-5. Maximum radionuclide inventories of SCCS components are given in table 12.2-3.

Table 11.2-4
ASSUMPTIONS USED IN DETERMINING SCCS ACTIVITIES

Item	Assumption
1.	Reactor is operating with an expected activity level as given in Table 11.1-1C.
2.	Primary-to-secondary leak rate is per NUREG 0017, Rev 1
3.	Full flow condensate polishing demineralizers (CPD) are not online.
4.	Blowdown demineralizer decontamination factors (DF) are as per NUREG 0017, Rev 1
5.	Blowdown flowrate: Maximum downcomer blowdown flow for one Steam Generator

11.2.2.2 Fuel Pool Cooling and Cleanup System

The FPCCS is described in subsection 9.1.3. Fuel pool specific activities are listed in table 11.1-5, based upon design assumptions discussed in subsection 11.1.7. The expected specific activities of the FPCCS, based on the assumptions given in table 11.2-6, are listed in table 11.2-7. Maximum radionuclide inventories of FPCCS components are given in table 12.2-4.

Table 11.2-5
SCCS EXPECTED PROCESS POINT ACTIVITIES (µCi/g)

Nuclide	SG Blowdown	Flash Tank Cond. Outlet	Flash Tank Vent	Blowdown Demin. Outlet	Condensate Flow	CPD Outlet
Kr-85m	4.67E-14	4.52E-14	4.52E-08	4.52E-14	9.54E-09	9.54E-09
Kr-85	1.02E-13	1.02E-13	1.02E-07	1.02E-13	2.11E-08	2.11E-08
Kr-87	2.53E-14	2.26E-14	2.26E-08	2.26E-14	5.03E-09	5.03E-09
Kr-88	8.49E-14	8.06E-14	8.06E-08	8.06E-14	1.72E-08	1.72E-08
Xe-131m	5.19E-14	5.19E-14	5.19E-08	5.19E-14	1.07E-08	1.07E-08
Xe-133	8.06E-12	8.05E-12	8.05E-06	8.05E-12	1.66E-06	1.66E-06
Xe-135	1.49E-13	1.47E-13	1.47E-07	1.47E-13	3.06E-08	3.06E-08
Xe-138	1.79E-14	1.09E-14	1.09E-08	1.09E-14	3.08E-09	3.08E-09
Br-84	1.81E-08	1.98E-08	9.91E-10	1.98E-10	1.62E-10	1.62E-10
I-131	1.01E-05	1.59E-05	7.95E-07	1.59E-07	9.86E-08	9.86E-08
I-132	1.78E-06	2.55E-06	1.28E-07	2.55E-08	1.71E-08	1.71E-08
I-133	1.23E-05	1.93E-05	9.65E-07	1.93E-07	1.21E-07	1.21E-07
I-134	4.75E-07	5.92E-07	2.96E-08	5.92E-09	4.40E-09	4.40E-09
I-135	4.97E-06	7.58E-06	3.79E-07	7.58E-08	4.83E-08	4.83E-08
Rb-88	8.62E-07	7.70E-07	7.70E-10	7.70E-08	4.18E-09	4.18E-09
Cs-134	6.18E-07	1.01E-06	1.01E-09	1.01E-07	3.82E-09	3.82E-09
Cs-136	3.26E-07	5.30E-07	5.30E-10	5.30E-08	2.01E-09	2.01E-09
Cs-137	4.46E-07	7.26E-07	7.26E-10	7.26E-08	2.76E-09	2.76E-09
Y-90	3.97E-11	6.44E-11	6.44E-14	6.44E-13	2.01E-13	2.01E-13
Y-91	2.21E-09	3.60E-09	3.60E-12	3.60E-11	1.12E-11	1.12E-11
Mo-99	2.79E-06	4.53E-06	4.53E-09	4.53E-08	1.41E-08	1.41E-08
Sr-89	1.21E-08	1.97E-08	1.97E-11	1.97E-10	6.13E-11	6.13E-11
Sr-90	3.46E-10	5.63E-10	5.63E-13	5.63E-12	1.75E-12	1.75E-12
Sr-91	1.79E-08	2.84E-08	2.84E-11	2.84E-10	9.01E-11	9.01E-11
Zr-95	2.07E-09	3.38E-09	3.38E-12	3.38E-11	1.05E-11	1.05E-11
Ru-103	1.55E-09	2.53E-09	2.53E-12	2.53E-11	7.87E-12	7.87E-12
Ru-106	3.46E-10	5.63E-10	5.63E-13	5.63E-12	1.75E-12	1.75E-12
Te-129	1.95E-08	2.62E-08	2.62E-11	2.62E-10	9.45E-11	9.45E-11
Te-132	9.02E-07	1.46E-06	1.46E-09	1.46E-08	4.57E-09	4.57E-09
Ba-140	7.56E-09	1.23E-08	1.23E-11	1.23E-10	3.83E-11	3.83E-11
La-140	4.86E-09	7.87E-09	7.87E-12	7.87E-11	2.46E-11	2.46E-11
Ce-144	1.14E-09	1.86E-09	1.86E-12	1.86E-11	5.80E-12	5.80E-12
Pr-143	1.72E-09	2.79E-09	2.79E-12	2.79E-11	8.70E-12	8.70E-12
Cr-51	6.55E-08	1.07E-07	1.07E-10	1.07E-09	3.32E-10	3.32E-10
Mn-54	1.07E-08	1.75E-08	1.75E-11	1.75E-10	5.45E-11	5.45E-11
Fe-55	5.53E-08	9.00E-08	9.00E-11	9.00E-10	2.80E-10	2.80E-10
Fe-59	3.45E-08	5.62E-08	5.62E-11	5.62E-10	1.75E-10	1.75E-10
Co-58	5.52E-07	8.99E-07	8.99E-10	8.99E-09	2.80E-09	2.80E-09
Co-60	6.91E-08	1.13E-07	1.13E-10	1.13E-09	3.51E-10	3.51E-10
H-3	3.53E-11	3.53E-11	3.53E-11	3.53E-11	3.53E-11	3.53E-11

Table 11.2-6
ASSUMPTIONS USED IN DETERMINING FPCCS ACTIVITIES

Item	Assumption
1.	Reactor operated prior to refueling with an expected RCS activity level as given in Table 11.1-1C.
2.	Initial activity in the SFP at the start of refueling is negligible.
3.	68,100 gallons of water with primary coolant is uniformly and instantly mixed with the RWT and SFP liquid upon head removal.
4.	Refueling pool and SFP activities listed in table 11.1-5 are the peak for the cycle, taken just after reactor vessel head removal
5.	The FPCCS purifies 150 gal/min from the SFP and 150 gal/min from the refueling pool in separate loops which return the flow to the pool from which it was taken.
6.	The fuel pool ion exchanger decontamination factors are Kr, Xe, H, / I, Br, / Cs, Rb, / Particulates, / Others DF = 1 / 100 / 2 / 1 / 100
7.	The fuel pool filter decontamination factors are: Kr, Xe, H, / I, Br, / Cs, Rb, / Particulates, / Others DF = 1 / 1 / 1 / 100 / 1
8.	Fuel pool ion exchanger outlet activities listed are based on peak refueling pool and spent fuel pool activities.

Table 11.2-7
FPCCS EXPECTED PROCESS POINT ACTIVITIES (μCi/g)[a]
(Sheet 1 of 2)

Radionuclide	Spent Fuel Pool	Refueling Pool	Spent Fuel Pool IX Outlet
H-3			4.20E-01
BR-83			3.50E-06
BR-84			1.88E-06
BR-85			2.16E-07
I-130			1.57E-06
I-131			2.07E-04
I-132			7.28E-05
I-133			2.77E-04
I-134			3.40E-05
I-135			1.40E-04
RB-86			2.00E-06
RB-88			7.15E-03
CS-134			1.34E-03
CS-136			3.03E-04
CS-137			1.12E-03
H-3			4.10E-01
Y-90			1.34E-09
Y-91	See Table 11.1-5	See Table 11.1-5	4.52E-08
Y-93			2.41E-08
MO-99			5.99E-05
SR-89			2.46E-07
SR-90			7.51E-09
SR-91			4.62E-07
ZR-95			4.24E-08
NB-95			3.58E-08
TC-99M			3.36E-05
RU-103			3.16E-08
RU-106			7.32E-09
RH-103M			3.25E-08
RH-106			7.52E-09
TE-125M			2.04E-08
TE-127M			2.00E-07
TE-127			6.07E-07

a. Values shown are representative of a core power of 3876 MWt with the original steam generators. For a core power of 3990 MWt with the replacement steam generators the values shown should be corrected by the ratio of core power.

Table 11.2-7
FPCCS EXPECTED PROCESS POINT ACTIVITIES (μCi/g)[a]
(Sheet 2 of 2)

Radionuclide	Spent Fuel Pool	Refueling Pool	Fuel Pool IX Outlet
TE-129M			9.81E-07
TE-129			1.15E-06
TE-131M			1.76E-06
TE-131			7.93E-07
TE-132			1.90E-05
BA-137M			2.49E-05
BA-140			1.54E-07
LA-140			1.06E-07
CE-141			4.92E-08
CE-143	See Table 11.1-5	See Table 11.1-5	2.82E-08
CE-144			2.40E-08
PR-143			3.51E-08
PR-144			2.46E-08
NP-239			8.47E-07
CR-51			1.65E-08
MN-54			8.79E-09
FE-55			6.16E-08
FE-59			1.04E-08
CO-58			2.09E-07
CO-60			8.33E-08

11.2.2.3 Liquid Radwaste System

Each unit of PVNGS is equipped with an identical and independent LRS. The principal functions of the LRS are:

A. To collect for processing radioactive and potentially radioactive liquid wastes from the plant.

B. To process liquid wastes to the high degree of purity necessary for recycle in the plant, since liquid releases are precluded by plant design.

C. To minimize the quantity of liquid waste transferred to the solid radwaste system for solidification and ultimate disposal.

The piping and instrumentation diagram (P&ID) of the LRS is shown in drawing numbers 01, 02, 03-N-LRP-001, -002 and -003.

Input waste streams to the LRS, are identified in table 11.2-8. This table includes annual average daily input flowrates and specific activities of the input streams as a fraction of primary coolant activity.

Input waste streams can be segregated to facilitate treatment. Wastes containing a high degree of total dissolved solids (TDS), including wastes from the chemical waste neutralizer tanks, chemical drain tanks, and the auxiliary, containment, radwaste, and fuel building sumps, are collected for processing in the high TDS holdup tank or in the low TDS tank. Wastes containing a low degree of TDS, including radioactive wastes from the turbine building, auxiliary steam condensate receiver tank, LRS adsorption bed, and recycle monitor tanks, are collected for processing in the high TDS tank or low TDS holdup

Table 11.2-8
WASTE INPUTS TO THE LRS (Sheet 1 of 2)

LRS Inputs	Expected Flow (gal/d-unit)	Design Flow (gal/d-unit)	Activity[a]
<u>High TDS Holdup Tanks</u>			
Containment sump	530	530	[b]
Auxiliary building floor drains	200	200	0.1 PCA
Chemical drain tank	440	440	See chemical drain tank inputs
Laboratory drains	400	400	0.002 PCA
	700	700	0.001 PCA
Total	2270	2270	
<u>Low TDS Holdup Tank</u>			
Turbine building floor drains	7,200	7,200	100% of main steam activity
Secondary system samples	1400	1400	100% of main steam activity

a. PCA = primary coolant activity.
b. 20 gpd @ 0.1 PCA, 10 gpd @ 1.67 PCA, and 500 gpd @ 0.001 PCA.

Table 11.2-8
WASTE INPUTS TO THE LRS (Sheet 2 of 2)

LRS Inputs	Expected Flow (gal/d-unit)	Design Flow (gal/d-unit)	Activity
Low TDS Holdup Tank (cont.)			
Total	8600	8600	
Chemical Drain Tanks			
Decon station waste plus showers	40	40	NUREG 0017
Primary system samples	200	200	0.05 PCA
Handwash Sink Drains	200	200	NUREG 0017
Total	440	440	

tank. Samples from the high and low TDS tanks are available by placing the tanks in a recirculation lineup and drawing a sample of the pump discharge. Turbine building drains are normally nonradioactive, activity being present only when there are primary-to-secondary leaks. To avoid processing more waste through the LRS than necessary, nonradioactive turbine building drains are processed by the chemical waste system. Besides the low TDS tank, an additional holdup tank is provided to accommodate overflow from either the low TDS or the high TDS holdup tank and is normally isolated from the supply headers. If necessary, this tank can be used to collect either low TDS or high TDS liquid waste. An internal mixing header uniformly mixes the contents of each holdup tank prior to and during processing. Acidic or caustic agents may be added for pH control, and antifoaming agents may be added if surfactants exist in the tank contents. Decontamination facility wastes from Unit 1 only and radio-chemistry laboratory wastes are collected in the chemical drain tanks prior to processing.

High TDS wastes are pumped directly from the holdup tank to the LRS evaporator for processing. The evaporator concentrates the waste up to 50 wt% total dissolved solids excluding neutralized boric acid which is concentrated up to 25 wt%. The evaporator concentrate is pumped to the concentrate monitor tanks and ultimately to the solid radwaste system. The concentrate monitor tanks are kept in a continuous recirculation mode while they contain radioactive concentrate. Samples are taken from an analysis point off the pump discharge. The distillate from the evaporator is passed through the LRS adsorption bed and mixed bed ion exchangers arranged in series and then is sent to

the recycle monitor tanks. The monitor tanks' liquid content is then stored for eventual use as makeup for the primary coolant system, the secondary system, or the spent fuel pool. The monitor tanks' contents may also be sent back to the low TDS holdup tank should further processing be desired.

Low TDS wastes are pumped from the holdup tank through the LRS ion exchanger prefilter for removal of larger particles, through the adsorption bed for removal of organics, and through the two mixed bed ion exchangers arranged in series for removal of trace radioisotopes, to the recycle monitor tanks. Waste from the low TDS tank may also be processed by the LRS evaporator in the same manner as High TDS.

Wastes collected in the chemical drain tanks are normally pumped to the high TDS or low TDS holdup tank for processing.

Boric acid from the chemical volume and control system (CVCS), although normally processed through the boric acid concentrator and sent to the refueling water tank, can also be processed through the LRS evaporator should the boric acid concentrator become nonfunctional. When processing boric acid, the LRS evaporator receives CVCS flow from the CVCS holdup tank pumps. Concentrated boric acid is sent to the concentrate monitor tanks and then to approved portable processing equipment. Distillate is sent to the adsorption bed and mixed bed ion exchangers for further processing and is eventually used as plant makeup water.

The LRS may also receive concentrated boric acid from the CVCS boric acid concentrator, should it be desired to dispose of the boric acid. In this case, concentrator bottoms are sent to the

LRS concentrate monitor tanks and ultimately to approved portable processing equipment.

Spent resin from the beds is sluiced with water from the reactor water makeup tank and is pumped to either the low activity or high activity spent resin tanks, or to a portable waste processing system. New resin for the mixed bed demineralizers is added manually from a drum containing new resin.

Liquid radwaste system expected process point specific activities, based on the assumptions given in table 11.2-9, are listed in table 11.2-10. Maximum LRS component inventories are listed in table 12.2-5.

11.2.2.4 Operating Procedures

Operation of the liquid waste management systems consists of a series of automatic and operator-controlled operations.

Collection is generally accomplished automatically, and processing paths are selected by the operator. To reduce the potential for radioactivity being introduced into the condensate storage tank, PVNGS procedures stipulate that the LRS recycle monitor tanks must be sampled prior to pumping down to the condensate storage tank. Besides the normal processing paths, certain other paths are incorporated for the changeout of specified equipment and the switching to redundant equipment.

Table 11.2-9
ASSUMPTIONS USED IN DETERMINING LRS ACTIVITIES

Item	Assumption				
1.	LRS waste inputs are as per table 11.2-8.				
2.	Primary coolant activity is as per Table 11.1-1C.				
3.	Equipment parameters are as per table 11.2-1.				
4.	Both the low TDS holdup tank and a high TDS holdup tank are processed simultaneously.				
5.	Decontamination factors (DF) of LRS process equipment are as follows:				
		Nobel Gases, Tritium	Halogens	CS,RB	Other
	LRS ion exchanger prefilter	1	1	1	1
	LRS adsorption bed	1	1	1	1
	First LRS mixed mixed bed demineralizer	1	100	2	100
	Second LRS mixed bed demineralizer	1	10	10	10
	LRS evaporator (feed:distillate)	1	10^3	10^4	10^4

Table 11.2-10

LRS EXPECTED PROCESS POINT ACTIVITIES (μCi/g) (Sheet 1 of 2)[(1)(2)]

Radioisotope	High/Low Combined TDS Tank Outlet	Chemical Drain Tank Outlet	Adsorption Bed Outlet	First Mixed Bed IX Outlet	Second Mixed Bed IX Outlet	Recycle Monitor Tank Outlet	Evaporator Distillate	Evaporator Concentrate	Concentrate Monitor Tank Outlet
H-3	2.04E-03	9.79E-03	2.05E-06	2.05E-03	2.05E-03	2.06E-03	2.05E-03	-	-
Cr-51	8.80E-06	4.50E-05	8.80E-09	8.80E-11	8.80E-12	8.10E-12	8.80E-09	7.27E-04	1.30E-04
Mn-54	1.65E-06	1.02E-05	1.65E-09	1.65E-11	1.65E-12	1.64E-12	1.65E-09	1.37E-04	1.17E-04
Fe-55	8.19E-06	4.40E-05	8.19E-09	8.19E-11	8.19E-12	8.18E-12	8.19E-09	6.84E-04	6.49E-04
Co-58	7.75E-05	3.80E-04	7.75E-08	7.75E-10	7.75E-11	7.50E-11	7.75E-08	6.44E-03	3.24E-03
Fe-59	4.79E-06	2.44E-05	4.79E-09	4.79E-11	4.79E-12	4.55E-12	4.79E-09	3.98E-04	1.35E-04
Co-60	1.04E-05	5.86E-05	1.04E-08	1.04E-10	1.04E-11	1.05E-11	1.04E-08	8.66E-04	8.44E-04
Br-83	8.04E-12	1.41E-13	-	-	-	-	8.04E-15	1.34E-10	-
Kr-83m	3.54E-11	6.21E-13	3.57E-11	3.57E-11	3.57E-11	-	3.57E-11	-	-
Br-84	-	-	-	-	-	-	-	-	-
Br-85	-	-	-	-	-	-	-	-	-
Kr-85m	7.46E-08	1.75E-08	7.52E-08	7.52E-08	7.52E-08	1.97E-12	7.52E-08	-	-
Kr-85	1.16E-03	5.61E-03	1.16E-03	1.16E-03	1.16E-03	1.16E-03	1.16E-03	-	-
Rb-86	2.41E-07	1.16E-06	2.41E-10	1.21E-10	1.21E-11	1.07E-11	2.41E-10	1.98E-05	1.58E-08
Kr-87	-	-	-	1.12E-15	1.12E-15	-	1.12E-15	-	-
Kr-88	2.09E-09	8.25E-11	2.11E-09	2.11E-09	2.11E-09	-	2.11E-09	-	-
Rb-88	2.34E-09	9.23E-11	2.34E-12	1.17E-12	1.17E-13	-	2.34E-12	5.41E-09	-
Kr-89	-	-	-	-	-	-	-	-	-
Sr-89	1.67E-06	8.12E-06	1.67E-09	1.67E-11	1.67E-12	1.59E-12	1.67E-09	1.38E-04	5.43E-05
Sr-90	5.04E-08	2.53E-07	5.04E-11	5.04E-13	5.04E-14	5.05E-14	5.04E-11	4.21E-06	4.19E-06
Y-90	3.19E-08	1.69E-07	3.19E-11	3.19E-13	3.19E-14	4.26E-14	3.19E-11	2.82E-06	4.19E-06
Sr-91	3.34E-08	4.37E-08	3.34E-11	3.34E-13	3.34E-14	-	3.34E-11	1.52E-06	-
Y-91m	2.15E-08	2.81E-08	2.15E-11	2.15E-13	2.15E-14	-	2.15E-11	9.73E-07	-
Y-91	3.31E-07	1.65E-06	3.31E-10	3.31E-12	3.31E-13	3.19E-13	3.31E-10	2.75E-05	1.20E-05
Y-93	2.15E-09	3.03E-09	2.15E-11	2.15E-14	2.15E-15	-	2.15E-12	1.00E-07	-
Zr-95	3.18E-07	2.17E-06	3.18E-10	3.18E-12	3.18E-13	3.07E-13	3.18E-10	2.65E-05	1.25E-05
Nb-95	3.07E-07	2.58E-06	3.07E-10	3.07E-12	3.07E-13	3.07E-13	3.07E-10	2.56E-05	1.91E-05
Mo-99	1.86E-04	8.11E-04	1.86E-07	1.86E-09	1.86E-10	8.17E-11	1.86E-07	1.41E-02	8.60E-09
Tc-99m	1.79E-04	7.79E-04	1.79E-07	1.79E-09	1.79E-10	7.84E-11	1.79E-07	1.35E-02	8.26E-09
Ru-103	2.18E-07	1.22E-06	2.18E-10	2.18E-12	2.18E-13	2.06E-13	2.18E-10	1.81E-05	5.32E-06
Rh-103m	2.19E-07	1.22E-06	2.19E-10	2.19E-12	2.19E-13	2.06E-13	2.19E-10	1.81E-05	5.33E-06
Ru-106	3.10E-07	6.70E-06	3.10E-10	3.10E-12	3.10E-13	3.08E-13	3.10E-10	2.59E-09	2.26E-03
Rh-106	3.10E-07	6.70E-06	3.10E-10	3.10E-12	3.10E-13	3.08E-13	3.10E-10	2.59E-03	2.26E-05
Te-125m	1.39E-07	6.71E-07	1.39E-10	1.39E-12	1.39E-13	1.33E-13	1.39E-10	1.15E-05	4.96E-06
Te-127m	1.37E-06	6.63E-06	1.37E-09	1.37E-11	1.37E-12	1.34E-12	1.37E-09	1.14E-04	7.26E-05
Te-127	1.39E-06	6.64E-06	1.39E-09	1.39E-11	1.39E-12	1.33E-12	1.39E-09	1.15E-04	7.22E-05
Te-129m	6.48E-06	3.13E-05	6.48E-09	6.48E-11	6.48E-12	6.05E-12	6.48E-09	5.36E-04	1.30E-04
Te-129	4.15E-06	2.01E-05	4.15E-09	4.15E-11	4.15E-12	3.88E-12	4.15E-09	3.44E-04	8.32E-05

(1) Values shown are representative of a core power of 3876 MWt with the original steam generators. For a core power of 3990 MWt with the replacement steam generators the values shown should be corrected by the ratio of core power.

(2) Isotopes with concentrations less that 1.0E-15 are considered insignificant and are reported by "-".

Table 11.2-10
LRS EXPECTED PROCESS POINT ACTIVITIES (μCi/g) (Sheet 2 of 2)[1][2]

Radioisotope	High/Low Combined TDS Tank Outlet	Chemical Drain Tank Outlet	Absorption Bed IX Outlet	First Mixed Bed IX Outlet	Second Mixed Bed IX Outlet	Recycle Monitor Tank Outlet	Evaporator Distillate	Evaporator Concentrate	Concentrate Monitor Tank Outlet
I-130	2.74E-07	4.94E-07	2.74E-09	2.74E-11	2.74E-12	4.34E-14	2.74E-09	1.39E-05	-
Te-131m	2.25E-06	7.85E-06	2.25E-09	2.25E-11	2.25E-12	3.71E-13	2.25E-09	1.51E-04	-
Te-131	4.11E-07	1.43E-06	4.11E-10	4.11E-12	4.11E-13	6.77E-14	4.11E-10	2.75E-05	-
I-131	1.09E-03	5.18E-03	1.09E-05	1.09E-07	1.09E-08	8.20E-09	1.09E-05	8.73E-02	3.48E-04
Xe-131m	5.06E-04	2.42E-03	5.10E-04	5.10E-04	5.10E-04	4.19E-04	5.10E-04	-	1.86E-05
Te-132	6.58E-05	2.93E-04	6.58E-08	6.58E-10	6.58E-11	3.24E-11	6.58E-08	5.04E-03	1.94E-08
I-132	8.78E-05	3.02E-04	6.78E-07	6.78E-09	6.78E-10	3.34E-11	6.78E-07	5.18E-03	2.00E-08
I-133	1.88E-04	5.39E-04	1.88E-06	1.88E-08	1.88E-09	1.49E-10	1.88E-06	1.14E-02	-
Xe-133m	4.30E-04	1.81E-03	4.33E-04	4.33E-04	4.33E-04	1.57E-04	4.33E-04	-	5.32E-12
Xe-133	6.21E-02	2.89E-01	6.26E-02	6.26E-02	6.26E-02	4.05E-02	6.26E-02	-	7.06E-07
I-134	-	-	-	-	-	-	-	-	-
Cs-134	8.04E-05	3.95E-04	8.01E-08	4.00E-08	4.00E-09	3.99E-09	8.01E-08	6.68E-03	6.26E-03
I-135	1.92E-06	9.33E-06	1.92E-08	1.92E-10	1.92E-11	1.37E-14	1.92E-08	6.99E-05	-
Xe-135m	5.99E-07	4.15E-07	6.03E-07	6.03E-07	6.03E-07	4.28E-15	6.03E-07	-	-
Xe-135	3.25E-05	4.22E-05	3.27E-05	3.27E-05	3.27E-05	1.41E-07	3.27E-05	-	-
Cs-136	3.51E-05	1.68E-04	3.51E-06	1.75E-08	1.75E-09	1.47E-09	3.15E-08	2.87E-03	8.14E-05
Xe-137	-	-	-	-	-	-	-	-	-
Cs-137	5.80E-05	2.91E-04	5.80E-08	2.90E-08	2.90E-08	2.90E-09	5.80E-08	4.84E-03	4.82E-03
Ba-137m	5.42E-05	2.72E-04	5.42E-08	5.42E-10	5.42E-11	2.71E-09	5.42E-08	4.53E-03	4.51E-03
Xe-138	-	-	-	-	-	-	-	-	-
Ba-140	9.25E-07	4.88E-06	9.25E-10	9.25E-12	9.25E-13	7.72E-13	9.25E-10	7.55E-05	2.05E-06
La-140	9.26E-07	4.92E-06	9.26E-10	9.26E-12	9.26E-13	8.52E-13	9.26E-10	7.71E-05	2.35E-06
Ce-141	3.30E-07	1.72E-06	3.30E-10	3.30E-12	3.30E-13	3.08E-13	3.30E-10	2.73E-05	6.35E-06
Ce-143	4.15E-08	1.51E-07	4.15E-11	4.15E-13	4.15E-14	801E-15	4.15E-11	2.83E-06	-
Pr-143	2.23E-07	1.07E-06	2.23E-10	2.23E-12	2.23E-13	1.91E-13	2.23E-10	1.83E-05	6.14E-07
Ce-144	2.77E-07	3.62E-06	2.77E-10	2.77E-12	2.77E-13	2.75E-13	2.77E-10	2.31E-05	1.94E-05
Pr-144	2.77E-07	3.62E-06	2.77E-10	2.77E-12	2.77E-13	2.75E-13	2.77E-10	2.31E-05	1.94E-05
Np-239	2.28E-06	9.66E-06	2.28E-09	2.28E-11	2.28E-12	8.61E-13	2.28E-09	1.69E-04	9.60E-12

A filter remains online until the pressure drop across it reaches the design limit. When the limit is reached, the process flow is either stopped or diverted to a redundant filter. The filter cartridge is then replaced by the method described in subsection 11.4.2.

A demineralizer remains online until the pressure drop across the vessel reaches the design limit, the resin bed is exhausted, or when the shift manager or control room supervisor determines it necessary to place the demineralizer offline. When the demineralizer is to be changed out, the process flow is terminated, the vessel isolated, and spent resin sluiced to the low activity spent resin tank, the high activity spent resin tank, or to the portable waste processing system. New resin is manually loaded into the vessel and processing continues.

The evaporator is operated on either a batch or semicontinuous basis, depending upon the system load. In the event of evaporator outage, liquid can be processed via ion exchange.

Operations of the SCCS and FPCCS are discussed in detail in subsections 10.4.6 and 9.1.3, respectively.

11.2.2.4.1 LRS Operation

The LRS is normally utilized to process floor and equipment drains. During periods of primary-to-secondary leakage, however, the LRS may also receive and process wastes generated in the turbine building, such as floor drains and demineralizer regenerants. Design inputs to the LRS are tabulated in table 11.2-8. The LRS can be divided into three process

trains; those liquids containing a low degree of total dissolved solids, those containing a high degree of total dissolved solids, and those containing chemicals. The LRS is designed so that the three trains may operate simultaneously.

Although the LRS is designed to separate the low and high degree of total dissolved solids, the current operations of the low and high TDS holdup tanks do not separate the inputs. As a result of this, all TDS holdup tanks are currently processed as high TDS waste described in section 11.2.2.4.1.2.

11.2.2.4.1.1 Low Total Dissolved Solids Wastes. The low TDS holdup tank normally collects wastes from the turbine building sump as shown in engineering drawings 01, 02, 03-N-LRP-001, -002 and -003. This sump contains radioactivity when steam generator tube leaks exist coincident with failed fuel. The primary sources of this sump are equipment and floor drains and condensate polishing and blowdown demineralizer regenerants. Other infrequent low TDS inputs include flows from the auxiliary steam condensate receiver tank, and the recycle water monitor tanks. Flow from the LRS adsorption bed may also be recirculated to the low TDS holdup tank if necessary for further removal of organics. When the low TDS holdup tank has been filled (as indicated by a high level alarm in the radwaste control room) or reaches some predetermined level, the contents are then recirculated and sampled for radiological and chemical analysis. Based on the analysis, acid, caustic, or an antifoaming agent is added, if necessary. The holdup tank contents are then recirculated for uniformity of flow composition while a portion of the flow is processed through an

ion exchanger prefilter, the LRS adsorption bed, and two mixed bed demineralizers arranged in series, and is finally sent to the recycle monitor tanks. The prefilter removes large particles, the adsorption bed removes organic contaminants, and the mixed bed demineralizers remove ionic species. Demineralized water collected in the recycle monitor tanks is then stored until needed for plant makeup or recycled to the low TDS holdup tank for further processing. Flow from the low TDS holdup tank is normally terminated manually upon a low level alarm, but is terminated automatically upon a low-low level signal. Flow is terminated or diverted to an alternate path by operator action based on a high-pressure drop across the prefilter, adsorption bed, or ion exchangers, an exhausted resin bed, or when the shift manager or control room supervisor determines it necessary. Low TDS waste may also be processed with the LRS evaporator in the same manner as high TDS waste described in section 11.2.2.4.1.2 below.

11.2.2.4.1.2 High Total Dissolved Solids Wastes. The high TDS holdup tank normally collects radioactive wastes from the auxiliary building, fuel building, containment radwaste and radwaste building sumps, the chemical waste neutralizer tank, and the chemical drain tanks. When the high TDS holdup tank has been filled (as indicated by a high level alarm in the radwaste control room) or reaches some predetermined level, the contents are then recirculated and sampled for radiological and chemical analysis. Based on the analysis, acid, caustic, or an antifoaming agent is added, if necessary. The holdup tank contents are then recirculated for uniformity of flow

composition while a portion of the flow is pumped directly to the LRS evaporator for processing. The evaporator is designed to operate on a batch or semicontinuous basis and the process flow is concentrated up to 50 wt% total dissolved solids excluding neutralized boric acid which is concentrated to 25 wt%. When the desired concentration is achieved, as indicated by evaporator density instrumentation, the evaporator concentrate is pumped to the concentrate monitor tanks and then to approved portable processing equipment. Evaporator distillate is further processed by the adsorption bed and mixed bed demineralizers before reaching the recycle monitor tanks. Flow from the high TDS holdup tank is normally terminated manually upon a low level alarm, but is terminated automatically upon a low-low level signal. A low-low TDS tank level signal will also shift the evaporator to standby. Flow is terminated or diverted to an alternate path by operator action based on evaporator or holdup pump malfunction, high-pressure drop across the adsorption bed or ion exchangers, an exhausted resin bed, or when the shift manager or control room supervisor determines it necessary.

11.2.2.4.1.3 Chemical Wastes. The chemical drain tanks collect potentially radioactive liquids from the radiochemistry lab and the decontamination facility (Unit 1 only) as shown on engineering drawings 01, 02, 03-N-LRP-001, -002 and -003. Normally these wastes are sent to the high TDS holdup tank for processing.

11.2.2.4.1.4 Abnormal Operation. The LRS design inputs are listed in table 11.2-8 and the design assumptions are listed in

table 11.2-9. Inputs in excess of those tabulated for the design basis operation can be caused by a single isolated occurrence condition, such as back-to-back refueling or equipment outages. Each 30,000-gallon high or low TDS holdup tank has sufficient capacity to allow for a waste evaporator outage of 48 hours concurrent with abnormal secondary chemistry requiring one condensate polishing demineralizer regeneration per day under the following conditions:

- Availability of the LRS ion exchanger processing capability.
- The online LRS holdup tanks are 50% full.
- The waste neutralizer tanks are full.
- Normal inputs continue to accumulate.

However, should additional capacity be required, the second high TDS holdup tank will accommodate the additional input.

Most LRS process equipment is backed up by redundant equipment within the LRS itself. Liquid radwaste system holdup tanks, chemical drain tanks, recycle monitor tanks, concentrate monitor tanks, and prefilters are all redundant. At least two redundant pumps are available for each service, with the exceptions being the evaporator main recirculation pump, the recycle monitor pump, and the evaporator steam condensate pump. The capability of further demineralization is provided by the option to recirculate flow through the demineralizers as many times as necessary. During equipment outages, the redundant equipment ensures that the liquid waste can be processed for

recycle to the plant or can be sent to portable processing equipment for packaging and disposal.

Vendor connections are available to allow processing of TDS Holdup Tank contents prior to entering the evaporator and during an evaporator outage or malfunction.

11.2.3 RADIOACTIVE RELEASES

During processing by the liquid waste management systems, radioactivity is removed so that the bulk of the liquid is restored to clean water which is recycled for plant use. The radioactivity removed from the liquids is concentrated in filters, ion exchange resins, and evaporator bottoms. The concentrated wastes are processed for packaging and eventual shipment to an approved offsite disposal location. There are no provisions or significant pathways for the release of radioactive liquids to the environment from PVNGS. All liquid waste is either processed and recycled for plant use or prepared for shipment in accordance with NRC and DOT regulations.

NOTE

> Liquids with radioactivity levels less than the release limits cited in the Offsite Dose Calculation Manual (ODCM) are discharged to the evaporation ponds. Therefore, evaporation pond leakage represents a potential (though insignificant) liquid release pathway. Liquid releases due to evaporation or through ground pathway will not exceed the concentration or dose limits for effluents in 10CFR20.1001-20.2401, Appendix B, Table 2, Column 2 and 10CFR50.

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11.3 GASEOUS WASTE MANAGEMENT SYSTEMS

Separate gaseous waste management systems are provided for each unit of Palo Verde Nuclear Generating Station (PVNGS). The systems are:

A. The gaseous radwaste system (GRS) which collects and stores for decay high activity gases vented from station processing equipment.

B. Low activity waste gas systems which filter waste gas prior to release to the atmosphere. The low activity waste gas systems are the building ventilation exhaust systems, the condenser air removal system, and the turbine gland sealing system.

The condenser air removal system and the turbine gland sealing system are described in subsections 10.4.2 and 10.4.3, respectively.

The building ventilation systems are described in section 9.4. The low activity waste gas systems design is not discussed in this section, except for those portions of the systems relating to gaseous waste management.

11.3.1 DESIGN BASES

11.3.1.1 Gaseous Radwaste System Design Bases

The GRS collects and processes radioactive or potentially radioactive waste gas. This gas, containing primarily hydrogen, is collected and stored in an oxygen-free system to guard against a hydrogen explosion and to allow for radioactive

decay. The GRS has been sized to provide the capability of holding radioactive gas for a 45-day decay period.

After holdup, as appropriate, the stored gases are sampled and then discharged at a controlled rate through a filter and a radiation monitor to the radwaste building exhaust. The radwaste building exhaust dilutes and filters the waste gas prior to release through the plant vent. The GRS limits the release of gaseous activity so that personnel exposure and activity releases in restricted and unrestricted areas are as low as is reasonably achievable (ALARA) within the guidelines set forth in 10CFR50, Appendix I.

11.3.1.1.1 Gaseous Radwaste System Equipment Description

The GRS is comprised of a collection header, a waste gas surge tank, two waste gas compressors, and three waste gas decay tanks. One compressor normally is used while the other is on standby. The waste gas surge tank accommodates gas surge volumes and allows for intermittent compressor operation. The waste gas decay tanks allow for radioactive decay. Subsequent to decay, the gas is discharged through a filter and a radiation monitor at a controlled rate to the ventilation exhaust for dilution prior to discharge. Radiation monitoring is provided on the discharge line from the waste gas decay tanks and on the main plant vent as described in section 11.5. The discharge line radiation monitor is interlocked to shut the discharge line isolation valves on high radiation level. The building ventilation exhaust systems are described in sections 9.4 and 12.2.

Components of the GRS are listed in table 11.3-1. Included are equipment flowrates and/or capacity, material of construction, and the design temperatures and pressures. All of the GRS equipment is similar to equipment that has been successfully used in other nuclear plant radwaste systems. The basic flow diagram of the GRS is shown in engineering drawing 13-N-GRF-001, and the piping and instrumentation diagram of the GRS is shown in engineering drawings 01, 02, 03-N-GRP-001.

The equipment layout of the GRS is presented as part of the radwaste building equipment layout in engineering drawings 13-P-OOB-002 through -011. The layout provides design features consistent with the recommendations of NRC Regulatory Guide 8.8 to minimize occupational radiation exposure to plant personnel. Waste gas compressors, surge tank, and gas decay tanks are segregated and shielded in separate compartments. In addition, nitrogen purging removes radioactive gases from components requiring maintenance. This aids in reducing radiation exposure to the operator. Redundant compressors minimize downtime of the system.

Table 11.3-1
GASEOUS RADWASTE SYSTEM PROCESS EQUIPMENT DESCRIPTION

Equipment	Quantity	Flowrate/ Capacity	Material of Construction	Design Pressure/ Temperature (psig/°F)
Gas surge tank	1	760 ft^3	Carbon steel with plastic lining	380/200
Compressors	2	10 std ft^3/min	Stainless steel	380/150
Waste gas decay tank	3	760 ft^3	Carbon steel with plastic lining	380/200

Piping runs are located in shielded pipe chases. Drain line routings prevent accumulation of drainage inside the piping. Local samples are drawn into a centrally-located sampling station, which is provided with a nitrogen purge and process piping shielding to minimize radiation exposure to the operator.

The maximum GRS component inventories are listed in table 12.2-5.

Sizing of the GRS is based on the most severe anticipated operational occurrences that could occur during normal operation as demonstrated in table 11.3-2. The volume of gas to be stored is determined by calculating the gas generated in the most restrictive time period in the core cycle.

During this 30-day interval, it is assumed that the gas stripper operates continuously, the volume control tank is vented twice, the reactor drain tank is vented continuously and

one RCS degassing occurs. Based on these assumptions, the GRS has capacity for a minimum of 45 days holdup, including anticipated operational occurrences. Calculated radioactive releases (see subsection 11.3.3) assume a 45-day holdup even though the average holdup time may be far greater.

11.3.1.1.2 Codes and Standards

Codes and standards applicable to the gaseous waste management system are listed in table 11.3-3. The GRS is located in the non-Seismic Category I radwaste building.

The GRS is designated as a non-Seismic Category I system with the exception of the containment isolation valves and connecting piping which are Seismic Category I. The gas decay tanks, compressors, surge tank, and interconnecting piping from the tanks, through and including the first normally closed isolation valve, are non-Seismic Category I, ANSI safety class 3, and Quality Group D (augmented).

11.3.1.1.3 Valves

Manual, remotely operated, and automatic valves used in the GRS are designed to minimize gas leakage. Engineering features such as diaphragms, bellows seals, and soft seats are employed in the system to prevent or minimize leakage. Each valve in the GRS is designed to meet the temperature, pressure, and code requirements for the specific application for which it is used.

Table 11.3-2
GASEOUS RADWASTE SYSTEM DESIGN ASSUMPTIONS

Item	Normal or Expected	Design
Primary system normal degassing	Continuous operation of gas stripper on letdown flow of 72 gal/min and 30 cc/kg dissolved gas (0.32 standard ft^3/min)	Continuous operation of gas stripper on letdown flow of 72 gal/min and 30 cc/kg dissolved gas (0.32 standard ft^3/min)
Plant degassing	One plant degassing per year (275 standard ft^3/year)	One plant degassing during the 30-day interval (275 standard ft^3)
Volume control tank	One venting per year (408 standard ft^3 per venting)	Two ventings per 30-day interval (816 standard ft^3 per interval)
Reactor drain tank	Continuous venting at 0.02 standard ft^3/min	Continuous venting at 0.02 standard ft^3/min

11.3.1.1.4 Compressors

Each compressor employs a double-diaphragm arrangement with an additional leak detection spacer diaphragm located between the two main diaphragms. Failure of either the top or bottom diaphragm results in a pressure increase in the leak detection spacer. The rise in pressure triggers a pressure switch, initiates an alarm, and automatically trips the compressor. The compressor is then shut down and isolated for repairs, and the standby compressor is started. As long as the second diaphragm remains intact, there is no possibility for gas to leak in or out of the system at this point. Only in the unlikely event of simultaneous failure of both diaphragms does the potential for leakage exist.

Table 11.3-3
EQUIPMENT CODES, GASEOUS RADWASTE SYSTEM

EQUIPMENT	CODES			
	Design and Fabrication	Materials[a]	Welder Qualifications and Procedure	Inspection and Testing
Tanks	ASME Code Section VIII, Div. 1	ASME Code Section II	ASME Code Section IX	ASME Code Section VIII Div. 1
Compressors	Manufacturer's[b] Standards	ASME Code Section II or Manufacturer's Standard	ASME Code Section IX (as required)	ASME[c] Section III, Class 3; or Hydraulic Institute
Piping and valves	ANSI B31.1	ASTM or ASME Code Section II	ASME Code Section IX	ANSI B31.1
Gaseous discharge filter and gas compressor prefilter	ASME Code Section VIII, Div. 1	ASME Code Section II	ASME Code Section IX	ASME Code Section VIII, Div. 1

a. Material manufacturer's certified test reports were obtained whenever possible.

b. Manufacturer's standard for the intended service. Hydrotested to 1.5 times the design pressure.

c. ASME Code Stamp and material traceability not required.

11.3.1.1.5 Instrumentation

The GRS instrumentation is shown in engineering drawings 01, 02, 03-N-GRP-001. The oxygen analyzers are discussed in subsection 9.3.2. The GRS radiation monitors are discussed in section 11.5. Compressor instrumentation necessary for operation can be read at a local panel outside the compressor room. Remote indication and alarms are provided in the radwaste system control panel area in the radwaste building. Gaseous radwaste system alarm conditions are retransmitted to the main control room.

The automatic isolation valves in the decay tank discharge header are interlocked to close on high radiation signals from the waste gas header monitor, high discharge flow, or low radwaste building exhaust flow. Therefore, even during the improbable instance where the discharge valve from the wrong decay tank is inadvertently opened, the release would be automatically terminated when the radiation setpoint is exceeded. The resultant activity released to the environment would be within plant technical specification limits for radioactive gaseous releases.

11.3.1.1.6 Hydrogen Control

The major sources of hydrogen in the GRS are the off-gases from the gas stripper, the volume control tank, and the reactor drain tank. These sources will produce a gas consisting primarily of hydrogen and nitrogen with trace quantities of oxygen and fission gases. These sources are piped to the waste gas surge tank from which gas is compressed into decay tanks.

The GRS and its input sources are initially purged at plant startup with nitrogen. The surge tank and gas surge header are monitored for oxygen, and hydrogen is assumed to be greater than 4% when in service as described in subsection 9.3.2. The oxygen analyzer continually samples upstream of the surge tank at the surge header and at the gas surge tank. An alarm on high oxygen (2%) from either of these sources is annunciated in the main control room and in the radwaste control room. Operating personnel can be dispatched to mitigate the situation via nitrogen dilution, purge, etc. An alarm on high-high oxygen (3.75%) from either of these sources is annunciated in the main control room and in the radwaste control room. Under these conditions the waste gas compressors will automatically trip, and nitrogen will be automatically injected into the GR system down stream of the check valve V-003. Automatic nitrogen injection will isolate the system and dilute oxygen concentration down stream of check valve V-003 (from the check valve to holdup tanks) to less than four percent per volume. In addition, low surge tank pressure automatically initiates an alarm to alert operating personnel of a tank leak which could potentially result in oxygen inleakage to the system. Thus, it is not necessary for the waste gas surge header, surge tank, decay tanks, valves, piping, and compressors to be designed to withstand an internal hydrogen explosion.

After a suitable storage period, the gas is released to the radwaste building exhaust vent, through a split path. The primary path is controlled by a flow controller at a rate of 45 standard cubic feet per minute or less. The secondary path flows through a pressure reducer to allow flow through a

radiation monitor at approximately 5 standard cubic feet per minute. The total release rate is 50 standard cubic feet per minute or less. The release rate is governed by the requirements of 10CFR20.1-20.601 and 10CFR50, Appendix I. The air flowrate through the vent is 25,500 standard cubic feet per minute, which results in a hydrogen concentration of less than 1%, well below the combustion limit of hydrogen in air. The gaseous discharge isolation valves will automatically shut on high discharge flowrate, low radwaste building exhaust, or high radiation level in the discharge line.

Potential buildup of hydrogen in the ventilation exhaust systems can come from storage tanks that contain liquids previously processed through the gas stripper. Consequently, with a gas stripper efficiency of 99.9% and a maximum hydrogen pressure of 50 psig (administrative limit) in the volume control tank, the maximum hydrogen concentration that can exist in the gas space above a liquid surface downstream of the gas stripper is 0.44%, well below the combustion limit of hydrogen in air.

Another potential source of hydrogen is liquids fed to the equipment drain tank and chemical drain tanks, but these will contain only small quantities of dissolved hydrogen. The sources of dissolved hydrogen in these tanks are reactor coolant system leakage and reactor coolant system samples.

These liquid sources release most of their dissolved hydrogen while being depressurized from system pressure to atmospheric pressure. This liquid is then diluted with other drains that contain no dissolved hydrogen.

Thus, the contents of the equipment drain tank and chemical drain tanks contain a low concentration of dissolved hydrogen at atmospheric pressure, precluding a hydrogen buildup in the gas space over the liquid surface of these tanks.

11.3.1.1.7 Cost-Benefit Analysis

Refer to Appendix 5B of the Environmental Report - Operating License Stage for the cost-benefit analyses.

11.3.1.2 Low Activity Waste Gas Systems

Low activity waste gases are routed to building vents through particulate filters. Personnel exposures and activity releases from these wastes in restricted and unrestricted areas are within the ALARA guidelines set forth in 10CFR50, Appendix I, when combined with the releases from the GRS.

11.3.2 SYSTEM DESCRIPTIONS

11.3.2.1 Gaseous Radwaste System

As shown in the GRS piping and instrumentation diagram (01, 02, 03-N-GRP-001), the GRS has a collection header, a waste gas surge tank, two waste gas compressors, and three waste gas decay tanks. One compressor is normally used, while the other is on standby. Liquid seals are not incorporated in the system design.

Sources for the GRS include the gases from:

- Reactor drain tank
- Volume control tank

- Refueling failed fuel detectors
- Gas stripper
- Reactor vessel vent

The high activity gases accumulate in the waste gas surge tank and are compressed and stored in the waste gas decay tanks. When the surge tank pressure reaches 3 psig, the compressor selected for operation starts automatically and starts charging the online decay tank. If the surge tank pressure reaches 3.5 psig, the standby compressor will automatically start. Operation of either compressor automatically stops when the surge tank pressure decreases to 1.5 psig, corresponding to a compressor suction pressure of 0.5 psig. When decay tank pressure reaches 350 psig, an alarm is actuated and compressor operation is terminated manually. Identical compressors are provided to minimize system downtime.

Each decay tank is sampled prior to discharge. No special mixing is considered necessary for the gas. Each sample is analyzed for radioactivity and the concentration, volume, and total radioactivity are recorded. Isotopic content of the waste gases is determined and recorded as specified in the station manual procedures.

The maximum rates and quantities of radionuclides released from the gaseous waste decay tanks will be in accordance with the limits imposed by the plant technical specifications. The rate of release from the decay tanks into the ventilation exhaust is limited so as not to exceed the release limits of 10CFR20.1-20.601. Releases are conducted to meet the ALARA objectives of 10CFR50, Appendix I.

Each tank is capable of being isolated. Only one tank is valved into operation at any one time to diminish the amount of radioactive gas that can be released due to a postulated rupture of a decay tank or connected piping.

Gaseous radwaste system capacity is based on the design assumptions listed in table 11.3-4. The sources, annual volume, and average flowrate into the GRS are shown on table 11.3-4 for maximum design operation assuming continuous gas stripping.

Bounding activity inputs to the GRS are listed in table 11.3-5. These inputs are based on reactor coolant gaseous activities shown in Table 11.1-1C. To maximize the activity into the GRS tanks the gas stripper is assumed to degas the primary coolant for 8.2 hours immediately prior to shutdown. This model was selected to yield upper bound sources. More detailed models which account for actual operation are less conservative.

11.3.2.2 Condenser Air Removal System

The mechanical operation and description of the condenser air removal system is discussed in subsection 10.4.2. The piping and instrumentation diagrams that indicate processing equipment, normal flow paths through the system, redundancy in equipment, system interconnections, and seismic and quality group interfaces are also presented in subsection 10.4.2.

11.3.2.3 Turbine Gland Sealing System

The mechanical operation and description of the turbine gland seal system are discussed in subsection 10.4.3. The piping and

instrumentation diagrams that indicate processing equipment, normal flow paths through the system, redundancy, system interconnections, and seismic and quality group interfaces are also presented in subsection 10.4.3.

Table 11.3-4
MAJOR SOURCES, VOLUMES, AND FLOWRATES OF
GASES TO THE GASEOUS RADWASTE SYSTEM

Source	Gas	Annual Volume (Standard ft^3)	Maximum[a] Flowrate (Standard ft^3/min)	Annual Flowrate (Standard ft^3/min)
Volume control tank	H_2	2,500		0.006
	N_2	610	20	0.002
	O_2	65		1.6E-4
Gas Stripper[b]	H_2	142,000		0.338
	N_2	2,950	20	0.007
	O_2	40		9.5E-5
Reactor drain tank	H_2	0		0
	N_2	7,759	20	0.02
	O_2	0		0
Refueling failed fuel detector	H_2	0		0
	N_2	2,000	20	0.005
	O_2	0		0

a. Flowrates are estimated expected maximums, not continuous.

b. Gas stripper values assume continuous gas stripping.

Table 11.3-5
ACTIVITY INPUT CONCENTRATIONS TO THE GASEOUS RADWASTE SYSTEM ($\mu Ci/cm^3$)[1]

Isotope	Gas Stripper	Volume Control Tank	Reactor Drain Tank
Kr-83m	4.55E-01	8.31E-03	5.65E-04
Kr-85m	2.38E+00	2.02E-02	5.26E-03
Kr-85	4.86E+00	4.53E-02	2.13E-01
Kr-87	1.30E+00	9.14E-03	8.56E-04
Kr-88	4.33E+00	3.50E-02	6.21E-03
Kr-89	1.08E-01	1.79E-04	3.04E-06
Xe-131m	2.62E+00	1.63E-01	8.90E-02
Xe-133m	4.86E+00	1.25E-01	8.53E-02
Xe-133	4.09E+02	7.12E-02	1.09E+01
Xe-135m	2.82E-01	1.63E-01	4.18E-03
Xe-135	7.60E+00	6.09E-01	4.58E-02
Xe-137	1.94E-01	3.58E-04	6.69E-06
Xe-138	9.51E-01	3.88E-03	1.42E-04
I-129	0.00E+00	0.00E+00	0.00E+00
I-130	4.70E-05	3.86E-09	2.68E-07
I-131	6.22E-03	5.42E-07	1.97E-04
I-132	2.19E-03	1.71E-07	1.47E-05
I-133	8.31E-03	7.05E-07	7.37E-05
I-134	1.02E-03	5.75E-08	4.63E-07
I-135	4.21E-03	3.36E-07	1.38E-05
Totals	4.39E+02	1.25E+00	1.14E+01

[1]Contributions from particulate isotopes are negligible due to partitioning in the VCT, RDT and Gas Stripper. Only Noble Gasses and Halogens are reported.

11.3.2.4 Building Ventilation Systems

The plant building ventilation systems discharge radioactive gaseous waste resulting from equipment leakage and are discussed in section 9.4. The radioactive sources are discussed in section 12.2.

11.3.3 RADIOACTIVE RELEASES

Expected annual releases from the GRS were estimated for normal operations using failed fuel corresponding to ANSI N237. The input activities are defined in subsection 11.3.2. The holdup time is considered to be 45 days. Results are shown in table 11.3-6. Estimated releases from the condenser air removal system, turbine gland sealing system, containment building, auxiliary building, fuel building, and turbine building for component activities which0 are consistent with ANSI N237 are also listed in this table. Expected effluent site boundary concentrations are also listed in table 11.3-6. These concentrations are based on the worst sector annual average atmospheric dispersion factor, presented in section 2.3.

Table 11.3-7 lists the assumptions that are used to calculate the airborne releases. Source terms and assumptions based upon Regulatory Guide 1.112, Revision 0, are used where appropriate.

During normal operation, including transients associated with anticipated operational occurrences, the potentially

significant points of airborne radioisotope releases are:

- Plant vent stack
- Fuel building ventilation exhaust
- Turbine building

Table 11.3-6
ANNUAL RELEASES PER UNIT FOR NORMAL OPERATION (ANSI N237 Failed Fuel)

	Release Point and Release (Ci/year/unit)											
		Plant Vent Stack										
Nuclide[1]	Turbine Building	Main Condenser Vacuum Pump Gland Seal Exhaust	Containment Building	Auxiliary/ Radwaste Buildings	BAC Discharge	GRS	Fuel Building	Total Release per Unit (Ci/yr)	Per Unit Site Boundary Annual Average Conc. (μCi/cc)	10CFR20 MPC (μCi/cc)	Fraction of MPC (1 Unit)	Fraction of MPC (3 Units)
Kr-83m	--	--	4.66E-01	4.89E-01	6.17E-02	1.50E-01	--	1.17E+00	3.56E-13	3.00E-08	1.19E-05	3.56E-05
Kr-85m	4.43E-04	1.82E+00	5.68E+00	2.77E+00	7.70E-01	7.51E-01	--	1.18E+01	3.59E-12	1.00E-07	3.59E-05	1.08E-04
Kr-85	9.37E-04	4.02E+00	7.80E+02	6.41E+00	4.07E+02	3.49E+02	--	1.55E+03	4.72E-10	3.00E-07	1.57E-03	4.72E-03
Kr-87	2.31E-04	9.74E-01	9.39E-01	1.32E+00	1.19E-01	4.15E-01	--	3.77E+00	1.15E-12	2.00E-08	5.74E-05	1.72E-04
Kr-88	7.98E-04	3.31E+00	6.78E+00	4.89E+00	8.86E-01	1.41E+00	--	1.73E+01	5.27E-12	2.00E-08	2.63E-04	7.90E-04
Kr-89	--	--	3.40E-03	2.18E-02	4.15E-04	3.45E-02	--	6.01E-02	1.83E-14	3.00E-08	6.11E-07	1.83E-06
Xe-131m	4.97E-04	2.04E+00	2.08E+02	3.26E+00	5.54E+01	9.07E+00	--	2.78E+02	8.46E-11	4.00E-07	2.12E-04	6.35E-04
Xe-133m	--	--	1.13E+02	5.98E+00	2.16E+01	1.58E+00	--	1.42E+02	4.33E-11	3.00E-07	1.44E-04	4.33E-04
Xe-133	7.76E-02	3.17E+02	2.01E+04	5.05E+02	4.28E+03	1.56E+02	--	2.54E+04	7.73E-09	3.00E-07	2.58E-02	7.73E-02
Xe-135m	--	--	4.31E-02	1.70E-01	7.10E-03	9.28E-02	--	3.13E-01	9.55E-14	3.00E-08	3.18E-06	9.55E-06
Xe-135	1.43E-03	5.85E+00	3.54E+01	9.11E+00	5.36E+00	2.52E+00	--	5.82E+01	1.77E-11	1.00E-07	1.77E-04	5.32E-04
Xe-137	--	--	7.34E-03	4.57E-02	9.11E-04	6.19E-02	--	1.16E-01	3.53E-14	3.00E-08	1.18E-06	3.53E-06
Xe-138	1.38E-04	6.35E-01	1.32E-01	5.47E-01	1.94E-02	3.05E-01	--	1.64E+00	4.99E-13	3.00E-08	1.66E-05	4.99E-05
Br-83	--	--	1.55E-05	8.89E-04	1.67E-07	1.14E-05	--	9.16E-04	2.79E-16	1.00E-10	2.79E-06	8.37E-06
Br-84	1.57E-06	2.99E-04	1.92E-07	3.47E-04	1.78E-08	5.80E-06	--	6.54E-04	1.99E-16	3.00E-08	6.64E-09	1.99E-08
Br-85	--	--	2.02E-08	9.00E-06	1.88E-10	6.63E-07	--	9.69E-06	2.95E-18	3.00E-08	9.84E-11	2.95E-10
I-130	--	--	3.31E-05	4.51E-04	5.67E-07	5.78E-06	--	4.90E-04	1.49E-16	1.00E-10	1.49E-06	4.48E-06
I-131	1.01E-03	1.35E-01	4.71E-02	6.43E-02	2.76E-03	1.21E-02	--	2.62E-01	7.99E-14	1.00E-10	7.99E-04	2.40E-03
I-132	1.67E-04	2.68E-02	3.03E-04	1.85E-02	1.74E-04	2.37E-04	--	4.62E-02	1.41E-14	3.00E-09	4.69E-06	1.41E-05
I-133	1.21E-03	1.68E-01	1.01E-02	8.41E-02	2.10E-04	1.09E-03	--	2.65E-01	8.07E-14	4.00E-10	2.02E-04	6.05E-04
I-134	4.22E-05	7.62E-03	5.57E-05	7.27E-03	5.37E-07	1.03E-04	--	1.51E-02	4.60E-15	6.00E-09	7.66E-07	2.30E-06
I-135	4.95E-04	7.03E-02	1.61E-03	3.89E-02	2.27E-05	4.68E-04	--	1.12E-01	3.41E-14	1.00E-09	3.41E-05	1.02E-04
H-3	2.70E-01	0.00E+00	2.13E+01	1.43E+01	5.01E+02	--	3.84E+02	9.21E+02	2.81E-10	2.00E-07	1.40E-03	4.21E-03
C-14	--	--	2.11E+00	5.92E+00	--	1.58E+00	--	9.54E+00	2.91E-12	1.00E-07	2.91E-05	8.72E-05
Ar-41	--	--	4.47E+01	--	--	--	--	4.34E+01	1.32E-11	4.00E-08	3.31E-04	9.92E-04
TOTAL	3.55E-01	3.36E+02	2.13E+04	5.60E+02	5.27E+03	5.35E+02	3.84E+02	2.84E+04			3.11E-02	9.32E-02

(1) Particulate isotopes are assumed to settle out of the air and are considered to be negligible at the site boundary. Accordingly, particulate isotopes are not reported.

Table 11.3-7
ASSUMPTIONS FOR ESTIMATING RADIOACTIVE RELEASES (PER UNIT)
(Sheet 1 of 3)

Item	Assumption
Primary-to-secondary leakage, lb/d	100[a]
Secondary leakage into turbine building	
Steam, lb/d	1700[a]
Condensate, gal/min	5[a]
Leakage into auxiliary/radwaste buildings, lb/d	160 at 1 PCA[a]
Leakage into containment building atmosphere (expressed as a percent of primary coolant inventory)	
Noble gases, %/d	3[a]
Iodines, %/d	0.001[a]
Iodine partition factors	
Auxiliary/radwaste building leakage	0.0075[a]
Turbine building leakage	
Steam	1[a]
Condensate	0.0075[a]
Main condenser vacuum pump/ gland seals	0.0075[a]
Expected primary coolant activity (PCA)	As per Table 11.1-1C
Expected secondary system activity	As per table 11.1-7
Expected tritium releases	As per table 11.1-3

a. From NUREG-0017

Table 11.3-7
ASSUMPTIONS FOR ESTIMATING RADIOACTIVE RELEASES (PER UNIT)
(Sheet 2 of 3)

Item	Assumption
Gaseous radwaste system input activity	As per table 11.3-5
Mass of primary coolant, lb	6.454×10^5
Filter efficiencies	
HEPA, %	95(b)
Charcoal, %	70(c)(d)
Flows using HEPA filters	Containment normal exhaust Auxiliary building exhaust Turbine building vacuum pump exhaust Radwaste building exhaust
Flows using charcoal filters	Containment normal exhaust Turbine building vacuum pump exhaust
Containment parameters	
Net free volume, ft^3	2.6×10^6
Purge rate (power access), ft^3/min	1200

b. Conservative assumption to allow for up to 1% HEPA bypass and penetration leakage

c. Regulatory Guide 1.140

d. Conservative assumption to allow for up to 1% carbon absorber bypass and penetration leakage (Refer to generic letter 83-13).

Table 11.3-7
ASSUMPTIONS FOR ESTIMATING RADIOACTIVE RELEASES (PER UNIT)
(Sheet 3 of 3)

Item	Assumption
Power access purge frequency, No./yr	51
Power access purge duration, h	16
Purge rate (refueling)	33,000
Auxiliary building parameters	
Net free volume, ft^3	13.7×10^5
HVAC exhaust flowrate, ft^3/min	58,400[d]
Turbine building parameters	
Net free volume, ft^3	7.13×10^6
HVAC exhaust flowrate, ft^3/min	474,160[d]
Boric acid concentrator distillate discharged, gal/y	358,000 as vapor[e]
Chemical and volume control system parameters	As per section 9.3.4
Gaseous radwaste system parameters	
Discharge rate, standard ft^3/min	50
Gas decay tank holdup time, d	45
Turbine gland seal exhauster moisture flowrate, lb/h	310

e. The discharge rate is based on the amount of primary water that must be discharged to maintain tritium airborne concentrations in the most restrictive building to a less than one-half of the 10CFR20.1-20.601 MPC limit for restricted areas. The discharge rate is not a function of water usage but rather a function of the RCS tritium production rate and the equilibrium tritium concentration at which the RCS is maintained. Refer to section 11.1.3.2.1 for additional information concerning tritium production and release.

11.3.3.1 Plant Vent Stack

The auxiliary building and radwaste building ventilation exhausts and containment purge exhaust are all directed to the plant vent alongside the turbine building. Exhaust to the atmosphere is vertical at 145 feet above grade. The effluent velocity is a minimum of 2000 feet per minute and has a maximum temperature of 120F.

11.3.3.2 Fuel Building Ventilation Exhaust

The fuel building ventilation exhaust is directed to a cylindrical vent in the roof of the fuel building. Exhaust to the atmosphere is vertical at 116 feet above grade. The vent is designed for a minimum effluent velocity of 2000 feet per minute, and has a maximum temperature of 120F.

11.3.3.3 Turbine Building Ventilation Exhaust

The operating deck of the turbine building exhausts to four power roof ventilators located on top of the turbine building. The turbine building lube oil room, demineralizer room and battery room exhaust through their own exhaust fans to the outside atmosphere. The turbine building exhaust to the atmosphere is through four cylindrical, 97-inch ID vents. Exhaust to the atmosphere is vertical at 248.7 feet above grade. The vents are designed for a minimum effluent velocity at 2000 feet per minute, and have a normal temperature of 120F.

11.3.3.4 Condenser Air Removal System

Air and noncondensable gases are removed from the shell side of the condenser by four mechanical vacuum pumps. Normally three

vacuum pumps are operating, with one pump drawing air from each condenser shell and the fourth pump is in standby. The vacuum pumps discharge to atmosphere via the plant vent unless radioactivity is detected by the radiation monitor in the discharge line. If radiation is detected, the vacuum pump discharge is automatically shifted to a charcoal adsorption train consisting of a moisture separator, electric heater, prefilter, activated charcoal filter, post-exhaust filter, and post-exhaust filter blower. The exhaust is routed to the plant vent, at 2400 feet per minute (minimum). The charcoal adsorption train electric heaters add heat as required to maintain 20F of superheat in the exhaust line.

11.3.3.5 Turbine Gland Sealing System Exhaust

The turbine gland sealing system exhausts to the same exhaust stack as the condenser vacuum pumps and normally exhausts directly to atmosphere, but will automatically shift exhaust paths to the charcoal adsorption train on high radioactivity.

11.3.3.6 Dilution Factors

Atmospheric dispersion (X/Q) factors are discussed in detail and tabulated in section 2.3. For annual releases, the worst sector annual average X/Q is used to calculate offsite concentrations.

11.3.3.7 Estimated Concentrations

Effluent site boundary concentrations for the total system are compared with 10CFR20.1-20.601 in table 11.3-6 for normal operation at failed fuel corresponding to ANSI N237. This

table demonstrates that the 10CFR20.1-20.601 limits are met. This also meets the intent of 10CFR50, Appendix A, GDC 60.

11.3.3.8 Estimated Doses

Estimated doses from gaseous releases are presented in Appendix 5B of the Environmental Report - Operating License Stage.

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11.4 SOLID WASTE MANAGEMENT SYSTEM

Solid waste management is provided by the solid radwaste system (SRS) which is designed to provide holdup and transfer capabilities for radioactive waste streams generated by plant operation, and to store these wastes until they are shipped offsite for processing or disposal. The system is located in the radwaste building, which is designated to withstand an operating basis earthquake. In addition to the SRS, there are two facilities which supplement solid waste management capabilities. The Dry Active Waste Processing and Storage (DAWPS) facility provides a centralized location for handling, processing, packaging, and storage of radioactively contaminated trash and maintenance of radioactive contaminated plant equipment in accordance with the requirements of 10 CFR Part 20 and NRC Generic Letter 81-38. The Low Level Radioactive Material Storage Facility (LLRMSF) provides an interim storage capacity for radioactive materials prior to reuse, shipment for processing or disposal, or transfer to other licensees.

11.4.1 DESIGN BASES

The design bases of the solid waste management system are:

A. The SRS provides the capability for processing and packaging concentrated waste solutions from the miscellaneous waste evaporator, spent resins from radioactive ion exchangers, and chemical drain tank wastes.

B. The SRS provides a means for packaging and disposal of spent radioactive cartridge filters and solid wastes from the LRS and CVCS.

C. The SRS provides a means of compacting and packaging miscellaneous dry radioactive materials, such as paper, rags, contaminated clothing, gloves, and shoe coverings, and a means for packaging contaminated metallic materials and incompressible solid objects, such as small tools and equipment parts.

D. The SRS provides a method of processing and packaging blowdown demineralizer resin and condensate polishing resin in the event that they become contaminated.

E. The DAWPS facility provides a centralized location for handling, processing and storage of radioactive laundry and material used or generated during the operation and maintenance of PVNGS. Maintenance activities may also be performed at the DAWPS facility in accordance with the requirements of 10 CFR Part 20. The radioactive material includes dry active waste (DAW) and plant components undergoing maintenance. The total radioactive inventory of all radioactive material in the DAWPS facility is limited to 15 curies.

DAW generated at PVNGS is packaged and shipped for off-site vendor processing or direct disposal. Some DAW may be compacted on site with the radwaste baler. Potentially contaminated dry waste is monitored in the DAWPS facility and released for disposal.

F. The LLRMSF provides for the interim storage of low-level radioactive material generated at PVNGS in accordance with Generic Letter 81-38. Radioactive material will not be processed in the LLRMSF. Liquid radioactive material and/or mixed waste will not be stored in the facility.

The shielding design is sufficient to satisfy the criteria established in 10CFR20 and 40CFR190. ALARA principles were emphasized during the configuration/ layout of the storage area. The storage area is accessible by a crane and/or forklift. The facility contains storage racks and an underground vault. A HVAC filtration system is available to minimize a release of potentially airborne radioactive material (i.e., container breach).

A control room is provided for monitoring the storage area (video camera) and is the central location for entry and exit into the Radiological Controlled Area (RCA). A RCA yard is provided on the outside of the LLRMSF building. A restricted area fence surrounds the LLRMSF building and the RCA yard.

G. The Old Steam Generator/Old Reactor Vessel Closure Head Storage Facility (OSG/ORVCHSF) provides long-term on-site storage of large contaminated components that are byproducts of nonroutine maintenance activities. Specifically, the OSG/ORVCHSF is designed to safely store the six Old Steam Generators and three Old Reactor Vessel Closure Heads (with

associated Control Rod Drive Mechanisms) for Unit 1, 2, and 3. The Old Steam Generators Storage facility is designed and built to Uniform Building Code (UBC) and ACI 318. The Building seismic category is provided in Table 3.2-1.

The maximum and expected input volumes to the SRS from each source of solid waste material are presented in table 11.4-1. The SRS input activities associated with the expected input volumes are presented in table 11.4-2.

Codes and standards applicable to the solid radwaste system are listed in table 3.2-1.

Collection, solidification, packaging, and storage of radioactive wastes will be performed so as to maintain any potential radiation exposure to plant personnel to as low as is reasonably achievable (ALARA) levels, consistent with the recommendations of Regulatory Guide 8.8 and within the dose limits of 10CFR20.1001-20.2401. Some of the design features incorporated to maintain ALARA criteria include remote system operation, remotely actuated flushing, quick disconnect, equipment layout permitting the shielding of components containing radioactive materials, and use of shielded casks for in-plant movement of high activity waste. Additional ALARA provisions of the SRS are described in section 12.1.

Packaging and transport of radioactive wastes will be in conformance with 10CFR71. Packaged wastes will be shipped in conformance with 49CFR170-178. Collection, solidification, packaging, and storage of radioactive wastes will be performed in conformance with 10CFR50.

Table 11.4-1
SRS INPUT VOLUMES (PER UNIT)

Source (Form)	Expected Volume (ft^3/yr)	Maximum Volume (ft^3/yr)	Bases
Wet Waste			
Evaporator concentrates	3,224	69,877	Regulatory Guide 1.112 April 1976
Spent resin	430	430	Reference 1
Chemical drain tank	0	294	Note 1
Blowdown demineralizer resin	0	282	Note 2
Condensate polishing resin	0	1,872	WASH 1258
Dry Waste			
Compactable and noncompactable dry wastes	11,091	11,091	AIF/NESP-008 (2)
Filters			
Cartridge filters (dry)	10.3	34.2	Reference 1
Total (ft^3/yr)	14,755	83,880	

Notes: 1. The chemical drain tank contents are normally processed by the liquid radwaste system. Maximum volume is based on an additional complete flush of each tank directly to the SRS per year.

2. Blowdown demineralizer resin is not normally changed more than once per year. Maximum volume is based on change out of both demineralizers during one year.

Table 11.4-2
SRS INPUT ACTIVITIES[a][c] (Ci/yr) (Sheet 1 of 3)
(PER UNIT)

Isotope	Filters	Ion Exchangers	Evaporator Concentrates	Dry Wastes[b]
Cr-51	2.02E+01	5.49E-03	1.49E-02	-
Mn-54	2.45E+01	2.56E-03	1.33E-02	-
Fe-55	1.80E+02	4.72E-03	7.40E-02	-
Co-58	4.29E+02	4.65E-02	3.70E-01	-
Fe-59	1.71E+01	2.90E-03	1.55E-02	-
Co-60	2.45E+02	5.90E-03	9.62E-02	-
Br-83	-	7.33E-01	0.00E+00	-
Br-84	-	1.43E-01	0.00E+00	-
Br-85	-	9.04E-03	0.00E+00	-
Rb-86	-	6.37E-01	1.95E-04	-
Rb-88	-	7.09E+00	0.00E+00	-
Sr-89	-	2.10E+01	6.43E-03	-
Sr-90	-	2.12E+00	5.26E-04	-
Y-90	-	2.09E+00	5.27E-04	-
Sr-91	-	3.33E-01	0.00E+00	-
Y-91m	-	2.10E-01	0.00E+00	-
Y-91	-	4.59E+00	1.42E-03	-
Y-93	-	1.83E-02	0.00E+00	-
Zr-95	-	4.35E+00	1.47E-03	-
Nb-95	-	6.23E+00	2.18E-03	-

a. Expected waste generation conditions only, maximum waste generation conditions are not tabulated because they are short-term inputs that are not representative of a year's continuous operation.

b. Nuclide breakdown was not made. Total activity is based on ONWI-20 data.

c. Values shown are representative of a core power of 3876 MWt with the original steam generators. For a core power of 3990 MWt with the replacement steam generators the values shown should be corrected by the ratio of core power.

Table 11.4-2
SRS INPUT ACTIVITIES[a][c] (Ci/yr) (Sheet 2 of 3)
(PER UNIT)

Isotope	Filters	Ion Exchangers	Evaporator Concentrates	Dry Wastes[b]
Mo-99	-	2.94E+02	1.84E-03	-
To-99m	-	2.71E+02	1.76E-03	-
Ru-103	-	2.10E+00	6.31E-04	-
Rh-103m	-	2.10E+00	6.31E-04	-
Ru-106	-	1.69E+00	2.61E-03	-
Rh-106	-	1.69E+00	2.61E-03	-
Te-125m	-	1.91E+00	5.88E-04	-
Te-127m	-	2.93E+01	8.66E-03	-
Te-127	-	2.95E+01	8.63E-03	-
Te-129m	-	5.65E+01	1.55E-02	-
Te-129	-	3.63E+01	9.91E-03	-
I-130	-	1.45E+00	0.00E+00	-
Te-131m	-	3.86E+00	4.66E-06	-
Te-131	-	7.37E-01	0.00E+00	-
I-131	-	2.94E+03	7.39E-02	-
Xe-131m	-	6.52E-02	2.21E-03	-
Te-132	-	1.08E+02	8.03E-04	-
I-132	-	1.23E+02	8.27E-04	-
I-133	-	4.28E+02	1.34E-04	-
Xe-133m	-	1.67E-01	4.83E-05	-
Xe-133	-	4.53E+00	2.39E-03	-
I-134	-	3.40E+00	0.00E+00	-
Cs-134	-	1.56E+03	7.72E-01	-
I-135	-	7.25E+01	0.00E+00	-
Xe-135m	-	1.92E-04	0.00E+00	-

Table 11.4-2
SRS INPUT ACTIVITIES[a][c] (Ci/yr) (Sheet 3 of 3)
(PER UNIT)

Isotope	Filters	Ion Exchangers	Evaporator Concentrates	Dry Wastes[b]
Xe-135	-	8.09E-03	0.00E+00	-
Cs-136	-	6.87E+01	1.09E-02	-
Cs-137	-	1.26E+03	6.03E-01	-
Ba-137m	-	1.17E+03	5.63E-01	-
Ba-140	-	3.40E+00	2.76E-04	-
La-140	-	3.71E+00	3.17E-04	-
Ce-141	-	2.75E+00	7.55E-04	-
Co-143	-	6.80E-02	0.00E+00	-
Pr-143	-	8.88E-01	8.10E-05	-
Ce-144	-	5.21E+00	2.30E-03	-
Pr-144	-	5.21E+00	2.30E-03	-
Np-239	-	3.50E+00	1.73E-05	-
Total	9.15E+02	8.55E+03	2.68E+00	8.00E+01

11.4.2 SYSTEM DESCRIPTION

11.4.2.1 General Description

The SRS is subdivided into four subsystems:

- Spent resin transfer subsystem
- Wet waste processing subsystem
- Dry waste disposal subsystem
- Filter handling and disposal subsystem

The original waste solidification subsystem (Hittman Nuclear) has been abandoned in place. The Hittman solidification subsystem remains installed in the plant, but the descriptive text related to its operation has been deleted. The description of the waste solidification subsystem has been replaced with a description of the wet waste processing subsystem. This subsystem consists of bypass lines that allow wet wastes to be transferred to portable processing equipment.

Plant layout drawings illustrating the packaging, storage, and shipping areas of the radwaste building are presented in engineering drawings 13-P-OOB-003 and -004. The equipment capacities of the SRS and its input streams are presented in table 11.4-3. The SRS piping and instrumentation diagram number is 01, 02, 03-N-SRP-001, -002 and -003. The process flow diagram of the SRS is found on drawing 13-N-SRF-001.

11.4.2.2 Component Description

A description of the SRS components is given in table 11.4-3 and equipment codes are given in table 11.4-4. The following is a functional description of the major system components:

A. Spent Resin Tanks

The high activity and low activity spent resin tanks are provided to hold up spent resin for decay prior to processing by the wet waste processing subsystem. Resin removal from the tanks is through a line which begins near the dilution nozzles at the bottom of the tank and exits at the top of the tank. Dilution water is injected at the bottom head near the resin removal line to facilitate dilution and mixing of the resin as the slurry enters the resin outlet pipe. Resin flow into the tanks is via the inlet pipe through the top head.

The capacity of the spent resin tanks is high enough to allow the simultaneous change out of all the high activity ion exchangers in one tank and one of each of the low activity ion exchangers in the other. Air or nitrogen connections are provided as a backup method for fluidizing the ion exchanger and spent resin tank beds.

B. Resin Transfer/Dewatering Pump

The resin transfer/dewatering pump is a progressive cavity pump which provides sluicing water to transfer resin from the auxiliary building and radwaste building ion exchangers to the spent resin tanks. The pump also dewaters the spent resin tanks. Sizing of the resin transfer/dewatering pump was based on the minimum slurry velocity needed to transport resin in suspension.

C. Shipping Containers and Shields

Shipping containers and transportation casks, used to transport radioactive material offsite, whether leased or purchased, will be in accordance with applicable DOT and NRC regulations. Shields used to transfer or store radioactive material onsite are not required to meet DOT or NRC regulations.

D. Radwaste Baler (Dry Waste Compactor)

The radwaste baler located in the low level storage area is used to package low-radiation level, solid compressible wastes into standard 55-gallon drums. The primary function of the baler is to reduce the volume of wastes that often contain a large void space. Potentially airborne radioactive material which escapes from the drum during compaction is exhausted by the baler exhaust fan through a HEPA filter into the low level storage area. The drums of compacted waste are moved by the bridge crane, forklift, or dolley and stored in the appropriate storage areas depending on dose rates and disposal options.

11.4.2.3 System Operation

11.4.2.3.1 Liquid Waste and Spent Resin Disposal

The wet waste processing subsystem operates on a batch basis to process evaporator concentrates, and spent resins. The system is designed to transfer and store spent blowdown demineralizer resin and spent condensate polishing resin if required.

Table 11.4-3
SRS EQUIPMENT DESCRIPTIONS

Item	Quantity	Capacity	Materials of Construction
Tanks			
Spent resin tanks, (SRN-X01A, B)	2	2010 gal	Stainless steel
Pumps			
Resin transfer/ dewatering Pump (SRN-P01)	1	90 gal/min	Stainless steel with Buna 'N' stator
Other			
Disposable liners	Consum-able	Boxes: 54.3-3000 ft^3 Drums: 55-89 gals Liners/HIC: 14.8-285.1 ft^3	Varies per Specifications
Radwaste baler (SRN-M01)	1	55-gallon drums	Carbon steel and stainless steel

Table 11.4-4
EQUIPMENT CODES

Equipment	Codes		
	Design and Fabrication	Materials[a]	Inspection and Testing
Pressure vessels	ASME Code Section VIII, Div. 1	ASME Code Section II	ASME Code Section VIII, Div. 1
Atmospheric or 0 to 15 psig tanks	ASME Code[b] Section III, Class 3, or API 620 & 650, AWWA D-100	ASME Code[b] Section II	ASME Code[b] Section III, Class 3 or API 620; 650 AWWA D-100
Piping and valves	ANSI 31.1	ASTM or ASME Code Section II	ANSI B 31.1
Pumps	Manufacturer's[c] Standards	ASME Code Section II or Manufacturer's Standard	ASME Code[b] Section III Class 3; or Hydraulic Institute

a. Material manufacturer's certified test reports were obtained whenever possible.

b. ASME Code Stamp and material traceability not required.

c. Manufacturer's standard for the intended service. Hydrotesting is 1.5 times the design pressure.

Sufficient capacity is provided to process radioactive wastes resulting from normal plant operations and anticipated operational occurrences.

Liquid waste solutions are processed by using approved technologies and procedures. Spent resins, including spent blowdown and condensate polisher resins, if required, are processed by transferring the resin into an approved disposal container and dewatering and drying the resin to meet burial requirements.

Liquid inputs from the concentrate monitor tanks and the spent resin tanks are fed into portable processing equipment and packaged into disposal containers or shipped off-site for further processing by a vendor.

The containers are surveyed for external contamination. If surface contamination is detected, the container is decontaminated as necessary. The containers are then moved to appropriate storage area for decay while awaiting shipment to a burial facility.

Complete waste processing and absence of free liquid prior to shipment is assured by the implementation of a process control program consistent with the recommendations of Branch Technical Position ETSB 11-3. The process control program is described and controlled in departmental procedures. Potential waste overflows are contained in the processing area to facilitate cleanup. Bypass lines and connections are provided to enable spent resins from the spent resin tanks and the radwaste and auxiliary building ion exchanger to be sent directly to portable processing equipment or disposal container located in

the truck bay area. In addition, a bypass of the spent resin tanks is provided to allow sluicing directly from the ion exchangers in the radwaste and auxiliary buildings to the portable processing equipment connection in the truck bay area.

11.4.2.3.2 Dry Waste Disposal

Dry waste, components, and equipment that have been contaminated during operation or maintenance are handled, processed, and packaged by qualified plant personnel or by outside contractors specializing in such activities.

11.4.2.3.3 Filter Handling and Disposal

The filters are separated into two classifications:

- Cartridge type filters with disposable elements
- Unshielded low activity filters with disposable elements

The following are cartridge type filters:

- One reactor makeup water filter (subsection 9.3.4)
- One boric acid filter (subsection 9.3.4)
- One reactor drain tank filter (subsection 9.3.4)
- Two seal injection filters (subsection 9.3.4)
- Two fuel pool filters (subsection 9.1.3)
- Two liquid radwaste system filters (subsection 11.2)
- Two purification filters (subsection 9.3.4)

The cartridge filters are located in shielded compartments in the auxiliary building. Filters that constitute a substantial radiation source are accessed from above by removing a concrete shield plug and replacing it with a working lead shield plug. (See engineering drawing 13-P-OOB-004 for filter locations.)

The filter vessel pressure seal is opened and the filter cartridge is lifted through a small hole in the working shield into the filter transfer cask. The lifting operation is done using a lifting winch and grapple attached to the transfer cask. After the filter cartridge is inside the transfer cask, the monorail hoist places the transfer cask onto the bottom section which is then pinned to the transfer cask. The transfer cask is then transferred via monorail to the radwaste building high level storage area. The monorail sets the transfer cask on the laydown area where the bottom section is unfastened. The transfer cask is placed over an empty space in a storage container or over the opening in a disposal container. Typically, filters are accumulated in a storage container until sufficient filters are available for packaging. After a disposal container has been filled with filters, the container is capped and decontaminated as necessary. The container is then transferred to an appropriate storage area to await shipment to a processing facility or, to a burial facility.

The following are unshielded low-activity filters:

- Two waste gas compressor prefilters (section 11.3)
- One gaseous radwaste system discharge filter (section 11.3)

- One blowdown demineralizer filter (subsection 10.4.6)

The gaseous radwaste system (GRS) filters are located in the radwaste building (elevation 140 feet) shown on engineering drawing 13-P-OOB-005. To change a GRS filter, it is isolated, drained, purged with nitrogen, and vented. The vessel flanged cover is opened and the filter element is manually transferred to the solid radwaste area for processing. The blowdown demineralizer filter is located outside the turbine building. To change it, the filter is drained, vented, manually changed, and transferred for storage or disposal. Unshielded low-activity filters are normally changed on high-differential pressure; however, radiation surveys performed allow changing frequencies to be adjusted to minimize man-rem exposure.

11.4.2.4 Packaging, Storage, and Shipment

All radioactive wastes will be prepared for shipment in containers which meet the requirements of U.S. Department of Transportation (DOT) and NRC regulations. Wet wastes are processed to an acceptable form for disposal or shipped in accordance with NRC and DOT regulations to a licensed waste processor. Dry, solid wastes are packaged in acceptable containers for processing or disposal.

All containers are capped prior to interim storage and offsite shipment.

Shielded transportation casks will be used when required.

Packaged radwaste is stored in a storage area and shielded as necessary. Unused, uncontaminated shipping containers are stored in allocated storage areas onsite. The solid radwaste

storage area is segregated into high-level and low-level storage areas. The shielded storage area for high-level solid radwaste contains 945 square feet (42 large containers stacked two high or 294 drums stacked two high) of usable floor area. The low-level storage area contains 350 square feet of usable floor area. Both the high and low level storage areas are designed to allow a 30-day decay of the expected annual waste volumes shown in table 11.4-5 prior to shipment offsite.

Containers can normally be shipped immediately after filling, provided the proper shielding is available, without exceeding DOT radiation limits. If 49CFR173 dose limitations cannot be met with the available shielding, the liners are stored and allowed to decay until the appropriate shielding is available. Onsite storage for decay of short-lived radionuclides is accomplished both prior to processing in liquid storage tanks and after processing in the waste storage area.

The maximum and expected annual volumes, including estimated curie content, of solid radwaste to be shipped offsite are given in tables 11.4-5 and 11.4-6 based on the following assumptions:

A. Evaporator concentrates are processed and stored in an appropriate storage area for 1 month (i.e., 1-month decay) prior to shipment.

B. Spent resin beads are stored for 6 months prior to drying. Resin is stored in an appropriate storage area for 1 month (i.e., 1-month decay) prior to shipment.

C. Cartridge filters are packaged and stored in the appropriate storage area for 1 month (i.e., 1-month decay) prior to shipment.

11.4.2.5 Dry Active Waste Processing and Storage (DAWPS) Facility

The DAWPS facility is designed to provide centralized handling, processing, packaging, and storage of radioactively contaminated trash generated during the operation and maintenance of PVNGS. The performance of maintenance on radioactively contaminated plant equipment may also be performed in the DAWPS facility in accordance with the requirements of 10 CFR Part 20. The contaminated trash, dry active waste (DAW), is composed of rags, paper, plastic, rubber, wood, glass, concrete, and metal and is, for the most part, low in its content of radioactivity.

The DAWPS facility serves as the centralized location for processing of contaminated trash, temporary storage of radioactive materials, tools, and interim storage of package waste until shipment to a burial site. The facility is a prefabricated metal building of approximately 17,500 square feet and approximately 60,000 cubic feet of storage space.

The building is divided in three basic compartments: 1) storage area, 2) processing area, and 3) offices and change area.

The DAWPS storage area provides storage for dry active waste (DAW), and other radioactive materials, such as tools and equipment. Radioactive material is packaged into containers

that meet NRC and/or DOT requirements for shipping or disposal. All storage drums and boxes are decontaminated before being placed into the waste storage area. Ventilation for this area shall be provided by the use of natural draft through louvers and an extractor fan. Packages are stored in accordance with administrative controls to ensure that exposures are maintained ALARA and within 10CFR20.1001-20.2401 and administrative limits.

The processing area contains the sorting, processing, and a receiving area for incoming material to be processed, an emergency eye-wash station, and an analytical work area (smear station). The processing area is equipped with a ventilation supply fan and evaporative cooler. The air return system is provided with prefilters, HEPA filters, and an access porthole for radiation monitoring equipment. While processing radioactive materials or performing maintenance on equipment, the processing area is maintained under negative pressure in relation to offices, storage, and outside areas, or administrative controls employed to ensure against the release of unmonitored airborne radioactivity.

Heating and cooling of the offices and restroom/locker room is accomplished by the use of air conditioning equipment.

Radiation protection for the DAWPS facility is as per section 12.5, Radiation Protection Program.

Table 11.4-5
SRS OUTPUT VOLUMES PER UNIT

Source	Expected Volume (ft^3/yr)	Maximum Volume (ft^3/yr)	Containers Shipped		
			Large Containers (expected/ max/yr)	Drums of Solidified Waste (expected/ max/yr)	Drums of Baled Waste (expected/ max/yr)
Wet Waste					
Evaporator concentrates	4,299	93,169	54/1,165	585/12,677	-
Spent resin beads	1,147	6,891	16/87	158/938	-
Chemical drain tank effluent	0	420	0/0	0/58	-
Dry Waste					
Baled waste	3,697	3,697	-	-	503/503
Filters					
Cartridge filters	160	610	-	22/83	-
Total	9,303	104,787	70/1,252	765/13,756	503/503

Table 11.4-6
SRS OUTPUT ACTIVITIES[(a)(c)] (Ci/yr/unit) (Sheet 1 of 2)

Isotope	Filters	Ion Exchangers	Evaporator Concentrates	Dry Wastes[3]
Cr-51	9.57E+00	2.92E-05	7.06E-03	-
Mn-54	2.29E+01	1.58E-03	1.24E-02	-
Fe-55	1.76E+02	4.05E-03	7.24E-02	-
Co-58	3.20E+02	6.00E-03	2.76E-01	-
Fe-59	1.09E+01	1.24E-04	9.86E-03	-
Co-60	2.42E+02	5.47E-03	9.51E-02	-
Rb-86	-	2.61E-04	6.39E-05	-
Sr-89	-	1.28E+00	4.31E-03	-
Sr-90	-	2.09E+00	5.25E-04	-
Y-90	-	2.09E+00	5.26E-04	-
Y-91	-	3.86E-01	9.99E-04	-
Zr-95	-	4.63E-01	1.07E-03	-
Nb-95	-	9.37E-01	1.75E-03	-
Mo-99	-	0.00E+00	1.07E-06	-
To-99m	-	0.00E+00	1.03E-06	-
Ru-103	-	5.28E-02	3.73E-04	-
Rh-103m	-	5.29E-02	3.73E-04	-
Ru-106	-	1.14E+00	2.46E-03	-
Rh-106	-	1.14E+00	2.46E-03	-
Te-125m	-	1.56E-01	4.11E-04	-
Te-127m	-	7.71E+00	7.16E-03	-
Te-127	-	7.68E+00	7.13E-03	-

a. Expected waste generation conditions only. Maximum waste generation conditions are not tabulated because they are short-term inputs that are not representative of 1 year's continuous operation.

b. Nuclide breakdown was not made. Total activity is based on ONWI-20 data.

c. Values shown are representative of a core power of 3876 MWt with the original steam generators. For a core power of 3990 MWt with the replacement steam generators the values shown should be corrected by the ratio of core power.

Table 11.4-6
SRS OUTPUT ACTIVITIES[a][c] (Ci/yr/unit) (Sheet 2 of 2)

Isotope	Filters	Ion Exchangers	Evaporator Concentrates	Dry Wastes[3]
Te-129m	-	7.81E-01	8.38E-03	-
Te-129	-	5.00E-01	5.37E-03	-
I-131	-	4.24E-05	5.60E-03	-
Xe-131m	-	1.69E-04	4.72E-04	-
Te-132	-	0.00E+00	1.35E-06	-
I-132	-	0.00E+00	1.39E-06	-
Xe-133	-	7.06E-12	4.73E-05	-
Cs-134	-	1.29E+03	7.51E-01	-
Cs-136	-	9.27E-04	2.19E-03	-
Cs-137	-	1.24E+03	6.01E-01	-
Ba-137m	-	1.16E+03	5.62E-01	-
Ba-140	-	3.90E-05	5.43E-05	-
La-140	-	4.49E-05	6.24E-05	-
Ce-141	-	3.35E-02	4.02E-04	-
Pr-143	-	2.01E-05	1.76E-05	-
Ce-144	-	3.12E+00	2.14E-03	-
Pr-144	-	3.12E+00	2.14E-03	-
Total	7.82E+02	3.72E+03	2.44E+00	8.00E+01

11.4.2.6 Low Level Radioactive Material Storage Facility (LLRMSF)

The LLRMSF is designed to store radioactive material and equipment generated only at PVNGS. The radioactive material to be stored in this facility will only be solid or dried materials. The LLRMSF consists of one building, approximately 21000 square feet, within a rectangular fenced restricted area. The interior spaces includes a truck bay with loading dock for handling of materials, a 30 ton bridge crane, a low level radioactive material warehouse, and a higher low level radioactive material below grade storage vault. A Control Room will serve for remote operations of the bridge crane.

The construction of the facility is of 24 inch concrete walls up to 16 feet above the warehouse floor. The wall thicknesses reduces to 10 inches above 16 feet and continues to the roof. The roof construction is prefabricated concrete tees and an additional layer of a minimum of 2 inches of concrete poured on top. Internal to the facility, the Control Room is constructed of 24 inch concrete walls, with a 4 inch prefabricated concrete roof. All walls, roofs, and the storage vault lids are considered radiation barriers.

Although the facility is an independent structure away from the power block, it still interfaces with several Plant systems. The following is a list of those systems:

Electrical	Security Alarm
Fire Protection Water	Domestic Water
Fire Alarm	Communication

HVAC equipment is provided to maintain environmental parameters and habitability. A heat pump is provided for the storage area and truck bay area to maintain environmental temperatures suitable for the areas. An exhaust fan equipped with efficiency pre-filters, HEPA filters and an access porthole for radiation monitoring equipment is provided to maintain the storage and truck bay areas under a negative pressure to the Control Room and outside areas. This is to ensure against an unmonitored or unfiltered air release.

A separate heat pump is provided for the Control Room to maintain a comfortable environmental condition suitable for occupancy. Outside make-up air is provided to maintain the Control Room under a positive pressure relative to the storage and truck bay areas.

Radiation protection of the LLRMSF is as per section 12.5, Radiation Protection Program.

11.4.2.7 Old Steam Generator and Old Reactor Vessel Closure Head Storage Facility (OSG/ORVCHSF)

The OSG/ORVCHSF provides long-term on-site storage of large contaminated components that are byproducts of non-routine maintenance activities. Specifically, the OSG/ORVCHSF is designed to safely store the six Old Steam Generators, three Old Reactor Vessel Closure Heads with associated Control Rod Drive Mechanisms, and three reactor head lift rigs for Unit 1, 2, and 3. The design features, building description, and the radioactive material contents of the OSG/ORVCHSF are described in Section 12.2.1.9.

11.4.3 REFERENCES

1. "NSSS Interface Requirements for Chemical and Volume Control System" for ANPP, 14273-PE-IR20 Revision 02, Nuclear Power Systems, Combustion Engineering Co., 26 May 1977, Windsor, Connecticut.

2. A Survey and Evaluation of Handling and Disposing of Solid Low Level Nuclear Fuel Cycle Wastes. AIF/NESP-008 (National Environmental Studies Project by NUS), October 1976, Rockville, Maryland.

11.5 PROCESS AND EFFLUENT RADIOLOGICAL MONITORING AND SAMPLING SYSTEMS

The process and effluent radiological monitoring systems monitor and furnish information to operators concerning activity levels in selected plant process systems and plant effluents. The area radiation monitoring instrumentation, also described in this section, supplements the personnel and area radiation survey provisions of section 12.5 to ensure proper personnel radiation protection.

The systems consist of permanently-installed sampling and/or monitoring devices together with a program and provisions for specific routine sample collections and laboratory analyses. The overall systems are designed to assist the operator in evaluating and controlling the radiological consequences of normal plant operation, anticipated operational occurrences, and postulated accidents. Resultant radiation exposures and releases of radioactive materials in effluents to unrestricted areas for normal operation are maintained as low as is reasonably achievable.

11.5.1 DESIGN BASES

11.5.1.1 Normal Operations and Anticipated Operational Occurrences

11.5.1.1.1 Process Monitoring System

The process monitoring system is designed to perform the following functions:

A. Provide assistance to operators to ensure the proper functional performance of the selected systems being monitored.

B. Provide for early detection of radioactive leakage into normally nonradioactive systems, including primary-to-secondary leakage, primary-to-atmosphere leakage, and process system leakage into normally non-radioactive systems. Included is the capability of both the containment building gaseous channel and the containment building particulate channel each to detect independently an increase in the reactor coolant system-to-containment atmosphere leak rate as two of the methods of leak detection required to follow the recommendation of NRC Regulatory Guide 1.45, except as noted in section 1.8.

C. Provide continuous remote indication and recording of airborne radioactive contamination in the form of particulates and iodines in areas where personnel normally have access, except in areas where the potential for airborne activity releases is negligible, in order to follow the recommendations of NRC Regulatory Guide 8.8 for control of occupational exposure to radiation.

11.5.1.1.2 Effluent Monitoring System

The effluent monitoring system is designed to perform the following functions in order to meet the requirements of

10CFR20.1- 20.601, 10CFR50, and follow the recommendations of Regulatory Guide 1.21 during normal operations, including anticipated operational occurrences:

A. Provide continuous representative sampling, monitoring, recording, and indication of gaseous radioactivity levels, and, as a minimum, continuous representative sampling of particulate and iodine radioactivity levels along principal effluent discharge paths.

B. Provide the capability, during the release of gaseous wastes from the waste gas decay tanks, to alarm and initiate automatic closure of the waste gas discharge valve before the limits of the Technical Specifications are exceeded.

C. Provide radiation level indication and alarm annunciation to the control room operators whenever Technical Specification limits for release of radioactivity are approached or exceeded.

D. For continuous effluent paths, provide a means for collection and laboratory analysis of required routine samples.

E. For batch releases, provide a means for collection and laboratory analysis of required routine samples prior to release.

11.5.1.1.3 Area Monitoring System

The area monitoring system is designed to perform the following functions in order to meet the requirements of 10CFR20.1-20.601, 10CFR50, Appendix A, and 10CFR70.24 and follow the recommendations of Regulatory Guides 8.2, 8.8, and 8.12 during normal operations, including anticipated operational occurrences:

A. Immediately alert plant personnel entering or working in nonradiation or low radiation areas of increasing or abnormally high radiation levels which, if unnoticed, could possibly result in inadvertent overexposures.

B. Inform the control room operator of the occurrence and approximate location of an abnormal radiation increase in nonradiation or low radiation areas.

11.5.1.1.4 Criteria for Location of Area Monitors

A. Areas that contain a liquid, gaseous, or particulate radiation source that potentially can produce a dose rate during normal operation greater than 2.5 mrem/h (zones 3, 4, and 5) are provided with an area monitor unless one of the following conditions exists:

   1. Another area monitor in the vicinity is capable of monitoring the area; there is line-of-sight access between the monitor and the area in question, and the monitor alarm point would be the same value for all areas served. An example would be the

compressed waste storage area and the full drum delay storage area which are served by one area radiation monitor.

2. The frequency of personnel access to the area is minimal, which is defined as access required only for infrequent repairs, unscheduled maintenance, or periodic surveillance. Examples would be the piping penetration rooms and the shutdown cooling heat exchanger areas. (Portable monitors are used to monitor such areas during personnel access.)

3. The probability of accidental release within the area is minimal; i.e., an area with only sealed containers or where the material in the space during normal operations has a low activity level. These areas include the volume control tank area and the recycle water monitor tank pump area.

4. Process monitors are provided that perform a function equivalent to an area radiation monitor in an area in which gaseous or airborne particulate activity is the major constituent. An example would be the radwaste building ventilation systems which are provided with gaseous process monitors to monitor for leakage from the waste gas compressors and waste gas decay tank valves.

B. Areas in which the new and spent fuel is received and stored, specifically the containment and fuel building, are provided with detectors which indicate

and alarm in the presence of abnormal radiation levels.

C. The location of each area radiation detector is indicated on the radiation monitor location figures 11.5-1 through 11.5-6. The radiation monitor location figures indicate the general location of the equipment, which may vary from unit to unit.

11.5.1.2 Postulated Accidents

The process, effluent, and area monitoring systems, collectively referred to as the radiation monitoring system (RMS), are designed to perform the following functions in order to meet the requirements of 10CFR50, 10CFR100, and follow the recommendations of NUREG-0737 and NRC Regulatory Guides 1.13, 1.97, and 8.12 for postulated accidents:

A. Provide the capability to alarm and initiate containment purge isolation in the presence of high airborne radioactivity within the containment which could potentially cause an offsite dose in excess of 10CFR100 limits.

B. Provide the capability to alarm and initiate isolation of the fuel building from the normal ventilation system and actuation of fuel building essential ventilation in the unlikely event of a fuel handling accident in the fuel building.

C. Provide the capability to alarm and initiate isolation of the control room normal ventilation system and

actuation of control room essential filtration in the unlikely event that radioactivity is introduced into the control building intake plenum.

D. Provide long-term, post-accident monitoring of ventilation exhaust from the auxiliary building ESF equipment areas following a loss-of-coolant accident.

E. Inform the control room operator of the occurrence and approximate location of abnormal radiation increases in a zone adjacent to the containment containing piping, electrical, or hatch penetrations.

F. Inform the control room operator and personnel in the immediate vicinity of the monitor of an abnormal radiation increase inside buildings where access is required to service equipment important to safety post-accident.

G. Provide long-term, post-accident monitoring of effluents from the plant vent, fuel building vent, main condenser vent, and the main steam relief and atmospheric dump valves.

11.5.2 SYSTEM DESCRIPTION

The installed radiation monitoring system was supplied as two separate orders. As consequence, there are differences in design and configuration. References to each order appear as "old scope" and "new scope". The old scope equipment includes monitors in loops 1, 2, 4, and 5 (see engineering drawing

13-N-997-184), and all of the portable air moveable units. New scope monitors comprise loops 3, 6, and 7.

Some of the major differences between the two configurations include remote versus local mounting of the control microcomputer and indication and control panel type and nomenclature.

Old scope monitors have the detection and/or sampling equipment and microcomputer included as part of the same assembly, while new scope monitors separate these assemblies. Further, the microcomputers, while providing similar functions, are electronically different.

Indication and display panels are also different. For old scope monitors, these include local indication and control (LIC), portable indication and control (PIC), and remote indication and control (RIC) units. New scope monitors employ KELIC's, KEPIC's, and KERIC's to fulfill these same functions. For control on a local basis (at the skid) some new scope monitors also offer a KESMIC or skid mounted indication and control unit. These new and old scope display units are not interchangeable. Additionally, old scope unit alarms are designated as "high" and "high high", corresponding to new scope "alert" and "high" functions.

Specific differences between new and old scope configurations are described in the system operation/maintenance manuals. Only general information as to function and capability will be referenced here.

In addition to the “old scope” and “new scope” equipment, the steam generator blowdown discharge monitors are installed with a local microcomputer which is connected to the system via a communications translator in loop 3.

11.5.2.1 Continuous Process, Effluent and Area Radiation Monitoring and Sampling

The requirements of the system design bases for continuous monitoring are satisfied by an integrated, microcomputer-based system of monitor channels with the associated sampling and auxiliary equipment as noted in table 11.5-1. Several detector channels are provided as part of common area monitoring.

Refer to section 9.3.4.5.6 for descriptions of the NSSS scope radiation monitors which are not part of the computer-based monitoring system.

Section 11.5.2.1.1 provides a description of system hardware including design features such as instrumentation, types and locations of readouts, annunciators, and alarms, provisions for emergency power supplies, and provisions for decontamination and replacement. Paragraph 11.5.2.1.2 provides information concerning redundancy, diversity, and independence of components. Paragraphs 11.5.2.1.3, 11.5.2.1.4, and 11.5.2.1.5 provide a description of the function and location of each process, effluent, and area monitor. Paragraph 11.5.2.1.6 provides a description of provisions for calibration, maintenance, and inspection.

Engineering drawing 13-N-997-184 is a basic block diagram of the RMS.

Table 11.5-1 is a tabulation of basic information describing each of the continuous process, effluent, and area radiation monitors and sampler, including monitor location, design background dose rate, type of monitor and measurement made, sampler and/or detector type, reference nuclide, range of activity concentrations or dose rates to be monitored and expected concentrations or dose rates, alarm setpoint, provisions for power supplies, and automatic actions initiated.

Bases for the ranges listed in table 11.5-1 are as follows:

A. For process monitors, the ranges include:

   1. Maximum calculated concentrations during normal operations and anticipated operational occurrences.

   2. The highest sensitivity commercially available when purchased in order to detect process system leakage and airborne contamination as early as possible.

B. For effluent monitors, the ranges include:

   1. Maximum calculated concentrations for normal operations, anticipated operational occurrences, and postulated accidents.

   2. Minimum concentrations that must be detected in order to allow automatic and/or operator actions

to avoid exceeding Technical Specifications for the release of radioactivity.

C. For area monitors the range extends from a minimum value of the radiation zone I upper limit to a maximum of the saturation limit of commercially available Geiger-Müeler tube detectors. Area ion chamber detectors meet Regulatory Guide 1.97 range requirements.

In order to satisfy the above criteria, fuel building vent and plant vent are provided with two monitoring skids. The two skids, together, provide overlapping low, mid, and high range monitoring channels which span a range of at least 11 decades.

Bases for the setpoints provided in table 11.5-1 are as follows:

A. For ESF monitors the listed setpoint is the maximum acceptable value considering measurement uncertainties and statistical error. Setpoints at or below these values will provide sufficient operator notification and/or initiation of automatic action as soon as possible in the presence of process system leakage, airborne contamination, or an accident condition.

B. For non-ESF effluent monitors, the noble gas channel setpoint is determined in accordance with the Offsite Dose Calculation Manual. Particulate/iodine setpoints are based on ALARA considerations.

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 1 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification (a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (µ Ci/cm^3)	Expected Concentrations (µ Ci/cm^3)	Alarm Setpoint (µ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
NON-ESF MONITORS													
Essential Cooling Water (ECW) System Monitors (XJ-SQN-RU-2 and XJ-SQN-RU-3) (Drawing 01, 02, 03-M-EWP-001)	2	Auxiliary Bldg.	2.5	Off-Line/Liquid	γ	Gross γ	Cs-137	10^{-6} -10^{-1}	LMD(i)	(p)	1 Min.	AC Power (q)	Alarm only.
Steam Generator (SG) Monitors (XJ-SQN-RU-4 and XJ-SQN-RU-5)	2	Auxiliary Bldg.	2.5	Off-Line/Liquid	γ	Gross γ	Cs-137	10^{-6} -10^{-1}	2 x 10^{-6}	(p)	1 Min.	AC Power (q)	Alarm only.
Nuclear Cooling Water (NCW) System Monitor (XJ-SQN-RU-6) (Drawing 01, 02, 03-M-NCP-001, -002 & -003)	1	Outside (Yard)	0.5	Off-Line/Liquid	γ	Gross γ	Cs-137	10^{-6} -10^{-1}	LMD	(p)	1 Min.	Instr.	Alarm only.

a. Refer to paragraph 11.5.2.1.1.6.

b. "γ" - NAI γ scintillation detector coupled with photomultiplier tube
"β" - Plastic phospor β scintillation detector coupled with photmultiplier tube
"SCA" - Single channel analyzer
"G-M" - Geiger-Mueller detector
"Ion" - Ion chamber

c. Area - Area Radiation (mostly γ)
"β-γ" - Total activity (β and γ)
"γ Dose" - Gamma radiation in R/hr
"Gross γ" - Total gamma activity
"Gross β" - Total beta activity
"I-131" - Activity from volatile I-131
"Nitrogen 16" - Activity from N-16

d. Time interval for a monitor to indicate 90% of it's final value from a step change in the input concentration. Particulate/Iodine channels assume a clean filter condition.

e. "INSTR": 120 V-ac non-1E instrument power
"(M)": Motor: 480 V-ac non-1E power
"VITAL 'A'": 120 V-ac vital instrument power, channel A
"VITAL 'B'": 120 V-ac vital instrument power, channel B

f. Automatic actions initiated on HIGH-HIGH alarm only. HIGH alarm annunciates but does not initiate a control action.

g. Blower Motor: 480 V-ac Class 1E power, train A.

h. Blower Motor: 480 V-ac Class 1E power, train B.

i. "LMD" - Less than minimum detectable.

k. Range for Particulate and Iodine channels given for continuous monitoring. Analysis of filters and iodine cartridges is typically better than 10^{-12} µCi/cc for lower end.

l. Area and process monitors are shown on radiation monitor locations, figures 11.5-1 through 11.5-6.

m. Seismic Category I, Class 1E powered. Performs no ESF function.

n. Detector and annunciator are located in containment. Microprocessor is located in auxiliary building.

o. In accordance with Technical Specifications.

p. Variable in accordance with ALARA.

q. Non-1E backed up by train A diesel.

r. Pump power is non-1E.

s. In accordance with the Offsite Dose Calculation Manual.

t. Basis nuclide for range and expected concentration determination only.

u. Monitor has additional setpoint basis. ESF basis is related to Part 100 limits; ODCM basis will always be more conservative.

v. Set to alert personnel to increasing concentrations during a containment purge which may result in alarming the plant vent monitor.

w. Set to alert personnel to increasing primary-to-secondary leakage.

x. Refer to table 11.1-7 for main steam concentration.

y. Environmental qualification not required because it completes its design function before exposure to a harsh environment.

z. Environmental qualification not required because this device is used for normal operations and is not required to function for mitigation of any initiating event considered by PVNGS EQ Program.

aa. Time to alarm and initiate CPIAS less than 4 seconds for ESF function when Technical Specifications setpoint of 2.5 mR/hr is used.

bb. In accordance with the Technical Requirements Manual.

cc. In accordance with the Technical Specification Bases

dd. Refer to table 7.3-12

ee. set to alert personnel to increasing radiation levels.

ff. in accordance with the Emergency Plan

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 2 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (μ Ci/cm^3)	Expected Concentrations (μ Ci/cm^3)	Alarm Setpoint (μ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
<u>NON-ESF MONITORS</u> (cont)													
Auxiliary Steam Condensate Receiver Tank Inlet (RTI) Monitor (XJ-SQN-RU-7)	1	Auxiliary Bldg.	2.5	Tank Recirc./Liquid	γ	Gross γ	Cs-137	10^{-6} -10^{-1}	LMD	(p)	1 Min.	AC Power(q)(r)	Alarm and divert aux. stm. condensate to liquid radwaste system.
Auxiliary Bldg. Ventilation Exhaust Filter Inlet (ABFI) Monitor (XJ-SQN-RU-8) (Drawing 01, 02, 03-M-HAP-001, -002, -003 & -004)	1	Auxiliary Bldg.	0.5	Off-Line/Fixed Paper Particulate Filter	β	Gross β	Cs-137	10^{-11} -10^{-4} (k)	LMD	(p)	15 Min.	AC Power (q)(r)	Alarm only
				Off-Line/Fixed Charcoal or Silver Xeolite Cartridge	γ/SCA	I-131	I-131	10^{-11} -10^{-4} (k)	6 X 10^{-10}	(p)	15 Min		Alarm only
Auxiliary Bldg. Lower Levels (ABLL) Ventilation Exhaust Monitor (XJ-SQN-RU-9) (Drawing 01, 02, 03-M-HAP-001, -002, -003 & -004)	1	Auxiliary Bldg.	2.5	Off-Line/Gas	β	Gross β	Kr-85	10^{-6} -10^{-1}	9 x 10^{-6}	(p)	1 Min.	AC Power (q)	Alarm only
Auxiliary Bldg. Upper Levels (ABUL) Ventilation Exhaust Monitor (XJ-SQN-RU-10) (Drawing 01, 02, 03-M-HAP-001, -002, -003 & -004)	1	Auxiliary Bldg.	2.5	Off-Line/Gas	β	Gross β	Kr-85	10^{-6} -10^{-1}	LMD	(p)	1 Min.	AC Power (q)	Alarm only
Waste Gas Decay Tank (WGDT) Monitor (XJ-SQN-RU-12) (Drawing 01, 02, 03-N-GRP-001)	1	Radwaste Bldg.	50	Inline/Gas	β	Gross β	Kr-85	10^{-3} -10^{+2}	1 x 10^{-1}	(s)	1 Min.	Instr.	Alarm and initiate close of the waste gas discharge valves.

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 3 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (µ Ci/cm^3)	Expected Concentrations (µ Ci/cm^3)	Alarm Setpoint (µ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
<u>NON-ESF MONITORS</u> (cont)													
Building Vent (BV) Monitors TSC- AJ-SQN-RU-13A	1 (Common to all Units)	Technical Support Center (TSC)	<0.5	Off-Line/Fixed Paper Particulate Filter	β	Gross β	Cs-137	10^{-11} -10^{-4} (k)	LMD	(p)	15 Min.	Instr.(m)	Alarm only
				Off-Line/Fixed Charcoal or Silver Xeolite Cartridge	γ/SCA	I-131	I-131	10^{-11} -10^{-4} (k)	LMD	(p)	15 Min		Alarm only
				Off-Line/Gas	β	Gross β	Kr-85	10^{-6} -10^{-1}	LMD	(p)	1 Min.		Alarm only
Radwaste Bldg. Ventilation Exhaust Filter Inlet (RBFI) Monitor (XJ-SQN-RU-14) (Drawing 01, 02, 03-N-HRP-001)	1	Outside (R/W Bldg. Roof)	3.0	Off-Line/Fixed Paper Particulate Filter	β	Gross β	Cs-137	10^{-11} -10^{-4} (k)	LMD	(p)	15 Min.	Instr.(m)	Alarm only
Waste Gas Area Combined Ventilation Exhaust (WGVE) Monitor (XJ-SQN-RU-15) (Drawing 01, 02, 03-N-HRP-001)	1	Radwaste Bldg.	2.5	Off-Line/Gas	β	Gross β	Kr-85	10^{-6} -10^{-1}	LMD	(p)	1 Min.	Instr.(m)	Alarm only
Operating Level Area (OLA) Monitor (XJ-SQN-RU-16)	1	Containment(n)	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	9 mr/h	(p)	30 sec.	Instr.	Alarm only
Incore Instrument Area (IIA) Monitor (XJ-SQN-RU-17)	1	Containment(n)	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	9 mr/h	(p)	30 sec.	Instr.	Alarm only
Control Room Area (CRA) Monitor (XJ-SQN-RU-18)	1	Control Bldg.	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	LMD	(p)	30 sec.	Instr.	Alarm only
New Fuel Area (NFA) Monitor (XJ-SQN-RU-19)	1	Fuel Bldg.	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	0.8 mr/h	≤ 15 mr/h (bb)	30 sec.	Instr.	Alarm only

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 4 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (μ Ci/cm^3)	Expected Concentrations (μ Ci/cm^3)	Alarm Setpoint (μ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
<u>NON-ESF MONITORS</u> (cont)													
Solid Waste Processing Station Area (SPA) Monitor (XJ-SQN-RU-20)	1	Radwaste Bldg.	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	1.5 mr/h	(p)	30 Sec.	Instr.	Alarm only
Solid Waste Storage Area (SSA) Monitor (XJ-SQN-RU-21)	1	Radwaste Bldg.	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	60 mr/h	(p)	30 Sec.	Instr.	Alarm only
Loading Bay Area (LBA) Monitor (XJ-SQN-RU-22)	1	Radwaste Bldg.	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	1.5 mr/h	(p)	30 Sec.	Instr.	Alarm only
Radiochemical Laboratory Area (RLA) Monitor (XJ-SQN-RU-23)	1	Auxiliary Bldg.	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	0.5 mr/h	(p)	30 Sec.	AC Power(q)	Alarm only
Central Calibration Facility Area (CFA) Monitor (XJ-SQN-RU-24)	1 Unit 1 only)	Outside (Yard)	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	0.5 mr/h	(p)	30 Sec.	Instr.	Alarm only
Controlled Machine Shop Area (MSA) Monitor (XJ-SQN-RU-25)	1	Radwaste Bldg.	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	0.5 mr/h	(p)	30 sec.	Instr.	Alarm only
Sample Room Area (SRA) Monitor (XJ-SQN-RU-26)	1	Auxiliary Bldg.	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	9 mr/h	(p)	30 sec.	AC Power(q)	Alarm only
Letdown Line Process Radiation Monitor (PRM) (XJ-SQN-RE-155D)	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	10^{-2} r/h to 10^{+5} r/h	21 mr/h	Variable	30 Sec.	Instr.(m)	Alarm only

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 5 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (μ Ci/cm^3)	Expected Concentrations (μ Ci/cm^3)	Alarm Setpoint (μ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
NON-ESF MONITORS (cont)													
"A" Refueling Machine (m) Area (RMA-A) Monitor (XJ-SQA-RU-33)	1	Containment (Normal Envir.) (n) (z)	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	0.5 mr/h	(p)	30 Sec.	Vital "A"	Alarm only
"B" Containment Building (m) Refueling Purge Exhaust (CBPE-B) Monitor (XJ-SQB-RU-34) (Drawing 01, 02, 03-M-CPP-001)	1	Auxiliary Bldg. (Normal Envir.) (z)	2.5	Off-Line/Gas	β	Gross β	Kr-85	10^{-6} -10^{-1}	LMD	(v)	1 Min.	Vital "B"(h)	Alarm only
"B" Containment Building(m) Atmosphere (CB-B) Monitor (XJ-SQB-RU-1) (Drawing 01, 02, 03-M-HCP-001)	1	Auxiliary Bldg. (Normal Envir.) (y)	2.5	Fixed Cartridge Particulate Filter	β	Gross β	Cs-137	10^{-11} -10^{-4} (k)	1.6 x 10^{-9}	2.3 x 10^{-6}(cc)	15 Min.	Vital "B"(h)	Alarm only
				Fixed Charcoal or Silver Xeolite Cartridge	γ/SCA	I-131	I-131	10^{-11} -10^{-4} (k)	LMD	5.13 x 10^{-5}	15 Min.		Alarm only
				Gas	β	Gross β	Kr-85	10^{-6} -10^{-1}	2 x 10^{-3}	6.6 x 10^{-2} (cc)	1 Min.		Alarm only
Main Steam Nitrogen 16 (MSN) Monitor (XJ-SQN-RU-142)	1	Turbine Bldg.	N/A	N/A	γ/SCA	Nitrogen 16	N-16	0 -10^{6} cpm	LMD	(w)	1 Min.	Instr.(m)	Alarm only
Steam Generator Blowdown Discharge (SGBD) Monitor (XJ-SQN-RU-200)	1	Outside (Yard)	0.025	In-Line Liquid	γ	Gross γ	Cs-137	10^{-7}-10^{-2}	2 X 10^{-7}	(s)	1 Min.	Instr.	Alarm Terminates Discharge

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 6 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (μ Ci/cm^3)	Expected Concentrations (μ Ci/cm^3)	Alarm Setpoint (μ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
ESF MONITORS													
"A" Control Room Ventilation Intake (CRVI-A) Monitor (XJ-SQA-RU-29) (Figure 6.4-1)	1	Control Bldg. (Normal Envir.)	0.5	Off-Line/Gas	β	Gross β	Kr-85	10^{-6} –10^{-1}	LMD	2 x 10^{-5} (o),(dd)	1 Min.	Vital "A" (g)	Alarm and initiate control room essential filtration (CREVAS).
"B" Control Room Ventilation Intake (CRVI-B) Monitor (XJ-SQB-RU-30) (Figure 6.4-1)	1	Control Bldg. (Normal Envir.)	0.5	Off-Line/Gas	β	Gross β	Kr-85	10^{-6} –10^{-1}	LMD	2 x 10^{-5} (o),(dd)	1 Min.	Vital "B" (h)	Alarm and initiate control room essential filtration (CREVAS).
"A" Fuel Pool Area (FPA-A) Monitor (XJ-SQA-RU-31)	1	Fuel Bldg. (Normal Envir.) (z)	N/A	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	0.5 mr/h	≤ 15 mr/h (bb),(dd)	30 Sec.	Vital "A"	Alarm and initiate fuel building essential ventilation (FBEVAS)
"A" Power Access Purge Area (PAPA-A) Monitor (XJ-SQA-RU-37)	1	Auxiliary Bldg. (LOCA Envir.) (z)	< 2.5	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	LMD	2.5 mr/h (o),(dd)	30 Sec. (aa)	Vital "A"	Alarm and initiate containment purge isolation (CPIAS).
"B" Power Access Purge Area (PAPA-B) Monitor (XJ-SQB-RU-38)	1	Auxiliary Bldg. (LOCA Envir.) (z)	< 2.5	N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	LMD	2.5 mr/h (o),(dd)	30 Sec. (aa)	Vital "B"	Alarm and initiate containment purge isolation (CPIAS).
Fuel Building (XJ-SQB-RU-145 (Also refer to Post Accident Section of Table)	1	Fuel Bldg.	0.5	Off-Line/Gas	β	Gross β	Xe-133	10^{-6} -10^{-1}	LMD	(s),(u),(dd)	1 Min.	Vital "B" (h)	Alarm and initiate Fuel Bldg. Essential Ventilation (FBEVAS)
MOVABLE (NON-ESF) MONITORS													
Portable Area Monitors	3	N/A		N/A	G-M	Area	Co-60	10^{-1} -10^{+4} mr/h	Variable	Variable	30 Sec.	120 V-ac convenience outlets	Alarm only.

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 7 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (μ Ci/cm^3)	Expected Concentrations (μ Ci/cm^3)	Alarm Setpoint (μ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
POST-ACCIDENT MONITORS													
Main Steam Line Effluent (MSLA, MSLB) Monitors XJ-SQN-RU-139 SJ-SQN-RU-140	2	Main Steam Support Structure (y)	Normal <0.5 Accident 10^{+4}	N/A	Ion	γ dose	Co-60	1.5×10^{0} to $1.0 \times 10^{+7}$ mr/h	LMD (x)	3 x BKG (bb)	30 Sec	Instr.(m)	Alarm only
Condenser Vacuum Pump/Gland Seal Exhaust Monitors (CVLR) XJ-SQN-RU-141	1	Turbine Building	<0.5	In-Duct	β	Gross β	Xe-133	Ch.A: 9×10^{-8} to 6.2×-10^{-2} Ch. B: 8.4×10^{-8} to 5.8×10^{-2}	Ch. A 9×10^{-6} Ch. B 2.4×10^{-4}	(w)	1 Min.	Instr.(m)	Alarm and initiate filtration of the condenser vacuum/ gland seal exhaust (Ch, A only)

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 8 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quan-tity Per Unit	Designated Location For Environmental Qualification(a)	Design Back-ground (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Refer-ence Nuclide (t)	Range (μ Ci/cm^3)	Expected Concen-trations (μ Ci/cm^3)	Alarm Setpoint (μ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
POST-ACCIDENT MONITORS (cont)													
Plant Vent Monitors	1	Turbine Building	<0.5	Off-Line/Gas	β	Gross β	Xe-133	10^{-6} to 10^{-1}	LMD	(s)	1 Min.	Instr.(m)	Alarm After proper over-lap, shifts to high range. RU-144 on increasing radiation level.
(PVLR) Low Range XJ-SQN-RU-143				Off-Line/Gas Particulate	β	Gross β	Cs-137	10^{-11} -10^{-4} (k)	LMD	(p)	15 Min.		Alarm only
				Off-Line/ Charcoal or Silver Xeolite Cartridge	γ/SCA	I-131	I-131	10^{-11}-10^{-4} (k)	LMD	(p)	15 Min.		Alarm only

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 9 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (μ Ci/cm^3)	Expected Concentrations (μ Ci/cm^3)	Alarm Setpoint (μ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
<u>POST-ACCIDENT MONITORS</u> (cont)													
(PVHR) High Range XJ-SQN-RU-144	1	Turbine Building	25 R/hr	Off-Line/Gas (Dual overlapping GM detectors)	G-M	β-γ	Xe-133	10^{-2} to 10^{+5}	LMD	(ee), (ff)	1 Min.	Instr.(m)	Alarm - After proper overlap, shifts to high range RU-143 on decreasing radiation level.
				Three separate Off-Line/ Particulate/ Iodine Cartridges Charcoal or Silver Xeolite)	No Detector								NA
Fuel Building Ventilation Exhaust Monitors XJ-SQB-RU-145 (Provides additional ESF functions as identified in ESF Section of Table)	1	Fuel Building	0.5	Off-Line/Gas	β	Gross β	Xe-133	10^{-6} to 10^{-1}	LMD	(s), (u)	1 Min.	Vital "B"(h)	After proper overlap, shifts to high range RU-146 on increasing radiation level.

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 10 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quan-tity Per Unit	Designated Location For Environmental Qualification(a)	Design Back-ground (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Refer-ence Nuclide (t)	Range (μ Ci/cm^3)	Expected Concen-trations (μ Ci/cm^3)	Alarm Setpoint (μ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
<u>POST-ACCIDENT MONITORS</u> (cont)													
(FBLR) Low Range XJ-SQB-RU-145				Off-Line/ Particulate	No Detector								N/A
				Off-Line/ Charcoal or Silver Xeolite Cartridge	No Detector								N/A
(FBHR) High Range XJ-SQB-RU-146	1	Fuel Building	25 R/hr	Off-Line/Gas (Dual overlap-ping GM detectors)	G-M	β-γ	Xe-133	10^{-2} to 10^{+5}	LMD	(s), (p)	1 Min.	Vital "B"(h)	Alarm - After proper overlap, shifts to low range RU-145 on decreasing radiation level.
				Three separate Off-Line/ Particulate/ Iodine Cartridges (Charcoal or Silver Xeolite)	No Detector								N/A
In Containment Area Monitors (HCAA) XJ-SQA-RU-148 (HCAB) XJ-SQB-RU-149	2	Containment (Post-LOCA)	N/A	N/A	Ion	γ dose	Co-60	1 R/h to 10^{+7} R/h	LMD	≤ 10 R/h	30 Sec.	Vital A (HCAA)/ Vital B (HCAB)	Alarm only
Primary Coolant Monitors (PCMA) XJ-SQA-RU-150 (PCMB) XJ-SQB-RU-151	2	Containment (Post-LOCA)	50 R/h gamma 30 R/h neutrons	N/A	Ion	γ dose	Co-60	1 R/h to 10^{+5} R/h	LMD	≤ 40 R/h	30 Sec.	Vital A (PCMA)/ Vital B (PCMB)	Alarm only

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 11 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (µ Ci/cm^3)	Expected Concentrations (µ Ci/cm^3)	Alarm Setpoint (µ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
<u>POST ACCIDENT MONITORS</u> (cont)													
Personnel IARM West Auxiliary 70' Level (WA70) XJ-SQN-RE-152A	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Personnel IARM East Auxiliary 70' Level (EA70) XJ-SQN-RE-152B	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Personnel IARM South Stairway - 40' Level Auxiliary SS4A) XJ-SQN-RE-152C	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Personnel IARM North Stairway - 51' 6" Level Auxiliary Bldg. (NS51) XJ-SQN-RE-152D	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Personnel IARM West Auxiliary Bldg. 100' Level (WA10) XJ-SQN-RE-153A	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Personnel IARM East Auxiliary Bldg. 100' Level (EA10) XJ-SQN-RE-153B	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Personnel IARM Recombiner Auxiliary 100' Level (RA10) XJ-SQN-RE-153C	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Personnel IARM West Auxiliary 120' Level (WA12) XJ-SQN-RE-154A	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 12 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (µ Ci/cm^3)	Expected Concentrations (µ Ci/cm^3)	Alarm Setpoint (µ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
<u>POST ACCIDENT MONITORS</u> (cont)													
Personnel IARM East Auxiliary 120' Level (EA12) XJ-SQN-RE-154B	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Personnel IARM Control Room 70' Level 140' (CR14) XJ-SQN-RE-154C	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM MSSS-"A" Side - 88' Level (MSBA) XJ-SQN-RE-155A	1	Main Steam Support Structure	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM MSSS-"B" Side - 88' Level (MSBB) XJ-SQN-RE-155B	1	Main Steam Support Structure	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM West Piping Auxiliary 70' Level (WPP7) XJ-SQN-RE-155C	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM East Piping Auxiliary 88' Level (EPP8) XJ-SQN-RE-156A	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM West Electrical Auxiliary 100' Level (WP10) XJ-SQN-RE-156B	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM East Electrical Auxiliary 100' Level (EP10) XJ-SQN-RE-156C	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only

Table 11.5-1
CONTINUOUS PROCESS AND EFFLUENT RADIATION MONITORING (Sheet 13 of 13)

Sampler/Monitor Location (Instr. Tag No.) (P&I Dwg. Ref.)(l)	Quantity Per Unit	Designated Location For Environmental Qualification(a)	Design Background (mr/h Co-60)	Sampler Type	Detector Type (b)	Activity Measured (c)	Reference Nuclide (t)	Range (µ Ci/cm^3)	Expected Concentrations (µ Ci/cm^3)	Alarm Setpoint (µ Ci/cm^3)	Response Time at Min. Detectable Conc.(d)	Power Supply(e)	Automatic Actions Initiated(f)
POST ACCIDENT MONITORS (cont)													
Penetration IARM MSSS-"A" Side - 100' Level (MSIA) XJ-SQN-RE-157A	1	Main Steam Support Structure	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM MSSS-"B" Side - 100' Level (MSIB) XJ-SQN-RE-157B	1	Main Steam Support Structure	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM West Auxiliary 120' Level (WP12) XJ-SQN-RE-157C	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM East Auxiliary 120' Level (EP12) XJ-SQN-RE-158A	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM West Auxiliary 140' Level (WP14) XJ-SQN-RE-158B	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM East Auxiliary 140' Level (EP14) XJ-SQN-RE-158C	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only
Penetration IARM Hot Lab Auxiliary 140' Level (HLSS) XJ-SQN-RE-158D	1	Auxiliary Bldg.	N/A	N/A	Ion	γ dose	Co-60	0.1 R/h to 10^{+4} R/h	LMD	(p)	30 sec.	Instr.(m)	Alarm only

C. For non-ESF area monitors, the nominal trip setpoint is set in accordance with ALARA.

11.5.2.1.1 General Description

Refer to engineering drawing 13-N-997-184. In order to optimize the reliability, flexibility, maintainability, and detection sensitivity and accuracy of the RMS, it is primarily digital in nature.

11.5.2.1.1.1 Field Unit. At each location where radiation is sampled and/or monitored by one or more channels, the sampling/detecting/auxiliary equipment is a single assembly and is referred to as a "field unit". For some monitors, the field unit also contains the control microcomputer, while in others, it is a remote assembly. Each field unit is capable of automatic continuous stand-alone operation, even if communications with the control room are interrupted. These capabilities include:

A. Acquisition and storage of radiation levels, setpoints, conversion factors, and other applicable monitor operating parameters. Data storage capacity for this purpose provides for complete storage of the preceding twenty-four 10-minute averages, 24 hourly averages, and 24 daily averages of radiation level and the complete files of critical parameters (setpoints, conversion constants, etc.) for all channels within the field unit.

B. Control of all monitor field unit functions.

C. A plug-in receptacle to which can be attached a portable indication and control (PIC) unit or post-accident monitor portable indication and control (KEPIC) unit to provide complete local control capability. (Not available on new scope monitors with local indication and control panels.)

The PIC/KEPIC unit is a self-contained electronics package, suitable for hand carrying. The unit includes digital readouts, hand switches, and circuitry to provide the following capabilities to the operator when plugged into the RMS field unit microcomputer.

1. When a LOCAL-REMOTE switch located on the PIC/KEPIC unit is in the REMOTE position, the PIC operator is able to request and receive indication of the currently stored value of 1) any critical parameter, or 2) radiation level information, for any channel operated by the connected microcomputer.

2. When the LOCAL-REMOTE switch on the PIC/KEPIC is in the LOCAL position, the PIC operator is able to completely control all functions of the connected microcomputer normally exercised at remote indication and control units. Whenever the LOCAL-REMOTE switch on the PIC/KEPIC is in LOCAL, the affected microcomputer is

automatically disconnected electrically from REMOTE indication and control.

D. For each area monitor, a permanently-mounted local indication and control (LIC) unit or post-accident monitor local indication and control (KELIC) unit. When the channel is operating, this unit indicates radiation level in mr/h and visually and audibly annunciates the presence of a high-high level alarm.

E. The steam generator blowdown discharge monitor field unit has a local analog display for the lower 3 decades (10^{-7} to 10^{-4} μCi/cc), with indication of power, computer fault, and alarm. A RS-485 port is provided for local configuration and data retrieval. Password verification is required to manipulate monitor configuration.

11.5.2.1.1.2 Communications and Remote Indication and Control.

11.5.2.1.1.2.1 ESF Monitors. Each ESF field unit has its own dedicated cable over which it communicates digitally with a dedicated microcomputer-controlled (old scope only) remote indication and control (RIC) module (KERIC for postaccident or new scope, safety-related indicator units) located in one of the RMS control room cabinets. Complete remote indication and control of each safety-related field unit is exercised at the RIC/KERIC. Each ESF RIC/KERIC automatically outputs a signal to the balance of plant ESF actuation system whenever a high-high (high for new scope equipment) radiation level setpoint is

exceeded at the field unit. In this way each ESF monitor is completely independent from any other monitor.

11.5.2.1.1.2.2 Non-ESF Monitors. Most of the non-ESF field units are connected together for communications in a single "daisy-chain" loop configuration along with the centralized server and associated workstations. Exceptions to this configuration are indicated on engineering drawing 13-N-997-184. There are workstations located in the RMS HP office, count room, and the unit control room. Each field unit in turn communicates digitally with the RMS server by passing messages from node to node around the loop. The equipment in the loop is designed such that field unit-RMS server communications is single failure-proof to industry standards.

In a parallel, identically configured loop with the RMS server are two interface modules, located in the ESF control room cabinets (one in the "A" cabinet and one in the "B" cabinet), which are connected, through qualified isolation devices, to each ESF monitor. These interface modules cannot interfere with the operation of the ESF monitors, but are automatically fed radiation level and alarm status data for each safety monitor. In this manner, complete radiation level and alarm status is normally available for display at the workstations for both ESF and non-ESF monitors.

11.5.2.1.1.3 <u>General System Performance</u>.

11.5.2.1.1.3.1 Measurement Capability. Radiation monitoring system process channels have the capability to measure and display radiation levels over a five decade (at least 11

decades for the fuel building vent and plant vent) range specified in table 11.5-1 for each channel. Radiation monitoring system area channels measure and display radiation levels over a five decade range, from 10^{-1} to 10^{4} mr/h for normal operation and 10^{-1} to 10^{4} R/h for post-accident operation.

A. For calibration purposes, minimum detectable levels (lower limit of range) for all process channels are detected under sample conditions of standard temperature and pressure.

B. Minimum detectable levels for all process channels are detected in the presence of a Co-60 external radiation field (design background) of a level specified for each process channel in table 11.5-1.

C. Minimum detectable levels for all process channels are detected at a minimum statistical confidence level above background of 95%.

D. Response times, defined as the time interval for a monitor to indicate 90% of its final value from a step change in the input concentration, are as follows:

   1. For area channels, the time is less than 30 seconds.

   2. For liquid and gas channels, the time is less than 1 minute.

   3. For particulate and I-131 channels, the time is less than 15 minutes.

4. Response time of every channel is approximately inversely related to radiation level at the detector for levels greater than the required minimum detectable level.

11.5.2.1.1.3.2 System Accuracy.

A. For all area radiation monitors, the displayed dose rate in the incident radiation energy range from 0.1 to 3 MeV is normalized to within +/- 20% when referenced to the response due to Co-60. For the incident range of 3 MeV to 7 MeV, the displayed dose rate may over respond in excess of these values.

For the normal range GM area monitors, a generic deadtime correction is applied. Furthermore, a "keep alive" background for the check source is maintained to give an indication of detector failure and will produce a conservative upscale bias of about 0.2 mR/hr which will be significant in the lower decade of operation. Site calibration of the GM area detectors uses a Cs-137 source which produces a conservative dose response for energies of both lower and higher incident gamma energies. The calibration tolerance for GM area detectors is typically +/- 10% with a linearity test of +/- 20% and a maximum allowed deadtime bias of 50% at the highest reading of 1.0E+04 mR/hr. The GM monitor range is 0.1 to 1.0E+04 mR/hr.

For the post-accident personnel, equipment access, primary coolant, and containment high-range ion

chamber area monitors, site calibration is based on an electronic calibration of the amplifier and readout unit with the internal "keep alive" sources used as an indication of proper detector operability due to ALARA concerns over high dose rates. The personnel and equipment access monitors have a range of 0.1 to 1.0E+04 R/hr. The primary coolant monitors have a range of 1.0 to 1.0E+05 R/hr. The containment high-range monitors have a range of 1.0 to 1.0E+07 R/hr.

B. For process liquid and gas channels, the displayed activity concentration is accurate to ±25% of the actual concentration present in the sampler for an unknown mixture having the same radiation emissions as the reference isotope. The reference isotopes for gas channels are Xe-133, Kr-86, and Kr-85, and for liquid channels, is Cs-137. Monitor displayed values in the lowest decade of operation may exceed actual activity concentration by greater than +25% due to inherent detector background. Monitor ranges are shown in table 11.5-1.

C. For process particulate and iodine channels, the displayed activity concentration is accurate to ±25% of the actual concentration present in the sample line for an unknown mixture having the same radiation emissions as the reference isotope based on a clean filter condition. The reference isotope for particulate channels is Cs-137 and for iodine channels is I-131.

Instantaneous monitor displayed values in the lower decades of operation may differ from actual activity concentration by greater than ±25% due to background interference from filter loading. Monitor ranges are shown in table 11.5-1.

11.5.2.1.1.3.3 Nonsaturating Design. Each RMS radiation channel has a nonsaturating design so that it indicates a level higher than its design range upper limit when exposed to a radiation level up to 100 times this limit.

11.5.2.1.1.4 Performance of ESF Monitors. Each separate ESF channel performs the following specific functions:

A. Provides continuous remote indication at the control room cabinet of current radiation level and channel status. These parameters are also available, upon request, at the display and control consoles (DCU).

B. Provides, upon demand, remote indication at the control room cabinet of the currently stored value of any channel critical parameter.

C. Provides complete remote manual control of the channel functions specified in paragraph 11.5.2.1.1.1. This control is exercised through operation of the RIC/KERIC unit.

D. Provides, upon demand, remote indication at the control room cabinet of historic trend values.

E. Provides an output control signal to the BOP ESFAS whenever a high-high (high, for new scope) radiation level is present. Each of these signals is brought to a relay which opens to alarm. Fail open contacts are connected to terminal strips located in the associated control room cabinet.

F. Provides the following isolated digital outputs, wired to the interface module referred to in paragraph 11.5.2.1.1.2.1:

1. Current radiation level

2. Channel alarm status

11.5.2.1.1.5 Performance of Non-ESF Monitors. Non-ESF channels perform the following specific functions:

A. Provides remote indication of current radiation level and channel status upon request, at the communication console in the control room, the workstation in the RMS HP office, and the count room of the associated unit. This information is provided in the form of graphical displays and provides real-time information to help the operator monitor radiation levels in plant effluent pathways as well as internal areas and processes.

B. Provides, upon demand, remote indication at the workstation of the currently stored value of any channel critical parameter.

C. Provides complete remote manual control of the field unit functions specified in paragraph 11.5.2.1.1.1. This control is exercised at the workstation.

11.5.2.1.1.6 Environmental Qualification.

11.5.2.1.1.6.1 Each ESF monitor which is required to function in a harsh environment resulting from an initiating event within the scope of the PVNGS EQ program is environmentally qualified in accordance with section 3.11 per location as specified in table 11.5-1.

11.5.2.1.1.6.2 ESF monitors and RMS control room cabinets are designated Seismic Category I and are seismically qualified as described in section 3.10. This equipment is also classified as Quality Class Q, and a quality assurance program has been implemented for this equipment.

11.5.2.1.1.7 Design and Fabrication Details.

11.5.2.1.1.7.1 Materials of Construction. Materials of construction for pressure-bearing surfaces wetted by process liquids or waste gas is austenitic stainless steel, type 304. Materials of construction for surfaces wetted by sampled air are austenitic stainless steel.

Materials for fasteners of stainless steel parts (bolts or nuts) and pump wearing parts (wear rings or seals) are austenitic stainless steel or other ASTM-specified material suitable for the water chemistry and/or radiation environment of the sampler.

11.5.2.1.1.7.2 Sampling Assembly. Each process or effluent channel includes a sampling assembly which consists of a sampler and the associated piping, fittings, and other components as required to transport the sample through the system. The sampling assembly is a closed sealed system and includes a sampling pump, valves, interconnecting piping, filters, fittings, flow and pressure transducers, and other local control and instrumentation elements as required. Sampler piping and connections are welded except where maintenance considerations make flanged or Swagelok joints necessary. Sampler outlet piping connections are located to minimize cleaning requirements and background buildup due to the adherence of radioactive particles to the sampler walls. For liquid samplers, welding of pressure-containing components is performed in accordance with ANSI B31.1. For ESF monitors, welding of pressure-containing components is performed in accordance with AWS D1.1-1972 (with 1973 revisions). Welding of other equipment is performed in accordance with industry standards.

For liquid and process channels, the sampler is a lead-shielded steel chamber. For particulate and iodine channels, the sampler is a lead-shielded filter assembly. Four π shielding is furnished for all process and effluent detectors except induct gas monitors and high range ion chambers for which background is not significant.

Airborne particulate and iodine monitors and samplers (see table 11.5-1) sample in accordance with the principles and methods of ANSI N13.1-1969, Guide to Sampling Airborne

Radioactive Materials in Nuclear Facilities. For normal range monitors, the particulate and iodine sample flow is maintained constant over the normal expected range of filter paper and/or charcoal cartridge differential pressure by an automatic control system. Accident range monitors employ manual sample flowrate control. Flow indication and local high- and low-sample flow alarm signals (old scope only) are provided. These signals actuate the channel failure alarm. New scope monitors provide remote low-sample flow alarms only. Sampling assembly fittings are provided which allow grab sampling of the monitored airstreams.

Refer to subsection 18.II.F.1.2 for TMI-related information pertaining to the particulate collection and iodine adsorption efficiency.

11.5.2.1.1.7.3 Detector Assembly. The detector assembly is a completely weatherproofed assembly and is capable of withstanding the design pressure and temperature of the piping system or environment of which it is a part, without leakage, collapse of the tube walls, or damage to the detector.

On process and effluent monitoring skids, the detector is installed in the sampler assembly.

A preamplifier is used with the detector to ensure reliable transmission of a high-quality signal to the channel microcomputer.

Scintillation detectors are beta- or gamma-sensitive detectors suitable for analysis of photopeaks up to 3 MeV. Photo-

multipliers are shielded to prevent gain changes due to orientation or stray magnetic fields. The case surrounding the detector assembly is constructed of a corrosion-resistant material suitable for continuous outdoor operation. The preamplifier is integral to the detector assembly, while the check source can be either internal or external, depending upon monitor and scintillator type.

For the steam generator blowdown discharge monitor, the detector is Am-241 doped to generate a continuous radiation signal that is monitored for quality and efficiency. The preamplifier is located in the microcomputer.

Geiger-Mueller (GM) detectors are halogen quenched beta-gamma sensitive tubes of sufficient size and wall thinness to detect the minimum specified dose rate. Area monitors with GM tubes have internal check sources and preamplifiers while GM detectors utilized on post-accident monitors incorporate an internal check source but external preamplifier. Ion chambers used inside the containment are fully qualified to post-LOCA conditions in accordance with IEEE 323-1974 and IEEE 344-1975. Ion chambers used outside the containment are qualified to the zone they are located in and cover the full range of γ dose for that area. Each ion chamber contains an internal "keep-alive" source consisting of a small amount of radioactive material. Signal conditioning and amplification is provided by a preamplifier installed at the monitor microcomputer.

11.5.2.1.1.7.4 Motors. The liquid sampler pump (RTI monitor only) and each airborne sampler blower motor is a standard 460 V-ac, three-phase motor.

Motor controllers include auxiliary contacts for use in the failure circuit of the respective radiation monitoring channels.

Remote motor control is provided via each workstation for non-ESF field units and via each RIC unit for ESF field units. Local motor control switches and indicating lights at the field unit are provided.

11.5.2.1.1.7.5 Power Supply. Electrical power having the following characteristics is made available as listed in table 11.5-1 for each monitor.

- Grounded, 60 Hz, three-phase, 480 V-ac ±10% (for motors only)
- Ungrounded, 60 Hz, single-phase, 120 V-ac ±10%

To protect data normally stored in field unit microcomputers, minimize system downtime following power failures and the impact on real-time performance of the RMS, field units have the following electrical power, failure and recovery modes:

A. For a short-term (less than 4 hours) sustained loss of power to a field unit, the affected microcomputer:

   1. Senses the impending loss of power and conducts an orderly shutdown. Battery backup power

supplies are rechargeable and provide a minimum of 4 hours of backup power to read/write memory.

2. Upon restoration of power, restarts immediately and automatically and functions normally without loss of any data stored in memory at the time of power loss.

B. For a long-term (4 hours or greater) sustained loss of power, loss of data stored in read-write memory can occur. For field unit microcomputers, sufficient program is located in read-only memory circuits so that, upon subsequent restoration of power, recovery to full functional status can be effected.

C. The RMS server, Control Room workstation, and HP office workstation are provided with an uninterruptable power supply system to maintain full system operation in times of short-term (less than 10 minutes) power failure. For long-term power outages, sufficient data is located in startup files so that, upon subsequent restoration of power, recovery to full functional status is effected automatically.

11.5.2.1.1.7.6 Output Relays. Alarm output relays are provided in the field unit for the XJ-SQN-RU-07, RU-12, RU-141 and RU-200 non-ESF monitors. They are also provided in the RIC/KERIC unit for each ESF monitor. The ESF monitor relays initiate the automatic control actions listed in table 11.5-1 to the BOP ESFAS circuits. All of the relays have fail-open

contacts. The relays are deenergized in the presence of a high-high (high for new scope equipment) alarm.

11.5.2.1.1.7.7 ESF Monitor Interface Units. These units include isolation devices (SRMS isolation modules) and interface electronics necessary to receive the following digital information from each of the ESF channels and communicate it to the non-ESF communications loop:

- Radiation level
- Channel failure alarm
- Channel test signal
- Alert radiation alarm (referenced as High Alarm for old scope)
- High radiation alarm (referenced as High-High alarm for old scope)

These interface units are located in the channel A and channel B sections of the ESF RMS control room cabinets.

11.5.2.1.1.7.8 The RMS Computer System includes the following devices:

- RMS Server: communicates with the microcomputers to retrieve current data, download parameters to the microcomputers (Non-1E only), and provide remote control (Non-1E only). Archives data received from the microcomputers. Provides alarm processing for local

points and propagates alarm processing for alarms remotely processed in the microcomputers.

- HP Office Workstation: communicates with RMS Server to display information to the user in a graphical format, sounds audible alarms, and allows the user to issue commands to the Non-1E microcomputers from the HP Office.
- HP Office Printer: permits on demand printing.
- Control Room Workstation: communicates with RMS Server to display information to the user in a graphical format, sound audible alarms, and allows the user to issue commands to the Non-1E microcomputers from the communications console in the control room.
- Count Room Workstation: communicates with RMS Server to display information to the user in a graphical format, sound audible alarms, and allows the user to issue commands to the Non-1E microcomputers from within the RCA.

Operator interface is provided through a series of graphical displays available on demand at any workstation.

Primary Displays/Functions include the following:

A. System Overview

The System Overview display provides the following current information for all monitors in the system:

1. Monitor Alarm Status
2. Channel Alarm Status

3. Channel Radiation/Radioactivity Levels

B. Operator Monitor

Displays all current information needed by the operator to quickly assess the status of the monitor and perform all remote commands. The display includes current channel readings, current alarm conditions, 1 hour historical trends of each channel, acknowledge alarms command and other pertinent commands. All commands require confirmation and security password.

C. Database Display

Displays all current parameters/readings transmitted to the RMS Server from the microcomputer. Parameter fields that may be changed are editable and may be downloaded to the monitor. Downloads require confirmation and security password.

D. Current Alarms Display

Displays all current alarm messages in the system. Messages are colored according to alarm level, and prioritized according to level (1 is the highest):

Red: Level 1 (High Alarm, Detector Saturation)

Yellow: Level 2 (Alert Alarm)

Orange: Level 3 (Equipment Failure, Condition Alarm)

Blue: Level 4 (User Defined)

Alarm messages are colored according to alarm level, unless the message is unacknowledged and cleared, then

the message is green. An acknowledgement field indicates an operator has responded to the alarm.

Associated with this display is a RMS Alarms Button. This button will be displayed independently of the current display the user is viewing and cannot be covered by other displays (or applications) as long as the system is running. The button color (solid or flashing) will reflect the current alarm status of the system, as described above. When the user clicks on the RMS Alarms Button, the system navigates to the Current Alarms Display which provides the operator with more detailed information regarding the current alarms.

E. System Messaging Application

Displays the most recent event messages, including: alarm messages, equipment failures, activities in progress, communication errors, operator commands, and operator comments.

F. Archive Retrieval Display

Retrieves data from the archive file based on point name (1 to 6 per retrieval), retrieval interval (start date, stop date or duration), archive source file (25 hour, 35 day, or 365 day files), resolution and destination (trend, tabular, ASCII file, or linear regression).

Secondary Displays/Functions are also provided to aid the operator in assessing various situations or scenarios that are

not described in detail here. For a complete description of system capabilities, the Radiation Monitoring System Computer System Requirements document should be referenced.

11.5.2.1.1.7.8.1 Automatic Controls. The RMS Server/Workstations can provide automatic control of each Non-1E monitor/channels through the manipulation of database parameters of the associated field unit microcomputer.

A. Automatic activation of the check source and monitoring for proper response at regular intervals specified in the channel critical parameter file.

B. Automatic restoration of a monitor to the RMS Server communication polling if the restore enable is set for the monitor.

11.5.2.1.1.7.8.2 Remote Manual Controls. The RMS Server/Workstations can also provide remote manual control of each monitor through the Operator Monitor Displays. Remote manual control includes the following, as applicable to the particular monitor/channel type:

A. Remote manual activation of the check source.

B. Remote manual startup or shutdown of sampling auxiliary equipment for maintenance.

C. Remote manual acknowledgment of alarms. Note that local alarm indication will not clear until locally acknowledged.

D. Changes to the monitor/channel memory resident critical parameters values.

Password security assures positive administrative control over access to the remote manual controls.

11.5.2.1.1.7.8.3 Annunciation and Recording. Provides real time annunciation and historical chronologically indexed logs of all events that affect the status of the RMS equipment. A change in status of any monitor or channel of monitor will cause a level, equipment, or condition alarm. Logs may be printed on demand. The presence of an alarm will generate an audible annunciation (if applicable), an alarm message on the Current Alarms Display, change in the color of monitor or channel wherever displayed in the system, and the RMS Alarms Button will reflect the condition. Local alarms must be cleared locally.

The RMS Server transmits the radiation levels of all channels to ERFDADS every 10 seconds.

11.5.2.1.1.7.9 ESF RMS Control Room Cabinets. The RIC/KERIC units output relays, digital-to-analog converters and recorders are mounted in control room cabinet assemblies. The cabinets also house the ESF monitor interface units (refer to paragraph 11.5.2.1.1.7.7). The freestanding NEMA 12 panels are divided into four sections, two for old scope (channel A equipment and channel B equipment), and two for the new scope, (channel A equipment and channel B equipment). Cabinet cooling is provided. The cabinets and contents are designated Seismic

Category I and are designed, constructed, and anchored accordingly. The cabinets are located adjacent to the non-ESF RMS control room cabinets away from the main control board area. New scope and old scope control room cabinets are not identical. While function and purpose is the same, design is different. Additional information is available in the operation-maintenance manuals.

11.5.2.1.1.7.10 Remote Indication and Control Units. Each RIC/KERIC unit is of modular design and rack-mounted. It is microcomputer controlled (old scope only) and connected by standard dual twisted wire pairs (TWP) to its associated field unit microcomputer. The RIC/KERIC unit includes a front panel with digital readouts, hand switches, and circuitry to satisfy the functional requirements of paragraph 11.5.2.1.1.4. The RIC/KERIC unit provides IEEE 323 qualified data recording.

11.5.2.1.1.7.11 Intentionally blank

11.5.2.1.1.7.12 Intentionally blank

11.5.2.1.1.7.13 Non-ESF RMS Control Room Cabinet. This cabinet is located adjacent to the ESF RMS control room cabinets. It houses the gas stripper monitoring system interface units. The gas stripper monitor is not connected to the remainder of the RMS. It does provide separate alarm and indication functions in the Control Room.

11.5.2.1.1.7.14 Portable Monitor Connection Boxes. At 18 locations throughout the unit, portable monitor connection

boxes are hardwired into the nonsafety communications loops. These connection boxes contain receptacles for plug-in jacks attached to portable area monitors which can be temporarily connected to the loop for remote display and control during inservice inspection and other radioactive maintenance. When no jack is connected to a box, it is designed to appear as a short in the nonsafety communications loop.

11.5.2.1.1.7.15 Portable Area Monitors. Each of the portable area monitors includes a single area channel. The complete detector assembly and electronics package is mounted together and is capable of being hand-carried. The detector is connected to the electronics package and is detachable for separate mounting. The electronics package is connected to plug-in jacks.

11.5.2.1.2 Redundancy, Diversity, and Independence

11.5.2.1.2.1 In order to satisfy the design bases for postulated accident conditions defined in paragraph 11.5.1.2, ESF channels are designed to monitor area and/or airborne radiation levels at key locations and provide alarm outputs to the balance of plant engineered safety features actuation system (BOP ESFAS). In keeping with this function, ESF channels are designed in accordance with IEEE Standards 279, 308, 323, 336, 338, 352, 379, 383, and 384.

11.5.2.1.2.2 ESF monitors and their associated RIC units form independent and redundant sensor channels A and B for three

safety feature actuation signals, CREFAS, FBEVAS, and CPIAS as follows:

- XJ-SQA-RU-29: CREFAS - channel A
- XJ-SQB-RU-30: CREFAS - channel B
- XJ-SQA-RU-31: FBEVAS - channel A
- XJ-SQB-RU-145: FBEVAS - channel B
- XJ-SQA-RU-37: CPIAS - channel A
- XJ-SQB-RU-38: CPIAS - channel B

11.5.2.1.2.3 Single Failure. Each pair of ESF monitors is designed to accommodate any random single failure without precluding the initiation of a safety features actuation signal when a true initiating radiation level exists. IEEE 379 is used as the guide for application of the single failure criterion.

11.5.2.1.2.4 Redundancy. For each safety feature actuation signal listed above, channels A and B are mutually redundant. A redundant element is defined as one whose function is totally duplicated by one or more identical (functionally) and mutual independent elements. Two identical elements are not redundant if they are not independent.

11.5.2.1.2.5 Independence. Redundant channels are electrically and physically isolated from each other such that

events (including faults) affecting one channel does not affect the other in any way.

11.5.2.1.2.6 Diversity. Diversity is provided for the FBEVAS signal by utilization of an area radiation monitor as channel A and an airborne gas radiation monitor as channel B.

11.5.2.1.3 Process Radiation Monitoring

11.5.2.1.3.1 Essential Cooling Water (ECWA, ECWB) (XJ-SQN-RU-02 and XJ-SQN-RU-03) Monitors. These two channels monitor the essential cooling water system trains A and B. A high activity alarm indicates a reactor coolant or reactor auxiliary system leak into the cooling water system. Upon receiving an indication that activity in the system is increasing, the alternate loop may be made operable, and the individual cooler outlets may be sampled to determine the defective component.

Each ECW monitor is situated in a bypass loop around an ECW pump which provides the necessary sample driving head. These monitors have been upgraded for pressure boundary components as referenced in Table 3.2-1.

11.5.2.1.3.2 Steam Generator Blowdown (SGB1, SGB2) (XJ-SQN-RU-04 and J-SQN-RU-05) Monitors. A monitor is located in each steam generator blowdown or downcomer sample line. A high activity alarm indicates primary-to-secondary leakage.

11.5.2.1.3.3 Nuclear Cooling Water System (NCW) (XJ-SQN-RU-06). The nuclear cooling water system is monitored for radioactive in-leakage. A high activity alarm indicates a leak from a reactor auxiliary system. Individual cooler outlets may be sampled to determine the defective component.

The NCW monitor is situated in a bypass loop around the NCW pump which provides the necessary sample driving head.

11.5.2.1.3.4 Auxiliary Steam Condensate Receiver Tank (RTI) (XJ-SQN-RU-07) Monitor. Auxiliary steam condensate returning from the boric acid concentrator and LRS evaporator is monitored before it leaves the receiver tank. A high activity alarm indicates radioactive leakage into the tubes of an evaporator during blowdown of the shell side, or due to improper operation. Upon a high-high alarm, the RTI monitor automatically diverts the condensate to the liquid radwaste system. This monitor draws and returns a sample from the sampled tank. A pumping system, to generate the required sample driving head, and a sample cooler, to cool the sample to less than 120F, are provided. The sample cooler is cooled by nuclear cooling water.

11.5.2.1.3.5 Auxiliary Building Ventilation Exhaust Filter (ABFI) Inlet (XJ-SQN-RU-08) Monitor. The auxiliary building ventilation exhaust is continuously monitored for airborne radioactive particulates and iodines.

The significant noble gas sources in the auxiliary building are monitored as listed in paragraphs 11.5.2.1.3.6 and

11.5.2.1.3.7. The exhaust from these areas is monitored directly before dilution in the building ventilation system. Auxiliary building exhaust is monitored by the plant vent effluent monitor.

11.5.2.1.3.6 Auxiliary Building Lower Levels Ventilation (ABLL) Exhaust (XJ-SQN-RU-09) Monitor. The combined ventilation exhaust from the train A penetration room and the rooms housing the letdown heat exchanger, the associated valve gallery, and the charging pumps is continuously monitored for gaseous activity. A high activity alarm indicates equipment leakage.

11.5.2.1.3.7 Auxiliary Building Upper Levels Ventilation (ABUL) Exhaust (XJ-SQN-RU-10) Monitor. The combined ventilation exhaust from the gas stripper room, the letdown ion exchanger room, associated valve galleries, and the sampling room is continuously monitored for gaseous activity. A high activity alarm indicates equipment leakage.

11.5.2.1.3.8 Waste Gas Decay Tank (WGDT) (XJ-SQN-RU-12) Monitor. This in-line channel monitors the decay tank discharge header for gaseous activity. A high alarm indicates an operational occurrence; e.g., inadvertent discharge or incorrect valve line up. The monitor initiates isolation of the decay tank discharge header on a high-high activity alarm.

11.5.2.1.3.9 Radwaste Building Ventilation Exhaust Filter (RBFI) Inlet (XJ-SQN-RU-14) Monitor. The radwaste building

ventilation system is continuously monitored for airborne particulate activity. The only significantly abundant isotopes which could be released from sources within the radwaste building are noble gases and particulates; therefore, an I-131 monitor is not provided. The only significant airborne noble gas leakage sources are monitored as listed in paragraph 11.5.2.1.3.10. Radwaste building exhaust is monitored by the plant vent.

11.5.2.1.3.10 Waste Gas System Area Combined Ventilation (WGVE) Exhaust (XJ-SQN-RU-15) Monitor. The waste gas system area combined ventilation exhaust is continuously monitored for gaseous activity. A high activity alarm indicates leakage from waste gas processing equipment or the associated valve gallery.

11.5.2.1.3.11 Control Room Ventilation Intake Monitors, (CRVA, CRVB) Channels A and B (XJ-SQA-RU-29 and XJ-SQA-RU-30). These gaseous channels monitor the control room ventilation supply for any inleakage of activity from the environment. Two monitors sample from the ventilation air intake duct as close to the intake point as possible. These monitors actuate the control room essential ventilation system. Refer to section 7.3 for a discussion of the safety function of these monitors.

11.5.2.1.3.12 Containment Building Refueling Purge Exhaust (CBPB) Monitor, Channel B (XJ-SQB-RU-34). The containment building refueling purge exhaust is continuously monitored for a gaseous activity release.

11.5.2.1.3.13 Containment Building Atmosphere Monitor, (CBB) Channel B (XJ-SQB-RU-01). The containment building atmosphere is continuously monitored for particulate, iodine, and gaseous activity. The sample is drawn from the containment building in a closed system, is monitored outside the containment, and then is returned to the containment building atmosphere after it passes through the samplers. The particulate and gaseous channels serve as two methods of RCPB leak detection in accordance with Regulatory Guide 1.45 except as noted in section 1.8. This monitor is designated Seismic Category I.

In order to obtain a representative sample of containment air, the sample line inlet is located on the operating level between two of the normal cooling units intakes. While shown on the 100-foot 0-inch elevation in figure 11.5-2, the sample point is actually on the 93-foot elevation. This location also facilitates RCPB leak detection by these monitors.

The CB-B monitor is located just outside the containment building. It samples the containment atmosphere through piping penetrations. Containment isolation valves (refer to subsection 6.2.4) shut on CIAS when containment pressure reaches the containment isolation pressure setpoint. Therefore, the CB-B monitor is designed to function properly subsequent to an event where pressure is applied to the sampler piping.

11.5.2.1.3.14 NSSS Process Radiation Monitor, (XJ-SQN-RE-155D). The process radiation monitor (PRM) is designed to provide information on both the long-term trends

and rapid changes in the level of radioactivity in the reactor coolant. The monitoring is continuous with the PRM located adjacent to the reactor coolant purification letdown line. Rapid escalations in reactor coolant activity may result from phenomena that is not related to the integrity of the fuel. Therefore, the PRM is not designed to provide an indication of the number of failed fuel rods. The PRM monitors the count rate of gross gamma activity in the reactor coolant. Determination of the percent of reactor power generated in fuel rods containing cladding defects or their vicinity in the core requires the analysis of the isotopic ratio of specific nuclides in the coolant. This is done to distinguish between fuel failures and other phenomena which may escalate activity levels such as iodine spiking or corrosion product releases. The determination of the actual number of fuel rods containing cladding defects requires the process of fuel assembly sipping.

The PRM is not designed to provide quantitative indication of fuel failure. The PRM alarm setpoint is adjusted to an activity value which is just above that normally measured in the coolant. Annunciation of the alarm would then indicate escalation in the reactor coolant activity level. The action upon receipt of the alarm is operator investigation of the cause and initiation of corrective action if required. The PRM does not provide any automatic control functions.

The PRM is used to monitor trends in reactor coolant activity. Plant procedures will require investigation of the cause of significant escalation, whether or not an alarm setpoint is reached. Technical Specifications describe limiting conditions

for operation and surveillance requirements concerning reactor coolant system specific activity, and requires chemical analysis of reactor coolant for gross activity and iodine activity. The required periodic measurements of dose equivalent I-131 will be used to monitor cladding integrity during operation. Should these trends indicate cladding failure, the reports described in the Technical Requirements Manual will be made to the NRC. A program of fuel assembly leak detection inspection will be conducted at the next refueling to determine the location and number of failed fuel rods, if a significant number is indicated.

The primary coolant activity monitoring subsystem is discussed in CESSAR Section 9.3.4.

11.5.2.1.3.15 Condenser Vacuum Pump/Gland Seal Exhaust (CVSE) (XJ-SQN-RU-141) Monitor. The vacuum pumps and gland seal condenser remove gases from the secondary system. The exhaust is continuously monitored for gaseous activity resulting from primary-to-secondary system leakage. There are two (2) detectors installed in the system. One detector (channel B) is installed in the vacuum pump combined discharge piping, while the second detector (channel A) is installed in the combined vacuum pump and gland seal discharge. The exhaust is piped to be combined with the plant vent exhaust and is monitored for effluent releases by monitors XJ-SQN-RU-143 and XJ-SQN-RU-144. No other airborne monitors are provided for the turbine building. The monitor provides automatic initiation of filtration (channel A only) of the condenser vacuum pump/gland

seal exhaust whenever the monitor channel is in a high-high alarm condition.

11.5.2.1.3.16 Main Steam Nitrogen-16 Monitor (XJ-SQN-RU-142). The main steam lines are monitored for the presence of N-16 gamma radiation by a 3 X 3 inch NaI scintillation detector mounted adjacent to each steam line. The presence of N-16 in the main steam lines is an indication of primary-to-secondary leakage.

11.5.2.1.3.17 Steam Generator Blowdown Discharge Monitor (XJ-SQN-RU-200). The steam generator blowdown discharge line to the retention tank is continuously monitored for radioactivity. A high alarm terminates the discharge by isolating the line in order to prevent significant levels of radioactivity in the retention tank.

11.5.2.1.4 Effluent Radiation Monitoring

The effluent radiation monitors have complete digital readout and control from the RMS office and the main control room. The high range monitors have three particulate and iodine sampler channels. Channels 1 and 2 are operator selectable with no fixed sample time intervals. Channel 3 is used as a timed grab sample with the sample time set by the operator. These sampler channels utilize sample cartridges that require analysis to determine isotopic concentrations. The installed particulate and iodine sample collection media uses minimal absorption of noble gases. Samples are preconditioned as necessary to assure accurate results without damaging the sample assemblies. Each

monitor is controlled by a remote microprocessor. This microprocessor is linked by a "daisy chain" to a RMS server which provides data to workstation to generate multiple informational displays on request by the operator. Monitors are provided with an open structural construction that provides for easy maintenance and good heat dissipation. Multiple detectors are used to achieve the dynamic range required.

Refer to subsection 18.II.F.1.1 for TMI-related information pertaining to noble gas effluent monitors.

11.5.2.1.4.1 This section intentionally blank.

11.5.2.1.4.2 Plant Vent (XJ-SQN-RU-143 and XJ-SQN-RU-144) (PVLR, PVHR) Monitor. The plant vent exhaust is continuously monitored for particulate, I-131, and gaseous activity.

A low and high range monitor is used to cover a range of eleven decades with one decade of overlap. Shielded particulate and iodine samples exist and are removed for analysis.

11.5.2.1.4.3 Fuel Building Ventilation Exhaust Monitor, (FBLR, FBHR) Channel B (XJ-SQB-RU-145 and XJ-SQB-RU-146). The fuel building exhaust is continuously sampled for particulate and I-131 activity, and monitored for gaseous activity. The gaseous channel also monitors the fuel building ventilation exhaust for release of activity due to a fuel handling accident. The FBLR monitor performs the safety function of isolating the normal ventilation system and activating the essential ventilation system (initiates a FBEVAS signal) on a

high-high activity alarm. Refer to section 7.3 for a discussion of the safety function of the fuel building ventilation exhaust monitor. During normal operation, the only significantly abundant isotope which would be released from the fuel building is tritium; therefore, gaseous activity is monitored and particulate and I-131 sampling capability is provided.

A low and high range monitor is used to cover a range of eleven decades with one decade of overlap. Particulate/iodine cartridge samples exist in the low and high range monitor and are removed for analysis. High range cartridge samplers are shielded.

11.5.2.1.5 Area Radiation Monitoring

One function of area radiation monitors (except for XJ-SQA-RU-37 and XJ-SQB-RU-38) listed in table 11.5-1 is to indicate and alarm locally and remotely the area dose rate to ensure proper personnel radiation protection. Several of the area monitors also perform other additional functions or have unique characteristics.

11.5.2.1.5.1 Central Calibration Facility Area (XJ-SQN-RU-24) (CFA) Monitor. The CFA monitor is located in a small outbuilding in the yard of Unit 1 which is shared by all three units as a central calibration facility.

11.5.2.1.5.2 INTENTIONALLY LEFT BLANK

11.5.2.1.5.3 Fuel Pool Area Monitor, Channel A (FPAA) (XJ-SQA-RU-31). The monitor is located on a wall over-looking the fuel pool where it monitors for a release of activity due to a fuel handling accident in the fuel building. The monitor performs the safety function of isolating the normal ventilation system and activating the essential ventilation system on a high-high dose rate alarm. Refer to section 7.3 for a discussion of the safety function of the monitor.

11.5.2.1.5.4 Refueling Area Monitor, Channel A (RMAA) (XJ-SQA-RU-33). The monitor is located on a wall overlooking the refueling cavity where it monitors for a release of activity due to a fuel handling accident in the containment.

11.5.2.1.5.5 Power Access Purge Area Monitors, Channels A (PAPA) and B (PAPB) (XJ-SQA-RU-37 and XJ-SQB-RU-38). The monitors are located between the containment power access purge exhaust duct and the refueling purge exhaust duct just outside the containment wall. During power operations, these channels monitor the duct for airborne radioactivity concentrations which could potentially result in an offsite dose exceeding 10CFR100 limits. These monitors perform the safety function of isolating the containment building purge supply and exhaust ducts (initiate CPIAS signals) on a high-high dose rate alarm. Refer to section 7.3 for a discussion of the safety functions of the monitors.

11.5.2.1.5.6 Main Steam Line (XJ-SQN-RU-139 and XJ-SQN-RU-140) Monitor. One area monitor with a collimating lead shield is mounted adjacent to each main steam line in the main steam support structure. Refer to figure 11.5-3. These monitors measure direct dose rates from the main steam line to identify radioactive effluent from the atmospheric dump and main steam relief valves. There are a total of four detectors with one remote microprocessor for each two detectors.

11.5.2.1.6 Inspection, Calibration and Maintenance

11.5.2.1.6.1 Maintenance. Outdoor sampling systems are housed in outdoor-type weatherproof enclosures. The enclosures are designed to permit performance of all control and routine maintenance and cleaning operations from the front or top of the enclosure. Interior wiring is run in conduit to terminal boards mounted in junction boxes.

Instrument air is supplied for flushing of gaseous or airborne monitors. Taps for connecting demineralized water are supplied for flushing all liquid monitors.

The interior surface finish of the sample chamber is designed to minimize contamination by absorption or adherence of radioactive material thereto and to facilitate cleaning by use of a cleaning solution. Sample chambers are removable to allow ultrasonic decontamination or replacement.

Equipment design incorporates plug-in electronic cards and rack-mounted system modules wherever possible to facilitate removal and replacement or repair.

11.5.2.1.6.2 Calibration and Inspection. A remotely operated check source or in the case of ion chamber detectors, an internal radioactive "keep-alive" source is provided with each detector assembly. The check source and keep-alive source are usable as convenient methods to provide a qualitative check of the associated detection and readout equipment. The check source provides a count rate sufficient to verify detector operation when the detector is near the bottom of its range. The keep-alive source provides a sufficient background current from the detector to the monitor to continuously verify detector operation.

Primary calibrations were performed by the manufacturer for each type of detector used in the RMS. As part of the primary calibration, detectors were exposed to known radiation fields or radioactivity concentrations, as applicable, that were traceable to the National Bureau of Standards (NBS), currently known as the National Institute of Standards and Technology (NIST). These calibrations determined detector sensitivity and efficiency for each type of detector used in the RMS. Due to design configuration control and in the case of the process monitors, fixed analysis geometry, additional primary calibrations of the monitors used in the field are not necessary. Subsequent calibrations need only verify that the monitor's response measured in the field correlates to the monitor's response measured during the primary calibration by using transfer calibration sources or by direct measurement.

The general method for performing field calibrations consists of the following steps:

1. Verifying the monitor electronic alignment.

2. Evaluating monitor response to known radiation fields, field calibration sources, or electronic input in order to verify that the monitor's efficiency is similar to that measured during the primary calibration.

3. Evaluating the linearity of the monitor's response using radioactive sources or electronic inputs.

The specific method of correlating a monitor's field response to the primary calibration depends on the type of detector and function of the monitor.

Scintillation (beta and gamma) detectors and Geiger-Mueller (GM) detectors used as process and effluent monitors are calibrated in the field using field calibration sources. These calibration sources relate the detector's response measured in the field to the response measured during the primary calibration that used a similar model of detector and transfer calibration sources in a geometry that is the same as the field calibration sources.

GM detectors used as area monitors (including area monitors that monitor process streams) are calibrated by placing the detector in a calibrated radiation field and verifying that monitor readings are consistent with the radiation field. Due to ALARA considerations, area monitors using ion chamber detectors (including area monitors that monitor process and effluent streams) are calibrated electronically by inputting known electronic signals into the monitor and verifying

response through its entire range. Ion chamber detector response is verified in the field using the internal radioactive keep-alive source. For all ion chamber detectors, with the exception of those used in the containment high range area monitors (RU-148 and RU-149), detector response is evaluated by ensuring a minimum response from the keep-alive source is present. For RU-148 and RU-149, the ion chambers used were exposed to an NIST (NBS) traceable radiation field by the manufacturer during the primary calibration. As part of this calibration, the background keep-alive source response was measured. During subsequent field calibrations, the response of the keep-alive source is verified to be consistent with that measured during the primary calibration. This provides the necessary traceability and in situ calibration response checks for the containment high range area monitors as required in NUREG-0737.

The RMS channels are checked and inspected periodically. Grab samples are collected for the isotopic analysis in accordance with the schedule in table 11.5-3. Setpoint checks are done on a monthly basis (except for RU-148, RU-149, RU-150, and RU-151 which are performed at the frequency specified in TSR 3.3.105.1), and calibration is performed at least every 18 months (except for RU-148, RU-149, RU-150, and RU-151 which are performed at the frequency specified in TSR 3.3.105.2) or at the indication of equipment malfunction. Instruments are serviced as required.

Field calibration of the indicated channels is performed following any equipment maintenance that can change the

accuracy of the instrument indication. It also may be scheduled if the check source indicates an abnormal response. Critical parameters are verified as part of the calibration process.

11.5.2.2 Routine Sampling

The requirements of the system design bases for routine continuous and discrete sampling of radioactivity are satisfied by a system of liquid, gaseous, and airborne samplers, laboratory equipment for sensitive radio-chemical analyses, and a program of procedures for obtaining and analyzing representative samples when and where appropriate. This section provides a detailed description of system hardware and procedures in general, including the types of sample nozzles and other sampling equipment used, the procedures to obtain representative samples, and analytical procedures.
Table 11.5-2 is a tabulation of basic information describing each of the sampling locations, including the basis for selecting the location, expected flow, composition, concentrations, and the types of effluents released at the location. Table 11.5-3 is a tabulation of basic information describing the schedule of analyses performed on each sample for each type of release, including the type of analyses performed (quantities measured), frequencies of performance, and analytical sensitivities

Table 11.5-2
ROUTINE SAMPLING

Sampling Location	Basis for Location Selection	Expected Process Flowrate	Sample Composition	Expected Concentrations ($\mu Ci/cm^3$)	Types of Effluent Releases (Refer to Table 11.5-3)
Waste gas decay tanks	Determination of identity and quantity of radionuclides being released; calibration check of WGDT monitor	0-50 standard ft^3/min	H_2, N_2	1.0×10^{-1} Kr-85	Batch release of fission and activation gases
Containment building atmosphere (CB-B) monitor	Determination of identity and quantity of radionuclides to be released during containment purge; calibration check of CB-B monitor	30,000 standard ft^3/min preaccess 2,000 mini-purge	Containment atmosphere	5.0×10^{-4} Xe-133 LMD[a] I-131 2.4×10^{-10} Cs-137	Batch release of fission and activation gases and tritium; releases of airborne radioactive iodines
Plant vent monitor	Determination of identity and quantity of radionuclides being released; calibration check of PV monitor	143,570 standard ft^3/min including 30,000 standard ft^3/min containment purge	Ventilation exhaust air	LMD [a]	Continuous releases of fission and activation gases and tritium; releases of airborne radioactive particulates; releases of airborne iodines
Fuel building vent monitor	Determination of identity and quantity of radionuclides being released; calibration check of fuel building monitor	43,000 standard ft^3/min	Ventilation exhaust air	LMD[a]	Continuous releases of fission and activation gases and tritium; releases of airborne particulates; releases of airborne radioactive iodines

a. "LMD" – Less than minimum detectable

Table 11.5-3
SCHEDULE OF SAMPLE ANALYSES AND SENSITIVITES (Sheet 1 of 2)

Gaseous Release Type	Sampling Frequency	Minimum Analysis Frequency	Type of Activity Analysis	Lower Limit of Detection (LLD) (μCi/ml)
A. Waste Gas Storage	P Each Tank Grab Sample	P Each Tank	Principal Gamma Emitters[1]	1.0E-04
B. Containment Purge	P Each Tank[3] Grab Sample	P Each Tank[3]	Principal Gamma Emitters[1]	1.0E-04
			H-3	1.0E-06
C. 1. Plant Vent **2. Fuel Bldg. Exhaust**	M[3] Grab Sample	M[3]	Principal Gamma Emitters[1]	1.0E-04
			H-3	1.0E-06
	Continuous	4/M Charcoal Sample	I-131	1.0E-12
			I-133	1.0E-10
	Continuous	4/M Particulate Sample	Principal Gamma Emitters[2] (I-131, Others)	1.0E-11
	Continuous	M Composite Particulate Sample	Gross Alpha	1.0E-11
	Continuous	Q Composite Particulate Sample	Sr-89, Sr-90	1.0E-11
D. All Radwaste Types as listed in A., B., and C., above	Continuous	Noble Gas Monitor	Noble Gases Gross Beta or Gamma	1.0E-06

1. The principal gamma emitters for which the LLD specification applies include the following radionuclides: Kr-87, Kr-88, Xe-133, Xe-133m, Xe-135, and Xe-138 for gaseous emissions.

2. The principal gamma emitters for which the LLD specification applies include the following radionuclides: Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, Cs-134, Cs-137, Ce-141 and Ce-144 for particulate emissions.

3. Analyses shall also be performed following SHUTDOWN, STARTUP, or a THERMAL POWER change exceeding 15% of the RATED THERMAL POWER within a 1-hour period if 1) analysis shows that the DOSE EQUIVALENT I-131 concentration in the primary coolant has increased more than a factor of 3; and 2) the noble gas activity monitor on the plant vent shows that effluent activity has increased by more than a factor of 3.

Table 11.5-3

SCHEDULE OF SAMPLE ANALYSES AND SENSITIVITES (Sheet 2 of 2)

FREQUENCY NOTATION FOR TABLE 11.5-3

NOTATION	FREQUENCY
M	At least once per 31 days.
4/M	At least 4 times per month at intervals no greater than 9 days and a minimum of 48 times per year.
P	Completed prior to each release.
Q	At least once per 92 days.

11.5.2.2.1 Sampling Equipment and Procedures

Sampling equipment and procedures are provided to assure that representative samples are obtained. Prior to sampling, large tanks of liquid waste are well-mixed in as short a time interval as practicable to assure that any sediments or particulate solids are distributed uniformly in the waste mixture. Sample lines are flushed for a sufficient period of time prior to sample extraction in order to remove sediment deposits and air and gas pockets. Periodically, a series of samples is taken during the interval of discharge to determine whether any differences exist as a function of time and to assure that individual samples are indeed representative of the effluent mixture. Periods of collection are kept as short as practicable, and polyethylene collection bottles are used to preclude the loss of radioactive material by deposition on the walls of the sample container or volatilization.

Effluent ventilation ducts and stacks are sampled continuously in accordance with ANSI N13.1-1969 for radioactive gases, particulates, and iodines. The containment atmosphere is sampled continuously for radioactive gases, particulates, and iodines by the containment building atmosphere radiation monitor. The sample is drawn from a point between the containment normal air-conditioning unit suctions. A containment atmosphere gas sample is collected for analysis prior to the initiation of a containment purge batch release. This sample is analyzed for tritium and the principal gamma emitters in accordance with the Offsite Dose Calculational

Manual (ODCM). Containment purge batch release contribution to the plant release will be incorporated into the continuous sample collected at the plant vent release point. Particulate, iodine, and noble gas samples will be collected four times per month for all continuous effluent airborne radiation monitors and samplers. Where composite samples are used, they are collected in proportion to the volume of each batch of effluent releases or in proportion to the rate of flow of the effluent stream. Prior to analysis, the composite is thoroughly mixed so that it is in proportion to the rate of flow of the effluent stream. Prior to analysis, the composite is thoroughly mixed so that the sample is representative of the average effluent release.

11.5.2.2.2 Analytical Procedures

Samples of process and effluent gases and liquids are analyzed in the laboratory by the following techniques as appropriate:

- Gross beta counting
- Gross alpha counting
- Gamma spectrometry
- Liquid scintillation counting
- Radio-chemical separations

Instrumentation available for laboratory measurement of radioactivity is described in paragraph 12.5.2.2.

Gross alpha analysis of air particulate is performed by direct counting of the filters. This method is checked periodically by counting duplicate samples, sources, and samples of known activities.

Gamma spectrometry is used for isotopic analysis of gaseous and airborne particulate and iodine samples.

Gaseous tritium samples are collected by condensation and/or absorption. Liquid samples for tritium analysis are purified prior to analysis. Samples are counted on a liquid scintillation counter.

11.5.3 EFFLUENT MONITORING AND SAMPLING

11.5.3.1 Implementation of General Design Criterion 64

Refer to subsections 11.5.1 and 11.5.2 for a detailed description of the means which are provided for monitoring effluent discharge paths for radioactivity that may be released for normal operations, including operation occurrences and from postulated accidents.

11.5.4 PROCESS MONITORING AND SAMPLING

11.5.4.1 Implementation of General Design Criterion 60

Refer to subsections 11.5.1 and 11.5.2 for a detailed description of the means which are provided for automatic closure of isolation valves in gaseous effluent discharge paths.

11.5.4.2 Implementation of General Design Criterion 63

Refer to subsections 11.5.1 and 11.5.2 for a detailed description of the means which are provided for monitoring of radiation levels in radioactive waste process systems.

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APPENDIX 11A

RESPONSES TO NRC REQUESTS FOR INFORMATION

CONTENTS

APPENDIX 11A

<u>QUESTION 11A.1</u> (NRC Question 460.1) (1.8, 11.2, 11.3, and 11.4)

Provide a table under section 1.8 comparing the design features of the liquid, gaseous and solid radwaste systems with the positions of Regulatory Guide 1.143 (July 1978), "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants." For each item for which an exception is taken, the applicability of the proposed exception should be justified. If sufficient justification is provided in other sections for the individual items, cross-references to those sections will be adequate.

RESPONSE: PVNGS complies with the position of Regulatory Guide 1.143 including implementation of quality assurance requirements for the radwaste management systems. (Refer to sections 9.3, 11.2, 11.3, 11.4, and 17.2.)

<u>QUESTION 11A.2</u> (NRC Question 460.7)

Provide the data required for radioactive source term calculations for PWRs using the format given in Chapter 4 of NUREG-0017, April 1976, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors."

RESPONSE: The response is given in subsection 11.1.9.

<u>QUESTION 11A.3</u> (NRC Question 460.8) (9.3 and 11.2)

Section 9.3 of the FSAR states that the turbine building liquid wastes will be pumped to the evaporation pond if the effluent quality will meet the standards for pH, conductivity

and radioactivity. Explain how tests will be conducted for the radioactivity of these wastes, and also give information on the ultimate disposal of the wastes that get collected in the evaporation pond.

RESPONSE: The response is given in paragraph 9.3.3.2.1.3.1.

QUESTION 11A.4 (NRC Question 460.9)

Describe the provisions for preventing overflow and/or containing the tank contents in the event of failure of the reactor makeup water tank.

RESPONSE: The response is given in subsection 9.3.4.

QUESTION 11A.5 (NRC Question 460.10) (11.3)

Information on hydrogen and oxygen gas analyzers is inadequate. Since the system is not designed to withstand a hydrogen explosion, at least one gas analyzer should be provided, operating continuously between the compressor and the storage tanks, with automatic control functions to prevent the formation or buildup to explosive hydrogen-oxygen mixtures in the storage tanks. Annunciating alarms should be provided locally and in the control room (see the acceptance criteria of the Standard Review Plan, Section 11.3, Rev. 1, "Gaseous Waste Management Systems"). Also, provide information such as the number of sample points, sampling frequency at each point, alarm provisions and control features for the described sequential monitoring system.

RESPONSE: The response is given in amended paragraph 9.3.2.3 and subsection 11.3.1.

APPENDIX 11A

QUESTION 11A.6 (NRC Question 460.11) (11.3)

In Table 11.3-5, Krypton-89 estimated input concentration to the gaseous radwaste system from the reactor drain tank is shown as $4.5 \times 10^{+3}$ μCi/cm^3. This appears to be too high when compared to values contained in NUREG-0017, and should be confirmed or corrected.

RESPONSE: The response is given in amended table 11.3-5.

QUESTION 11A.7 (NRC Question 460.12) (11.3)

Describe the provisions included in the design of the gaseous waste treatment system to stop continuous leakage paths (see the requirement stated under Acceptance Criteria II.3 of SRP Section 11.3, Rev. 1).

RESPONSE: There are no continuous leakage paths in the gaseous waste treatment system as defined under Acceptance Criteria II.3 of SRP Section 11.3, Rev. 1.

QUESTION 11A.8 (NRC Question 460.13) (11.3)

Comparison with NUREG-0017 suggests that table 11.3-6 of the FSAR on annual releases of gaseous effluents contains some errors. For example, estimates of noble gas to be released from the containment building and Xe-133 to be released from the auxiliary/radwaste buildings are lower than would be expected. This table should be reevaluated and corrected if appropriate.

RESPONSE: The response is given in amended table 11.3-6.

APPENDIX 11A

<u>QUESTION 11A.9</u> (NRC Question 460.14) (11.3)

The system design provides for the return of the flashed steam from the blowdown flash tank to the secondary system via the No. 4 feedwater heaters (see paragraph 10.4.6.2.2 of the FSAR). Also, a charcoal/HEPA filtration system is provided for the main condenser air removal system exhausts (see table 11.3-7 of FSAR). Since these two augments have already been included in the system design, they should be excluded from the cost-benefit analysis (see Tables 5B-8 through 5B-11 of the Environmental Report) as per I.d of Appendix I to 10CFR Part 50.

RESPONSE: The response is provided in the revised Appendix 5B to the ER-OL and incorporated into Supplement 2 to the ER-OL.

<u>QUESTION 11A.10</u> (NRC Question 460.15) (11.4)

Clarify whether wastes collected in the evaporation pond will be an additional input to the solid radwaste system (SRS) input volumes. If so, provide estimates of the volumes and activities of these wastes.

RESPONSE: All potentially radioactive inputs to the evaporation pond will be tested for radioactivity prior to discharge into the evaporation ponds. Those wastes determined radioactive will be sent to the liquid radwaste system for processing. Therefore, waste collected in the evaporation pond will not be an additional input to the solid radwaste system.

APPENDIX 11A

QUESTION 11A.11 (NRC Question 460.16) (11.4)

Explain how the SRS output activities provided in table 11.4-6 for evaporator concentrates, spent resin beads, cartridge filters and disposable crud filters are related to their corresponding input activities provided in table 11.4-2.

RESPONSE:

The following assumptions were utilized in establishing SRS output activities in table 11.4-6:

1. Evaporator concentrates are solidified and stored in the high activity storage area for 1 month (i.e., 1-month decay) prior to shipment.

2. Spent resin beads are stored for 6 months prior to solidification. Solidified resin is stored in the high activity storage area for 1 month (i.e., 1-month decay) prior to shipment.

3. Cartridge filters are solidified and stored in the high activity storage area for 1 month (i.e., 1-month decay) prior to shipment.

4. Disposable crud filters are stored for one month (i.e., 1-month decay in the high activity storage area) prior to shipment.

QUESTION 11A.12 (NRC No. 460.18) (11.5)

We have reviewed your submittal dated April 6, 1981, relating to TMI Action Plans II.F.1, Attachments 1 and 2, and III.D.1.1 of NUREG-0737. We find your information scant and very inadequate. Please provide the information on these action items as required by NUREG-0737. For guidance, you may refer to

submittals on these action plans for other PWRs such as San Onofre, Units 2 and 3, and Summer Nuclear Station, which have been found acceptable by the staff.

RESPONSE: An expanded discussion of noble gas monitoring and effluent sampling per Attachments 1 and 2 to NUREG-0737, Item II.F.1, is provided in subsections 18.II.F.1.1 and 18.II.F.1.2.

Paragraph 12.1.3.6 also addresses leak reduction design measures per Item III.D.1.1 of NUREG-0737. Measurement and testing of covered systems will not take place until the startup of these systems. Accordingly, expansion of the LLIR for operational leak reduction testing cannot be provided until after startup.

APPENDIX 11B

DERIVATION OF

CORE RESIDENCE TIMES

CONTENTS

APPENDIX 11B

DERIVATION OF CORE RESIDENCE TIMES

The derivation of the core residence times for circulating crud as shown in Section 11.1.2.1 is as follows:

Circulating Crud:

The number of radioactive atoms (N_f) in the crud film on in-core surfaces at any time is:

$$\frac{dN_f}{dt} = \Sigma_i \varphi - \lambda_i N_f \qquad \text{B1}$$

Solving for N_f yields the following:

$$N_f = \frac{\Sigma_i \varphi}{\lambda_i}\left(1 - e^{-\lambda_i t_{res}}\right) \text{atoms/g} \qquad \text{B2}$$

Where:

	$\sum_i \varphi$	is the activation rate for each isotope, i (d/g-sec),
	λ_i	is the decay constant for each isotope ($secs^{-1}$), and
	t_{res}	is the desired core residence time (seconds).

The number of radioactive atoms (N_c) released to the reactor coolant at any time is:

$$\frac{DN_c}{dt} = N_f[ER]A_c - (\alpha + \beta + \lambda_i)N_c \text{atoms/sec}$$

Solving for N_c yields the following:

$$N_c = \frac{Nf[ER]AC}{(\alpha+\beta+\lambda_i)}\left(1 - e^{-(\alpha+\beta+\lambda_i)t}\right) \qquad \text{B3}$$

Where:

	ER	is the erosion rate (g/cm^2-sec),
	A_c	is the core surface area (cm^2),

α is the plateout rate (sec^{-1})

β is the purification cleanup rate (sec^{-1}), and

λ_i is the decay constant (sec^{-1})

Total amount of crud (M_C) released to the reactor coolant any time is:

$$\frac{dM_c}{dt} = [ER]A_T - (\alpha + \beta)M_c \qquad B4$$

Where M_C includes both radioactive and nonradioactive material.

Solving for M_C yields:

$$M_c = \frac{[ER]A_T}{(\alpha+\beta)}\left(1 - e^{-(\alpha+\beta)t}\right)\text{grams} \qquad B5$$

Where: ER is the erosion rate (g/cm^2-sec),

A_T is the total system area (cm^2),

α is the plateout rate (sec^{-1}), and

β is the purification cleanup rate (sec^{-1}).

The activity (A_i) of the crud released to the reactor coolant is:

$$A_i = \frac{\lambda_i N_c}{M_c}, \text{ dps per gram of crud in reactor coolant} \qquad B6$$

Substituting the values of N_C and M_C into the above expression and assuming λ_i is small when compared to α and β, the activity of the crud is as follows:

$$A_i = \Sigma_i \varphi\left(1 - e^{-\lambda_i t_{res}}\right)\frac{A_c}{A_t}(0.06) \text{ dpm/mg - crud} \qquad B7$$

Where 0.06 is a constant changing dps/g-crud to dpm/mg-crud.

This activity (A_i) is also assumed to be the activity of the crud which plates out on out-of-core surfaces.

Solving equation (B7) for t_{res} yields equation (1) in UFSAR Section 11.1.2.

Deposited Crud

The activity (A_j) of the deposited crud is:

$$A_j = \lambda_i N_f = \Sigma_i \varphi \left(1 - e^{-\lambda_i t_{res}}\right) 0.06 \qquad \text{B8}$$

Solving equation (B8) for t_{res} yields equation (2) in UFSAR Section 11.1.2.

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CHAPTER 12

RADIATION PROTECTION

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12. RADIATION PROTECTION

12.0 ORGANIZATION AND METHODOLOGY

This chapter describes the radiation protection measures considered during the design and construction of the Palo Verde Station as well as the operating policies used to ensure that internal and external radiation exposures to station personnel, contractors, and the general population due to station conditions, including anticipated operational occurrences, will not only be within applicable limits, but will be as low as is reasonably achievable (ALARA).

12.0.1 CHAPTER 12 INFORMATION

The information contained in this chapter can be characterized into two types, 1) the information that describes how the shielding installed at Palo Verde was designed and determined adequate, and 2) the organization and responsibilities, equipment and facilities, and procedures for maintaining the radiation exposures identified above within current limits and ALARA. The difference between this information is the information described in item 1 is considered original licensing information and is treated as historical, whereas the information in item 2 is expected to reflect the current implementation of the health physics program. Historical information is not expected to be actively maintained as the plant design changes and has been identified as “Original Licensing” or "Historical Information."

12.0.2 RADIATION PROTECTION MEASURES

Radiation protection measures include: separation of radioactive components into separately shielded cubicles; use of shielding designed to adequately attenuate radiation emanating from pipes and equipment which are sources of significant ionizing radiation; use of remotely operated valves or hand-wheel extensions; ventilation of areas by systems designed to minimize inhalation and submersion doses; installation of permanent radiation monitoring systems; control of access to the site and to restricted areas; training of personnel in radiation protection; and development and implementation of administration policies and procedures to maintain exposures ALARA.

12.1 ENSURING THAT OCCUPATIONAL RADIATION EXPOSURES ARE ALARA

12.1.1 POLICY CONSIDERATIONS

It is the policy of the management of Arizona Public Service Company (APS), operating agent for PVNGS, to keep occupational radiation exposure to personnel ALARA. Administrative programs and procedures, in conjunction with facility design, ensure that the occupational radiation exposures to personnel will be kept ALARA.

12.1.1.1 Original Design and Construction Policies

The ALARA philosophy was applied during the initial design of the plant and implemented via internal design reviews and documentation. These reviews were conducted and documented

consistent with the recommendations of Regulatory Guide 8.8. A description of these reviews and their scope is provided in appendix 12B. In addition, the design was reviewed for ALARA considerations by the APS Senior Health Physicist, a certified health physicist.

The plant design was reviewed, updated, and modified as necessary during the design and construction phases. Engineers reviewed the plant design and integrated the layout, shielding, ventilation, and monitoring designs with traffic control, security, access control, maintenance, inservice inspection, and radiation protection aspects to ensure that the overall design produced a plant which will achieve exposures that are ALARA.

Piping containing radioactive fluids was routed as part of the engineering design effort. This ensured that lines expected to contain significant radiation sources were adequately shielded and properly routed to minimize exposure to personnel.

Onsite inspections were also conducted, as necessary during construction, to ensure that the shielding and piping layout meets established criteria. During construction, visual inspections were made to ensure that there were no major defects in the shield walls as they were placed. During initial power operations, radiation surveys were conducted to ensure that the shielding meets design requirements during normal operation and maintenance of the plant.

12.1.1.2 Operation Policies

The Nuclear Administrative and Technical Manual is one of the major means of promulgating the operational ALARA policy. This policy is demonstrated in the radiation protection program, the training program, and station procedures.

Section 12.5 of this chapter describes the Radiation Protection Program and also provides an overview of the organizational structure and responsibilities.

The responsibilities and qualifications of the personnel who fill supervisory positions are discussed in subsections 13.1.2 and 13.1.3.

It is the responsibility of both the director, nuclear training, and the radiation protection manager to implement radiation protection training for company employees and contractors commensurate with the requirements of 10CFR19 and Regulatory Guide 8.8. The radiation protection manager, verifies that personnel follow the radiation protection procedures designed to ensure that exposures are maintained ALARA. To ensure compliance with this policy, the radiation protection manager is charged with the responsibility to promptly advise higher management of practices which exceed their authority to correct. In addition, periodic reviews of the ALARA program (annually at a minimum), including review of radiation exposure records and operating procedures are conducted.

Personnel requiring access to the restricted area and/or radiological controlled areas will receive training as

necessary to permit access to these areas. These personnel will be tested to evaluate each worker's knowledge, competency, and understanding relative to the training provided.

Prior to the initial startup of the first unit, station procedures to be used for work involving significant personnel radiation exposure were reviewed to verify that the procedures adhere to the ALARA philosophy. Revisions to station procedures involving significant personnel radiation exposure will continue to receive an ALARA review. System or station modifications affecting personnel radiation exposure will also be reviewed to see that the ALARA concept is applied.

The radiation protection manager will periodically survey station operations to identify situations in which exposures can be reduced.

12.1.2 ORIGINAL DESIGN CONSIDERATIONS

This section discusses the methods and features by which the policy considerations of subsection 12.1.1 are applied to the original plant design. Provisions and designs for maintaining personnel exposures ALARA are presented in detail in subsections 12.3.1, 12.3.2, and 12.5.3.

12.1.2.1 General Design Considerations for Shielding and ALARA Exposures

General design considerations, shielding, and methods employed to maintain in-plant radiation exposures ALARA consistent with the recommendations of NRC Regulatory Guide 8.8, Section C.1, have two objectives:

A. Minimizing the necessity for and amount of personnel time spent in radiation areas.

B. Minimizing radiation levels in routinely occupied plant areas in the vicinity of plant equipment expected to require personnel attention.

Plant operating personnel are protected as necessary by shielding wherever a potential radiation hazard may exist. The shielding performs the following additional functions:

A. Assists in maintaining radiation exposure to plant control room personnel within the limits of 10CFR50, Appendix A, Criterion 19, in the unlikely event of an accident.

B. Protects certain components from excessive activation or excessive radiation exposure.

C. Facilitates access for maintenance of components.

In order to maintain exposure ALARA, a design radiation zone classification system was developed and used during the design process. Plant areas were classified in accordance with table 12.1-1.

12.1.2.1.1 Neutrons

Neutron shielding design considerations were as follows:

A. Shielding was designed to ensure the area does not become a scattering source, producing excessive doses in other regions.

B. Shielding was designed to ensure that neutron activation does not result in doses exceeding the permitted shutdown dose rates in the region.

C. Neutron radiation damage limits of equipment were not exceeded unless provisions are made for periodic replacement.

Table 12.1-1

RADIATION ZONE CLASSIFICATION

Zone Designation	Dose Rate (mrem/h)
1	Less than 0.5
2	0.5 to 2.5
3	2.5 to 15
4	15 to 100
5	Over 100

12.1.2.1.2 Gamma Radiation

Gamma radiation shielding design considerations were as follows:

A. Shielding was designed to reduce gamma dose rates throughout the plant to levels consistent with expected occupancy during normal operation as specified by the design radiation zones.

B. As a minimum, shielding was designed to reduce gamma dose rates from sources external to a radioactive compartment to levels comparable to dose rates resulting from equipment within that compartment. This design ensured that in a compartment undergoing maintenance, the radiation levels due to operating equipment in adjacent compartments would be the lesser of the zone 3 limit (15 mrem/hr) or the operational dose rate of the equipment under repair.

C. Shielding was provided to attenuate radiation from sources external to equipment compartments so that expected maintenance could be performed without exceeding exposure limits.

D. Shielding was designed to reduce gamma radiation after reactor shutdown to levels which allow access for required maintenance operations.

E. Gamma radiation damage limits for the equipment are not exceeded unless provisions were made for periodic replacement.

12.1.2.2 Facility Layout General Design Considerations for ALARA

In order to implement an ALARA program, the following design guidelines were considered to the extent practical during plant design.

A. Facility General Design Considerations

1. The layout for personnel access, routing of piping and location of components was in a manner to minimize personnel radiation exposure during both operation and maintenance. Access control and traffic patterns were evaluated to assure that radiation exposures were maintained ALARA. In the interest of maintaining doses ALARA, access to a given design radiation zone generally did not require passing through a higher design radiation zone.

2. Radioactive components of the same system were grouped together as practical to minimize radioactive piping runs. Ion exchangers and spent resin collection system components were located as close to the radwaste solidification area as practical. Radioactive wastes were assumed to be stored in shielded enclosures separated from normally accessible areas.

3. Due to the desirability of low background radiation levels, the counting room was located away from highly radioactive components.

4. Due to frequent access requirements, control panels, readout devices, and transmitters, where possible, were located in low radiation zones (design radiation zone 2 or less) in order to minimize operator exposures.

5. In order to reduce radiation exposures due to sampling operations, sample stations were isolated insofar as practical from other radioactive equipment, and exposed sample piping is minimized. Primary and secondary system samples taken within the containment except for safety injection tanks were piped to the plant laboratory to minimize the need to access the containment.

B. Shielding Design Guidelines

1. Significantly radioactive components such as tanks, filters, ion exchangers, pumps, and heat exchangers were located in shielded compartments.

2. In those process systems whose components contain major sources of radiation, valves and instrumentation were separated by shielding from the components.

3. Although use of permanent shielding is preferred, portable or temporary shielding and convenient means for handling it was provided where shielding was required but fixed shielding was impractical. Access and the capability of the structure to

support such portable or temporary shielding was been evaluated during design review.

4. Access to shielded compartments is generally by means of shielded labyrinth arrangements such that direct exposure to radioactive equipment from normal access areas was eliminated. For highly radioactive passive components such as tanks, ion exchangers, and filters, completely enclosed compartments were provided with access via a shielded hatch, or labyrinth entry way with a locked gate.

5. Where space limitations preclude the use of ordinary concrete for shielding, lead, iron, or high density concrete was used instead.

6. Use of removable concrete shielding blocks for frequent personnel access or equipment removal was been avoided by design when practical.

7. Redundant radioactive components were located in separate shielded compartments, where practical, to allow for maintenance on one while the other remained in service. If radioactive components were located in the same compartments, space was provided for installation of temporary shielding during maintenance.

8. As a general rule, radioactive equipment was separated by shielding from nonradioactive equipment to facilitate maintenance on the latter.

9. When corrugated steel decking was used as forming for concrete floor slabs, the minimum thickness of the resulting slab satisfies the specified shielding requirement.

10. Voids such as those created by embedded HVAC ducts or piping were avoided where practicable in shield walls. Unavoidable large voids in shield walls or slabs were evaluated to determine their effect upon shielding requirements.

11. Shielding requirements for periodic operations such as filter handling were determined on the basis of ALARA considerations including level of radioactivity and frequency and duration of exposure.

C. Guidelines for the Control of Radioactive Contamination

1. Large tanks containing radioactive fluids were enclosed in watertight compartments or were surrounded by curbs. Threshold berms were provided for other radioactive equipment compartments to control the spread of contaminated leakage.

2. Sloped floors and floor drains were provided for radioactive equipment compartments including valve galleries and pipe chases. Radioactive drains were designed to minimize "backgassing."

3. Radioactive equipment drains were piped directly to one of the drainage systems instead of allowing contaminated fluid to flow across the floor to the floor drain. The use of temporary flexible tubing to direct fluids to local floor drains or to portable containers during venting and draining operations may be acceptable when the frequency of operation and volume of fluid involved do not make the use of direct connections to a collection system cost effective.

4. Suitable coatings were applied to floors and walls susceptible to radioactive contamination in order to facilitate decontamination operations.

D. Valve Gallery Design Guidelines and Considerations

Valve galleries were provided for valves serving equipment containing or processing highly radioactive material. Valve galleries provide shielding from the process equipment to personnel operating or servicing valves as follows:

1. The amount of exposed piping in the valve gallery is minimized.

2. When possible, a shielded pipe chase is provided adjacent to the valve gallery for the purpose of routing radioactive piping. Such pipe chases are located below valve galleries, if practical, in order to minimize crud deposition in valves.

3. If the radiation level within a valve gallery is high, valve stem extensions through the valve gallery wall to an adjacent corridor are supplied for frequently operated valves so that they may be operated from a design radiation zone 2 area.

4. Sufficient space is provided in valve galleries to facilitate maintenance on valves.

E. Radioactive Piping Design Guidelines

1. Radioactive piping was not field-routed.

2. Piping was routed so that it does not exceed applicable design radiation zone level.

3. Radioactive piping routed through design radiation zone 1 or zone 2 areas are enclosed in a shielded pipe chase, if required.

4. Radioactive piping was routed through the highest design radiation zones practical.

5. Potentially radioactive piping was routed behind components or structures which provide shielding to areas where maintenance is likely to be performed.

6. Radioactive pipes were routed close to floors, ceilings, and walls where practical, but were kept away from doors and entrances outside containment.

7. When practical, radioactive piping was separated from nonradioactive piping.

8. If practical, valves or instrumentation was not located within radioactive pipe chases.

9. Piping layout provides sufficient space for installing and maintaining special equipment or tools as required.

10. Piping insulation was designed for quick removal in any radiation area where routine maintenance and/or inservice inspection was anticipated.

11. Care was taken in routing radioactive piping to minimize background radiation interference with area radiation monitoring sensors.

F. Inservice Inspection Guidelines

Provisions were made for inservice inspections to minimize potential personnel exposures. By design, high radiation zones permit prompt ingress and egress and have adequate space to accommodate the work force, special tools, laydown space, removal of internals, temporary shielding, and auxiliary ventilation systems as may be required during inservice inspection.

G. Crud Trap Design Guidelines

1. The length of pipe runs was minimized for radioactive piping when possible.

2. Low points and dead legs in radioactive piping were minimized.

3. Placement of valves at piping low points was minimized.

4. Valves have flow characteristics that result in a smooth flow path through the valve to minimize the velocity change and resulting potential for crud trapping.

5. Internal surfaces of liquid flow paths are smooth and as free as practical from abrupt discontinuities in cross-sections.

6. Lines were sized to achieve turbulent flow where practical (Re >10,000).

7. Thermal expansion loops were raised instead of depressed, if possible.

8. Flow paths avoid abrupt changes in direction. Bends of several pipe diameters or long radius elbows were utilized wherever practical.

9. Butt welds, where practical, were used on radioactive process piping whose nominal pipe diameter is greater than 2 inches. Backing rings were not used.

10. The use of screwed fittings in radioactive piping systems was avoided, where practical. If such fittings were required, a seal weld was applied.

11. Flanged joints or suitable rapid disconnect fittings were used in cases where maintenance requirements clearly indicate that such

construction was preferable (e.g., for pump maintenance).

12. The origin of branch process lines having little or no flow during normal operation were taken off above the horizontal midplane of the main process pipe, where practical.

13. Strainers were located in process streams immediately downstream of ion exchangers to minimize the introduction of resin fines into process systems and to mitigate the consequences of a resin retention screen break.

In addition, the following special considerations were given to piping which processes spent resins:

14. Ball, plug, or diaphragm valves were used, depending upon the function, in spent resin lines. Strainer, check, and Y-valves were not utilized in piping systems which process spent resins.

15. Orifices were not utilized in spent resin piping systems.

16. Butt welds were employed where practical for spent resin piping regardless of size. Large radius elbows, or large diameter bends, were used where practical in routing all such piping.

17. Ninety-degree tees were not used in spent resin piping systems except to introduce clean services such as air, nitrogen, or water into such lines.

Dead legs were avoided and any necessary flushing connections were taken off above the horizontal centerplane of the resin piping.

18. Spent resin lines were sized to achieve turbulent flow to minimize resin deposits and subsequent buildup.

19. Provisions were made for the ion exchangers as well as the resin lines to be pressurized with air, nitrogen, or water to clear plugged lines. The water or nitrogen is introduced at a tee downstream of each valve, and the leg of the tee is above the resin line to avoid clogging of the clean service inlet line.

H. Component Isolation, Draining, and Flushing Considerations

1. Serviceable radioactive components can be isolated and drained.

2. Major components of radwaste systems have redundant drainage capability so that the failure of a single drain will not prevent cleaning or purging of such a system.

3. High-point vent and low-point drain connections were provided where practical in piping systems which process highly radioactive fluids. These connections were placed to facilitate flushing of the associated process equipment.

4. Vent and drain connections were equipped with suitable fittings so that flushing and/or drain system piping can be temporarily connected.

5. Isolation valves for vent and drain connections were located as close to the process piping as practical.

I. Penetration Design Considerations

1. Penetrations through the primary shield were designed to minimize neutron streaming and the resultant activation of the steam generators and reactor coolant pumps and piping.

2. When possible, radioactive and nonradioactive piping were separated within the penetration area, with provisions for the utilization of temporary shielding for maintenance purposes.

3. In general, piping, electrical, and HVAC penetrations through radiation shields were designed to minimize radiation streaming into accessible areas. The following considerations apply:

   a. Cross-sectional areas of penetrations were minimized.

   b. Where practical, penetrations were oriented so there is an offset between the radiation source and accessible areas.

   c. If such an offset orientation was impractical, the penetration was located as far above the

floor elevation as possible to minimize direct exposure of personnel.

d. If the above methods were not utilized, alternative means are employed. For piping penetrations, the alternatives include grouting the annular space of the penetration or utilizing shield collars around the piping at the openings of the penetration to reduce radiation streaming.

For ventilation and electrical penetrations, use of baffle shields to eliminate streaming into accessible areas is acceptable.

12.1.2.3 ALARA General Equipment Design Considerations

In order to maintain exposures ALARA, the following design guidelines were considered to the extent practical in plant design.

12.1.2.3.1 Radioactive Equipment Design Considerations

Radioactive equipment design considerations relative to equipment contamination and service time include:

A. Reliability, durability, construction, and design features of equipment, components, and materials to reduce or eliminate the need for repair or preventive maintenance.

B. Servicing convenience of anticipated maintenance or potential repair, including ease of disassembly and

modularization of components for replacement or removal to a lower radiation area for repair.

C. Provisions, where practical, to remotely or mechanically operate, repair, service, monitor, or inspect equipment (including inservice inspection in accordance with American Society of Mechanical Engineers (ASME) Section XI).

D. Redundancy of equipment or components to reduce the need for immediate repair when radiation levels may be high.

12.1.2.3.2 Equipment General Design Considerations

Equipment general design considerations directed toward minimizing radiation levels in proximity to equipment or components requiring personnel attention included:

A. Provision for draining, flushing, or, if necessary, remotely cleaning equipment and piping containing radioactive material.

B. Design of equipment, piping, and valves to minimize the buildup of radioactive material and to facilitate flushing of crud traps. The use of cobalt containing alloys in systems exposed to primary coolant has been minimized except where very hard erosion resistant surfaces are necessary (e.g., stellite seat materials on valves). C-E-supplied components which will be exposed to primary coolant have less than 0.2% cobalt, nominally. Refer also to Table 5.2-5 through 5.2-31B.

C. Provisions for minimizing the spread of contamination into equipment service areas, including direct drain connections.

D. Provisions for isolating equipment from radioactive process fluids.

E. Provision for a spent fuel pool cleanup system to maintain the radiation level of the fuel pool area within the design radiation zone 2 limit. See table 12.1-1 for the description of design radiation zones.

F. Heat exchangers have been provided with corrosion-resistant tubes with tube-to-tube sheet joints fabricated to minimize leakage.

   Impact baffles are provided and process fluid velocities are limited as necessary to minimize erosive effects. Provisions are made for removal of the tubes for maintenance.

G. Pumps in radioactive systems have been purchased with mechanical seals to reduce seal servicing time. Additionally, smaller pumps are provided with flanged connections for ease in removal. Pump casings were provided with drain connections for draining the pump for maintenance.

H. Water was used as the fluidizing medium in tanks from which resin is transported. Resin tanks incorporate integral self-cleaning screens in overflow connections

to retain resins within the tank. Overflow connections for radioactive tanks have been piped to the liquid radwaste system (LRS).

I. Filters were supplied with the means to either remotely backflush the filter or to perform cartridge replacement with remote tools.

J. Demineralizers were designed to remotely remove spent resins hydraulically and replace new resins from a remote location. Resin strainers were designed for full system pressure drop.

K. Evaporators were provided with chemical addition connections to allow the use of chemicals for descaling operations.

L. The reactor head laydown area was designed to substantially reduce both the dose to those changing O-ring seals and personnel working in adjacent areas.

An interior shield wall separates the O-ring changeout from the radiation field under the hemispherical head. An exterior shield wall isolates the activated flange and external surfaces from adjacent work activities.

M. Frequently operated valves of highly radioactive systems were designed for remote operation. Motor operators, air operators, and reach rods have been provided where necessary. The criteria for selecting valve operators were as follows:

1. Valves located in design radiation zones 3, 4, and 5 which are operated frequently (for example, on a weekly basis or more often) are equipped with a remote actuator such as a reach rod, an electric motor actuator, or a pneumatic actuator and position indicator. These valves are controlled from the applicable control station or operating aisle.

2. Valves which are operated occasionally (for example, one to twelve times a year) were classified as follows:

   a. Valves which are located in design radiation zone 4 or less may be manually operated directly.

   b. Valves which are located in design radiation zone 5 have been equipped with a reach rod, or if a reach rod cannot be installed, an electric motor actuator or pneumatic actuator and a position indicator.

3. Valves which are operated infrequently during normal plant operations (for example, less than once a year) are manually operated directly unless their operation results in excessive personnel exposure. In cases where the operation of such a valve may lead to exposures in excess of 0.1 man-rem per year, consideration was given to fitting the valve either with a simple reach

rod if feasible, or a remote actuator and position indicator if necessary. The 0.1 manrem per year was derived from a judgmental evaluation of the potential exposure savings versus the cost to provide and maintain a remote operator throughout plant life.

4. A mechanical reach rod assembly is used where an electric motor or pneumatic actuator is not necessary. Directional changes and rod lengths are kept to a minimum. This allows easier maintenance if needed, and minimizes radiation exposure.

5. Valves which are operated after an accident are provided with a means of remote operation in cases where the operation of such a valve may lead to exposures in excess of 1.25 rem.

N. Leakage of radioactive material is minimized by use of appropriate valve gaskets and valve packing. For example, one of the following is provided for radioactive valves 2-1/2 inches and larger:

1. Packing contains grafoil or graphite yarn

2. Diaphragm or bellows seal valves are used where minimal leakage is required.

Radiation tolerant materials are used in valves in accordance with their radioactive service. Chemical seals are provided on instrument sensing lines for

process piping which may contain highly radioactive solids to reduce the servicing time required to keep the lines free from solids.

O. Primary instrument devices, which for functional reasons are located in high radiation areas, have been designed for uncomplicated removal for calibration or servicing. Some instruments, such as thermocouples are provided in duplicate in highly radioactive areas to reduce access and service time.

P. The sample laboratory is equipped with adequate shielding and a fume hood. The sample laboratory and sample stations are equipped with a sink or funnel arrangement so that sample lines may be purged to the LRS or chemical and volume control system prior to sampling. Also, sample lines incorporate the capability of being flushed.

Q. A remotely operated resin dewatering system is employed to minimize exposure during radwaste processing. Remotely operated equipment is provided where practical to minimize operator radiation exposure.

12.1.2.4 General Design Considerations to Keep Post-Accident Exposures ALARA

The facility layout was designed to assist in keeping occupational exposures ALARA even after a design basis accident. While exposures will be significantly higher than

during normal operation, required access is provided to vital areas and systems without exceeding 5 rem/hr. Zone maps showing dose rates in the event of a LOCA with sump recirculation are provided in drawing 13-N-RAR-018 through -028. Zone maps for the hypothetical condition of a LOCA with an intact primary but with a degraded core are provided in drawings 13-N-RAR-029 through -038. A discussion of the source terms for these events is provided in subsection 12.2.3. The dose rates projected for these two sets of drawings do not assume decay beyond that corresponding to the onset of recirculation. Even so, virtually unrestricted access will be permitted within the control and diesel generator buildings, as well as portions of the upper floor of the auxiliary building (such as the Auxiliary Building area of the operations support center).

The only other area where post-accident access will be required is to the hydrogen monitors/recombiners. Projected dose rates without the recombiners in operation, but at the onset of recirculation, are expected to be approximately 10 to 30 rem/hr (sump recirculation).

As the recombiners have to be installed within 72 hours after the DBA, the area will not be accessed until dose rates have dropped due to decay to about 1/10 the doses noted above. Thus, the installation dose rate (assuming sump recirculation) will be less than 5 rem/hr. While the dose rate would be greater than 5 rem/hr for an intact primary-degraded core event, the recombiners would not need to be installed since an

intact primary would not be consistent with hydrogen generation inside the containment. If hydrogen generation were postulated, this would necessitate a break or opening in the primary. Consequently, sump recirculation would be available with the concomitant release of noble gases and dilution by the refueling water tank. These consequences would lead to the doses noted above for the sump recirculation mode of cooling (i.e., dose rates less than 5 rem/hr).

ESF grade filtered ventilation is provided for auxiliary building rooms below elevation 100 feet (refer to section 9.4). This will reduce airborne sources due to recirculation and/or containment leakage. Non-ESF grade filtered ventilation is available for use to reduce airborne sources above elevation 100 feet in the auxiliary building (refer to section 9.4). The use of non-ESF filtration is acceptable since there are no recirculation components above elevation 100 feet. Thus, the only significant source of airborne activity is containment leakage. This leakage has already been accounted for in off-site dose analyses which assumed direct containment leakage to the atmosphere. Secondly, this filter discharges via the plant vent. The plant vent will be monitored in accordance with NUREG-0737 and Regulatory Guide 1.97, Revision 2, to provide notification of decreased filter efficiency.

Therefore, considering direct and airborne sources, access can be provided to those vital areas necessary for control of the plant and personnel exposures will meet GDC 19 and NUREG-0737 limits.

12.1.3 OPERATIONAL CONSIDERATIONS

In accordance with APS policy and consistent with the recommendations of Regulatory Guides 8.8 and 8.10, the radiation exposure of plant personnel will be kept ALARA by means of the radiation protection program discussed in section 12.5. The radiation protection policies and practices contained therein are promulgated through the training program discussed in section 13.2, through the Radiation Protection Division of the Nuclear Administrative and Technical Manual discussed in subsection 12.1.1 and section 12.5.

Based upon the experience of other utilities, the design of PVNGS was reviewed so that this information could be incorporated into the design as previously discussed in subsection 12.1.1.

The criteria and/or conditions under which various operating, maintenance, and inspection procedures are implemented and some of the techniques that are used to ensure that occupational radiation exposures are ALARA are discussed below.

From the Atomic Industrial Forum (AIF) National Environmental Studies Project report,[(1)] it has been determined that the majority of exposure at operating PWRs is received during plant outages from maintenance and inspection activities and not from normal operating activities. This is logical since operators can normally stay outside shield walls to read instruments or operate valves and have to enter cubicles containing radioactive equipment for short periods of time only to check equipment, whereas maintenance and inspection personnel usually

must go inside cubicles or behind shield walls and must be in close proximity to the lines, valves, instruments, or other pieces of equipment which are radiation sources in order to perform their job. The major sources of exposure, as defined in the AIF report, are steam generator repairs (88% of exposure at one plant, 27% at the average plant), reactor vessel head removal (6%), and inservice inspection (6%) accounting for a total of 40% of the annual exposure at the average PWR.

Since the above sources cause the major exposures, some of the ALARA techniques that may be used to reduce these exposures are discussed in sections 12.1.3.1 through 12.1.3.5.

12.1.3.1 General ALARA Techniques

A. Use permanent shielding, where practical, by having workers stay behind walls or in areas of lower radiation level when not actively involved in work. As practical, use temporary shielding if the total exposure, which includes the exposure received during installation and removal of shielding, is reduced.

B. Systems and major pieces of equipment which are subject to crud buildup have been equipped with connections which can be used for flushing. Prior to performing maintenance work, consider the practicality and effectiveness of flushing and/or chemically decontaminating the system or piece of equipment in order to reduce the crud levels and personnel exposure.

C. Work conducted in radiological controlled areas will require a radiation exposure permit (REP). Refer to section 12.5. The purpose of the REP is to carefully prepare for the job so that it can be performed in a proper and safe manner with minimum personnel radiation exposure.

D. On complex jobs involving exceptionally high radiation levels, "dry runs" may be made, and in some cases mockups may be used to familiarize the workers with the exact operations they must perform at the jobsite. At the completion of the job, a debriefing session may be held to determine if the work could have been completed more efficiently. This information should be recorded. In addition, if any personnel contaminations or internal contamination was encountered during the job it should be recorded. This information will provide guidance at the preplanning stage of future similar operations. These techniques will assist in improving worker efficiency and thus will minimize the amount of time spent in the radiation field.

E. As much work as practical should be performed outside radiation areas. This includes items such as reading instruction manuals or maintenance procedures, adjusting tools or jigs, repairing valve internals, and prefabricating components.

F. For long-term jobs, consideration should be given to setting up remote monitoring systems so that work can be monitored from a lower radiation area.

G. On some jobs, special tools or jigs may be used when their use would permit the job to be performed more efficiently or would prevent errors, thus reducing the time in the radiation field. Special tools may also be used if their use would increase the distance from the source to the worker, thus reducing the exposure rate. Unless special tools or jigs are necessary to accomplish the job, special tools or jigs should be used only if the total exposure, which includes that received during installation and removal, is reduced.

H. Entry and exit points should be set up in areas so that personnel are exposed to as low a level of radiation as practical. This will be done because personnel may spend a significant amount of time changing protective clothing and respiratory equipment in these entry-exit areas. These entry and exit points are set up to limit the spread of contamination from the work area.

I. Protective clothing and respiratory equipment should be selected on the basis of worker protection and habitability.

J. Plastic glove boxes, which can be taped around valves or other fixed components, and plastic bags should be used where practical so that personnel can work on equipment without being exposed to the contamination

produced during the work, and to limit the spread of contamination.

K. Individuals should be instructed to stay in the lowest radiation area consistent with performing their assigned jobs.

L. Personnel will wear electronic dosimeters for work in high radiation areas so that they can determine their accumulated exposure at any time during the job. This is in addition to their TLD.

M. On jobs with exceptionally high radiation levels, worker exposures should be monitored using a remote monitoring or timing device to ensure that personnel do not receive more exposure than intended. The individual monitoring the workers exposure should be in a low dose rate area.

12.1.3.2 Specific ALARA Considerations for Steam Generator Repair

The techniques in paragraph 12.1.3.1, except for listing J, are normally used when inspecting and plugging steam generator tubes.

After access to the steam generator primary heads is obtained, covers are installed, if practical, over the hot and cold leg nozzle openings with a layer of material to prevent tools and debris from entering the pipes. If personnel are required to work inside the primary head for a significant amount of time, consideration is given to adding temporary shielding.

Normally, however, this is not worthwhile since at least half the exposure is due to shine from crud inside the steam generator tubes which cannot be easily shielded because the tube sheet area must normally be kept clear for inspection or tube plugging.

12.1.3.3 Specific ALARA Considerations for Reactor Head Removal and Installation

Techniques described in paragraph 12.1.3.1, except for listings B, J, and M, are normally used when removing and installing the reactor head. Quick disconnect electrical cables and reactor head ventilation ducts which can be quickly removed are used to reduce time spent in radiation areas. Temporary shielding can be installed around the outer control rod drive mechanisms to reduce exposure if crud collects in the control rod drive housing. A multiple stud tensioner is normally used to reduce radiation exposures by expediting removal and installation of the reactor head.

12.1.3.4 Specific ALARA Considerations for Inservice Inspections (ISI)

Techniques in paragraph 12.1.3.1 are normally used when performing ISI. Remote testing devices will be used in the conduct of the examinations, where practical. Written and possibly photographic or videotape records will be made of preservice inspection operations that have potential for future significant radiation exposure to personnel. By training the examiners and alerting them to the specific problems that they

can expect to encounter, less time will be spent in radiation areas.

12.1.3.5 Specific ALARA Considerations for Other Operations Involving Radiation Exposure

Other operations such as refueling, radwaste handling, spent fuel handling, loading and shipping, routine maintenance, sampling, and calibration are discussed in subsection 12.5.3.

12.1.4 REFERENCES

1. National Environmental Studies Project, Compilation and Analysis of Data on Occupational Radiation Exposure Experienced at Operating Nuclear Power Plants, SAI Services, September 1974.

12.2 RADIATION SOURCES

This section discusses and identifies the sources of radiation that form the basis for shield design calculations and the sources of airborne radioactivity used for the design of personnel protective measures and for dose assessment.

12.2.1 CONTAINED SOURCES

The shielding design source terms are based on full-power operation with 1% fuel cladding defects. Sources in the primary coolant include fission products released from fuel clad defects, and activation and corrosion products. The sources in the reactor coolant corresponding to 1% defects are discussed in Section 11.12. Throughout most of the reactor coolant system, activation products, principally nitrogen-16 (N-16), are the primary radiation sources for shielding-design. For all systems transporting radioactive materials, conservative allowance is made for transit decay, while at the same time providing for daughter product formation.

The design sources are presented in this section by building location and system and were used to develop the final shield design. The information contained in Section 12.2.1 is considered original licensing information and is treated as historical[1]. The plant shielding design is such that the personnel doses should be below the limits established by

[1]Plant shielding source terms for the current plant configuration with power uprate and Replacement Steam Generators have been evaluated. These impacts are minor and do not appreciably alter the plant shielding design. Plant Radiation Zone Maps as described in UFSAR Section 12.3.1.2 remain unchanged.

10CFR Part 20.1 - 20.601 and the design features are consistent with the guidelines of Regulatory Guide 8.8 Revision 3.

Location of the equipment discussed in this section is shown in the general arrangement drawings of section 1.2.

12.2.1.1 Containment

12.2.1.1.1 Reactor Core

The primary radiations emanating from the reactor core during normal operation are neutrons and gamma rays. A conservative assumption of 105% of normal operating power of 3800 MWt was originally used to calculate total dose rate outside the primary and secondary shields. These calculations therefore remain valid for the power uprate to 103% of the original power rating of 3800 MWt. CESSAR Section 12.2.1.1.1 contains historical neutron and gamma spectras.

12.2.1.1.2 Reactor Coolant System

Sources of radiation in the reactor coolant system are fission products released from fuel and activated corrosion products that are circulated in the reactor coolant. These sources and their bases are listed in Section 11.1.

The activation product nitrogen-16 is the predominant activity in the reactor coolant pumps, steam generators, and reactor coolant piping. The N-16 activity in each of the components depends on the total transit time to the component. The derivation of N-16 activity is shown in Section 11.1.4.

See Section 11.1 for activity and crud thickness values.

12.2.1.1.3 Main Steam Supply System

Radioactivity in the main steam supply system is based on a steam generator tube leakage rate of 1 gallons per minute concurrent with 1% failed fuel. These sources are listed in table 12.2-1. These sources were developed assuming that the condensate polishing demineralizers are not in use. It is assumed that the blowdown rate to the blowdown demineralizers is 1% of the main steam rate.

12.2.1.1.4 Spent Fuel Handling and Transfer

The spent fuel assemblies are the predominant long term source of radiation in the containment after plant shutdown for refueling. A reactor operating time necessary to establish near-equilibrium fission product buildup for the reactor at rated power is used in determining the source strength. As a result of new core design, dose analysis were performed to assess the maximum expected fuel composition. The results showed that dose rates to the fuel pool equipment and personnel in the area remained within established limits as discussed in Section 9.1.4.3.4.

12.2.1.1.5 Processing Systems

12.2.1.1.5.1 Chemical and Volume Control System (CVCS). Radiation sources in the CVCS consist of radionuclides carried in the reactor coolant. Nitrogen-16 (N-16) is the predominant radiation source in the reactor coolant system. The design of the CVCS ensures that most of the N-16 has decayed before the letdown stream leaves the containment by placing a delay mechanism in the letdown flow to obtain an additional

95 seconds decay of N-16. All CVCS system heat exchangers other than the regenerative heat exchanger are located in the auxiliary building.

A. General Design Bases

The shielding design was based on the maximum expected activity in each component as listed in Tables 12.2-2a, b, c, d, and e. This information is considered original licensing information and not expected to be updated.

B. Specific Component Bases

1. Regenerative Heat Exchanger

Total tube volume (letdown) 2.0×10^4 cm^3

Total shell volume (charging) 1.6×10^5 cm^3

Letdown has RCS specific activities

Charging has volume control tank (VCT) specific activities

2. Letdown Heat Exchanger

Total tube volume is based on 69 gallons of water with reactor coolant specific activity.

3. Seal Injection Heat Exchanger

Total tube volume is based on 15 gallons of water with volume control tank specific activity.

C. Ion Exchangers (Table 12.2-8)

1. Purification Ion Exchanger

Total curie inventory is based on a resin buildup of 1.2 effective years. This ion exchanger is

used for lithium removal and normal purification of RCS letdown. When it is used for lithium removal it is on line an average of 58 days prior to placing it in service as a purification ion exchanger for 292 days.

All nuclides except Xe, Kr, Rb and Cs have a decontamination factor (DF) of 10 and efficiency of 90%, Xe and Kr have a DF of 1.0 and efficiency of 0%, Rb and Cs have a DF of 2.0, and efficiency of 50%.

2. Preholdup Ion Exchanger

Total curie inventory is based on resin buildup of 1.0 effective year (292 days). All nuclides except Xe, Kr, Rb, Cs, have a decontamination factor (DF) of 10 and an efficiency of 90%, Rb and Cs have a DF of 100 and efficiency of 99%, Xe and Kr have a decontamination factor of 1 and an efficiency of 0%.

Sources processed by the prehold-up Ion-exchanger include 1.1 x 10^6 gallons of letdown previously processed through the purification Ion exchanger and purification filter, 200 gpd from the Reactor Drain Tank (RDT) and 50 gpd from the Equipment Drain Tank (EDT).

3. Boric Acid Condensate Ion Exchanger

Total curie inventory is based on resin buildup of 1.0 effective year (292 days). Anion

decontamination factors of 10, and efficiency of 90% were used. All other ions have a decontamination factor of 1 and an efficiency of 0%. Total liquid processed is 1.83 x 10^5 gallons.

D. Filters (Table 12.2-9)

Total curie inventories on all CVCS filters are based on crud buildup of 292 days. All CVCS filters remove crud with a decontamination factor of 10 and an efficiency of 90%.

E. Tanks (Table 12.2-10)

1. Reactor Drain Tank (RDT)

The total curie inventory in the RDT is based on a water volume of 2565 gallons and an equivalent vapor volume of 217 ft^3. The tank vapor-liquid phases are in equilibrium and the tank liquid activity fraction is 1.0 of the RCS.

2. Equipment Drain Tank (EDT)

The total curie inventory in the EDT is based on a water volume of 5102 gallons and an equivalent vapor volume of 895 ft^3. The tank vapor-liquid phases are in equilibrium and the tank liquid activity fraction is 0.1 of the RCS.

3. Volume Control Tank (VCT)

The total curie inventory in the VCT is based on the average water volume in the tank of 3170 gallons of RCS letdown and an effective vapor

volume of 292 ft^3. Gas stripping was considered and the VCT vapor gas is in equilibrium with the liquid.

4. Hold-up Water Tank (HT)

   The total curie inventory in the HT is based on the average volume of 246,930 gallons. Gas stripping was considered and the tank vapor-liquid phases are assumed not in equilibrium. Activity in the tank is based on holdup of 200 gpd from the RDT, 50 gpd from the EDT and 3,767 gpd from RCS letdown.

5. Reactor Make-up Water Tank (RMWT)

   The total curie inventory in the RMWT is based on a water volume of 492,954 gallons. Activity in the tank is based on 9.9×10^5 gallons processed by the Boric Acid Concentrator.

6. Refueling Water Tank (RWT)

   The total curie inventory in the RWT is based on a water volume of 697,818 gallons. Activity in the tank is based on 1.8×10^5 gallons processed by the Boric Acid Concentrator.

Table 12.2-1
MAIN STEAM SUPPLY SYSTEM MAXIMUM
RADIOACTIVITY CONCENTRATIONS[a][b] (μCi/g) (Sheet 1 of 2)

Radio-nuclide	Primary Activity Concen-tration	SG Liquid Concen-tration	SG Steam Concen-tration	Hotwell Concen-tration
Kr-85m	1.40(+00)	5.40(-05)	5.40(-05)	1.31(-05)
Kr-85	2.60(-02)	1.02(-06)	1.02(-06)	2.49(-07)
Kr-87	8.60(-01)	3.22(-05)	3.22(-05)	7.57(-06)
Kr-88	2.40(+00)	9.19(-05)	9.19(-05)	2.21(-05)
Xe-131m	8.40(-02)	3.28(-06)	3.28(-06)	8.06(-07)
Xe-133	2.70(+01)	1.05(-03)	1.05(-03)	2.59(-04)
Xe-135	5.30(+00)	2.06(-04)	2.06(-04)	5.02(-05)
Xe-138	6.10(-01)	1.96(-05)	1.96(-05)	3.92(-06)
Br-84	3.40(-02)	1.88(-05)	1.88(-07)	1.70(-07)
I-129	3.90(-08)	7.87(-11)	7.87(-13)	7.75(-13)
I-131	2.90(+00)	5.81(-03)	5.81(-05)	5.72(-05)
I-132	8.10(-01)	1.01(-03)	1.01(-05)	9.77(-06)
I-133	4.30(+00)	8.13(-03)	8.13(-05)	7.99(-05)
I-134	5.70(-01)	4.42(-04)	4.42(-06)	4.13(-06)
I-135	2.40(+00)	4.00(-03)	4.00(-05)	3.90(-05)
Rb-88	2.40(+00)	8.69(-04)	8.69(-07)	8.00(-07)
Rb-89	7.30(-02)	2.36(-05)	2.36(-08)	2.12(-08)
Cs-134	7.60(-02)	1.53(-04)	1.53(-07)	1.74(-07)
Cs-136	9.60(-02)	1.93(-04)	1.93(-07)	2.19(-07)
Cs-137	3.00(-01)	6.05(-04)	6.05(-07)	6.87(-07)
Cs-138	1.10(+00)	6.32(-04)	6.32(-07)	6.33(-07)
N-16	1.50(+02)[c]	4.04(-04)	4.04(-04)	3.75(-06)
H-3	6.60(-01)	1.30(-01)	1.30(-01)	1.30(-01)
Y-90	6.20(-04)	1.21(-06)	1.21(-09)	1.22(-09)
Y-91	2.10(-02)	4.19(-05)	4.19(-08)	4.20(-08)

a. One gallon per minute primary to secondary leakage.

b. Numbers in parentheses denote powers of ten.

c. This is N-16 activity at the reactor vessel outlet nozzle (5.66×10^6 disintegration/cm^3-seconds)

Table 12.2-1
MAIN STEAM SUPPLY SYSTEM MAXIMUM
RADIOACTIVITY CONCENTRATIONS[a][b] (μCi/g) (Sheet 2 of 2)

Radio-nuclide	Primary Activity Concen-tration	SG Liquid Concen-tration	SG Steam Concen-tration	Hotwell Concen-tration
Mo-99	2.20(+00)	4.31(-03)	4.31(-06)	4.32(-06)
Sr-89	4.00(-03)	7.98(-06)	7.98(-09)	8.01(-09)
Sr-90	2.00(-04)	4.00(-07)	4.00(-10)	4.01(-10)
Sr-91	3.80(-03)	6.66(-06)	6.66(-09)	6.64(-09)
Zr-95	5.90(-03)	1.18(-05)	1.18(-08)	1.18(-08)
Ru-103	6.60(-03)	1.32(-05)	1.32(-08)	1.32-(08)
Ru-106	1.60(-03)	3.20(-06)	3.20(-09)	3.21(-09)
Te-129	1.20(-02)	1.12(-05)	1.12(-08)	1.07(-08)
Te-132	3.00(-01)	5.89(-04)	5.89(-07)	5.91(-07)
Te-134	3.90(-02)	2.68(-05)	2.68(-08)	2.51(-08)
Ba-140	6.80(-03)	1.35(-05)	1.35(-08)	1.36(-08)
La-140	6.40(-03)	1.24(-05)	1.24(-08)	1.24(-08)
Ce-144	3.70(-03)	7.39(-06)	7.39(-09)	7.41(-09)
Pr-143	5.40(-03)	1.07(-05)	1.07(-08)	1.08(-08)
Cr-51	1.90(-03)	3.79(-06)	3.79(-09)	3.80(-09)
Mn-54	3.10(-04)	6.19(-07)	6.19(-10)	6.21(-10)
Fe-55	1.60(-03)	3.20(-06)	3.20(-09)	3.21(-09)
Fe-59	1.00(-03)	2.00(-06)	2.00(-09)	2.00(-09)
Co-58	1.60(-02)	3.19(-05)	3.19(-08)	3.20(-08)
Co-60	2.00(-03)	4.00(-06)	4.00(-09)	4.01(-09)

TABLE 12.2-2a

(Sheet 1 of 2)

CVCS HEAT EXCHANGER SOLUBLE INVENTORIES

Maximum Values
(curies)

Nuclide	Letdown	Regenerative	Seal Injection
N-15	1.5(+00)*	-	0.
KR-85M	4.4(-01)	3.10(-2)	9.1(-05)
KR-85	9.7(-03)	6.00(-4)	2.1(-06)
KR-87	2.4(-01)	1.95(-2)	4.3(-05)
KR-88	6.8(-01)	5.49(-2)	1.4(-04)
XE-131M	6.0(-02)	1.92(-3)	1.3(-05)
XE-133	6.3(+00)	6.12(-1)	1.4(-03)
XE-135	1.1(+00)	1.20(-1)	2.3(-04)
XE-138	1.6(-01)	1.38(-2)	1.9(-05)
BR-34	8.9(-03)	-	1.4(-04)
RB-88	6.8(-01)	5.34(-2)	4.4(-02)
RB-89	3.9(-02)	-	2.4(-03)
SR-89	1 1(-03)	1.66(-3)	2.4(-05)
SR-90	3.7(-05)	9.00(-5)	7.9(-07)
Y-90	1.1(-03)	4.78(-4)	2.4(-07)
SR-91	1.7(-03)	8.63(-5)	3.6(-06)
Y-91	1.6(-04)	4.78(-4)	3.6(-06)
ZR-95	2.0(-04)	1.00(-6)	4.4(-06)
MO-99	1.5(-01)	5.05(-2)	3.3(-03)
RU-103	1.4(-04)	1.51(-4)	3.0(-06)
RU-106	5.0(-05)	3.55(-5)	1.1(-06)
TE-129	2.6(-03)	2.75(-4)	4.7(-05)
I-129	1.1(-08)	-	2.4(-10)
I-131	8.9(-01)	6.70(-2)	1.9(-02)
TE-132	5.5(-02)	1.85(-2)	1.2(-03)
I-132	1.8(-01)	-	3.5(-03)
I-133	9.7(-01)	-	2.1(-02)
TE-134	7.6(-03)	-	1.3(-04)
I-134	1.5(-01)	1.28(-2)	2.5(-03)
CS-134	2.9(-02)	5.47(-3)	3.1(-03)
I-135	6.5(-01)	5.36(-2)	1.4(-02)
CS-136	1.6(-02)	6.16(-3)	1.7(-03)
CS-137	7.6(-02)	2.18(-2)	8.2(-03)

* Numbers in parenthesis denote powers of ten.

TABLE 12.2-2a (Cont'd.) (Sheet 2 of 2)

CVCS HEAT EXCHANGER SOLUBLE INVENTORIES

Maximum Values
(curies)

Nuclide	Letdown	Regenerative	Seal Injection
CS-138	2.4(-01)	-	1.8(-02)
BA-140	1.4(-03)	1.54(-4)	3.1(-05)
LA-140	5.0(-04)	1.45(-4)	1.1(-05)
PR-143	1.9(-04)	1.24(-4)	4.0(-06)
CE-144	1.2(-04)	8.43(-5)	2.6(-06)
CR-51	5.9(-04)	1.00(-4)	9.0(-08)
TE-132	-	6.82(-3)	-
BR-84	-	7.64(-4)	-
I-133	-	9.69(-2)	-
MN-54	8.1(-05)	2.10(-6)	1.5(-08)
FE-55	4.2(-04)	-	7.6(-08)
FE-59	2.6(-04)	1.20(-6)	4.7(-08)
CO-58	4.2(-03)	1.90(-4)	7.6(-07)
CO-60	5.2(-04)	2.10(-5)	9.5(-08)
XE-135m	-	insignificant	-

* Numbers in parentheses denote powers of ten.

TABLE 12.2-2b

CVCS HEAT EXCHANGER ACTIVITY, MAXIMUM VALUES

(γ/sec)

Heat Exchanger	Letdown			Regenerative			Seal Injection		
Energy Group Mev	Crud Plateout	Soluble	Total	Crud Plateout	Soluble	Total	Crud Plateout	Soluble	Total
0.25	2.5(+9)	1.0(+11)	1.0(+11)	1.1(+10)	1.1(+10)	2.2(+10)	8.6(+7)	8.4(+8)	9.3(+8)
0.50	2.4(+10)	5.7(+10)	8.1(+10)	1.0(+11)	8.6(+9)	1.1(+11)	8.4(+8)	1.3(+9)	2.1(+9)
0.75	8.3(+10)	3.6(+10)	1.2(+11)	3.6(+11)	6.0(+9)	3.7(+11)	2.8(+9)	1.0(+9)	3.8(+9)
1.00	2.2(+8)	2.0(+10)	2.0(+10)	9.5(+8)	3.9(+9)	4.9(+9)	7.3(+6)	7.9(+8)	8.0(+8)
1.38	4.4(+9)	2.6(+10)	3.0(+10)	1.8(+10)	4.9(+9)	2.3(+10)	1.4(+8)	9.3(+8)	1.1(+9)
2.00	4.9(+8)	3.9(+10)	3.9(+10)	2.1(+9)	5.7(+9)	7.8(+9)	1.7(+7)	8.0(+8)	8.2(+3)
3.00	-	3.5(+9)	3.5(+9)	-	7.3(+8)	7.3(+8)	-	1.5(+8)	1.6(+8)
4.00	-	1.3(+8)	1.3(+8)	-	3.6(+7)	3.6(+7)	-	8.6(+6)	8.6(+6)
6.00	-	7.9(+9)	7.9(+9)	-	3.3(+10)	3.3(+10)	-	-	-

* Numbers in parentheses denote powers of ten.

TABLE 12.2-2c
(Sheet 1 of 2)
CVCS ION EXCHANGER INVENTORIES

Maximum Values
(curies)

Nuclide	Purification IX	Deborating IX	Preholdup IX	Boric Acid Condensate IX
N-16	3.3(-02)*	0.0	0.0	0.0
KR-85M	1.8(+00)	1.8(+00)	1.7(+00)	3.3(-08)
KR-85	3.9(-02)	3.9(-02)	3.9(-02)	2.9(-08)
KR-87	9.6(-01)	9.6(-01)	9.2(-01)	9.2(-09)
KR-88	2.8(+00)	2.8(+00)	2.6(+00)	5.7(-08)
XE-131M	2.4(-01)	2.4(-01)	2.4(-01)	1.3(-07)
XE-133	2.6(+01)	2.6(+01)	2.5(+01)	9.9(-06)
XE-135	4.4(+00)	4.4(+00)	4.2(+00)	2.6(-07)
XE-138	6.6(-01)	6.6(-01)	6.3(-01)	1.2(-09)
BR-84	3.9(-01)	3.8(-02)	1.4(-03)	6.7(-10)
RB-88	1.1(+01)	1.4(+00)	2.8(-01)	2.9(-08)
RB-89	5.3(-01)	8.0(-02)	1.4(-02)	1.5(-09)
SR-89	1.1(+02)	4.7(-04)	5.4(-01)	4.8(-08)
SR-90	1.5(+01)	1.5(-05)	7.1(-02)	1.7(-09)
Y-90	5.8(-02)	4.5(-06)	2.3(-04)	1.6(-10)
SR-91	1.4(+00)	6.9(-04)	5.0(-03)	4.9(-09)
Y-91	1.9(+01)	6.7(-05)	8.8(-02)	7.0(-09)
ZR-95	2.5(+01)	8.2(-05)	1.2(-01)	8.7(-09)
MO-99	8.5(+02)	6.3(-02)	3.4(+00)	2.3(-06)
RU-103	1.1(+01)	5.6(-05)	5.1(-02)	5.7(-09)
RU-106	1.5(+01)	2.0(-05)	7.4(-02)	2.3(-09)
TE-129	2.5(-01)	2.4(-02)	8.9(-04)	8.9(-10)
I-129	4.4(-03)	1.1(-05)	2.1(-05)	1.9(-09)
I-131	1.4(+04)	6.5(+02)	6.2(+01)	3.8(-03)
TE-132	3.5(+02)	3.7(+01)	1.4(+00)	5.6(-05)
I-132	3.4(+01)	3.3(+00)	1.2(-01)	2.4(-07)
I-133	1.7(+03)	1.6(+02)	6.3(+00)	8.9(-05)

* Number in parentheses denote powers of ten.

TABLE 12.2-2c (Cont'd.) (Sheet 2 of 2)

CVCS ION EXCHANGER INVENTORIES

Maximum Values
(curies)

Nuclide	Purification IX	Deborating IX	Preholdup IX	Boric Acid Condensate IX
TE-134	4.5(-01)*	4.4(-02)	1.6(-03)	1.0(-09)
I-134	1.1(+01)	1.0(+00)	3.8(-02)	3.0(-08)
CS-134	6.5(+03)	5.9(-02)	1.8(+02)	4.5(-07)
I-135	3.6(+02)	3.6(+01)	1.3(+00)	7.1(-06)
CS-136	2.6(+02)	3.2(-02)	7.3(+00)	1.9(-07)
CS-137	1.9(+04)	1.5(-01)	5.5(+02)	1.2(-06)
CS-138	6.8(+00)	4.8(-01)	1.8(-01)	1.9(-08)
BA-140	3.7(+01)	5.9(-04)	1.6(-01)	4.8(-08)
LA-140	1.7(+00)	2.0(-04)	6.5(-03)	4.9(-09)
PR-143	5.0(+00)	7.6(-05)	2.2(-02)	6.2(-09)
CE-144	3.5(+01)	4.9(-05)	1.7(-01)	5.5(-09)
CR-51	2.7(+00)	4.5(-02)	1.3(-02)	1.9(-09)
MN-54	2.4(+00)	7.9(-03)	1.2(-02)	1.9(-09)
FE-85	1.5(+01)	4.1(-02)	7.4(-02)	3.7(-10)
FE-50	2.3(+00)	2.4(-02)	1.1(-02)	1.1(-09)
CO-58	5.6(+01)	4.0(-01)	2.7(-01)	1.8(-08)
CO-60	2.0(+01)	5.2(-02)	9.7(-02)	2.4(-09)

* Numbers in parentheses denote powers of ten

TABLE 12.2-2d

CVCS FILTER INVENTORIES

Maximum Values
(curies)

Nuclide	Seal Injection	Reactor Drain	Boric Acid	Purification	Reactor Makeup Water
CR-51	8.2(-02)*	4.7(-02)	2.2(-05)	2.7(+01)	4.0(-07)
MN-54	7.2(-02)	4.6(-02)	1.4(-04)	2.4(+01)	8.8(-07)
FE-55	4.6(-01)	2.9(-01)	1.1(-03)	1.5(+02)	6.1(-06)
FE-59	6.9(-02)	4.1(-02)	3.4(-05)	2.3(+01)	4.6(-07)
C0-58	1.7(+00)	1.0(+00)	1.4(-03)	5.5(+02)	1.4(-05)
C0-60	6.0(-01)	3.9(-08)	1.6(-03)	2.0(+02)	8.3(-06)

* Numbers in parentheses denote powers of ten.

TABLE 12.2-2e

(Sheet 1 of 2)

CVCS TANK INVENTORIES

Maximum Values
(curies)

Nuclide	Reactor Drain	Equipment Drain	Volume Control	Holdup	Reactor Makeup Water	Refueling Water
KR-85M	1.2(+01)*	1.1(+00)	3.6(-01)	6.6(-00)	1.4(-06)	5.7(-03)
KR-85	4.0(+00)	2.0(-01)	8.3(-03	1.5(-01)	1.3(-04)	1.4(-01)
KR-87	4.1(+00)	4.5(-01)	1.6(-01)	1.6(+00)	1.7(-07)	7.7(-11)
KR-88	1.5(+01)	1.5(+00)	5.2(-01)	9.7(+00)	1.5(-06)	1.5(-04)
XE-131M	1.0(+01)	1.4(+00)	2.9(-02)	1.1(-01)	1.6(-04)	8.0(-01)
XE-133	7.7(+02)	7.5(+01)	3.0(+00)	7.1(+00)	5.9(-03)	7.3(+01)
XE-135	3.0(+01)	2.7(+00)	5.0(-01)	1.7(+01)	1.2(-05)	5.4(-01)
XE-138	2.3(+00)	2.8(-01)	3.4(-02)	9.7(-02)	1.4(-09)	0.
BR-84	1.2(-01)	1.5(-02)	2.9(-02)	8.3(-04)	1.5(-10)	0.
RB-88	9.3(+00)	1.2(+00)	9.3(+00)	1.2(-02)	1.5(-08)	0.
RB-89	5.4(-01)	6.6(-02)	5.1(-01)	5.5(-04)	6.4(-10)	0.
SR-89	4.0(-02)	5.1(-03)	5.3(-03)	1.8(-02)	5.1(-05)	7.7(-02)
SR-90	1.4(-03)	2.6(-04)	1.7(-04)	6.3(-04)	3.2(-06)	6.2(-03)
Y-90	2.3(-04)	2.2(-05)	5.0(-05)	9.2(-05)	1.7(-08)	2.8(-04)
SR-91	2.6(-02)	2.9(-03)	7.6(-03)	4.4(-03)	8.2(-08)	2.9(-03)
Y-91	5.8(-03)	7.7(-04)	7.6(-04)	2.6(-03)	7.0(-06)	1.2(-02)
ZR-95	7.1(-03)	9.7(-04)	9.2(-04)	3.2(-03)	1.0(-05)	1.5(-02)
MO-99	3.3(+00)	3.0(-01)	7.0(-01)	1.3(+00)	2.6(-04)	4.1(+00)
RU-103	4.7(-03)	5.7(-04)	6.4(-04)	2.1(-03)	5.4(-06)	8.3(-03)
RU-106	1.8(-03)	3.3(-04)	2.3(-04)	8.3(-04)	3.9(-06)	6.9(-03)
TE-129	3.6(-02)	4.4(-03)	9.9(-03)	8.0(-04)	2.0(-10)	1.3(-13)
I-129	4.1(-07)	8.0(-08)	5.0(-08)	1.9(-07)	9.7(-11)	1.9(-06)
I-131	2.4(+01)	2.2(+00)	4.1(+00)	1.1(+01)	7.8(-04)	3.3(+01)
TE-132	1.2(+00)	1.1(-01)	2.5(-01)	5.0(-01)	1.2(-05)	1.6(+00)
I-132	2.5(+00)	3.0(-01)	7.4(-01)	1.4(-01)	5.4(-08)	9.2(-06)
I-133	1.6(+01)	1.7(+00)	4.4(+00)	4.3(+00)	2.0(-05)	9.1(+00)
TE-134	1.0(-01)	1.3(-02)	2.6(-02)	1.1(-03)	2.3(-10)	0.
I-134	2.0(+00)	2.5(-01)	5.3(-01)	3.0(-02)	6.6(-09)	2.0(-15)
CS-134	1.1(+00)	2.2(-01)	6.6(-01)	1.5(-01)	8.2(-04)	3.3(+00)

* Number in parentheses denote powers of ten.

TABLE 12.2-2e (Cont'd.)(Sheet 2 of 2)

CVCS TANK INVENTORIES

Maximum Values
(curies)

Nuclide	Reactor Drain	Equipment Drain	Volume Control	Holdup	Reactor Makeup Water	Refueling Water
I-135	9.6(+00)*	1.1(+00)	2.9(+00)	1.3(+00)	1.6(-06)	2.7(-01)
CS-136	4.8(-01)	4.4(-02)	3.7(-01)	7.1(-02)	9.0(-05)	1.1(+00)
CS-137	2.8(+00)	5.5(-01)	1.7(+00)	4.0(-01)	2.3(-03)	9.2(+00)
CS-138	3.3(+00)	4.0(-01)	3.9(+00)	1.1(-02)	1.7(-08)	0.
BA-140	4.3(-02)	4.0(-03)	6.6(-03)	1.9(-02)	2.2(-05)	5.9(-02)
LA-140	9.4(-03)	9.3(-04)	2.3(-03)	3.3(-03)	3.4(-07)	9.6(-03)
PR-143	5.6(-03)	5.3(-04)	8.5(-04)	2.5(-03)	3.0(-06)	7.8(-03)
CE-144	4.4(-03)	7.7(-04)	5.5(-04)	2.0(-03)	9.1(-06)	1.6(-02)
CR-51	1.6(-02)	1.8(-03)	1.9(-04)	7.1(-04)	1.5(-06)	1.8(-02)
MN-54	3.0(-03)	5.3(-04)	3.1(-05)	1.3(-04)	6.2(-07)	3.7(-03)
FE-55	1.5(-02)	2.9(-03)	1.6(-04)	6.6(-04)	3.5(-06)	2.0(-02)
FE-59	9.0(-03)	1.1(-03)	1.0(-04)	3.9(-04)	1.1(-06)	9.9(-03)
CO-58	1.5(-01)	2.1(-02)	1.6(-03)	6.3(-03)	2.2(-05)	1.7(-01)
CO-60	1.9(-02)	3.7(-03)	2.0(-04)	8.3(-04)	4.5(-06)	2.6(-02)

* Number in parentheses denote powers of ten.

12.2.1.1.5.2 Steam Generator Blowdown System. Radiation sources in the steam generator blowdown system shown in table 12.2-3 are based on the primary-to-secondary leakage rate and failed fuel rate stated in paragraph 12.2.1.1.3. However, the liquid is assumed to be processed through the steam generator blowdown system at the maximum rate of 1% of main steam rate. High-conductivity solutions resulting from regeneration of blowdown demineralizers will normally be processed in the chemical waste neutralizing tanks (see section 10.4), in the absence of primary-to-secondary leakage. Radioactive high-conductivity solutions will be processed by the LRS (see section 11.2).

12.2.1.1.5.3 Condensate Polishing System. For shielding and dose assessment purposes, the condensate polishing system does not yield substantive doses since radioactivity will be present in the demineralizers only in the event of coincident steam generator tube leaks and condenser tube leaks. Space for shielding has, however, been reserved should dual tube leaks occur. Demineralizer inventory for dual leakage is shown in table 12.2-3.

Table 12.2-3
MAXIMUM RADIOACTIVITY INVENTORIES
OF SECONDARY PROCESSING SYSTEMS (Ci) (Sheet 1 of 2)

Radionuclide	Blowdown Flash Tank	Blowdown Demineralizer	Polishing Demineralizer
Kr-83m	0.0	0.0	0.0
Kr-85m	1.2 (-03)	0.0	0.0
Kr-85m	2.3 (-05)	0.0	0.0
Kr-87m	7.3 (-04)	0.0	0.0
Kr-88m	2.1 (-03)	0.0	0.0
Kr-89m	0.0	0.0	0.0
Xe-131m	7.5 (-05)	0.0	0.0
Xe-133m	0.0	0.0	0.0
Xe-133	2.4 (-02)	0.0	0.0
Xe-135m	0.0	0.0	0.0
Xe-135	4.7 (-03)	0.0	0.0
Xe-137	0.0	0.0	0.0
Xe-138	4.5 (-04)	0.0	0.0
Br-83	0.0	0.0	0.0
Br-84	4.3 (-04)	8.7 (-04)	1.1 (-04)
Br-85	0.0	0.0	0.0
I-129	1.8 (-09)	3.3 (-05)	3.2 (-06)
I-130	0.0	0.0	0.0
I-131	1.3 (-01)	9.8 (+01)	9.4
I-132	2.3 (-02)	2.0 (-01)	2.2 (-02)
I-133	1.8 (-01)	1.5 (+01)	1.5
I-134	1.0 (-02)	3.4 (-02)	4.1 (-03)
I-135	9.1 (-02)	2.3	2.4 (-01)
Rb-86	0.0	0.0	0.0
Rb-88	2.0 (-02)	2.1 (-02)	1.8 (-04)
Rb-89	5.4 (-04)	5.1 (-04)	4.1 (-06)
Cs-134	3.5 (-03)	5.4 (+01)	5.4 (-01)
Cs-136	4.4 (-03)	5.1	5.1 (-02)
Cs-137	1.4 (-02)	2.4 (+02)	2.4
Cs-138	1.4 (-02)	2.8 (-02)	2.6 (-04)
H-3	3.0	0.0	0.0
Y-90	2.7 (-05)	7.1 (-03)	1.0 (-04)
Y-91m	0.0	0.0	0.0
Y-91	9.5 (-04)	5.2	7.4 (-02)
Y-93	0.0	0.0	0.0

Table 12.2-3
MAXIMUM RADIOACTIVITY INVENTORIES
OF SECONDARY PROCESSING SYSTEMS (Ci) (Sheet 2 of 2)

Radionuclide	Blowdown Flash Tank	Blowdown Demineralizer	Condensate Polishing Demineralizer
Mo-99	9.8 (-02)	2.6 (+01)	3.7 (-01)
Sr-89	1.8 (-04)	8.7 (-01)	1.2 (-02)
Sr-90	9.1 (-06)	1.8 (-01)	2.5 (-03)
Sr-91	1.5 (-04)	5.8 (-03)	8.2 (-05)
Zr-91	2.7 (-04)	1.6	2.2 (-02)
Nb-95	0.0	0.0	0.0
Tc-99m	0.0	0.0	0.0
Ru-103	3.0 (-04)	1.1	1.6 (-02)
Ru-106	7.3 (-05)	1.1	1.5 (-02)
Rh-103m	0.0	0.0	0.0
Rh-106	0.0	0.0	0.0
Te-125m	0.0	0.0	0.0
Te-127m	0.0	0.0	0.0
Te-127	0.0	0.0	0.0
Te-129m	0.0	0.0	0.0
Te-129	2.5 (-04)	1.2 (-03)	1.7 (-05)
Te-131m	0.0	0.0	0.0
Te-131	0.0	0.0	0.0
Te-132	1.3 (-02)	4.2	5.9 (-02)
Te-134	6.1 (-04)	1.7 (-03)	2.4 (-05)
Ba-137m	0.0	0.0	0.0
Ba-140	3.1 (-04)	3.8 (-01)	5.4 (-03)
La-140	2.8 (-04)	4.6 (-02)	6.4 (-04)
Ce-141	0.0	0.0	0.0
Ce-143	0.0	0.0	0.0
Ce-144	1.7 (-04)	2.4	3.3 (-02)
Pr-143	2.4 (-04)	3.2 (-01)	4.6 (-03)
Pr-144	0.0	0.0	0.0
Np-239	0.0	0.0	0.0
Cr-51	8.6 (-05)	2.3 (-01)	3.3 (-03)
Mn-54	1.4 (-05)	2.0 (-01)	2.9 (-03)
Fe-55	7.3 (-05)	1.3	1.8 (-02)
Fe-59	4.5 (-05)	1.9 (-01)	2.7 (-03)
Co-58	7.3 (-04)	4.7	6.6 (-02)
Co-60	9.1 (-05)	1.7	2.4 (-02)

12.2.1.2 Auxiliary Building

12.2.1.2.1 Shutdown Cooling System

The pumps, heat exchangers, and associated piping of the shutdown cooling system (SDCS) are potential carriers of radioactive materials. For plant shutdown, the SDCS pumps and heat exchanger sources of radioactivity result from the radioactive isotopes carried in the reactor coolant, discussed in Section 12.2.1.1.2, after 4 hours of decay following shutdown and dilution.

Table 12.2-1h provides a listing of the maximum specific source strenghts (MeV/gm-sec) in the SDCS.

TABLE 12.2-1h

SHUTDOWN COOLING SYSTEM (SDCS) SPECIFIC SOURCE STRENGTHS
FROM CESSAR TABLE 12.2-11
Maximum Values (MeV/gram-sec)

Decay Time	Energy (MeV)								
(hr)	0.3	0.63	1.10	1.55	1.99	2.38	2.75	3.25	3.70
1	3.3(+4)*	2.4(+5)	6.7(+4)	1.9(+4)	4.7(+3)	3.4(+2)	1.6(+2)	9.9(+1)	1.2(+2)
10	2.5(+4)	1.2(+5)	2.9(+4)	7.5(+3)	2.2(+3)	2.9(+1)	6.7(-1)	6.2(-1)	8.9(-3)
100	1.8(+4)	4.4(+4)	6.3(+3)	2.4(+3)	3.5(+2)	2.2(+1)	2.7(-2)	8.7(-3)	-

*number in parentheses denotes power of ten

12.2.1.2.2 Nuclear Cooling Water System

The nuclear cooling water system is normally nonradioactive or of very low level activity due to inleakage. The process

radiation monitor (section 11.5) for this system has a sensitivity of 1×10^{-6} $\mu Ci/cm^3$ of Cs^{137} uniformly distributed throughout the nuclear cooling water system. For shielding and dose assessment purposes, the nuclear cooling water system does not yield substantive doses.

12.2.1.3 Fuel Building

12.2.1.3.1 Spent Fuel Storage and Transfer

The predominant radioactivity sources in the spent fuel storage and transfer areas in the fuel building are the spent fuel assemblies. Spent fuel assembly sources are discussed in Section 12.2.1.1.4. For shielding design, the spent fuel pool is assumed to contain the design maximum number of fuel assemblies. Of these, 241 spent fuel assemblies are assumed to be from unloading the full core with 72 hours decay, and 81 assemblies are assumed to be from previous refueling operations with 90 days decay. Shielding during dry fuel storage, transfer, and transport operations is provided by the NAC-UMS® transportable storage canister (TSC), transfer cask (TFR), and vertical concrete cask (VCC) as applicable. In addition to this shielding, the NAC-UMS® Certificate of Compliance (CoC) requires a minimum decay time of five years for assemblies selected for dry fuel storage.

12.2.1.3.2 Spent Fuel Pool Cooling and Cleanup System

Sources in the spent fuel pool cooling and cleanup (SFPCC) system are a result of transfer of radioactive isotopes from the reactor coolant into the spent fuel pool during refueling operations. The reactor coolant activities for fission,

corrosion, and activation products are decayed for the amount of time required to remove the reactor vessel head following shutdown, are reduced by operation of the CVCS purification ion exchangers, and are diluted by the total volumes of the water in the reactor vessel, refueling pool, and spent fuel pool. This activity then undergoes subsequent decay and accumulation on the SFPCC filters and ion exchangers as discussed in subsection 11.1.7. These sources are listed in table 12.2-4.

During dry fuel storage as described in section 9.1.4.2.3.2, the annulus flush system may use temporary ion exchange vessels to reduce the radioactivity of the spent fuel pool water contained within the cask loading pit to minimize the contamination transferred to the transportable storage canister. These vessels accumulate similar activity to that listed in Table 12.2-4 for the spent fuel pool purification system. Dose rates are controlled in accordance with Chapter 12.5.

12.2.1.4 Turbine Building

12.2.1.4.1 Main Steam Supply and Power Conversion Systems

Potential radioactivity in the main steam supply and power conversion systems is a result of steam generator tube leaks and fuel cladding defects as discussed in paragraph 12.2.1.1.3. This radioactivity is sufficiently low so that no radiation shielding for equipment in secondary systems, other than portions of the steam generator blowdown system (paragraph 12.2.1.1.5.2), is required in order to meet the design radiation zone requirements.

12.2.1.5 Radwaste Building

12.2.1.5.1 Liquid and Solid Radwaste Systems

Radioactive inputs to the radwaste system sources include fission and activation product radionuclides produced in the core and reactor coolant. The components of the radwaste systems contain varying degrees of activity.

The concentrations of radionuclides present in the process fluids at various locations in the radwaste systems, such as pipes, tanks, filters, ion exchangers, and evaporators, are discussed in section 11.1. Shielding for each component of the radwaste systems is based on maximum activity conditions as shown in table 12.2-5. Pumps are modeled using the appropriate geometries and process point activities.

12.2.1.5.2 Gaseous Radwaste System

Radiation sources for each component of the waste gas system are based on operation with the maximum activity conditions as given in sections 11.1 and 11.3. Tabulation of the maximum activities is shown in table 12.2-5.

12.2.1.6 Sources Resulting from Design Basis Accidents

The radiation sources from design basis accidents include the design basis inventory of radioactive isotopes in the reactor coolant, plus postulated fission product releases from the fuel. Accident parameters and sources are discussed and evaluated in chapter 15.

12.2.1.7 Stored Radioactivity

The principal sources of activity not enclosed by plant structures are the independent spent fuel storage installation (ISFSI), the refueling water tank (RWT), the holdup tank (HT), the reactor makeup water tank (RMWT), and the condensate storage tank (CST). The annual dose to an individual at the site boundary due to normal operation of the ISFSI is limited to the values specified in 10CFR72.104. The CST is expected to contain concentrations of radionuclides that yield a surface dose rate of 0.25 mrem/h or less. Radionuclide inventories of the RWT, RMWT, and HT are listed in Table 12.2-2e.

Spent fuel is stored in the spent fuel pool until it is placed in dry fuel storage systems for storage at the ISFSI or the spent fuel shipping cask for transport offsite. Storage space is allocated in the radwaste building for storage of spent filter cartridges and processed spent resins, evaporator bottoms, and chemical wastes. Radioactive wastes stored inside plant structures are shielded so that there is design radiation zone I access outside the structure. If radiation levels outside the structure exceed the design radiation zone limit, or it becomes necessary to temporarily store radioactive wastes outside plant structures, radiation protection measures are taken by the radiation protection staff to assure compliance with 10CFR20.1001 - 20.2402 and to be consistent with the recommendations of NRC Regulatory Guide 8.8.

The dry active waste processing and storage (DAWPS) facility and the low-level radioactive material storage facility

(LLRMSF) are part of the Solid Waste Management System, and are described in 11.4.

The DAWPS facility was built to the standards of RG 1.143 and GL 81.38, but was not determined to require designed shielding. The isotopic composition of material stored at the DAWPS facility is based on the station waste stream shown in Table 11.4-2, SRS Input Activities (Ci/yr/unit). The curie content, form, isotopic distribution, and use of radioactive materials in the DAWPS facility are described in 11.4.1. The 15 Curie limit is based on minimizing exposure at the site boundary in the event of a fire in the DAWPS facility.

The LLRMSF was designed for the interim storage of up to 60,000 Ci of dry and solidified radioactive waste. The Curie limit and isotopic distribution of this waste are based on Solid Radwaste System Output Activities, reflected in Table 11.4-6, SRS Output Activities (Ci/yr/unit) using a nominal 5 year period of waste accumulation. Material stored in the LLRMSF shall be in strong tight containers suitable for the material contained and the intended storage duration. Repackaging which may be required based on disposal site criteria will not be conducted in the LLRMSF. Repackaging due to container failures will be handled on location.

An Independent Spent Fuel Storage Installation (ISFSI) was built at Palo Verde to store spent fuel which no longer requires active cooling. Refer to Independent Spent Fuel Storage Installation 72.212 Evaluation Report for a description of the form and use of radioactive material stored at the ISFSI. Refer to Engineering Calculation 13-NC-RC-0203 for the

isotopic composition, Curie content, models and parameters used for calculating source magnitudes, and method for source term specification for material stored at the ISFSI.

12.2.1.8 Field Run Pipe Routing

The procedures for routing of radioactive piping are discussed in paragraph 12.1.2.2. Radioactive piping was routed as part of the engineering design effort. Radioactive piping was not field-routed.

12.2.1.9 Old Steam Generator and Old Reactor Vessel Closure Head Storage Facility (OSG/ORVCHSF)

The OSG/ORVCHSF is a long term storage facility designed to store the six old steam generators, three old reactor vessel closure heads and associated control element drive mechanisms, and three old reactor vessel closure head lift rigs from the three units.

The old steam generator section of the facility is constructed of concrete with 18″ walls and roof, 10″ general flooring, and 6′ thick load bearing slabs. The old reactor vessel closure head section of the facility is constructed of concrete with 30″ perimeter walls, an 18″ common wall with the old steam generator storage facility, 24″ roof, and 18″ general floor. The radiological design of the OSG/ORVCHSF provides adequate shielding to satisfy Palo Verde licensing basis requirements as per 10 CFR Part 20 and incorporates ALARA design features as per Regulatory Guide 8.8.

The building's radiological design has been evaluated for the storage configuration. The maximum dose rate at the RCA and Restricted boundary, considered the outside walls of the facility, is below the total effective dose equivalent to members of the public; does not exceed 0.1 rem in a year, as specified in 10 CFR 20.1301, Dose limits for individual members of the public. Per UFSAR Table 12.1-1, this results in a radiation zone classification of zone 1 allowing unrestricted access to the Site areas outside the facility, and zone 4 (OSG Section)/zone 5 (ORVCHSF Section) within the facility.

The OSG/ORVCHSF is classified as non safety related, non quality related (NQR), and non power generation structure. The OSGSF that houses the original Unit 2 steam generators is designed to the requirements of the Uniform Building Code (UBC). The remaining portion of the OSGSF that houses the original Unit 1 and 3 steam generators, and the ORVCH portion of the facility that houses the three Unit's reactor vessel closure heads are designed to the requirements of the International Building Code (IBC). The buildings' designs for dead, live, wind, seismic, and flood loads meet or exceed the UFSAR requirements for seismic category II structures.

The OSG/ORVCHSF is a stand-alone facility that does not interface with any plant structures or systems during any mode of plant operation. No offsite or onsite electrical power is provided, there is no forced or natural ventilation, and there are no normally open penetrations providing access to the stored radioactive material. There is no normal release path for the radioactive material within the facility.

The OSG/ORVCHSF is not designed for normal occupancy, and access is infrequent. Personnel access is controlled physically by the use of large concrete tilt panels or shield blocks and administratively by requiring specific approval from Radiation Protection personnel.

The OSG/ORVCHSF is located North East of Unit 1 cooling towers and West of Low Level Radioactive Material Storage Facility as shown on Site General Arrangement Plan, drawing number 13-C-ZVA-003.

The old steam generators are enclosed by the installation of nozzle covers and plugs, welded in place, and the exterior surfaces are coated with a fixative to minimize the spread of loose surface contamination.

The reactor vessel closure heads are enclosed by the installation of a 3" thick metal bottom plate, applying a fixative to the exterior surfaces, and securely covering the ORVCH with a heavy tarp to minimize the spread of loose surface contamination. The enclosures for the old steam generators and old reactor vessel closure heads provide radiation shielding, prevents access to the internal surfaces, and prevents the release of radioactive material into the storage facility.

The six steam generators have a nominal envelope volume of 18,050 ft3 each; for a total volume of 108,300 ft3.

The three reactor vessel closure heads have a nominal envelope volume of 7,172 ft3 each; for a total volume of 21,516 ft3.

The expected waste volume contained within the facility is approximately 130,000 ft3 and is comprised of the six steam

generators, three reactor vessel closure heads, and three reactor vessel closure heads’ lift rigs.

The total radioactivity of the six old steam generators is determined to be 8.45E+03 Curies. The total radioactivity associated with the three old reactor vessel closure heads is determined to be 1.95E+01 Curies. Table 12.2-5a Palo Verde Old Steam Generator and Old Reactor Vessel Closure Head Storage Facility Radioactivity Content provides the radioactivity by item, isotope, and level. The characterization considers the activation of the material and deposition of activation and fission product material on the items. The material is in a solid form.

The original steam generators and reactor vessel closure heads no longer serve a design function, are permanently removed from service, and are placed in storage until final disposal is accomplished. The expected storage time is until Plant decommissioning, not precluding the possibility for earlier disposal.

The source term used as the shielding design input for the old steam generators was 261 Ci of Co-60 per steam generator, and the geometry for the calculation is a horizontal cylinder; see calculation number A0-NC-ZL-0203.

The highest source term used as the shielding design input for the old reactor vessel closure heads was 6.87 Ci of Co-60, and the geometry for the calculation is a vertical cylinder; see calculation number A0-NC-ZL-0206.

Measured dose rates on contact with the facility’s outside walls are less than 0.05 mR/hr.

Radiation surveys are performed semi-annually outside of the structure to ensure the radiation levels meet 10 CFR part 20 requirements. Collection ports are provided to monitor airborne radioactive contaminants without entry into the facility. A water collection sump is provided inside the structure with a sump monitoring port to accommodate checking the collection sump without entry into the facility.

Table 12.2-4
SPENT FUEL POOL COOLING AND CLEANUP SYSTEM
MAXIMUM RADIOACTIVITY INVENTORY (μCi) (Sheet 1 of 2)

Radionuclide	Ion Exchanger	Filter
Kr-83m	0.0	0.0
Kr-85m	0.0	0.0
Kr-85	0.0	0.0
Kr-87	0.0	0.0
Kr-88	0.0	0.0
Kr-89	0.0	0.0
Xe-131m	0.0	0.0
Xe-133m	0.0	0.0
Xe-133	0.0	0.0
Xe-135m	0.0	0.0
Xe-135	0.0	0.0
Xe-137	0.0	0.0
Xe-138	0.0	0.0
Br-83	0.0	0.0
Br-84	0.0	0.0
Br-85	0.0	0.0
I-129	1.3	0.0
I-130	0.0	0.0
I-131	9.1 (+06)	0.0
I-132	0.0	0.0
I-133	4.9 (+02)	0.0
I-134	0.0	0.0
I-135	1.5 (-08)	0.0
Rb-86	0.0	0.0
Rb-88	0.0	0.0
Rb-89	0.0	0.0
Cs-134	2.4 (+06)	0.0
Cs-136	4.7 (+05)	0.0
Cs-137	6.6 (+06)	0.0
Cs-138	0.0	0.0
N-16	0.0	0.0
H-3	0.0	0.0
Y-90	1.0 (+01)	0.0
Y-91m	0.0	0.0
Y-91	7.3 (+03)	0.0

Table 12.2-4
SPENT FUEL POOL COOLING AND CLEANUP SYSTEM
MAXIMUM RADIOACTIVITY INVENTORY (μCi) (Sheet 2 of 2)

Radionuclide	Ion Exchanger	Filter
Y-93	0.0	0.0
Mo-99	1.5 (+05)	0.0
Sr-89	4.7 (+04)	0.0
Sr-90	4.2 (+03)	0.0
Sr-91	1.8 (-06)	0.0
Zr-95	9.6 (+03)	0.0
Nb-95	0.0	0.0
Tc-99m	0.0	0.0
Ru-103	5.0 (+03)	0.0
Ru-106	4.6 (+03)	0.0
Rh-103m	0.0	0.0
Rh-106	0.0	0.0
Te-125m	0.0	0.0
Te-127m	0.0	0.0
Te-127	0.0	0.0
Te-129m	0.0	0.0
Te-129	0.0	0.0
Te-131m	0.0	0.0
Te-131	0.0	0.0
Te-132	9.5 (+04)	0.0
Te-134	0.0	0.0
Ba-137m	0.0	0.0
Ba-140	2.4 (+04)	0.0
La-140	5.3 (+01)	0.0
Ce-141	0.0	0.0
Ce-143	0.0	0.0
Ce-144	1.0 (+04)	0.0
Pr-143	3.3 (+03)	0.0
Pr-144	0.0	0.0
Np-239	0.0	0.0
Cr-51	1.0 (+04)	1.0 (+04)
Mn-54	2.8 (+03)	2.8 (+03)
Fe-55	1.5 (+04)	1.5 (+04)
Fe-59	6.4 (+03)	6.4 (+03)
Co-58	1.1 (+05)	1.1 (+05)
Co-60	2.0 (+04)	2.0 (+04)

Table 12.2-5
MAXIMUM RADIOACTIVITY INVENTORIES OF EQUIPMENT IN THE RADWASTE BUILDING (Ci) (Sheet 1 of 2)

Radionuclide	High TDS Holdup Tank	Low TDS Holdup Tank	Concentrate Monitor Tank	Recycle Monitor Tank	LRS Evaporator	High Activity Spent Resin Tank	Low Activity Spent Resin Tank	LRS Mixed Bed Ion Exchanger	LRS Adsorption Bed
Kr-85m	1.2 (-1)	4.9 (-6)	0.0	4.6 (-7)	0.0	0.0	0.0	0.0	0.0
Kr-85	1.2 (-1)	9.9 (-7)	0.0	2.6 (-2)	0.0	0.0	0.0	0.0	0.0
Kr-87	1.8 (-2)	8.3 (-7)	0.0	2.2 (-8)	0.0	0.0	0.0	0.0	0.0
Kr-88	1.2 (-1)	5.3 (-6)	0.0	3.1 (-7)	0.0	0.0	0.0	0.0	0.0
Xe-131m	5.3 (-1)	2.9 (-6)	0.0	5.9 (-2)	0.0	0.0	0.0	0.0	0.0
Xe-133	3.8 (+1)	8.5 (-4)	0.0	1.9	0.0	0.0	0.0	0.0	0.0
Xe-135	5.9 (-1)	3.8 (-5)	0.0	7.1 (-6)	0.0	0.0	0.0	0.0	0.0
Xe-138	2.3 (-3)	9.5 (-8)	0.0	4.7 (-10)	0.0	0.0	0.0	0.0	0.0
Br-84	2.9 (-4)	9.3 (-7)	0.0	1.0 (-11)	0.0	8.2 (-01)	0.0	1.0 (-8)	1.0 (-8)
I-129	1.2 (-5)	3.2 (-6)	8.7 (-5)	2.5 (-9)	5.2 (-5)	8.8 (-03)	0.0	3.2 (-4)	3.2 (-4)
I-131	3.0 (+1)	8.3	1.4 (+1)	6.0 (-3)	5.5 (+1)	2.9 (+04)	4.2 (+01)	3.3 (+1)	3.3 (+1)
I-132	2.6 (-2)	9.3 (-4)	0.0	4.4 (-8)	0.0	7.1 (+01)	0.0	4.4 (-5)	4.4 (-5)
I-133	1.8	5.5 (-1)	8.2 (-5)	2.0 (-4)	3.0 (-3)	3.6 (+03)	0.0	2.4 (-1)	2.4 (-1)
I-134	7.8 (-3)	5.9 (-5)	0.0	1.1 (-9)	0.0	2.3 (+01)	0.0	1.1 (-6)	1.1 (-6)
I-135	2.9 (-1)	3.0 (-2)	1.7 (-13)	4.2 (-6)	2.0 (-11)	7.6 (+02)	0.0	4.1 (-3)	4.1 (-3)
Rb-88	1.2 (-2)	1.3 (-5)	0.0	3.9 (-9)	0.0	2.4 (+01)	0.0	3.9 (-8)	3.9 (-8)
Rb-89	6.1 (-4)	2.6 (-7)	0.0	7.0 (-11)	0.0	1.2	0.0	6.9 (-10)	6.9 (-10)
Cs-134	2.0 (+1)	5.2	1.4 (+2)	2.1 (-1)	8.4 (+1)	1.3 (+04)	2.3 (+02)	2.3 (+2)	2.3 (+2)
Cs-136	1.5	4.5 (-1)	1.6	1.7 (-2)	3.9	5.3 (+02)	1.0	1.5	1.5
Cs-137	8.7 (+1)	2.3 (+1)	6.3 (+2)	9.2 (-1)	3.8 (+2)	3.9 (+04)	1.2 (+03)	1.2 (+3)	1.2 (+3)
Cs-138	7.8 (-3)	3.0 (-5)	0.0	1.7 (-8)	0.0	1.4 (+01)	0.0	1.7 (-7)	1.7 (-7)
H-3	2.2	1.4 (-1)	3.6 (-1)	5.7 (-1)	2.2 (-1)	0.0	0.0	0.0	0.0
Y-90	9.1 (-4)	4.8 (-4)	2.6 (-5)	2.9 (-7)	3.0 (-4)	1.2 (-01)	0.0	6.3 (-4)	6.3 (-4)
Y-91	1.7	5.0 (-1)	7.4	3.9 (-4)	6.8	3.8 (+01)	1.3 (+01)	1.4 (+1)	1.4 (+1)
Mo-99	3.8	1.8	1.2 (-1)	1.1 (-3)	1.4	1.7 (+03)	2.0	2.4	2.4
Sr-89	3.0 (-1)	8.2 (-2)	1.2	6.4 (-5)	1.1	2.2 (+02)	2.0	2.0	2.0
Sr-90	6.3 (-2)	1.7 (-2)	4.6 (-1)	1.3 (-5)	2.7 (-1)	3.0 (+01)	1.0	1.7	1.7
Sr-91	1.1 (-3)	1.1 (-4)	2.0 (-12)	2.2 (-8)	1.6 (-10)	2.8	0.0	2.2 (-5)	2.2 (-5)
Zr-95	5.4 (-1)	1.5 (-1)	2.4	1.2 (-4)	2.1	5.0 (+01)	0.0	4.6	4.6
Nb-95	1.2 (-5)	0.0	3.6 (-5)	2.0 (-13)	4.2 (-5)	0.0	0.0	4.4 (-9)	4.4 (-9)
Ru-103	3.7 (-1)	1.1 (-1)	1.2	8.3 (-5)	1.4	2.2 (+01)	2.0	2.1	2.1
Ru-106	3.9 (-1)	1.1 (-1)	2.6	8.3 (-5)	1.6	3.0 (+01)	8.0	8.1	8.1
Te-129	1.9 (-4)	2.8 (-6)	0.0	6.8 (-11)	0.0	5.2 (-01)	0.0	6.7 (-8)	6.7 (-8)
Te-132	8.4 (-1)	3.0 (-1)	4.6 (-2)	1.9 (-4)	4.4 (-1)	7.4 (+02)	0.0	4.9 (-1)	4.9 (-1)
Te-134	3.2 (-4)	2.4 (-6)	0.0	3.5 (-11)	0.0	9.5 (-01)	0.0	3.5 (-8)	3.5 (-8)
Ba-140	1.2 (-1)	3.4 (-2)	1.2 (-1)	2.5 (-5)	3.0 (-1)	7.4 (+01)	0.0	2.1 (-1)	2.1 (-1)
La-140	4.9 (-3)	2.6 (-3)	1.9 (-5)	1.3 (-6)	3.6 (-4)	3.4	0.0	2.1 (-3)	2.1 (-3)
Ce-144	8.3 (-1)	2.3 (-1)	5.3	1.8 (-4)	3.5	7.0 (+01)	1.6 (+01)	1.6 (+1)	1.6 (+1)
Pr-143	9.0 (-2)	2.9 (-2)	1.0 (-1)	2.1 (-5)	2.4 (-1)	1.0 (+01)	0.0	1.9 (-1)	1.9 (-1)
Cr-51	7.7 (-2)	2.1 (-2)	2.0 (-1)	1.6 (-5)	2.6 (-1)	5.5	0.0	2.9 (-1)	2.9 (-1)
Mn-54	7.2 (-2)	1.9 (-2)	4.7 (-1)	1.5 (-5)	3.1 (-1)	4.8	1.0	1.4	1.4
Fe-55	4.6 (-1)	1.2 (-1)	3.2	9.8 (-5)	2.0	3.0 (+01)	1.1 (+01)	1.1 (+1)	1.1 (+1)
Fe-59	6.6 (-2)	1.8 (-2)	2.4 (-1)	1.4 (-5)	2.5 (-1)	4.6	0.0	4.0 (-1)	4.0 (-1)
Co-58	1.6	4.5 (-1)	7.6	3.5 (-4)	6.5	1.1 (+02)	1.4 (+01)	1.5 (+1)	1.5 (+1)
Co-60	6.1 (-1)	1.6 (-1)	4.3	1.3 (-4)	2.6	4.0 (+01)	1.5 (+01)	1.5 (+1)	1.5 (+1)

Table 12.2-5
MAXIMUM RADIOACTIVITY INVENTORIES OF EQUIPMENT
IN THE RADWASTE BUILDING (Ci) (Sheet 2 of 2)

Radionuclide	Waste Gas Surge Tank	Waste Gas Decay Tank	Boric Acid Condensate IX	Radionuclide	Waste Gas Surge Tank	Waste Gas Decay Tank	Boric Acid Condensate IX
Kr-83m	1.7 (+1)	1.1	0.0	Mo-99	1.2 (-3)	2.3 (-3)	2.3 (-6)
Kr-85m	1.1 (+2)	1.4 (+1)	3.3 (-8)	Sr-89	5.2 (-6)	6.7 (-5)	4.8 (-8)
Kr-85	1.7 (+2)	3.3 (+3)	2.9 (-8)	Sr-90	1.5 (-7)	3.3 (-6)	1.7 (-9)
Kr-87	4.5 (+1)	2.2	9.2 (-9)	Sr-91	9.0 (-6)	2.6 (-6)	4.9 (-9)
Kr-88	1.8 (+2)	1.6 (+1)	5.7 (-8)	Zr-95	9.0 (-7)	1.3 (-5)	8.7 (-9)
Kr-89	3.8 (-1)	7.1 (-3)	0.0	Nb-95	7.3 (-7)	8.3 (-6)	0.0
Xe-131m	1.2 (+2)	7.3 (+2)	1.3 (-7)	Tc-99m	6.2 (-4)	1.2 (-4)	0.0
Xe-133m	2.5 (+2)	3.2 (+2)	0.0	Ru-103	6.6 (-7)	7.8 (-6)	5.7 (-9)
Xe-133	2.0 (+4)	6.2 (+4)	9.9 (-6)	Ru-106	1.5 (-7)	3.0 (-6)	2.3 (-9)
Xe-135m	4.0	9.3 (-2)	0.0	Rh-103m	3.8 (-7)	1.7 (-8)	0.0
Xe-135	3.9 (+2)	9.3 (+1)	2.6 (-7)	Rh-106	1.7 (-9)	3.5 (-11)	0.0
Xe-137	8.7 (-1)	1.6 (-2)	0.0	Te-125m	4.2 (-7)	5.7 (-6)	0.0
Xe-138	1.2 (+1)	2.8 (-1)	1.2 (-9)	Te-127m	4.2 (-6)	6.7 (-5)	0.0
Br-83	5.4 (-5)	4.7 (-6)	0.0	Te-127	1.2 (-5)	3.3 (-6)	0.0
Br-84	1.6 (-5)	5.7 (-7)	6.7 (-10)	Te-129m	2.1 (-5)	2.3 (-4)	0.0
Br-85	2.9 (-7)	6.1 (-9)	0.0	Te-129	1.5 (-5)	7.8 (-7)	8.9 (-10)
I-129	0.0	0.0	1.9 (-9)	Te-131m	3.7 (-5)	3.2 (-5)	0.0
I-130	2.9 (-5)	1.1 (-5)	0.0	Te-131	6.0 (-6)	1.9 (-7)	0.0
I-131	4.1 (-3)	2.1 (-2)	3.8 (-3)	Te-132	4.1 (-4)	9.1 (-4)	5.6 (-5)
I-132	1.1 (-3)	9.6 (-5)	2.4 (-7)	Te-134	0.0	0.0	1.0 (-9)
I-133	5.4 (-3)	3.3 (-3)	8.9 (-5)	Ba-137m	1.3 (-5)	2.8 (-7)	0.0
I-134	3.8 (-4)	1.7 (-5)	3.0 (-8)	Ba-140	3.3 (-6)	2.3 (-5)	4.8 (-8)
I-135	2.5 (-3)	5.2 (-4)	7.1 (-6)	La-140	2.2 (-6)	2.5 (-6)	4.9 (-9)
Rb-86	4.2 (-7)	4.7 (-6)	0.0	Ce-141	1.0 (-6)	1.1 (-5)	0.0
Rb-88	3.0 (-4)	1.1 (-5)	2.9 (-8)	Ce-143	5.8 (-7)	5.5 (-7)	0.0
Rb-89	0.0	0.0	1.5 (-9)	Ce-144	4.9 (-7)	9.4 (-6)	5.5 (-9)
Cs-134	1.2 (-4)	3.4 (-3)	4.5 (-7)	Pr-143	7.3 (-7)	5.3 (-6)	6.2 (-9)
Cs-136	6.6 (-5)	6.1 (-4)	1.9 (-7)	Pr-144	1.4 (-7)	4.0 (-9)	0.0
Cs-137	9.0 (-5)	2.6 (-3)	1.2 (-6)	Np-239	1.7 (-5)	2.8 (-5)	0.0
Cs-138	0.0	0.0	1.9 (-8)	Cr-51	3.2 (-4)	2.9 (-3)	1.9 (-9)
H-3	0.0	0.0	0.0	Mn-54	5.2 (-5)	8.9 (-4)	1.9 (-9)
Y-90	1.8 (-8)	9.5 (-1)	1.6 (-10)	Fe-55	2.7 (-4)	5.0 (-3)	3.7 (-10)
Y-91M	2.8 (-6)	1.2 (-7)	0.0	Fe-59	1.7 (-4)	1.8 (-3)	1.1 (-9)
Y-91	9.4 (-7)	1.3 (-5)	7.0 (-9)	Co-58	2.7 (-3)	3.4 (-2)	1.8 (-8)
Y-93	4.5 (-7)	1.4 (-7)	0.0	Co-60	3.3 (-4)	6.3 (-3)	2.4 (-9)

Table 12.2-5a
Palo Verde Old Steam Generator and Old Reactor Vessel Closure Head Storage Facility Radioactivity Content (Curies)

Nuclide	**Unit 1**		**Unit 2**		**Unit 3**		**Unit 1**	**Unit 2**	**Unit 3**
	OSG 'A'	**OSG 'B'**	**OSG 'A'**	**OSG 'B'**	**OSG 'A'**	**OSG 'B'**	**ORVCH**	**ORVCH**	**ORVCH**
H-3	1.92E+01	1.93E+01	9.23E+00	8.42E+00	1.50E+01	1.65E+01	5.12E-03	6.26E-03	5.07E-03
C-14	1.62E+00	1.63E+00	5.29E+00	4.83E+00	6.98E+00	7.66E+00	2.32E-02	2.89E-02	2.05E-02
Cr-51	5.61E+01	5.64E+01	6.04E+01	5.51E+01	7.24E+01	7.95E+01	NP	NP	NP
Mn-54	1.11E+01	1.12E+01	1.16E+01	1.06E+01	6.81E+00	7.48E+00	2.68E-02	2.27E-02	3.20E-02
Fe-55	8.62E+02	8.66E+02	8.54E+02	7.80E+02	4.80E+02	5.27E+02	3.05E+00	3.42E+00	3.30E+00
Fe-59	3.09E+01	3.11E+01	2.58E+01	2.35E+01	2.47E+01	2.71E+01	NP	NP	NP
Co-57	1.11E+00	1.12E+00	NP	NP	6.19E-01	6.80E-01	3.68E-03	2.85E-03	5.08E-03
Co-58	2.73E+02	2.74E+02	3.25E+02	2.97E+02	1.48E+02	1.63E+02	3.75E-04	7.62E-05	1.85E-03
Co-60	1.19E+02	1.19E+02	1.38E+02	1.26E+02	5.74E+01	6.30E+01	1.46E+00	1.84E+00	2.07E+00
Ni-59	8.72E-01	8.77E-01	1.18E+00	1.07E+00	NP	NP	1.86E-01	2.31E-01	1.64E-01
Ni-63	4.62E+01	4.64E+01	6.54E+01	5.97E+01	2.52E+01	2.77E+01	1.10E+00	1.37E+00	1.05E+00
Zn-65	NP	NP	NP	NP	NP	NP	8.94E-05	7.11E-05	6.27E-05
Sr-89	5.25E-02	5.28E-02	2.41E-01	2.20E-01	2.54E-02	2.79E-02	NP	NP	NP
Sr-90	8.42E-03	8.47E-03	3.38E-02	3.09E-02	1.05E-02	1.15E-02	5.44E-04	6.69E-04	4.84E-04
Zr-95	2.88E+01	2.90E+01	8.37E+01	7.64E+01	3.92E+01	4.30E+01	NP	NP	5.34E-05
Nb-94	NP	NP	NP	NP	NP	NP	2.33E-06	3.23E-06	4.54E-06
Nb-95	5.44E+01	5.47E+01	1.29E+02	1.18E+02	6.30E+01	6.92+01	NP	NP	NP
Tc-99	*<1.41E-02*	*<1.42E-02*	5.84E-03	5.33E-03	*<1.03E-02*	*<1.13E-02*	NP	NP	NP
Ru-103	9.82E-01	9.88E-01	1.77E+00	1.62E+00	NP	NP	NP	NP	NP
Ag-110m	1.55E+00	1.56E+00	NP	NP	NP	NP	NP	NP	NP
Sn-113	3.40E+00	3.42E+00	3.58E+00	3.27E+00	2.08E+00	2.29E+00	5.12E-05	NP	1.31E-04
Sb-124	1.04E+01	1.05E+01	3.58E+01	3.26E+01	5.78E+00	6.34E+00	NP	NP	
Sb-125	5.36E+00	5.39E+00	9.97E+00	9.10E+00	3.32E+00	3.64E+00	2.26E-02	2.47E-02	2.24E-02
Te-123m	2.09E-01	2.10E-01	4.33E-01	3.95E-01	5.09E-01	5.59E-01	NP	NP	NP
I-129	*<1.66E-02*	*<1.67E-03*	*<8.33E-03*	*<7.60E-03*	*<1.07E-03*	*<4.47E-03*	NP	NP	NP
Cs-134	4.24E-01	4.26E-01	3.11E-01	2.84E-01	NP	NP	NP	NP	NP
Cs-137	2.36E-02	2.37E-02	1.98E-01	1.80E-01	1.33E-02	1.46E-02	7.61E-03	9.36E-03	6.76E-03
Ce-141	8.26E-02	8.31E-02	6.94E-01	6.33E-01	NP	NP	NP	NP	NP
Ce-144	1.33E-01	1.34E-01	1.43E+00	1.31E+00	6.46E-01	7.10E-01	2.34E-03	1.85E-03	3.16E-03
Pu-238	7.60E-02	7.64E-02	9.98E-03	9.11E-03	8.42E-04	9.25E-04	7.81E-05	9.68E-05	6.88E-05
Pu-239	2.87E-02	2.88E-02	7.24E-03	6.60E-03	4.06E-04	4.46E-04	5.83E-05	7.26E-05	5.12E-05
Pu-241	2.15E+00	2.16E+00	6.22E-01	5.68E-01	2.18E-02	2.40E-02	2.01E-03	2.44E-03	1.80E-03
Am-241	1.39E-01	1.40E-01	8.27E-03	7.55E-03	7.59E-04	8.33E-04	2.26E-04	2.81E-04	1.98E-04
Cm-242	1.15E-01	1.15E-01	3.94E-02	3.60E-02	8.71E-04	9.56E-04	4.72E-06	2.68E-06	8.80E-06
Cm-243	8.62E-02	8.66E-02	1.20E-02	1.09E-02	6.19E-04	6.80E-04	7.51E-05	9.24E-05	6.67E-05
Total:	1.53E+03	1.54E+03	1.76E+03	1.61E+03	9.52E+02	1.05E+03	5.89E+00	6.96E+00	6.68E+00
Reference	11/29/05	11/29/05	10/31/03	10/31/03	11/01/07	11/01/07	06/01/13	06/01/13	06/01/13

NP = Not present

Values shown in italics are lower limit of detection values.

12.2.2 AIRBORNE RADIOACTIVE MATERIAL SOURCES

This section deals with the models, parameters, and sources required to evaluate airborne concentrations of radionuclides during plant operations in various plant radiation areas where personnel occupancy is expected.

Leakage sources are dependent upon the concentrations of radionuclides in the primary system, secondary system, spent fuel pool, and the refueling pool. The assumptions and parameters required to evaluate the isotopic airborne concentrations in the various applicable regions are listed in table 12.2-6. The chemical and volume control system (CVCS) and the spent fuel pool cooling and cleanup system (SFPCCS) were designed to purify reactor coolant through ion exchangers after reactor shutdown and cooldown. This ensures that the effect of activity spikes will not significantly contribute to the containment airborne activity during refueling operations. The contribution to airborne activity due to reactor vessel head removal is considered negligible as the reactor vessel head vent is connected to the gaseous radwaste system.

The detailed listing of the expected airborne isotopic concentrations in the applicable regions is presented in table 12.2-7. The final design of the plant ensures that the expected airborne isotopic concentrations in the applicable regions are well below the maximum permissible concentration for the critical organ for the appropriate isotope for occupational workers, as adjusted on the basis of expected weekly occupancy in the regions.

Table 12.2-6
ASSUMPTIONS USED IN DETERMINING AIRBORNE RADIOACTIVITY (Sheet 1 of 2)

Item	Value	Reference
Leakage		NUREG-0017
Primary to secondary, lb/d	100	
Auxiliary and radwaste building (with respect to primary coolant), lb/d	160	
Turbine building, lb/h	1,700	
Charging pump room, gal/h	1	Table 11.1-3
Auxiliary building IX valve gallery, gal/h	0.15	
Radwaste building conc tank valve gallery, gal/h	0.05	
Radwaste building LRS pumps valve gallery, gal/h	0.22	
Iodine partition factors		
Steam generators	0.01	Table 11.1-6
All buildings except containment	0.0075	NUREG-0017
Containment (fraction of RCS iodine released to building atmosphere per day)	0.00001	NUREG-0017
Building/area vent flowrates, ft^3/min		
Containment		
Refueling purge exhaust (high volume)	33,000	
Normal purge exhaust (low volume)		

Table 12.2-6
ASSUMPTIONS USED IN DETERMINING AIRBORNE RADIOACTIVITY (Sheet 2 of 2)

Item	Value	Reference
Building/area vent flowrates, ft^3/min (cont)		
Fuel building exhaust	42,686	
Auxiliary building exhaust	58,400	
Turbine building exhaust	443,100	
Charging pump room	1,100	
Auxiliary building IX valve gallery	400	
Radwaste building conc tank valve gallery	250	
Radwaste building LRS pumps valve gallery	500	
Building/area free volumes, ft^3		
Containment	2.6×10^6	
Fuel building	7.5×10^5	
Turbine building	6.9×10^6	
Auxiliary building	1.2×10^6	
Charging pump room	8.5×10^3	
IX valve gallery	4.0×10^3	
Radwaste building	4.6×10^5	
Concentrate tanks valve gallery	1.5×10^3	
LRS pump valve gallery	4.4×10^3	

12.2.2.1 Model for Calculating Airborne Concentrations

Plant areas with airborne radioactivity are characterized by a constant leakrate of a radioactive source at a constant source strength with a constant exhaust rate of the contaminant. This leads to a peak or equilibrium airborne concentration of the radioisotope in the regions as calculated by the following equation:

$$C_i(t) = (L\,R)_i\,A_i\,(P\,F)_i\,\frac{\left(1 - e^{-\lambda_{Ti}t}\right)}{\left(V\,\lambda_{Ti}\right)} \qquad (1)$$

where:

$(L\ R)_i$ = leak or evaporation rate of the i^{th} radioisotope in g/s, in the applicable region,

and

A_i = activity concentration of the i^{th} leaking or evaporating radioisotope in μCi/g

$(P\ F)_i$ = partition factor or the fraction of the leaking activity that is airborne for the i^{th} radioisotope

λ_{Ti} = total removal rate constant for the i^{th} radioisotope in s^{-1} from the applicable region

$= (\lambda_{di} + \lambda_e)$

(λ_{di} and λe are the removal rate constants in s^{-1} due to radioactive decay and the exhaust

from the applicable region respectively for the i^{th} radioisotope)

t = time interval between the start of the leak and the time at which the concentration is evaluated in seconds

V = free volume of the region in which the leak occurs in cm^3

C_i (t) = airborne concentration of the i^{th} radioisotope at time t in $\mu Ci/cm^3$ in the applicable region

From the above equation, it is evident that the peak or equilibrium concentration, $C_{Eq,i}$ of the i^{th} radioisotope in the applicable region will be given by the following expression:

$$C_{Eq,i} = (L\ R)_i\ A_i\ (P\ F)_i\ /\ (V\ \lambda_{Ti}) \qquad (2)$$

With high exhaust rates, this peak concentration will be reached within a few hours.

Table 12.2-7
NORMAL AIRBORNE RADIOACTIVITY CONCENTRATIONS
(μCi/cm^3)[(a)]

Radionuclide[1]	MPC Air (μCi/cm^3) (40 hr week)	Containment Bldg Power Access	Containment Bldg Refueling	Fuel Bldg	Auxiliary Building Corridor	Auxiliary Building Charging Pump Room	Auxiliary Building IX Valve Gallery	Radwaste Building Corridor	Radwaste Building Conc Tk Valve Gallery	Radwaste Building LRS Pumps Valve Gallery	Turbine Bldg Operating Deck
Kr-83m	1(-6)	2.63E-07	-	-	5.83E-10	4.28E-08	1.39E-08	5.67E-10	-	-	1.28E-14
Kr-85m	6(-6)	3.10E-06	-	-	3.41E-09	2.35E-07	7.38E-08	3.32E-09	-	-	7.28E-14
Kr-85	1(-6)	3.78E-04	-	-	4.95E-09	3.21E-07	1.03E-07	4.82E-09	-	3.24E-09	1.06E-13
Kr-87	1(-6)	5.32E-07	-	-	1.54E-09	1.18E-07	3.75E-08	1.50E-09	-	-	3.64E-14
Kr-88	1(-6)	3.77E-06	-	-	5.83E-09	4.17E-07	1.28E-07	5.67E-09	-	1.19E-15	1.28E-13
Kr-89	1(-6)	1.94E-09	-	-	2.31E-11	3.96E-09	1.06E-09	2.25E-11	-	-	1.50E-15
Xe-131m	2(-6)	9.86E-05	-	-	3.52E-09	2.35E-07	7.49E-08	2.35E-09	-	9.40E-10	5.67E-14
Xe-133m	1(-6)	5.65E-05	-	-	7.04E-09	4.71E-07	1.39E-07	6.85E-09	-	4.86E-11	1.50E-13
Xe-133	1(-5)	9.49E-03	-	-	5.83E-07	3.85E-05	1.28E-05	5.67E-07	-		1.28E-11
Xe-135m	1(-6)	2.46E-08	-	-	1.87E-10	2.03E-08	6.10E-09	1.82E-10	-	-	6.10E-15
Xe-135	4(-6)	1.84E-05	-	-	1.10E-08	7.49E-07	2.46E-07	1.07E-08	-	6.70E-15	2.46E-13
Xe-137	1(-6)	4.18E-09	-	-	4.73E-11	8.13E-09	2.14E-09	4.60E-11	-	-	2.89E-15
Xe-138	1(-6)	7.53E-08	-	-	6.05E-10	6.85E-08	2.03E-08	5.89E-10	-	-	2.03E-14
Br-83	3(-9)	2.63E-11	-	-	4.86E-12	7.35E-12	1.26E-11	4.73E-12	-	-	2.00E-15
Br-84	1(-6)	3.32E-13	-	-	8.75E-13	3.57E-12	6.09E-12	8.51E-13	-	-	-
Br-85	1(-6)	3.49E-14	-	-	1.05E-14	1.68E-13	2.42E-13	1.02E-14	-	-	-
I-130	3(-9)	5.26E-11	-	-	3.89E-12	3.36E-12	6.09E-12	3.78E-12	-	-	1.79E-15
I-131	9(-9)	7.04E-08	-	-	6.37E-10	4.31E-10	7.77E-10	6.20E-10	8.40E-14	1.05E-11	3.36E-13
I-132	2(-7)	5.28E-10	-	-	9.94E-11	1.58E-10	2.73E-10	9.66E-11	-	-	3.15E-14
I-133	3(-8)	1.56E-08	-	-	7.88E-10	6.09E-10	1.05E-09	7.67E-10	-	1.16E-14	3.78E-13
I-134	5(-7)	9.80E-11	-	-	2.38E-11	6.83E-11	1.16E-10	2.31E-11	-	-	6.83E-15
I-135	1(-7)	2.67E-09	-	-	3.02E-10	2.94E-10	5.36E-10	2.94E-10	-	-	1.37E-13
CR-51	2(-6)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Mn-54	4(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Co-57	2(-7)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Co-58	5(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Co-60	9(-9)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Fe-59	5(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Sr-89	3(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Sr-90	1(-9)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Zr-95	3(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Nb-95	1(-7)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Ru-103	8(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Ru-106	6(-9)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Sb-125	3(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Cs-134	1(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Cs-136	2(-7)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Cs-137	1(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Ba-140	4(-8)	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
Ce-141	2(-7)	9.63E-11	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13	<1.0E-13
H-3	5(-6)	6.29E-07	2.50E-06	4.16E-07	1.65E-08	1.65E-08	1.65E-08	1.65E-08	1.65E-08	1.65E-08	3.80E-11
C-14	4(-6)	7.35E-08	-	-	-	-	-	-	-	-	
AR-41	2(-6)	1.93E-06	-	-	-	-	-	-	-	-	
Total		1.01E-02	2.50E-06	4.16E-07	6.40E-07	4.12E-05	1.37E-05	6.22E-07	1.65E-08	2.07E-08	5.26E-11

a. Numbers in parentheses denote powers of 10.

1. Particulate isotopes are unlikely to become airborne due to their high affinity for chemical binding and large atomic mass. Particulate concentrations are assumed to be less than 1.0E-13 µCi/cc.

12.2.3 SOURCES USED IN NUREG-0737 POST-ACCIDENT SHIELDING REVIEW

The post-accident shielding review described in paragraph 12.1.2.4 used initial core releases equivalent to those recommended in Regulatory Guides 1.4 and 1.7, and Standard Review Plan 15.6.5, and considered two LOCA events. The first was a LOCA with recirculation accomplished via the containment sump. The second was a LOCA with an intact primary with recirculation accomplished via the shutdown cooling system. The following core releases were used in the review:

A. Source A: Containment airborne: 100% noble gases, 25% iodines - see table 12.2-8.

B. Source B: Reactor coolant: 100% noble gases, 50% halogens, 1% solids - see table 12.2-9

C. Source C: Containment sump: 50% halogens, 1% solids - see table 12.2-10.

Volumes used for each source were:

A. Source A: Containment free volume of 2.6×10^6 cubic feet.

B. Source B: Reactor coolant system (RCS) volume of 1.37×10^4 cubic ft.

C. Source C: The minimum volume of water, 8.99×10^4 cubic feet present at the time of recirculation. (RCS + refueling water tank + safety injection tanks.)

A LOCA with sump recirculation is represented by sources A and C. An intact primary-degraded core LOCA is represented by sources A and B (source A was not reduced even though there is no mechanism to assume noble gases in both sources). The

systems assumed to be operating for each event are shown in table 12.2-11. The results of the shield review are presented in paragraph 12.3.1.3.

Time integrating dose curves, normalized to initial time equals zero, were developed for the sources as an aid in developing post-accident access plans. These curves are presented as figures 12.2-1 (A) (source A), 12.2-2 (A) (source B), and 12.2-3 (A) (source C).

TABLE 12.2-8
LOCA SOURCE A - CONTAINMENT AIRBORNE
(Curies)

Nuclide	Activity (4070 MWt)
Kr-85m	5.28E+07
Kr-85	1.79E+06
Kr-87	8.77E+07
Kr-88	1.30E+08
Kr-89	1.69E+08
Kr-90	2.03E+08
I-129	1.79E+00
I-131	2.55E+07
Xe-131m	1.06E+06
I-132	3.87E+07
I-133	5.72E+07
Xe-133	2.29E+08
I-134	6.69E+07
I-135	5.19E+07
Xe-135m	7.39E+07
Xe-135	2.18E+08
I-137	2.38E+07
Xe-137	2.17E+08
Xe-138	2.02E+08

12.2-9
4070 MWt LOCA SOURCE B – REACTOR COOLANT
(Curies)

Nuclide	Activity	Nuclide	Activity	Nuclide	Activity
Se-84	1.54E+05	Sn-129	1.20E+05	Cs-140	1.32E+06
Br-84	7.92E+06	Sb-129	3.01E+05	Ba-140	1.54E+06
As-85	2.21E+04	Te-129m	5.83E+04	La-140	1.64E+06
Se-85	5.98E+04	Te-129	2.87E+05	La-143	1.24E+06
Br-85	8.41E+06	I-129	3.58E+00	Ce-143	1.26E+06
Kr-85m	5.28E+07	Sn-131	2.58E+05	Pr-143	1.22E+06
Kr-85	1.79E+06	Sb-131	6.77E+05	Ce-144	1.30E+06
Br-87	1.31E+07	Te-131m	1.91E+05	Pr-144	1.30E+06
Kr-87	8.77E+07	Te-131	7.42E+05		
Kr-88	1.30E+08	I-131	5.11E+07		
Rb-88	4.70E+05	Xe-131m	1.06E+06		
Br-89	8.84E+06	Sn-132	2.14E+05		
Kr-89	1.69E+08	Sb-132	4.27E+05		
Sr-89	6.22E+05	Te-132	1.27E+06		
Br-90	5.04E+06	I-132	7.75E+07		
Kr-90	2.03E+08	Sb-133	5.45E+05		
Rb-90	5.42E+05	Te-133m	7.71E+05		
Sr-90	1.59E+05	Te-133	9.47E+05		
Y-90	1.65E+05	I-133	1.14E+08		
Rb-91	7.59E+06	Xe-133	2.29E+08		
Sr-91	8.32E+05	Cs-134	4.24E+05		
Y-91m	4.82E+05	Te-134	1.48E+06		
Y-91	8.53E+05	I-134	1.34E+08		
Sr-95	1.02E+06	Te-135	8.65E+05		
Y-95	1.30E+06	I-135	1.04E+08		
Zr-95	1.35E+06	Xe-135m	7.39E+07		
Nb-95	1.35E+06	Xe-135	2.18E+08		
Zr-99	1.46E+06	Cs-135	9.79E-01		
Mo-99	1.63E+06	Cs-136	9.18E+04		
Tc-99m	1.46E+06	I-137	1.06E+08		
Mo-103	1.55E+06	Xe-137	2.17E+08		
Tc-103	1.57E+06	Cs-137	2.40E+05		
Ru-103	1.59E+06	Ba-137m	2.28E+05		
Tc-106	9.09E+05	Xe-138	2.02E+08		
Ru-106	9.01E+05	Cs-138	1.61E+06		

TABLE 12.2-10
4070 MWt LOCA SOURCE C - CONTAINMENT SUMP
(Curies)

Nuclide	Activity	Nuclide	Activity	Nuclide	Activity
Se-84	1.54E+05	Sn-129	1.20E+05	Cs-140	1.32E+06
Br-84	7.92E+06	Sb-129	3.01E+05	Ba-140	1.54E+06
Se-85	5.98E+04	Te-129m	5.83E+04	La-140	1.64E+06
Br-85	8.41E+06	Te-129	2.87E+05	La-143	1.24E+06
Br-87	1.31E+07	I-129	3.58E+00	Ce-143	1.26E+06
Rb-88	4.70E+05	Sn-131	2.58E+05	Pr-143	1.22E+06
Br-89	8.84E+06	Sb-131	6.77E+05	Ce-144	1.30E+06
Sr-89	6.22E+05	Te-131m	1.91E+05	Pr-144	1.30E+06
Rb-90	5.42E+05	Te-131	7.42E+05		
Sr-90	1.59E+05	I-131	5.11E+07		
Y-90	1.65E+05	Sn-132	2.14E+05		
Rb-91	7.59E+06	Sb-132	4.27E+05		
Sr-91	8.32E+05	Te-132	1.27E+06		
Y-91m	4.82E+05	I-132	7.75E+07		
Y-91	8.53E+05	Sb-133	5.45E+05		
Sr-95	1.02E+06	Te-133m	7.71E+05		
Y-95	1.30E+06	Te-133	9.47E+05		
Zr-95	1.35E+06	I-133	1.14E+08		
Nb-95	1.35E+06	Cs-134	4.24E+05		
Zr-99	1.46E+06	Te-134	1.48E+06		
Mo-99	1.63E+06	I-134	1.34E+08		
Tc-99m	1.46E+06	Te-135	8.65E+05		
Mo-103	1.55E+06	I-135	1.04E+08		
Tc-103	1.57E+06	Cs-135	9.79E-01		
Ru-103	1.59E+06	Cs-136	9.18E+04		
Tc-106	9.09E+05	I-137	1.06E+08		
Ru-106	9.01E+05	Cs-137	2.40E+05		
		Ba-137m	2.28E+05		
		Cs-138	1.61E+06		

Table 12.2-11
SYSTEMS USED IN POST-ACCIDENT SHIELDING REVIEW[a][b]

Source Type	LOCA with Sump Recirculation	LOCA - Degraded Core - Intact Primary
A	• Containment air • Hydrogen control system	• Containment air • Hydrogen control system
B		• Safety injection system • Containment spray system • Shutdown cooling system • Post-accident sampling system • Letdown system[c]
C	• Safety injection system • Containment spray system • Shutdown cooling system • Post-accident sampling system • Letdown System[c]	

a. Where redundant systems exist, both are assumed in use.

b. Radwaste systems not used post-accident.

c. Portions up to purification filter inlet.

12.3 RADIATION PROTECTION DESIGN FEATURES

12.3.1 FACILITY DESIGN FEATURES

Specific design features to maintain personnel exposures as low as reasonably achievable (ALARA) are discussed in this section. The design features recommendations given in Regulatory Guide 8.8, Paragraph C.2, are utilized to minimize exposures to personnel.

Facilities and equipment of a specialized nature for handling special nuclear source and byproduct material are not required except for fuel handling and radioactive waste processing. Fuel handling and radwaste processing equipment are described in section 9.1 and chapter 11, respectively. Materials handled in the radiochemistry laboratory and low activity sealed sources used for laboratory calibration purposes do not require special handling equipment. Unsealed sources and radioactive samples that pose an airborne contamination hazard are handled in conventional hoods which exhaust to the auxiliary building ventilation system, described in section 9.4.

12.3.1.1 Plant Design Description for ALARA

Equipment and plant design features employed to maintain radiation exposures ALARA are based upon the design considerations of section 12.1 and are outlined here for several general classes of equipment (paragraph 12.3.1.1.1) and several typical plant layout situations (paragraph 12.3.1.1.2).

12.3.1.1.1 Common Equipment and Component Designs for ALARA

Refer to CESSAR Section 12.3.1.2 for components in CESSAR scope

12.3.1.1.1.1 Filters. Filters in the auxiliary building that accumulate radioactive particles are supplied with the means to perform cartridge replacement with remote tools. Cartridge replacement of the blowdown demineralizer filter may utilize long-handled tools, as needed to maintain exposures ALARA.

Cartridge filters have adequate space for removal, cask loading, and transport. A filter handling system has been incorporated into PVNGS for all filters that could constitute a substantial radiation source. The use of the handling system is based upon ALARA principals. In use, the handling system is placed over the filter in the space normally occupied by its concrete hatch. The lead base of the system adequately attenuates cartridge radiation. A leaded glass window provides the operator with a complete view of the filter housing and cartridge while he is performing the changeout with remote tools. The cartridge can then be lifted into a shield cask placed on the base. The shielding provided by the filter handling system ensures the operators exposure is maintained ALARA while removing and transporting filters. An overhead monorail is used to transport cask and cartridge to the radwaste storage area.

12.3.1.1.1.2 Ion Exchangers. With the exception of potentially radioactive blowdown processing system ion exchangers, ion exchangers for radioactive systems are designed

so that spent resins can be remotely and hydraulically transferred to spent resin tanks and that fresh resin can be loaded into the ion exchanger remotely.

Underdrains and downstream strainers are designed for full system pressure drop. The ion exchangers and piping are designed with provisions for being flushed with compressed air or nitrogen, or demineralized water.

12.3.1.1.1.3 Evaporators. The liquid radwaste system (LRS) evaporator is provided with chemical addition connections to allow the use of chemicals for descaling operations. Space is provided to allow uncomplicated removal of heating tube bundles. The nonradioactive components are separated from those that are radioactive by a shield wall. Instruments and controls necessary for evaporator operation are located on the design radiation zone 2 side of the shield wall. Frequently operated valves in radioactive lines are capable of being operated from the design radiation zone 2 side of the shield wall.

12.3.1.1.1.4 Pumps. Pumps in radioactive and potentially radioactive systems are provided with mechanical seals to reduce seal servicing time. These pumps include those in the nuclear cooling water, essential cooling water, safety injection, containment spray, spent fuel pool cooling, radwaste, and chemical and volume control systems. Pumps and associated piping are arranged to provide adequate space for access to the pumps for servicing. Pumps in the above systems

are provided with flanged connections for ease in removal. Pump casings are provided with drain connections for draining the pump for maintenance. Plant layout ensures that maintenance can be performed in such a way that exposure to major radiation sources is minimized.

12.3.1.1.1.5 Tanks. Tanks in radioactive and potentially radioactive systems are provided with sloped bottoms and bottom outlet connections whenever practical.

A. Tanks with flat bottoms sloped toward the outlet include:

   1. Reactor makeup water tank
   2. Radwaste holdup tanks
   3. Refueling water tank
   4. Chemical and volume control system holdup tank
   5. Liquid radwaste evaporator condensate storage tanks
   6. Condensate storage tank
   7. Chemical waste tanks
   8. Liquid radwaste monitor tanks

   These tanks have outlet connections located on the side of the tank as near to the bottom as possible.

B. Tanks with rounded bottoms and low point outlet connections include:

1. Spent resin tanks
2. Volume control tank
3. Reactor drain tank
4. Chemical drain tank
5. Equipment drain tank

Overflow lines are directed to the LRS to control contamination within plant structures. Tanks are contained in separate compartments with drains directed to the LRS or the chemical and volume control system.

12.3.1.1.1.6 Heat Exchangers. Heat exchangers are provided with corrosion-resistant tubes of stainless steel or other suitable materials with tube to sheet joints welded or expanded to minimize leakage. Impact baffles are provided, and tube side and shell side velocities are limited to minimize erosive effects.

12.3.1.1.1.7 Instruments. Instrument devices are located in low radiation zones and away from radiation sources whenever practical. Primary instrument devices, which are located in high radiation areas for functional reasons, are designed for easy removal for calibration. Readout devices are located in design low radiation areas, such as corridors and the control room, for servicing.

Some instruments (such as thermocouples) are provided in duplicate in high radiation areas to reduce access and service time. In the containment most instruments are located outside the secondary shield.

Integral radiation check sources or LED check sources are provided for response verification for airborne radiation monitors and safety-related area radiation monitors. These check sources provide a method to remotely response check each detector.

12.3.1.1.1.8 Valves. To minimize personnel exposures due to valve operation, motor-operated, diaphragm, or other remotely actuated valves are used in highly radioactive systems that require frequent valve operation.

Valves are located in valve galleries and are shielded from major system components wherever Possible. Long runs of exposed piping are minimized in valve galleries. In areas where manual valves are used in frequently operated process lines, either valve stem extenders or shielding is provided, so that personnel need not enter the high radiation area for normal valve operation. The criteria for selecting valve operators are detailed in paragraph 12.1.2.3.2.

For valves located in radiation areas, provisions are made to drain adjacent radioactive components when maintenance is required.

Valves for clean, nonradioactive systems are separated from radioactive sources and are located in readily accessible areas.

Manually operated valves in the filter and high activity ion exchanger valve compartments required for normal operation and shutdown are equipped with reach rods extending through the valve gallery walls. Personnel do not enter the valve galleries during flushing operations. The valve gallery shield walls are designed for maximum expected filter and ion exchanger activities.

For most larger valves (2-1/2 inches and larger) in lines carrying radioactive fluids, a grafoil or graphite yarn is used as a packing component. Diaphragm or bellows seal valves are used where minimal leakage is required.

12.3.1.1.1.9 Piping. The piping in pipe chases is designed for the life-time of the unit. There are no valves or instrumentation in pipe chases. Wherever radioactive piping is routed through areas where routine maintenance is required, pipe chases are provided to reduce the radiation contribution from these pipes to levels appropriate for the inspection requirements. Piping containing radioactive material is routed to minimize radiation exposure to the unit personnel.

12.3.1.1.1.10 Floor Drains. Floor drains and properly sloped floors are provided for each room or cubicle containing serviceable components containing radioactive liquids. Local

gas traps or porous seals are not used on radwaste floor drains. Gas traps are provided at the common sump or tank.

12.3.1.1.1.11 Sample Stations. Sample stations for routine sampling of process fluids are located in the radiochemical laboratory in the auxiliary building. Shielding is provided at the sample stations. Valves in sample lines are provided with reach rods as necessary to minimize personnel exposure during sampling.

12.3.1.1.1.12 Clean Services. Whenever possible, clean services and equipment such as compressed air piping, clean water piping, ventilation ducts, and cable trays are not routed through radioactive pipeways.

12.3.1.1.1.13 Reactor Coolant System Leakage Control. Exposures from airborne radionuclides to personnel entering the containment will be minimized by controlling the amount of reactor coolant leakage to the containment atmosphere. Examples of such controlled leakage are listed below:

1. Primary pressurizer safety valve leakage is directed to the Reactor Drain tank, as discussed in Section 5.2.2.
2. Instrumentation is provided to detect abnormal reactor coolant pump seal leakage. The reactor coolant pumps are equipped with two stages of seals plus a vapor or backup seal as described in Section 5.2.5.2.2. Additionally, the space between the double O-ring seal on the reactor vessel closure head is monitored to detect leakage past the inner

O-ring. Leakage is directed to the reactor drain tank, as discussed in subsection 5.2.5.

12.3.1.1.2 Common Facility and Layout Designs for ALARA

This section describes the design features utilized for standard type plant processes and layout situations. These features are employed in conjunction with the general equipment designs described in paragraph 12.3.1.1.1, and include the features discussed in the following sections.

12.3.1.1.2.1 Valve Galleries. Valve galleries are provided with shielded entrances for personnel protection. Where practical, the valve galleries are divided so that personnel requiring access are exposed only to valves and piping associated with one component at any given location. Floor drains are provided to control radioactive leakage. To facilitate decontamination in valve galleries, concrete surfaces are covered with a smooth-surfaced coating, which allows easy decontamination.

12.3.1.1.2.2 Piping. Pipes carrying radioactive materials that pose a radiation hazard are routed through controlled access areas. Each piping run is individually analyzed to determine the potential radioactivity level and surface dose rate. Where it is necessary that radioactive piping be routed through corridors or other low radiation areas, shielded pipeways are provided. Whenever practical, valves and instruments are not placed in radioactive pipeways. Whenever

practical, equipment compartments are used as pipeways only for those pipes associated with equipment in the compartment.

When practical, radioactive and nonradioactive piping are separated to minimize personnel exposure. Should maintenance be required, provision is made to isolate and drain radioactive piping and associated equipment.

Piping is designed to minimize low points and dead legs. Drains are provided on piping where low points and dead legs cannot be eliminated. Long radius elbows. or bends of several pipe diameters, are utilized whenever practicable for pipes carrying radioactive material.

Piping, carrying resin slurries or evaporator bottoms, is run vertically as much as possible.

Whenever possible, branch lines having little or no flow during normal operation are connected above the horizontal midplane of the main pipe.

12.3.1.1.2.3 Penetrations. To minimize radiation streaming through penetrations, as many penetrations as practicable are located with an offset between the source and the accessible areas. If offsets are not practical, penetrations are located as far as possible above the floor elevation to reduce the exposure to personnel. If these two methods are not used, alternate means are employed, such as baffle shield walls or grouting the area around the penetration.

12.3.1.1.2.4 Contamination Control. Access control and traffic patterns are considered in the basic plant layout to minimize the spread of contamination. Equipment vents and drains from highly radioactive systems are piped directly to the collection system instead of allowing any radioactive fluid to flow across to the floor drain. All-welded piping systems are employed on radioactive systems to the maximum extent practicable to reduce system leakage and crud buildup at joints.

Decontamination of potentially contaminated areas and equipment within the plant is facilitated by the application of suitable smooth-surface coatings to the concrete floors and walls.

Sloped floors and floor drains are provided in potentially contaminated areas of the plant. In addition, radioactive and potentially radioactive drain systems are separated from non-radioactive drain systems. Rooms with equipment or tanks that contain radioactive fluids have curbs to contain potential spills or leaks. Large tanks containing radioactive fluids are enclosed in water tight compartments or are surrounded by curbs.

In controlled access areas where contamination is expected, radiation monitoring equipment is provided (section 11.5 and subsection 12.3.4). Those systems that become highly radioactive, such as the spent resin lines in the radwaste system, are provided with flush and drain connections.

12.3.1.1.2.5 Equipment Layout. In systems where process cleanup equipment is a major radiation source, pumps, valves, and instruments are separated from the process component. This allows servicing and maintenance of these items in reduced radiation areas. Control panels are located in low radiation areas (design radiation zone 1 or 2).

Major components (such as tanks, ion exchangers, and filters) in radioactive systems are isolated in individual shielded compartments. Labyrinth entranceway shields or shielding doors are provided for each compartment from which radiation could stream or scatter to access areas and exceed the design radiation zone dose limits for those areas. For potentially high radiation components (such as ion exchangers and tanks), completely enclosed shielded compartments with hatch openings or labyrinth entryways with locked gates are used. For some infrequently serviced components, completely enclosed shielded compartments with removable concrete block walls are used. Nonradioactive equipment that requires maintenance is located outside radiation areas.

Exposure from routine in-plant inspection is controlled by locating, whenever possible, inspection points in properly shielded, low-background radiation areas. Radioactive and nonradioactive systems are separated as far as practicable to limit radiation exposure from routine inspection of non-radioactive systems. For radioactive systems, emphasis is placed on adequate space and ease of motion in a properly shielded inspection area. Where longer times for routine

inspection are required, and permanent shielding is not feasible, sufficient space for portable shielding is provided. For example, a remotely operated device is provided for inservice inspections of the reactor vessel. Access to high-radiation areas is under the supervision of the radiation protection personnel.

12.3.1.1.2.6 Field-Run Piping. Radioactive process piping design (i.e., routing or shielding) is not performed in the field.

12.3.1.1.2.7 Packaged Units. Each package unit is skid-mounted with all motors and pumps located on the periphery at the skid for ease of access and for quick removal to low-radiation area for maintenance or repair. Package components are provided with provisions for flushing, draining, and chemical cleaning. Heat exchangers are readily accessible for maintenance. As many control elements as possible are mounted remotely from the radioactive components so that the package can be remotely controlled and monitored. Components are designed with a minimum of crevices to reduce the accumulation of radioactive materials.

12.3.1.2 Design Radiation Zoning and Access Control

Access into the plant structures, plant yard areas and the low-level radioactive material storage facility is regulated and controlled.

Plant areas are categorized as design radiation zones according to expected maximum radiation levels and anticipated personnel occupancy with consideration given toward maintaining personnel exposures ALARA. Each design radiation zone defines the radiation level range to which the aggregate of contributing sources must be attenuated by shielding. Each room, corridor, and pipeway of every plant building is evaluated for potential radiation sources during normal, shutdown, spent resin transfer, and emergency operations; for maintenance occupancy requirements; for general access requirements; and for material exposure limits to determine appropriate zoning. The design radiation zone categories employed and their descriptions are given in table 12.1-1. The specific design zoning for each plant area is shown in drawings 13-N-RAR-001 through -017 and 13-N-RAR-039 (dry cask transfer operations). Frequently accessed areas, e.g., corridors, are shielded for design radiation zone 1 or zone 2 access. Licensing documents, ISFSI 72.212 Evaluation Report and NAC-UMS Universal Storage System FSAR 72-1015, provide information regarding ISFSI radiation protection design features. The area inside of the ISFSI is classified as a Radiation Zone 3.

The control of entry or exit of plant operating personnel to controlled access areas, and procedures employed to ensure that radiation levels and allowable working time are within the limits prescribed by 10CFR20.1001-20.2402 is described in section 12.5.

12.3.1.3 Radiation Zones - Post-Accident

Radiation zone maps were developed in accordance with NUREG-0737 to review potential access throughout the plant post-accident period. The facility layout assists in keeping occupational exposures ALARA even after a design basis accident. While exposures will be significantly higher than during normal operation, required access is provided to vital areas and systems without exceeding 5 rem/hr. Zone maps showing expected dose rates in the event of a LOCA with sump recirculation are provided as drawings 13-N-RAR-018 through -028. Zone maps for the hypothetical condition of a LOCA with an intact primary but with a degraded core are provided as drawings 13-N-RAR-029 through -038. The source terms correspond to those noted in subsection 12.2.3. The dose rates projected for these two sets of drawings do not assume decay beyond that corresponding to the onset of recirculation.

Even so, virtually unrestricted access will be permitted within portions of the upper floor of the auxiliary building (such as the Auxiliary Building area of the operations support center) and the lower levels of the control building. Continuous occupancy will be permitted in the control room, satellite technical support center (STSC), TSC, and diesel generator building, as dose rates will be 15 mrem/hr or less. Estimated radiation levels in vital areas were based on radiation sources from the post-accident operation of the following systems: containment, safety injection/shutdown cooling/containment spray, chemical and volume control system (up to purification

filter inlet), post-accident sampling, and hydrogen recombiners. The gaseous radwaste system will not be used post-accident. Palo Verde does not have a standby gas treatment system or an equivalent.

12.3.2 SHIELDING

The bases for the nuclear radiation shielding and the shielding configurations are discussed in this section.

12.3.2.1 Design Objectives

The basic objective of the plant radiation shielding, in conjunction with a program of controlled personnel access to, and occupancy of, radiation areas, is to reduce personnel and population exposures to levels that ALARA. Shielding and equipment layout and design are considered in ensuring that exposures are kept ALARA during anticipated personnel activities in areas of the plant containing radioactive materials, utilizing the design recommendations given in Regulatory Guide 8.8, Paragraph C.2, where practical.

An analysis of the PVNGS shielding design was performed to determine if TMI level source strengths would inhibit maintenance access or violate 10CFR50, Appendix A, General Design Criterion (GDC) 19. The review demonstrated that personnel radiation exposures in vital areas during post-accident activities will meet the criteria of NUREG-0737 and the GDC 19 design basis. The design review of plant shielding

discussed fulfills the NRC requirements outlined in NUREGs-0578 and -0737 as well as in Regulatory Guide 1.97, Revision 2.

Four plant conditions are considered in the nuclear radiation shielding design: normal full-power operation; shutdown; spent resin transfer; and emergency operations (for required access to safety-related equipment).

The shielding design objectives for the plant during normal operation (including anticipated operational occurrences), and shutdown operations are:

A. To ensure that radiation exposure to plant operating personnel, contractors, administrators, visitors, and proximate site boundary occupants are ALARA and within the limits of 10CFR20.1-20.601.

B. To assure sufficient personnel access and occupancy time to allow normal anticipated maintenance, inspection, and safety-related operations required for each plant equipment and instrumentation area.

C. To reduce potential equipment neutron activation and mitigate the possibility of radiation damage to materials.

The shielding design objectives for emergency operations are:

A. To ensure that radiation exposure to plant personnel in vital areas are maintained within the requirements of NUREG 0737.

B. To ensure that the control room, and TSC will be sufficiently shielded so that the direct dose plus the

inhalation dose (calculated in chapter 15) will not exceed the limits of 10CFR50, Appendix A, General Design Criterion 19.

C. To ensure that radiation exposure to an individual at site Exclusion Boundary Area (EAB) and Low Population Zone (LPZ) are maintained within 10 CFR 100 requirements.

12.3.2.2 General Shielding Design

Shielding is provided to attenuate direct radiation through walls and scattered radiation through penetrations to less than the upper limit of the design radiation zone for each area shown in drawings 13-N-RAR-001 through -017 and 13-N-RAR-039 (dry cask transfer operations). The shielding requirements for plant areas are presented in drawings 13-N-RAR-001 through -017 and 13-N-RAR-039. Design criteria for penetrations are consistent with the recommendations of Regulatory Guide 8.8, and are discussed in paragraph 12.3.1.1.2.

Should dose rates in excess of design zone criteria occur during PVNGS operation, PVNGS will add shielding or revise access to the affected area so as to ensure proper access control.

The material used for most of the plant shielding is ordinary concrete with a minimum bulk density of 140 pounds per cubic foot. Whenever poured-in-place concrete has been replaced by concrete blocks, design ensures protection on an equivalent shielding basis as determined by the density of the concrete

block selected. Concrete radiation shields are designed following the recommendations of Regulatory Guide 1.69 as discussed in section 1.8. Water is used as the primary shield material for areas above the spent fuel storage area.

12.3.2.2.1 Containment Shielding Design

During reactor operation, the containment protects personnel occupying adjacent plant structures and yard areas from radiation originating in the reactor vessel and primary loop components. The concrete containment wall, together with the reactor vessel and steam generator compartment shield walls, is designed to reduce radiation levels outside the containment from sources within the containment to less than 0.5 mrem/h. The containment shield is reinforced, prestressed concrete completely surrounding the nuclear steam supply system. The wall is 4 feet thick, and the dome varies from 4 feet at the springline to 3 feet 6 inches at the top.

For design basis accidents, the containment shield together with the control room shielding reduces the plant radiation intensities from fission products inside the containment to acceptable levels, as defined by 10CFR50, Appendix A, General Design Criterion 19, for the control room.

Where personnel and equipment hatches or penetrations pass through the containment wall, additional shielding is provided to attenuate radiation to the required level defined by the outside design radiation zone during normal operation and

shutdown, and to acceptable levels as defined by 10CFR50 during design basis accidents.

12.3.2.2.2 Containment Interior Shielding Design

During reactor operation, many areas inside the containment are design radiation zone 5 and normally inaccessible. However, the secondary bio-shielding is designed to reduce dose rates to approximately 15 mrem/h from direct neutron and gamma dose from the active core region. The areas that require potential access during power operation are designed to minimize neutron and gamma dose from this source of radiation. The design radiation zone maps of the containment are shown in drawings 13-N-RAR-001 through -017 (these zone maps reflect dose contribution from all radiation sources in the areas).

The main sources of radiation are the reactor vessel and the primary loop components, consisting of the steam generators, pressurizer, reactor coolant pumps, and associated piping. The reactor vessel is shielded by the concrete primary shield, reactor cavity shield, and by the concrete secondary shield which also surrounds all other primary loop components. Air cooling is provided to prevent overheating, dehydration, and degradation of the shielding and structural properties of the primary shield and reactor cavity shield.

The primary shield is a large mass of reinforced concrete surrounding the reactor vessel and extending upward from the containment floor to form the walls of the fuel transfer canal.

Refer to Section 3.B.3.1.6 for detailed discussion of the primary shield.

The reactor cavity shield, an annular mass of concrete, is below the reactor vessel nozzles between the vessel and the primary shield as shown in figure 12.3-1. This shield minimizes neutrons streaming from the annulus between the reactor vessel and the primary shield. The bottom of the cavity shield is located at about elevation 96 feet. The top of the cavity shield is located at about elevation 100 feet. Estimates of neutron dose rates vary spatially over the operating level from 50 to 60 mrem/hr at airlock and near preaccess filter unit to approximately 100 to 500 mrem/hr at locations that can view the CEDM cable structure and up to 1 to 2 rem/hr at locations along the edge of the refueling canal. Neutron dose levels outside the steam generator compartments at elevations below the operating level are expected to be negligible due to shielding by the concrete operating level floor.

The primary shield and reactor cavity shield are designed to meet the following objectives:

A. In conjunction with the secondary shield, to reduce the radiation level from sources within the reactor vessel and reactor coolant system to allow limited access to the containment during normal, full-power operation.

B. After shutdown, limit the radiation level from sources within the reactor vessel, to permit limited access to reactor coolant system equipment.

C. To limit neutron flux activation of component and structural materials.

The regenerative heat exchanger of the letdown portion of the chemical and volume control system is located in a shielded compartment that is normally design radiation zone 5. Shielding is provided for it consistent with its postulated maximum activity (subsection 12.2.1) and with the access and design zoning requirements of adjacent areas.

After shutdown, the containment is accessible for limited periods of time and all access is controlled. Areas are surveyed to establish allowable working periods. Dose rates are expected to range from 0.5 to 1000 mrem/h, depending on the location inside the containment (excluding reactor cavity). These dose rates result from residual fission products, neutron-activated materials, and corrosion products in the reactor coolant system.

Spent fuel is the primary source of radiation during refueling. Because of the extremely high activity of the fission products contained in the spent fuel elements and the proximity of design radiation zone 2 areas, extensive shielding is provided for areas surrounding the spent fuel pool and the fuel transfer canal to ensure that radiation levels remain below design zone levels specified for adjacent areas. Water provides the shielding over the spent fuel assemblies during fuel handling

(refer to figure 12.3-4). Furthermore, substantial structural barriers to limit access in the vicinity of the fuel transfer tube during fuel handling operations have been provided. Refer to figure 12.3-2 for the fuel transfer shielding arrangement.

The secondary shield is a reinforced concrete structure surrounding the reactor coolant equipment, including piping, pumps, and steam generators.

This shield protects personnel from the direct gamma radiation resulting from reactor coolant activation products and fission products carried away from the core by the reactor coolant. In addition, the secondary shield supplements the primary shield by attenuating neutron and gamma radiation escaping from the primary shield. The secondary shield is sized to allow limited access to the containment during full power operation. The thickness of secondary shield walls is 4 feet.

12.3.2.2.3 Auxiliary Building Shielding Design

During normal operation, the major components in the auxiliary building with potentially high radioactivity are those in the chemical and volume control system, the shutdown cooling system, the fuel pool cooling and cleanup system, and the primary sampling system.

Shielding is provided as necessary around the following equipment in the auxiliary building to ensure the design radiation zone and access requirements are met for surrounding areas:

A. Letdown heat exchangers and piping

B. Purification, preholdup, and deborating ion exchangers

C. Chemical and volume control tank

D. Charging pumps and piping

E. Shutdown cooling heat exchangers

F. Chemical drain tanks and pumps

G. CVCS and radwaste filters

H. Spent fuel pool cleanup ion exchangers and filters

I. Spent resin tanks and piping

J. Gas stripper

K. Seal injection heat exchanger

L. Boronometer (abandoned in-place)

M. Process radiation monitor

N. Seal injection filters

Shielding is based upon operation with maximum activity conditions as discussed in sections 11.1, 11.2, and 11.3 and subsection 12.2.1.

Depending on the equipment in the compartments, the access varies from design radiation zones 2 through 5. Corridors are shielded to allow design radiation zone 2 access. Operator areas for valve galleries are designed for design radiation zone 3 access. Frequently operated valves in high radiation areas are provided with remote actuators extending to design radiation zone 2 or zone 3 areas. (See paragraph 12.1.2.3.2, listing M.)

Removable sections of block shield walls, or concrete hatches with offset gaps to reduce radiation streaming are provided for replacement of ion exchangers, pumps, and heat exchangers.

12.3.2.2.4 Fuel Building Shielding Design

Concrete shield walls surrounding the spent fuel cask loading and storage area, fuel transfer and storage pools, and fuel transfer tube between the containment and fuel transfer pool are sufficiently thick to limit radiation levels outside the shield walls in accessible areas to design radiation zone 2. Access to the fuel transfer tube through the concrete radiation shield is provided by a heavy concrete hatch through the roof of the shield as shown in figure 12.3-3. The hatch is labeled to caution maintenance personnel that there are potentially lethal radiation fields during fuel transfer.

Water in the spent fuel pool provides shielding above the spent fuel transfer and storage areas. The relationship between dose rate over spent fuel during transfer and depth of covering water is shown in figure 12.3-4. Radiation levels at the fuel handling equipment are not expected to exceed 2.5 mrem/h.

The spent fuel pool cooling and cleanup (SFPCC) system (section 9.1) shielding is based on the maximum activity discussed in section 12.2 and the access and design zoning requirements of adjacent areas. Equipment in the SFPCC system to be shielded includes the SFPCC heat exchangers, pumps, and piping. (SFPCC filters and ion exchangers are located in the auxiliary building.)

12.3.2.2.5 Radwaste Building Shielding Design

Radwaste systems are principally located in the radwaste building. Additionally, the boric acid concentrator and the boric acid concentrate ion exchanger are in the radwaste building.

Major components or areas requiring shielding are:

- Low activity and high activity spent resin tanks
- Spent resin transfer pump
- Spent resin transfer valve gallery
- LRS evaporator and piping
- LRS concentrate tanks and pumps
- Boric acid concentrator
- Boric acid and LRS ion exchangers and their valve gallery
- Waste gas compressors and valve galleries
- Waste gas surge and decay tanks

Shielding is based on maximum expected radioactivity as noted in section 12.2. Depending on the equipment in the compartments, the access varies from design radiation zones 2 through 5. Corridors are shielded to allow design radiation zone 2 access. Operator areas for valve galleries are designed for zone 3 access. Frequently operated valves in high-radiation areas are provided with remote actuators extending to

design radiation zone 2 or zone 3 areas. (See paragraph 12.1.2.3.2, listing M.)

Removable sections of block shield walls and concrete plugs with offset gaps to reduce radiation streaming are provided for replacement of ion exchangers, if required.

Partial shield walls are placed between equipment in compartments with more than one piece of equipment to permit maintenance access (e.g., evaporator packages).

12.3.2.2.6 Turbine Building Shielding Design

Radiation shielding is not required for any equipment in the steam and power conversion system located in the turbine building. All areas in the turbine building are classified as design radiation zone 1.

12.3.2.2.7 Control Room Shielding Design

Engineering drawing 13-P-OOB-005 represents a layout drawing of the control room, showing its relationship to the containment.

The design basis loss-of-coolant accident (LOCA) dictates the shielding requirements for the control room. Consideration is given to shielding provided by the containment structure. Shielding and adequate radiation protection are provided to permit access and occupancy of the control room under LOCA conditions without personnel receiving radiation exposure in excess of 5 rem whole-body or its equivalent to other organs from all contributing modes of exposure for the duration of the

accident, in accordance with 10CFR50 Appendix A, General Design Criterion 19.

The design basis LOCA is described in section 15.6 and is based on the recommendations of Regulatory Guide 1.4. The dose to personnel, from airborne fission products inside the containment and in the radioactive cloud outside the control room, for the 30-day period following a postulated LOCA is discussed in section 15.6.

The parameters used in the demonstration of control room habitability, in addition to Regulatory Guide 1.4, are listed in section 6.4.4

12.3.2.2.8 Diesel Generator Building Shielding Design

There are no radiation sources in the diesel generator building; therefore, no shielding is required for the building.

12.3.2.2.9 Miscellaneous Plant Areas and Plant Yard Areas

Sufficient shielding is provided for plant buildings containing radiation sources so that radiation levels at the outside surfaces of the buildings are maintained below design radiation zone 1 levels. The steam generator blowdown ion exchangers, filter, and valve gallery are located inside of concrete shield walls. Plant yard areas that are frequently occupied by plant personnel are fully accessible during normal operation and shutdown. These areas are surrounded by a security fence, and closed off from areas accessible to the general public. Access to outside storage tanks that have a design contact dose rate

greater than 0.5 mrem/h is restricted by a concrete shield sufficiently high so that dose rates to personnel in plant yard areas are limited to less than 0.5 mrem/h from sources within those tanks. Where shielding penetrations and manways create a potential for dose rates to exceed 0.5 mrem/hr, access is administratively controlled as described in Section 12.5.3.

12.3.2.2.10 Low-Level Radioactive Material Storage Facility (LLRMSF) Shielding Design

The LLRMSF was designed for interim storage of solid radioactive material as defined in Generic Letter 81-38. The shielding is sufficient to accommodate a container contact dose rate of 750 mr/hr. An underground vault is provided for containers producing a dose rate in excess of 750 mr/hr. If a container producing greater than 750 mr/hr is to be stored above the vault, additional shielding (shadow shielding, storage module or credit for distance) must be implemented as necessary.

Additional shielding is to be provided on the vault lids as necessary to maintain radiological boundary criteria.

LLRMSF control room shielding is provided to protect personnel from direct radiation during a transfer of radioactive material into the storage area.

12.3.2.2.11 Independent Spent Fuel Storage Installation (ISFSI) Shielding Design

The ISFSI is designed for interim dry storage of spent nuclear fuel. The shielding is sufficient to comply with the requirements of 10CFR72.104 and 10CFR72.106. The design basis dose rate at the surface of the VCC is 50 mr/hr average. The design basis dose rate at the inlets and outlets is 100 mr/hr. The design basis dose at the owner controlled boundary is 25 mr annual whole body dose for Normal and Off-Normal conditions and 5 rem whole body for accident conditions.

For a detailed discussion of the VCC shielding properties, refer to NAC-UMS® FSAR Chapter 5. For a detailed discussion of compliance with 10CFR72.104 and 10CFR72.106 requirements, refer to NAC-UMS® FSAR Chapter 10 and ISFSI 72.212 Evaluation Report.

The ISFSI also incorporates an earthen berm to protect personnel within the owner controlled area. The ISFSI is surrounded by a security fence and is closed off from areas accessible to the general public.

12.3.2.3 Shielding Calculational Methods

The shielding thicknesses provided to ensure compliance with plant radiation zoning and to minimize plant personnel exposure are based on maximum equipment activities under the plant operating conditions described in chapter 11 and section 12.2. The thickness of each shield wall surrounding radioactive equipment is determined by approximating the actual geometry and physical condition of the source or sources. The isotopic

concentrations are converted to energy group sources using data from standard references.[(1),(2),(3),(4),(5)]

The geometric model assumed for shielding evaluation of tanks, heat exchangers, filters, ion exchangers, evaporators and piping, and the containment is a finite cylindrical volume source.

The methods and equations of Rockwell's Reactor Shielding Design Manual[(6)] are used to calculate dose rates. Buildup is calculated using Taylor coefficients presented in RSIC-10[(7)], and Broder's Method of Buildup Determination, presented in the Engineering Compendium on Radiation Shielding[(8)], is used for laminated shields.

In addition, industry-accepted computer programs are used for shielding analysis. ANISN[(9)], QAD[(10)], MICROSHIELD[(11)], and MORSE[(12)] are typical computer programs utilized for this purpose. ANISN is a multigroup, one-dimensional discrete ordinates transport program that solves the one-dimensional Boltzmann transport equation for neutrons and gamma rays in slab, sphere, or cylinder geometry. Using a finite difference technique, ANISN allows general anisotropic scattering; i.e., an L^{th} order Legendre expansion of the scattering cross-sections. Monte Carlo techniques may be used for more complicated geometries such as penetrations. QAD is a point-kernel general purpose program for estimating the effects of gamma rays and neutrons that originate in a volume distributed source. Description of the three-dimensional geometry of the

problem is accomplished by using quadratic equations to define surfaces. Two updated versions of the QAD computer program, QAD-CG[13] and QADMOD-G[14], are also used in shielding analysis. QAD-CG utilizes the Combinatorial Geometry subroutines from MORSE in place of the quadratic surface input. QADMOD-G is used for the calculation of gamma-ray fluxes or dose rates at discrete locations within a complex source-geometry configuration. MICROSHIELD is a microcomputer adaptation of the main frame computer program ISOSHLD[15] and is primarily utilized in shielding analysis of simple source-geometry configurations. ANISN is used for primary shield design and QAD is used for configurations not conveniently modeled as a cylindrical source with annular shields.

For design of the reactor cavity, a three-dimensional model was used to simulate radiation streaming from the reactor surface to the containment using the MORSE Monte Carlo program. The source terms used for the MORSE program were divided into 13 neutron energy groups.

The shielding thicknesses are selected to reduce the aggregate computed radiation level from contributing sources below the upper limit of the design radiation zone specified for each plant area. Shielding requirements are evaluated at the point of maximum radiation dose through any wall. Therefore, the actual anticipated radiation levels in the greater region of each plant area is less than this maximum dose and therefore less than the design radiation zone upper limit.

Where shielded entryways to compartments containing high-radiation sources are necessary, labyrinths or mazes are designed using general purpose gamma-ray scattering programs(16)(17) or methods summarized in RSIC-21.(18) The mazes are constructed so that the scattered dose rate, plus the transmitted dose rate through the shield wall from contributing sources, is below the upper limit of the design radiation zone specified for each plant area.

12.3.3 VENTILATION

The plant heating, ventilating, and air conditioning (HVAC) systems are designed to provide a suitable environment for personnel and equipment during normal operation and events of moderate frequency or certain infrequent events. Parts of the plant HVAC systems perform safety-related functions.

12.3.3.1 Design Objectives

The plant HVAC systems for normal plant operation and events of moderate frequency or certain infrequent events are designed to meet the requirements of 10CFR20.1-20.601 and 10CFR50.

12.3.3.2 Design Criteria

Design criteria for the plant HVAC systems include:

A. During normal operation and events of moderate frequency or certain infrequent events, the average and maximum airborne radioactivity levels to which

plant personnel are exposed are ALARA and within the limits specified in 10CFR20.1-20.601.

B. During normal operations and events of moderate frequency or certain infrequent events, the dose from concentrations of airborne radioactive material in unrestricted areas beyond the site boundary is ALARA and within the limits specified in 10CFR20.1-20.601 and 10CFR50, Appendix I.

C. The plant site dose limitations of 10CFR100 will be adhered to following those hypothetical accidents described in chapter 15.

D. The dose to control room personnel shall not exceed the limits specified in General Design Criterion 19 of Appendix A to 10CFR50 following those hypothetical accidents described in chapter 15.

12.3.3.3 Design Guidelines

To accomplish the design objectives, the following guidelines are followed wherever practical.

12.3.3.3.1 Guidelines to Minimize Airborne Radioactivity

A. Access control and traffic patterns are considered in the basic plant layout to minimize the spread of contamination.

B. Equipment vents and drains are piped directly to a collection device connected to the collection system

instead of allowing any radioactive fluid to flow across the floor to the floor drain.

C. All-welded piping systems are employed on systems containing radioactive fluids to the maximum extent practical to reduce system leakage.

D. Suitable coatings are applied to the concrete floors and walls of potentially contaminated areas to facilitate decontamination.

E. Design of potentially contaminated equipment incorporates features that minimize the potential for airborne radioactivity during maintenance operations. These features may include connections on pump casings for draining and flushing the pump prior to maintenance, or flush connections on piping systems that could become highly radioactive.

12.3.3.3.2 Guidelines to Control Airborne Radioactivity

A. The airflow is directed from areas with lesser potential for contamination to areas with greater potential for contamination.

B. In building compartments with a potential for contamination, the exhaust is designed for greater volumetric flow than is supplied to the area to minimize the amount of uncontrolled exfiltration from the area.

C. Air cleaning systems criteria for emergency systems are discussed under Regulatory Guide 1.52 in section 1.8.

   System design for both normal and emergency systems is described in section 9.4.

D. Means are provided to isolate the containment and fuel buildings upon indication of radioactive contamination to prevent the discharge of contaminants to the environment and minimize in-plant exposure.

E. Means are provided to isolate the control room to minimize inleakage of contaminated air to the operator.

F. Suitable containment isolation valves are installed to ensure that the containment integrity is maintained. See additional discussion in subsections 3.1.47, 3.1.49, and 6.2.4.

G. Redundancy and Seismic Category I classification features are provided for components of the HVAC systems required for safe shutdown of the reactor plant.

12.3.3.3.3 Guidelines to Minimize Personnel Exposure from HVAC Equipment

Access and service of ventilation systems in potentially radioactive areas are provided by component location to

minimize operator exposure during maintenance, inspection, and testing as follows:

A. Ventilation equipment rooms for outside air supply units and building exhaust system components are located in design radiation zone 2 and are accessible to the operators. Ventilation exhaust filtration units for the auxiliary and fuel buildings are located on the roofs of the respective buildings and are designated as being design radiation zone 3 areas. Work space is provided around each unit for anticipated maintenance, testing, and inspection. Filter-adsorber units generally are consistent with the recommendations of Regulatory Guide 1.52 for access and service requirements. (Refer to section 1.8).

B. Local HVAC equipment that services the normal building requirements is located in areas of low contamination when practical.

12.3.4 AREA RADIATION AND AIRBORNE RADIOACTIVITY MONITORING INSTRUMENTATION

Section 11.5 describes the function, operation, design, and locations of the radiation monitoring system (RMS). The RMS provides 28 fixed area and 16 fixed airborne monitors per unit as noted in section 11.5. Additionally, there are 18 portable monitor connection boxes located throughout each unit that can connect any of the three portable area monitors available for

each unit for use during extended maintenance. Thus, a portable monitor can be placed where necessary to provide dose rate surveillance. This will reduce doses to radiation protection personnel, while providing necessary surveillance.

Refer to section 11.5 for a further description of the radiation monitoring system, its sensitivity, and setpoints, as well as a description of how the RMS fulfills the applicable requirements of Regulatory Guides 1.21, 8.2, 8.8, 8.12, and ANSI N13.1.

12.3.5 REFERENCES

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12. RSIC Computer Code Collection CCC-203, MORSE-CG, General Purpose Monte Carlo Multi-Group Neutron and Gamma Ray Transport Code with Combinatorial Geometry.

13. RSIC Computer Code Collection CCC-307, QAD-CG, A Combinatorial Geometry Version of QAD-P5A.

14. RSIC Computer Code Collection CCC-396, QADMOD-G, A Point Kernel Gamma-Ray Shielding Code.

15. RSIC Computer Code Collection CCC-79, ISOSHLD, A Kernel Integration Code for General Purpose Isotope Shielding Analysis.

16. Grove Engineering, Inc., MICROSKYSHINE, A Microcomputer Program to Analyze The Photon Skyshine Contribution to Exposure Rate from Shielded Sources, Rockville, MD, May 1987.

17. Malenfant, R. E., "G3: A General Purpose Gamma-Ray Scattering Program," Los Alamos Scientific Laboratory, LA 5176, June 1973.

18. Selph, W. E., "Neutron and Gamma Ray Albedos," ORNL-RSIC-21, February 1968.

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12.4 DOSE ASSESSMENT

Regulatory Guide 8.19 states that Section 12.4 is used to assure that adequate attention to dose reducing design changes are maintained during the preliminary design and construction stages. Regulatory Guide 8.19 also states that the dose assessments found in Section 12.4 are intended as a search for dose reducing techniques, not for NRC regulatory enforcement purposes. The information provided in Section 12.4 is considered original licensing information and is not maintained. Annually, critical aspects of this section are reported to the NRC in accordance with 10 CFR 20.2206 and plant technical specifications. These reports provide the NRC with actual dose received at PVNGS during the previous year.

12.4.1 RADIATION EXPOSURES WITHIN THE PLANT

Within each accessible area in the plant, the peak external dose rate due to direct radiation is considered as the maximum dose rate for which the area, by design, is zoned (subsection 12.3.2). These dose rates are not expected to occur during normal operation because the plant shielding is based on maximum coolant activities corresponding to 1% defective fuel cladding. The annual average isotopic concentrations of fission products are expected to be much less than the maximum. Therefore, the actual dose rates in a given design radiation zone are expected to be significantly less than the maximum calculated dose rate in that design radiation zone. Another source of radiation exposure within the plant comes from airborne radionuclides. Radiation exposure from this source to occupational workers in the accessible areas of

the plant is usually insignificant in comparison with the exposure to direct radiation from radioactive sources. Under certain circumstances (e.g., operational access within the containment) doses from airborne activity may be a major fraction of the allowed limits.

Based on operating plant experience, numerous design features are incorporated into the design of PVNGS to minimize plant personnel exposure. The PVNGS design reflects attention to ALARA detail due to the ALARA reviews conducted during design as noted in appendix 12B. Specific design measures taken to minimize doses during maintenance and operation include the following:

A. Radioactive systems are designed such that the components which remove fission and corrosion products are placed in the process stream as early as practicable.

B. To reduce personnel exposure time at valve stations, motor-operated or pneumatic-operated valves are used where practical. Where manual valves are used, provisions are made, when necessary, for shielding the operator from the valve by use of shield walls and valve stem extensions.

C. Gauges, instrumentation, and sampling stations that require frequent visual inspections are located in corridors or on local or central control boards to minimize exposures.

D. For valve maintenance, provisions are made for drainage of associated equipment.

E. Temporary and portable shielding is provided for use by plant personnel during maintenance.

F. Radioactive liquid and gas piping is routed to minimize radiation exposure to plant personnel.

G. Other specific design features to minimize exposures are described in section 12.3. These included a remote filter handling system, reactor cavity shielding, and a delay in CVCS piping to allow for decay of nitrogen-16 prior to letdown fluid leaving containment.

The following examples of design changes are typical of those made due to ALARA reviews:

A. Installation of jib cranes inside containment to speed maintenance.

B. Permanent shielding and remote cleaning has been provided at the reactor vessel head laydown area.

From operating plant experience for pressurized water reactors (PWRs) between the years 1970 and 1974, the distribution of personnel and man-rem doses according to functions for light-water reactors is presented in tables 12.4-1, 12.4-2, and 12.4-3.(1) Based on this operating data and on reference 2, the total man-rem dose from PVNGS is estimated to be 193 man-rem/year-unit for station personnel. A survey of man-rem dose to contract maintenance personnel based upon the 1979 data of NUREG-0713 is shown in table 12.4-4. The table indicates that, on average, contractor doses are approximately 285 man-rem per nuclear power plant (BWR and PWR, combined), annually. This

tabulation does not reflect credit for the dose reduction measures designed into PVNGS (refer to section 12.3) and may be considered an upper bound of contractor exposure. Thus, total annual exposures for station and contract personnel are projected to be less than (193 + 285 =) 478 man-rem/unit. A breakdown of this estimated man-rem by job category and design radiation zone is presented in tables 12.4-5 and 12.4-6. The assumptions used in determining these doses are presented in table 12.4-7.

12.4.2 RADIATION EXPOSURE OUTSIDE THE PLANT

12.4.2.1 Construction Worker Doses

The annual individual external dose and the immersion dose received by workers at units under construction from operating units have also been estimated. These estimates, based on 2000 hours per year exposure, are summarized in table 12.4-8 for Unit 3.

Unit 3 was chosen as it will have the highest dose rate during construction of any of the PVNGS units. The total man-rem dose to construction personnel, based on the estimated labor requirements shown in table 12.4-9 are summarized in table 12.4-10.

Table 12.4-1

HISTORICAL DATA FROM OPERATING PWR PLANTS[(a)] (Sheet 1 of 2)

Year	Plant	Design Power Level (MWe)	Megawatt Year	Total No. of Personnel	Total Annual Dose (Man-Rem)
1970	Connecticut Yankee	575	424.7	734	689
	San Onofre - Unit 1	450	365.9	251	155
1971	Connecticut Yankee	575	502.2	289	342
	Ginna	490	327.8	340	430
	San Onofre - Unit 1	450	362.1	121	50
1972	Connecticut Yankee	575	515.6	355	325
	Ginna	490	295.6	677	1,032
	Point Beach - Unit 1	497	378.3	NA	580
	Robinson	707	580.0	245	215
	San Onofre - Unit 1	450	372.2	326	256
1973	Connecticut Yankee	575	293.1	841	673
	Ginna	490	409.6	421	244
	Palisades	821	286.6	901	1,109
	Point Beach - Units 1	497, 497	693.7 for 1 and 2	729	570
	& 2 (2nd Unit	707	455.1	831	695
	4/73)	450	273.7	878	329
	Robinson				

a. These are taken from data for operating PWR plants given in reference 1. In compiling this table, generally data from the first year of plant operation have not been considered. Only data from those PWR plants that are designed to operate at power levels greater than or equal to 450 MWe were chosen.

Table 12.4-1

HISTORICAL DATA FROM OPERATING PWR PLANTS[a] (Sheet 2 of 2)

Year	Plant	Design Power Level (MWe)	Megawatt Year	Total No. of Personnel	Total Annual Dose (Man-Rem)
1974	Connecticut Yankee	575	519.1	550	201
	Ginna	490	253.7	884	1,224
	Maine Yankee	790	432.6	620	420
	Oconee - Unit 1	886	724.3	844	517
	Palisades	821	10.5	774	627
	Point Beach - Units 1 and 2	497, 497	760.2 for 1 and 2	400	295
	Robinson	707	578.1	853	672
	San Onofre - Unit 1	450	377.8	219	71
	Surry - Units 1 and 2	823, 823	717.4 for 1 and 2	1,715	884
	(Unit 2 5/73)	745, 745	966.4 for 1 and 2	794	454
	Turkey Point - Units 3 and 4 (Unit 4 9/73)				

Table 12.4-2

HISTORICAL YEARLY AVERAGES AND GRAND AVERAGE FOR NUMBER OF PERSONNEL AND MAN-REM DOSES FOR OPERATING PWR PLANTS[a]

Year	No. of Units	Total No. of Personnel	Total Man-Rem Dose	Average No. of Personnel	Average Man-Rem Dose
1970	2	985	844	493	422
1971	3	750	822	250	274
1972	5	1,603[b]	2,408	401	482
1973	7	4,601	3,620	657	517
1974	13	7,653	5,365	589	413
1970-74	30	15,592[c]	13,059	538	435

a This table is based on the data given in table 12.4-1.

b. The entry corresponds to four plants only, since no information on personnel is available for Point Beach, Unit 1.

c. The entry corresponds to a total of 29 plants only.

Table 12.4-3

HISTORICAL DISTRIBUTION OF PERSONNEL AND MAN-REM DOSES FOR VARIOUS FUNCTIONS OF OPERATING LIGHT-WATER REACTORS[(a)]

Work and Job Function	Percentage of Total Personnel	Percentage of Total Man-Rem
Routine operations and surveillance	19.2	14
Routine maintenance	34.5	45
Inservice inspection	1.44	3
Special maintenance	28.71	20
Radwaste handling	2.08	4
Refueling	14.07	14

a. The basis for this table is the information provided in Table 5 of reference 1 for 39% of the total exposures from lightwater reactors in 1974. This includes PWRs and BWRs.

Table 12.4-4

MAN-REM EXPOSURES TO CONTRACTOR PERSONNEL, 1979

Work and Job Function	Total Man-Rem[a]	Average Man-Rem[b]
Routine operations and surveillance	487.3	11.6
Routine maintenance	1794.2	42.7
Inservice inspection	1602.4	38.2
Special maintenance	7023.9	167.2
Radwaste handling	311.5	7.4
Refueling	768.7	18.3
Total		285.4

a. From Table 8 of NUREG-0713.

b. 42 units. Refer to Table 5 of NUREG-0713.

Table 12.4-5

ESTIMATED ANNUAL PVNGS MAN-REM DOSES BY JOB CATEGORY

(HISTORICAL DATA)

Category	Man-Rem/Unit		Percentage of Total Man-Rem/Unit	
Operations		99.1		51.3
Maintenance:				
Routine	(42.1)		(21.8)	
Inservice Inspection	(2.8)		(1.5)	
Special	(18.7)		(9.7)	
Total	(63.6)	63.6	(33.0)	33.0
Radwaste handling		9.9		5.1
Refueling		20.4		10.6
Total		193.0		100.0

a. Breakdown of maintenance exposure is by the relative ratios of routine and special maintenance and inservice inspection shown in table 12.4-3.

Table 12.4-6

HISTORICAL ESTIMATES OF ANNUAL GAMMA DOSE TO PVNGS PERSONNEL (3 UNITS)

Radiation Zone	Expected Average Dose Rate in Zone (mrem/hr)	Expected Number of Manhours of Occupancy per Year By Job Category[a]						Total Manhours	Estimated Annual Man-Rem Exposure[b]
		Operation	Maintenance[c]			Radwaste Handling	Refueling		
			Routine	Inservice Inspection	Special				
1	0.13	606,140	86,030	5,735	38,235	16,200	34,400	786,740	102.3
2	0.63	25,800	14,294	953	6,353	5,800	5,400	58,600	36.9
3	4.0	18,832	17,500	1,167	7,777	3,620	7,472	56,368	222.5
4	25.0	2,612	1,244	83	553	380	660	5,532	138.3
5	100.0	616	50	4	22	0.0	68	760	76.0
Total	--	654,000	119,118	7,942	52,940	26,000	48,000	908,000	579.0 (3 unit)
Man-Rem	--	297.3	126.2	8.5	56.2	29.7	61.1	579.0	579.0
% of Man-Rem	--	51.3	21.8	1.5	9.7	5.1	10.6	100	--
									193.0 per unit

a. Contractors not included. Refer to table 12.4-4.

b. Detailed breakdown by job classification presented in table 12.4-7.

c. Breakdown of maintenance exposure is by the relative ratios of routine and special maintenance and inservice inspection shown in table 12.4-3.

Table 12.4-7

DESIGN RADIATION ZONE OCCUPANCY BY JOB CLASSIFICATIONS (Sheet 1 of 2)

(HISTORICAL ESTIMATE)

Classification of Personnel[a]	Number	Category[b]	Percentage of Time Spent in Zone				
			1	2	3	4	5
Station management	2	O	100				
Support services, training, and security	114	O	100				
			97	1	1.3	0.5	0.2
Scheduling and licensing	7	O	97	1	1.3	0.5	0.2
Quality Department	13	O	97	1	1.3	0.5	0.2
Engineering and technical services	3	O	97	1	1.3	0.5	0.2
	13	O	100				
	20	O	95	3	1.5	0.5	

a. The numbers in this table represent typical expected personnel.

b. O = Operation
M = Maintenance
RH = Radwaste Handling
R = Refueling

Table 12.4-7

DESIGN RADIATION ZONE OCCUPANCY BY JOB CLASSIFICATIONS (Sheet 2 of 2)

(HISTORICAL ESTIMATE)

Classification of Personnel[a]	Number	Category[b]	Percentage of Time Spent in Zone				
			1	2	3	4	5
Operations	1	O	100				
	74	O	97	1		0.	0.2
	18	O	65	25	1.3	5	0.1
	6	RH	65	25		2.	
	12	M	65	25	7.7	2	0.1
Maintenance/instrumentation and control	1	O	100				
	20	O	97	1		0.	0.2
	16	O	60	20	1.3	5	0.1
	14	M	60	20	19.	0.	0.1
	52	M	80	5	3	6	
	6	R	60	20	19.	0.	0.2
	7	R	80	5	3	6	0.2
	7	R	80	5	14	1.	
Radiation protection	2	O	97	1		0.	0.2
	3	O	90	5	1.3	5	0.3
	8	O	60	20		0.	0.2
	8	M	60	20	3.8	9	0.1
	7	RH	60	20	19.	0.	
Chemistry	1	O	97	1		0.	0.2
	3	O	90	8	1.3	5	
	7	O	60	20	2		0.1
	4	M	60	20	19.	0.	0.1
	4	R	60	20	3	6	0.2
					19.	0.	
Total	454						

Table 12.4-8

ESTIMATE OF ANNUAL INDIVIDUAL BODY DOSE AT UNIT 3

FROM UNITS 1 AND 2

Location	Total Body Dose (mrem/yr)		
	Immersion	Direct	Total
Unit 3 turbine building	0.27	3.88	4.15
Unit 3 containment	0.23	0.64	0.87
Unit 3 auxiliary building	0.23	0.64	0.87
Unit 3 cooling tower	0.11	0.02	0.13

Table 12.4-9

ESTIMATED LABOR REQUIREMENTS

Time Period	Average Number of Workers
2nd quarter 1983	3176
3rd quarter 1983	2676
4th quarter 1983	2676
1st quarter 1984	2320
2nd quarter 1984	1960
3rd quarter 1984	1592
4th quarter 1984	1592
1st quarter 1985	1220
2nd quarter 1985	1040
3rd quarter 1985	872
4th quarter 1985	708
1st quarter 1986	352
April 1986	276

Table 12.4-10

MAN-REM DOSES TO CONSTRUCTION PERSONNEL

Year	Doses
1983	4.1
1984	5.5
1985	4.0
1986	0.5
Total	14.1

12.4.2.2 Exposures at the Site Boundary and in Uncontrolled Areas

Maximum annual exposures resulting from plant operation do not exceed applicable NRC regulations.

Estimated concentrations and doses at the site boundary due to radioactive gaseous releases are discussed in section 11.3. There are no radioactive liquid releases from PVNGS.

The direct radiation from the containment, the auxiliary building, the radwaste building, and the turbine building is negligible compared to that from the refueling water tank and holdup tank. The estimated annual dose at the nearest site boundary (from direct radiation), based on 8760 hour occupancy, is 9.5×10^{-3} mrem.

12.4.3 REFERENCES

1. Murphy, T. D., et al., NUREG-75/032, Occupational Radiation Exposure at Light Water Cooled Power Reactors 1969-1974, USNRC Radiological Assessment Branch, June 1975.

2. National Environmental Studies Project, Compilation and Analysis of Data on Occupational Radiation Exposure Experienced at Operating Nuclear Power Plants, SAI Services, September 1974.

12.5 RADIATION PROTECTION PROGRAM

12.5.1 ORGANIZATION

12.5.1.1 Program Administration

The Palo Verde Nuclear Generating Station (PVNGS) operating organization is presented in subsection 13.1.2. The radiation protection manager is responsible for station radiation protection program administration. This position is also known as the director, radiation protection or director, site radiation protection. These titles may be used interchangeably throughout the UFSAR and Technical Specifications. He is also responsible for ensuring that station operations meet the radiation protection requirements of 10CFR19 and 10CFR20.1001-20.2402, and for ensuring that station operations meet the radiation protection requirements of 10CFR50, Appendix I. Commitment to the recommendations of Regulatory Guide 1.8 is discussed in section 1.8. Commitments to the philosophies embodied in Regulatory Guides 8.2, 8.8, and 8.10 are discussed in section 1.8.

Radiation protection superintendents will implement the radiation protection program. They will direct the preparation of necessary reports and procedures within their areas of responsibility. Radiation protection superintendents and the personnel reporting to them will conduct the daily functions associated with the radiation protection program including radiation surveys and associated sample collection and analysis. Backshift radiation protection surveillance will be provided by radiation protection technicians.

12.5.1.2 Program Objectives

Objectives of the radiation protection program are to ensure that personnel exposure to radiation and radioactive materials is within the requirements of 10CFR20.1001-20.2402 and that such exposure is kept as low as is reasonably achievable (ALARA). Furthermore, the objective is to control station effluent releases to ensure that these releases do not exceed the limits of the station radiological effluent controls program as specified in technical specifications.

12.5.1.3 Radiation Protection Program

The station radiation protection program will be officially initiated when appropriate portions are implemented to receive radioactive material licensed to APS and will be in effect continuously thereafter until the units are decommissioned. This program consists of rules, practices, and procedures that are used to accomplish objectives stated above in a practical and safe manner.

The radiation protection program will ensure that:

A. Personnel permitted access to radiation controlled areas receive appropriate radiation protection training.

B. Appropriate access control techniques and protective clothing are used to limit external contamination.

C. Respiratory protection equipment is used where needed to limit internal contamination.

D. Radiological controlled areas are segregated and appropriately posted to limit radiation exposure.

E. Instruments and equipment are properly calibrated so that accurate radiation, contamination, and airborne activity surveys can be performed.

F. Appropriate personnel dosimetry devices are supplied.

G. An internal dose assessment program (whole-body counting and/or bioassay) is conducted.

H. Incoming and outgoing shipments of radioactive materials are properly handled.

I. Necessary measures are performed to keep exposures ALARA.

A more detailed discussion of the procedures used to implement this program is contained in subsection 12.5.3.

The program also ensures that appropriate effluent release samples are collected and analyzed consistent with the recommendations of Regulatory Guide 1.21.

The radiation protection program will be periodically reviewed as discussed in paragraph 12.1.1.2.

12.5.2 EQUIPMENT, INSTRUMENTATION, AND FACILITIES

The radiation protection equipment, instrumentation, and facilities include an access control island, radiation protection office, radiation protection counting room, first aid room, personnel decontamination facility, locker rooms, protective clothing, fixed and portable radiation detectors, fixed and portable air samplers, and personnel dosimeters. Chemistry and radiochemistry laboratories and a radiochemistry

counting room are located near the access control island of each unit.

12.5.2.1 Radiation Protection Equipment

Equipment for personnel protection and contamination control is described in the following paragraphs.

12.5.2.1.1 Respiratory Protection Equipment

Various types of respiratory protection equipment are provided for use to protect against airborne radioactive contamination as prescribed in the Nuclear Administrative and Technical Manual. Respiratory protection equipment is normally located at, and issued from the unit tool issue rooms, however, it can be issued from other approved locations. Typical respiratory protection equipment includes:

A. Pressure demand air line respirator: A pressure demand, full-facepiece air line mask which has Mine Safety and Health Administration (MSHA) or National Institute of Occupational Safety and Health (NIOSH) approval.

B. Air supplied hood with constant flow air supply which has NIOSH approval.

C. Self Contained Breathing Apparatus: A pressure demand, full-facepiece self-contained mask which has MSHA or NIOSH approval.

D. Filter respirator: A full-facepiece filter mask which has MSHA or NIOSH approval.

12.5.2.1.2 Protective Clothing

Various types of protective clothing are stocked at the plant to protect against contamination. Typical clothing includes:

A. Body protection

1. Lab coats

2. Coveralls

3. Plastic suits

B. Head protection

1. Surgeons caps

2. Cloth hoods

C. Hand protection

1. Disposable gloves

2. Rubber gloves

3. Glove liners

D. Foot protection

1. Plastic shoe covers

2. Cloth boot covers

3. Rubber overshoes

12.5.2.1.3 Contamination Control Equipment

Contamination control equipment is used to prevent or limit the spread of radioactive contamination and to assist in its removal. The equipment is stored in appropriate locations

within the unit. Typical contamination control equipment includes items such as:

- Vacuum cleaners with absolute filters
- Mops and wringer buckets
- Disposable and reusable sheeting
- Rolls of absorbent paper
- Plastic bags of assorted sizes
- tape
- Barricade posts with radiation rope or tape
- Radiation and contamination signs
- Temporary Laundry Equipment

12.5.2.2 Radiation Protection Instrumentation

The instrumentation used by radiation protection personnel or used for radiation protection monitoring is discussed below. The categories are: laboratory type radiation detection instrumentation; portable radiation detection monitoring instrumentation; personnel monitoring instruments; fixed area radiation monitoring system; fixed airborne radiation monitoring and sampling system; and portable air sampling/ monitoring equipment. Quantities shown are minimum for the site to support normal routine operations. During periods of increased instrument usage, additional instrumentation will be supplied from the reserve instrument inventory as needed.

12.5.2.2.1 Laboratory Type Radiation Detection Instrumentation

The laboratory type radiation detection equipment, which can be used for analysis of air and smear samples, is normally located in the radiation protection counting room. However, laboratory type detection equipment may be used at the access control point or elsewhere provided background radiation levels are acceptable.

The criteria for selection of these various counters were to obtain instrumentation that could reliably and quickly count the required samples.

These instruments are calibrated prior to initial use and semiannually thereafter, when in use, with sources traceable to the National Institute of Standards and Technology. These instruments will undergo calibration checks daily or at each use, whichever is less frequent. These calibration checks will be more comprehensive than the response checks for portable instruments and will verify the instruments operation.

The types and minimum quantities of counting room instruments, with some of their peripherals, are listed below. The instruments include:

A. Scintillation type alpha counting system and peripheral equipment.

B. G.M. type beta-gamma counting system with scaler.

12.5.2.2.1.1 Radiochemistry Laboratory Counting Room Instruments. In addition to the instruments described in paragraph 12.5.2.2.1, there are two other principal instruments

that, although used primarily for the radiochemistry program, can be considered to have some radiation protection function:

A. A multi-channel analyzer (MCA) system, consisting of an intrinsic germanium detector with lead shield, connected to an MCA with a computer for data analysis and quantification of gamma emitting radionuclides.

B. A liquid scintillation counting system for low energy beta analysis.

These instruments are calibrated prior to initial use and annually thereafter, when in use, with sources traceable to the National Institute of Standards and Technology.

12.5.2.2.2 Portable Radiation Detection Survey Instrumentation

The portable radiation detection instruments include those instruments used to perform alpha, beta, gamma, or neutron surveys for radiation or contamination control. Most of these instruments are stored so that they are easily accessible to personnel in the units.

The criteria for selection of these instruments were to obtain accurate and reliable instrumentation that could be easily serviced and that would cover the entire spectrum of radiation measurements expected to be made at the station during normal operation, shutdowns, and accident conditions.

These instruments are calibrated at least every six months, when in use, with sources traceable to the National Institute of Standards and Technology. Response checks will be made daily or at each use, whichever is less frequent, to verify

that the instruments are functioning properly between calibrations.

Sufficient quantities of each type of instrument will be obtained to permit calibration and maintenance without diminishing the radiation protection capability. Quantities of the below listed types of instruments shall be maintained on hand to provide the listed minimum quantities for the site after allowing for instruments out of service (in need of calibration or repairs). These quantities are sufficient to provide for normal expected instrument usage.

A. Twelve portable G-M dose rate meters used to measure gamma dose rates up to 1000 mrem/h.

B. Twelve ion chamber type dose rate meters used to measure beta-gamma dose rates up to 5 rem/h.

C. Twelve ion chamber type dose rate meters used to measure beta-gamma dose rates up to 50 rem/h.

D. Twelve very high range gamma dose rate meters with a range up to 1000 rem/h.

E. Six ion chamber type dose rate meters used to measure beta-gamma dose rates up to 10,000 rem/h.

F. Four alpha survey meters with a range up to 500,000 cpm.

G. Four neutron survey meters with a readout covering the range of 0 to 5000 mrem/h.

12.5.2.2.3 Personnel Monitoring Instruments

Personnel monitoring instrumentation is provided to determine external and internal contamination levels and radiation doses received by personnel.

Dose measuring devices are divided into two types; record dosimeters (thermoluminescent dosimeters) and incremental dosimeters (electronic dosimeters). The criteria for selection of record dosimeters was to have devices that could be quickly and accurately evaluated by station personnel. The criteria for selection of electronic incremental dosimeters was to have devices that could easily be read by the individual, would interface with the radiological records and access control database to provide an automated access/control system, and would provide both audible and visual warnings to individuals when preset dose or dose rate thresholds are exceeded. The criteria for selection of external contamination measuring equipment were to have devices available at checkpoints and other areas that could be used to determine the location of contamination (friskers) and at the normal exit from the controlled area and security-protected area that require minimal action by personnel being checked (whole-body friskers and/or portal monitors). The principal criterion for selection of the whole-body counting system was to have a system readily available to supply information concerning internal exposure.

The friskers, portal monitors, whole-body friskers, and thermoluminescent dosimeter (TLD) readers are calibrated electronically and/or with a source at least semiannually. A response check on the friskers is performed daily. Whole-body

friskers and small article monitors are response checked weekly or whenever performance could have been affected. Portal monitors are response checked monthly or whenever performance could have been affected. The TLD readers are response checked daily. Electronic dosimeters are calibrated semiannually, the whole-body counting system is calibrated at least annually using a phantom containing various radionuclides. Calibration checks of the whole-body system are performed daily when the system is in operation.

Quantities of each type of device will be obtained to permit calibration and repair without diminishing the radiation protection supplied. The devices and minimum numbers of each for the site include:

A. Count rate meters that are used as friskers to detect beta-gamma external contamination. They are normally used with G-M detectors (at least 60).

B. One portal monitor used to check for gamma external contamination at the exit to the protected area. The portal contains several scintillation detector channels to provide head-to-foot detection capability. A sensor activates the counting circuit when a person steps into the portal. Visual and audible alarms are provided. (A backup set is available to substitute for an inoperative portal monitor).

C. Three hundred electronic dosimenters. These dosimeters have the capability to generate both audible and visual alarms when preset limits for dose and/or dose rates are exceeded.

D. One primary automatic TLD reading system with an alternate is used onsite for the determination of personnel exposures.

E. One whole-body counter, located onsite. The multi-channel analyzer and computer are programmed to analyze the data and report the radionuclides and activities detected.

F. Containers for collection of urine samples (normally used for tritium) and for fecal samples (possibly used under accident conditions) will be available. These samples are sent to a vendor for analysis.

12.5.2.2.4 Fixed Area Radiation Monitoring System

The fixed area radiation monitoring system (FARMS) is a subsystem of the permanent in-plant radiation monitoring system (RMS) and consists of three groups of monitors per unit:

- Normal range area monitors
- Post-accident range area monitors
- Portable normal range area monitors

Additionally, there is an area monitor in the central calibration facility shared by all units.

The system provides readout and alarms in the unit control room and RMS office. The fixed area radiation monitoring system's criteria for selection, detailed system description, maintenance and calibration methods and frequencies, and detector ranges, sensitivities, and locations are given in section 11.5.

12.5.2.2.5 Fixed Airborne Radiation Monitoring and Sampling System

The fixed airborne radiation monitoring and sampling system (FabRM/SS) is a sub-system of the permanent in-plant radiation monitoring system (RMS) and consists of three groups of monitors per unit:

- Normal range area monitors
- Post-accident range monitors
- Movable normal range monitors

Additionally there is one monitor in each of the two Emergency Response Facilities that monitors the ventilation systems.

The system is used to determine the levels of airborne radioactivity in plant effluent discharge paths and in in-plant areas. Airborne radioactivity levels will be maintained in accordance with PVNGS Technical Specifications.

The general criteria for selection of the fixed airborne radiation monitoring and sampling equipment were:

A. To install fixed airborne radiation monitoring and sampling equipment on the plant effluent discharge paths with alarms in the control room so that automatic (or operator) action can be taken to correct abnormal situations.

B. To install fixed airborne radiation monitoring and sampling equipment in in-plant areas where airborne activity was expected to occur or where it would need to be determined during an emergency.

The location of the fixed airborne radioactivity monitoring and sampling equipment, as well as a detailed system description, detector types, sensitivities, and ranges, and equipment calibration frequency and methods are given in section 11.5.

12.5.2.2.6 Portable Air Sampling/Monitoring Equipment

Portable air sampling/monitoring equipment is used to determine the levels of radioactivity in effluent discharge paths and in-plant areas where fixed airborne radiation monitoring and sampling equipment is not in service or is not installed as required by the Technical Specifications or Offsite Dose Calculation Manual.

The criteria for selection of the portable air sampling/ monitoring equipment were:

A. To use portable air sampling/monitoring equipment in place of fixed airborne radiation monitoring and sampling equipment as required by the Technical Specifications or Offsite Dose Calculation Manual.

B. To use portable air sampling/monitoring equipment for in-plant determinations, to monitor work areas where airborne activity levels could be high.

C. To use portable air sampling/monitoring equipment to determine airborne activity at some jobsites during maintenance and normal operation.

The air sampling/monitoring equipment is routinely maintained and detectors are calibration checked using check sources that are related to initial calibration. As long as the check

source response does not change significantly, a complete calibration will not be performed.

Air sample flowrate measuring devices for portable air samplers will be calibrated as follows:

A. Portable samplers utilized as backup equipment to fixed monitor/samplers will be calibrated at least every 18 months.

B. Portable samplers used for short-term air sampling to obtain quick grab samples such as at the beginning of a job, or during activities that could significantly increase the airborne activity level, will be calibrated at least every 6 months.

C. Portable samplers described in listing B above and utilized in emergency preparedness kits will be calibrated or replaced in the kits at least every 12 months.

Typical portable air sampling and monitoring instrumentation quantities are listed below:

A. Portable CAMs capable of measuring gross beta and/or alpha airborne activity. These monitors are capable of generating both visual and audible alarms.(6)

B. High volume air samplers used for short-term air sampling to obtain quick grab samples, such as at the beginning of a job or during activities that could significantly increase the airborne activity level.(6)

12.5.2.2.7 Radiological Records and Access Control

A computerized radiation exposure management information system is available to assist radiation protection personnel in preparation of the records and reports required by 10CFR19 and 10CFR20.1001-20.2402.

The major functions of the radiological records and access control software are:

- Maintain a personnel data and exposure file.
- Maintain a file of job-related exposure data.
- Generate required occupational exposure reports.
- Provide a tool to track the availability and assignment of dosimetry devices.
- Generate reports for radiological protection management
- Provide a data base for radiologically controlled area access control.

12.5.2.3 Facilities Related to Radiation Protection

12.5.2.3.1 Unit Radiation Protection Complex

The entire radiation protection complex discussed below, which is located at the 140-foot level in the auxiliary building, is shown in engineering drawing 13-P-OOB-005. These facilities are arranged so that the men's and women's locker rooms are outside the RCA, adjacent to the RP island complex.

The secondary chemistry laboratory, RMS facilities, and radiation protection office entrances are located outside the boundaries of the radiologically controlled area.

Radiation protection personnel occupy the radiation protection laboratory complex. They issue special dosimeters and other equipment as required by the REP. The RMS, access control, and radiation survey data can be reviewed and processed in this area.

Also within the confines of the radiologically controlled area are the first aid room, decontamination room, the RP instrument room, the radiochemistry laboratory, sample room and counting room, and the radiation protection counting room.

12.5.2.3.2 Central Calibration Facility

A central calibration facility is located near the condensate storage tank outside and north of Unit 1 (see engineering drawing 13-C-ZVA-005 and 13-P-OOB-001). The facility contains a neutron source and shielded calibration range. Thermoluminescent dosimeter neutron response checks and portable radiation measurement instrument calibrations are typically performed in this facility.

A satellite calibration laboratory is located in the Unit 1 Corridor Building to perform maintenance and calibration activities on radiation protection instrumentation. The facility contains low activity radioactive sources used during instrument calibration. The radioactive sources stored and used in the laboratory do not significantly impact background radiation levels. A radiological controlled area is established within the calibration laboratory to support work activities on contaminated equipment.

12.5.2.3.3 Decontamination Facility

The decontamination facility is located near the radwaste building of Unit 1. Liquid wastes from the decontamination facility are piped to a line common to the laundry building which goes to the Unit 1 chemical drain tanks. The solid waste generated from the decontamination facility is manually transferred to the solid radwaste system for packaging.

12.5.2.3.4 Outage Support Facility

The OSF provides a central location for the rework of contaminated plant equipment and storage pf plant components, equipment, and tools necessary to support ongoing maintenance of the units. Neither radioactive waste processing nor storage of radioactive waste is permitted in or outside of the building.

The OSF contains a large crane bay, machine shop, and an RP instrument laboratory in the primary work area on the ground floor along with a Radiation Protection controlled access and egress island, locker rooms, and a protective clothing issue station. The instruments used in the laboratory are per section 12.5.2.2.1. Office, conference, and living spaces are on the second floor. The OSF is located within the site primary Protected Area/Restricted Area fence and includes an administratively controlled area, as described in section 12.5.3.2, for the purpose of limiting exposure of individuals to radiation and radioactive materials.

The OSF drain system is not designed to support drainage of intentionally contaminated liquid. The OSF has two independent

ventilation systems so that the ventilation system in the contaminated work spaces does not return air to the ventilation system supplying non-contaminated areas of the building. Air supply for the crane bay is provided through ventilation ducts in the overhead and is cooled via roof-top chillers and, when running, the exhaust AFUs maintain the north end of the building at a slightly negative pressure relative to the environs and to the building office spaces. The crane bay ventilation exhaust system is through two AFUs located in each of the north corners of the crane bay. Each AFU contains HEPA filters and sample ports in the exhaust duct that allow for environmental effluent monitoring.

12.5.3 PROCEDURES

Radiation protection procedures are established to keep personnel radiation exposures ALARA and within the limits of 10CFR20.1001-20.2402. These procedures are discussed in paragraph 12.5.3.2. Policy and operational considerations for maintaining personnel radiation exposures are discussed in subsections 12.1.1 and 12.1.3.

12.5.3.1 Radiation and Contamination Surveys

Radiation protection personnel normally perform routine radiation and contamination surveys of accessible areas of the units. These surveys consist of radiation dose rate measurements and/or contamination smears as appropriate for the specific area. Air sampling is performed based upon the specific task being performed or if plant conditions warrant such samples. Surveys related to specific activities may be

performed if necessary prior to, during, or after activities that would be expected to produce additional significant radiation exposure to individuals. Advanced radworkers perform radiation and contamination surveys associated with activities of low radiological significance. Survey procedures and routine survey schedules are provided in the Nuclear Administrative and Technical Manual.

12.5.3.2 Procedures and Methods to Maintain Exposures ALARA

Operating, maintenance, and radiation protection procedures are reviewed, as discussed in subsection 12.1.1, to identify situations in which potential exposures could be reduced. Such ALARA considerations include:

A. Restricted Areas

Restricted areas as defined in 10CFR20.1003 are established at the protected area fence and access is controlled at that point for the purpose of protecting individuals from exposure to radiation and radioactive materials.

B. Controlled Areas

Procedures establish permanent and temporary controlled areas within the restricted areas where access is further administratively controlled for the purpose of limiting exposure of individuals to radiation and radioactive materials. Radiation and high radiation areas identified within controlled areas are posted appropriately and access control

maintained in accordance with PVNGS Technical Specifications and 10 CFR 20.

C. Radiation Exposure Permits

Procedures require radiation exposure permits for entry into radiologically controlled areas. These permits are a principal administrative means of managing personnel radiation exposure and describe the radiological controls required to perform the activity and maintain personnel radiation exposure ALARA. The permit contains information pertinent to the activity such as radiation and/or contamination levels in the area, allowable stay times, protective clothing requirements, respiratory protection equipment requirements, special personnel monitoring requirements, and temporary shielding requirements.

Radiation exposure permits require the approval of radiation protection supervision or designated alternates.

D. Selected Operating and Maintenance Activities

Operating and maintenance activities that can result in significant individual exposures are controlled by written procedures. Procedures controlling refueling, radwaste handling, spent fuel handling, radiochemical sampling, loading and shipping of radioactive materials, and procedures controlling inservice inspections, normal operation, routine maintenance, and calibrations that are expected to require issuance

of a radiation exposure permit, are reviewed for ALARA considerations, as discussed in subsection 12.1.1.

12.5.3.3 Control of Access and Stay Time in Radiation Areas

Physical and administrative controls assure that the philosophy of maintaining personnel exposures ALARA is implemented, as specified in section 12.1 and paragraph 12.5.3.2.

Authorized personnel who enter station restricted areas are issued appropriate dosimetry devices in accordance with Nuclear Administrative and Technical Manual procedures.

12.5.3.4 Contamination Control

Contamination limits for personnel, equipment, and areas are listed in the Radiation Protection Division of the Nuclear Administrative and Technical Manual. Surveys are performed as discussed in paragraph 12.5.3.1, to determine contamination levels. Areas found contaminated beyond specified limits are roped off or otherwise delineated with a physical barrier, posted appropriately, and decontaminated as soon as practical. A stepoff pad or other appropriate means may be used to prevent the spread of contamination.

Nuclear Administrative and Technical Manual procedures incorporate those recommendations of Regulatory Guide 1.39 which are considered applicable for housekeeping activities occurring during the operations phase that are comparable to those occurring during the construction phase (refer to section 1.8).

Tools and equipment used in contaminated areas are monitored prior to removal from the controlled area. If they are to be released to an uncontrolled area, they must meet uncontrolled (clean) area limits, and must be decontaminated or packaged and labelled as necessary to meet these limits. Decontamination facilities are discussed in subsection 12.5.2. If the tools and equipment are to be transferred to another controlled area through an uncontrolled area, they may be bagged, wrapped, or similarly enclosed to prevent the spread of contamination while being transferred.

Control of personnel contamination (external and internal) is provided by use of protective clothing and respiratory protection equipment as discussed in subsection 12.5.2. Each individual is responsible for monitoring himself and his clothing when he crosses a local control point or the main access control point. If contamination above allowable limits is found, the individual is decontaminated using facilities previously described in subsection 12.5.2.

12.5.3.5 Airborne Activity Exposure Control

When airborne radioactivity is detected in excess of the limits of 10CFR20.1003, the area is posted as an airborne radioactivity area, and access is controlled in accordance with paragraph 12.5.3.2.

Occupancy is restricted, process or other Engineering Controls are utilized, or respiratory protection equipment is provided to maintain exposures TEDE ALARA if personnel entry is required into areas where the source of airborne radioactivity cannot be removed or controlled. The selection of respiratory protection

equipment is established by historical data and current contamination levels, which are used to evaluate potential airborne hazards. The respiratory protection program is organized to conform to the applicable portions of ANSI Z88.2. Effectiveness of the respiratory protection program is evaluated by various types of bioassay analyses.

Respiratory equipment discussed in subsection 12.5.2 is available at unit tool issue rooms. Supplementary emergency respiratory equipment is available in the control room and in emergency kits.

The following controls are incorporated in the program:

A. Each respirator user is advised that he may leave an airborne radioactivity area for psychological or physical relief from respirator use. Each user shall leave the area in the case of respirator malfunction or any other condition that might cause reduction in the protection afforded the user.

B. Air samples and surveys are made to identify the presence of airborne radioactivity and to estimate individual exposures.

C. Procedures are established to ensure correct fitting, use, maintenance, and cleaning of respirator equipment. Each individual qualified to use respiratory protection equipment receives a quantitative fit test annually and checks each respirator for proper fit prior to use.

12.5.3.6 Personnel Monitoring

Station employees, contractor personnel, support personnel, and visitors are required to wear TLD or electronic dosimeters when in a controlled area. In addition, incremental dosimetry is issued to individuals working under a radiation exposure permit. The exposure readings of this incremental dosimetry is used for specific ALARA job exposure evaluation, as well as to indicate current individual exposure status. Use of neutron dosimeters complies with the requirements of 10CFR20.1501.

The Nuclear Administrative and Technical Manual requires bioassays, including whole-body counting, consistent with the recommendations of Regulatory Guides 8.9 and 8.26. The type of determination and the frequency of determination depends upon the work environment of the individual and the work situation.

Personnel dosimetry is evaluated on at least an annual basis and is used as the dosimetry of record for the individual unless evaluation determines an alternate exposure evaluation is more representative of the dose received.

Exposure data of personnel issued personal dosimeters in accordance with 10CFR20.1502 is maintained on NRC Form 5, or equivalent. Occupational exposures incurred by individuals prior to working at PVNGS are summarized on NRC Form 4, Occupational External Radiation Exposure History, or the equivalent. These records are maintained at PVNGS and will be preserved for the lifetime of the plant or until the NRC authorizes their disposal. Reports of overexposure to radiation workers are made to the NRC and the individual involved pursuant to 10CFR19 and 10CFR20.1001-20.2402.

12.5.3.7 Handling of Radioactive Material

Licensed sources used for calibration are used by or under the direction of personnel who have received training in the safe use and handling of sources. A radiation exposure permit will be required if such use could result in significant personnel exposure.

Suitable methods for the safe handling of radioactive materials are implemented to maintain external and internal doses at levels that are ALARA. External doses are minimized by a combination of time, distance, and shielding considerations. Internal doses are minimized by the measurement and control of loose contamination and airborne radioactivity. Nuclear Administrative and Technical Manual procedures provide instructions for handling radioactive sources.

Sealed radionuclide sources having activities greater than the quantities of radionuclides defined in Appendix C to 10CFR20.1001-20.2402 and Schedule B of 10CFR30 are subject to material controls for radiological protection. Those controls include:

A. Monitoring of packages containing radioactive materials for external dose rate and removable contamination upon receipt at the station and prior to shipment away from the station.

B. Each sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting material or 5 microcuries of alpha emitting material are leak tested every six months to determine if the removable contamination exceeds 0.005

microcuries. The following types of sources are exempted from the 6 month leak testing: 1) tritium and gaseous sources, 2) sources in storage, 3) startup sources and fission detectors. Sources in storage are leak tested prior to use or transfer to another licensee unless tested with the previous 6 months. Startup and fission detector are leak tested following repair, or maintenance, or 31 days prior to being subjected to core flux, or installed in the core. Startup sources and fission detector are not subject to leakage testing following to exposure to core flux.

C. Labeling of licensed sources with the radiation symbol, stating the activity, radionuclide, and source identification number.

D. Secure storage of sources which are not installed in an instrument or other piece of equipment.

E. Inventory of sources every year.

12.5.3.8 Radiation Protection Training

Personnel requiring access to a restricted area and/or radiological controlled area will receive training as necessary to permit access to these areas. These personnel will be tested to evaluate each worker's knowledge, competency, and understanding relative to the training provided.

General employee training is discussed in section 13.2. The training program includes instruction in applicable provisions of the NRC regulations for the protection of personnel from radiation and radioactive material 10CFR20.1001-20.2402 and

instruction to women concerning prenatal radiation exposure. The training addresses the following topics and requirements:

- Sources of radiation
- Measurement of radiation
- Biological effects
- Limits and guidelines
- As Low As Reasonably Achievable (ALARA)
- Radiation dosimetry
- Contamination
- Internal exposure
- Radiation Work Permit (RWP)
- Postings
- Radiological alarms
- Radioactive waste
- Rights and responsibilities

In addition to general employee training, radiation protection personnel and advanced radworkers also receive training in areas which apply to their specific job functions such as radiation and contamination surveys, air sampling techniques, use of portable and laboratory instrumentation, release limits, and safe handling of sources.

APPENDIX 12A

RESPONSES TO NRC REQUESTS FOR INFORMATION

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APPENDIX 12B

PVNGS REVIEWS TO ACHIEVE AN ALARA DESIGN

UFSAR Appendix 12B provides historical information regarding how the initial ALARA reviews were performed during the initial design of PVNGS. The section provides a brief summary of the actions, formal and informal, taken to ensure that the ALARA guideline delineated in UFSAR section 12 were met. Current PVNGS administrative procedures provide guidance to assure that modifications and design changes are reviewed to maintain exposures ALARA. Therefore, UFSAR Appendix 12B is considered historical information and is not maintained.

APPENDIX 12B
PVNGS REVIEWS TO ACHIEVE AN ALARA DESIGN

Nuclear power plant radiation exposures are received primarily during work on components in the reactor coolant and radwaste systems and on components located adjacent to those systems. Therefore, the main thrust of the PVNGS design exposure reduction effort has been directed toward these systems. It included considerations such as the following:

A. Maintenance frequency is minimized by improving component reliability and by reducing routine maintenance, inspection, and operational requirements.

B. Maintenance time is minimized by a plant layout which facilitates access during maintenance, and by satisfactory working conditions during maintenance.

C. Radiation levels are reduced in the area of maintenance-prone components by a plant layout that separates these components from highly radioactive components, and provides appropriate design features that facilitate flushing and decontamination and that minimize crud trap formation.

Incorporating these general considerations into the PVNGS design has required that all disciplines coordinate their efforts to incorporate ALARA features.

The engineer for PVNGS, Bechtel, was assigned the lead role for the implementation of ALARA design, subject to periodic audits and reviews of their performance by APS personnel.

Bechtel conducted regular, interdisciplinary reviews of the design to implement ALARA design and to establish that reasonable efforts had been made to reduce occupational radiation exposures.

Three formal levels and one informal level of approval were required before the PVNGS design was approved as meeting the ALARA guidelines delineated in sections 12.1 and 12.3.

Designers consulted informally with engineers to eliminate potential problems as the design progressed. Thus, design features were evaluated effectively during the time that the cost impact of changes was minimal. The engineers had experience in the areas of shielding, operations, maintenance and maintainability, OSHA requirements, decontamination, and health physics.

A formal multidiscipline meeting (type I) was held to review each area of the plant for concrete placement. Bulk shielding was evaluated. Walls were checked for proper thickness. Proper maintenance access was ensured. Entrance labyrinths were used as necessary. Concrete voids due to HVAC or electrical penetrations were modified or shielded. If the concerns were resolved, type I approval was given and the area was released for piping design.

A type II review of each piping system or subsystem in the plant was held. These multidiscipline meetings examined piping layouts for crud traps, proper routing (e.g., not in a doorway or corridor), and maintainability. Shielding was checked for adequacy.

After the type I and type II reviews were completed, a type III review of each building level was held. This final release for construction review examined the interface between the collective systems and plant area under review. It verified that the design evolution had proceeded along the guidelines given in the prior two levels of review.

Each review was documented by the use of the ALARA/ISI review checklist (table 12B-1).

APPENDIX 12B

Table 12B-1

ALARA/ISI REVIEW CHECKLIST (Sheet 1 OF 6)

PLANT AREA: ____

____

DATE: ____

ATTENDEES:

CIVIL/STRUCTURAL ____

CODES ____

ELECTRICAL ____

CONTROLS ____

NUCLEAR ____

PROJECT OFFICE ____

PLANT DESIGN ____

MECHANICAL ____

ARCHITECTURAL ____

CONSTRUCTION ________________________ START UP ______________

ACTION ITEMS	DISCUSSION	RESPONSIBLE DISCIPLINE
1		
2		
3		
4		

APPENDIX 12B

Table 12B-1

ALARA/ISI REVIEW CHECKLIST (SHEET 2 OF 6)

ACTION ITEMS	DISCUSSION	RESPONSIBLE DISCIPLINE
5		
6		
7		
8		
9		
10		
11		
12		

APPENDIX 12B

Table 12B-1

ALARA/ISI REVIEW CHECKLIST (Sheet 3 OF 6)

Resp	VERIFICATION \ SYSTEM/AREA					
	I. GENERAL LAYOUT GUIDELINES					
J	1. Control panels, readout devices and transmitters shall be located in low radiation zones (zone 2 or less).					
N	2. Sample sites shall be isolated from other radioactive equipment.					
	3. The following shielding considerations shall be observed.					
N	a) Valves and instrumentation on process systems which contain major sources of radiation will be shielded from the system components.					
N	b) Access to shielded compartments shall normally be by means of shielded labyrinth arrangements. Highly radio- active passive components shall be in completely enclosed compartments and shall be provided with access via a shielded hatch.					
N	c) Radioactive equipment shall be separated by shielding from nonradioactive equipment to facilitate unrestricted maintenance on the latter.					
	4. Control of radioactive contamination.					
C/S	a) Large tanks containing radioactive fluids shall be enclosed in water tight compartments or be surrounded by curbs.					
PD	b) Sloped floors and floor drains shall be provided for all radioactive equipment compartments.					
PD	c) Vents and drains required for radio- active equipment maintenance shall be piped directly to a drainage system.					
	5. Valve galleries					
PD	a) Exposed piping in the valve gallery will be minimized.					

ALARA DISPOSITION KEY

Satisfactory - S   Not Applicable - NA
Action Required - AR   Not Observed - NO

APPENDIX 12B

Table 12B-1

ALARA/ISI REVIEW CHECKLIST (Sheet 4 OF 6)

Resp	VERIFICATION \ SYSTEM/AREA					
M/N	b) Frequently used valves shall be capable of being operated from a Zone 2 area.					
PD	c) Sufficient space shall be provided in valve galleries to facilitate mainten-ance on valves.					
	6. The following considerations shall apply to the routing of radioactive piping in order to minimize operator exposures:					
N	a) Piping shall be routed so that it does to constitute violation of specified radiation zones.					
N	b) Radioactive piping shall not be routed through zone 1 or zone 2.					
N	c) Piping shall be routed through the highest radiation zones practicable.					
PD	d) Piping shall be routed behind components or structures, close to floors and ceil- ings and next to walls.					
N	e) Radioactive piping shall be separated from nonradioactive piping for maintenance purposes.					
M,J	f) Valves or instrumentation within radioactive pipe chases shall be restricted.					
	II. <u>PIPING AND PENETRATION DESIGN GUIDELINES</u>					
PD	1. Length of pipe runs and number of bends shall be minimized.					
PD	2. Low points and dead legs in radioactive piping shall be minimized.					
PD	3. Valves shall not be located at low points in piping					
PD	4. Thermal expansion loops shall be raised.					
PD	5. Branch process lines having little or no flow shall be taken off slightly above the horizontal midplane of the main process pipe					

APPENDIX 12B

Table 12B-1

ALARA/ISI REVIEW CHECKLIST (Sheet 5 OF 6)

Resp	VERIFICATION / SYSTEM/AREA					
J	6. Instrument taps shall be taken off slightly above the horizontal midplane of the process piping.					
PD	7. Strainers shall be located immediately downstream of Ion Exchangers					
N	8. Resin lines shall be continuously sloped in direction of flow.					
	9. The following provisions for component isolation, draining, and flushing shall be incorporated.					
M/PD	a) Isolating and draining capability for all serviceable components.					
PD	b) High-point vent and low-point drains					
N/PD	c) Vent and drain valves required for radioactive equipment maintenance shall be located to minimize operator exposure.					
N	10. Penetration shall be designed to minimize radiation streaming by location, offsetting, grouting or shielding.					
	III. <u>ISI ACCESS REQUIREMENTS</u>					
I	1. Adequate access shall be provided to conduct required inservice inspection.					
I	2. Spool pieces shall be installed in piping to allow for volumetric inservice inspection of welds where required					
I	3. Adequate plant services, power, lighting, ventilation, water, instrument air shall be available					
	IV. MAINTENANCE/CONSTRUCTION					
C/N	1. Adequate embeds, beams, etc., shall be provided for equipment installation (over 50#)					

Table 12B-1

ALARA/ISI REVIEW CHECKLIST (Sheet 6 OF 6)

Resp	VERIFICATION \ SYSTEM/AREA					
	2. Adequate envelope shall be provided for maintenance including space for					
C/N	a) Rigging					
M/PD	b) Special tools					
M/PD	c) Work force					
M/PD	d) Laydown					
N	e) Temporary shielding					
M	f) Temporary ventilation					
M/PD	g) Equipment / valve removal					
M/PD	3. Access shall be provided as required for equipment/valve maintenance, operation and surveillance testing					
PD	4. Equipment manways shall be readily accessible.					
PD	5. Adequate clearance shall be provided around open panel doors					
M/ PD/N	6. Equipment replacement/repair shall be possible within the time limits of the Technical Specifications					
PD	7. A minimum of 10" clearance shall be provided between any component, other than support,and the floor or ceiling					

CHAPTER 13

CONDUCT OF OPERATIONS

CONTENTS

CONTENTS (cont)

FIGURES

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13. CONDUCT OF OPERATIONS

13.1 ORGANIZATIONAL STRUCTURE OF APPLICANT

13.1.1 MANAGEMENT AND TECHNICAL SUPPORT ORGANIZATION

Arizona Public Service Company (APS), one of the owners of the Palo Verde Nuclear Generating Station (PVNGS), has the overall responsibility for management, operation and oversight of the facility. APS provides a staff of personnel that either conducts these operations or provides support services for operations. Members of the management and technical support organization staff may be located onsite or offsite.

The executive vice president, nuclear and CNO, reports directly to the chief executive officer of APS, and is responsible to provide leadership to the Nuclear Generation organization and overall management of the activities related to the operation, maintenance, and modification of the Palo Verde Nuclear Generating Station, including the entire owner controlled property.

The executive vice president, nuclear and CNO, has overall responsibility to ensure that all PVNGS activities, including operation, maintenance, and modification of the units are performed in strict compliance with regulatory requirements, consistent with the requirements for protection of the health and safety of the general public and company personnel, and in accordance with company policy.

The overall organizational structure, reporting relationships, and responsibilities for management and technical support of the facility are described in the PVNGS Operations Quality Assurance Program Description (QAPD).

The onsite operating organization and its responsibilities and authorities are further described in UFSAR Section 13.1.2, the Unit Technical Specifications, and station administrative procedures.

13.1.2 OPERATING ORGANIZATION

The responsibilities and authorities of key members of the operating organization are described in this section. The following APS positions have the responsibility and authority for directing or placing a PVNGS unit in a reduced power or shutdown condition to ensure nuclear safety:

- executive vice president and CNO
- senior vice president site operations
- site general plant manager
- operations director
- unit operations managers
- shift managers
- control room supervisors
- control room operators

13.1.2.1 Executive Vice President and CNO is responsible for:

- overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety;
- ensuring that all PVNGS activities, including operation, maintenance, and modification of the units and related

nuclear facilities are performed in strict compliance with regulatory requirements, consistent with the requirements for protection of the health and safety of the general public and company personnel, and in accordance with company policy;

This position fulfills the role of the corporate officer described at 5.2.1.c of the PVNGS Unit Technical Specifications.

13.1.2.2 The <u>Senior Vice President Site Operations</u> is responsible for:

- overall PVNGS site and plant management, including operations of the nuclear power plants, spent fuel storage facility, and water reclamation facility
- providing technical and engineering support for operations, maintenance, and modification of the power plants and facilities located at the plant site
- establishing and administering policies, providing procedures, and maintaining standards of performance that ensure safe operation
- ensuring site operations are in compliance with requirements of the operating license, applicable regulations, and regulatory commitments

13.1.2.3 The Site General Plant Manager has direct line responsibility for operation and maintenance of the PVNGS nuclear plants and is responsible for direction of plant operations.

This position fulfills the role of the Plant Manager as described in 5.2.1.b of the PVNGS Unit Technical Specifications.

13.1.2.4 The Operations Director is responsible for:

- approving operational programs and procedures
- managing and directing safe operation of the facility in accordance with regulatory requirements, the Operating Licenses, and company policies, programs, and procedures
- providing programs for ensuring that surveillance testing is performed as required

13.1.2.5 Units 1, 2 and 3 Operations Managers are responsible for:

- conducting unit operations in a safe manner in accordance with the technical specifications and station procedures
- supervising the activities of the operating personnel
- coordinating the activities and performance of the shift managers to ensure that the conduct of the operating staff is consistent with protection of the health and safety of the public and is in compliance with all applicable rules, regulations, and procedures

- ensuring that identified plant deficiencies receive the appropriate work priority to maintain plant safety and reliability
- reviewing various operating logs and records for accuracy, completeness, adherence to applicable administrative procedures, regulations and technical specifications, and to maintain current knowledge of plant activities

This position satisfies the requirements of the Operations Department Leader as described in the PVNGS Unit Technical Specifications. This position will hold a senior reactor operator license to satisfy the requirements of the PVNGS Unit Technical Specifications 5.2.2.d.

13.1.2.6 Operating Shift Crews

Normally during non-outage periods, operating crews will be manned on a five shift, self-relieving 5-crew basis. An operating crew for each unit will normally consist of a shift manager and control room supervisor (who will possess senior reactor operator licenses), two reactor operators (who will possess reactor operator licenses), and four non-licensed operators (nuclear auxiliary operators). The minimum shift operating crew composition for various modes of operation is described in the PVNGS Unit Technical Specifications and in section 18.I.A.1.3.

A site Fire Department of at least five members shall be maintained onsite at all times. Fire Department composition may be less than the minimum requirements for a period of time

not to exceed two hours in order to accommodate unexpected absence of fire department members, provided immediate action is taken to restore the fire department manning to minimum requirements.

The Fire Department shall not include the Shift Manager, the STA, nor the 3 other members of the minimum shift crew necessary for safe shutdown of the unit and any personnel required for other essential functions during a fire emergency. One Reactor Operator is assigned to support the Fire Department as the Fire Team Advisor.

13.1.2.6.1 Shift Managers are responsible for the safe operation of the unit during their assigned shifts.

13.1.2.6.2 Control Room Supervisors are responsible to provide a backup to the shift manager and supervise shift personnel in the conduct of operations.

13.1.2.6.3 Limited Senior Reactor Operator (LSRO) for Refueling. The limited senior reactor operator (LSRO) for refueling is responsible to the shift manager for directly supervising core alterations and those specific evolutions or work activities that could result in core alterations.

This individual will be a senior reactor operator conditionally licensed for refueling operations and who has no concurrent duties when performing functions of the LSRO. A fully-licensed senior reactor operator with no concurrent duties may perform the functions of the LSRO.

13.1.2.6.4 Reactor Operators are responsible for:

- operating and directing operations of mechanical, electrical, and reactor systems from the control room
- reactor safety in accordance with Technical Specifications, company policies, and procedures

13.1.2.6.5 Nuclear Auxiliary Operators are responsible, under the direction of the control room supervisor, for operating plant systems and assisting in fuel handling operations, as directed.

13.1.2.6.6 Shift Technical Advisor is responsible for:

- providing advisory technical support to the Shift Manager in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to safe operation
- meeting qualification requirements specified by the Commission Policy Statement on Engineering Expertise on Shift

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13.2 TRAINING PROGRAM

Personnel to staff PVNGS are selected to ensure they will have the qualifications necessary to satisfactorily perform their assigned functions. To augment the formal education, training and experience of station personnel, training programs have been instituted for site employees and contract personnel. The Director, Nuclear Training has overall responsibility for the conduct and administration of training programs for the staff of PVNGS.

Refer to the PVNGS Operations Quality Assurance Program Description for other training program requirements and associated responsibilities.

The Director, PV Water Resources has the overall responsibility for the conduct and administration of the Water Reclamation Facility training programs.

Training program content is described in training program descriptions.

13.2.1 TECHNICAL TRAINING PROGRAMS:

Technical training programs for the staff of PVNGS have been developed based on a systematic approach to training as defined by 10CFR55.4.

The technical training programs include those listed in 10CFR50.120, "Training and qualification of nuclear power plant personnel" and these programs are periodically evaluated by the National Nuclear Accrediting Board (NNAB).The Director, Nuclear Training has direct responsibility for administration of the

training programs identified in 10CFR50.120, "Training and qualification of nuclear power plant personnel."

13.2.2 GENERAL TRAINING DESCRIPTION

13.2.2.1 Types of Training

Station personnel may be qualified through formal education and experience, formal job training, related technical training, on-the-job training, or a combination thereof.

13.2.2.2 Qualification of Personnel

Personnel training and qualification is delineated in training program descriptions or administrative procedures. The Nuclear Training Department assists each unit staff organization in the development of training and the maintenance of personnel qualifications. Site personnel and their leaders are responsible to ensure they are qualified prior to performing assigned tasks.

13.2.2.3 General Employee Training

Site access training meets the requirements delineated in ANSI/ANS 3.1-1978 and is provided to long-term site employees and to all personnel prior to their being granted unescorted access to restricted areas. This training is implemented using industry guidance and regulatory requirements and includes topics such as instruction on evacuation signals, evacuation routes, and procedures for reporting a fire. The course requires satisfactory completion of written or computer-aided examination.

Radiological protection training is provided to personnel prior to their being granted unescorted access to radiological controlled areas. The training addresses the following topics and requirements:

- Sources of radiation
- Measurement of radiation
- Biological effects
- Limits and guidelines
- As Low As Reasonably Achievable (ALARA)
- Radiation dosimetry
- Contamination
- Internal exposure
- Radiation Work Permit (RWP)

The course requires satisfactory completion of a written or computer-aided examination.

Temporary personnel receive training based on the access level required and their knowledge and experience, as validated by written or computer-aided examination.

13.2.3 FIRE PROTECTION TRAINING

13.2.3.1 General Employee Fire Protection Training

As a portion of General Employee Training, station personnel are trained in the following aspects of fire protection:

- Station Fire Protection Program
- Station Evacuation Routes

- Fire Reporting Procedures
- Job Related Fire Prevention and Suppression
- Control of Ignition Sources

13.2.3.2 Fire Department Training

The Fire Department training program ensures that the capability to fight potential fires is established and maintained. The program consists of initial classroom instruction followed by periodic classroom training, firefighting practice, and fire drills. The program is based on specific 10CFR50, Appendix R training requirements and selected recommended practices by the National Fire Protection Association (NFPA) Standard (1987) 1001 for the equipment and practices applicable to the PVNGS Fire Department for Firefighter Level I.

Periodic classroom refresher training sessions are held to repeat the classroom instruction for all fire department members over a 24 month period. Changes to the fire protection program and plant changes impacting fire response capability are reviewed as necessary in the training sessions. Senior fire department members receive instruction in incident command.

Practice sessions are held for each shift fire department on fighting fires similar to those expected in nuclear power plants. These sessions provide Fire Department members with experience in actual fire extinguishment and use of self-contained breathing apparatus under strenuous conditions encountered in firefighting. These practice sessions are

provided at least once per year for each fire department member.

Fire department drills are performed at regular intervals not exceeding 3 months for each shift. Each fire department member is encouraged to participate in each drill, but is required to participate in at least 2 drills per year.

A sufficient number of these drills, but not less than one for each fire department shift per year, are unannounced to determine the firefighting readiness of the fire department, shift fire captain, and fire protection systems and equipment.

At least one drill per year is performed on a "backshift" for each fire department shift. The drills are pre-planned to establish the training objectives of the drill and shall be critiqued to determine how well the training objectives have been met.

Unannounced drills are planned and critiqued by the fire training officer or designee. Performance deficiencies of a fire department shift or individual fire department members are remedied by scheduling additional training for the department or individual. Unsatisfactory drill performance is followed by a repeat drill within 30 days.

At 3 year intervals, a randomly selected unannounced drill is critiqued by qualified individuals independent of the PVNGS Fire Department staff. A copy of the written report of each critique is available for review.

Fire drills as a minimum include the following:

A. Assessment of fire alarm effectiveness, time required to notify and dispatch the fire department, and selection, placement, and use of equipment, as well as firefighting tactics and strategies.

B. Assessment of each fire department member's knowledge of his or her role in the firefighting strategy for the area assumed to contain the fire. Assessment of the fire department member's conformance with established firefighting procedures and use of firefighting equipment.

C. The simulated use of firefighting equipment required to cope with the situation and type of fire selected for the drill. The area and type of fire chosen for the drill differ from those used in the previous drill so that fire department members are trained in fighting fires in various plant areas. The situation selected simulates the size and arrangement of a fire that could reasonably occur in the area selected, allowing for fire development due to the time required to respond, obtain equipment, and size up the fire, and assuming loss of automatic suppression capability.

D. Assessment of the shift fire captain's direction of the fire suppression activities as to thoroughness, accuracy, and effectiveness.

Individual records of training provided to each fire department member are maintained for at least 3 years to ensure that each member receives training in all parts of the training program.

Retraining or broadened training is scheduled for all fire department members whose performance records show deficiencies.

The Fire Department training program also includes training for personnel who inspect and test fire protection equipment, to ensure that they are certified to perform that work. The training consists of on-the-job training conducted by qualified Fire Department personnel. Written records of each individual's qualifications are maintained.

The Fire Department training program includes hazardous materials handling training. The program is based on the requirements of OSHA 29CFR1910.120, for the equipment and practices applicable to the PVNGS Fire Department. Training will consist of initial classroom and practical sessions, followed by annual refresher training.

13.2.3.3 Security Department Fire Protection Training

Instruction is provided for security personnel that addresses (a) entry procedures for outside fire departments, (b) crowd control for people exiting the station, and (c) procedures for reporting potential fire hazards observed when touring the facility.

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13.3 EMERGENCY PLANNING

13.3.1 PRELIMINARY PLANNING (PSAR)

This section is not applicable to the FSAR.

13.3.2 EMERGENCY PLAN (FSAR)

A comprehensive emergency plan for Palo Verde Nuclear Generating Station is provided as a separate volume to this application.

Additional information, concerning agreements with offsite local, state, and federal officials and agencies, is included as an appendix to the Emergency Plan.

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13.4 REVIEW AND AUDIT

Operating phase activities that affect nuclear safety are reviewed and audited. The review and audit program is implemented prior to initial fuel loading and is described in the PVNGS Operations Quality Assurance Program Description (QAPD).

13.5 PLANT PROGRAMS AND PROCEDURES

The PVNGS Operations Quality Assurance Program Description (QAPD) describes administrative and operating procedures that will be used by the operating organization to ensure that routine operating, off-normal, and emergency activities affecting nuclear safety are conducted in a safe manner.

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13.6 INDUSTRIAL SECURITY

13.6.1 PRELIMINARY PLANNING (PSAR)

This section is not applicable to the FSAR.

13.6.2 SECURITY PLAN (FSAR)

A description of the physical security program for Palo Verde Nuclear Generating Station is provided as a separate part of the application withheld from public disclosure pursuant to Paragraph 2.790 (d), 10CFR Part 2, Rules of Practice.

13.7 TECHNICAL REQUIREMENTS MANUAL (TRM)

13.7.1 TRM CONTENT

The TRM includes requirements that have been relocated from the PVNGS Technical Specifications to a licensee-controlled document in accordance with the provisions specified in amendment number 117 for Units 1, 2, and 3, dated May 20, 1998. Compliance with the TRM is required in order to remain within the PVNGS design and/or licensing bases. Changes to the TRM must be controlled as described in 13.7.2.

The TRM contains specifications, administrative controls, bases, and component lists.

13.7.1.1 Component Lists

Section T7.0 of the TRM contains itemized lists of components subject to Technical Specification or TRM surveillance testing for five tables of components lists which were removed from the Technical Specifications in accordance with Generic Letter 91-08 in amendments 85, 73 and 57 for Units 1, 2, and 3, respectively. These component lists, located in TRM section 7, include:

- Remote Shutdown Disconnect Switches (T7.0.100)

  Identifies the switches subject to the requirements of Technical Specification section 3.3.11.

- Remote Shutdown Control Circuits (T7.0.200)

  Identifies the control circuits subject to the requirements of Technical Specification section 3.3.11.

- Containment Isolation Valves (T7.0.300) Identifies the containment isolation valves subject to the requirements of Technical Specification section 3.6.3.

- Motor Operated Valve Thermal Overload Protection and Bypass Devices (T7.0.400)

  Identifies the motor operated valves with bypass devices subject to the requirements of TRM section T3.8.102.

- Containment Penetration Conductor Overcurrent Protective Devices (T7.0.500)

  Identifies the overcurrent protective devices subject to the requirements of TRM section T3.8.101 (the TRM references the appropriate station procedure).

13.7.2 TRM CHANGE CONTROL

Changes to the TRM shall be made under appropriate administrative controls and reviews.

Changes may be made to the TRM without prior NRC approval provided the changes do not involve either of the following:

- A change in the Technical Specifications incorporated in the license; or

- A change to the UFSAR or TRM that requires NRC approval pursuant to 10 CFR 50.59.

Any proposed change to the TRM that involves either of the above criteria must be approved by the NRC as a PVNGS license amendment before the change may be made.

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APPENDIX 13A

RESPONSES TO NRC REQUESTS FOR INFORMATION

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APPENDIX 13B

PROJECT DESIGN, CONSTRUCTION AND PREOPERATIONAL ACTIVITIES (Historical)

PROJECT DESIGN, CONSTRUCTION
AND PREOPERATIONAL
ACTIVITIES (Historical)

NOTE: Construction is complete for the three units of the Palo Verde Nuclear Generating Station (PVNGS). Sections 13B.1 through 13B.1.2.4 describe project design and construction (project phase) and preoperational activities and will not be updated. This information is maintained as a historical reference only.

13B.1 Design and Operating Responsibilities

The following paragraphs summarize the degree to which design, construction, and preoperational activities have been accomplished and describe the specific responsibilities and activities relative to technical support for operations.

13B.1.1 Design and Construction Activities

13B.1.1.1 Principal Site-Related Engineering Work

A. Meteorology

A preoperational meteorological monitoring program was established at the Palo Verde site in 1973 to provide a base of meteorological data that bear upon plant design, operation, and safety. The program has been conducted by NUS Corporation and supervised and assisted by the Arizona Public Service Company (APS) nuclear organization. Meteorological data continues to be collected at PVNGS and will be collected through the life of the facility.

B. Geology

Onsite and offsite PVNGS geotechnical studies have been performed by ERTEC, as required, and include determination of site suitability in accordance with 10CFR100 and inspecting and mapping excavations for Seismic Category I buildings and pipelines for PVNGS.

C. Seismology

ERTEC has completed seismic studies on site response spectra and time history as discussed in section 2.5.

D. Hydrology

NUS Corporation has completed hydrologic studies including calculation of the probable maximum flood (PMF) for the PVNGS site and calculation of ground water levels beneath the PVNGS site. Detailed information concerning hydrology is discussed in section 2.4.

E. Demography

NUS Corporation has completed demographic studies relative to population located within 50 miles of the plant site, as discussed in subsection 2.1.3, and land use studies relative to the location of industrial, transportation,

and military facilities near the plant site, as discussed in section 2.2.

F. Environmental Effects

A construction phase environmental control program was put into effect in early 1976. Groundwater and ecological monitoring programs were approved by the NRC in May of 1976. The program is designed to monitor the requirements contained in the final environmental statement for PVNGS 1, 2, and 3 for compliance and to detect unanticipated environmental impacts due to construction activities. Preoperational radiological and environmental monitoring programs have been developed to provide baseline radiological and ecological data for the PVNGS site. These programs are described in the PVNGS Environmental Report-Operating License Stage.

13B.1.1.2 Design of Plant Ancillary Systems. An evaluation of engineering progress for PVNGS Unit 1 and common areas as of December 1982 indicates an overall completion of 90% including TMI related changes and 99% including non-TMI-related changes. Refer to subsection 1.1.5 of the FSAR for the scheduled completion date.

13B.1.1.3 Review and Approval of Plant Design Features. Design control and review is performed in accordance with QA program for PVNGS 1, 2, and 3 as discussed in PVNGS 1, 2, and 3 PSAR Section 17.1.

13B.1.1.4 Site Layout With Respect to Environmental Effects and Security Provisions. In order to minimize the visual impact of the plant on the environment, the external features of the plant facilities have been designed to establish an acceptable relationship between site and plant through the use of materials and colors that are compatible with the environment.

Security provisions in accordance with 10CFR73.55 have been incorporated into the overall site development and plant design as discussed in Section 13.6.

13B.1.1.5 Development of Safety Analysis Reports. Overall responsibility for preparation of the FSAR rests with the APS Nuclear Regulatory Affairs Department. Preparation of the individual FSAR sections is assigned to the cognizant technical groups within APS, or to Bechtel for balance of plant systems, Combustion Engineering for NSSS systems, NUS for environmental programs, and ERTEC for geotechnical sections.

13B.1.1.6 Review and Approval of Material and Component Specifications. Safety-related project specifications are reviewed in accordance with the QA program for PVNGS and conform with 10 CFR 50, Appendix B, and ANSI Standard N45.21971.

13B.1.1.7 Procurement of Materials and Equipment. As of October 23, 1981, approximately 99% of the specifications for material and equipment have been awarded. Completion of this activity is scheduled by November 1982.

13B.1.1.8 Management and Review of Construction Activities. The APS Nuclear Construction Department is responsible for review, monitoring, and construction activities. As of February 1983, construction progress was as follows:

Unit 1 and Common Areas	99.0%
Unit 2	96.3%
Unit 3	58.6%
Water Reclamation Facility	99.0%

13B.1.2 Preoperational Activities

13B.1.2.1 Development of Human Engineering Design Objectives and Design Phase Review of Proposed Control Room Layouts. Prior to control room design, Bechtel Power

Corporation, in conjunction with an APS nuclear operations consultant and APS nuclear engineering personnel, performed a study of power plant control rooms. The results of this study were factored into the design of the PVNGS control rooms. Several of the features that were implemented in order to improve the man-machine interface are:

A. Indicators are dual where possible to minimize panel size.

B. Control boards are built in a "slide-along" configuration which provides a single arrangement of controls for similar pieces of equipment.

C. The control boards for the PVNGS units and for the simulator are identically designed, minimizing operator confusion between units.

D. Pushbuttons are engraved with the name of their function (e.g., "on", "open"), equipment name (engraved on a nameplate) is above the button. This alleviates the concern of having too much information on the button.

E. Related indicators and switches are grouped by operation or individual piece of equipment, rather than functional grouping to minimize operator errors.

F. The electrical distribution panel and the chemical and volume control systems (CVCS) panel are built in a mimic arrangement with colored plastic material designed to distinguish interconnections and to aid the operator in system line-ups.

G. Three common alarm displays are located at key positions on the control boards to provide the operator with immediate notification of alarm conditions. Alarm descriptions are displayed in "double-high" characters for greater visibility.

H. Control room overhead lighting level is set to minimize fatigue and glare in accordance with Human Engineering Design studies.

I. Control boards are "benchboard" style arranged in a horseshoe to minimize distances for operator response and to increase the operator’s ability to effectively monitor the control panels.

13B.1.2.2 Development and Implementation of Staff Recruiting and Training Programs. Recruiting of PVNGS operations personnel to fill the positions described in paragraph 13.1.2.1 was implemented in 1978. Key supervisory positions were filled in 1978. The

training program and its implementation schedule are discussed in section 13.2.

13B.1.2.3 Deleted.

13B.1.2.4 Development of Plant Maintenance Programs.
Maintenance planning for all safety-related equipment was conducted on a ¾ inch = 1 foot model of the PVNGS power block during the final stages of design. Key supervisory positions responsible for development of plant maintenance programs have been filled.

CHAPTER 14

INITIAL TEST PROGRAM (Historical)

CONTENTS

CONTENTS (cont)

CONTENTS (cont)

TABLES

FIGURES

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14. INITIAL TEST PROGRAM (Historical)

All of the information in Chapter 14 is historical. It describes the preoperation testing and startup testing. Therefore, it is not subject to the update requirements of 10 CFR 50.71(e).

14.1 SPECIFIC INFORMATION TO BE INCLUDED IN PRELIMINARY SAFETY ANALYSIS REPORTS

This section is not applicable for the FSAR.

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14.2 SPECIFIC INFORMATION TO BE INCLUDED IN FSAR (Historical)

14.2.1 SUMMARY OF TEST PROGRAM AND OBJECTIVES

14.2.1.1 Summary of the Startup Test Program

The startup test program includes testing activities commencing with the completion of construction and installation and ending with the completion of the power ascension testing. This test program demonstrates that components and systems operate in accordance with design requirements and meet the requirements of 10CFR50, Appendix B, Criterion XI. The startup test program results confirm that performance levels meet the operational safety requirements delineated in the FSAR, and verify the adequacy of component and system design and system operability over the operating range of the system. It also aids in the establishment of baseline performance data and serves to verify that normal operating procedures and emergency procedures accomplish their intended purposes. The startup test program consists of prerequisite testing plus the following four phases:

- Phase I — Preoperational testing
- Phase II — Fuel loading and post-core hot functional testing
- Phase III — Initial criticality and low power physics testing
- Phase IV — Power ascension testing

The administrative controls established for use during the startup program are contained in the Station Manual.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

14.2.1.1.1 Prerequisite Testing

Prerequisite testing consists of tests and inspections required to assure construction is complete and that systems are ready for phase I testing.

The startup test program is conducted in accordance with the operations quality assurance program described in section 17.2.

Prerequisite testing verifies that construction activities associated with the respective structures, components, and systems have been satisfactorily completed. Prerequisite testing consists of preliminary tests and inspections which include, but are not limited to, initial instrument calibration, flushing, cleaning, circuit integrity and separation checks, hydrostatic pressure tests, and functional tests of components. Delineation of specific prerequisite test requirements will be established in accordance with Startup Administrative Procedures.

14.2.1.1.2 Phase I Testing - Preoperational Testing

Phase I, preoperational testing, is performed to demonstrate that structures, systems, and components operate in accordance with design operating modes, throughout the full design operating range. Where required, simulated signals or inputs are used to demonstrate the full range of the systems that are used during normal operation. Systems that are not used during normal plant operation, but must be in a state of readiness to perform safety functions, are checked under various modes and test conditions prior to fuel load.

SPECIFIC INFORMATION TO
BE INCLUDED IN FSAR

Whenever practical, these tests are performed under the conditions expected when the systems would be required to function. When these conditions cannot be attained or appropriately simulated at the time of the test, the system is tested to the extent practical under the given conditions, with additional testing completed at a time when appropriate conditions can be attained.

Preoperational testing ensures that systems and equipment perform in accordance with the Safety Analysis Report. Analysis of test results is made to verify that systems and components are performing satisfactorily, and if not, to provide a basis for recommended corrective action.

An index of preoperational tests is provided in sub-section 14.2.12, and a description of each test procedure is provided in appendix 14B.

14.2.1.1.3 Phase II Testing - Fuel Loading and Post Core Hot Functional Testing

Refer to CESSAR Section 14.2.1.2 for a description of initial fuel loading and post-core hot functional testing.

14.2.1.1.4 Phase III Testing - Initial Criticality and Low Power Physics Testing

Refer to CESSAR Section 14.2.1.2 for a description of initial criticality and low power physics testing.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

14.2.1.1.5 Phase IV Testing - Power Ascension Tests

Refer to CESSAR Section 14.2.1.2 for a description of power ascension testing.

14.2.2 ORGANIZATION AND STAFFING [Historical]

14.2.2.1 Management Organization

The executive vice president, Arizona Nuclear Power Project (ANPP), has overall responsibility for defining the responsibilities, requirements, and interfaces necessary to safely and efficiently design, construct, start up, operate, maintain, and modify the Palo Verde Nuclear Generating Station (PVNGS). He is assisted in the performance of these duties by the vice president, nuclear production, and the assistant vice president, nuclear production, who are assigned the overall responsibility for ensuring the safe design, construction, startup, operation, and technical support of PVNGS.

The vice president, nuclear production, and the assistant vice president, nuclear production, are assisted in the performance of their duties by the manager, transition, and the PVNGS plant manager who are assigned the following responsibilities:

- Manager, transition - project management during the transition phase of the project including the prerequisite and phase I test programs.
- PVNGS plant manager - plant operations and the phases II through IV test programs.

Responsibilities associated with startup test programs include the preparation of test procedures, performance of applicable initial tests, and the preparation of appropriate test related documentation. Test procedures are prepared by either the Startup or Nuclear Operation Departments with assistance from the NSSS supplier, Combustion Engineering Inc. (C-E); the architect-engineer, Bechtel Power Corporation (BPC); and other vendors as required. These procedures are subject to review and comment by the appropriate project organizations.

The organizations assigned responsibility for conducting the tests are responsible for establishing specific requirements for scheduling and accomplishing testing, as well as for providing the necessary direction and coordination of groups having responsibility for specific activities in the startup test program. The organizations participating in the initial test program are discussed in the following sections.

14.2.2.2 Transition Department

The Transition Department is responsible for project management during the transition phase (subsystem transfer from construction to subsystem acceptance by operations) of the project. This includes providing central project direction and coordination of support activities by other interfacing organizations.

The Transition Department is composed of representatives from the principal interface organizations (nuclear construction, nuclear engineering, startup, operations, scheduling, C-E, and

BPC) and is headed by the manager, transition. Arizona Public Service Company (APS) quality assurance provides a representative to the Transition Department to assist in quality assurance matters.

14.2.2.2.1 Manager, Transition

The manager, transition, is responsible for the startup program, setting engineering/construction priorities to meet the startup schedules, completing systems prior to acceptance by operations, and supporting operations to full power. The manager, transition, is assisted in his duties by the unit startup manager who is assigned the responsibility for the functional and technical aspects for the startup program.

14.2.2.3 Startup Department

The Startup Department is responsible for the prerequisite and phase I test programs at PVNGS. The unit startup manager is responsible to the manager, transition, for the conduct of the startup test program through phase I testing. The functions and responsibilities of key members of the Startup Department are described in paragraphs 14.2.2.3.1 through 14.2.2.3.4.

14.2.2.3.1 Unit Startup Manager

The unit startup manager is responsible to the manager, transition, for the technical and functional aspects of the startup program including the conduct of the prerequisite and phase I programs and is specifically charged with the following additional responsibilities:

- Approval of startup administrative control procedures
- Review and approve requests for vendor assistance
- Review and recommend approval of requests for modifications or changes required during the test program
- Review progress of startup activities with contractors, vendors, and company management
- Represent the Startup Department on interdepartmental and interorganizational committees associated with the startup test program
- Delegate, as necessary, the authority to perform duties normally associated with the position of unit startup manager
- Establish and dissolve those positions/organizations not specifically chartered by this document as deemed necessary to complete phase I testing
- Approval of prerequisite and phase I test procedures
- Maintain liaison with the Bechtel project manager and the Combustion Engineering Inc. site manager, keeping them informed of status, problems, and support requirements
- Accept systems for test and operation

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

14.2.2.3.2 Startup Administration Manager

The startup administration manager is responsible for the development and implementation of programs necessary for the support of testing activities; including administrative controls, test procedure preparation, cost and budgeting support, material control, document control, and computerized testing and work activity tracking programs. He is also responsible for the coordination of activities involved in the receipt and release of subsystems through startup.

14.2.2.3.3 Test Working Group Chairman

The functions and responsibilities of this individual are explained in paragraph 14.2.2.8.

14.2.2.3.4 Group Supervisors

- Supervise and/or coordinate the activities of assigned personnel
- Assign test responsibility to lead startup engineers
- Issue periodic progress reports and work schedules for their startup group, as required
- Issue special reports concerning startup activities as directed by the unit startup manager
- Maintain liaison with contractors and vendors to coordinate their activities relating to the startup test programs

- Direct the work of the C-E/BPC technical personnel assigned during the startup test program
- Request, coordinate, and monitor vendor representative assistance, as required
- Review test procedures, test procedure modifications, and test results in accordance with startup administrative control procedures
- Review and recommend changes in plant design and/or construction activities to facilitate testing, operation, and maintenance

14.2.2.3.5 Lead Startup Engineer

- Assign a principal startup engineer for each assigned system or subsystem, and periodically review assignments to maintain an appropriate distribution of work load.
- Supervise the activities of and provide guidance to assigned principal startup engineers and assure that their activities are conducted in accordance with the Startup Procedures.
- Provide technical guidance and assistance in the preparation of test procedures.
- Determine the testing requirements, sequence, and test method on assigned systems. Recommend plant scheduling changes as necessary to support the testing effort.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

- Review test procedures, test procedure modifications, and test data in accordance with startup administrative control procedures.
- Recommend changes in plant design and/or construction to facilitate testing, operation, and maintenance.
- Review periodic progress reports and work schedules.
- Assist in the preparation of special reports concerning startup activities when required.
- Review system discrepancies and deficiencies and the status of their resolution and correction for assigned systems.

14.2.2.3.6 Test Directors/Principal Startup Engineers

- Conduct assigned tests using and ensuring compliance with approved test procedures.
- Suspend testing if the test cannot safely be conducted as written until the problem is resolved.
- Sign off individual steps in preoperational test procedures and ensure that required data is recorded.
- Assure required startup materials, instruments, and consumables are available to support scheduled startup activities.
- Conduct pretest and preshift startup briefings.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

14.2.2.3.7 Startup Engineer

- Conduct work assignments in accordance with startup administrative control procedures.
- Prepare assigned test procedures.
- Review engineering drawings and documents and prepare requests for construction and engineering changes, to facilitate both operation and maintenance.

The Startup Department will be augmented by contractor and vendor support personnel, as necessary. These personnel may be integrated into the Startup Department and function in any position designated by the startup manager.

14.2.2.4 Palo Verde Nuclear Generating Station Organization

The PVNGS station organization is described in section 13.1 and will be utilized to the fullest extent practicable in the startup test program. Plant staff personnel will support the startup test program by:

- Providing procedures.
- Performing when requested, component tests (e.g., wiring verification and instrument calibration).
- Performing preventive and corrective maintenance on permanent plant equipment accepted for startup testing.
- Operating permanently installed equipment for testing during the conduct of that startup test program.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

- Providing technical support and assistance for startup testing and related activities.
- Conducting phases II through IV test programs. The responsibility and authority of key members involved in the test program are described in paragraphs 14.2.2.4.1 through 14.2.2.4.4.

14.2.2.4.1 Technical Support Manager

- Review and approve phases II through IV test procedures.
- Review and approve phases II through IV test results as specified in Technical Specifications, Section 6.5

14.2.2.4.1.1 Engineering Manager. The engineering manager is responsible to the PVNGS plant manager for the conduct of phases II through IV test programs and the completion of outstanding prerequisite and phase I program tests on systems jurisdictionally controlled by operations personnel. In addition, he is charged with the following responsibilities:

- Maintain liaison with the technical support manager, Bechtel resident engineer, C-E site manager, and transition manager, keeping them informed of status, problems, and support requirements.
- Review and recommend the approval of requests for vendor assistance as recommended by the Engineering Department supervisors.

- Review and approval/concurrence of test procedures, test procedure changes, and test results in accordance with the Station Manual.

- Review and recommend approval of requests for construction and engineering modifications or changes required during the test program.

- Review progress of startup activities with contractors and vendors.

- Represent the Engineering Department on interdepartmental and interorganizational committees associated with the startup test program.

14.2.2.4.2 Engineering Group Supervisors

- Supervise and/or coordinate the activities of their sections.

- Assign test responsibility to responsible engineers.

- Maintain liaison with contractors and vendors to coordinate their activities relating to the preoperational test program.

- Direct the work of the C-E NSSS technical personnel assigned during phases II through IV test program.

- Request, coordinate, and monitor vendor representative assistance, as required.

- Review and recommend approval of test procedures, test procedure modifications, and test results in accordance with established procedures.

14.2.2.4.3 Test Program Director

- Direct the performance of testing activities through the assigned responsible engineers.
- Ensure that required records, reports, test results and other documents are prepared, reviewed and routed as required by Station Manual procedures.
- Recommend plant scheduling changes and work arounds as necessary to support the testing effort.
- Assure that required startup materials, instrument and consumable supplies are available to support scheduled startup activities.
- Coordinate the preparation and maintenance of phases II through IV startup test procedures with assigned station groups.
- Issue periodic progress reports and work schedules for phases II through IV activities.
- Issue special reports concerning startup activities as directed by the engineering manager.

SPECIFIC INFORMATION TO
BE INCLUDED IN FSAR

14.2.2.4.4 Responsible Engineers

- Assures that assigned test procedures are written, reviewed, and approved in accordance with the Station Manual as scheduled.
- Assures all prerequisites for assigned tests are completed prior to the performance of the test.
- Conducts assigned tests using and ensuring compliance with approved test procedures.
- Keeps the test program director informed of the status of the preparation and performance of assigned tests.
- Suspends testing if the test cannot safely be conducted as written until the problem is resolved.
- Signs off individual steps in test procedures and ensures that required data is recorded.
- Assures that required startup materials, instruments, and consumables are available to support scheduled startup activities.
- Conducts pretest and preshift startup briefings.
- A responsible engineer will be assigned by the test program director to provide overall direction for all testing activities on each shift.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

14.2.2.5 Combustion Engineering

Combustion-Engineering will provide onsite technical assistance to APS during the installation, startup, testing, and initial operations of each NSSS. Through this effort, C-E aids APS and assures itself that each NSSS is installed, started, tested, and operated in conformance with design intent. Combustion-Engineering onsite personnel provide technical assistance and act as technical liaison with C-E headquarters to resolve problems within C-E scope. Combustion-Engineering provides a member of the test working group. Combustion-Engineering will review and comment on test procedures involving their scope of supply.

14.2.2.6 Bechtel Power Corporation

Bechtel Power Corporation, under the direction of APS, has been designated as the engineer-constructor of PVNGS. As the engineer, BPC will provide a representative to serve as a member of the test working group and staff augmentation addressed in subsection 14.2.2. As the constructor, BPC will coordinate the construction schedules with test program requirements and provide manpower support as needed to meet the schedule, to correct deficiencies, or to make repairs.

14.2.2.7 Other Technical Specialties

In addition to the staff described in subsection 14.2.2, APS will augment the Startup Staff from other contractors and vendors as deemed necessary.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

14.2.2.8 Test Working Group

The function of the Test Working Group (TWG) is to advise the transition and unit startup managers of the technical adequacy of the phase I testing program. The TWG functions include coordinating organizational responsibility in areas of test procedure and test results reviews, evaluations, and approval recommendations. The TWG is headed by a chairman appointed by the transition manager and consists of the following minimum membership:

- Startup representative
- C-E project representative
- Bechtel project representative
- APS nuclear engineering representative
- Operating Department representative

If any of the TWG members are unable to attend meetings, an alternate member with full authority to act for that member is present when that member's input is required.

In addition, the TWG is responsible to the transition manager for the following functions during the startup:

- Review of phase I test procedures.
- Review of changes to phase I test procedures.
- Review of results of phase I tests.

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BE INCLUDED IN FSAR

14.2.2.9 Plant Review Board

The Plant Review Board (PRB) will review procedures for use beginning with initial fuel loading as discussed in subsection 13.4.1 and, as required, prerequisite and phase I tests performed by the plant organization staff on plant systems accepted from the Startup Department. The membership of this group is described in section 13.4. In addition to the functions described in section 13.4, this group will review the results of startup tests performed in accordance with procedures requiring their review; and before fuel load, review a listing of all prerequisite and phase I carryover tests to phases II through IV, the justification for their deferral beyond fuel load and a proposed schedule for their performance.

14.2.2.9.1 Plant Review Board Test Results Review Group

Prior to initial fuel loading the PRB will establish the Test Results Review Group (TRRG). The TRRG will review and recommend approval of test procedures in accordance with Section 6.5.1 of PVNGS Technical Specifications. The TRRG will also be responsible for the review and approval recommendation of test results. The TRRG is headed by the engineering manager as established by Station Manual procedures and contains members with expertise in the following areas:

- Reactor physics
- Mechanical engineering
- Electrical engineering

- I&C
- Plant operations
- Chemistry
- Radiation protection
- Quality systems and engineering

14.2.2.10 Organizational Responsibilities

The organization chart showing lines of authority for the functional groups involved in startup testing through phase I is provided in figure 14.2-1. Additional personnel to assist the plant staff during the testing and startup period will be provided by other APS resources, Bechtel and C-E, or others as required.

Arizona Public Service Company management retains overall responsibility for preoperational testing and startup through the vice president, nuclear production. The operations manager under the PVNGS plant manager is responsible for:

- Preparation of operating and emergency procedures
- Operation of plant equipment during system testing phases I, II, III, and IV.
- Providing a TWG member.

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14.2.2.10.1 The unit startup manager under the transition manager is responsible for the activities discussed in paragraph 14.2.2.3.1.

14.2.2.10.2 The C-E project manager is responsible for the preparation of the NSSS test guidelines or procedures. The C-E site manager, reporting to the C-E project manager, is responsible for the following:

- Providing a TWG member.
- Reviewing test procedures pertaining to or interfacing with C-E-supplied systems, equipment, and changes thereto, including the reviews discussed in LLIR, Item I.C.7.
- Evaluating test results for tests pertaining to C-E-supplied systems and equipment.
- Coordinating the resolution of problems dealing with NSSS equipment.
- Providing technical consultation on matters relating to the operation and testing of C-E-supplied systems and equipment.
- Providing adequate qualified support personnel including vendor representatives as necessary.

14.2.2.10.3 The Bechtel project organization provides technical advice and consultation on matters relating to the

design, construction, operation, and testing of systems and equipment.

Accordingly, the Bechtel project organization is responsible for the following:

- Providing a TWG member.
- Reviewing test procedures pertaining to Bechtel scope of supply systems (e.g., balance of plant systems).
- Evaluating balance of plant test results.
- Coordinating resolution of problem areas by providing technical support and liaison with the Startup Organization and the Bechtel construction and design groups.
- Providing startup assistance as requested.

14.2.2.10.4 The APS nuclear engineering representative acts as a TWG member and provides liaison with APS nuclear engineering during the startup effort.

14.2.2.11 Qualifications

Staffing and qualifications of the plant organization are detailed in chapter 13, Conduct of Operations.

14.2.2.11.1 Personnel Qualification Requirements

Personnel responsible for conduct of startup program tests (including TWG/TRRG members) shall be qualified as follows:

SPECIFIC INFORMATION TO
BE INCLUDED IN FSAR

A. Minimum qualification of individuals that direct or supervise the conduct of individual prerequisite and phase I tests:

1. At the time of assignment to the function, the individual should have a Bachelor's Degree in engineering or the physical sciences or the equivalent, and 1 year of applicable power plant experience. Included in the 1 year of experience should be at least 3 months of indoctrination/ training in nuclear power plant systems and component operation of a nuclear power plant that is substantially similar in design to PVNGS. In addition, the individual will undergo indoctrination/training on the PVNGS plant, or,

2. A high school diploma, or the equivalent, and 4 years of power plant experience. Credit for up to 2 years of this 4-year experience may be given for related technical training on a one-for-one time basis. Included in the 4 years of experience should be at least 3 months of indoctrination/ training in nuclear power plant systems and component operation of a nuclear power plant that is substantially similar in design to PVNGS. In addition, the individual will undergo indoctrination/training on the PVNGS plant, or,

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3. Be qualified to the requirements of paragraph 14.2.2.11.1, sublisting B.1 or B.2 or listing C.

B. Minimum qualifications of individuals that direct or supervise the conduct of individual phases II through IV tests:

1. At the time of assignment to the function, the individual should have a Bachelor's Degree in engineering or the physical sciences or the equivalent, and 2 years of applicable power plant experience of which at least 1 year shall be applicable nuclear power plant experience, or,

2. A high school diploma or the equivalent and 5 years of applicable power plant experience of which at least 2 years shall be applicable nuclear power plant experience. Credit for up to 2 years of nonnuclear experience may be given for related technical training on a one-for-one time basis, or,

3. Written authorization from the PVNGS plant manager that the individual is qualified to supervise or direct specific phases II through IV test(s), based on a case-by-case evaluation of the individual's qualifications relative to the specific test(s). In this case, a responsible engineer who is qualified per sublisting 1 or 2 above will be available for consultation regarding the specific test.

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Included in the experience should be at least 3 months of indoctrination/training in nuclear power plant systems and component operation of a nuclear power plant that is substantially similar in design to PVNGS. In addition, the individual will undergo indoctrination/ training on the PVNGS plant.

C. Minimum qualifications of individuals assigned to groups responsible for review and approval of phase I test procedures and/or review and approval of test results.

At the time the activity is being performed, individuals assigned to perform these activities shall have a minimum of 8 years of applicable power plant experience with a minimum of 2 years of applicable nuclear power plant experience. A maximum of 4 years of nonnuclear experience may be fulfilled by satisfactory completion of academic training at the college level.

Included in the experience should be at least 3 months of indoctrination/training in nuclear power plant systems and component operation of (1) PVNGS or (2) a nuclear power plant of substantially similar design. In addition, individuals qualifying under item 2 will undergo indoctrination/training on the PVNGS plant.

D. The review and approval of phases II through IV test procedures and the review and approval of test results will be done per Section 6.5.1 of the PVNGS Technical Specifications.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

E. Subsequent to system acceptance, the minimum qualification for individuals that direct or supervise and review/approve prerequisite and phase I test procedures and test results:

1. Startup personnel who direct or supervise the conduct of phase I tests shall be qualified to the requirements of paragraph 14.2.2.11.1, listing A.

2. Plant operations personnel who direct or supervise the conduct of prerequisite tests shall be qualified to the requirements of subsection 13.1.3. Plant operation personnel who direct or supervise the conduct of phase I tests shall be qualified to the requirements of paragraph 14.2.2.11.1, listing B.

3. Plant operation personnel who review and approve phase I test procedures and test results shall be qualified to the requirements of subsection 13.1.3.

   The review and approval of test procedures and test results will be done in accordance with the Station Manual procedures.

14.2.2.12 Utilization of the Plant Staff

The plant operating, maintenance, and engineering personnel are utilized to the extent practicable during the startup test program. The plant staff operates permanently installed and powered equipment for phases I through IV and subsequent system tests. Service personnel such as instrument, chemistry,

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computer, radiation protection, and maintenance personnel are used extensively to perform tests and inspections applicable to their field of specialization.

Phases II through IV and subsequent test procedures and test results are reviewed by the plant staff as specified in the Station Manual.

14.2.3 TEST PROCEDURES

The unit startup manager has the responsibility for assuring the preparation and designating the approval process for prerequisite and phase I test procedures at PVNGS. The technical support manager is responsible for ensuring that phases II through IV test procedures are prepared and approved in accordance with the Station Manual. Detailed procedure guidelines and procedures provided by the appropriate design organization are utilized to develop various system test procedures. Thus, test procedures are based on requirements of system designers. If a design organization prepares sufficiently detailed procedures, these procedures may serve in lieu of test guidelines. Procedures prepared by outside organizations will undergo the same review process as procedures prepared by PVNGS plant staff.

14.2.3.1 Prerequisite Test Procedure Preparation

Prerequisite test procedures are prepared under supervision of the unit startup manager.

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BE INCLUDED IN FSAR

Test procedures will be prepared using pertinent reference material provided by the appropriate design and/or vendor organization.

Prerequisite test procedures contain the following major divisions:

- Purpose/objective
- Reference
- Definitions and abbreviations
- Precautions and limitations
- Prerequisites (initial conditions)
- Instructions (including acceptance criteria)
- Restoration

Prerequisite test procedures are reviewed as specified in administrative procedures. At the completion of these reviews, any changes are incorporated in the test procedure by the originating organization.

The unit startup manager has approval authority for assigned prerequisite tests and may in writing delegate approval authority.

14.2.3.2 Test Procedure Preparation

Detailed test procedures for phase I tests are prepared under the unit startup manager's supervision. The test procedures for phases II through IV tests are prepared under the

supervision of the engineering manager. Each test procedure will be prepared using pertinent reference material provided by the appropriate design and vendor organizations, FSAR, Technical Specifications, and applicable regulatory guides. A test procedure is prepared for each specific system test to be performed during the four phases of the test program. Each system test procedure contains the following major divisions:

- Test objectives
- Acceptance criteria
- References
- Prerequisites
- System initial conditions
- Environmental conditions
- Special precautions
- Detailed procedure (including data collection)
- Restoration
- Documentation of test results

Phase I test procedures are reviewed as specified in startup administrative control procedures. At the completion of these reviews, any required changes are incorporated in the test procedure by the originating organization.

The unit startup manager has the approval authority for phase I test procedures.

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Startup test procedures for post-fuel load tests (phases II through IV) and changes to such procedures will be reviewed and approved in accordance with the requirements of the facility Technical Specifications.

14.2.3.3 Special Test Procedures

Special test procedures may become necessary during the phases I through IV test program for investigative purposes. The preparation, review, and approval of these special procedures are governed by administrative control procedures. Special test procedures that deal with nuclear safety are processed under the same controls as normal startup test procedures.

14.2.4 CONDUCT OF TEST PROGRAM (PHASES I THROUGH IV)

When a phase I through phase IV system test procedure has been released for performance, a test director/principal startup engineer/responsible engineer will be responsible for (1) ensuring that prerequisites are satisfactorily met or allowable exceptions are noted in accordance with Station Manual procedures, and (2) verifying that the testing is performed as required by the procedure. The test is then performed by PVNGS operating personnel or others in accordance with the approved test procedure.

The operations shift manager is responsible for the safe operation of the plant during the performance of phase I through phase IV testing. The operations shift manager takes

action necessary to assure the safe operation of the facility. He may stop any system test in progress and place the plant in a safe condition.

The test director/principal startup engineer/responsible engineer ensures that the tests are conducted in accordance with the test procedure.

Required data resulting from the test is compiled within the test procedure in specified data blanks, on specially prepared data sheets, or as otherwise specified by administrative control procedures. Personnel completing data forms or checklists will sign and date the forms. Upon test completion, the test data are compared with the test acceptance criteria, and any discrepancies noted are resolved in accordance with applicable Station Manual procedures.

Once a procedure has been approved, procedure changes will be made in accordance with the provisions of the Station Manual.

14.2.4.1 Signoff Provisions

Each approved test procedure shall contain signoff provisions for prerequisites and for all procedural steps. For component tests the person conducting the test is responsible for signing and dating each data form in the spaces provided, as the data is entered. For phases I through IV test prerequisites, the test director/principal startup engineer/responsible engineer shall initial the appropriate space in the test procedure. Signoff of the individual steps within the body of the test

procedure is the responsibility of the test director/principal startup engineer/responsible engineer.

For prerequisite tests, a qualified individual designated by the test director/principal startup engineer may sign off procedural steps and data sheets.

14.2.4.2 Maintenance/Modification Procedures

Work authorization documents, controlled in accordance with the Station Manual, are used to initiate maintenance and implement modifications on systems that are jurisdictionally turned over from the construction organization. The work authorization document assigns the organization responsible for the completion of the activity and specifies any retest requirements. Upon completion of the activity, a copy of the signed-off form is returned to the responsible testing organization to ensure retest requirements are met. Results of retests due to maintenance will be reviewed by the appropriate principal startup engineer/responsible engineer or the shift manager. Results of retests due to modifications will be reviewed and approved in the same manner as those from the original tests.

14.2.4.3 Test Performance

For prerequisite and phases I through IV testing, an individual who is qualified in accordance with paragraph 14.2.2.11.1 will be designated as the test director/principal startup engineer/responsible engineer. The official copy of the test

procedure shall be available in the test area during the performance of a preoperational or startup test. The person conducting the test is charged with responsibility for performing the test in accordance with the approved test procedure. If, during the performance of the test, it is determined that the test cannot be conducted as written, it is the responsibility of the person conducting the test to resolve the problem in accordance with approved administrative control procedures.

14.2.5 REVIEW, EVALUATION, AND APPROVAL OF PHASE I THROUGH PHASE IV TEST RESULTS

Individual test results will be reviewed and approved as provided in the Station Manual. Completed procedures and test reports will be reviewed for acceptance. The specific acceptance criteria for determining the success or failure of the test will be included as part of the procedure and will be used during the review.

The principal startup engineer/responsible engineer will present the completed test procedure and test report with remarks and recommendations to the responsible group supervisor as appropriate. The group supervisor will review the completed procedure for conformance with testing requirements as well as for acceptance of the test results. Following this review, the completed procedure and test report will be submitted to the test working group, the test results review group, or the Plant Review Board for final review, evaluation, and approval recommendation. If the as-built configuration of a system is

not capable of demonstrating its ability to meet the acceptance criteria, an engineering evaluation will be performed.

Test results for each phase of the test program will be reviewed and verified as complete (as required) and satisfactory before testing in the next phase is started. Preoperational testing on a system will not normally be started until all applicable prerequisite tests have been completed, reviewed, and approved. Prior to initial fuel loading and the commencement of initial criticality, a comprehensive review of required completed preoperational procedures will be conducted by the test working group and/or the TRRG. This review will provide assurance that required plant systems and structures will be capable of supporting the initial fuel loading and subsequent startup testing.

It is intended that phase I testing be completed prior to commencing initial fuel loading. In attempting to accomplish this task, plant systems under jurisdictional control of the Startup Department will be the responsibility of the unit startup manager to complete as delineated in paragraph 14.2.2.3.1. If prerequisite and phase I testing is incomplete at the time of system acceptance by operations personnel, the engineering manager, under the direction of the PVNGS plant manager, will ensure completion of the testing per the Station Manual administrative control procedures.

The TRRG will review and recommend to the PRB approval of phase I test procedures and test results that have not been completed at the time of system acceptance. Prerequisite tests

will be reviewed and approved in accordance with the Station Manual.

Phase I tests which will be performed after initial fuel loading will be performed under the administrative controls governing phases II through IV testing. These tests will be performed by either startup or operations personnel as determined on a case-by-case basis.

The startup testing phases (phases II, III, and IV) of the test program are subdivided into the following categories: initial fuel load, postloading hot functional testing, initial criticality, low power physics testing, and power ascension testing.

It ends with the completion of testing at 100% power. Each subdivision is a prerequisite which must be completed, reviewed, and approved before tests in the next category are started. Power ascension tests will be scheduled and conducted at pre-determined power levels. The testing plateaus to be used for PVNGS startup testing are specified in CESSAR Section 14.2.1.2. Insofar as practical, so that the safety of the plant will not be totally dependent on the performance of untested systems, systems relied upon to prevent, limit, or mitigate the consequences of postulated accidents will be tested to verify that operating requirements are met prior to exceeding approximately 25% power.

The plateaus for the power ascension testing are indicated in each test summary. Results from each test conducted at a given plateau will be evaluated prior to proceeding to the next

level. For those tests which result in a plant transient for which a realistic plant transient performance analysis has been performed, the test results will be compared to the results of the realistic transient analysis rather than the results of the transient analysis based on accident analysis assumptions.

Following completion of testing at 100% of rated power, final test results will be reviewed, evaluated, and approved.

14.2.5.1 Review, Evaluation, and Approval of Prerequisite Test Results

Prerequisite test results will be reviewed and approved in accordance with startup administrative control procedures.

14.2.6 TEST RECORDS

A single copy of each phase I through phase IV test procedure is designated as the official copy to be used for testing. The official copy and information specifically called for in the test procedure, such as completed data sheets, instrumentation calibration data, and chart recordings, are retained at PVNGS for the life of the plant in accordance with Station Manual procedures for record retention.

14.2.7 CONFORMANCE OF TEST PROGRAMS WITH REGULATORY GUIDE

The startup test program is consistent with CESSAR Section 14.2.7 and the recommendations of the following regulatory guides associated with startup: Regulatory Guides 1.9, 1.18, 1.20, 1.30, 1.37, 1.41, 1.52, 1.68, 1.68.2,

1.68.3, 1.79, 1.108, 1.116, 1.118, and 1.140 with exceptions as noted and revisions as specified in section 1.8.

14.2.8 UTILIZATION OF REACTOR OPERATING AND TESTING EXPERIENCES IN DEVELOPMENT OF TEST PROGRAM

PVNGS operations reviews reactor operating and testing experiences at other facilities similar in design and capacity to PVNGS.

This review is accomplished by circulating licensee event reports (LERs) or summaries of LERs and NRC I&E bulletins, circulars, and information notices to startup and operation personnel so that pertinent information can be utilized in the startup program.

14.2.9 TRIAL USE OF PLANT OPERATING AND EMERGENCY PROCEDURES

The schedule for the development of plant operating and emergency procedures is discussed in section 13.5. Whenever practical, test procedures reference the plant operating and emergency procedures. In the test program, plant operating procedures are used extensively in the operation of the plant. Plant emergency procedures are verified whenever possible during the test program. When practical, surveillance test procedures are performed after completion of preoperational tests.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

14.2.10 INITIAL FUEL LOADING AND INITIAL CRITICALITY

14.2.10.1 Fuel Loading

Refer to CESSAR Section 14.2.10.1 for a description of initial fuel loading. Core alterations during initial fuel loading are directly supervised by a person holding a senior reactor operator license.

14.2.10.2 Initial Criticality

Refer to CESSAR Section 14.2.10.2 and paragraph 1.9.2.4.16 for a description of initial criticality.

14.2.11 TEST PROGRAM SCHEDULE

The test program for each unit should encompass approximately 24 months. Approximately 2 months of this time has prerequisite tests as the controlling path. Preoperational and precore hot functional testing are the controlling path for about 16 months. The remaining 6 months are devoted to fuel loading, post-core hot functionals, low power physics, and power ascension testing.

The scheduling of individual tests or test sequences is made to ensure that systems and components that are to prevent or mitigate the consequences of postulated accidents are tested prior to fuel loading. Tests that require a substantial core power level for proper performance are performed at the lowest power level commensurate with obtaining acceptable test data. Safety-related systems are tested to provide reasonable

assurance that they operate satisfactorily when required, prior to exceeding 25% of rated thermal power.

Prerequisite testing followed by phase I testing will commence when construction has authorized the testing of components/ testable portions of systems by the Startup Department; however, phase I testing will not commence until jurisdiction for those components/testable portions of systems have been transferred to the Startup Department. Test procedures will contain a list of prerequisites that must be completed and verified prior to the start of a particular test. The use of prerequisites in test procedures ensures that the safety of the plant is not dependent on the performance of untested systems.

Phase I test procedures are scheduled to be approved and available for review by the NRC inspectors at least 60 days prior to their scheduled performance date. Phases II through IV startup test program administrative control procedures, the majority of the individual test procedures, and the following milestone controlling procedure documents: Fuel Loading, Post-Core HFT, Initial Criticality, Low Power Physics Test and Power Ascension, are scheduled to be approved and available for review at least 60 days prior to fuel load. The remaining individual test procedures will be scheduled for approval and available for review by the NRC inspectors at least 60 days prior to their intended performance date.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

14.2.12 INDIVIDUAL TEST DESCRIPTIONS

Individual test descriptions are listed in table 14.2-1 and are presented in appendix 14B.

FSAR paragraphs 1.9.2.4.9 and 1.9.2.4.14 through 1.9.2.4.17, 1.9.2.4.19, 1.9.2.4.21, and 1.9.2.4.22 describe deviations to testing described in CESSAR Section 14.2.12.

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

Table 14.2-1

INDEX OF INDIVIDUAL TEST DESCRIPTIONS (Sheet 1 of 3)

Phase I Tests

See CESSAR Section 14.2.12 for a description of preoperational tests performed on equipment within the C-E licensing scope of supply. See paragraph 1.9.2.4 for exceptions to or deviations from CESSAR Section 14.2.12 test descriptions.

See CESSAR Sections 4.2.5, 5.1.4, 5.4.7.1.3, 6.3.1.3, 6A-7.0,

6B-7.0, 7.1.3, 7.2.3, 7.3.3, 8.3.1, 8.3.2, 9.1.4.6, 9.3.4.6 for BOP CESSAR system interfaces which will be tested.

CESSAR Section 14.2.12.2.8, item 2.5, requiring COLSS to be in operation is not applicable for precore RCS flow measurement.

Phase I Tests on Other Systems

1. Main steam, main steam isolation valves, and safety valves
2. Containment spray system
3. Condensate storage tank and transfer system
4. Class 1E 125 V-dc power system
5. Class 1E 4.16 kV power system
6. Class 1E 480V power switchgear system
7. Class 1E 480V power MCC system
8. Class 1E instrument ac power
9. Diesel generator electrical tests and load sequencing
10. Emergency lighting
11. Pipe shock and vibration test
12. Containment isolation actuation system
13. Auxiliary feedwater system
14. Reactor containment integrated and local leak rate tests
15. Diesel fuel oil storage system
16. Diesel generator mechanical systems
17. Essential chilled water system
18. Essential cooling water system

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

Table 14.2-1

INDEX OF INDIVIDUAL TEST DESCRIPTIONS (Sheet 2 of 3)

19. Fuel pool cooling and cleanup system
20. Essential spray pond system
21. Auxiliary building essential HVAC and fuel building essential exhaust systems
22. Diesel generator building HVAC
23. Control building essential HVAC
24. Containment hydrogen control system
25. Radioactive waste drain system
26. Radiation monitoring system
27. DELETED
28. Nuclear cooling water system
29. Post-accident monitoring system
30. Plant computer
31. Loose parts monitoring system
32. Plant annunciator
33. Seismic instrumentation
34. Gas analyzer
35. In-plant communications systems
36. Private offsite communication system
37. Circulating water system
38. Fire protection system
39. Turbine electrohydraulic control
40. Gaseous radwaste system
41. Containment purge and HVAC system
42. Instrument air system
43. Polar crane
44. Containment HVAC
45. Feedwater system

SPECIFIC INFORMATION TO

BE INCLUDED IN FSAR

Table 14.2-1

INDEX OF INDIVIDUAL TEST DESCRIPTIONS (Sheet 3 of 3)

46.	Radwaste building HVAC
47.	Turbine building HVAC
48.	Radwaste solidification system
49.	Liquid radwaste system
50.	Secondary chemistry control system
51.	Load group assignment verification

APPENDIX 14A

RESPONSES TO NRC REQUESTS

FOR INFORMATION

(Historical)

CONTENTS

CONTENTS (cont)

CONTENTS (cont)

APPENDIX 14A

<u>QUESTION 14A.1</u> (NRC comment on subsection 14.2.12) (6/18/80) (14.2.12)

Individual test descriptions not provided (will be provided by October 1, 1980).

RESPONSE: The response is given in amended subsection 14.2.12.

<u>QUESTION 14A.2</u> (NRC Question 640.1) (14.2.2.6)

Paragraph 14.2.2.7 states that the architect engineer is only required as part of the TWG to review Phase I Preoperational test procedures, although he is responsible for reviewing changes and results for both Phase I and II tests. Explain how the architect engineer can effectively review procedures changes and results without having reviewed the initial procedure, or modify paragraph 14.2.2.6 to eliminate this apparent discrepancy.

RESPONSE: The response is given in amended paragraph 14.2.2.6.

<u>QUESTION 14A.3</u> (NRC QUESTION 640.2) (14.2.7)

Section 1.8 references Section 1.8 of CESSAR in regards to Regulatory Guide 1.20. CESSAR Section 1.8 then references CESSAR Subsection 3.9.2.4, which states that the first System 80 unit that will go online will be the lead plant and will be used as the System 80 prototype. Provide a test description that satisfies the guidelines of Regulatory Guide 1.20 as described in CESSAR Subsection 3.9.2.4. The test abstract should clearly indicate which portions will be deleted

if the Palo Verde unit is not the first System 80 plant to go on-line or if subsequent Palo Verde units are to be tested.

RESPONSE: The response was provided on the CESSAR docket. See Question 14A.39.

QUESTION 14A.4 (NRC Question 640.3) (14.2.7)

Subsection 14.2.7 states the Regulatory Guide 1.18 with exceptions as noted and revisions as specified in section 1.8 will be used. Delete the following exceptions to Regulatory Guide 1.18 given in section 1.8 or provide more detailed technical justification for the reduced testing.

(1) C.1 - Not holding pressure constant for at least one hour at each level before recording strains and deflections.

(2) C.3 - Not measuring tangential deflections.

RESPONSE: The response is given in amended section 1.8.

QUESTION 14A.5 (NRC Question 640.4) (14.2.9)

Subsection 14.2.9 states that the schedule for the development of plant operating and emergency procedures is discussed in section 13.5. Section 13.5 gives only the schedule for administrative procedures (available approximately six months prior to fuel loading of Unit 1). Modify subsection 14.2.9 and/or section 13.5 to provide a schedule for the development of plant procedures as required by Regulatory Guide 1.70. This schedule should be established to maximize, where practical, the availability of plant operating and emergency procedures so

that user-testing can be accomplished during the initial test program.

RESPONSE: The response is given in amended subsection 13.5.2.

<u>QUESTION 14A.6</u> (NRC Question 640.5) (14.2.11)

Subsection 14.2.11 states that test procedures are "normally" scheduled to be approved and available for review by NRC inspectors at least 60 days prior to their scheduled performance. Provide a list of those tests that will not be available for review 60 days prior to use, or cite the "abnormal" conditions which will prevent those procedures from being available in accordance with the requirements of Regulatory Guide 1.68, Appendix B.

RESPONSE: The response is given in amended subsection 14.2.11.

<u>QUESTION 14A.7</u> (NRC Question 640.6) (14.2.12)

Provide a commitment to include in your test program any design features to prevent or mitigate anticipated transients without scram (ATWS) that may now, or in the future, be incorporated into your plant design.

RESPONSE: Any design features to prevent or mitigate anticipated transients without scram (ATWS) that are incorporated in the PVNGS plant design now, or may be incorporated into the PVNGS plant design in the future, will be included in a test program.

QUESTION 14A.8 (NRC Question 640.7)

List any tests, or portions of tests, described in subsection 14.2.12 which you do not intend to perform on each unit and provide technical justification for deletion of each.

RESPONSE: PVNGS will perform all preoperational tests referred in subsection 14.2.12 for each unit. Refer to CESSAR for scope of startup testing beyond initial unit. (Refer to CESSAR Tables 14.2-1 and 14.2-2 and FSAR paragraphs 1.9.2.4.9, 1.9.2.4.13, and 1.9.2.4.15.)

QUESTION 14A.9 (NRC Question 640.8) (14.2.12)

Our review of your initial test program description disclosed that the operability of several of the systems and components listed in Regulatory Guide 1.68 (Rev. 0), Appendix A, may not be demonstrated. Expand your FSAR to include appropriate test descriptions (or identify existing descriptions) that address the following items from Appendix A, or provide technical justification in subsection 14.2.7 for any exceptions to the guide:

(1) A.4.a. Feedwater system

(2) h. Secondary plant chemical treatment system

(3) 5.j. Radwaste building and turbine building ventilation

(4) 7.a. Containment overpressure (structural integrity)

(5) e. Functional test of containment isolation valves

(6) 10.c. Operability and leak test of sectionalizing devices in the fuel storage pool and refueling canal

(7) 13. Liquid and solid radwaste systems

RESPONSE: The response is given in amended appendix 14B test descriptions addressing the following:

1. Feedwater system
2. Secondary plant chemical treatment system
3. Radwaste building and turbine building ventilation system
4. Containment overpressure (SIT)
5. Functional test of containment isolation valves
6. Operability and leak test of sectionalizing devices in the fuel storage pool and refueling canal
7. Liquid and solid radwaste systems

QUESTION 14A.10 (NRC Question 640.9) (14.2.12)

A CESSAR interface is defined in Subsection 1.1.3 of CESSAR as a requirement that the balance of plant have a certain capability necessary for assuring that a CESSAR design scope system will fulfill its safety functions. It is not clear from your preoperational test procedure descriptions that you intend to demonstrate compliance with these interface requirements. As a minimum, your test procedure description (chapter 14 of your FSAR) should contain a generic commitment to demonstrate

compliance with all CESSAR interfaces including those contained in the following subsections of CESSAR:

(1)	4.2.5	Reactor
(2)	5.1.4	RCS
(3)	5.4.7.1.3	RHR
(4)	6.3.1.3	ECCS
(5)	6A-7.0	CSS
(6)	DELETED	
(7)	7.1.3	Instrumentation and controls
(8)	7.2.3	RPS
(9)	7.3.3	ESFAS
(10)	8.3.1	Electrical ac
(11)	8.3.2	Electrical dc
(12)	9.1.4.6	Fuel handling
(13)	9.3.4.6	CVCS

RESPONSE: The response is given in amended table 14.2-1.

QUESTION 14A.11 (NRC Question 640.10(1)) (14.2.12)

We could not conclude from our review of your individual test descriptions that comprehensive testing is scheduled for several systems and components. Therefore, clarify or expand the appropriate test descriptions to address the following items:

14B.1 - Provide assurance that the main steam relief valves will be tested at normal operating temperature and that the testing fluid will be steam.

RESPONSE: The response is given in amended section 14B.1.

<u>QUESTION 14A.12</u> (NRC Question 640.10(2)) (14.2.12)

14B.2(a) - Recently, questions have arisen concerning the operability and dependability of certain ESF pumps. Upon investigation, the staff found that some completed preoperational test procedures did not describe the test conditions in sufficient detail. Provide assurance that the preoperational test procedures for the containment spray pumps will require recording the status of the pumped fluid (e.g., pressure, temperature, chemistry, amount of debris) and the duration of testing for each pump. In addition, provide preoperational test descriptions to verify that the containment spray pumps operate in accordance with the manufacturer's head-flow curve. Include in the description the bases for the acceptance criteria. (The bases provided should consider both flow requirements for ESF functions and pump NPSH requirements, see Interface 7.13.1 of Appendix 6A in CESSAR).

RESPONSE: The response is given in amended section 14B.2. In addition, PVNGS will ensure that the preoperational test procedures for the containment spray pumps will require recording of the status of pump fluid, the duration of testing, and comparison with manufacturer's head flow curve for each pump.

<u>QUESTION 14A.13</u> (NRC Question 640.10(3)) (14.2.12)

14B.2(b) - Verify that paths for the air flow test of containment spray nozzles overlap the water flow test paths of the pumps to demonstrate that there is no blockage in the flow path.

RESPONSE: The response is given in amended section 14B.2.

<u>QUESTION 14A.14</u> (NRC Question 640.10(4)) (14.2.12)

14B.2(c) - Testing of the containment spray system should include verification of pump suction from the containment sump while in the recirculation mode.

RESPONSE: During the system flushing/cleaning phase of startup testing, the flow path from the ECCS sump to the ECCS suction headers will be verified as unobstructed.

<u>QUESTION 14A.15</u> (NRC Question 640.10(5)) (14.2.12)

14B.4 - DC Power System Test -- State your plans to verify that individual cell limits are not exceeded during the design discharge test and to demonstrate that the dc loads will function as necessary to assure plant safety at a battery terminal voltage equal to the acceptance criterion that has been established for minimum battery terminal voltage for the discharge load test. Assure that each battery charger is capable of floating the battery on the bus or recharging the completely discharged battery within 24 hours while supplying the largest combined demands of the various steady-state loads under all plant operating conditions.

RESPONSE:

(1) Section 14B.4 will be amended in the future to include the requirement to monitor individual cell voltages during the design discharge test.

(2) Section 14B.4 will be amended in the future to include the requirement to verify that dc loads will function, as necessary, at a battery terminal voltage equal to the acceptance criteria established for minimum battery terminal voltage.

(3) Section 4.0 of 14B.4 addresses the acceptance criteria of subsection 8.3.2. More specifically, paragraph 8.3.2.1.2.2 requires the battery charger to restore the battery from the design minimum charge state to the fully charged state within 12 hours while supplying the largest combined demand of all the steady-state loads regardless of the status of the plant during these demands.

It is determined that part (3) of Question 640.10(5) is sufficiently addressed.

QUESTION 14A.16 (NRC Question 640.10(6)) (14.2.12)

14B.6-7 - The acceptance criteria "undue thermal or mechanical stress" and "appropriate design documents" are unacceptably vague. Provide more specific acceptance criteria.

RESPONSE: The response is given in amended sections 14B.6 and 14B.7.

APPENDIX 14A

<u>QUESTION 14A.17</u> (NRC Question 640.10(7)) (14.2.12)

14B.4-8-a - PVNGS is a three-unit facility and, therefore, there is the possibility of subtle interconnections between units. Describe the status of the power supplied to "other" units to ensure independence during power distribution testing. The descriptions should address both normal and emergency ac and dc power distribution systems. Provide assurance that cross-ties will not exist which could cause loss of emergency bus power to one unit due to testing of the other unit.

RESPONSE: Units not undergoing testing will be protected from being affected by transients due to actions at a unit under test by the unit independent protection systems.

<u>QUESTION 14A.18</u> (NRC Question 640.10(8)) (14.2.12)

14B.4-8-b - The initial test program should verify the capability of the offsite power system to serve as a source of power to the emergency buses. Tests should demonstrate the capability of each startup transformer to supply power to its unit's emergency buses while carrying its maximum load of plant auxiliaries and the other unit's emergency buses. Tests should also demonstrate the transfer capabilities of the unit's emergency bus feeders upon loss of one source of offsite power. These tests should be performed as early in the test program as the availability of necessary components allows. Provide descriptions of the tests that will demonstrate these capabilities.

RESPONSE: Each startup transformer is capable of supplying 100% of the startup or normally operating loads of one unit

simultaneously with the engineered safety feature (ESF) loads associated with two load groups of another unit. The non-Class 1E ac buses normally are supplied through the unit auxiliary transformer, and the Class 1E buses normally are supplied through the startup transformers. In the event of failure of the unit auxiliary transformer, a turbine trip, or reactor trip, an automatic fast transfer of the 13.8 kV buses to the startup transformers is initiated to provide power to the auxiliary loads. Transfers of all buses can be initiated by the operator from the control room.

In addition, the 13.8 kV intermediate buses have access to all three transformers such that a loss of one transformer can be sustained without affecting the availability of off-site power to any of the three units.

Preferred power for Class 1E buses is supplied from the startup transformers through the 13.8 kV switchgear and the 13.8 to 4.16 kV ESF transformers.

A test abstract will be generated to demonstrate load group assignment verification and transfer capabilities of the 13.8 kV buses to the startup transformers.

QUESTION 14A.19 (NRC Question 640.10(9)) (14.2.12)

14B4-8-c - Subsection 1.8 of your FSAR states compliance with Regulatory Guide 1.41; however, it is not clear from our review of your test procedure abstracts that the intent of this guide is met. Expand your existing test abstracts to indicate this compliance. Testing in conformance with Regulatory Guide 1.41 should incorporate the following:

(a) - Provide assurance that all sources of power supply to vital buses are capable of carrying full accident loads. If some portions of the power supplies cannot be full-load tested, provide justification.

(b) - Verify that testing is conducted with only one power source at a time.

(c) - Verify that buses not under test are monitored to verify absence of voltage.

RESPONSE:

(a) The response is given in the response to 640.10(10) 14.B.4-8-d.

(b) Testing will be begun from a deenergized state with only one power source applied to the circuitry under test.

(c) Following energization of buses under test, interconnecting buses will be monitored to verify absence of voltage.

QUESTION 14A.20 (NRC Question 640.10(10)) (14.2.12)

14B.4-8-d - Your test descriptions are not sufficiently detailed to ascertain if the voltage levels at the safety-related buses are optimized for the full load and minimum load conditions that are expected throughout the anticipated range of voltage variations of the offsite power source by appropriate adjustment of the voltage tap settings of the intervening transformers. We require that the adequacy of the design in this regard be verified by actual measurement and by correlation of measured values with analytical results. Provide a description of the method for making this verification.

RESPONSE: PVNGS will measure the station distribution buses, including Class 1E buses initially and prior to loading, and record voltages. PVNGS will also measure and record the station distribution buses including Class 1E buses upon loading the bus to at least 30%. This will occur prior to completion of the initial test program.

PVNGS will measure and record grid and Class 1E bus voltages and bus loading during the startup of a large Class 1E motor and also during the starting of a large non-Class 1E motor.

The above information will be reviewed to verify analytical data.

QUESTION 14A.21 (NRC Question 640.10(11)) (14.2.12)

14B.9 - Section 1.8 of your FSAR states compliance with Regulatory Guide 1.108; however, it is not clear from our review of your test procedure abstracts that the intent of

this guide is met. Expand this test abstract, as well as 14B.16 if necessary, to indicate this compliance.

RESPONSE: Since PVNGS is committed to Regulatory Guide 1.108 as stated in section 1.8 of the FSAR, PVNGS feels that this is sufficient clarification that we intend to meet the requirements therein.

QUESTION 14A.22 (NRC Question 640.10(12)) (14.2.12)

14B.10 - Paragraph 9.5.3.2.2.3 states that emergency lighting is provided for 8 hours, not 90 minutes to 2 hours as stated in the acceptance criteria of this test. Clarify this apparent inconsistency.

RESPONSE: The response is given in amended section 14B.10.

QUESTION 14A.23 (NRC Question 640.10(13)) (14.2.12)

14B.11 - Our review of recent licensee event reports disclosed that a significant number of reported events concerned the operability of hydraulic and mechanical snubbers. Provide a description in this test abstract of the inspections or tests that will be performed following system operation to ensure that snubber operation is adequate.

RESPONSE: The response is given in amended section 14B.11.

QUESTION 14A.24 (NRC Question 640.10(14)) (14.2.12)

14B.13(a) - Our review of licensee event reports has disclosed several instances of auxiliary feedwater pump failure to start on demand. It appears that many of these failure could have been avoided if more thorough testing had been conducted during

the plant's initial test programs. In order to discover any problems affecting pump start-up and to demonstrate the reliability of your emergency cooling system, state your plans to demonstrate at least five consecutive, successful, cold, quick pump starts during your initial test program.

RESPONSE: The response is given in amended section 14B.13.

QUESTION 14A.25 (NRC Question 640.10(15)) (14.2.12)

14B.13(b) - Subsection 10.4.9 does not reference pump starting times, valve operation times, or operation of alarms, indicating instruments, or status lights. A reference for these items is required.

RESPONSE: The response is given in amended section 14B.13.

QUESTION 14A.26 (NRC Question 640.10(16)) (14.2.12)

14B.14 - Include in this test abstract a commitment to verify that containment recirculation fan motor current is within its design value at conditions representative of accident conditions. Address such issues as air density, temperature, humidity, fan speed, and blade angle.

RESPONSE: The PVNGS design does not use the containment recirculation fans post-accident. The containment spray system provides the needed mixing of the containment atmosphere post-accident.

<u>QUESTION 14A.27</u> (NRC Question 640.10(17)) (14.2.12)

14B.29 - Paragraph 7.5.1.1.5 is not an acceptable reference for acceptance criteria for this test. Provide a more specific reference.

RESPONSE: The response is given in amended paragraph 7.5.1.1.5.

<u>QUESTION 14A.28</u> (NRC Question 640.10(18)) (14.2.12)

14B.30 - Section 7.7 is not an acceptable reference for acceptance criteria for this test. Provide a more specific reference.

RESPONSE: The response is given in amended section 14B.30.

<u>QUESTION 14A.29</u> (NRC Question 640.10(19)) (14.2.12)

14B.41 - It is not clear from our review of this test abstract, and subsection 9.4.6, that the containment ventilation system will be verified to maintain the containment at less than atmospheric pressure as required by Regulatory Guide 1.68 (Rev. 0) Appendix A.7.b. Expand this abstract to clearly reflect compliance with this regulatory position.

RESPONSE: Paragraph 9.4.6.2.2c requires the containment ventilation system to maintain a negative pressure in the containment during the purge cycle.

<u>QUESTION 14A.30</u> (NRC Question 640.10(20)) (14.2.12)

14B.43(a) - Expand this test abstract to include a 100% dynamic load test and a 125% static load test.

RESPONSE: The 100% dynamic and 125% status tests were accomplished during construction certification. PVNGS will verify test documentation as part of section 2.4 of 14B.43.

<u>QUESTION 14A.31</u> (NRC Question 640.10(21)) (14.2.12)

14B.43(b) - Phrases such as "as designed", "as required", and "within specification limits" are unacceptably vague. Provide more specific references for acceptance criteria.

RESPONSE: The response is given in amended section 14B.43.

<u>QUESTION 14A.32</u> (NRC Question 640.11) (14.2.12)

Our review of licensee event reports has disclosed that many events have occurred because of dirt, condensed moisture, or other foreign objects inside instruments and electrical components (e.g., relays, switches, breakers). Describe any tests or inspections that will be performed or any administrative controls that will be implemented during your initial test program to prevent component failures such as these at your facility.

RESPONSE: A preventive maintenance program is established for electrical equipment at system turnover. Preventive maintenance tasks such as inspection and cleaning are identified for inclusion into this program. Component checks during the startup testing ensures the equipment is visually inspected for any abnormalities. System functional checks will also be performed to verify component integrity during the preoperational phase.

APPENDIX 14A

QUESTION 14A.33 (NRC Question 640.12) (14.2.12)

Provide test descriptions: 1) that will verify that the plant's ventilation systems are adequate to maintain all ESF equipment within its design temperature range (see Subsection 3.11.4 of CESSAR) during normal operations; and 2) that will verify that the emergency ventilation systems are capable of maintaining all ESF equipment within their design temperature range with the equipment operating in a manner that will produce the maximum heat load in the compartment. If it is not practical to produce maximum heat loads in a compartment, describe the methods that will be used to verify design heat removal capability of the emergency ventilation systems.

Note that it is not apparent that post-accident design heat loads will be produced in ESF equipment rooms during the power ascension test phase; therefore, simply assuring that area temperatures remain within design limits during this period will probably not demonstrate the design heat removal capability of these systems. It will be necessary to include measurement of air and cooling water temperatures and flows and the extrapolations used to verify that the ventilation systems can remove the postulated post-accident heat loads.

RESPONSE: ESF equipment HVAC are addressed in sections 14B.21, 14B.22, and 14B.23. The data obtained from the above tests will be extrapolated to verify heat removal capabilities.

QUESTION 14A.34 (NRC Question 640.13) (14.2.12)

Provide a preoperational test description to test containment penetration coolers. On those penetrations where coolers are not used, provide a startup test description that will demonstrate that concrete temperatures surrounding hot penetrations do not exceed design limits.

RESPONSE: The response is given in amended section 14B.44. In addition, the penetrations have been designed to limit the concrete temperature in the vicinity of the penetrations to 200F (ASME 3 Div 2 Article CC-3340) which will be verified during the test program. This specific requirement is identified in Specification 13-MM-500, Paragraph 4.6.3.5.

QUESTION 14A.35 (NRC I&E Question 18) (14.2.2)

Please describe the composition, membership, qualifications, duties, responsibilities, quorum requirements, meeting frequency, and documentation requirements of the Plant Review Board referenced in FSAR paragraph 14.2.2.7. In addition, your response should verify the following:

a. The scope of the reviews performed by this Board include those specified by 10CFR50.59 and Section 4.3 of ANSI N18.7-1976.

b. Organizational arrangements provide for interdisciplinary review of subject matter.

c. The qualifications of the personnel performing the review are at least equivalent to those described in Section 4.4 of ANSI 3.1-1978.

d. Reviews are documented and results are forwarded to appropriate members of management.

RESPONSE: The scope of reviews, organizational arrangements, qualifications of members, and review process of the Plant Review Board are controlled by the Technical Specifications.

<u>QUESTION 14A.36</u> (NRC I&E Question 22) (14.2.3)

Paragraph 14.2.3.2 of the FSAR includes the statement, "The Plant Manager has the approval authority for Phase I through Phase IV test procedures, and may delegate approval authority to appropriate plant personnel." Please describe the circumstances under which such authority may be delegated and the job titles or qualifications of the individuals who might receive such authority.

RESPONSE: The response is given in amended paragraphs 14.2.2.5.1, 14.2.2.5.1.1, and 14.2.2.3.2.

<u>QUESTION 14A.37</u> (NRC I&E Question 23)

Please indicate your understanding that startup test procedures for post-fuel loading tests and changes to such procedures will be reviewed and approved in accordance with the requirements stated in the facility Technical Specifications.

RESPONSE: The response is given in amended paragraph 14.2.3.2.

QUESTION 14A.38 (NRC Question 640.14) (14.2.12)

Our review of your test program description disclosed that the operability of several of the systems and components listed in Regulatory Guide 1.68 (Rev. 0), Appendix A, may not be demonstrated by your initial test program. Expand your FSAR to include appropriate test descriptions (or modify existing descriptions) to address the following items from Appendix A of the guide, or provide technical justification in subsection 14.2.7 for each exception.

A. Preoperational Testing

A.1.b(7) Atmospheric steam dump valves.

A.9.a ECCS expansion and restraint tests.

C. Low Power Testing

C.1.i Chemical tests to demonstrate ability to analyze and control water quality.

RESPONSE:

A.1.b(7). The response is given in amended section 14B.1.

A.9.a. The response is given in section 14B.11.

C.1.i. The response will be given in the CESSAR docket.

QUESTION 14A.39 (NRC Question 640.15) (14.2.7)

In response to Item 640.2 (Question 14A.3), you stated that response will be provided on the CESSAR docket. Provide a specific reference for that response.

RESPONSE: Combustion Engineering submitted the Comprehensive Vibration Assessment Program (CVAP) report from the prototype System 80 plant (i.e., Palo Verde) for NRC review in a letter from A.E. Scherer, C-E, to Darrell G. Eisenhut, NRC, dated February 16, 1984 (LD-84-008). Revision 1 of this report was submitted to the NRC in a letter from A.E. Scherer, C-E, to Hugh L. Thompson, NRC, dated March 7, 1985 (LD-85-009).

QUESTION 14A.40 (NRC Question 640.16) (14.2.11)

In response to Item 640.5 (Question 14A.6), you committed to provide copies of startup test procedures to NRC for review at least 60 days prior to fuel loading. FSAR subsection 14.2.11 should be revised to be consistent with this commitment (Amendment 12 modification).

RESPONSE: Amendment 12 reflects the PVNGS commitment to meet the intent of Regulatory Guide 1.68, Appendix B, Rev. 0. That is, to provide in a timely manner Phases I through IV test procedures to assist the NRC regional personnel in implementing their inspection program.

With regard to the Startup Test Program, Phases II through IV, the intent of amendment 12 of the PVNGS FSAR was to relax our previous statement of having all startup test procedures available for review by the NRC 60 days prior to fuel load. The anticipated length of the startup test program will be 1 year, consisting of approximately 128 test procedures to be performed at various times throughout the program for a minimum total of 240 test performances. With the large number of individual test procedures to be

provided, it is not unreasonable to specify that the approved test procedures would be available for the NRC review 60 days prior to its intended performance.

Our full intent, however, was to have 60 days prior to fuel load at a minimum, the following procedures available for the inspector's review:

(1) Administrative procedures governing the conduct of the initial startup test program.

(2) Controlling procedure documents for startup test program milestones that include prerequisites, precautions, and instructions in establishing the plant conditions required to conduct the individual test procedures:

(a) Fuel loading

(b) Post hot functional test

(c) Initial criticality

(d) Low power physics test

(e) Power ascension

In addition, a majority of the 128 individual test procedures were also to be available for the inspector's review at this time.

To avoid any confusion or misunderstanding of the wording in subsection 14.2.11, the following is proposed:

"Phase I test procedures are scheduled to be approved and available for review by the NRC inspectors at least 60 days prior to their scheduled performance date. Phases II

through IV startup test program administrative control procedures, the majority of the individual test procedures, and the following milestone controlling procedure documents: fuel loading, post-core HFT, initial criticality, low power physics test and power ascension, are scheduled to be approved and available for review at least 60 days prior to fuel load. The remaining individual test procedures will be scheduled for approval and available for review by the NRC inspectors at least 60 days prior to their intended performance date."

See FSAR subsection 14.2.11.

APS believes this revision satisfies the intent of Regulatory Guide 1.68, Rev. 0, in providing, in a reasonable time period prior to procedure performance, a procedure for the NRC inspector's review to assist them in establishing an inspection program during major milestones of the initial startup test program.

<u>QUESTION 14A.41</u> (NRC Question 640.17) (14.2.1-12)

In the FSAR chapter 14 table of figures, FSAR figures 14.2-1 and 14.2-2 state that they will be provided later. Figure 14.2-1 is referenced in FSAR paragraph 14.2.2.11 (Organizational Responsibilities), while figure 14.2-2 is not referenced in the current FSAR chapter 14 submittal. The figures should be provided or deleted (Amendment 12 modification).

RESPONSE: APS has recently undergone a realignment of the organization that resulted in additional revision to FSAR

chapter 14 since amendment 12 was submitted. See FSAR section 14.2. Figure 14.2-2 is delete from the text.

QUESTION 14A.42 (NRC Question 640.18) (14.2.12)

a. In response to item 640.10 (5) part 2 (Question 14A.15), you committed to revise the 125 V-dc power system test (section 14B.4) to demonstrate that the DC loads will function as necessary to assure plant safety at a battery terminal voltage equal to the acceptance criterion that has been established for minimum battery terminal voltage for the discharge load test. Revise section 14B.4 to demonstrate that all dc loads required for safe shutdown, as installed, will function properly at the minimum battery terminal voltage (amendment 12 modification).

b. Provide assurance that voltage measurements will be taken at each load required for safe shutdown to assure an acceptable voltage drop from the appropriate Class 1E bus to each load.

RESPONSE:

a. The APS response to NRC Question 640.10 (5) can be found in section 14A.15 of the PVNGS FSAR. Item (2) of the APS response states: "Section 14B.4 will be amended in the future to include the requirement to verify that dc loads will function, as necessary, at a battery terminal voltage equal to the acceptance criteria established for minimum battery terminal voltage."

   The APS response does not state that the minimum battery terminal voltage that is established for the discharge load test will be used as the battery terminal voltage

for the dc system test. APS has instead relied upon previous NRC guidance (telecons in December 1983 with Bill Long, NRC) to determine the upper bound starting battery terminal voltage for the dc system test. Per the previous NRC guidance, the upper bound battery terminal voltage is that voltage defined by the PVNGS Technical Specifications below which the battery is declared to be inoperable.

The purpose of the dc system test is to verify the operability of the dc loads, in the system, at the minimum operable (acceptable) battery terminal voltage. FSAR section 14B.4 will be amended to state that it will be verified that the dc loads required for safe shutdown not verified by vendor tests and systems analysis, will function properly, as installed, at a battery terminal voltage equal to the minimum acceptable battery terminal voltage (see FSAR section 14B.4).

b. As stated in the responses to 640.18a, the purpose of the dc system test is to verify the operability of the dc loads, in the system, at the minimum acceptable battery terminal voltage. By verifying the operability of the dc loads required for safe shutdown, installed in the system, at the minimum acceptable battery terminal voltage conditions, APS is assured that the dc loads will function in the manner so as to bring PVNGS to a safe shutdown. Therefore, it is our intent to only verify operability and not the voltage seen by each load.

APPENDIX 14B

PREOPERATIONAL TEST DESCRIPTION

(Historical)

CONTENTS

CONTENTS (cont)

CONTENTS (cont)

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APPENDIX 14B

PREOPERATIONAL TEST DESCRIPTION (Historical)

14B.1 MAIN STEAM, MAIN STEAM ISOLATION VALVES, SAFETY VALVES, AND ATMOSPHERIC DUMP VALVES

1.0 OBJECTIVE

To demonstrate the functional performance of the main steam system including main steam isolation valve (MSIV) closing times, steam generator safety relief valves' operability, and atmospheric steam dump valves' operability. Steam generator safety relief valves' operability will be demonstrated with steam at temperatures and pressures representative of their service conditions.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Support systems available.

2.4 Test equipment available and test instrumentation calibrated.

3.0 TEST METHOD

3.1 Demonstrate manual and automatic system controls.

3.2 Verify flow paths.

3.3 Determine closing times of the MSIVs and the MSIV bypass valves.

3.4 Demonstrate operability of safety relief valves and verify seat leaktightness.

3.5 Demonstrate operability of atmospheric steam dump valves.

3.6 Verify operation of automatic drain valves.

3.7 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The main steam system operates as described in section 10.3 when using the above test methods.

14B.2 CONTAINMENT SPRAY SYSTEM

1.0 OBJECTIVE

To functionally check the operation of the containment spray system including the performance of the containment spray pumps, and to provide verification of an unobstructed flow path from the spray pumps to the spray nozzles by using water and air with overlapping flow paths.

2.0 PREREQUISITES

2.1 Construction activities are complete on the items to be tested.

2.2 Refueling water tank available.

2.3 System will be filled, vented, and lined up per station operation procedures for normal operation.

2.4 Instruments are calibrated.

3.0 TEST METHOD

3.1 Flow will be established with each spray pump by recirculating water from the refueling water tank.

3.2 Pump performance will be checked.

3.3 Alarms will be checked.

3.4 Air will be used to establish air flow in each spray header and flow shall be verified from each nozzle. The air flow will be established to ensure an unobstructed flow path at a point which overlaps the flow path verification utilizing water.

4.0 ACCEPTANCE CRITERIA

The containment spray system operates as described in subsections 6.2.2 and 6.5.2 when using the above test methods.

14B.3 CONDENSATE STORAGE TANK AND TRANSFER SYSTEM

1.0 OBJECTIVE

To demonstrate that the condensate storage tank and transfer system is capable of storing and transferring condensate/demineralized water to systems as required.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrumentation calibration completed.

2.3 Support systems available.

2.4 Test instrumentation available and calibrated.

3.0 TEST METHOD

3.1 Verify automatic and manual system control functions.

3.2 Demonstrate operability of flow paths.

3.3 Verify ability of system to provide makeup water to various systems as required with either condensate transfer pump in service.

3.4 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The condensate storage tank and transfer system operates as described in subsection 9.2.6 when using the above test methods.

14B.4 125 V-DC POWER SYSTEM

1.0 OBJECTIVE

To demonstrate, by verification of the system design and by component performance testing, that the 125 V-dc power system provides a reliable source of power for startup, operation, and shutdown under normal and emergency conditions, and to verify that the four separate power sources and their respective loads are independent of each other.

2.0 PREREQUISITES

2.1 Construction activities completed on components to be tested.

2.2 Meters and relays calibrated.

2.3 Batteries fully charged with normal height of electrolyte.

2.4 Load resistor bank available for battery capacity test.

2.5 Construction activities completed on safety related equipment supplied by the battery system for the integrated system test.

2.6 Battery room ventilation available.

2.7 Appropriate ac and dc power sources available.

3.0 TEST METHOD

3.1 Inspection to verify that construction and component installation is in accordance with the system design.

3.2 Battery capacity and charger performance will be verified in both float and equalize mode.

3.3 Alarms and tripping devices will be tested.

3.4 The ground detector will be checked.

3.5 The load capacity of **the** battery will be measured by discharging the battery through a variable resistive load programmed to match the emergency discharge requirements of the battery. (Battery charger disconnected.)

3.6 Individual cell voltage will be monitored during the design discharge test.

3.7 Verify that dc loads required for safe shutdown, not verified by vendor tests and system analysis, will function properly, as installed, at a battery terminal voltage equal to the minimum acceptable battery terminal voltage. If system analysis is used, the worst case for each type load will be proven operable by an actual field test.

4.0 ACCEPTANCE CRITERIA

4.1 The 125 V-dc power system will perform the functions described in applicable portions of

subsection 8.3.2 when using the above test methods.

4.2 Dc supplied loads required for safe shutdown, not verified by vendor tests and system analysis will function, as installed and required, at a battery terminal voltage equal to the acceptance criteria established for minimum battery terminal voltage. If system analysis is used, the worst case for each type load will be proven operable by an actual field test.

14B.5 CLASS 1E 4.16 KV POWER SYSTEM

1.0 OBJECTIVE

To demonstrate the operation of the control logic and protective devices of the 4.16 kV ESF switchgear.

2.0 PREREQUISITES

2.1 Construction activities completed on items to be tested.

2.2 Permanently installed instrumentation properly calibrated and operable.

2.3 Test instrumentation available and properly calibrated.

2.4 125 V-dc power available.

2.5 All 4.16 kV feeders and buses meggered with acceptable results.

2.6 4.16 kV power is available from the normal and alternate ESF transformer sources.

2.7 Switchgear assembly, breakers, control, and protective equipment/circuits have been inspected and tested and are capable of being placed into service.

3.0 TEST METHOD

3.1 Demonstrate the operability of the 4.16 kV ESF bus normal and alternate supply breakers, locally and remotely.

3.2 Demonstrate the operability of the bus protection and lockout devices.

3.3 Demonstrate the operability of the synchronizing circuits.

3.4 Verify all metering and annunciation.

4.0 ACCEPTANCE CRITERIA

The 4.16 kV ESF buses perform as described in applicable portions of section 8.3 when using the above test methods.

14B.6 CLASS 1E 480V POWER SWITCHGEAR SYSTEM

1.0 OBJECTIVE

The 480V Class 1E switchgear shall function in such a manner as to provide electric power at the correct voltage to the loads connected to the bus.

2.0 PREREQUISITES

2.1 Construction is complete and the system is released for testing in accordance with the Startup Manual.

2.2 Sufficient load is available to be connected to the buses to demonstrate their operability.

2.3 Approved P&IDs, logic diagrams, wiring diagrams, and vendors' technical data are available.

3.0 TEST METHOD

3.1 Verify proper operation of the bus protective relaying, including undervoltage relaying, by simulation.

3.2 Verify proper operation of the breaker interlocks by simulation.

3.3 Load the bus with sufficient load to verify its ability to perform its intended function.

4.0 ACCEPTANCE CRITERIA

4.1 All interlocks and controls perform their intended function as described in appropriate design documents.

4.2 The 480V Class 1E switchgear operates as described in section 8.3.

14B.7 CLASS 1E 480V POWER MCC SYSTEM

1.0 OBJECTIVE

The 480V Class 1E motor control centers shall function in such a manner as to provide electric power at the correct voltage to the loads connected to these centers.

2.0 PREREQUISITES

2.1 Construction is complete and the system is released for testing in accordance with the Startup Manual.

2.2 Sufficient load is available to be connected to the buses to demonstrate their operability.

2.3 Approved P&IDs, logic diagrams, wiring diagrams, and vendors' technical data are available.

3.0 TEST METHOD

3.1 Verify proper operation of the bus protective relaying by simulation.

3.2 Verify proper operation of the breaker interlocks by simulation.

3.3 Load the bus with sufficient load to verify its ability to perform its intended function.

4.0 ACCEPTANCE CRITERIA

4.1 All interlocks and controls perform their intended function as described in appropriate design documents.

4.2 The 480V Class 1E motor control centers operate as described in section 8.3.

14B.8 CLASS 1E INSTRUMENT AC POWER

1.0 OBJECTIVE

To demonstrate that the four 120 V-ac vital buses and associated power supplies are capable of supporting their design loads and can be transferred to the alternate sources.

2.0 PREREQUISITES

2.1 Construction activities completed on the system(s) to be tested.

2.2 Permanently installed instrumentation properly calibrated and operable.

2.3 Test instrumentation available and properly calibrated.

2.4 All 125 V-dc power systems available to ac inverters for the vital buses.

2.5 Alternate vital bus source available.

3.0 TEST METHOD

3.1 Operability and setpoint(s) shall verified for each alarm and tripping device.

3.2A Test manual transfer switch operation (Unit 1 only).

3.2B Test automatic static transfer switch operation (Units 2 and 3).

3.3 Each bus will be load tested, using both its normal and alternate power supply, by imposing its design connected load.

4.0 ACCEPTANCE CRITERIA

The vital ac power systems will perform the functions described in applicable portions of paragraph 8.3.1.1.6 when using the above test methods.

14B.9 DIESEL GENERATOR ELECTRICAL TESTS AND LOAD SEQUENCING

1.0 OBJECTIVE

To demonstrate the capability of the emergency diesel generators and their support equipment to provide emergency power to safely shut down the reactor, remove residual heat, and maintain safe shutdown conditions upon loss of preferred power.

2.0 PREREQUISITES

2.1 Construction activities are complete on items to be tested.

2.2 Provisions for loading the diesel generator are available.

2.3 Associated instrumentation has been calibrated.

2.4 Appropriate ac and dc power sources available.

3.0 TEST METHOD

3.1 Local/remote, manual/automatic mode combinations will be verified for all support equipment including the fuel systems, starting air, and switchgear.

3.2 Manual control and starting of the diesel will be demonstrated and operating parameters monitored.

3.3 Emergency starting conditions will be demonstrated and recorded.

3.4 Repetitive starting capability tests will be performed.

3.5 Load tests will be conducted to verify the performance of each unit with permanently connected and auto-connected emergency (accident) loads.

4.0 ACCEPTANCE CRITERIA

Each diesel generator set will perform as described in applicable portions of paragraph 8.3.1.1.4 when using the above test methods.

14B.10 EMERGENCY LIGHTING

1.0 OBJECTIVE

To demonstrate the transfer capability from ac lighting to emergency lighting, and verify the adequacy of the lighting provided.

2.0 PREREQUISITES

2.1 Construction activities completed on the items to be tested.

2.2 The normal, essential, and emergency lighting systems are operational, as applicable.

3.0 TEST METHOD

3.1 Emergency lighting transfer capability shall be tested by deenergizing the applicable normal or essential lighting circuits.

3.2 Performance of the emergency lighting fixtures shall be monitored to verify the duration of illumination capability.

3.3 Lighting intensity levels in the control room shall be measured.

4.0 ACCEPTANCE CRITERIA

4.1 Upon the loss of essential lighting, the emergency lighting system shall be energized automatically, with the exception of certain self-contained battery-powered emergency lighting

fixtures located in non-safe shutdown areas of the plant that are not provided with essential lighting. These fixtures are fed from the normal lighting system, and shall energize automatically upon loss of normal lighting in the area.

4.2 All self-contained emergency lighting units and all nonself-contained emergency lighting units within the control room and sections of the control room panel area required for safe shutdown shall provide illumination for a minimum continuous period of 8 hours following loss of the ac power source.

4.3 The lighting level in the control room (horseshoe area) shall be 6 fc and sections of the control room panel area required for safe shutdown shall be 3 fc.

4.4 The emergency lighting systems are capable of providing illumination in the event of loss of ac power, and shall operate as described in subsection 9.5.3.

4.5 All self-contained and nonself-contained emergency lighting units necessary for the operation of safe shutdown equipment, including access and egress routes thereto, shall provide illumination for a minimum continuous period of 8 hours following loss of the ac power source.

4.6 All self-contained and nonself-contained emergency lighting units not necessary for the

operation of safe shutdown equipment, including access and egress routes thereto, shall provide illumination for a minimum continuous period of 1-1/2 hours following the loss of ac power source.

14B.11 PIPE SHOCK AND VIBRATION TEST

1.0 OBJECTIVE

To demonstrate that essential NSSS and BOP piping is free to expand thermally as required and to verify stress analysis of piping under transient conditions.

2.0 PREREQUISITES

2.1 All construction activities completed on the piping to be analyzed.

2.2 Temporary instrumentation installed as required to monitor the vibration, shock, and deflection of the piping under test.

2.3 Baseline positions and alignments recorded.

2.4 Preservice examination of all selected snubbers conducted within 6 months of initial associated system heat up for hot functional testing and verifying the following:

(1) There are no visible signs of snubber damage or impaired operability as a result of storage, handling, or installation.

(2) The snubber location, orientation, position setting, and configuration (attachments, extensions, etc.) are according to design drawings and specifications.

(3) Snubbers are not seized, frozen, or jammed.

(4) Adequate swing clearance is provided to allow snubber movement.

(5) If applicable, fluid is to the recommended level and is not leaking from the snubber system.

(6) Structural connections such as pins, fasteners, and other connecting hardware such as lock nuts, tabs, wire, and cotter pins are installed correctly.

If the period between the initial preservice examination and initial system preoperational test exceeds 6 months due to unexpected situations, reexamination of items (1), (4), and (5) shall be performed. Snubbers which are installed incorrectly or otherwise fail to meet the above requirements shall be repaired or replaced and reexamined in accordance with the above criteria.

3.0 TEST METHOD

3.1 Piping vibration, thermal expansion, and dynamic effects testing is described in paragraph 3.9.2.1. Systems to be monitored

include: A) ASME Code Class 1 and 2 piping systems, B) high energy piping systems inside Seismic Category I structures, C) high energy portions of systems whose failures could reduce the functioning of Seismic Category I plant features to an unacceptable safety level, and D) Seismic Category I portions of moderate energy piping systems located outside containment. Safety-related piping systems to be tested are listed in table 3.2-1 as ANSI N18.2 Safety Class 1, 2, or 3.

The thermal expansion of ASME Section III, Class 1, 2, and 3 high energy piping and ASME high energy steam piping up to the turbine stop valves shall be measured at selected points. The thermal movements of snubbers associated with the above piping whose operating temperature exceeds 250F shall be verified per the following:

(1) During initial system heatup and cooldown, at specified temperature intervals for any system which attains operating temperature, verification of the snubber expected thermal movement.

(2) For those systems that do not attain operating temperature, verification via observation and/or calculation that the snubber will accommodate the projected thermal movement.

(3) Verification of the snubber swing clearance at specified heatup and cooldown intervals. Any discrepancies or inconsistencies shall be evaluated for cause and corrected prior to proceeding to the next specified interval.

Other ASME high energy steam and feedwater piping shall be visually examined to assure that it expands freely.

The steady-state vibration of ASME Section III, Class 1, 2, and 3 piping and high energy steam and feedwater piping shall be visually examined by an engineer (qualified per paragraph 14.2.2.12.1) to ascertain qualitatively the effects of flow induced vibrations.

The dynamic effects testing shall be performed on those piping systems, larger than 1 inch in diameter, which are essential to safety, and are expected to undergo significant transient behavior due to: fast valve closure, operation of pressure-relieving valves, pump starts and stops, steam hammer, water hammer, and sudden expansions during normal plant operations and trips.

Instrument lines will not be monitored. ASME Code Class 1, 2, and 3 instrument lines are designed with flexible seismic isolation devices downstream of instrument root valves. Because of

the small size of applicable instrument lines (1 inch and smaller) and short sections that are subject to system vibration, failure is considered remote and is not postulated to cause failure of Seismic Category I plant equipment. Similarly, service air or nitrogen lines 1 inch diameter and smaller that are attached to monitored systems will not be monitored.

3.2 Data acquisitions shall be accomplished with instruments possessing the accuracy and sensitivity needed to demonstrate satisfactory system performance. In each case the data acquisition system shall be designed for reliable data collection.

Thermal expansion data will consist of pipe movement and temperatures; these parameters will be monitored by measurements and visual references at cold and hot zero power conditions. However, selected piping and components will be visually monitored during plant heatup and cooldown.

Steady-state vibration data will consist of qualitative visual observation of steady-state vibration during normal system operation. When significant vibration is noted, quantitative measurements using temporary vibration monitoring instruments shall be made.

Dynamic response data will consist of pressure fluctuations, pipe acceleration/displacement, and pipe support reactions to load changes. The instrumentation used will be of high frequency response with adequate ranges to cover the physical quantity being measured.

Selected major high energy pipes with significant thermal differential shall be monitored by linear measurements at selected points. Points selected for monitoring will be tabulated in test procedures which will be available for NRC review onsite 60 days prior to the conduct of applicable tests, and will be representative of the area in which they are located or representative of identical piping and will provide meaningful and significant results. The remainder of the high- and moderate energy piping will be visually inspected by an engineer (qualified per paragraph 14.2.2.12.1).

4.0 ACCEPTANCE CRITERIA

The acceptance criteria for thermal expansion shall ensure sufficient clearance has been provided to allow free and unrestricted thermal expansion of essential plant piping and components. Where thermal deflection is measured, the deflections shall be compared to the stress analysis of the piping system.

The acceptability of steady-state vibration of piping, components, and supports shall be based on

observations by an engineer (qualified per paragraph 14.2.2.12.1). Should significant vibrations occur, an engineering evaluation shall be made by analyzing the displacement amplitudes and corresponding stress levels to the acceptance criteria. The acceptance criteria for steady-state vibration shall be that the maximum measured amplitude shall not induce a stress in the piping greater than one-half the alternating stress intensity at 10^6 stress cycles as defined in Section III of the ASME Boiler and Pressure Vessel Code.

Dynamic effects acceptance criteria will be provided for those piping systems where significant transient behavior is anticipated. Measured displacements, pressures, and temperatures shall be compared to those derived by the stress analysis.

Should any abnormalities occur while operationally testing piping systems which are not instrumented, those piping systems shall be checked for any indications of structural damage. An engineering determination shall be made as to the cause of the abnormality and its effect on structural integrity. If it is determined that structural integrity will be degraded below an acceptable level, corrective actions shall be taken, and appropriate retesting accomplished.

14B.12 CONTAINMENT ISOLATION ACTUATION SYSTEM

1.0 OBJECTIVE

To verify the proper functional performance of the containment isolation actuation system.

2.0 PREREQUISITES

2.1 Construction is complete on the items to be tested.

2.2 Associated instrumentation is calibrated.

3.0 TEST METHOD

3.1 Using the built-in test panel of engineered safety features actuation system (ESFAS), test each group relay for a containment isolation activation system actuation and verify valve actuation to be correct.

3.2 Using an input signal to the plant protection system, verify that a CIAS signal is initiated by the PPS to the ESFAS and the associated containment isolation valves function by taking their designated containment isolation position.

4.0 ACCEPTANCE CRITERIA

Containment isolation actuation system operates as described in subsection 6.2.4 when using above test methods.

14B.13 AUXILIARY FEEDWATER SYSTEM

1.0 OBJECTIVE

To demonstrate the ability of the auxiliary feedwater system to:

1.1 Supply sufficient auxiliary feedwater to the steam generators for reactor startup, normal reactor cooldown, and design emergency conditions.

1.2 Respond correctly to automatic and manual system controls.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Support systems available.

2.4 Test instrumentation available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate automatic and manual system controls.

3.2 Verify system flowrates and pressures, including operation of the turbine-driven auxiliary feed-water pump over its design range of inlet steam conditions.

3.3 Verify and record pump on demand starting times and valve opening and closing times.[a][b]

3.4 Verify and record alarms, indicating instruments and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The auxiliary feedwater system operates as described in subsection 10.4.9 and manufacturer's design specifications when using the above test methods.

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a. Pump on demand starting time verification will be done a minimum of five times. Each time must be successful and from a cold, quick start condition.

b. This applies to the turbine-driven auxiliary feedwater pump only.

14B.14 REACTOR CONTAINMENT INTEGRATED AND LOCAL LEAK RATE TESTS

1.0 OBJECTIVE

To demonstrate, prior to initial reactor operation, that leakage through the primary reactor containment and systems and components penetrating primary containment do not exceed the allowable leakage rate values as specified in the Technical Specifications.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Structural integrity test (described in paragraph 3.8.1.7) satisfactorily completed.

2.3 Leakage rate determination instrumentation available and properly calibrated.

2.4 Containment ventilation system, personnel airlock, and isolation valves are operable.

2.4 Containment inspection completed.

3.0 TEST METHOD

3.1 Perform individual local leakage tests on containment isolation valves and penetrations as described in section 6.2.

3.2 Perform a containment building integrated leakage rate test at the calculated peak internal pressure per section 6.2.

4.0 ACCEPTANCE CRITERIA

The containment leakage shall not exceed the plant technical specification limits stipulated in Section 3/4.6.1 of the Technical Specifications.

14B.15 DIESEL FUEL OIL STORAGE SYSTEM

1.0 OBJECTIVE

To demonstrate the ability of the diesel generator fuel oil storage and transfer system to provide a reliable and adequate supply of fuel oil to each emergency diesel generator.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibrations completed.

2.3 Support systems available.

2.4 Test instrumentation available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate operability of flow paths.

3.2 Verify automatic and manual system control functions.

3.3 Verify fuel oil transfer rate.

3.4 Verify alarms, indicating instruments and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The diesel generator fuel oil storage and transfer system operates as described in subsection 9.5.4 when using the above test methods.

14B.16 DIESEL GENERATOR MECHANICAL SYSTEMS

1.0 OBJECTIVE

To verify proper operation of the emergency diesels including their cooling, starting, and lubrication systems.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Support systems available.

2.4 Test instrumentation available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate operability of flow paths.

3.2 Verify manual and automatic controls of the cooling, starting, and lubrication systems.

3.3 Demonstrate starting and operation of the diesel engines.[a]

3.4 Verify diesel engine protective trip functions.

3.1 Verify alarms, indicating instruments, and status lights are functional.

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a. See diesel generator electrical tests for starting and loading reliability test program.

4.0 ACCEPTANCE CRITERIA

4.1 Each diesel operates per applicable portions of section 8.3 when using the above test methods.

4.2 Each diesel generator cooling water system, starting system, and lubrication system operates as described in subsections 9.5.5, 9.5.6, and 9.5.7, respectively, when using the above test methods.

14B.17 ESSENTIAL CHILLED WATER SYSTEM

1.0 OBJECTIVE

To demonstrate proper operation of the essential chilled water system.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Support systems available.

2.4 Test instruments available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate manual and automatic system controls, including automatic start features.

3.2 Verify system flowrates.

3.3 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The essential chilled water system operates as described in paragraph 9.2.9.2 when using the above test methods.

14B.18 ESSENTIAL COOLING WATER SYSTEM

1.0 OBJECTIVE

To demonstrate proper operation of the essential cooling water system.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Support systems available.

2.4 Test instruments available and calibrated.

2.5 Portions of fuel pool cooling system and nuclear cooling water system supplied by essential cooling water available.

3.0 TEST METHOD

3.1 Verify adequate flow to components supplied with essential cooling water.

3.2 Demonstrate manual and automatic system controls, including automatic pump starts and valve operations.

3.3 Verify alarms, indicating instruments and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The essential cooling water system operates as described in paragraph 9.2.2.1 when using the above test methods.

14B.19 FUEL POOL COOLING AND CLEANUP SYSTEM

1.0 OBJECTIVE

To demonstrate the ability of the fuel pool cooling and cleanup system to satisfy operational performance requirements with regard to design flow paths, flow capacity, and mechanical operability.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Test instrumentation available and properly calibrated.

2.4 Spent fuel pool and reactor vessel cavity construction leak tests completed.

2.5 Support systems available.

3.0 TEST METHOD

3.1 Demonstrate manual and automatic system controls.

3.2 Verify system flowrates.

3.3 Verify alarms, indicating instruments, and status lights are functional.

3.4 Demonstrate operability and perform leak tests of sectionalizing devices in the spent fuel pool.

4.0 ACCEPTANCE CRITERIA

The fuel pool cooling and cleanup system operates as described in subsection 9.1.3 when using the above test methods.

14B.20 ESSENTIAL SPRAY POND SYSTEM

1.0 OBJECTIVE

To demonstrate proper operation of the safety-related portion of the essential spray pool system.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Support systems available.

2.4 Test instrumentation available and calibrated.

3.0 TEST METHOD

3.1 Verify adequate flow to heat exchangers and spray nozzles.

3.2 Verify that actuation signals are properly received and executed.

3.3 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The safety-related portion of the essential spray pond system operates as described in subsection 9.2.1 when using the above test methods.

14B.21 AUXILIARY BUILDING ESSENTIAL HVAC AND FUEL BUILDING ESSENTIAL EXHAUST SYSTEMS

1.0 OBJECTIVE

To demonstrate proper operation of the auxiliary building essential HVAC system and the fuel building essential exhaust system.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Test instruments available and calibrated.

2.4 Support systems available.

3.0 TEST METHOD

3.1 Verify design air flow.

3.2 Demonstrate manual and automatic system controls.

3.3 Demonstrate ability of essential exhaust fans to maintain a negative pressure in the fuel building and the auxiliary building below elevation 100 feet 0 inch.

3.4 Perform in-place testing of filtration units as discussed in section 1.8.

3.5 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The auxiliary building essential HVAC system and the fuel building essential exhaust system operate as described in paragraphs 9.4.2.2 and 9.4.5.2, respectively, when using the above test methods.

14B.22 DIESEL GENERATOR BUILDING HVAC

1.0 OBJECTIVE

To demonstrate proper operation of the essential portion of the diesel generator building HVAC system.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Diesel generator control system and required power systems available.

2.4 Test instruments available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate manual and automatic system controls, including start of essential ventilation equipment when the diesel generator starts.

3.2 Verify design air flows.

3.3 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The essential portion of the diesel generator building HVAC system operates as described in subsection 9.4.7 when using the above test methods.

14B.23 CONTROL BUILDING ESSENTIAL HVAC

1.0 OBJECTIVE

To demonstrate proper operation of the control building essential HVAC system to ensure adequate environmental conditions for personnel and essential equipment for emergency conditions.

2.0 PREREQUISITES

2.1 Construction activity is completed.

2.2 Component testing and instrument calibration completed.

2.3 Test instrumentation available and properly calibrated.

2.4 Support systems available.

3.0 TEST METHOD

3.1 Demonstrate manual and automatic system controls.

3.2 Verify design air flows.

3.3 Demonstrate the capability of the system to isolate and maintain the control room and habitability areas at a positive pressure.

3.4 Perform in-place testing of filtration units as discussed in section 1.8.

3.5 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The control building essential HVAC operates as described in section 6.4 and subsection 9.4.1 when using the above test methods.

14B.24 CONTAINMENT HYDROGEN CONTROL SYSTEM

1.0 OBJECTIVE

To demonstrate the ability of the system to function as designed to prevent the post-LOCA hydrogen concentration in containment from exceeding established limits.

2.0 PREREQUISITES

2.1 Construction activities completed on components to be tested.

2.2 Component testing and instrument calibration completed.

2.3 Test instrumentation available and properly calibrated.

2.4 Support systems available.

3.0 TEST METHOD

3.1 Demonstrate automatic and manual system controls.

3.2 Verify recombiner air flow and thermal capacities meet design requirements.

3.3 Verify alarms, indicating instruments, and status lights are functional.

3.4 Perform in-place testing of filtration units as discussed in section 1.8.

4.0 ACCEPTANCE CRITERIA

The containment hydrogen control system operates as described in subsection 6.2.5 when using the above test methods.

14B.25 RADIOACTIVE WASTE DRAIN SYSTEM

1.0 OBJECTIVE

To demonstrate proper operation of the equipment and floor drainage system provided for the ESF equipment rooms in the auxiliary building.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Water source available for supplying drains and sumps.

2.4 Support systems available.

2.5 Test instrumentation available and calibrated.

3.0 TEST METHOD

3.1 Verify flow paths.

3.2 Demonstrate automatic and manual system controls.

3.3 Verify separation of drain systems for trains A and B ESF equipment rooms.

3.4 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The drainage system for the ESF equipment rooms operates as described in applicable portions of subsection 9.3.3 when using the above test methods.

14B.26 RADIATION MONITORING SYSTEM

1.0 OBJECTIVE

To verify the proper functional operation of the radiation monitoring system.

2.0 PREREQUISITES

2.1 Construction activities completed on the radiation monitoring system.

2.2 The radiation monitor has been calibrated.

2.3 External test instrumentation has been calibrated.

2.4 Check sources are available.

3.0 TEST METHOD

3.1 Utilizing a check source, verify response of detector to a radiation field to verify proper monitor operation.

3.2 Verify the self-testing feature of each monitor, where applicable.

3.3 Verify control actuation by each monitor and record the response time where applicable.

3.4 Verify proper local and remote alarm actuation where applicable.

4.0 ACCEPTANCE CRITERIA

The radiation monitoring system operates as described in subsection 12.3.4 when using the above test methods.

14B.27 IODINE REMOVAL SUBSYSTEM (Abandoned in Place)

14B.28 NUCLEAR COOLING WATER SYSTEM

1.0 OBJECTIVE

To demonstrate proper operation of the nuclear cooling water system.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Test instruments available and calibrated.

2.4 Support systems available.

3.0 TEST METHOD

3.1 Verify adequate flow to components supplied with nuclear cooling water.

3.2 Demonstrate manual and automatic system controls.

3.3 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The nuclear cooling water system operates as described in paragraph 9.2.2.2 when using the above test methods.

14B.29 POST-ACCIDENT MONITORING SYSTEM

1.0 OBJECTIVE

1.1 To verify that all instruments of the post-accident monitoring system are properly installed.

1.2 To ensure that all instruments in the post-accident monitoring system have appropriate ranges and are calibrated.

2.0 PREREQUISITES

2.1 Construction activities on the post-accident monitoring system have been completed.

2.2 Appropriate test equipment is available and has been calibrated.

2.3 Appropriate instrument power sources are available.

3.0 TEST METHOD

3.1 Verify that the range of each instrument is as specified in CESSAR Section 7.5.2.5 and CESSAR Table 7.5-3.

3.2 Verify proper calibration of each instrument in the post-accident monitoring system.

4.0 ACCEPTANCE CRITERIA

Instrument ranges and accuracies shall be as specified in paragraph 7.5.1.1.5.

14B.30 PLANT COMPUTER

1.0 OBJECTIVES

To verify that all system hardware is installed and operating properly; and that all system software responds correctly to external inputs, and provides proper outputs to the computer peripheral equipment.

2.0 PREREQUISITES

2.1 All construction and installation activities are completed on the items to be tested.

2.2 Required manufacturer's and/or owner's manuals are available.

2.3 Inherent and external test instrumentation is calibrated and available.

2.4 Support systems required for operation of the plant computer are operational.

3.0 TEST METHOD

3.1 Test programs are to be run, sequenced as specified by the manufacturer, to ascertain the reliability of computer systems to perform all required hardware functions.

3.2 External inputs to the system shall be simulated and the outputs measured using the external test instrumentation.

3.3 Computer functional programs shall be verified using proper software and/or control panel inputs, as applicable.

3.4 Alarm and indication functions shall be verified by the computer system instrumentation and/or the external test measurements, as applicable.

4.0 ACCEPTANCE CRITERIA

Plant computer system operates as described in Section 7.7.1.3.2 of CESSAR when using above test methods.

APPENDIX 14B

14B.31 LOOSE PARTS MONITORING SYSTEM

1.0 OBJECTIVE

To demonstrate that the loose parts monitoring system is properly installed and operates as designed.

2.0 PREREQUISITES

2.1 All construction activities on the loose parts monitoring system are complete.

2.2 All associated instrumentation have been calibrated.

2.3 Appropriate test instrumentation, is available and calibrated.

3.0 TEST METHOD

3.1 Verify system response to simulated loose parts.

3.2 Verify the proper operation and installation of all recording devices.

3.3 Verify and calibrate all system alarms and indicators.

4.0 ACCEPTANCE CRITERIA

The loose parts monitoring system operates as described in section 7.7, listing C, when using above test methods.

14B.32 PLANT ANNUNCIATOR

1.0 OBJECTIVE

1.1 To verify that the annunciators system is properly installed and will respond to a change of state of any field contact.

1.2 To verify that the annunciator system will transfer to the redundant power source upon receipt of a supply voltage reduction.

2.0 PREREQUISITES

2.1 All construction and installation activities are completed on the annunciators and associated systems.

2.2 Support systems required for the operation of the annunciators have been tested and are operating.

2.3 Appropriate test equipment is available and calibrated.

2.4 Appropriate ac and dc power sources are operable.

3.0 TEST METHOD

3.1 Self test features of the system shall be tested and verified to be operational.

3.2 "First out" feature shall be tested and verified operational.

3.3 Each field contact shall be actuated and appropriate annunciator response verified.

4.0 ACCEPTANCE CRITERIA

Annunciator system operates as described in section 7.6 when using the above test methods.

14B.33 SEISMIC INSTRUMENTATION

1.0 OBJECTIVES

To demonstrate proper operation of the seismic monitoring instrumentation.

2.0 PREREQUISITES

2.1 Construction activities on the seismic monitoring instrumentation have been completed.

2.2 All associated instrumentation has been calibrated.

2.3 Appropriate test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify operability of internal calibration devices by recording calibration records on all applicable sensors.

3.2 Verify system response to simulated seismic events by actuating the appropriate trigger units, recording accelerograph outputs and playing back all records for analysis.

3.3 Verify and calibrate all systems alarms and indicators.

3.4 Verify the proper operation and installation of all peak recording accelerographs.

4.0 ACCEPTANCE CRITERIA

The seismic instrumentation system operates as described in subsection 3.7.4 when using the above test methods.

APPENDIX 14B

14B.34 GAS ANALYZER

1.0 OBJECTIVE

To verify the gas analyzer package will automatically monitor hydrogen and oxygen concentrations.

2.0 PREREQUISITES

2.1 Construction activities on all systems connected to gas analyzer package are complete.

2.2 Sample points are hooked up to the gas analyzer package.

2.3 Associated instrumentation has been calibrated.

2.4 System lined up for normal operation per station operating procedures.

3.0 TEST METHOD

3.1 Check proper operation of the sequence selector for automatic monitoring of inputs.

3.2 Check ability to correctly measure and record known oxygen and hydrogen concentrations.

3.3 Check alarm setpoints.

4.0 ACCEPTANCE CRITERIA

The automatic gas analyzer operates as described in subsection 9.3.2 when using the above test methods.

14B.35 IN-PLANT COMMUNICATIONS SYSTEM

1.0 OBJECTIVE

To demonstrate the adequacy of the in-plant communications system to provide communications between vital plant areas and to test the operability of the emergency evacuation alarms.

2.0 PREREQUISITES

2.1 All construction activities on the in-plant communications system are complete.

2.2 Support systems required for operation of the inplant communications system are available.

2.3 All possible plant equipment that contributes to the ambient noise level should be in operation.

3.0 TEST METHOD

3.1 Verify the unit/area evacuation system functions properly.

3.2 Verify that the telephone system functions properly, that each station is assigned to the current restriction class.

3.3 Verify the sound powered phone system functions properly.

3.4 Verify the radio communication system functions properly.

3.5 Verify the public address system functions properly.

4.0 ACCEPTANCE CRITERIA

The in-plant communications system operates as described in subsection 9.5.2 when using above test methods.

14B.36 LOCAL LAW ENFORCEMENT AGENCY OFFSITE COMMUNICATION SYSTEMS

1.0 OBJECTIVE

To demonstrate the proper operation of the local law enforcement agency (LLEA) offsite communication systems.

2.0 PREREQUISITES

2.1 All construction activities have been completed on the LLEA offsite communication systems.

2.2 Support systems required for operation of the LLEA offsite communication systems are available.

3.0 TEST METHOD

3.1 Verify proper operation of the LLEA radio.

3.2 Verify proper operation of the LLEA land lines.

3.3 Verify proper operation of 115 V-ac power sources for the LLEA land line.

4.0 ACCEPTANCE CRITERIA

The LLEA offsite communications systems operate as described in subsection 9.5.2 when using above test methods.

14B.37 CIRCULATING WATER SYSTEM

1.0 OBJECTIVE

To demonstrate proper operation of the circulating water system.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Support systems available.

2.4 Intake structure flooded and water quality within limits.

3.0 TEST METHOD

3.1 Demonstrate flow paths.

3.2 Verify automatic and manual system controls function properly.

3.3 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The circulating water system operates as described in subsection 10.4.5 when using the above test methods.

14B.38 FIRE PROTECTION SYSTEM

1.0 OBJECTIVE

To demonstrate the proper operation of the fire protection system in the detection of fires and the capabilities to contain and extinguish fires.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Test equipment and instrumentation available and properly calibrated.

2.4 Support systems available.

3.0 TEST METHOD

3.1 Demonstrate the proper operation of the fire detection system.

3.2 Demonstrate the proper operation of the fire water system.

(1) Demonstrate the head and flow characteristics of the diesel engine-driven fire water pumps, the electric motor-driven fire water pump, and the operation of all auxiliaries.

(2) Verify control logic.

(3) Verify flowrates in the various flow paths of the fire water system.

3.3 Demonstrate the proper operation of the CO_2 fire protection system.

3.4 Demonstrate the proper operation of the Halon fire protection system.

3.5 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The fire protection system operates as described in subsection 9.5.1 when using the above test methods.

14B.39 TURBINE ELECTROHYDRAULIC CONTROL

1.0 OBJECTIVE

To verify proper performance of the turbine electrohydraulic control system.

2.0 PREREQUISITES

2.1 Construction activities on the turbine electrohydraulic control system are complete.

2.2 Associated instrumentation has been calibrated.

2.3 Appropriate test equipment is available and has been calibrated.

2.4 Proper fluid levels throughout the system have been verified.

2.5 Appropriate ac and dc power sources are available and operable.

3.0 TEST METHOD

3.1 Using external instrumentation, simulate input signals and record the response of the electrohydraulic control system.

3.2 Verify proper outputs in all modes of operation.

3.3 Verify all system interlocks, overrides, annunciators, and indicators are operational.

4.0 ACCEPTANCE CRITERIA

The turbine electrohydraulic control system operates as described in paragraph 10.2.2.3 when using above test methods.

APPENDIX 14B

14B.40 GASEOUS RADWASTE SYSTEM

1.0 OBJECTIVE

To demonstrate the ability of the gaseous radwaste system to collect and process radioactive gases vented from plant equipment.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Support systems available.

2.3 Component testing and instrument calibration completed.

2.4 Test instrumentation available and calibrated.

3.0 TEST METHOD

3.1 Verify flow paths.

3.2 Demonstrate that discharge isolation features and other system controls function properly.

3.3 Verify alarms, indicating instruments, and status lights are functional.

3.4 Verify systems ability to compress and store waste gas and release it in a controlled manner.

4.0 ACCEPTANCE CRITERIA

The gaseous radwaste system operates as described in section 11.3 when using the above test methods.

14B.41 CONTAINMENT PURGE AND HVAC SYSTEM

1.0 OBJECTIVE

To demonstrate proper operation of the containment normal cooling, cleanup and purge systems, CEDM cooling system, and cavity cooling system.

2.0 PREREQUISITES

2.1 Construction activities complete.

2.2 Component testing and instrument calibration complete.

2.3 Support systems available.

2.4 Test instruments available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate manual and automatic system controls.

3.2 Verify alarms, indicating instruments, and status lights are functional.

3.3 Verify design air flows.

3.4 Perform in-place leak testing of HEPA/charcoal filtration units, except for cleanup HEPA/charcoal filters as described in response to Question 9A.38.

4.0 ACCEPTANCE CRITERIA

The containment normal cooling, cleanup and purge systems, CEDM cooling system, and cavity cooling

system operate as described in applicable portions of subsection 9.4.6 when using the above test methods.

14B.42 INSTRUMENT AIR SYSTEM

1.0 OBJECTIVE

To demonstrate proper operation of the instrument air system.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Support systems available.

2.4 Test instrumentation available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate automatic and manual system controls for compressors, air dryers, valves, etc.

3.2 Verify ability of nitrogen system to backup instrument air system.

3.3 Verify instrument air quality meets design requirements.

3.4 Verify alarms, indicating instruments and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The instrument air system operates as described in applicable portions of section 9.3 when using the above test methods.

14B.43 POLAR CRANE

1.0 OBJECTIVE

To demonstrate the functional performance of the containment polar crane.

2.0 PREREQUISITES

2.1 Electric power available.

2.2 Instrumentation available and calibrated.

2.3 Construction activities are complete on the crane and associated equipment.

2.4 Construction has successfully completed certified load test.

3.0 TEST METHOD

3.1 Verify operability of trolley, bridge, and hoist.

3.2 Check hoist and trolley speeds.

3.3 Check capability of crane to position over all required containment building equipment.

4.0 ACCEPTANCE CRITERIA

4.1 Trolley, bridge, hoist, and all interlocks operate as required by purchase order specifications.

4.2 Hoist and trolley speeds are within purchase order specification limits.

4.3 Crane can position over all required equipment.

14B.44 CONTAINMENT HVAC - TENDON GALLERY AND PENETRATION COOLING SYSTEMS

1.0 OBJECTIVES

1.1 Demonstrate the manual operation of the tendon gallery normal supply fan.

1.2 Demonstrate the manual operation of the tendon gallery normal exhaust fan.

1.3 Demonstrate the operation of the penetration cooling normal exhaust fans.

1.4 Demonstrate the manual and automatic operation of the penetration cooling supply fans and their exhaust dampers.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Support systems available.

2.4 Test instrumentation available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate automatic and manual system controls.

3.2 Verify and record delay times when fans start on automatic.

3.3 Verify and record alarms, indicating instruments, and status lights are functional

4.0 ACCEPTANCE CRITERIA

4.1 The tendon gallery normal supply fan will start and stop by actuation of handswitch in the control room.

4.2 The tendon gallery normal exhaust fan will start and stop by actuation of handswitch in the control room.

4.3 Penetration cooling exhaust fans will start and stop by actuation of handswitches at the local panel.

4.4 Penetration cooling supply fans will start and stop by actuation of handswitches at the local control panel.

4.5 Penetration cooling supply fans start automatically after a 60-second time delay upon receipt of a low dp signal.

4.6 Penetration cooling supply dampers open and shut as their respective fans start and stop.

4.7 Heat removal capability will be verified for the tendon gallery system.

4.8 Heat removal capability will be verified for the penetration cooling system.

14B.45 FEEDWATER SYSTEM[a]

1.0 OBJECTIVE

To demonstrate that the feedwater system is capable of supplying feedwater to the steam generators and maintaining steam generator level.

2.0 PREREQUISITES

2.1 Construction activities are complete.

2.2 All permanently-installed instrumentation is calibrated and operable.

2.3 Test instrumentation is available and calibrated.

2.5 Plant systems required to support testing are operable, or temporary systems are installed and operable.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Demonstrate all design flow paths.

3.3 Verify the starting, head, and flow characteristics of the turbine-driven feedwater pumps at the full range of steam pressures.

3.4 Demonstrate minimum flow recirculation protection.

3.2 Verify proper operation of protective devices, controls, interlocks, instrumentation, and alarms, using actual or simulated inputs.

---
a. Portions of this test will be performed after initial fuel load.

3.6 Verify, if appropriate, proper operation, failure mode, stroking speed, and position indication of control and feedwater isolation valves.

4.0 ACCEPTANCE CRITERIA

The feedwater system performs as described in subsection 10.4.7.

APPENDIX 14B

14B.46 RADWASTE BUILDING HVAC

1.0 OBJECTIVE

1.1 To demonstrate design air quantities and a controlled airflow pattern from areas of low potential radioactivity to areas of increasingly higher radioactivity to prevent the spread of airborne radioactivity during normal operation of building HVAC supply systems (HRN-A01 A and B), exhaust systems (HRN-J01 A and B), and radwaste building control room normal air handler (HRN-A02).

1.2 To demonstrate the filtration of exhaust air particulates by system HEPA filters before passing to the plant exhaust stack.

1.3 To demonstrate a slightly negative building pressure to prevent exfiltration of conditioned space air to the atmosphere.

1.4 To demonstrate the radwaste building control room air handler recirculates conditioned airflow at prescribed temperatures using chill water or electric heating.

1.5 To demonstrate the proper operation of the oil impingement filters and air washer pumps (HPN-P01 A and B).

1.6 To demonstrate appropriate operation and position of automatic dampers (HRN-M01 to M06).

1.7 To demonstrate appropriate operation, indication and temperature rise of electric duct heaters (HRN-E01 A and B).

1.8 To demonstrate annunciation and indication of all alarms and design operation of temperature controls.

2.0 PREREQUISITES

2.1 Construction, inspection, testing, completion and release of radwaste HVAC systems according to specification.

2.2 HR-01 and HR-02 phase I testing complete.

2.3 Release of supporting and interfacing construction systems required to implement startup test activities to include:

2.3.1 DS-05 domestic water and WC01 chill water.

2.3.2 E-NHN-M14 and M27 480V MCC.

2.3.3 E-NGN-L05 and L16 480V load center.

2.3.4 E-NKN-D42 and D-43 dc distribution panel.

2.3.5 RKO1 annunciator.

2.3.6 Appropriate valve lineup and breaker and control switch positions for building HVAC systems.

3.0 TEST METHOD

3.1 Actuate handswitches (HS-1, 2, 30, 31, 60) to verify design operation, indication, and status of HVAC rotating units.

3.2 Demonstrate automatic and manual system controls.

3.3 Cycle temperature controllers to verify proper operation of HVAC rotating units and dampers (HRN-M01, M02, M03, M04, M05, and M06).

3.4 Verify alarm annunciation in response to selected alarm signals.

3.5 Verify design air and water flow paths, quantities, and temperatures to distribution and metering devices.

3.6 Perform in-place testing of filtration units as discussed in section 1.8.

4.0 ACCEPTANCE CRITERIA

Appropriate installation and operation according to specifications, submittals (vendor, manufacturer, engineering), and design drawings (instrument, electrical, and mechanical) verified.

14B.47 TURBINE BUILDING HVAC

1.0 OBJECTIVE

To demonstrate that the turbine building normal supply (HTN-A01 and A02, A, B, C) and general exhaust systems (HTN-J01A, B, C, D; HTN-J01B, A, B; HTN-J04; HTN-J03 A and B and HTN-J02 A and B) provide the designed environment for personnel and equipment during normal operation and shutdown, and appropriate exhaust for battery rooms, lube oil area, demineralizer room, and switchgear rooms.

2.0 PREREQUISITE

2.1 Construction activities completed.

2.2 IA08 instrument and service air available.

2.3 E-NGN-L08 and L15 Class 1E 480V load center available.

2.4 E-NHN-M02, M07, M11, M12, M22, M23 non-Class 1E 480V MCC available.

2.5 NK01 non-Class 1E 125 V-dc power distribution system available.

2.6 RK01 annunciator available.

2.7 Valve lineup (initial) and breaker and control switch positions for building HVAC systems completed.

3.0 TEST METHOD

3.1 Actuate hand switches (HS-1, 2, 3, 4, 5, 6, 85, 86, 87, 88, 89) to verify design operation, indication, and status of HVAC rotating supply and exhaust systems.

3.2 Cycle temperature (TC-7, 8, 9, 10, 11, 12, 60, 61, 62, 63, 64, 65, 66, 67) to verify proper operation of HVAC units and dampers (HT-M01, M02, M03, M04, M05, M06, M07, M08, M09, M010, M011, M012, M013, M014, M015).

3.3 Verify manual and automatic operation of duct heaters (HTN-E01, E02, E03, E04, E05, E06). (PVNGS Units 1 and 3 only - not required in Unit 2)

3.4 Verify automatic and manual system controls.

3.5 Verify alarm annunciation in response to selected alarm signals.

3.6 Verify design air paths, quantities, and temperatures to distribution and metering devices.

3.7 Verify proper operation of the oil impingement filters and air washer pumps (HTN-HT-P01A, B and C).

4.0 ACCEPTANCE CRITERIA

Appropriate installation and operation according to specifications, submittals (vendor, manufacturer, and engineering), and design drawings (instrument, electrical, and mechanical) verified.

14B.48 RADWASTE SOLIDIFICATION SYSTEM

1.0 OBJECTIVE

To demonstrate the capability of the system to:

1.1 Collect and convert spent resins and concentrated liquids into dry solid waste with no free water.

1.2 Transport and store solid waste until it can be shipped offsite for burial.

1.3 Compact and package miscellaneous dry radioactive material.

2.0 PREREQUISITE

2.1 All construction complete and system is turned over for testing in accordance with approved procedures.

2.2 System flushing and hydro completed.

2.3 All generic and integrated testing completed.

2.4 Supply of resins and chemicals available for use.

2.5 All required test equipment properly installed and calibrated.

3.0 TEST METHOD

3.1 Transfer resin/liquids from various tanks to waste feed tank.

3.2 Operate system in auto for various concentrations/mixes and verify operations as per purchase specification.

3.3 Operate or simulate all interlocks and/or alarms to verify they function per design.

3.4 Complete a complete drumming cycle, verify equipment operates per design.

3.5 Cut open a solidified drum after 24 hours and confirm: a) no free water; b) waste and concrete is homogeneously mixed.

4.0 ACCEPTANCE CRITERIA

4.1 The solidified mass meets the requirements for storage and shipment as referenced in section 11.4.

4.2 Complete solidification and absence of free water as per HNDC document N623-P-010 titled System Performance Test Plan.

14B.49 LIQUID RADWASTE SYSTEM

1.0 OBJECTIVE

To demonstrate that the system will:

1.1 Collect and process radioactive and potentially radioactive liquid waste.

1.2 Process liquid waste to a high degree of purity necessary for recycle into the plant.

1.3 Minimize the quantity of liquid waste transferred to the solid radwaste system.

2.0 PREREQUISITE

2.1 Construction is completed and the system is turned over for operation in accordance with the approved procedures.

2.2 Required test instruments are calibrated and installed.

2.3 Required support systems are operable.

2.4 All generic and integrated tests are completed.

3.0 TEST METHOD

3.1 Verify the head and capacity of system pumps.

3.2 Verify ΔP across heat exchangers, demineralizers, and filters at rated flow.

3.3 Verify proper operation of automatic and manual system controls.

3.4 Verify logic, interlocks, alarms, and status lights are per design.

4.0 ACCEPTANCE CRITERIA

The system operates as described in paragraph 11.2.2.3 when using the above test methods.

14B.50 SECONDARY CHEMISTRY CONTROL SYSTEM

1.0 OBJECTIVE

To demonstrate proper operation of the secondary chemistry control system (SCCS) which is an integrated system comprised of the condensate demineralization and blowdown processing subsystem and the chemical monitoring and addition subsystem.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 Component testing and instrument calibration completed.

2.3 Test instruments available and calibrated.

2.4 Support systems available.

3.0 TEST METHOD

3.1 Verify automatic and manual system control functions.

3.2 Demonstrate operability of flow paths.

3.3 Verify ability of system to provide specified chemistry control of the secondary power cycle systems.

3.4 Verify alarms, indicating instruments, and status lights are functional.

4.0 ACCEPTANCE CRITERIA

The secondary chemistry control system operates as described in subsection 10.4.6 when using the above test methods.

14B.51 LOAD GROUP ASSIGNMENT VERIFICATION

1.0 OBJECTIVE

To demonstrate that the redundant onsite safety features electrical power systems and their associated load groups are independent of each other or any other electrical power system and to demonstrate the automatic fast transfer of the 13.8 kV buses to the startup transformer in the event of failure of the unit auxiliary transformer, a turbine trip, or a reactor trip.

2.0 PREREQUISITES

2.1 Construction activities completed on components to be tested.

2.2 Component and integrated testing completed.

2.3 Required support systems for the test are released from construction with the required component and integrated testing completed on those systems.

2.4 Plant conditions must be carefully reviewed to ensure that the equipment under test can be operated safely without any unforseen or potentially harmful consequences.

2.5 Properly calibrated test equipment is available to support the test.

2.6 Circuit breakers, control switches, and valve positions for the test have been verified.

3.0 TEST METHOD

3.1 Demonstrate the independency of the redundant onsite (ESF) electrical power systems (train A and train B) to each other and to any other electrical system.

3.2 Verify that the diesel generators respond and the appropriate switchgear, load centers, and motor control centers function correctly on a loss of offsite power.

3.3 Simulate designed accident actuation signals from the NSSS ESFAS cabinets and BOP ESFAS cabinets and verify design accident loads start.

3.4 Verify that designed accident loads associated with a given train remain inoperable when the designed actuation signals are simulated from the opposite train.

3.5 Verify that the forced shutdown loads associated with train A and train B start when required and after being allowed to reach a stable operating condition, the loads will function properly without evidence of abnormal conditions.

3.6 Verify that the Class 1E 125 V-dc control centers, after being isolated from their associated battery and battery chargers, will remain deenergized.

3.7 Verify that in the event of failure of the unit auxiliary transformer, an automatic fast transfer

of the 13.8 kV buses to the startup transformer is initiated.

3.8 Verify that in the event of a turbine trip an automatic fast transfer of the 13.8kV buses to the startup transformer is initiated.

3.9 Verify that transfers of all buses can be initiated from the control room.

4.0 ACCEPTANCE CRITERIA

The load group assignment verification and 13.8 kV buses perform as described in applicable portions of section 8.3 when using the above test methods.

CHAPTER 15
ACCIDENT ANALYSES
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15. ACCIDENT ANALYSES

15.0 INTRODUCTION

Nuclear power plant safety is evaluated by analyzing the response of the plant to postulated disturbances in process variables, and to postulated malfunctions or failures of equipment. Such analyses provide a significant contribution to the selection of Technical Specification Limiting Conditions for Operation (LCOs), Limiting Safety System Settings (LSSSs), and design specifications for components and systems from the standpoint of public health and safety. Such analyses are also a focal point of the Nuclear Regulatory Commission’s (NRC) Operating License reviews.

In this chapter, the effects of anticipated process disturbances and postulated component failures are examined to determine their consequences, to evaluate the capability built into the plant to control or accommodate such failures and situations, and to identify any limitations of expected performance. In other words, the Chapter 15 safety analyses are performed to show that, given certain design basis requirements and specifications for Systems, Structures, and Components (SSCs), overall plant response and performance will be acceptable should a Design Basis Event (DBE) occur.

The events analyzed herein include Anticipated Operational Occurrences (AOOs), off-design transients that may induce fuel failures above those expected from normal operational occurrences, and postulated accidents of low probability. These analyses include an assessment of the radiological

consequences of assumed fission product releases, up to and including the greatest potential hazard from any accident considered credible.

15.0.1 CLASSIFICATION OF TRANSIENTS AND ACCIDENTS

15.0.1.1 Format and Content

The format and content of this UFSAR chapter is structured in accordance with the guidance contained in Chapter 15 of NRC Regulatory Guide 1.70, Revision 3 [Reference 1]. Acceptance criteria for the safety analyses are derived, on a case-by-case basis, from NUREG-75/087 [Reference 2], NUREG-0800 [Reference 3], and/or licensing agreements negotiated with NRC staff, as documented in licensee correspondence and NRC safety evaluations associated with the PVNGS Operating License dockets. Chapter contents are maintained in accordance with 10 CFR 50.71(e) [Reference 4], NRC Regulatory Guide 1.181, Revision 0 [Reference 5], and Nuclear Energy Institute (NEI) Publication 98-03, Revision 1 [Reference 6], as described in UFSAR Section 1.8.

15.0.1.2 Event Categories

Each postulated initiating event has been assigned to one of the following categories:

- Increased heat removal by the secondary system
- Decreased heat removal by the secondary system
- Decreased reactor coolant flow
- Reactivity and power distribution anomalies

- Increase in Reactor Coolant System (RCS) inventory
- Decrease in RCS inventory
- Radioactive release from a subsystem or component

The assignment of an initiating event to one of these categories is made according to Reference 1, 2, and 3.

Although Reference 1 recommends that this chapter include safety analyses for Anticipated Transients Without Scram (ATWS), such analyses are not presented herein. This deviation from regulatory guidance is justified because, following publication of Reference 1, the NRC staff and Nuclear Steam Supply System (NSSS) vendors did not reach final agreement on safety analysis methodologies and acceptance criteria for ATWS events, as documented in Reference 7. In lieu of such an agreement, the NRC promulgated 10 CFR 50.62 [Reference 8], which mandated the installation of diverse plant systems to reduce the risks associated with an ATWS event. PVNGS compliance with the ATWS rule is documented in an NRC safety evaluation report dated October 18, 1990 [Reference 9], and is based on the installation of a Supplementary Protection System (DAFAS), as described in UFSAR Sections 7.2.5 and 7.3.5, respectively.

15.0.1.3 Event Frequencies

As noted in UFSAR Chapter 3, PVNGS SSCs are classified according to their importance in preventing and mitigating postulated events, using the classification system described in ANSI N18.2-1973, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants" [Reference 10].

ANSI N18.2-1973 divides postulated transients and accidents into four broad categories for design purposes, based on their relative estimated frequency of occurrence. The events analyzed in this chapter are likewise classified into these four broad categories, or conditions for design, which are as follows:

- Normal Operations (Condition I). Condition I occurrences are defined as operations that are expected frequently or regularly in the course of power operation, refueling, maintenance, or maneuvering of the plant.
- Incidents of Moderate Frequency (Condition II). Condition II occurrences are defined as incidents, any one of which may occur during a calendar year for a particular plant.
- Infrequent Events (Condition III). Condition III occurrences are defined as incidents, any one of which may occur during the lifetime of a particular plant.
- Limiting Faults (Condition IV). Condition IV occurrences are defined as faults that are not expected to occur, but are postulated nonetheless because their consequences include the potential for the release of significant amounts of radioactive material.

15.0.1.4 Events and Event Combinations

The events and event combinations in this chapter are presented with respect to the event-specific acceptance criteria. For each applicable acceptance criterion in an event category, only the limiting event or event combination is presented in analytical detail. As required by Reference 1, qualitative

discussions are provided for all other events or event combinations explaining why they are not limiting.

For event combinations that require consideration of a single failure, the limiting failures for the NSSS transient and accident safety analyses in this chapter are selected from those listed in Table 15.0-0. Only low probability, dependent failures (e.g., loss of off-site power following turbine trip) and independent pre-existing failures are considered credible and included in the table. Pre-existing failures are equipment failures existing prior to the event initiation that are not revealed until called upon during the event (e.g., a failure of an auxiliary feedwater pump). High probability, dependent occurrences are always included in the event analysis, if they have an adverse impact (e.g., loss of main feedwater pumps following a loss of electric power).

Table 15.0-0 lists a "Loss of Offsite power (LOP) following turbine trip" as a Single Failure to be considered in Safety Analysis. However, the LOP is treated differently depending on the event combination under consideration. The combination of the initiating event with coincident occurrences and single failures changes the event classification and acceptance criteria. For moderate frequency (Condition II) events, the LOP may be treated as the limiting single failure. In that case, the event becomes an infrequent (Condition III) event, with different acceptance criteria. One example is the Inadvertent Opening of a Steam Generator Atmospheric Dump Valve (UFSAR Section 15.1.4). This event by itself is a moderate frequency event. However, once a LOP is taken as the limiting single failure, the event becomes an infrequent event with

different acceptance criteria. For Condition IV limiting fault events, such as Loss of Coolant Accidents, Main Steam Line Break, Feedwater Line Break and Steam Generator Tube Rupture, a LOP is treated as a coincident occurrence, along with the limiting fault, and an additional single failure is then postulated. This application of the LOP to safety analysis ensures that the supporting SSCs can perform their design functions with offsite power unavailable, as required by the General Design Criteria.

Analytical assumptions regarding the availability and operation of plant SSCs (e.g., pressurizer heaters and sprays) are described in each event section on a case-by-case basis. Additionally, each safety analysis section describes the analytical credit that has been taken, if any, for administrative controls and procedures, manual equipment operation, or plant operator actions to mitigate an event.

Table 15.0-0
SINGLE FAILURES
(Sheet 1 of 3)

STEAM BYPASS CONTROL SYSTEM (SBCS)	
1.	Failure to modulate open
2.	Failure to quick open
3.	One bypass valve fails to quick close
4.	Excessive steam bypass flow
5.	Failure to generate automatic withdrawal prohibit signal during steam bypass operation
6.	Failure to generate the reactor power cutback signal
REACTIVITY CONTROL SYSTEMS	
7.	Regulating group(s) fail(s) to insert or withdraw
8.	A single Control Element Assembly (CEA) stuck[a]
9.	A CEA subgroup stuck[a]
10.	Failure to initiate or execute the reactor power cutback
11.	CEAs withdraw upon automatic withdrawal prohibit and/or CEA withdrawal prohibit
FEEDWATER CONTROL SYSTEM	
12.	Failure of reactor trip override
13.	Failure of high level override

a. Control element drive mechanism does not respond to control signal. Release of CEA(s) on trip is not inhibited.

Table 15.0-0
SINGLE FAILURES
(Sheet 2 of 3)

TURBINE-GENERATOR CONTROL SYSTEM

14. Setback without cutback

15. Failure to modulate the turbine control valves

16. Failure to setback given a cutback
(100% > initial power > 75%)

17. Failure to setback
(75% > initial power > 60%)

18. Failure to runback
(60% > initial power)

19. Failure to trip the turbine

PRESSURIZER PRESSURE CONTROL SYSTEM (PPCS)

20. Failure of spray control valves to open

21. Failure of spray control valves to close

22. Failure of backup heaters to turn on

23. Failure of backup heaters to turn off

PRESSURIZER LEVEL CONTROL SYSTEM (PLCS)

24. Backup charging pump fails to turn on

25. Backup charging pump fails to turn off

26. Letdown flow control valve fails to close

27. Letdown flow control valve fails to open

MAIN FEEDWATER SYSTEM

28. One Main Feedwater Isolation Valve (MFIV) fails to close

29. One backflow check valve fails to close

Table 15.0-0
SINGLE FAILURES
(Sheet 3 of 3)

MAIN STEAM SYSTEM
30. One Main Steam Isolation Valve (MSIV) fails to close
31. One Atmospheric Dump Valve (ADV) fails to open
32. One Main Steam Safety Valve (MSSV) fails to reclose
AUXILIARY FEEDWATER SYSTEM
33. Failure of any one auxiliary feed pump to start
EMERGENCY CORE COOLING SYSTEM (ECCS)
34. Failure of one High Pressure Safety Injection (HPSI) or Low Pressure Safety Injection (LPSI) pump
ELECTRICAL POWER SOURCES
35. Loss of offsite power following turbine trip[b]
36. Failure to achieve fast transfer of a non-Class 1E bus to the startup transformer
37. Failure of one emergency generator to start, run or load

b. Section 15.0.2.4 describes the loss of off-site power following a turbine trip in more detail, including the time delay between turbine stop valve closure and loss of offsite power.

15.0.1.5 Section Numbering

The safety analyses in this chapter are divided into sections and subsections as described in Table 15.0-1.

Table 15.0-1
CHAPTER 15 SUBSECTION DESIGNATION

Each event of event combination section number begins with the sequence "15.W.X" where:

15	= 15	Safety analyses that are presented in UFSAR Chapter 15
W	= 1	Increase in heat removal by the secondary system
	2	Decrease in heat removal by the secondary system
	3	Decrease in RCS flow rate
	4	Reactivity and power distribution anomalies
	5	Increase in RCS inventory
	6	Decrease in RCS inventory
	7	Radioactive release from a subsystem or component
X	= 1, 2, etc.	Event title

15.0.1.6 Sequence of Events Analysis

The Sequence of Events Analysis (SEA) has been performed for each limiting event and event combination, for which detailed safety analysis results are presented in this chapter. The purpose of the SEA is to determine the following:

A. The step-by-step sequence of events from event initiation to the final stabilized condition;

B. The extent to which normally operating plant instrumentation and controls are assumed to function;

C. The extent to which plant and reactor protective systems are required to function;

D. The credit taken for the functioning of normally operating plant systems; and

E. The operation of engineered safety systems that are required.

SEAs have been specifically omitted for those events that, though representing limiting events for their category, do not result in the actuation of safety systems, or for which a detailed, quantitative analysis was not presented. For the safety analyses that appear in this chapter, the primary results of each SEA are presented in a sequence of events table and described in the text. Each sequence of events table presents a chronology of events that may be anticipated to occur during a transient, from event initiation to a final stabilized condition (or until operator action is taken to place the reactor in a safe shutdown condition). The accompanying text provides additional clarification, including

information regarding systems operation and a discussion of the effects of postulated single failures. The sequence of events table and corresponding text fulfill the regulatory guidance contained in Reference 1, by providing a step-by-step chronology and detailed discussion of systems operation for limiting transients.

The results of some SEAs are also presented in an optional format for the safety analyses, consisting of two additional tables and a figure. The first of the two optional tables is a matrix that identifies the extent to which normally operating plant systems are assumed to function during a transient. The second table specifies the Reactor Protective System (RPS) and Engineered Safety Features (ESF) that are actuated to accomplish safety functions during the course of the event. The optional figure is a Sequence of Events Diagram (SED), or a simple block diagram that provides a systematic analysis of components that are required to function during a transient. For some of the safety analyses, pertinent information that would otherwise appear on these tables of figure is instead described in the text.

The SEDs, together with the chronological list of events and the SEA symbol and acronym drawing (Figures 15.0-1), may be used to trace the actuation and interaction of the systems used to mitigate the consequences of each event. The SED is a block diagram, composed of several success paths that define a set of safety actions leading from the initiating event to the accomplishment of a specific safety function. All of the safety functions used in the SEDs are defined in Figure 15.0-1. A success path may be composed of two branches, one indicated

by a solid line, describing the sequence of events that occur in the transient analysis, and the other, indicated by a dotted line, describing an alternative or back-up path to a given means of accomplishing a safety function. An alternate dotted path is specified if the analysis assumed the action of a non-safety system in achieving a particular safety function. Non-safety systems are indicated by an "NS" in the upper right-hand corner of the system block.

The redundancy of a system or component is indicated by a fraction (e.g., 1/2, 2/4) placed beneath the system block. The numerator specifies the number of trains or components required to perform the action, and the denominator specifies the number of trains or components normally available. In cases where no alternate path exists and a single system or component is included in a success path, the symbol "S.F." will be used to indicate that no single active failure will prevent the accomplishment of the safety action.

Components or systems that require no active initiation or actuation to perform their function are considered to be passive and are marked as such with a "P" in the lower left-hand corner of the system block. The absence of a passive label implies that a component is considered to be active and must be actively initiated to perform its function.

Manual operations performed on a given system or component are indicated by placing an "M" in the lower left-hand corner of the system block. When a manual action is required, the sensed variables necessary to perform the action are shown as inputs

and the location of the input signal is shown above the input signal circle.

The system setpoint values assumed in the transient analysis, e.g., trip signal setpoints, is noted along the success path. Time delays or the time required to perform an action are shown as a number with square brackets.

All events presented in sequence of events diagrams in the main body of this chapter are shown from event initiation to achievement of the cold shutdown operating mode. Not all events require that the plant be taken to cold shutdown. The SEDs only demonstrate that for any event presented here it is possible to take the plant to cold shutdown by means of the safety actions indicated.

15.0.2 SYSTEMS OPERATION

During the course of any event various systems may be called upon to function. Some of these systems are described in Chapter 7 and include those electrical, instrumentation, and control systems designed to perform a safety function (i.e., those systems that must operate during an event to mitigate the consequences) and those systems not required to perform a safety function (see UFSAR Sections 7.2 through 7.6 and 7.7, respectively).

15.0.2.1 Reactor Protection

The Reactor Protective System (RPS) is described in UFSAR Section 7.2.

RPS trips credited in the safety analyses, including Core Protection Calculator (CPC) trips, are identified in the sequence of events description for each limiting event and event combination. Analytical trip setpoints are chosen to be consistent with, or conservative with respect to, the RPS trip setpoint allowable values delineated in the PVNGS Technical Specifications and the RPS trip setpoints delineated in UFSAR Section 7.2. Where applicable, analytical trip setpoints are adjusted to account for instrumentation loop uncertainties derived from design control calculations. The safety analyses also take into consideration the RPS response times associated with the various trip functions.

The RPS response time is the sum of the sensor response time and the reactor trip delay time. The sensor response time is defined as the time from when the value of the monitored parameter at the sensor equals or exceeds the RPS trip setpoint, until the sensor output equals or exceeds the trip setpoint. The sensor response is modeled by using a transfer function for the particular sensor used. The reactor trip delay time is defined as the elapsed time from the time the sensor output equals or exceeds the trip setpoint to the time the reactor trip breakers are fully open.

As noted in UFSAR Section 3.9.4, the Control Element Assemblies (CEAs) are designed with a maximum drop time of 4.0 seconds, where the drop time is defined as the interval between the time power is removed from the Control Element Drive Mechanism (CEDM) holding coils and the time at which the CEAs reach 90% of their fully inserted positions. For those safety analyses that model CEA insertion following a reactor trip, the

4.0-second CEA drop time is subdivided into two intervals: the holding coil delay time and the CEA insertion time. During the holding coil delay time, which is defined as the time interval between opening of the reactor trip breakers and the time at which the magnetic flux of the CEDM holding coils has decayed enough to allow for CEA motion, the CEAs are assumed to remain in their withdrawn positions. Following expiration of the holding coil delay time, the CEAs are assumed to drop 90% into the core during the remaining CEA insertion time. CEA drop time testing is conducted periodically in accordance with the PVNGS Technical Specifications and Technical Requirements Manual. Analytical treatment of CEA shutdown reactivity worth versus CEA position is described in UFSAR Section 15.0.3.3.3.

15.0.2.2 Engineered Safety Features

The Engineered Safety Feature Actuation Systems (ESFAS) and electrical, instrumentation, and control systems required for safe shutdown are described in UFSAR Sections 7.3 and 7.4, respectively. Analytical ESFAS setpoints and response times are chosen to be consistent with, or conservative with respect to, the setpoint allowable values delineated in the PVNGS Technical Specifications and the response times delineated in UFSAR Section 7.3. Where applicable, analytical ESFAS setpoints are adjusted to account for instrumentation loop uncertainties derived from design control calculations.

15.0.2.3 Control Systems

Control and instrumentation systems which may, but are not required to, perform safety functions are described in UFSAR

Section 7.7. These include various control systems and the Core Operating Limits Supervisory System (COLSS) which is a monitoring system. In general, normal operation of these control systems is assumed unless lack of operation would make the consequences of the event more adverse. In such cases, the particular control system is assumed to be inoperative, or in the most adverse mode, until the time of operator action. Although these systems are not credited for a safety function, such as mitigation during an event, some safety analyses may credit the normal operation of these systems, consistent with the plant operating procedures, for the purpose of setting initial conditions for event analysis. For example, the Feedwater Line Break (FWLB) long-term cooling analysis assumes that the Pressurizer Level Control System (PLCS) is initially in normal-automatic operation, with a programmed correspondence between the initial pressurizer water level and RCS loop average temperature. When initial conditions for an event analysis are established in this manner, the values of certain process variables (e.g., temperature, pressure, etc.) may not correspond to their respective Technical Specification limits, and a NRC review may be required to credit the initial normal operation of these systems as an element of methodology for safety analysis.

15.0.2.4 Loss of Off-Site Power Following Turbine Trip

The PVNGS off-site and on-site electric power systems are described in UFSAR Sections 8.2 and 8.3, respectively. The PVNGS turbine-generator system is described in UFSAR Section 10.2.

During normal plant operations, the Reactor Coolant Pumps (RCPs) are powered from non-Class 1E, 13.8-kV AC busses NAN-S01 and NAN-S02, which are electrically connected through the unit auxiliary transformer and the isolated phase busses to the turbine generator. The generator converts mechanical energy from the turbine to electrical power. Under normal conditions, a fast bus transfer would be initiated upon tripping of the unit auxiliary transformer output breakers, and alternate supply breakers would close within a few cycles to connect NAN-S01 AND NAN-S02 to the startup transformers. The startup transformers supply NAN-S01 and NAN-S02 during plant startup or at other times when the turbine generator or unit auxiliary transformer is out of service.

In the event of a turbine trip during normal plant operations, not involving an electrical fault or underfrequency, the turbine generator will remain synchronized to the extra high voltage transmission network until residual energy in the turbine is dissipated. The generator will motor for a short period of time, and will not trip until a sustained reverse power condition exists and the reverse power relay actuates. Reverse power relay actuation will simultaneously trip the generator exciter, the 525-kV breaker and the unit auxiliary transformer output breakers, thereby initiating a fast bus transfer. An analysis of twenty-six PVNGS trips, that occurred between 1990 and 1998, confirms that the time delay between turbine trip (i.e., turbine stop valve closure) and reverse power relay actuation has varied between 3.969 seconds and 7.55 seconds. Statistical analysis of the data indicates that the time delay would be greater than or equal to three seconds,

with a confidence level in excess of 98%. Therefore, in the event of a turbine trip with the RCPs busses connected to the unit auxiliary transformer, the RCPs will receive electrical power for at least three seconds following the turbine trip. Furthermore, a postulated single failure of a breaker to achieve a fast transfer to the backup power supply, which would result in the coastdown of two RCPs, would cause a less rapid loss of flow than the postulated loss of off-site power following a turbine trip (see Table 15.0-0), which would result in the coastdown of all four RCPs.

If the turbine generator were to trip with the RCP busses connected to the startup transformers, the RCPs would likewise receive off-site power for at least three seconds following the turbine trip. Reference 11 notes that the loss of a power generating unit on the transmission network such as the loss of a nuclear power plant due to a turbine trip, may generate frequency deviations in the transmission network which normally operates at 60 Hz. Under certain conditions the resulting electrical system instability may cause a loss of off-site power to that unit. The degree of instability is characterized by the rate of transmission network frequency degradation, which is dependent upon the magnitude of the load mismatch and the physical parameters of the transmission network. The physical response of the transmission network is dependent upon the available spinning reserve and the stiffness of the transmission network, that is, the ability to damp out frequency oscillations through load damping. Load shedding may also be utilized to restore the balance between load and power generation and to return the transmission network frequency to

60 Hz. When corrective actions are not sufficient to avert frequency degradation, loss of off-site power to the plant can occur as a result of that plant tripping offline. Most units are automatically disconnected from the transmission network between 56 Hz and 58 Hz, to prevent underfrequency damage to plant components. For System 80 plants such as PVNGS, Reference 11 conservatively assumed that a frequency of 57.6 Hz would be the setpoint at which a loss of off-site power occurs.

In order to determine the conservative lower bound for the time delay between turbine trip and loss of off-site power, Reference 11 employed the electrical grid system for the Florida Peninsula. This grid can tie into only the Georgia and Alabama grid systems, which can make up only 400 MWe through the transmission lines to Florida. Therefore, the Florida grid becomes an "electrical island" for a generation deficiency caused by the loss of a 1300 MWe unit. On curves of grid frequency response for this grid system, the effects of a generation deficiency caused by tripping of a System 80 plant were superimposed. Based on this evaluation, a 3.1 second time delay between turbine trip and loss of off-site power was calculated. This time delay is a conservative lower bound because the evaluation assumed:

A. No credit for spinning reserve and load shedding;

B. The Florida grid "electrical island" conditions (no support from neighboring grid systems);

C. Loss of a System 80 plant as a 10% generation loss, which is a much higher percentage than the actual loss (i.e., less than 3.5%); and

D. Loss of off-site power at 57.6 Hz for all System 80 plants.

Therefore, for the purpose of simulating the response of PVNGS systems during certain postulated events, a three-second delay may be assumed to occur between a main turbine trip and a loss of off-site power (see Table 15.0-0). The UFSAR Chapter 15 accident analyses that credit this three-second delay include the RCP rotor seizure event, the RCP shaft break event, steam generator tube ruptures, and, beginning with operating Cycle 11, the feedwater line break long-term cooling analysis. This constitutes a credit taken for the functioning of normally operating plant systems, as discussed in UFSAR Section 15.0.1.6.

It should be noted, however, that these analyses do not explicitly model a slight decrease in reactor coolant flow that may occur during this three second period, which might result from frequency degradation at the RCP busses. This modeling assumption is justified by further consideration of the transmission network described in UFSAR Section 8.2.2, to which the PVNGS units are electrically connected. Specifically, this transmission network can withstand the loss of a PVNGS unit, such as that resulting from a turbine trip, without system instability and with a frequency degradation of less than 0.1 Hz over the three second duration. Assuming a linear relationship between electrical frequency and reactor coolant flow, a frequency degradation of 0.1 Hz would result in only 0.17% reactor coolant flow degradation from full flow. This small amount of flow degradation is less than the conservatisms

inherent in the overall uncertainty factors for the CPCs and the Core Operating Limits Supervisory System (COLSS).

15.0.3 CORE AND SYSTEM PERFORMANCE

15.0.3.1 Mathematical Model

The NSSS response to various events was simulated using digital computer programs and analytical methods, as described below as well as in individual event analysis sections of this chapter.

15.0.3.1.1 Loss of Flow Analysis Method

The method used to analyze events initiated by failures causing a decrease in reactor coolant flowrate is discussed in UFSAR Appendix 15D.

15.0.3.1.2 CEA Ejection Analysis Method

The general methodology used to analyze the reactivity and power distribution anomalies associated with CEA ejection events is documented in the Nuclear Steam Supply System (NSSS) vendor's Topical Report CENPD-190-A [Reference 12], which was approved by the NRC for reference in license applications on June 10, 1976. Exceptions to NRC Regulatory Guide 1.77, Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors [Reference 13], are described in UFSAR Section 1.8.

Fuel performance (e.g., fuel temperature and enthalpy) is evaluated with STRIKIN-II computer code (see UFSAR Section 15.0.3.1.5). For operating Cycle 10 and earlier cycles, peak RCS pressure was evaluated with the CESEC computer code (see

UFSAR Section 15.0.3.1.3.1). Beginning with operating Cycle 11, however, peak RCS pressure is evaluated with the CENTS computer code (see UFSAR Section 15.0.3.1.3.2), as approved by the NRC staff in the safety evaluation report associated with Amendment No. 137 to the PVNGS operating licenses [Reference 14]. For radiological dose assessments associated with postulated CEA ejection events, NSSS analysis codes (e.g., CESEC) are used to estimate the long-term releases from the secondary system until shutdown cooling entry occurs, as described in UFSAR Section 15.4.8.

15.0.3.1.3 NSSS Simulation Computer Programs

15.0.3.1.3.1 CESEC Computer Program

NSSS transient simulations, used in long term CEA Ejection radiological consequence evaluations, are performed with the CESEC computer code. The CESEC computer code is described in an April 1974 Topical Report [Reference 15]. The CESEC II and CESEC III versions of the code, which incorporate ATWS model modifications and additional improvements that extend the range of applicability of code models, are described in Supplements to that Topical Report [References 16, 17, 18, 19, and 20].

CESEC computes key system parameters during a transient including core heat flux, pressures, temperatures, and valve actions. A partial list of the dynamic functions included in this NSSS simulation includes: point kinetics neutron behavior, Doppler and moderator reactivity feedback, boron and CEA reactivity effects, multi-node average and hot channel reactor core thermal-hydraulics, reactor coolant pressurization and mass transport, reactor coolant system safety valve

behavior, steam generation, steam generator water level, turbine bypass, main steam safety and turbine admission valve behavior, as well as alarm, control, protection, and engineered safety feature systems. The steam turbines, condensers, and their associated controls are not included in the simulation. Steam generator feedwater enthalpy and flowrate are provided as input to CESEC.

During the course of execution, CESEC obtains steady-state and transient solutions to the set of equations that mathematically describe the physical models of the subsystems mentioned above. Simultaneous numerical integration of a set of nonlinear, first-order differential equations with time-varying coefficients is carried out by means of a simultaneous solution. As the time variable evolves, edits of the principal systems parameters are printed at prespecified intervals. An extensive library of the thermodynamic properties of uranium dioxide, water, and zircaloy is incorporated into this program. Through the use of CESEC, symmetric and asymmetric plant response over a wide range of operating conditions can be determined.

The CESEC III version of CESEC used in the analyses explicitly models the steam void formation and collapse in the upper head region of the reactor vessel and is documented in Reference 21. Other improvements to this version of CESEC include: a more detailed thermal-hydraulic model that explicitly simulates the mixing in the reactor vessel from asymmetric transients, an RCS flow model that calculates the time dependent reactor coolant mass flow rate in each loop, a wall heat model, a three-dimensional reactivity feedback model, a safety injection tank

model, and a primary-to-secondary heat transfer model that calculates the heat transfer for each generator node rather than for a steam generator as a whole.

15.0.3.1.3.2 CENTS Computer Program

The CENTS computer program is a computer code developed by the NSSS vendor for the simulation of NSSS transient behavior under normal and abnormal conditions. CENTS is intended to replace the CESEC code originally used to simulate the transient response of the NSSS. The CENTS computer code is documented in Reference 22 and has been approved by the NRC for use in the licensing analyses for PWRs originally designed by Combustion Engineering in Reference 23. The CENTS code approval was subject to five limitations:

1). The CENTS DNBR calculation for determining overall trends in thermal margin should not be used for licensing analyses.

2). The application of CENTS is limited to Combustion Engineering NSSS plants until additional information is submitted and approved.

3). CENTS should not be used for performing LOCA or severe accident licensing analyses.

4). CENTS must use only the point kinetics model in licensing applications.

5). CENTS must not be used for performing CEA ejection licensing analyses. (However, in a safety evaluation report associated with Amendment No. 137 to the PVNGS operating licenses [Reference 14], the NRC staff approved

the CENTS computer code for evaluating peak RCS pressure for CEA ejection events. NRC approval was granted on a plant-specific basis for PVNGS, rather than on a generic industry basis. Therefore, beginning with operating Cycle 11, PVNGS CEA ejection licensing analyses utilize the CENTS code for this purpose.)

Enhancements to CENTS were made by Westinghouse to more accurately model plant systems and transient behavior of the reactor. These improvements to the CENTS code are documented in Reference 31 and were approved by the NRC in Reference 32 & 33.

CENTS is a best-estimate code designed to provide a realistic simulation of the neutronics, thermal-hydraulics and plant systems response during transient conditions. CENTS computes key system parameters during a transient including core heat flux, pressures, temperatures, and valve actions. A partial list of the dynamic functions included in this NSSS simulation includes: point kinetics neutron behavior, Doppler and moderator reactivity feedback, boron and CEA reactivity effects, multi-node average and hot channel reactor core thermal-hydraulics, reactor coolant pressurization and mass transport, reactor coolant system safety valve behavior, steam generation, steam generator water level, turbine bypass, main steam safety and turbine admission valve behavior, as well as alarm, control, protection, and engineered safety feature systems. The steam turbines, condensers, and their associated controls are not included in the simulation. Steam generator feedwater enthalpy and flowrate are provided as input to CENTS.

During the course of execution, CENTS obtains steady-state and transient solutions to the set of equations that mathematically describe the physical models of the subsystems mentioned above. The RCS model is formulated with five one-dimensional conservation equations. The conservation equations are integrated implicitly by means of a simultaneous solution of the linearized conservation equations. As the time variable evolves, edits of the principal systems parameters are printed at prespecified intervals. An extensive library of the thermodynamic properties of uranium dioxide, water, and zircaloy is incorporated into this program. Through the use of CENTS, symmetric and asymmetric plant response over a wide range of operating conditions can be determined.

CENTS uses a more detailed NSSS model than CESEC. The improvements include: the addition of explicit models for determining the nodal solute concentrations and heat loss to the containment, a multi-node versus single node steam generator model, and a non-equilibrium non-homogeneous versus equilibrium homogeneous primary system model.

15.0.3.1.4 COAST Computer Program

The COAST computer program is used to calculate the reactor coolant flow coastdown transient for any combination of active and inactive pumps and forward or reverse flow in hot or cold legs. The program is described Reference 24.

The equations of conservation of momentum are written for each of the flow paths of the COAST model assuming unsteady one-dimensional flow of an incompressible fluid. The equation of conservation of mass is written for the appropriate nodal

points. Pressure losses due to friction and geometric losses are assumed proportional to the flow velocity squared. Pump dynamics are modeled using a head-flow curve for a pump at full speed and using four-quadrant curves, which are parametric diagrams of pump head and torque on coordinates of speed versus flow, for a pump at other than full speed.

15.0.3.1.5 STRIKIN-II Computer Program

The STRIKIN-II computer program is used to simulate the heat conduction within reactor fuel rods and its associated surface heat transfer. The STRIKIN-II program is described in Reference 25.

The STRIKIN-II computer program provides a single, or dual, closed channel model of a core flow channel to calculate the clad and fuel temperatures for an average or hot fuel rod, and the extent of the zirconium water reaction for a cylindrical geometry fuel rod. STRIKIN-II includes:

- Incorporation of all major reactivity feedback mechanisms.
- A maximum of six delayed neutron groups.
- Both axial (maximum of 20) and radial (maximum of 20) segmentation of the fuel element.
- Control rod scram initiation on high neutron power.

15.0.3.1.6 TORC and CETOP Computer Programs

The TORC and CETOP computer programs are used to simulate the fluid conditions within the reactor core region and to calculate fuel pin Departure from Nucleate Boiling Ratio

(DNBR). The TORC program is described in References 26 and 27. The CETOP computer program is described in Reference 28.

15.0.3.1.7 Reactor Physics Computer Programs

Numerous computer programs are used to produce the input reactor physics parameters required by the NSSS simulation and reactor core programs previously described. These reactor physics computer programs are described in UFSAR Chapter 4.

15.0.3.2 Initial Conditions

The events described in this chapter and its appendices have been analyzed over a wide range of initial conditions that encompasses a variety of steady-state operational configurations.

In accordance with Reference 1, the most adverse conditions within permitted operating bands for principal process variables have generally been used as initial conditions for the safety analyses. In this context, Reference 1 defines a permitted operating band as the permitted fluctuations in a given parameter or variable, plus any associated uncertainties. However, if the results and conclusions of a safety analysis are insensitive to the initial value chosen for a specific process variable, then a nominal value may instead be used as an initial condition for that variable.

If a process variable is delineated in or controlled by the PVNGS Technical Specifications (e.g., RCS cold leg temperature), the corresponding Limiting Conditions for Operation (LCOs) and Surveillance Requirements (SRs) are

typically utilized to define the permitted fluctuations for that variable. The permitted operating band may then be determined by accounting for instrumentation loop uncertainties, which are obtained from design control calculations. This approach ensures consistency between the physical plant, the Technical Specifications, and the safety analyses presented in this UFSAR chapter, as required by 10 CFR 50.36 [Reference 29].

If a process variable is not explicitly controlled by the Technical Specifications (e.g., steam generator water level in Mode 1), then the safety analysis guidance contained in Reference 10 may instead be utilized to determine the permitted fluctuations for that variable. Specifically, Reference 10 states that the initial conditions chosen for an analysis should account for the full range of expected normal operating conditions, including the following:

- Operating modes (for example, startup, shutdown, loops out of service, refueling);
- Systems under manual control considering alarm points, manual action required, and protective overrides; and
- Variations in plant parameters with power and core exposure.

In such a case, the selection of an initial condition will therefore be consistent with normal plant operating procedures, including control room alarm response procedures and their required operator actions.

15.0.3.3 Input Parameters

15.0.3.3.1 Doppler Coefficient

The fuel temperature coefficient of reactivity (Doppler coefficient) is described in UFSAR Section 4.3. In the safety analyses, the Doppler coefficient is adjusted to account for higher feedback effects in the higher power density core regions, as well as to account for uncertainties in determining the actual fuel temperature reactivity effects. Each analysis utilizes either a more negative or less negative Doppler feedback, in order to produce a more adverse result that is closer to the analytical acceptance criteria.

15.0.3.3.2 Moderator Temperature Coefficient

The Moderator Temperature Coefficient (MTC) of reactivity is described in UFSAR Section 4.3. MTC values used in the safety analyses are consistent with the limitations specified in the PVNGS Technical Specifications and the PVNGS Core Operating Limits Reports (COLRs), which vary as a function of both core power level and time in cycle, that is, Beginning-of-Cycle (BOC) to End-of-Cycle (EOC). A conservative MTC value is selected for each analysis on a case-by-case basis.

15.0.3.3.3 Shutdown CEA Reactivity

The shutdown reactivity is dependent on the CEA worth available on reactor trip, the axial power distribution, the position of the regulating CEAs, and the time in core life. Please refer to the individual event descriptions in this chapter, to determine the CEA worth that was assumed in each analysis.

Power Dependent Insertion Limits (PDILs), included in the COLR, assure adequate CEA worths are available upon reactor trip.

An example of a shutdown reactivity worth versus position curve, for an Axial Shape Index (ASI) of approximately +0.3, is shown in Figure 15.0-2.

15.0.3.3.4 Effective Delayed Neutron Fraction

The effective neutron lifetime and delayed neutron fraction are functions of fuel burnup. For each analysis, the values of the neutron lifetime and the delayed neutron fraction are selected consistent with the time in life analyzed.

15.0.3.3.5 Decay Heat Generation Rate

Analyses assume decay heat generation based upon an infinite reactor operation at the initial core power level identified for each event.

15.0.4 RADIOLOGICAL CONSEQUENCES

Some of the safety analyses presented in this chapter predict that steam or liquid will be released from the RCS or main steam system. Because radioactive material could be present in these discharges, these events are anticipated to result in radiological dose consequences for control room personnel or for the off-site general public. Appendix 15B describes an activity release model that has been used to assess the radiological consequences of certain postulated accidents presented in this chapter. Where applicable, event-specific radiological dose assessment models, which differ from those

presented in Appendix 15B, are described on a case-by-case basis in the individual event sections of this chapter.

For radiological event analyses, steam and liquid mass releases to the environment are typically derived from computer code simulations or from alternate calculations. Estimated releases are utilized in the radiological dose analyses, for the purpose of determining whole body and thyroid doses at the Exclusion Area Boundary (EAB), the outer boundary of the Low Population Zone (LPZ), the control room and other required habitable areas. Where applicable, steam and liquid leakage from plant systems, as well as analytical credits taken for automatic actuations (e.g., ESFAS functions) and manual operator actions are described in the individual event sections in this chapter.

Unless specified otherwise in the individual event sections in this chapter, the major assumptions used for calculating radiological releases to the environment are as follows:

A. The initial RCS activity level is established consistent with the PVNGS licensing basis for the event under consideration. For some events, the event methodology requires that the initial RCS activity be set to the maximum activity due to continuous full power operation with 1% failed fuel. For other events, initial conditions are based on the Technical Specification limit for RCS dose equivalent I-131 and Xe-133 specific activities.

B. The initial secondary system activity level is equal to 0.1 μCi/gm dose equivalent I-131.

C. Primary-to-secondary steam generator tube leakage is included in the calculation of activity releases to the environment from the steam generators. The leakage assumed in the safety analyses is a 1 gpm primary—to-secondary tube leak (i.e., total leakage for two steam generators), consistent with PVNGS Technical Specification 5.5.9.

D. For events that require consideration of “iodine spiking” the following are used:

1. For iodine spiking generated by the event, the iodine appearance rate is increased by a factor of 335.

2. For an abnormally high iodine concentration due to a previous iodine spike, a reactor coolant activity of 60 μCi/gm dose equivalent I-131 is assumed.

E. Breathing rate (from Table 15B-3).

F. Atmospheric dispersion factor (χ/Q) (from Table 2.3-31)

G. Dose conversion factors from ICRP-30 for radioiodines are used for thyroid inhalation dose calculations, all other dose conversion factors are obtained from Regulatory Guide 1.109.

TABLE 15.0-2

RCS IODINE SOURCE TERM FOR THE RADIOLOGICAL DOSE CONSEQUENCES SAFETY ANALYSIS

Isotope	Source Term (Ci/MWt)
I-131	25,100
I-132	38,100
I-133	56,220
I-134	65,760
I-135	51,040

TABLE 15.0-3

RCS NOBLE GAS SOURCE TERM FOR THE RADIOLOGICAL DOSE CONSEQUENCES SAFETY ANALYSIS

Isotope	Source Term (Ci/MWt)
Kr-83m	4,153
Kr-85m	13,000
Kr-85	440
Kr-87	21,540
Kr-88	32,020
Xe-131m	260
Xe-133m	1,384
Xe-133	56,220
Xe-135m	18,200
Xe-135	53,640
Xe-138	49,700

15.0.5 REFERENCES

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15.1 INCREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

15.1.1 DECREASE IN FEEDWATER TEMPERATURE

15.1.1.1 Identification of Causes and Frequency Classification

A decrease in main feedwater temperature may be caused by an interruption of extraction steam to one or more feedwater heaters due to a heater drain pump malfunction, or a loss of heater drain tank or heater level control.

A decrease in main feedwater temperature event is classified as an incident of moderate frequency. A decrease in main feedwater temperature event in combination with an additional single failure is classified as an infrequent event.

15.1.1.2 Sequence of Events and System Operation

As noted in UFSAR Section 10.4.7, the main feedwater system may be operated in two different modes during normal plant power operations. In the bypass mode of operation, approximately 80% of the total feedwater flow that is delivered to the steam generators passes through two parallel trains of high pressure feedwater heaters, with the remainder of the feedwater flow bypassing these heater trains via an open bypass valve. In the turbo mode of operation, the bypass valve is closed and 100% of the total delivered feedwater flow passes through the high pressure feedwater heater trains.

In either mode of operation, the temperature of the feedwater that passes through each parallel train of three high pressure feedwater heaters is increased by approximately 100°F. Feedwater heating is provided by extraction steam from the high pressure turbine and the first and second stage reheaters,

which flows through the shell side of the feedwater heaters. Shell side condensate from each train of heaters is drained to a heater drain tank. Heater drain pumps return the condensate to the inlets of the main feedwater pumps, upstream of their respective high pressure feedwater heater trains.

If extraction steam were to be suddenly and completely lost to one train of three high pressure heaters, the temperature of the feedwater delivered to the steam generators would be reduced by approximately 40°F to 50°F, respectively, if the feedwater system were operating in the bypass or turbo mode at nominal system flow rates.

A sudden decrease in feedwater temperature would result in a decrease in reactor coolant temperature which, in the presence of a negative Moderator Temperature Coefficient (MTC), would increase core power. A sudden cooldown would likewise cause a decrease in Reactor Coolant System (RCS) and steam generator pressures. Detection of the event could therefore be accomplished by a high reactor power alarm or a steam generator low pressure alarm. If the transient were to result in an approach to Specified Acceptable Fuel Design Limits (SAFDLs), trip signals generated by the Core Protection Calculators (CPCs) would ensure that low Departure from Nucleate Boiling Ratio (DNBR) and high Local Power Density (LPD) limits are not exceeded.

15.1.1.3 Core and System Performance

A decrease in main feedwater temperature event would not challenge fuel pellet integrity. During the event, any short-term increase in reactor power, or three-dimensional shift in power generation within the core, would not be of sufficient magnitude to raise the linear heat rate above that required to cause fuel centerline melting.

A decrease in main feedwater temperature event would result in a smaller decrease in RCS temperature than an increase in main steam flow event involving the quick opening of eight Steam Bypass Control System (SBCS) valves or an inadvertent opening of a steam generator atmospheric dump valve (OSGADV) (see UFSAR Section 15.1.4). The smaller RCS cooldown would result in less of a power increase, and hence less of a decrease in the minimum hot channel DNBR during the transient. The minimum hot channel DNBR establishes whether a fuel design limit has been exceeded and therefore whether fuel cladding degradation might be anticipated.

For the decrease in main feedwater temperature event in combination with a single failure, the parameter of concern is likewise the minimum hot channel DNBR. Factors that would cause a decrease in DNBR include an increase in coolant temperature, a decrease in coolant pressure, an increase in local heat flux (including radial and axial power distribution effects), and a decrease in coolant flow rate. Evaluation of postulated single failures shows that the worst single failure for this event is a Loss of Offsite Power (LOP) following a

turbine trip, which would cause the Reactor Coolant Pumps (RCPs) to coast down and rapidly reduce the coolant flow rate. This event, however, would result in a Nuclear Steam Supply System (NSSS) response that is similar to, but less severe than, that caused by the increase in main steam flow event involving the quick opening of eight SBCS valves or an inadvertent opening of a steam generator atmospheric dump valve (OSGADV) in combination with LOP (See UFSAR Section 15.1.3 and 15.1.4). These events result in more severe RCS cooldown that in turn results in more of an increase in power, and hence more of a decrease in the minimum hot channel DNBR. Therefore, the DNBR at the moment RCPs begin to coastdown would be bounded by those events. For this reason, the infrequent decrease in the feedwater temperature event (in combination with a single failure) is bounded by the infrequent event involving the quick opening of eight SBCS valves and the inadvertent opening of steam generator atmospheric dump valve (OSGADV) (in combination with single failure) with respect to the DNBR SAFDL.

In addition, this event would result in a more benign minimum DNBR than the resulting from the limiting infrequent event that is described in the UFSAR Appendix 15.E. the event described in UFSAR Appendix 15.E establishes a limiting infrequent event, including all incidents of moderate frequency in combination with a single failure, with respect to DNBR degradation, assuming that the DNBR is already at the SAFDL when the single failure, LOP, occurs.

15.1.1.4 RCS Pressure Boundary Barrier Performance

A decrease in main feedwater temperature event is characterized by an initial cooldown of the primary and secondary systems, and decreasing RCS and steam generator pressures. If the event results in a reactor trip and Main Steam Isolation Signal (MSIS), repressurization of the RCS and steam generators would occur due to decay heat from radionuclides in the core, heat stored in the metal structures of the NSSS, and heat from any operating RCPs. Additionally, if pressurizer pressure decreases below the Safety Injection Actuation Signal (SIAS) setpoint, safety injection flow may also result in repressurization of the RCS. Eventually, however, plant operators would take action to cool down and depressurize the plant to Shutdown Cooling (SDC) entry conditions. This may be accomplished by feeding the steam generators with Auxiliary Feedwater (AFW) flow and by releasing steam through the Atmospheric Dump Valves (ADVs).

The subsequent heatup and repressurization of the NSSS would not challenge RCS pressure boundary peak pressure limits. Prior to the operators taking action to cool down the plant, the secondary system peak pressure would be limited by the Main Steam Safety Valves (MSSVs), which have sufficient capacities to relieve the steam that may be generated by NSSS heat sources. Furthermore, if the heat transfer rate from the RCS to the secondary system were degraded for any reason, as might occur when a LOP results in a loss of forced RCS coolant flow, the Pressurizer Safety Valves (PSVs) may also open to limit the

RCS peak pressure. Because the maximum allowable lift settings for the MSSVs and PSVs are well below the peak pressure regulatory limits for this event, a decrease in feedwater temperature, or a decrease in feedwater temperature in combination with a single failure, would not challenge the RCS pressure boundary through overpressurization of either the primary or secondary systems.

15.1.1.5 Containment Performance and Radiological Consequences

A decrease in feedwater temperature event in combination with an additional single failure (for example, a LOP following turbine trip) is classified as an infrequent event, which may result in limited fuel cladding degradation. Offsite radiological dose consequences are limited to a small fraction, or 10%, of 10 CFR Part 100 guideline values. Additionally, radiation exposures for control room personnel are subject to the limits specified in General Design Criterion (GDC) 19 of 10 CFR 50 Appendix A. The offsite and control room radiological dose consequences associated with this infrequent event are bounded by those that may result from an Inadvertent Opening of a Steam Generator Atmospheric Dump Valve with a Loss of Offsite Power (IOSGADVLOP) event, (see UFSAR Section 15.1.4) and/or the limiting infrequent event (see UFSAR Appendix 15.E), and are in compliance with regulatory guidelines.

15.1.1.6 Conclusions

Evaluation of the decrease in feedwater temperature event shows that:

- Pressure in the RCS will be maintained below 110% of its design value (i.e., 110% of 2500 psia, or 2750 psia).
- Pressure in the main steam system will be maintained below 110% of the steam generator shell side design value (i.e., 110% of 1270 psia, or 1397 psia).
- For the moderate frequency decrease in feedwater temperature event (without an additional single failure), fuel cladding integrity will be maintained.
- For the infrequent decrease in feedwater temperature event (with an additional single failure), limited fuel cladding degradation may occur. However, offsite and control room radiological dose consequences are bounded by those that may result from an IOSGADVLOP event, (see UFSAR Section 15.1.4) and/or the limiting infrequent event (see UFSAR Appendix 15.E), and are in compliance with regulatory guidelines.

15.1.2 INCREASE IN MAIN FEEDWATER FLOW

15.1.2.1 Identification of Causes and Frequency Classification

An increase in main feedwater flow to the steam generators may be caused by inadvertent equipment malfunctions in the Feedwater Control System (FWCS), resulting in the opening of feedwater control valves beyond their desired positions, or an increase in feedwater pump speed.

An increase in main feedwater flow event is classified as an incident of moderate frequency. An increase in main feedwater

flow event in combination with an additional single failure is classified as an infrequent event.

15.1.2.2 Sequence of Events and System Operation

During normal power operations, feedwater flow is automatically controlled by the FWCS through main feedwater control valves, which establish steam generator feedwater balancing in conjunction with variable-speed feedwater pump turbine drives. If a hypothetical equipment malfunction were to suddenly increase FWCS demand signals to their maximum output values, the control valves would stroke fully open and the feedwater pumps would accelerate to maximum speed. If the plant were operating at full power when this occurred, the maximum increase in feedwater flow that would result is estimated to be approximately 25% of the nominal main feedwater system flow rate.

A sudden increase in main feedwater flow to the steam generators would result in a decrease in reactor coolant temperature which, in the presence of a negative MTC, would increase core power. A sudden increase in feedwater flow would also cause an increase in steam generator water level and a decrease in RCS and steam generator pressures. Detection of the event could therefore be accomplished by a high reactor power alarm, a steam generator low pressure alarm, or a steam generator high water level alarm. If the transient were to result in an approach to SAFDLs, trip signals generated by the CPCs would ensure that low DNBR and high LPD limits were not exceeded. Likewise, if steam generator water level increased

significantly, a reactor trip and main steam isolation on high steam generator level would occur, thereby protecting the steam generators from overfilling.

15.1.2.3 Core and System Performance

An increase in main feedwater flow event would not challenge fuel pellet integrity. During the event, any short-term increase in reactor power, or three-dimensional shift in power generation within the core, would not be of sufficient magnitude to raise the linear heat rate above that required to cause fuel centerline melting.

An increase in main feedwater flow event would result in a smaller decrease in RCS temperature than an increase in main steam flow event involving the quick opening of eight SBCS valves or the inadvertent opening of a steam generator atmospheric dump valve (OSGADV) (see UFSAR Section 15.1.3 and 15.1.4). The smaller RCS cooldown would result in less of a power increase, and hence less of a decrease in the minimum hot channel DNBR during the transient. The minimum hot channel DNBR establishes whether a fuel design limit has been exceeded and therefore whether fuel cladding degradation might be anticipated.

For the increase in main feedwater flow event in combination with a single failure, the parameter of concern is likewise the minimum hot channel DNBR. Factors that would cause a decrease in DNBR include an increase in coolant temperature, a decrease in coolant pressure, an increase in local heat flux (including

radial and axial power distribution effects), and a decrease in coolant flow rate. Evaluation of postulated single failures shows that the worst single failure for this event is a LOP following a turbine trip, which would cause the RCPs to coast down and rapidly reduce the coolant flow rate. This event, however, would result in a Nuclear Steam Supply System (NSSS) response that is similar to, but less severe than, that caused by the increase in main steam flow event involving the quick opening of eight SBCS valves or an inadvertent opening of a steam generator atmospheric dump valve in combination with LOP (See UFSAR Section 15.1.3 and 15.1.4). The quick opening of eight SBCS valves results in more severe RCS cooldown that in turn results in more of an increase in power, and hence more of a decrease in the minimum hot channel DNBR. Therefore, the DNBR at the moment RCPs begin to coastdown would be bounded by those events. For this reason, the infrequent increase in the feedwater flow event (in combination with a single failure) is bounded by the infrequent event involving the quick opening of eight SBCS valves and inadvertent opening of a steam generator atmospheric dump valve (OSGADV) (in combination with single failure) with respect to the DNBR SAFDL.

In addition, this event would result in a more benign minimum DNBR than that resulting from the limiting infrequent event that is described in the UFDAR Appendix 15.E. The event described in UFSAR Appendix 15.E establishes a limiting infrequent event, including all incidents of moderate frequency in combination with a single failure, with respect to DNBR

degradation, assuming that the DNBR is already at the SAFDL when the single failure, LOP, occurs.

15.1.2.4 RCS Pressure Boundary Barrier Performance

An increase in main feedwater flow event is characterized by an initial cooldown of the primary and secondary systems, decreasing RCS and steam generator pressures, and increasing steam generator water level. If the event results in a reactor trip and MSIS, repressurization of the RCS and steam generators may occur due to decay heat from radionuclides in the core, heat stored in the metal structures of the NSSS, and heat from any operating RCPs. Additionally, if pressurizer pressure decreases below the SIAS setpoint, safety injection flow may also serve to repressurize the RCS. Eventually, however, plant operators would take action to cool down and depressurize the plant to SDC entry conditions. This may be accomplished by feeding the steam generators with AFW flow and by releasing steam through the ADVs.

The subsequent heatup and repressurization of the NSSS would not challenge RCS pressure boundary peak pressure limits. Prior to the operators taking action to cool down the plant, the secondary system peak pressure would be limited by the MSSVs, which have sufficient capacities to relieve the steam that may be generated by NSSS heat sources. Furthermore, if the heat transfer rate from the RCS to the secondary system were degraded for any reason, as might occur when a LOP results in a loss of forced RCS coolant flow, the PSVs may also open to limit the RCS peak pressure. Because the maximum allowable

lift settings for the MSSVs and PSVs are well below the peak pressure regulatory limits for this event, an increase in main feedwater flow, or an increase in main feedwater flow in combination with a single failure, would not challenge the RCS pressure boundary through overpressurization of either the primary or secondary systems.

15.1.2.5 Containment Performance and Radiological Consequences

An increase in main feedwater flow event in combination with an additional single failure (for example, a LOP following turbine trip) is classified as an infrequent event, which may result in limited fuel cladding degradation. Offsite radiological dose consequences are limited to a small fraction, or 10%, of 10 CFR Part 100 guideline values. Additionally, radiation exposures for control room personnel are subject to the limits specified in General Design Criterion (GDC) 19 of 10 CFR 50 Appendix A. The offsite and control room radiological dose consequences associated with this infrequent event are bounded by those that may result from an IOSGADVLOP event, (see UFSAR Section 15.1.4) and/or the limiting infrequent event (see UFSAR Appendix 15.E), and are in compliance with regulatory guidelines.

15.1.2.6 Conclusions

Evaluation of the increase in main feedwater flow event shows that:

- Pressure in the RCS will be maintained below 110% of its design value (i.e., 110% of 2500 psia, or 2750 psia).

- Pressure in the main steam system will be maintained below 110% of the steam generator shell side design value (i.e., 110% of 1270 psia, or 1397 psia).
- For the moderate frequency increase in main feedwater flow event (without an additional single failure), fuel cladding integrity will be maintained.
- For the infrequent increase in main feedwater flow event (with an additional single failure), limited fuel cladding degradation may occur. However, offsite and control room radiological dose consequences are bounded by those that may result from an IOSGADVLOP event, (see UFSAR Section 15.1.4) and/or the limiting infrequent event (see UFSAR Appendix 15.E), and are in compliance with regulatory guidelines.

15.1.3 INCREASE IN MAIN STEAM FLOW

15.1.3.1 Identification of Causes and Frequency Classification

An increase in main steam flow event may be caused by equipment malfunctions or inadvertent operator actions that result in the sudden opening of one or more Steam Bypass Control System (SBCS) valves; the opening of a turbine admission valve beyond its desired position; or the opening of an Atmospheric Dump Valve (ADV). Postulated events that involve the SBCS and turbine admission valves, which are located downstream of the Main Steam Isolation Valves (MSIVs), are addressed in this UFSAR section. Inadvertent openings of ADVs, which are located upstream of the MSIVs, are addressed in UFSAR Section 15.1.4.

An increase in main steam flow event is classified as an incident of moderate frequency. An increase in main steam flow event in combination with an additional single failure is classified as an infrequent event.

15.1.3.2 Sequence of Events and System Operation

When the plant is operating at full power, main steam flow will increase if a turbine admission valve suddenly opens beyond its desired position, or if one or more SBCS valves suddenly open. The largest possible increase in main steam flow would occur if an equipment malfunction resulted in the simultaneous quick opening of all eight SBCS valves (SBCVs). The maximum allowable capacity of each non-safety-related SBCV is 11% of the Design Steam Rate (DSR), where the DSR is based on the original licensed power level of 3800 MWt. The DSR is less than the nominal steam flow rate at the current licensed Rated Thermal Power (RTP). Given the maximum capacity of each SBCV, main steam flow would increase by less than 88% of the steam flow corresponding the current licensed RTP.

Table 15.1.3-1 provides the sequence of events for the limiting moderate frequency increase in main steam flow analysis, involving a quick opening of all eight SBCVs at 100% power. This sequence of events was obtained by simulating the event with the computer codes identified in Section 15.1.3.3. Figures 15.1.3-1 through 15.1.3-12 show the short-term response of key NSSS parameters during the portion of the event that presents the greatest challenge to SAFDLs. Specifically, Figure 15.1.3-11 shows how DNBR approaches and passes through a minimum value shortly after event initiation. Figures 15.1.3-13 through 15.1.3-15 show the long-term response of key parameters prior to the time at which operators are assumed to take control of plant (i.e., 30 minutes after event initiation).

The sudden increase in main steam flow (Figure 15.1.3-1) results in a decrease in reactor coolant temperature (Figure 15.1.3-2) which, in the presence of a negative MTC, results in an increase in reactivity (Figure 15.1.3-3), core power (Figure 15.1.3-4), and core heat flux (Figure 15.1.3-5).

INCREASE IN HEAT REMOVAL

BY THE SECONDARY SYSTEM

Table 15.1.3-1

SEQUENCE OF EVENTS FOR THE LIMITING MODERATE FREQUENCY STEAM BYPASS CONTROL SYSTEM MALFUNCTION SAFETY ANALYSIS

Time	Event
0.00	Eight SBCS valves quick-open
6.49	Steam generator pressure reaches MSIS setpoint
6.72	CPC VOPT reaches reactor trip setpoint
7.47	Reactor trip breakers open
7.72	Turbine trip occurs
8.08	CEAs begin to fall
8.50	Minimum DNBR occurs
12.10	MSIVs close. Flow through SBCS valves stops.
112.02	MSSVs open on steam generator 1[1]
112.02	MSSVs open on steam generator 2[1]
112.39	Maximum steam generator 2 pressure occurs
165.58	MSSVs close on steam generator 1[1]
165.58	MSSVs close on steam generator 2[1]
323.52	Pressurizer Pressure reaches SIAS septoint.
363.52	HPSI flow Begins
600.55	Maximum steam generator 1 pressure occurs
665.64	AFW flow delivered to steam generator 1
665.64	AFW flow delivered to steam generator 2
1009.47	AFW flow shutoff reached in steam generator 2.
1011.11	AFW flow shutoff reached in steam generator 1.
1800.00	Plant operators take control of the plant

[1]Only the first opening and closing of the MSSVs are documented.

Table 15.1.3-1 (Page 2 of 2)

SEQUENCE OF EVENTS FOR THE LIMITING MODERATE FREQUENCY STEAM BYPASS CONTROL SYSTEM MALFUNCTION SAFETY ANALYSIS

Time	Event
1000	Steam generator No. 1 water level recovers to high level AFAS setpoint. AFW flow stopped to steam generator No. 1
1073	MSSVs open on steam generator No. 2
1074	MSSVs open on steam generator No. 1
1114	MSSVs close on steam generator No. 2
1115	MSSVs close on steam generator No. 1
1269	MSSVs open on steam generator Nos. 1 and 2
1279	Steam generator No. 1 water level decreases to low level AFAS setpoint. AFW flow reinitiated to steam generator No. 1
1280	Steam generator No. 2 water level decreases to low level AFAS setpoint. AFW flow reinitiated to steam generator No. 2
1302	MSSVs open on steam generator Nos. 1 and 2
1556	Steam generator No. 2 water level recovers to high level AFAS setpoint. AFW flow stopped to steam generator No. 2
1559	Steam generator No. 1 water level recovers to high level AFAS setpoint. AFW flow stopped to steam generator No. 1
1688	MSSVs open on steam generator Nos. 1 and 2
1728	MSSVs close on steam generator No. 2
1729	MSSVs close on steam generator No. 1
1800	Plant operators take control of plant

A sudden increase in main steam flow would also cause a short-term increase in the indicated steam generator water level due to swell effects (Figure 15.1.3-6), and an almost immediate decrease in both RCS and steam generator pressures (Figures 15.1.3-7 and 15.1.3-8, respectively). Despite the short-term increase in indicated steam generator water level, the mass of liquid in both steam generators would actually decrease slightly due to increased steam flow during the early part of the transient (Figure 15.1.3-9). Detection of the event may be accomplished by a high reactor power alarm, an RCS low pressure alarm, or a steam generator low pressure alarm.

Rapid cooling of the RCS would increase coolant density and cause a temporary reduction in pressurizer level (Figure 15.1.3-10). When the colder fluid exiting the steam generator reaches the core inlet, the core power will increase, causing the core heat flux to increase, albeit with a delay of a few seconds. This increased heat flux, in conjunction with the decreased RCS pressure, would cause the DNBR to decrease (Figure 15.1.3-11).

As the event proceeds, the steam generator pressure decreases and approaches the Low Steam Generator Pressure Trip (LSGPT). At the same time, reactor power increases toward a CPC auxiliary trip, the Variable Overpower Trip (VOPT). A VOPT will occur before the LSGPT for more negative values of MTC; however, for less negative values of MTC, the power increase may not be sufficient to result in the VOPT before the steam generator pressure reaches the LSGPT. The most limiting

analysis case, which yielded the lowest DNBR value, was found to occur when the VOPT and LSGPT trips occurred at approximately the same time.

Following reactor trip, Control Element Assemblies (CEAs) would fall into the reactor core, rapidly reducing reactivity, core power, and core heat flux. As indicated in Table 15.1.3-1, minimum DNBR is predicted to occur shortly after the CEAs begin inserting into the core.

The course of the transient depends on the choice of MTC, because the LSGPT occurs in conjunction with a Main Steam Isolation Signal (MSIS). Thus, depending on which trip signal intervenes, and even how close the LSGPT is to the setpoint, the system responses for the steam system may take one of two different paths.

In the case of tripping on the LSGPT, the MSIS accompanying the trip would result in closure of the MSIVs and Main Feedwater Isolation Valves (MFIVs). Closure of these valves would stop the flow of main feedwater to the steam generators (Figure 15.1.3-12) as well as the flow of steam out of the open SBCVs. It would also stop the temperature and pressure decrease in the RCS temporarily and there would be no Safety Injection Actuation Signal (SIAS).

If the trip were to occur on the VOPT and the steam generator pressure were far enough above the MSIS setpoint to avoid an immediate MSIS, there would be a turbine trip associated with the VOPT, but the flow through the SBCVs would continue. Thus, in spite of the turbine trip, RCS pressure would continue to

decrease as heat loss through the open SBCVs exceeds the post-trip heat generation rate in the NSSS. As the RCS continued to cool down, the pressurizer would eventually empty and pressurizer pressure would decrease to the SIAS setpoint, actuating the safety injection pumps. After a brief time delay, during which the High Pressure Safety Injection (HPSI) pumps reach full speed, safety injection flow would be delivered to the RCS, provided RCS pressure was below the shutoff head of the HPSI pumps. Shortly thereafter, the decreasing steam generator pressure would reach the MSIS setpoint, thereby halting the steam flow from both steam generators and effectively stopping the cooldown.

Following the MSIS, the RCS and steam generators would begin to repressurize, due to the heat released by fission product decay, running RCPs, hot metal structures in the NSSS and, in the event of VOPT, the HPSI flow (Figures 15.1.3-13 and 13.1.3-14, respectively). The pressure in the steam generators would continue to rise until the MSSV setpoint is reached. At this point, the MSSVs would open, limiting the pressure and releasing steam generator inventory. As the steam generator pressure dropped from this release, the MSSVs would close and the steam generator pressure would begin rising again. The release of inventory associated with each lifting of the MSSVs would cause the liquid levels in the steam generators to decrease until they reach the Auxiliary Feedwater Actuation Signal (AFAS) setpoint. This would initiate the delivery of AFW flow to the steam generators, which would continue until the high level reset was reached.

After initiation of AFW flow to the steam generators, the plant would achieve quasi-steady-state conditions with heat removal provided by cycling of the MSSVs, and makeup water provided by cycling of the AFW system as water levels rise and fall in both steam generators. Pressurizer level would likewise rise and fall as the RCS periodically heats up, then temporarily cools down again with each MSSV lift (Figure 15.1.3-15).

Operator action is not credited in the safety analysis until 30 minutes following the SBCS malfunction. At that time, it is assumed that plant operators will take action to initiate a controlled plant cooldown to SDC entry conditions, for example by establishing a steaming path through the ADVs.

15.1.3.3 Core and System Performance

An event involving an increase in main steam flow would not challenge fuel pellet integrity. During the event, any short-term increase in reactor power, or three-dimensional shift in power generation within the core, would not be of sufficient magnitude to raise the linear heat rate above that required to cause fuel centerline melting.

An increase in main steam flow event results in thermal margin degradation very similar to that experienced in the IOSGADV moderate frequency event with respect to the DNBR SAFDL. The mathematical models, input parameters, initial conditions, and results of the SBCS malfunction safety analysis are described in the subsections below for this moderate frequency event.

For the infrequent increase in main steam flow event in combination with a single failure, the parameter of concern is also the minimum hot channel DNBR. Factors that would cause a decrease in DNBR include an increase in coolant temperature, a decrease in coolant pressure, an increase in local heat flux (including radial and axial power distribution effects), and a decrease in coolant flow rate. Evaluation of postulated single failures shows that the worst single failure for this event is a LOP following a turbine trip, which would cause the RCPs to coast down and rapidly reduce the coolant flow rate.

The infrequent event involving an increase in main steam flow is initiated by the quick opening of eight SBCVs combined with LOP. This event is bounded by the IOSGADVLOP event with respect to the DNBR SAFDL and dose consequences for those events involving an increase in heat removal by the secondary system.

The SBCS malfunction with a LOP is still bounded by the infrequent event described in the UFSAR Appendix 15.E, the Loss of Flow (LOF) from a SAFDL. The LOF from a SAFDL establishes a limiting infrequent event with respect to DNBR degradation for all moderate frequency events in combination with a single failure by assuming that the DNBR is already at the SAFDL when the LOF occurs. The minimum DNBR during the limiting moderate frequency event involving increased main steam flow remains above the DNBR SAFDL and, when combined with LOP following a turbine trip, would yield a minimum DNBR that is higher than that for the LOF from a SAFDL. Hence, the limiting infrequent

event for an increase in main steam flow (quick opening of eight SBCVs with a single failure) is bounded with respect to the DNBR by the IOSGADVLOP and the limiting infrequent event evaluated in UFSAR Appendix 15.E.

15.1.3.3.1 Mathematical Models

The moderate frequency event for an increase in main steam flow was analyzed with the following mathematical models:

- The CENTS computer code was used to simulate the NSSS transient response. The CENTS computer code is described in UFSAR Section 15.0.3.1.3.2 and in an NSSS vendor topical report.[(1)(2)]

- The CPC FORTRAN computer code was used to simulate CPC reactor trip functions and to predict the time at which the CPC VOPT setpoint would be reached. This time, with appropriate delays for signal processing and opening of the reactor trip breakers, was utilized in CENTS code input. The CPCs are described in UFSAR Section 7.2, and associated algorithms and simulation code are described in NSSS vendor topical reports.[(3)(4)]

- The CETOP-D computer code, which uses the CE-1 Critical Heat Flux (CHF) correlation, was used to calculate the initial and transient DNBR values. CETOP-D was also used to determine initial Power Operating Limit (POL) conditions for this event (see UFSAR Section 15.1.3.3.2 for additional information on POL conditions). The

CETOP-D computer code is described in UFSAR Section 4.4 and in NSSS vendor topical reports.[5][6][7]

15.1.3.3.2 Input Parameters and Initial Conditions

Table 15.1.3-2 summarizes the key input parameters and initial conditions utilized in the safety analysis for the limiting moderate frequency event involving an increase in main steam flow.

The following points serve to explain the selection of initial conditions as they appear in Table 15.1.3-2:

- During normal plant power operations, the Core Operating Limits Supervisory System (COLSS) monitors various parameters to assist operators in maintaining plant conditions within the Technical Specification Limiting Conditions for Operation (LCOs). When COLSS is in service, it continuously calculates the core power at which the DNBR SAFDL would be reached, based on the measured temperature, pressure, flow, radial peaking factor, and axial power distribution. This COLSS-calculated core power is then divided by a numerical value, called the Required Overpower Margin (ROPM), to yield a DNBR Power Operating Limit (POL). If the measured core power exceeds the calculated POL, a COLSS alarm would alert plant operators to take action as required by Technical Specifications. The DNBR POL therefore serves to preserve thermal margin to accommodate potential operational transients. For this

safety analysis, it was assumed that the plant would be operating at a POL condition immediately prior to the event, at the most limiting RCS flow rate. Because the event simulation was initiated from a calculated POL, additional power measurement uncertainties were not added to the initial assumed core power level. Analytical values for the initial core inlet temperature, pressurizer pressure, and RCS coolant flow rate corresponding to the POL were determined with the CETOP-D computer code, for an initial core power of 100% of RTP.

Table 15.1.3-2

INPUT PARAMETERS AND INITIAL CONDITIONS FOR THE STEAM BYPASS CONTROL SYSTEM MALFUNCTION SAFETY ANALYSIS

Parameter	Assumed Value
Initial Core Power (% of RTP)	100%
Initial core Inlet Temperature (¡F)	566
Initial Pressurizer Pressure (psia)	2100
Initial RCS Flow Rate (% of Design Rated)	110.4
Initial Pressurizer Water Level (% Narrow Range)	24
Initial Steam Generator Water Level (% Wide Range)	80.7
Moderator Temperature Coefficient ($\Delta\rho$/¡F)	$-2.25x10^{-4}$
Doppler Fuel Temperature Coefficient	Least Negative
Delayed Neutron Kinetics	EOC
Axial Shape Index for DNBR calculation	-0.2
CEA Worth at Trip (%$\Delta\rho$)	8.0
Fuel Rod Gap Conductance (BTU/hr-ft^2-¡F)	6100
Total Number of Plugged Steam Generator Tubes	0
Single Failure	None

- DNBR degradation during the event is sensitive to the initial pressurizer water level and a minimum value was selected for the initial conditions, based on parametric evaluation.

- DNBR degradation during the event is not sensitive to the initial steam generator level unless a high steam generator level trip were credited. Since no credit is taken for that trip, it was disabled and nominal values were used for initial steam generator level. The CENTS code automatically calculates the initial steam generator pressure, given steam generator water level, reactor power, and other inputs to the computer code.

- The SBCS malfunction event causes a rapid cooldown of the RCS. Using the most negative MTC allowed by the Technical Specifications and COLR would result in the most rapid power increase and the greatest overshoot in power after the VOPT. However, because the heat flux lags behind the power, it does not necessarily produce the greatest decrease in DNBR. As the MTC is made less negative, the power excursion is slowed down. This allows the heat flux to stay closer to the power and it allows the VOPT to shift upwards a small amount. The heat flux at the time of minimum DNBR increases for this event as the MTC is made less negative and the DNBR decreases. As the MTC is made less and less negative, a point is reached at which the LSGPT and the VOPT are reached concurrently. This MTC results in the lowest

minimum DNBR. Making the MTC less negative will result in the LSGPT occurring with the power below the VOPT setpoint. This decreases the heat flux and increases the minimum DNBR. The value shown in Table 15.1.3-2 corresponds to the limiting case, for which the VOPT and LSGPT occur at approximately the same time.

- The least negative Doppler fuel temperature coefficient curve, which corresponds to Beginning of Cycle (BOC) conditions, was used. Use of the least negative values minimizes the addition of negative reactivity caused by increasing fuel temperature. This is not important for cases with intermediate values of MTC, but for the case with the most negative MTC, this choice will result in a more rapid increase in reactor core power.

- End of Cycle (EOC) values were chosen to model delayed neutron kinetics. EOC values enhance the power excursion by minimizing the effect of delayed neutrons on the rate of power increase. This is not important for cases with intermediate values of MTC, but for the case with the most negative MTC, this choice will result in a more rapid increase in reactor core power.

- If power generation is shifted toward the bottom of the core, the insertion of negative reactivity following reactor trip will be somewhat delayed until the CEAs have inserted farther into the core. The scram reactivity curve was therefore based on a positive ASI representing a bottom-peaked core. The time versus scram reactivity curve was

adjusted to account for a 0.6-second CEA holding coil time delay following opening of the reactor trip breakers, and normalized to model 90% CEA insertion at 4.0 seconds after power is removed from Control Element Drive Mechanism (CEDM) coils, (see UFSAR Section 3.9.4).

- The CEA worth at trip represents the minimum SCRAM worth for Hot Full Power (HFP) conditions at BOC, assuming the most reactive CEA remains stuck out of the core following reactor trip. This is more limiting (less negative) than the anticipated scram reactivity worth at other times during the operating cycle for HFP conditions.

- The fuel rod gap conductance value was selected in a manner that energy from the fuel would quickly reach the surface of the fuel rod clad. A large value results in a higher heat flux and greater degradation of DNBR during the initial power excursion.

- It was assumed that steam generator tubes were not plugged for this safety analysis. This enhances heat transfer from the RCS to the main steam system, which in turn enhances the initial RCS cooldown and maximizes the positive reactivity insertion due to the negative MTC. Additionally, this enhances the decrease in RCS pressure during the cooldown, which serves to degrade DNBR.

- For the moderate frequency event involving an increase in main steam flow, an additional single failure was not assumed.

For those safety-related Reactor Protective System (RPS) and Engineered Safety Features Actuation System (ESFAS) setpoints and response times that had a direct effect on acceptance criteria for this event, analytical values were chosen to be consistent with, or conservative with respect to, limiting numerical values that appear in the PVNGS Technical Specifications and UFSAR Chapter 7.

15.1.3.3.3 Results

The analysis shows that the calculated minimum DNBR approaches a value of 1.41 at 8.5 seconds following event initiation. This value is greater than the DNBR SAFDL of 1.34. The linear heat rate will not present a credible challenge to fuel centerline melting. Therefore, fuel damage is not predicted to occur for this event.

15.1.3.4 RCS Pressure Boundary Barrier Performance

The increased steam flow events are characterized by a cooldown and depressurization of the primary and secondary systems in the short-term. However, this initial cooldown and depressurization is reversed after automatic halting of the steam flow following an MSIS resulting in heat-up and repressurization of primary and secondary systems. A comparison of the RCS pressures and temperatures shows that the RCS temperature and pressure decrease for the increased main steam flow event due to the opening of one SBCV is similar to that for the IOSGADV event described in UFSAR Section 15.1.4 because of the same flow capacity of an ADV and SBCV (11% of

the DSR). Opening of more SBCVs would result in a larger cooldown and depressurization of the RCS than the IOSGADV event in the short-term. Additionally, over the longer term, steam flow through the open SBCVs would be halted automatically following an MSIS and controlled heat removal would be achieved by both steam generators, while an IOSGADV event would result in dry-out of one steam generator and long-term controlled heat removal would be achieved through only one steam generator. As a result of the increased cooling from the stuck-open ADV, the RCS would be cooler for the IOSGADV for several minutes post-SCRAM. However, because the heat is being removed through only one steam generator, the RCS temperature and pressure for the IOSGADV would be significantly higher than that for the SBCS malfunction in the long term. Secondary pressures are limited by the MSSV setpoints and will be no greater for the SBCS malfunction than the intact steam generator in the IOSGADV. Based on the above, the maximum primary and secondary pressures for moderate frequency and infrequent events involving a main steam flow increase (inadvertent opening of one or more SBCVs) are bounded by those for moderate frequency and infrequent IOSGADV events, respectively.

15.1.3.5 Containment Performance and Radiological Consequences

An increase in main steam flow event in combination with an additional single failure (for example, LOP following turbine trip) is classified as an infrequent event. Offsite radiological dose consequences are limited to a small fraction, or 10%, of 10 CFR Part 100 guideline values. Additionally,

radiation exposures for control room personnel are subject to the limits specified in General Design Criterion (GDC) 19 of 10 CFR 50 Appendix A. The offsite and control room radiological dose consequences associated with this infrequent event are bounded by those that may result from an IOSGADVLOP event, and are in compliance with regulatory guidelines (see UFSAR Section 15.1.4.5).

15.1.3.6 Conclusions

Evaluation of the increase in main steam flow event shows that:

- Pressure in the RCS will be maintained below 110% of its design value (i.e., 110% of 2500 psia, or 2750 psia).
- Pressure in the main steam system will be maintained below 110% of the steam generator shell side design value (i.e., 110% of 1270 psia, or 1397 psia).
- For the moderate frequency increase in main steam flow event (without an additional single failure), fuel cladding integrity will be maintained.
- For the infrequent increase in main steam flow event (with an additional single failure), limited fuel cladding degradation may occur. However, offsite and control room radiological dose consequences are bounded by those that may result from an IOSGADVLOP event, and are in compliance with regulatory guidelines (see UFSAR Section 15.1.4)

15.1.4 INADVERTENT OPENING OF A STEAM GENERATOR ATMOSPHERIC DUMP VALVE

15.1.4.1 Identification of Causes and Frequency Classification

An IOSGADV is postulated to occur as a result of an inadvertent operator action or equipment malfunction in the valve control system.

An IOSGADV event is classified as an incident of moderate frequency. An IOSGADV event in combination with an additional single failure is classified as an infrequent event.

15.1.4.2 Sequence of Events and System Operation

The sequence of events and NSSS response to an IOSGADV event is similar to that described in UFSAR Section 15.1.3 for the increase in main steam flow event involving a sudden opening of the same or one or more SBCS valves. An IOSGADV event, however, would result in a smaller short-term increase in the main steam flow rate than the SBCS malfunction event which evaluates opening of one or more (up to eight) SBCS valves – each with flow capacity equal to that of an ADV. Additionally, over the longer term, steam flow through the open ADV would not be halted automatically following an MSIS, and the affected SG would continue to discharge steam to the atmosphere, eventually drying out. Therefore, the short-term NSSS response to an IOSGADV event would occur more slowly than for the SBCS malfunction event, but long-term controlled heat removal would be achieved through one rather than both steam generators.

Table 15.1.4-1 provides the sequence of events for an IOSGADV event in which a single failure involving a LOP after turbine trip has been assumed. This sequence of events was obtained by simulating the event with the computer codes identified in UFSAR Sections 15.1.4.3 and 15.1.4.4. Figures 15.1.4-1 through 15.1.4-14 depict the response of key NSSS parameters during this event.

An inadvertent opening of a steam generator ADV causes the main steam flow rate to increase (Figure 15.1.4-1), which results in a decrease in RCS hot leg, cold leg, and average coolant temperatures (Figures 15.1.4-2, 15.1.4-3, and 15.1.4-4, respectively). In the presence of a negative MTC, the decrease in RCS temperature results in an increase in reactivity (Figure 15.1.4-5), core power (Figure 15.1.4-6), and core heat flux (Figure 15.1.4-7). The increase in main steam flow rate would likewise cause a short-term increase in the indicated steam generator water level due to swell effects (Figure 15.1.4-8) and a decrease in both RCS and steam generator pressures (Figures 15.1.4-9 and 15.1.4-10, respectively). Despite the short-term increase in indicated steam generator water level, 2the mass of liquid in both

Table 15.1.4-1

SEQUENCE OF EVENTS FOR THE IOSGADVLOP SAFETY ANALYSIS

Time	Event
0.0	Inadvertent opening of an SG ADV
187.97	Steam generator pressure reaches reactor trip setpoint
187.97	Steam generator pressure reaches MSIS setpoint
187.97	Turbine trip occurs
187.97	LOP occurs
189.12	Reactor trip breakers open
189.73	CEAs begin to fall
190.64	Minimum DNBR occurs
193.58	MSIVs close. Steam flow from unaffected steam generated halted
239.67	MSSVs open, unaffected SG
255.79	Pressurizer empties
269.74	MSSVs close, unaffected SG
270.46	Pressurizer pressure reaches SIAS setpoint
310.48	HPSI pumps begin injecting into the RCS
1119.50	Affected SG dries out
1800.00	Plant operators close the open ADV on affected SG
1800.00	Plant operators take control of the plant

steam generators would not change significantly during the first few minutes of the transient (Figure 15.1.4-11).

Detection of the event may be accomplished by a high reactor power alarm, an RCS low pressure alarm, or a steam generator low pressure alarm. Reactor trip may be initiated by the CPCs on VOPT or an approach to the DNBR SAFDL, or by the RPS on a low steam generator pressure trip. As the event proceeds, the steam generator pressure decreases and approaches the Low Steam Generator Pressure Trip (LSGPT). For negative values of MTC, reactor power also increases toward a CPC auxiliary trip, the Variable Overpower Trip (VOPT). A VOPT will occur before the LSGPT for more negative values of MTC; however, for less negative values of MTC, the power increase may not be sufficient to result in the VOPT before the steam generator pressure reaches the LSGPT. The most limiting analysis case, which yielded the lowest DNBR value, was found to occur when the VOPT and LSGPT trips occurred at approximately the same time. Table 15.1.4-1 reflects a trip due to low steam generator pressure, with an MSIS occurring simultaneously at the analysis low steam generator pressure setpoint.

A turbine trip would occur following the reactor trip. The IOSGADVLOP case considers that the transmission network becomes unstable and collapses upon the sudden loss of generating capacity from the affected unit. A LOP would occur following the turbine trip. At least three seconds of offsite power is anticipated following the turbine trip (see UFSAR Section 15.0), however, the safety analysis results presented

in Table 15.1.4-1 conservatively model a simultaneous reactor trip, turbine trip, and LOP. This conservative assumption is tied to NRC acceptance of the fuel failure analysis convolution methodology. All four RCPs would then begin to coast down as a result of the LOP cutting power to the RCP motors, and the RCS would transition from forced flow to natural circulation conditions.

Short-term cooling of the RCS would increase coolant density, causing pressurizer level to decrease and the pressurizer to temporarily empty (Figure 15.1.4-12). The short-term increase in core heat flux and decrease in RCS pressure would, however, effectively reduce coolant subcooling and thereby cause the hot channel DNBR to decrease. DNBR would be degraded further in the first few seconds following the LOP, due to the rapid decrease in RCS flow rate as the RCPs coast down (Figure 15.1.4-13). CEAs will also fall into the reactor core following the reactor trip, rapidly reducing reactivity, core power, and core heat flux. As indicated in Table 15.1.4-1, minimum DNBR is predicted to occur shortly after the CEAs begin inserting into the core.

The MSIS would result in closure of the MSIVs, thereby halting the flow of steam from the unaffected or intact steam generator, which serves to maintain secondary system inventory. The MSIS would also result in closure of the MFIVs, stopping the flow of main feedwater to both steam generators (Figure 15.1.4-14). Because the RCS hot leg temperature would be higher than the temperature in the intact steam generator

following the MSIS, heat transfer from the RCS would continue to that steam generator. Eventually, the intact steam generator would heat up and repressurize to the lift setting of the first bank of MSSVs. The affected steam generator, however, would continue to blow down and depressurize because its open ADV is located upstream of the MSIVs. The affected steam generator would therefore eventually dry out.

The safety analysis predicts that AFW flow would not be automatically delivered to either steam generator. In the case of the unaffected steam generator, the safety analysis shows that closure of the MSIVs and FWIVs effectively preserves secondary system inventory, so that steam generator’s water level does not decrease to the AFAS setpoint within the first thirty minutes of the event sequence. Additionally, the analysis shows that AFW flow is not automatically delivered to the affected steam generator, even though its water level steadily decreases to the AFAS setpoint. This is due to an AFW Lockout that occurs when the affected steam generator’s pressure decreases significantly below the pressure in the unaffected steam generator. The AFW Lockout, that is based on the pressure difference between steam generators prevents addition of feedwater to the affected steam generator, and thus a loss of AFW inventory to the environment via the affected steam generator.

While blowdown continues through the open ADV on the affected steam generator, heat losses from the RCS to the secondary system would exceed the heat generation rate in the RCS which,

after a reactor trip and LOP, would be limited to decay heat from radioactive isotopes in the core and heat released by metallic components and structures in the NSSS. Pressurizer pressure would therefore decrease to the SIAS setpoint. Safety injection flow would be delivered to the RCS, however, only when RCS pressure decreases below the shutoff head of the HPSI pumps.

Following dryout of the affected steam generator, heat losses from the RCS to the secondary system would decrease sharply, and the RCS would begin to heat up. RCS repressurization would occur due to safety injection flow as well as the heat released by fission product decay and hot metal structures in the NSSS. The rate of heat transfer to the unaffected steam generator would also decrease as the temperature difference between that steam generator and its associated RCS hot leg decreased. The safety analysis shows that both the PSVs and the first bank of MSSVs would eventually lift to relieve pressure in the NSSS and to provide additional energy removal from the primary and secondary systems.

Operator action is not credited in the IOSGADVLOP safety analysis until thirty minutes following event initiation. At that time, it is assumed that plant operators will take action to manually close the ADV and to initiate a controlled plant cooldown to SDC entry conditions.

15.1.4.3 Core and System Performance

A moderate frequency IOSGADV event would result in an RCS cooldown that is similar to, but slower than, that caused by an increase in main steam flow event involving the quick opening of eight SBCS valves (see UFSAR Section 15.1.3). However, due to the more limiting MTC value chosen for this event, the reactor trip is delayed until the SGLPT occurs. The results of the IOSGADV are very close to the SBCS malfunction event, even though that event results in a greater increase in main steam flow and a faster RCS cooldown.

For the infrequent IOSGADVLOP event, the parameter of concern is likewise the minimum hot channel DNBR. Factors that would cause a decrease in DNBR include an increase in coolant temperature, a decrease in coolant pressure, an increase in local heat flux (including radial and axial power distribution effects), and a decrease in coolant flow rate. Evaluation of postulated single failures shows that the worst single failure for this event is a LOP following a turbine trip, which would cause the RCPs to coast down and rapidly reduce the coolant flow rate. This event results in a NSSS response that is similar to, that caused by the increase in main steam flow event involving the quick opening of eight SBCS valves in combination with LOP (See UFSAR Section 15.1.3). However, even though the quick opening of eight SBCS valves results in more severe RCS cooldown and higher increase in power, the IOSGADVLOP event results in a more limiting minimum hot channel DNBR than other infrequent events involving an increase in heat

removal. For this reason, the infrequent IOSGADV event (in combination with a single failure) bounds the infrequent event involving the quick opening of eight SBCS valves (in combination with single failure) with respect to the DNBR SAFDL.

15.1.4.3.1 Mathematical Model

The limiting infrequent event involving an increase in heat removal by the secondary system – an IOSGADVLOP – was analyzed with respect to RCS pressure boundary performance with the following mathematical models:

- The CENTS computer code was used to simulate the NSSS response, including the predicted time of reactor trip due to low steam generator pressure. The CENTS computer code is described in UFSAR Section 15.0.3.1.3.2 and in an NSSS vendor topical report.[1][2]

- The CETOP-D computer code, which uses the CE-1 CHF correlation, was used to determine the initial DNBR POL conditions for this event (see UFSAR Section 15.1.4.4.2 below). The CETOP-D computer code is described in UFSAR Section 4.4 and in NSSS vendor topical reports.[5][6][7]

15.1.4.3.2 Input Parameters and Initial Conditions

Table 15.1.4-2 and 15.1.4-3 summarizes the key input parameters and initial conditions utilized in the safety analysis for an IOSGADV and IOSGADVLOP event. The following points serve to

explain the selection of initial conditions as they appear in Table 15.1.4-2:

- During normal power operations, the Core Operating Limits Supervisory System (COLSS) monitors various parameters to assist operators in maintaining plant conditions within the Technical Specification LCOs. When COLSS is in-service, it continuously calculates the core power at which the DNBR SAFDL would be reached, based on the measured temperature, pressure, flow, radial peaking factor, and axial power distribution. This COLSS-calculated core power is then divided by a numerical value, called the Required Overpower Margin (ROPM), to yield a DNBR Power Operating Limit (POL). If the measured core power exceeds the calculated POL, a COLSS alarm would alert plant operators to take action as required by Technical Specifications. The DNBR POL therefore serves to preserve thermal margin to accommodate potential operational transients. For this safety analysis, it was assumed that the plant would be operating at a POL condition immediately prior to the event, at the most limiting RCS flow rate. Because the event simulation was initiated from a calculated POL, additional power measurement uncertainties were not added to the initial assumed core power level. Analytical values for the initial core inlet temperature, pressurizer pressure, and RCS coolant flow rate corresponding to the POL were determined with the CETOP-D computer code, for an initial core power of 100% of RTP.

Table 15.1.4-2
INPUT PARAMETERS AND INITIAL CONDITIONS FOR THE
IOSGADV SAFETY ANALYSIS

Parameter	Value
Initial Core Power (% of RTP)	100%
Initial Core Inlet Temperature (°F)	566
Initial Pressurizer Pressure (psia)	2100
Initial RCS Flow Rate (% of Design Rated)	110.4
Initial Pressurizer Water Level (% Narrow Range)	24
Initial Steam Generator Water Level (% Wide Range)	86
Moderator Temperature Coefficient ($\Delta\rho$/°F)	$-0.20\text{x}10^{-4}$
Doppler Fuel Temperature Coefficient	Least Negative
Delayed Neutron Kinetics	BOC
Axial Shape Index for DNBR Calculation	-0.2
CEA Worth at Trip (%$\Delta\rho$)	8.0
Fuel Rod Gap Conductance (BTU/hr-ft^2-°F)	6100
Total Number of Plugged Steam Generator Tubes	0
Single Failure	None

INCREASE IN HEAT REMOVAL

BY THE SECONDARY SYSTEM

Table 15.1.4-3
INPUT PARAMETERS AND INITIAL CONDITIONS FOR THE
IOSGADV SAFETY ANALYSIS

Parameter	Value
Initial Core Power (% of RTP)	100%
Initial Core Inlet Temperature (°F)	566
Initial Pressurizer Pressure (psia)	2100
Initial RCS Flow Rate (% of Design Rated)	110.4
Initial Pressurizer Water Level (% Narrow Range)	24
Initial Steam Generator Water Level (% Wide Range)	86
Moderator Temperature Coefficient ($\Delta\rho$/°F)	-0.40×10^{-4}
Doppler Fuel Temperature Coefficient	Least Negative
Delayed Neutron Kinetics	BOC
Axial Shape Index for DNBR Calculation	-0.2
CEA Worth at Trip (%$\Delta\rho$)	8.0
Fuel Rod Gap Conductance (BTU/hr-ft^2-°F)	662
Total Number of Plugged Steam Generator Tubes	0
Single Failure	LOP

- Parametric evaluation determined that the DNBR degradation during the event is sensitive to the initial pressurizer water level, and the minimum pressurizer water level was used.

- Parametric evaluation determined that the DNBR degradation during the event is sensitive to the initial steam generator water level, and the maximum initial steam generator water level was used. The CENTS code automatically calculates the initial steam generator pressure, given steam generator water level, reactor power, and other inputs to the computer code.

- The IOSGADVLOP event causes a slower cooldown of the RCS than the SBCS malfunction, but the LOP portion of the event causes a heatup of coolant in the core region as the flow rate decreases during RCP coastdown. Using the most negative MTC allowed by the Technical Specifications and COLR would result in the most rapid power increase and the greatest overshoot in power after the VOPT. However, because the heat flux lags behind the power, it does not necessarily produce the greatest decrease in DNBR. As the MTC is made less negative, the power excursion is slowed down. This allows the heat flux to stay close to the power and it allows the VOPT to shift upwards a small amount. The heat flux at the time of minimum DNBR increases for this event as the MTC is made less negative and the DNBR decreases. As the MTC is made less and less negative, a point is reached at which the

LSGPT and the VOPT are reached concurrently. This MTC results in the lowest minimum DNBR.

- The least negative Doppler fuel temperature coefficient curve, at BOC, was assumed. Least negative values minimize the addition of negative reactivity caused by increasing fuel temperature.

- BOC values were chosen to model delayed neutron kinetics, based on the parametric study described above.

- If power generation in the core is shifted toward the bottom, the insertion of negative reactivity following reactor trip will be somewhat delayed until the CEAs have inserted farther into the core. The scram reactivity curve was therefore based on a positive ASI representing a bottom-peaked core. The time versus scram reactivity curve was adjusted to account for a 0.6-second CEA holding coil time delay following opening of the reactor trip breakers, and normalized to model 90% CEA insertion at 4.0 seconds after power is removed from CEDM coils (see UFSAR Section 3.9.4). However, for DNBR calculations, having power at the top of the core would be more limiting and the ASI for the DNBR calculations was based on a negative ASI.

- The CEA worth at trip represents the minimum scram worth for HFP conditions at BOC, assuming the most reactive CEA remains stuck out of the core following reactor trip. This is more limiting (less negative) than the

anticipated scram reactivity worth at other times during the operating cycle for HFP conditions.

- For the fuel rod gas gap conductance, a high value was selected for IOSGADV and a low value was selected for IOSGADVLOP, based on the parametric study described above.
- It was assumed that steam generator tubes were not plugged for this safety analysis, based on the parametric study described above.
- For the limiting infrequent event analysis, an additional single failure involving a LOP was assumed.

For those safety-related Reactor Protective System (RPS) and Engineered Safety Features Actuation System (ESFAS) setpoints and response times that had a direct effect on acceptance criteria for this event, analytical values were chosen to be consistent with, or conservative with respect to, limiting numerical values that appear in the PVNGS Technical Specifications and UFSAR Chapter 7.

15.1.4.3.3 Results

The moderate frequency IOSGADV and infrequent IOSGADVLOP events would not challenge fuel pellet integrity. During these events, any short-term increase in reactor power, or three-dimensional shift in power generation within the core, would not be of sufficient magnitude to raise the linear heat rate above that required to cause fuel centerline melting.

The analysis shows that the calculated minimum DNBR for the IOSGADV event approaches a value of 1.40 at 138 seconds following event initiation. This value is greater than the DNBR SAFDL of 1.34.

For the infrequent IOSGADVLOP event (i.e., an IOSGADV event with an additional single failure), limited fuel cladding degradation may occur. However, offsite radiological dose consequences will not exceed a small fraction, or 10%, of 10 CFR Part 100 guideline values. Likewise, control room dose consequences will not exceed the limits specified by GDC 19 of 10 CFR 50 Appendix A.

15.1.4.4 RCS Pressure Boundary Barrier Performance

The IOSGADV and IOSGADVLOP events, like the SBCS malfunction event described in UFSAR Section 15.1.3, are characterized by an initial cooldown of the primary and secondary systems, and decreasing RCS and steam generator pressures. However, because the affected steam generator would dry out even following an MSIS, heat removal after an IOSGADV or IOSGADVLOP event must be accomplished through only one intact steam generator, at least until plant operators take action to close the open ADV on the affected steam generator. Therefore, unlike the SBCS malfunction event, heat removal may not be sufficient to prevent repressurization of the RCS and the unaffected steam generators. For this reason, the IOSGADV is the limiting moderate frequency (and limiting infrequent, when combined with single failure) event involving an increase in heat removal by

the secondary system with respect to RCS pressure boundary performance.

The performance of the RCS pressure boundary is evaluated herein for the limiting infrequent event involving an increase in heat removal by the secondary system with a single failure, an IOSGADVLOP. The conclusions, however, also apply to the moderate frequency IOSGADV event, because peak pressures in the RCS and secondary systems are limited by PSV and MSSV setpoints and capacities, respectively.

15.1.4.4.1 Mathematical Model

The mathematical model is the same as described in Section 15.1.4.3.1.

15.1.4.4.2 Input Parameters and Initial Conditions

The input parameters and initial conditions are the same as described in Section 15.1.4.3.2.

15.1.4.4.3 Results

The IOSGADVLOP safety analysis shows that pressurizer pressure may increase to the maximum PSV lift setting allowed by the Technical Specifications around the end of the 30-minute simulation. Immediately prior to the PSV lift the peak RCS pressure is calculated to be less than 2560 psia, for both RTPs which is below the regulatory limit for this event (i.e., 110% of the RCS design pressure of 2500 psia, or 2750 psia).

The IOSGADVLOP safety analysis, like the SBCS malfunction analysis described in UFSAR Section 15.1.3, also shows that the peak secondary system pressure occurs when the first bank of MSSVs cycle open. The calculated peak secondary system pressure is less than 1305 psia, which is below the regulatory limit for this event (i.e., 110% of the steam generator shell side design pressure of 1270 psia, or 1397 psia).

Therefore, the peak RCS and secondary system pressures will not pose a challenge to the RCS pressure boundary, for the limiting moderate frequency and infrequent event, with respect to pressure limits, involving an increase in heat removal by the secondary system.

15.1.4.5 Containment Performance and Radiological Consequences

An inadvertent opening of a steam generator ADV in combination with an additional single failure (i.e., LOP following turbine trip) is classified as an infrequent event. Offsite radiological dose consequences are limited to a small fraction, or 10%, of 10 CFR Part 100 guideline values. Additionally, radiation exposures for control room personnel are subject to the limits specified in General Design Criterion (GDC) 19 of 10 CFR 50 Appendix A.

Control room radiological assessments for bounding unfiltered inleakage are presented in UFSAR Section 6.4.7. The results presented in that UFSAR section for a postulated Reactor Coolant Pump (RCP) sheared shaft event with a stuck open ADV bound the anticipated control room exposure for the IOSGADVLOP event. The RCP sheared shaft event is predicted to result in a

higher percentage of fuel failure than the IOSGADVLOP event which, in combination with a stuck open ADV, would result in a correspondingly higher control room dose than the IOSGADVLOP event.

The offsite radiological dose consequences associated with the infrequent IOSGADVLOP event are evaluated in the following UFSAR subsections.

15.1.4.5.1 Mathematical Models

For the offsite radiological dose assessment, activity in the RCS is calculated on the basis of the pre-event radioiodine and noble gas activity levels (which are limited by plant Technical Specifications), to which is added the anticipated post-event increase in activity levels due to fuel pin failures. The increase in activity levels due to fuel pin failures is dependent upon the radial peaking factor, which affects the radionuclide inventory in the fuel rod gas gap, as well as the fuel failure fraction, which defines the number of pins that are assumed to release radionuclides to the RCS coolant.

Once the activity level in the RCS is determined, the amount of activity carried over to the steam generators by primary-to-secondary leakage is calculated. All of the activity that is contained in or leaked to the affected steam generator within the first 30 minutes of the event is assumed to be released to the atmosphere. At 30 minutes, analytical credit is taken for plant operators closing the open ADV on the affected steam generator, thereby halting the release of radionuclides from that steam generator to the environment.

Activity that leaks into the unaffected steam generator is assumed to mix with that steam generator's secondary inventory. The level of activity in this generator will therefore increase as the event proceeds. After the operators close the ADV on the affected steam generator, they may begin a controlled cooldown using the unaffected steam generator. The activity released from the unaffected steam generator to the environment may then be determined, based on a steaming rate that will remove decay heat and successfully cool down the NSSS to SDC entry conditions.

Based on the activity releases, the thyroid and whole body doses at the Exclusion Area Boundary (EAB) and Low Population Zone (LPZ) are calculated as a function of the product of the radial peaking factor (Fr) and fuel failure fraction (FF). The production of Fr and FF that just corresponds to the acceptance limits, that is a small fraction (10%) of 10 CFR Part 100 guideline values, is calculated from this functional relationship. As long as this calculated product for a reload does not exceed the value corresponding to the acceptance limits, the calculated doses for that reload will not exceed the acceptance limits.

15.1.4.5.2 Input Parameters and Initial Conditions

Offsite radiological dose consequences associated with the IOSGADVLOP event were analyzed under the assumptions listed in Section 15.0.4 and the following conditions:

1. Isotope inventories were based on a core power level of 4070 MWt, or 102% of the RTP of 3990 MWt.

2. Based on Technical Specification limits, the initial assumed activity in the NSSS was:

   - RCS Dose Equivalent (DEQ) I-131: 1.0 μCi/gm
   - RCS Noble Gas(DEQ) Xe-133: 550 μCi/gm
   - Secondary System DEQ I-131: 0.10 μCi/gm

3. An RCS liquid mass of 555,000 lbm of water was used in the analysis, including 45,000 lbm of water in the pressurizer. Additionally, 4,500 lbm of steam was assumed to be in the pressurizer. Although the RCS may hold more mass, these values were selected to increase the iodine concentration following postulated fuel failures, which conservatively increases offsite dose consequences.Since the PSVs lift for this event, the dose calculation conservatively takes into account the activity released to containment, even though the Reactor Drain Tank is sized to remain intact from the PSV discharge.

4. A steam generator liquid mass of 160,600 lbm per steam generator was used in the analysis. Although the steam generators may hold more mass, this value was selected to increase the iodine concentration in the affected steam generators, which conservatively increases offsite dose consequences.

5. A primary-to-secondary leak rate of 0.5 gpm (720 gallons per day) per steam generator was assumed. This is consistent with the PVNGS Technical Specification 5.5.9.

6. It was assumed that 10% of the iodine and noble gas inventories in the fuel pins were resident in the fuel rod gas gap, and available for release upon clad rupture.

7. All of the activity in the fuel rod gas gap was assumed to be released to the RCS coolant upon fuel pin failure.

8. All of the iodines associated with leakage to the affected steam generator were assumed to be released to the environment i.e. with a decontamination factor of 1.0, until the open ADV was closed at 30 minutes into the event sequence. After 30 minutes, the affected steam generator did not contribute further to radiological releases, because all subsequent steaming associated with decay heat removal and controlled plant cooldown were assumed to occur through the unaffected steam generator.

9. Iodines associated with leakage to the unaffected steam generator are released to the environment during steaming with decontamination factor of 100 since the steam generator inventory, i.e. level, is maintained.

10. It was assumed that plant operators would not initiate a controlled plant cooldown to SDC entry conditions for at least 30 minutes following event initiation. However, it should be noted that a faster RCS cooldown rate would

increase steam releases during the first two hours following the event, which would produce more severe thyroid doses at the EAB. On the other hand, a slower RCS cooldown rate would allow radionuclide concentrations to build up in the secondary system, which would produce more severe 8-hour doses at the LPZ. Therefore, radiological dose calculations were performed using two different cooldown rates:

- A maximum Technical Specification cooldown rate of 100°F/hr, initiated at 30 minutes into the event sequence.
- A slower cooldown rate of 40°F/hr, initiated at 30 minutes into the event sequence, which would bring the RCS to SDC entry conditions at approximately 8 hours following event initiation.

11. Decay heat during the 8-hour period following the event was based on the 1979 ANS decay heat curve, with a 2σ uncertainty. Use of a maximum decay heat curve increases the amount of steam released to the environment, thereby resulting in more severe dose consequences.

12. Although the LOP would cause the RCPs to coast down during an IOSGADVLOP event, it was conservatively assumed that all four RCPs would remain in operation for the radiological dose analysis. Therefore, 26 MWt of RCP heat was added to the 2-hour EAB and 8-hour LPZ dose

calculations, which conservatively increased steam releases and offsite doses during the controlled cooldown.

13. A value of 740,000 BTU/°F was used to represent the specific heat capacity of the RCS, the RCS clad, and the steam generators. Use of this value increases the amount of steam that must be released to the environment during the controlled cooldown.

14. The χ/Q atmospheric dispersion factors used in the analysis are the short-term factors shown in UFSAR Table 2.3-31.

15. Although the results of the transient simulation of IOSGADVLOP shows the DNBR remained above SAFDL and thus no fuel pin failures occurred, the radiological dose analysis conservatively assumes a fuel failure fraction of 5.5%.

16. A radial peaking factor of 1.72, corresponding to the maximum allowable radial peaking factors for PVNGS cores, was used in the analysis.

15.1.4.5.3 Results

An IOSGADV in combination with an additional single failure (a LOP following turbine trip) is classified as an infrequent event, which may result in limited fuel cladding degradation. Offsite radiological dose consequences are limited to a small fraction or 10%, of 10 CFR Part 100 guideline values. Therefore the radiological limits for the limiting infrequent increase in heat removal by the secondary system event, IOSGADVLOP are 30 Rem for the thyroid and 2.5 Rem for the whole body. Additionally, radiation exposures for control room personnel are subject to the limits specified in GDC 19 of 10 CFR 50 Appendix A.

The radiological dose analysis conservatively assumed 5.5% fuel failure in the bounding analysis for dose consequences. The results of the IOSGADVLOP radiological dose analysis for this assumed percentage of failed fuel are shown in Table 15.1.4-4.

Table 15.1.4-4
OFFSITE RADIOLOGICAL DOSES FOR IOSGADVLOP SAFETY ANALYSES

Thyroid Dose (REM)		Whole Body Dose (REM)	
0-2 Hour EAD	0-8 Hour LPZ	0-2 Hour EAB	0-8 Hour LPZ
25.1	12.6	0.7	0.7

The dose consequences remain below the acceptance criteria for the IOSGADVLOP event.

15.1.4.6 Conclusion

Evaluation of the IOSGADV event shows that:

- Pressure in the RCS will be maintained below 110% of its design value (i.e., 110% of 2500 psia, or 2750 psia).
- Pressure in the main steam system will be maintained below 110% of the steam generator shell side design value (i.e., 110% of 1270 psia, or 1397 psia).
- For the moderate frequency IOSGADV event (without an additional single failure), fuel cladding integrity will be maintained.
- For the infrequent IOSGADVLOP event (i.e., an IOSGADV event with an additional single failure), limited fuel cladding degradation may occur. However, offsite radiological dose consequences will not exceed a small fraction, or 10%, of 10 CFR Part 100 guideline values. Likewise, control room dose consequences will not exceed the limits specified by GDC 19 of 10 CFR 50 Appendix A.

15.1.5 STEAM SYSTEM PIPING FAILURES INSIDE AND OUTSIDE CONTAINMENT – OPERATING MODES 1 AND 2

15.1.5.1 Identification of Causes and Frequency Classification

A Main Steam Line Break (MSLB) is a postulated break or rupture of a pipe in the main steam system, either inside or outside the containment building.

A MSLB is classified as a limiting fault. Protection by design is therefore provided for MSLBs, up to and including the complete severance of a Seismic Category I main steam line upstream of the containment isolation valves (i.e., Main Steam Isolation Valves).

15.1.5.2 Sequence of Events and System Operation

A MSLB is characterized as a cooldown event, because the blowdown of main steam through a pipe break would result in excessive energy removal from the NSSS and a power-to-load mismatch. Additionally, if the MSLB occurred upstream of a Main Steam Isolation Valve (MSIV), the affected steam generator would continue to blow down and dry out following a Main Steam Isolation Signal (MSIS). Long-term controlled heat removal must then be accomplished through the remaining unaffected steam generator.

The largest possible MSLB is a double-ended guillotine rupture of a main steam line upstream of an MSIV. The PVNGS steam lines, however, have integral venturi flow restrictors installed in the outlet nozzles of both steam generators. The maximum steam blowdown rate is therefore limited by the cross-sectional throat area of each flow restrictor, which is approximately 1.283 ft^2.

Two types of analyses are performed for postulated MSLBs that may occur during operating Modes 1 (Power Operation) and 2 (Startup). MSLBs are analyzed for that portion of the accident immediately prior to and during reactor trip, when CEAs begin

to fall into the core (henceforth referred to as the "pre-trip" phase), as well as for that portion of the accident following CEA insertion, when continued cooldown of the NSSS causes moderator density to increase and the reactor again approaches criticality (henceforth referred to as the "post-trip" phase). There is a greater potential for fuel damage during the pre-trip phase of a MSLB than during the post-trip phase, because post-trip fission power levels are sufficiently low to prevent a significant degradation in fuel performance. For this reason, the pre-trip analyses are performed for limiting Hot Full Power (HFP) initial conditions. The post-trip analyses, however, are performed for both HFP and Hot Zero Power (HZP) initial conditions, to assess the potential for fuel damage as a result of a Return-to-Power (R-t-P) following postulated MSLBs inside containment.

The PVNGS MSLB analyses therefore cover a wide range of initial conditions in Modes 1 and 2. These analyses, which are described in further detail below, are as follows:

A. Pre-trip analyses that maximize the potential for a short-term power excursion, a decrease in the hot channel minimum DNBR value, and radiological consequences:

   1. SLB Case – A MSLB outside containment at HFP, in combination with a stuck CEA and with offsite power available. Credit is taken for a Core Protection Calculator (CPC) auxiliary trip, the Variable Over Power Trip (VOPT). There are no credible single

failures that might occur during the pre-trip phase of the accident to enhance the power excursion or degrade thermal margin.

2. SLBLOP Case – A MSLB outside containment at HFP, in combination with a stuck CEA and a coincident Loss of Offsite Power (LOP). Credit is taken for a low RCP shaft speed trip. There are no credible single failures that might occur during the pre-trip phase of the accident to enhance the power excursion or degrade thermal margin.

B. Post-trip analyses that maximize the potential for a R-t-P:

1. SLBFP Case – A MSLB inside containment at HFP with offsite power available, in combination with a stuck CEA and a single failure of a High Pressure Safety Injection (HPSI) pump. Credit is taken for a CPC VOPT.

2. SLBFPLOP Case – A MSLB inside containment at HFP with a coincident LOP, in combination with a stuck CEA and a single failure of a HPSI pump. Credit is taken for a low RCP shaft speed trip.

3. SLBZP Case – A MSLB inside containment at HZP with offsite power available, in combination with a stuck CEA and a single failure of a HPSI pump. Credit is taken for a CPC VOPT.

4. SLBZPLOP Case – A MSLB inside containment at HZP with a coincident LOP, in combination with a stuck CEA and a single failure of a HPSI pump. Credit is taken for a low RCP shaft speed trip.

Detailed analysis of the two pre-trip cases reveals that the SLB case is the limiting pre-trip MSLB safety analysis for PVNGS. This case yields the highest peak power excursion and the lowest hot channel minimum DNBR value, before the CEAs have completed their fall into the reactor core. Likewise, detailed analysis of the four post-trip cases reveals that the SLBFPLOP case is the limiting post-trip MSLB safety analysis for PVNGS. Of the four post-trip cases, the SLBFPLOP yields both the highest post-trip reactivity value and the highest post-trip fission power.

Table 15.1.5-1

SEQUENCE OF EVENTS FOR THE
LIMITING PRE-TRIP MSLB SAFETY ANALYSIS (SLB CASE)

Time (seconds) RTP 3990 MWt	Event
0.00	Double-ended guillotine MSLB (SG#1)occurs outside containment
3.62	CPC VOPT setpoint reached
4.37	Reactor trip breakers open
4.37	Turbine trip occurs
4.98	CEAs begin to fall
5.03	Steam generator level reaches MSIS setpoint
5.37	Peak power occurs
6.00	Hot channel minimum DNBR occurs

The sequences of events for the limiting SLB (pre-trip) and SLBFPLOP (post-trip) cases are provided in Tables 15.1.5-1 and 15.1.5-2, respectively. These sequences were obtained by simulating the MSLB events with the computer codes identified in UFSAR Section 15.1.5.3.

Because the sequence of events and timing for the pre-trip SLB case is very similar to that provided in UFSAR Section 15.1.3 for the SBCS malfunction safety analysis, figures that depict the short-term response of key NSSS parameters are not provided here for the SLB analysis. However, Figures 15.1.5-1 through 15.1.5-14 are provided to depict the NSSS response for the longer-term SLBFPLOP post-trip analysis.

Like the SBCS malfunction and IOSGADV events, a MSLB causes the main steam flow rate to rapidly increase (Figure 15.1.5-1), which results in a power-to-load mismatch and a decrease in RCS temperature (Figure 15.1.5-2). In the presence of a negative MTC, the decrease in RCS temperature results in a short-term increase in reactivity (Figure 15.1.5-3), core power (Figure 15.1.5-4), and core heat flux (Figure 15.1.5-5). The rapid cooldown will also result in an initial decrease in RCS pressure (Figure 15.1.5-6). Blowdown of the affected steam generator results in an initial decrease in steam generator pressures and levels (Figure 15.1.5-7 and 15.1.5-8, respectively) although a very short-term increase in the indicated steam generator water level due to swell effects is also anticipated (Figure 15.1.5-8) which may trigger a MSIS on high steam generator level. Upon MSIS, the MSIVs would close,

halting the steam release from the unaffected steam generator. As a consequence, decrease in the pressure and inventory of the unaffected steam generator could stop, while the affected steam generator pressure and level continue to decrease.

Table 15.1.5-2
SEQUENCE OF EVENTS FOR THE
LIMITING POST-TRIP MSLB SAFETY ANALYSIS (SLBFPLOP CASE)

Time (seconds)	Event
0.00	Double-ended guillotine MSLB (SG #1) occurs inside containment
0.00	LOP occurs
0.00	RCPs begin to coast down
0.00	SG level reaches MSIS setpoint and FWIVs close
0.65	RCP shaft speed reaches CPC auxiliary trip setpoint
0.95	Reactor trip breakers open
1.55	CEAs begin to fall
5.62	MSIVs closed. Steam flow from steam generator No. 2 halted
13.72	SG Differential Pressure AFW Lockout occurs
19.80	AFW actuation and delivery to SG #2
69.97	SIAS occurs due to low pressurizer pressure
79.05	Pressurizer empties
88.23	Void begins to form in reactor vessel upper head
89.97	One HPSI pump begins injecting into the RCS
171.53	Safety injection boron reaches RCS cold legs
251.01	AFAS cutoff setpoint is reached in SG #2 and AFW flow is terminated
295.41	Maximum post-trip reactivity occurs
341.01	Time of Maximum Return to Power
341.41	MacBeth minimum DNBR occurs
360.81	Steam generator No. 1 dries out
1800	Plant operators take control of the plant

Detection of a MSLB may be accomplished by a high reactor power alarm, an RCS or steam generator low pressure alarm, recognition of a power-to-load mismatch, or a high containment pressure alarm (if the MSLB occurs inside containment).

The PVNGS MSLB safety analyses credit the CPC VOPT or the RPS Low SG Pressure Trip for the case when offsite power is available (e.g., SLB case), and a CPC low RCP shaft speed trip when a coincident LOP is postulated to occur (e.g., SLBFPLOP case). For the limiting post-trip SLBFPLOP case, the coolant flow rate through the RCS would decrease rapidly following the LOP, as the RCPs coast down and the RCS transitions from forced flow to natural circulation conditions (Figure 15.1.5-9).

As explained in UFSAR Section 15.1.5.3 below, assessment of fuel performance degradation differs between the pre-trip and post-trip MSLB safety analyses. For pre-trip cases, consideration is given to the short-term increase in core heat flux and decrease in RCS pressure, which would effectively reduce coolant subcooling and thereby cause the hot channel DNBR to decrease. Also, for pre-trip analyses, the minimum DNBR is predicted to occur as CEAs are falling into the reactor core during the reactor trip. For these pre-trip cases, the minimum DNBR which is computed using the CE-1 Critical Heat Flux (CHF) correlation is compared to the DNBR SAFDL which is based on a statistical combination of uncertainties methodology (see UFSAR Section 4.4.2.2). Table 15.1.5-1 shows that the hot channel minimum DNBR occurs very early in the limiting SLB event sequence.

For post-trip analyses, however, fuel degradation cannot be assessed in the same manner, because the applicable range of the CE-1 CHF correlation does not extend to the low RCS flow rates and low pressures that may occur following a reactor trip. Therefore, as explained in UFSAR Section 15.1.5.3, post-trip analyses utilize the Macbeth[17][18] CHF correlation to calculate a minimum DNBR value that occurs well after the CEAs have reached the bottom of the core. Table 15.1.5-2 and Figure 15.1.5-14 show that the Macbeth minimum DNBR occurs several minutes into the SLBFPLOP event sequence. Unlike DNBR values calculated with the CE-1 CHF correlation, Macbeth DNBR values are compared to a deterministic limit of 1.30 rather than a statistical one.

Although a coincident LOP and loss of forced flow through the RCS may result in higher coolant temperatures in the vicinity of the core, overall the RCS would still continue to cool down while the faulted steam generator dried out. This cooldown would increase RCS coolant density, causing the pressurizer to temporarily empty (Figure 15.1.5-10) and a void to form in the reactor vessel upper head (Figure 15.1.5-11). Pressurizer pressure would eventually decrease to the SIAS setpoint, actuating the safety injection pumps. Even if one HPSI pump failed to start on demand, sufficient safety injection flow would still be delivered to the RCS after the RCS pressure decreased below the shutoff head of the remaining operable HPSI pump (Figure 15.1.5-12). Safety injection flow into the RCS would serve not only to repressurize the system and provide inventory control, but would also deliver soluble boron that

would add negative reactivity and slow down an approach to criticality or R-t-P.

Low pressure in the affected steam generator would eventually result in an MSIS and closure of the MFIVs, stopping the flow of main feedwater to both steam generators (Figure 15.1.5-13), and in closure of the MSIVs, thereby halting the flow of steam from the unaffected steam generator, which serves to maintain secondary system inventory.

Table 15.1.5-2 indicates that MSIS occurs at time = 0.0 in the event. This is due to the choice of initial steam generator water level. Since the MSIS occurs at time = 0.0, the unaffected SG is isolated from the break and pressurizes to the MSSV setpoints early in the transient. The lockout function prevents the addition of feedwater to the affected steam generator, and thus an unwanted loss of AFW inventory to the environment through the affected steam generator. However, due to the conservative choice of AFAS setpoint, AFAS is actuated in the unaffected SG. AFW continues to supply the unaffected steam generator as needed during the transient. Following dryout of the affected steam generator, decay heat from fission products in the core, and heat released by the hot metal structures of the NSSS, would raise temperatures and repressurize both the RCS and the intact steam generator. However, due to the additional cooling provided by the auxiliary feedwater, neither the main steam system or reactor coolant system pressure boundaries are challenged later in the event sequence.

Operator action is not credited in the MSLB safety analyses until 30 minutes following event initiation. At that time, it is assumed that plant operators will take action to initiate a controlled plant cooldown to SDC entry conditions, for example by manually establishing AFW flow and a steaming path through the ADVs associated with the unaffected steam generator.

15.1.5.3 Core and System Performance

Because MSLBs result in rapid reactivity insertions and power excursions, they are evaluated with respect to degradation in fuel performance, and the potential for post-trip criticality or R-t-P.

For pre-trip MSLB safety analyses, initial conditions are chosen to obtain the most adverse power excursion and fuel performance degradation. Because the hot channel minimum DNBR value provides a measure of fuel performance degradation, pre-trip analyses consider those parameters and conditions that would cause the greatest decrease in the local or hot channel DNBR, such as an increase in local heat flux, an increase in reactor coolant temperature, a decrease in reactor coolant flow rate, and a decrease in reactor coolant pressure.

Likewise, for post-trip MSLB safety analyses, initial conditions are chosen to maximize the potential for a R-t-P, as measured by the maximum post-trip reactivity value, the timing of the reactivity insertion, the duration of the reactivity peak, and the maximum post-trip fission power which then translated into minimum local or hot channel DNBR.

15.1.5.3.1 Mathematical Models

15.1.5.3.1.1 Pre-Trip Safety Analyses

The PVNGS pre-trip MSLB safety analyses utilized the following mathematical models:

- The CENTS computer code was used to simulate the NSSS transient response. The CENTS computer code is described in UFSAR Section 15.0.3.1.3.2 and in an NSSS vendor topical report.(1)(2)

- The FORTRAN CPC computer code was used to simulate CPC reactor trip functions. Predicted times for reactor trips, with appropriate delays for signal processing and opening of the reactor trip breakers, were utilized in CENTS code input. The CPCs are described in UFSAR Section 7.2, and associated algorithms and simulation code are described in NSSS vendor topical reports.(3)(4)

- The CETOP-D computer code, which uses the CE-1 CHF correlation, was used to calculate initial and transient DNBR values. CETOP-D was also used to determine initial Power Operating Limit (POL) conditions. The CETOP-D computer code is described in UFSAR Section 4.4 and in NSSS vendor topical reports.(5)(6)(7)

- The TORC computer code, which uses the CE-1 CHF correlation, was used to calculate the minimum DNBR value at the time of minimum DNBR predicted by the CETOP-D code, if CETOP-D predicted a minimum DNBR value below the DNBR

SAFDL. Because the models in the CETOP-D code are not as detailed as those in TORC, DNBR predictions from CETOP-D are typically adjusted by penalty factors to ensure conservatism. Use of the more detailed TORC computer code reduces the need for penalty factors and provides a more accurate prediction of the DNBR value than the CETOP-D code. The TORC computer code is described in UFSAR Section 4.4 and in NSSS vendor topical reports.(10)(11)

15.1.5.3.1.2 Post-Trip Safety Analyses

The PVNGS post-trip MSLB safety analyses utilized the following mathematical models:

- The CENTS computer code was used to simulate the NSSS transient response. The CENTS computer code is described in UFSAR Section 15.0.3.1.3.2 and in an NSSS vendor topical report.(1)(2)

- The FORTRAN CPC computer code was used to simulate CPC reactor trip functions. The CPCs are described in UFSAR Section 7.2, and associated algorithms and simulation code are described in NSSS vendor topical reports.(3)(4)

- As noted above, the determination of DNBR for post-trip MSLB analyses requires methods that differ from those used for pre-trip analyses. This is because the verified range of the CE-1 CHF correlation, which is used in the CETOP-D and TORC computer codes, does not extend to lowpressures and low flow rates that may exist in the RCS following a

reactor trip. Therefore, the Macbeth correlation[17][18] is utilized to ascertain the margin to DNB during the post-trip phase. The Macbeth correlation calculates the CHF as a function of mass flux, inlet subcooling, system pressure, heated diameter, and channel length. Use of a channel heat balance allows the correlation to be converted to a “local conditions” form, thereby allowing the CHF to be determined as a function of height in the hot channel. The effect of non-uniform axial heating may be incorporated by using the method applied by Lee in Reference 19. Because the CEA of greatest reactivity worth is assumed to remain out of the core following the reactor trip, the Macbeth DNBR calculations must account for the high localized power peak that may exist in the core post-trip. The post-trip analyses therefore utilize a maximum fission power dependent core peaking factor, F_Q, that is a function of both fission power and coolant flow rate through the core. F_Q values are therefore different for forced flow cases (i.e., offsite power available) than for cases in which the RCPs coast down (i.e., a LOP occurs). The Macbeth CHF correlation is also described in the CENTS computer code topical report.[1]

15.1.5.3.2 Input Parameters and Initial Conditions

15.1.5.3.2.1 Pre-Trip Safety Analyses

Table 15.1.5-3 summarizes the key input parameters and initial conditions utilized in the limiting pre-trip MSLB safety

analyses, SLB case, which were selected to obtain the most adverse power excursion and fuel performance degradation. The following points serve to explain the selection of initial conditions as they appear in Table 15.1.5-3:

- For the SLB case, a CPC VOPT auxiliary reactor trip was credited. The initial core power was set to 95% of RTP for this case, thereby allowing the VOPT setpoint to increase as core power rises early in the simulations. This causes a slight delay in the reactor trip and enhances the initial power excursion. Because the same ROPM value is used at power levels ≥ 95% of RTP, initial thermal margin to the DNBR SAFDL is the same at 95% power as at 100% power.

- A maximum core inlet temperature was selected because it maximizes the average temperatures in the RCS coolant loops. Maximizing the initial RCS average loop temperature tends to maximize the initial steam generator pressure, and hence maximizes the cooldown rate and reactivity insertion following a MSLB. The values in Table 15.1.5-3 include instrument uncertainty.

- The pre-trip analyses are not sensitive to the initial pressurizer pressure. Therefore, a nominal value was used.

- A maximum RCS flow rate was used in the CENTS code. CENTS code output was then passed to the CETOP-D code to perform transient DNBR calculations. CETOP-D DNBR calculations

were initiated from a Power Operating Limit (POL) corresponding to the maximum RCS flow rate.

- The pre-trip analyses are not sensitive to either the initial pressurizer or steam generator water levels. Therefore, nominal values were used.
- A MSLB causes a rapid cooldown of the RCS. Therefore, the most negative MTC allowed by the Technical Specifications and COLR was used to maximize the positive reactivity insertion caused by the cooldown.
- The least negative Doppler fuel temperature coefficient curve, at Beginning of Cycle (BOC), was conservatively assumed. Least negative values minimize the addition of negative reactivity caused by increasing fuel temperature. Therefore, the reactor core may achieve a higher peak power and heat flux during the initial RCS cooldown.
- End of Cycle (EOC) values were chosen to model delayed neutron kinetics. EOC values serve to emphasize the initial power excursion by minimizing the effect of delayed neutrons on the rate of power increase.

Table 15.1.5-3

INPUT PARAMETERS AND INITIAL CONDITIONS FOR THE LIMITING PRE-TRIP MAIN STEAM LINE BREAK (SLB CASE) SAFETY ANALYSES

Parameter	Assumed Value
	RTP 3990 MWt
Initial Core Power (% of RTP)	95
Initial Core Inlet Temperature (°F)	566
Initial Pressurizer Pressure (psia)	2250[a]
Initial RCS Flow Rate (% of Design Rated)	116
Initial Pressurizer Water Level (% Narrow Range)	52[a]
Initial Steam Generator Water Level (% Wide Range)	81[a]
Moderator Temperature Coefficient ($\Delta\rho$/°F)	-4.4×10^{-4}
Doppler Fuel Temperature Coefficient	BOC
Delayed Neutron Kinetics	EOC
Axial Shape Index for Scram Curve	+0.3
CEA Worth at Trip (%$\Delta\rho$)	-8.0
Fuel Rod Gap Conductance (BTU/hr-ft^2-°F)	6984
Number of Plugged Steam Generator Tubes (Total)	0
Break Size (ft^2)	1.283
Loss of Offsite Power	No

(a) Nominal range values are used since the event is not sensitive to these parameters.

- If power generation in the core is shifted toward the bottom, the insertion of negative reactivity during reactor trip will be delayed until the CEAs have inserted farther into the core. The scram reactivity curve was therefore based on a positive ASI representing a bottom-peaked core. The time versus scram reactivity curve was adjusted to account for a 0.6-second CEA holding coil time delay following opening of the reactor trip breakers, and normalized to model 90% CEA insertion at 4.0 seconds after power is removed from CEDM coils (see UFSAR Section 3.9.4).

- The CEA worth at trip represents the minimum scram worth for Hot Full Power (HFP) conditions at BOC, assuming the most reactive CEA remains stuck out of the core following reactor trip. This is more limiting (less negative) than the anticipated HFP scram reactivity worth at other times during the cycle, this is conservative.

- The fuel rod gas gap conductance value was selected so that energy from the fuel would quickly reach the surface of the fuel rod clad. This results in a higher heat flux which closely follows core power, and greater degradation of DNBR during the initial power excursion.

- It was assumed that steam generator tubes were not plugged for the pre-trip MSLB safety analyses. This enhances the initial rate of heat transfer from the RCS to the main steam system, which in turn enhances the initial RCS cooldown and maximizes the positive reactivity insertion

due to the negative MTC. Additionally, this enhances the decrease in RCS pressure during the cooldown, which serves to degrade DNBR.

- A large break size was assumed for the MSLB, with steam blowdown limited by the cross-sectional throat area of the flow restrictors in the outlet nozzles of both steam generators. A large break size maximizes the initial cooldown rate and resulting reactivity insertion.

- For the limiting case, a LOP was not assumed to occur, so the reactor trip would be delayed until the CPC VOPT auxiliary trip was received. There are no credible single failures (see UFSAR Table 15.0-0) that would serve to enhance the power excursion or degrade thermal margin during the first few seconds of the pre-trip MSLB simulations; therefore, an additional single failure was not postulated.

For those safety-related Reactor Protective System (RPS) and Engineered Safety Features Actuation System (ESFAS) setpoints and response times that had a direct effect on acceptance criteria for this event, analytical values were chosen to be consistent with, or conservative with respect to, limiting numerical values that appear in the PVNGS Technical Specifications and UFSAR Chapter 7.

15.1.5.3.2.2 Post-Trip Safety Analyses

Table 15.1.5-4 summarizes the key input parameters and initial conditions utilized in the PVNGS post-trip MSLB safety

analyses. Because degradation in fuel performance during the post-trip phase of a MSLB can only occur if there is a R-t-P, analytical values were selected to maximize the potential for an approach to criticality or a R-T-P. As noted above, the magnitude of a R-t-P is primarily determined by the maximum post-trip reactivity value, the timing of the reactivity insertion, and the duration of the reactivity peak.

The following points serve to explain the selection of initial conditions as they appear in Table 15.1.5-4:

- A maximum initial core power, including a 2% power measurement uncertainty, was selected for the HFP cases. Use of a maximum initial core power maximizes the initial core outlet temperature as well as the initial average temperature in the RCS coolant loops. Maximizing the initial core outlet temperature maximizes the initial energy stored in the water and metal of the upper head region of the reactor vessel, and also maximizes the saturation pressure of the liquid in this region. Following a MSLB, when RCS pressure falls below the saturation pressure of the liquid in the upper head region, this stored energy will help vaporize liquid and thereby slow the rate at which the RCS pressure decreases. Selecting the RCP Seal Leakage to be 0.0 gpm also slows the rate at which the RCS pressure decreases. This in turn tends to delay and reduce the rate of safety injection, which minimizes the negative reactivity due to boron at the time of R-t-P. Furthermore, maximizing the

initial average temperature of the RCS coolant loops maximizes the initial steam generator pressure, which maximizes the blowdown and rate of energy removal following a MSLB. Increasing the rate of energy removal likewise increases the RCS core inlet temperature cooldown rate which, in the presence of a negative MTC, enhances the positive reactivity insertion due to the cooldown. Maximizing the initial RCS average temperature also causes the cooldown to occur over a more adverse portion of the moderator reactivity function, i.e., the portion having the greatest rate of change of reactivity with temperature.

- Maximum initial core inlet temperatures were selected because they maximize the average temperatures in the RCS coolant loops. As explained above, maximizing the initial RCS average loop temperature tends to maximize the initial steam generator pressure, and hence maximizes the cooldown rate and reactivity insertion following a MSLB. The values shown in Table 15.1.5-4 reflect the maximum allowed RCS cold leg temperatures including instrument uncertainty.

- A high initial pressurizer pressure and pressurizer water level was selected. This increases transient RCS pressures, thereby delaying and impeding safety injection flow and the delivery of boron to the core region.

INCREASE IN HEAT REMOVAL

BY THE SECONDARY SYSTEM

Table 15.1.5-4

INPUT PARAMETERS AND INITIAL CONDITIONS FOR THE LIMITING POST-TRIP MAIN STEAM LINE BREAK (SLBFPLOP CASE) SAFETY ANALYSES

Parameter	Assumed Value
Initial Core Power (% of RTP)	102
Initial Core Inlet Temperature (°F)	566
Initial Pressurizer Pressure (psia)	2325
Initial RCS Flow Rate (% of Design Rated)	95
Initial Pressurizer Water Level (%)	60
Initial Steam Generator Water Level (% Narrow Range)	96
Auxiliary Feedwater Actuation Setpoint (% Wide Range)	82
Auxiliary Feedwater Cutoff Setpoint (% Wide Range)	99
Moderator Temperature Coefficient ($\Delta\rho$/°F)	$-4.4\text{x}10^{-4}$
Doppler Fuel Temperature Coefficient	EOC
Delayed Neutron Kinetics	BOC
Inverse Boron Worth (ppm/%$\Delta\rho$)	-130
Axial Shape Index for Scram Curve	+0.6
CEA Worth at Trip (%$\Delta\rho$)	-8.75
Fuel Rod Gap Conductance (BTU/hr-ft^2-°F)	656
Number of Plugged Steam Generator Tubes (Total)	2516
Break Size (ft^2)	1.283
Loss of Offsite Power	Yes
Additional Single Failure	One HPSI pump
RCP Seal Leakage (gpm)	0.0

- A minimum initial core flow rate maximizes the rate of core inlet temperature cooldown following a MSLB, which in turn maximizes the reactivity insertion in the presence of a negative MTC cooldown curve.

- A high initial steam generator water level corresponding to the high SG level alarm setpoint was selected for both steam generators based on parametric analysis. This increases the cooldown rate following a MSLB. However, it will also result in an MSIS at time = 0.0 and FWIV closure. In addition, the use of a high initial water level in the unaffected SG could prevent level from decreasing to the AFAS low level setpoint during the event.

- MTC has a significant effect on the potential for a R-t-P following a MSLB, due to the magnitude of the positive reactivity that results from the RCS cooldown. Therefore, the most negative MTC cooldown curve was used for this analysis, corresponding to End of Cycle (EOC) conditions. That is, because a loss of CEA reactivity worth may occur as the moderator becomes denser during the cooldown, reactivity is adjusted to account for the effects of changes in moderator density. Additionally, the moderator reactivity contribution to core power was based on cold-edge temperature, which is weighted to account for the colder water returning to the RCS from the faulted steam generator, rather than the core bulk or average temperature.

- An EOC (most negative) Doppler fuel temperature coefficients curve was used for the post-trip MSLB analyses. Use of a most negative curve adversely affects R-t-P by adding relatively more positive reactivity as the fuel goes from operating temperatures prior to the MSLB, to lower temperatures that occur during the post-MSLB cooldown.

- Relative to other parameters, the delayed neutron fraction has a minor effect on the potential for a R-t-P. Beginning of Cycle (BOC) values were conservatively chosen because they result in relatively more delayed neutrons, which delay the rate of decrease in core power post-trip. This in turn extends the duration of a reactivity peak or R-t-P if it occurs.

- A maximum value was selected for the inverse boron worth, to reduce the negative reactivity that is inserted as a result of boron injected by the Safety Injection (SI) system. A sweep-out volume of 60.6 cubic feet was used for the SI lines, representing the volume of water that must be displaced before safety injection boron reaches the primary system.

- The rate at which negative reactivity is added by CEAs during a reactor trip has little effect on the potential for a post-trip R-t-P. Therefore, the initial axial power distribution is of little importance for post-trip MSLB safety analyses. However, the axial power distribution that was selected was bottom-peaked to delay the full

effect of scram reactivity for as long as possible. Additionally, the time versus scram reactivity curve was adjusted to account for a 0.6-second CEA holding coil time delay following opening of the reactor trip breakers, and normalized to model 90% CEA insertion at 4.0 seconds after power is removed from CEDM coils (see UFSAR Section 3.9.4).

- The CEA worth at trip represents the minimum allowed scram worth at EOC, assuming the most reactive CEA remains stuck out of the core following the trip. The selection of EOC values is consistent with the selection of the MTC and Doppler values, i.e., they represent the same point in time in an operating cycle.

- The post-trip MSLB safety analyses utilized a fuel rod gas gap conductance value which results in a bounding core average effective fuel temperature at full power EOC conditions. A higher full power fuel temperature results in a larger reactivity addition as the core goes from HFP to HZP conditions, which results in a larger scram worth requirement to prevent return to power.

- It was assumed that steam generator tubes were plugged for the post-trip MSLB safety analyses. Although this would tend to reduce heat transfer from the RCS to the main steam system, which may reduce the initial RCS cooldown, a parametric evaluation showed that increased tube plugging has a more adverse effect during the post-trip phase. The initial RCS cooldown was maximized by conservatively

assuming that the full steam generator heat transfer area would be maintained throughout blowdown of the faulted steam generator, rather than decreasing as steam generator water mass decreased. The heat transfer area was ramped down to zero only after the mass of liquid in the steam generator decreased below 100 lbm. Tube plugging therefore had more of a direct effect on post-trip RCS temperatures and flow rates, especially under natural circulation conditions, which in turn affected post-trip DNBR values and the potential for a R-t-P.

- A large break size was assumed for each post-trip MSLB analysis, with steam blowdown limited by the cross-sectional throat area of the flow restrictors in the outlet nozzles of both steam generators. A large break size maximizes the initial cooldown rate and resulting reactivity insertion.

- For the limiting case, a LOP was assumed to occur coincident with the MSLB. This assumption results in an early RCP coastdown, which affects both the post-trip minimum DNBR value and the timing and magnitude of a R-t-P. Although a lower core flow rate tends to result in a smaller R-t-P, a lower flow rate has more of a direct effect on the minimum DNBR value than does the magnitude of the R-t-P. Therefore, a LOP coincident with a MSLB yields the greatest potential for degradation in post-trip fuel performance.

- For the post-trip MSLB analyses, an additional single failure involving the failure of a HPSI pump to start on demand was assumed (see UFSAR Table 15.0-0). This single failure served to reduce the capacity of the SI system to provide boron to the core region of the RCS, which increased the potential for a R-t-P. Other postulated singles failures, including a single failure of a Main Steam Isolation Valve (MSIV) to close, were determined to be less limiting than the single failure of a HPSI pump.

For those safety-related Reactor Protective System (RPS) and Engineered Safety Features Actuation System (ESFAS) setpoints and response times that had a direct effect on acceptance criteria for this event, analytical values were chosen to be consistent with, or conservative with respect to, limiting numerical values that appear in the PVNGS Technical Specifications and UFSAR Chapter 7.

15.1.5.3.3 Results

15.1.5.3.3.1 Pre-Trip Safety Analyses

The limiting pre-trip MSLB safety analysis, for a break that occurs outside containment without a coincident LOP (i.e., the SLB case), shows that core power reached a peak around 115% - 116% of RTP, shortly after the CEAs begin to fall into the core. However, during the event, the short-term excursion in reactor power would not be of sufficient magnitude to raise the linear heat rate above that required to cause fuel centerline melting.

The limiting pre-trip MSLB safety analysis also shows that the hot channel minimum DNBR (computed with the CE-1 CHF correlation and CETOP code) was calculated to be 1.33 for 3990 MWt RTP cores. Since CETOP DNBR values are conservative relative to TORC DNBR values, cycle specific Thermal Hydraulic calculations are performed to confirm that the calculated DNBR value remains above the SAFDL. These cycle specific calculations also ensure that the radiological dose consequences presented in Section 15.1.5.5 for this event remain bounding.

15.1.5.3.3.2 Post-Trip Safety Analyses

The results of the limiting post-trip MSLB core performance safety analyses (SLBFPLOP) are summarized in Table 15.1.5-5.

The SLBFP, SLBZP, and SLBZPLOP cases were determined to be non-limiting with respect to acceptance criteria for post-trip MSLB core performance analyses. That is, Macbeth minimum DNBR values during the low flow, low pressure post-trip phase did not decrease below a deterministic limit of 1.30; post-trip fission power steadily decreased; and the maximum post-trip reactivity achieved in each case indicated that the reactor remained shut down after the CEAs had fully inserted into the core.

For the limiting SLBFPLOP case, however, post-trip fission power and reactivity initially decreased, and then began to increase again as the moderator continued to cool down. The maximum fission power and reactivity occur before the affected

SG dries out. High pressure safety injection boron ensures that the reactor remains shut down and the minimum DNBR remains above the deterministic limit of 1.30 during the post-trip period.

The core linear heat rate during the post-trip phase is dependent upon the post-trip fission power, the decay heat released by radioactive isotopes in the core, and applicable peaking factors. For the limiting SLBFPLOP case, it was determined that the linear heat rate would remain well below that required to cause fuel centerline melting.

It is therefore concluded that fuel damage will not occur during the post-trip phase of a postulated MSLB.

Table 15.1.5-5

CORE PERFORMANCE SAFETY ANALYSIS RESULTS FOR THE LIMITING POST-TRIP MAIN STEAM LINE BREAK (SLBFPLOP CASE) SAFETY ANALYSES

Parameter	Results
Macbeth Minimum DNBR	2.42
Time of Macbeth Minimum DNBR (sec)	341
Maximum Post-Trip Fission Power (% RTP)	1.385×10^{-2}
Time of Maximum Post-Trip Fission Power (sec)	341
Maximum Post-Trip Reactivity (%$\Delta\rho$)	0.02036
Time of Maximum Post-Trip Reactivity (sec)	295

15.1.5.4 RCS Pressure Boundary Barrier Performance

Postulated MSLBs during Modes 1 (Power Operation) and 2 (Startup), like the SBCS malfunction and IOSGADVLOP events described in UFSAR Sections 15.1.3 and 15.1.4, respectively, are characterized by an initial cooldown of the primary and secondary systems, and decreasing RCS and steam generator pressures. Additionally, like an IOSGADVLOP event, the affected steam generator would not be completely secured following an MSIS if the MSLB occurs upstream of an MSIV. If this were to occur, the affected steam generator would eventually dry out, and long-term heat removal would have to be accomplished through the unaffected steam generator. Therefore, for a large MSLB upstream of an MSIV, long-term heat removal via the MSSVs may not be sufficient to prevent re-pressurization of the RCS to the lift setting of the PSVs (see UFSAR Section 15.1.4).

In addition to the long term repressurization, the RCS performance is investigated in the short-term for brittle fracture criterion because of low temperature and high pressure conditions that may occur simultaneously due to the rapid cooldown and the high pressure safety injection. This investigation merely consists of comparing the conditions observed during MSLB event with the low temperature overpressurization analyses detailed in UFSAR Chapter 5.

15.1.5.4.1 Mathematical Models

The mathematical models that were used to analyze the performance of the RCS pressure boundary are the same as those described in UFSAR Section 15.1.5.3.1.

15.1.5.4.2 Input Parameters and Initial Conditions

The key input parameters and initial conditions that were used to analyze the performance of the RCS pressure boundary are the same as those described in UFSAR Section 15.1.5.3.2.

15.1.5.4.3 Results

Figure 15.1.5.6 and 15.1.5.7 shows the RCS and SG pressure response for the limiting post-trip MSLB, a SLBFPLOP. Due to the early MSIS, the unaffected SG is isolated from the break. Heat up and pressurization occurs, but is turned around by the addition of AFW to the unaffected SG. Later in the event sequence after the AFW cutoff setpoint is reached, the unaffected SG begins to heat up and repressurize again. The peak secondary pressure is limited by the MSSV setpoints, which is below the acceptable design limit (i.e., 110% of the steam generator shell side design pressure of 1270 psia, or 1397 psia). Well before the end of the post-trip MSLB simulation, RCS pressure turns around and begins to increase as a result of safety injection flow, decay heat, and heat released from the hot metal structures that comprise the NSSS. Auxiliary feedwater addition and cooling by the intact SG helps keep the RCS pressure below the PSV setpoint of 2450 psia

during the 30 minute transient. Therefore, peak RCS pressure remains below the acceptable design limit for this event (i.e., 110% of the RCS design pressure of 2500 psia, or 2750 psia).

During a MSLB event, combination of low temperature and high pressure does not challenge the RCS integrity due to the brittle fracture since the combination of temperature and pressure remain well within the reactor vessel design that is evaluated in UFSAR Chapter 5. Therefore, the peak RCS and secondary system pressures that may occur following a MSLB in Modes 1 and 2 will be maintained within acceptable design limits.

15.1.5.5 Containment Performance and Radiological Consequences

A MSLB is classified as a limiting fault, for which radiological dose consequences are subject to various regulatory limits. Specifically, if fuel failure is postulated to occur, or if the MSLB is assumed to occur following an operational transient that has raised the RCS iodine concentration to the maximum value permitted by Technical Specifications (i.e., a Preaccident Iodine Spike, or PIS case), then offsite radiological doses must not exceed 10 CFR Part 100 guideline values. That is, 2-hour doses at the Exclusion Area Boundary (EAB) and 8-hour doses at the outer boundary of the Low Population Zone (LPZ) would be limited to a thyroid dose of 300 Rem and a whole body dose of 25 Rem. However, if the reactor trip or RCS depressurization following the MSLB is assumed to create an accident-Generated Iodine Spike (GIS) without fuel failure, then offsite dose consequences must not

exceed a small fraction, or 10%, of 10 CFR Part 100 guideline values. Finally, radiation exposures for control room personnel are subject to the limits specified in General Design Criterion (GDC) 19 of 10 CFR 50 Appendix A.

Control room radiological assessments for bounding unfiltered inleakage are presented in UFSAR Section 6.4.7. The limiting cases presented in that UFSAR section bound the anticipated control room exposures for postulated MSLB events. For example, the results presented therein for a Steam Generator Tube Rupture (SGTR) with a stuck open ADV bound a MSLB with a PIS or GIS iodine spike. Likewise, a MSLB that is limited to 1% fuel failure is bounded by the RCP sheared shaft event with a stuck open ADV, because the sheared shaft event results in a higher percentage of fuel damage.

The offsite radiological dose consequences associated with limiting fault MSLBs are evaluated in the following subsections.

15.1.5.5.1 Mathematical Models

The offsite radiological consequences of postulated MSLBs are evaluated for breaks that may occur outside the containment building.

Activity in the RCS is calculated on the basis of initial radioiodine and noble gas activity levels, which are limited by plant Technical Specifications, to which is added the increase in activity due to fuel failure or iodine spikes. For postulated fuel failure, the increase in RCS activity is

dependent upon the radial peaking factor, which affects the radionuclide inventory in the fuel rod gas gap, as well as the fuel failure fraction, which defines the number of pins that are assumed to release radionuclides to the RCS coolant. For PIS and GIS cases, the increase in RCS activity is determined by analytical iodine spiking factors.

Once the activity level in the RCS is determined, the amount of activity carried over to the secondary system by primary-to-secondary leakage is calculated. All of the activity that is contained in or leaked to the affected steam generator is assumed to be released to the environment.

Once primary and secondary activity releases to the environment are quantified, the thyroid and whole body doses at the EAB and LPZ are calculated.

15.1.5.5.2 Input Parameters and Initial Conditions

Offsite radiological dose consequences associated with MSLBs were analyzed under the assumptions listed in Section 15.0.4 and the following conditions:

1. Isotope inventories were based on a core power level of 4070 MWt, or 102% of the RTP of 3990 MWt.
2. Based on Technical Specification limits, the initial assumed activity in the NSSS was:
   - RCS Dose Equivalent (DEQ) I-131: 1.0 μCi/gm
   - RCS Noble Gas(DEQ) Xe-133: 550 μCi/gm

- Secondary System DEQ I-131: 0.10 μCi/gm

3. For PIS cases, the initial concentration of DEQ I-131 in the RCS was increased by a factor of 60. For GIS cases, an accident-generated spiking factor of 500 was used to compute the time-dependent RCS iodine concentration.

4. An RCS liquid mass of 555,000 lbm of water was used in the analysis, including 45,000 lbm of water in the pressurizer. Additionally, 4,500 lbm of steam was assumed to be in the pressurizer. Although the RCS may hold more mass, these values were selected to increase the iodine concentration following postulated fuel failures, which conservatively increases offsite dose consequences.

5. Since the PSVs may lift for this event, the dose calculation conservatively takes into account activity that might be released to containment, even though the Reactor Drain Tank is sized to remain intact from the PSV discharge.

6. Steam generator liquid masses ranging from 160,600 lbm of water (bounding low value for a transient) to 310,000 lbm of water (bounding high value for HZP) were considered in the analysis. This range of steam generator liquid masses bounds the masses that would occur during normal operation or during a transient. A minimum value of steam generator liquid mass tends to increase the releases for cases with fuel failures, thereby increasing offsite dose consequences. However, in cases without fuel failure, the releases from the affected steam generator have a much

larger contribution and a maximum steam generator, and a maximum liquid mass can increase the offsite dose consequences.

7. A primary-to-secondary leak rate of 0.5 gpm (720 gallons per day) per steam generator was assumed. This is consistent with the PVNGS Technical Specification 5.5.9 and conservative with respect to the current Technical Specification limit.

8. All of the iodines associated with the affected steam generator were assumed to be released to the environment, i.e., with a decontamination factor of 1.0.

9. Iodines associated with leakage to the unaffected steam generator are released to the environment during steaming with decontamination factor of 100 since the steam generator inventory, i.e. level, is maintained.

10. A radial peaking factor of 1.72 was used, which conservatively increased the radioisotope inventories that were predicted to reside in the fuel rods.

11. It was assumed that 10% of the iodine and noble gas inventories in the fuel pins were resident in the fuel rod gas gap, and available for release upon clad rupture.

12. All of the activity in the fuel rod gas gap was assumed to be released to the RCS coolant upon fuel pin failure which was assumed to be 1%.

13. It was assumed that plant operators would not initiate a plant cooldown to SDC entry conditions for at least

30 minutes following event initiation. However, it should be noted that a faster RCS cooldown rate would increase steam releases during the first two hours following the event, which would produce more severe thyroid doses at the EAB. On the other hand, a slower RCS cooldown rate would allow radionuclide concentrations to build up in the secondary system, which would produce more severe 8-hour doses at the LPZ. Therefore, radiological dose calculations were performed using two different cooldown rates:

- A maximum Technical Specifications cooldown rate of 100°F/hr, initiated at 30 minutes into the event sequence.
- A slower cooldown rate of 40°F/hr, initiated at 30 minutes into the event sequence, which would bring the RCS to SDC entry conditions at approximately 8 hours following event initiation.

14. Decay heat following the MSLB was based on the 1979 ANS decay heat curve, with a 2σ uncertainty. Use of a maximum decay heat curve increases the amount of steam released to the environment, thereby resulting in more severe dose consequences.

15. It was assumed that all four RCPs would remain in operation for the duration of the radiological dose analysis. Therefore, 26 MWt of RCP heat was included in the dose calculations, which conservatively increased

steam releases and offsite doses during the controlled cooldown.

16. A value of 740,000 BTU/°F was used to represent the specific heat capacity of the RCS, the RCS clad, and the steam generators. Use of this value increases the amount of steam that must be released to the environment during the controlled cooldown.

17. The χ/Q atmospheric dispersion factors used in the analysis are the short-term factors shown in UFSAR Table 2.3-31.

Table 15.1.5-8 shows that the offsite dose consequences of a MSLB outside containment with an accident-Generated Iodine Spike (GIS), will not exceed 10% of the 10 CFR Part 100 guideline values (i.e., 30 Rem thyroid and 2.5 Rem whole body). Likewise, a MSLB outside containment, with either a Preaccident Iodine Spike (PIS) or 1% fuel failure, will not exceed 10 CFR Part 100 guideline values (i.e., 300 Rem thyroid and 25 Rem whole body). The results shown in Table 15.1.5-6 are therefore in compliance with the regulatory guidelines for postulated MSLBs. These results bound the core power levels of 3990 MWt or less.

Because the potential for fuel failure is sufficiently limited (see UFSAR Section 15.1.5.3.3), it is also concluded that the core will remain in place and intact with no loss of core cooling capabilities.

15.1.5.5.3 Results

Table 15.1.5-6 presents the calculated offsite radiological dose consequences for postulated MSLBs outside containment.

Table 15.1.5-6

OFFSITE RADIOLOGICAL DOSES FOR MSLBs
OUTSIDE THE CONTAINMENT BUILDING

MSLB Case	Fuel Failure Fraction	Thyroid Dose (REM)		Whole Body Dose (REM)	
		0-2 Hour EAB	0-8 Hour LPZ	0-2 Hour EAB	0-8 Hour LPZ
PIS	0%	2.2	1.4	0.005	0.003
GIS	0%	2.5	5.2	0.02	0.04
Fuel Failure[a]	1%	17.7	19.4	0.24	0.24

a. Although fuel damage is not predicted to occur (see UFSAR Section 15.1.5.3.3) the analyses for potential radiological dose consequences assume that the maximum percentage of fuel pins allowed to fail for a MSLB with the break outside containment is 1%.

15.1.5.6 Conclusions

Evaluation of postulated MSLBs in plant operating Modes 1 (Power Operation) and 2 (Startup) shows that:

- Pressure in the RCS will be maintained below 110% of its design value (i.e., 110% of 2500 psia, or 2750 psia).
- Pressure in the main steam system will be maintained below 110% of the steam generator shell side design value (i.e., 110% of 1270 psia, or 1397 psia).
- If a MSLB results in an accident-Generated Iodine Spike (GIS), offsite radiological dose consequences will not exceed a small fraction, or 10%, of the 10 CFR Part 100 guideline values.

- If a MSLB results in 1% failed fuel, or if it occurs with a Preaccident Iodine Spike (PIS), offsite radiological dose consequences will not exceed 10 CFR Part 100 guideline values.
- Control room dose consequences following a MSLB will not exceed the limits specified by GDC 19 of 10 CFR 50 Appendix A.

15.1.6 STEAM SYSTEM PIPING FAILURES INSIDE AND OUTSIDE CONTAINMENT - OPERATING MODE 3

15.1.6.1 Identification of Causes and Frequency Classification

A Main Steam Line Break (MSLB) is a postulated break or rupture of a pipe in the main steam system, either inside or outside the containment building.

A MSLB is classified as a limiting fault. Protection by design is therefore provided for MSLBs, up to and including the complete severance of a Seismic Category I main steam line upstream of the containment isolation valves (i.e., Main Steam Isolation Valves).

15.1.6.2 Sequence of Events and System Operation

A MSLB is characterized as a cooldown event, because the blowdown of main steam through a pipe break would result in excessive energy removal from the NSSS and a power-to-load mismatch. Additionally, if the MSLB occurred upstream of a Main Steam Isolation Valve (MSIV), the affected steam generator would continue to blow down and dry out following a Main Steam

Isolation Signal (MSIS). Long-term controlled heat removal must then be accomplished through the remaining unaffected steam generator.

The largest possible MSLB that may occur is a double-ended guillotine rupture of a main steam line upstream of an MSIV. The PVNGS steam lines, however, have integral venturi flow restrictors installed in the steam generator outlet nozzles. The maximum steam blowdown rate is therefore limited by the cross-sectional throat area of a flow restrictor, which is approximately 1.283 ft^2.

Postulated MSLBs that may occur in operating Mode 3 (Hot Standby) are analyzed with respect to fuel performance, as well as to demonstrate the adequacy of shutdown margin requirements. There are four significant differences between the MSLB analyses performed for Modes 1 and 2 (see UFSAR Section 15.1.5) and those performed for Mode 3:

- In Mode 3, reactor trip breakers may be either open or closed at the time of event initiation, and CEAs may therefore be either inserted into or withdrawn from the core.
- In Mode 3, the reactor would be subcritical at the time of event initiation, with reactivity limited to a $k_{effective}$ that is less than 0.99.
- In Mode 3, RCS cold leg temperature at the time of event initiation would be in the range of approximately 350°F (the lower limit of Operating Mode 3) to 572°F.

- In Mode 3 with the initial RCS cold leg indicated temperature ≥ 485°F, Technical Specifications require that two trains of Emergency Core Cooling System (ECCS) be operable. Below 485°F, only one train of High Pressure Safety Injection (HPSI) is required to be operable. Application of the Single Failure Criterion therefore results in a total loss of safety injection capability for Mode 3 MSLB analysis initiated at lower cold leg temperatures.

Consequently, MSLB safety analysis was performed for a wide range of Mode 3 conditions. For the analysis, initial subcriticalities were determined on the basis of Temperature-Dependent Shutdown Margin (TDSDM) requirements discussed in UFSAR Section 15.1.6.3.3.

Samples of the Mode 3 MSLB analysis are as follows:

A. An inside containment break initiated at an RCS cold leg temperature of 572°F, with a coincident LOP.

B. An inside containment break initiated at an RCS cold leg temperature of 572°F, with offsite power available.

C. An inside containment break initiated at an RCS cold leg temperature of 572°F, with LOP and Steam Generator (SG) tube plugging.

D. An inside containment break initiated at an RCS indicated cold leg temperature of 500°F, with a coincident LOP.

E. An inside containment break initiated at an RCS indicated cold leg temperature of 485°F, with a coincident LOP and no HPSI pump available.

F. An inside containment break initiated at an RCS indicated cold leg temperature of 450°F, with a coincident LOP and no HPSI pump available.

G. An inside containment break initiated at an RCS indicated cold leg temperature of 350°F, with a coincident LOP and no HPSI pump available.

This safety analysis reveals that the case initiated at an RCS cold leg temperature of 572°F with a coincident LOP and SG tube plugging yields the maximum total reactivity, maximum core power fraction, and maximum heat flux fraction for a postulated Mode 3 MSLB. This case therefore also yields the lowest Macbeth DNBR and highest linear heat rate values, making it the limiting case with respect to the potential for fuel degradation.

The sequence of events for this limiting case is provided in Table 15.1.6-1. (For breaks initiated at lower RCS cold leg temperatures, the timing of events may differ, and safety injection may not be credited in the analysis as explained above.) This sequence of events was obtained by simulating the limiting Mode 3 MSLB event with the mathematical models identified in UFSAR Section 15.1.6.3.

For this limiting case, the MSLB will initially cause the main steam flow rate to rapidly increase, then gradually decrease as

the affected steam generator blows down and depressurizes (Figure 15.1.6-1). The excess steam demand will cool the RCS, decreasing cold leg temperatures in both RCS loops (Figure 15.1.6-2) as well as the average core inlet and outlet temperatures (Figure 15.1.6-3). In the presence of a negative MTC, the decrease in RCS temperature will result in an increase in reactivity (Figure 15.1.6-4), core power (Figure 15.1.6-5), and core heat flux (Figure 15.1.6-6). Figure 15.1.6-6 shows that the core heat flux may peak twice during the event simulation. The first peak occurs during the first few seconds of the transient, as forced flow through the core rapidly decreases following the LOP, and as MSIVs are closing and slowing the rate of decrease in core inlet temperature. The second peak occurs later, as the rate of increase in moderator reactivity slows, and negative reactivity from safety injection boron effectively stops the increase in core power.

Table 15.1.6-1

SEQUENCE OF EVENTS FOR THE LIMITING
SUBCRITICAL MAIN STEAM LINE BREAK WITH LOP SAFETY ANALYSIS
(RCS T_{cold} = 572°F)

Time (seconds)	Event
0.0	Double-ended guillotine MSLB (on SG#1) occurs inside or outside containment
0.0	LOP occurs
0.0	RCPs begins to coast down
6.49	Steam generator pressure reaches MSIS setpoint
6.99	Void begins to form in reactor vessel upper head
11.58	SIAS trip setpoint reached
12.10	All MSIVs closed. Steam flow from steam generator No. 2 halted
41.58	One HPSI pump begins injecting water into the RCS
174.0	Safety injection boron reaches RCS cold legs
212.0	Maximum total reactivity occurs
291.9	Macbeth minimum DNBR occurs
292.0	Maximum core power fraction occurs
295.0	Maximum heat flux fraction occurs
1800.0	Plant operators take control of the plant

Like MSLBs that may occur in Modes 1 and 2, the rapid cooldown following a Mode 3 MSLB will also result in decreasing RCS and steam generator pressures (Figures 15.1.6-7 and 15.1.6-8, respectively). Additionally, although some secondary system inventory may initially be lost from the unaffected steam generator, closure of the MSIVs following an MSIS will serve to retain water in that generator (Figure 15.1.6-9).

Detection of a Mode 3 MSLB may be accomplished by an RCS or steam generator low pressure alarm, a steam generator low level alarm, recognition of an excess steam demand, or a high containment pressure alarm (if the MSLB occurs inside containment).

For the limiting Mode 3 MSLB, Table 15.1.6-1 does not reflect a reactor trip or CEA insertion following a trip. Although a trip is anticipated in the actual plant, it should be noted that CEAs may already be fully inserted into the core when the plant is in Mode 3. Therefore, for analytical purposes, CEA worth at trip is not explicitly modeled with a time-dependent scram curve, but rather it is accounted for in the initial assumed subcriticality. This analytical practice is utilized for Mode 3 MSLBs because the minimum DNBR and maximum linear heat rate values occur later in the event sequence, after any trippable CEAs have fallen into the core.

Table 15.1.6-1 reflects a coincident LOP in the sequence of events. Following a LOP, the coolant flow rate through the RCS would decrease rapidly, as the RCPs coast down and the RCS transitions from forced flow to natural circulation conditions

(Figure 15.1.6-10). Although a loss of forced flow may result in locally higher coolant temperatures in the core region, overall the RCS would still continue to cool down while the faulted steam generator dries out. This cooldown would increase RCS coolant density, causing the pressurizer level to drop temporarily (Figure 15.1.6-11) and a void to form in the reactor vessel upper head.

Pressurizer pressure would likewise decrease to the SIAS setpoint, actuating any operable safety injection pumps. As noted above, however, consideration of Technical Specification requirements and the Single Failure Criterion results in only one HPSI pump starting on demand, if the initial cold leg indicated temperature is greater than or equal to 485°F. At these higher temperatures, safety injection flow into the RCS would serve to deliver soluble boron and add negative reactivity, thereby counteracting the positive reactivity insertion due to the moderator cooldown and Doppler effects. At lower initial cold leg temperatures, however, the moderator reactivity insertion is less severe, and soluble boron is not required to halt the increase in reactivity and core power in the presence of adequate CEA worth at trip. For analytical purposes, no safety injection flow is credited for initial cold leg indicated temperatures that are less than or equal to 485°F.

Operator action is not credited in the Mode 3 MSLB safety analysis for 30 minutes following event initiation. At that time, however, it is assumed that plant operators would take action to stabilize the plant in a safe shutdown condition.

15.1.6.3 Core and System Performance

15.1.6.3.1 Mathematical Models

The PVNGS Mode 3 MSLB safety analysis utilized the following mathematical models:

- The CENTS computer code was used to simulate the NSSS transient response. The CENTS computer code is described in UFSAR Section 15.0.3.1.3.2 and in an NSSS vendor topical report.[1][2]

- Because the range of the CE-1 CHF correlation does not extend to low pressures and low flow rates that may exist in the RCS following a Mode 3 MSLB, the Macbeth correlation[17][18] is utilized to determine the margin to DNB. The Macbeth correlation calculates CHF as a function of mass flux, inlet subcooling, system pressure, heated diameter, and channel length. Use of a channel heat balance allows the correlation to be converted to a "local conditions" form, thereby allowing CHF to be determined as a function of height in the hot channel. The effect of non-uniform axial heating is incorporated by using the method applied by Lee in Reference 19. The Macbeth CHF correlation is also described in the CENTS computer code topical report.[1]

15.1.6.3.2 Input Parameters and Initial Conditions

Table 15.1.6-2 summarizes the key input parameters and initial conditions utilized in the PVNGS Mode 3 MSLB safety analyses.

The following points serve to explain the selection of initial conditions as they appear in Table 15.1.6-2:

- Initial core power level is established by the initial subcriticality corresponding to each RCS cold leg temperature, where the initial subcriticality is assumed to equal the minimum required TDSDM for the reactor trip breakers closed configuration case (see Figure 15.1.6-12). Evaluation of the reactor trip breakers open configuration case is discussed in Section 15.1.6.3.3.
- Initial core inlet temperatures were selected to bound the plant configurations, and TDSDM allowed by Technical Specifications in Mode 3.

Table 15.1.6-2

INPUT PARAMETERS AND INITIAL CONDITIONS
FOR THE LIMITING SUBCRITICAL MAIN STEAM LINE BREAK
SAFETY ANALYSES (RCS T_{COLD} = 572°F)

Parameter	Assumed Values
Initial Subcriticality (%Δρ)	-6.50
Initial Core Power (% of RTP)	1.54×10^{-6}
Initial Core Inlet Temperature (°F)	572
Initial Pressurizer Pressure (psia)	1340
Initial RCS Flow Rate (% of Design Rated)	95
Initial Pressurizer Water Level (% Narrow Range)	60
Initial Steam Generator Water Level (Feet)	33 (61% WR)
Moderator Temperature Coefficient (Δρ/°F)	-4.4×10^{-4}
Doppler Fuel Temperature Coefficient	EOC
Delayed Neutron Kinetics	EOC
Inverse Boron Worth (ppm/%Δρ)	-130
Fuel Rod Gap Conductance (BTU/hr-ft^2-°F)	5755
Number of Plugged Steam Generator Tubes (Total %)	10
Break Size (ft^2)	1.283
Loss of Offsite Power	Yes
Additional Single Failure	HPSI

- An initial pressurizer pressure of 1340 psia was assumed for the case of 572°F cold leg temperature. The SIAS setpoint was set at the saturation pressure of the cold leg indicated temperature. For other temperature cases, a lowest possible Pressurizer pressure and lowest SIAS setpoint (saturation pressure) are used.
- The initial assumed core flow rate affects the rate of core inlet temperature cooldown following a MSLB, which in turn affects the positive reactivity insertion in the presence of a negative MTC cooldown curve. In accordance with station operating procedures, between 2 and 4 RCPs may be in operation during Mode 3, depending upon the RCS cold leg temperature. Additionally, Technical Specifications allow for all RCPs to be de-energized for up to one hour (per 8-hour period). For comparative purposes, the safety analyses described herein assumed 4 RCPs were in operation at the time of event initiation. For those cases with a coincident LOP, all RCPs were then immediately de-energized at event initiation. For cases with offsite power available, Mode 3 MSLB analysis was performed with various RCP operating configurations. The analysis confirmed that the conclusions described herein remain valid, i.e., the limiting case with regard to fuel performance is the case initiated from an RCS cold leg temperature of 572°F with a coincident LOP, and the shutdown margin requirements for trip breakers closed configuration.

- A high Pressurizer level was selected since use of a high level tends to delay SIAS. The analysis conservatively assumes a pressurizer level corresponding to 60% of Pressurizer level control range.

- The safety analysis performs parametrics on the Pressurizer pressure and steam generator level. High steam generator level increases the stored energy, results in a more severe blowdown, a faster cooldown rate following the MSLB, and a greater reactivity insertion in the presence of a negative MTC cooldown curve. However, this also causes the Pressurizer pressure to drop much lower such that the HPSI pump is able to inject more highly borated water into the core.

- When the liquid inventory in a steam generator decreased below 5000 lbm as a result of the blowdown, the primary-to-secondary system heat transfer rate was ramped down to zero as the mass decreased to 2500 lbm.

- The most negative MTC cooldown curve was used for this analysis, corresponding to End of Cycle (EOC) conditions.

- An EOC (most negative) Doppler fuel temperature coefficients curve was used for the Mode 3 MSLB analysis. Use of EOC values is consistent with the selection of the most negative MTC cooldown curve. Use of a most negative curve adds relatively more positive reactivity as a result of a change in fuel temperature following a MSLB.

- Relative to other parameters, the delayed neutron fraction has a minor effect on core power following a Mode 3 MSLB. EOC values were chosen, consistent with the use of EOC MTC and Doppler values.

- A maximum value was selected for the inverse boron worth, to reduce the negative reactivity that would be inserted as a result of boron injected by the Safety Injection (SI) system. The sweep-out volume represents the volume of water that must be displaced before safety injection boron reaches the primary system. The Safety analysis for this event uses a more conservative (larger) sweep-out volume than the required value of 60.6 cubic feet in the SI line from the RCS. Boron injection was credited only for those cases initiated from an RCS cold leg indicated temperature of 485°F or higher (see UFSAR Section 15.1.6.2).

- The maximum fuel rod gas gap conductance value was selected so that energy from the fuel would quickly reach the surface of the fuel rod clad. This results in a heat flux that closely follows core power, and therefore more thermal margin degradation as power increases.

- Steam generator tube plugging decreases the heat transfer rate from the RCS to the secondary system and thereby decreases the initial SG pressure. A lower SG pressure promotes an earlier MSIS but delays the SIAS (due to higher pressurizer pressure). The combination effect determines the resulting limiting condition. Based on the

parameteric evaluation, it is shown that the limiting case is 10% tube plugged for 3990 MWt configuration.

- A large break size was assumed for the analysis, with steam blowdown limited by the cross-sectional throat area of the flow restrictors in the outlet nozzles of both steam generators. A large break size maximizes the cooldown rate and resulting reactivity insertion.

- For the Mode 3 MSLB analysis, an additional single failure involving the failure of one HPSI pump to start on demand was assumed (see UFSAR Table 15.0-0). For those cases initiated at an RCS cold leg indicated temperature of 485°F or higher, this single failure served to reduce the capacity of the SI system to provide boron to the RCS. For those cases initiated at lower RCS cold leg temperatures, this failure resulted in a total loss of SI capacity (see UFSAR Section 15.1.6.2). A single failure affecting SI capacity is more limiting with respect to core performance than a postulated failure of an MSIV to close following an MSIS.

15.1.6.3.3 Results

Key results for the limiting Mode 3 MSLB safety analysis are summarized in Table 15.1.6-3.

Table 15.1.6-3

RESULTS FOR THE LIMITING SUBCRITICAL MAIN STEAM LINE BREAK SAFETY ANALYSES (RCS T_{COLD} = 572°F)

Parameter	Results
Peak Linear Heat Generation Rate (KW/ft)	12.8
Maximum Core Power (% of RTP)	1.46
Maximum Total Reactivity (%$\Delta\rho$)	0.236
Minimum MacBeth DNBR	1.95

The case initiated at an RCS cold leg temperature of 572°F, with a coincident LOP and SG tube plugging, yielded the largest total reactivity, the largest core power fraction, and the largest heat flux fraction for any of the analyzed Mode 3 MSLBs. Further analysis of this case revealed that, if both the fission power and decay power components were taken into consideration, the peak transient linear heat rate would be less than that required to cause fuel centerline melting. Additionally, the calculated Macbeth DNBR remained above the deterministic limit of 1.30. Therefore, it is concluded that fuel clad degradation would not occur following a postulated MSLB in Mode 3.

As noted previously, the Mode 3 MSLB safety analysis cases were initiated from subcritical conditions, where the initial subcriticality was assumed to be equal to the minimum required TDSDM for an indicated cold leg temperature (see Table 15.1.6-2 and Figure 15.1.6-12). However, as Figure 15.1.6-12 shows, the

minimum required TDSDM differs between the trip breakers open configuration and the trip breaker closed configuration. Generally, if the reactor trip breakers are open, the minimum SDM required by the Core Operating Limits Report (COLR) is less than that required when the breakers are closed, across the entire range of cold leg temperatures allowed in Mode 3.

However, it should also be noted that the Technical Specification definition for SDM states that the single CEA of highest reactivity worth is assumed to be fully withdrawn from the core. Therefore, if the CEAs are in a confirmed inserted configuration with reactor trip breakers open, the amount of reactivity by which the plant would actually be subcritical would be the sum of the SDM and the Stuck Rod Worth (SRW). Figure 15.1.6-12 illustrates an example in which the SRW is assumed to be 2.0% $\Delta\rho$.

Figure 15.1.6-12 shows that the plant must be subcritical by a SDM of at least 4.0% $\Delta\rho$ to 6.5% $\Delta\rho$ (depending upon the value of T_{cold}) when reactor trip breakers are closed, or by a SDM of at least 1.0% $\Delta\rho$ to 5.0% $\Delta\rho$ when reactor trip breakers are open. However, for the breakers open condition, these SDM values are based on the assumption that the most reactive rod is held out of the core. In the trip breakers open configuration, this “stuck” rod is actually inserted into the core, adding another 2.0% $\Delta\rho$ of subcriticality. Therefore, for the trip breakers open configuration, the reactor would actually be subcritical by at least 3.0% $\Delta\rho$ to 7.0% $\Delta\rho$ (depending upon the value of T_{cold}).

Further comparison of the curves in Figure 15.1.6-12 shows that, for RCS cold leg temperatures greater than 450°F, the reactor would be less subcritical (i.e., at a higher initial core power level) for the trip breakers closed configuration than for the trip breakers open configuration. Therefore, the Mode 3 MSLB safety analyses described herein for the trip breakers closed configuration (above 450°F), clearly bound the trip breakers open configuration when the SRW is at least 2.0% $\Delta\rho$.

Conversely, for RCS cold leg indicated temperatures less than 450°F, the reactor would be initially less subcritical for the trip breakers open configuration than for the trip breakers closed configuration. Therefore, it is concluded that the trip breakers open configuration likewise bound the trip breakers closed configuration if the SRW is at least 2.0% $\Delta\rho$.

Therefore, verification that the SRW is at least 2.0% $\Delta\rho$ for reload core designs, ensures that the Mode 3 MSLB safety analysis described herein bounds both the trip breakers open and trip breakers closed configurations, across the full spectrum of Mode 3 cold leg temperatures.

15.1.6.4 RCS Pressure Boundary Barrier Performance

15.1.6.4.1 Mathematical Models

The mathematical models that were used to analyze the performance of the RCS pressure boundary are the same as those described in UFSAR Section 15.1.6.3.1.

15.1.6.4.2 Input Parameters and Initial Conditions

The key input parameters and initial conditions that were used to analyze the performance of the RCS pressure boundary are the same as those described in Section 15.1.6.3.2.

15.1.6.4.3 Results

The safety analysis shows that Mode 3 MSLB is primarily characterized as a cooldown event and that, following an MSIS, both RCS and steam generator pressures will tend to stabilize (see Figures 15.1.6-7 and 15.1.6-8). Because heat sources in the NSSS are not sufficient to raise pressurizer pressure to the minimum PSV lift setting specified in the Technical Specifications, the peak RCS pressure will remain below the acceptable design limit for this event (i.e., 110% of the RCS design pressure of 2500 psia, or 2750 psia). Likewise, pressure in the main steam system will remain below the minimum allowable MSSV lift settings and therefore below the acceptable design limit for this event (i.e., 110% of the steam generator shell side design pressure of 1270 psia, or 1397 psia).

15.1.6.5 Containment Performance and Radiological Consequences

The core performance safety analysis in UFSAR Section 15.1.6.3 indicates that MSLBs in Mode 3 (Hot Standby) will not result in fuel clad degradation. Hence, significant offsite and control room dose consequences are not anticipated for such events. Nonetheless, because MSLBs are classified as limiting faults, their postulated consequences include the potential to release

significant amounts of radioactive material to the environment. It is concluded that the radiological consequences of MSLBs that may occur during Mode 3 are conservatively bounded by the results presented in UFSAR Section 15.1.5.5 for MSLBs that may occur in Modes 1 (Power Operation) or 2 (Startup).

15.1.6.6 Conclusions

Evaluation of postulated MSLBs in plant operating Mode 3 (Hot Standby) shows that:

- Pressure in the RCS will be maintained below 110% of its design value (i.e., 110% of 2500 psia, or 2750 psia).
- Pressure in the main steam system will be maintained below 110% of the steam generator shell side design value (i.e., 110% of 1270 psia, or 1397 psia).
- Offsite and control room radiological dose consequences are bounded by the results presented in UFSAR Section 15.1.5.5 for MSLBs that may occur in Modes 1 (Power Operation) or 2 (Startup).

15.1.7 REFERENCES

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15.2 DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

15.2.1 LOSS OF EXTERNAL LOAD

15.2.1.1 Identification of Event and Causes

The loss of external load event is caused by the disconnection of the turbine generator from the transmission network.

15.2.1.2 Sequence of Events and Systems Operation

A loss of external load generates a turbine trip which results in a reduction in steam flow from the steam generators to the turbine, due to the closure of the turbine stop valves. The steam bypass control system (SBCS) and reactor power cutback system (RPCS) are both normally in the automatic mode and would be available upon turbine trip to accommodate the load rejection without necessitating reactor trip or the opening of main steam safety valves. Should a turbine trip occur with these systems in the manual mode, a complete termination of main steam flow results and reactor trip would occur on high pressurizer pressure. If no credit is taken for immediate operator action, the main steam safety valves will open to limit the secondary pressure increase and provide a heat sink for the nuclear steam supply system (NSSS). The operator can initiate a controlled system cooldown using the SBCS any time after reactor trip occurs.

15.2.1.3 Analysis of Effects and Consequences

The results of the loss of load event are no more limiting with respect to reactor coolant system (RCS) pressurization than

those of the loss of condenser vacuum (LOCV) event presented in subsection 15.2.3. The LOCV also results in a turbine trip; however, feedwater flow is assumed to terminate following LOCV whereas it is assumed to ramp down to 5% following the loss of load. This larger reduction in heat removal capability results in a higher peak RCS pressure for the LOCV.

Like the LOCV, the departure from nucleate boiling ratio (DNBR) increases during the loss of load due to the increasing pressure. Thus, the initial DNBR is also the minimum DNBR. For the loss of load, due to its similarity with the LOCV event, there are no concurrent single failures which, when combined with the loss of external load, result in consequences more severe than the LOCV event with respect to RCS pressurization. The limiting single failure with respect to fuel performance is the loss of offsite power following a turbine trip. This event with a loss of offsite power results in an event similar to the loss of flow (LOF) event discussed in subsection 15.3.1. Results of the LOF event are directly applicable to the loss of external load with loss of offsite power following a turbine trip.

15.2.1.4 Conclusions

For the loss of load event and the loss of load with a single failure, the RCS pressure remains below 2750 psia thus ensuring primary integrity, and the minimum DNBR remains above the limit thus ensuring fuel cladding integrity.

15.2.2 TURBINE TRIP

15.2.2.1 Identification of Event and Causes

A turbine trip may result from a number of conditions which cause the turbine generator control system (TGCS) to initiate a turbine trip signal. A turbine trip initiates closure of the turbine stop valves.

15.2.2.2 Sequence of Events and Systems Operation

A turbine trip results in a reduction in steam flow from the steam generators to the turbine due to the closure of the turbine stop valves. The SBCS and RPCS are both normally in the automatic mode and would be available upon turbine trip to accommodate the load rejection without necessitating reactor trip or the opening of main steam safety valves. Should a turbine trip occur with these systems in the manual mode, a complete termination of main steam flow results and reactor trip would occur on high pressurizer pressure. If no credit is taken for immediate operator action, the main steam safety valves will open to limit the secondary pressure increase and provide a heat sink for the NSSS. The operator can initiate a controlled system cooldown using the SBCS any time after reactor trip occurs.

15.2.2.3 Analysis of Effects and Consequences

The results of the turbine trip event are no more limiting with respect to RCS pressurization than those of the LOCV event presented in subsection 15.2.3. The LOCV also results in a

turbine trip; however, feedwater flow is assumed to terminate following LOCV whereas it is assumed to ramp down to 5% following the turbine trip. This larger reduction in heat removal capability results in a larger peak RCS pressure for the LOCV.

Like the LOCV, the DNBR increases during the turbine trip due to the increasing pressure. Thus, the initial DNBR is also the minimum DNBR for the loss of load. Due to its similarity with the LOCV events, there are no concurrent single failures which when combined with the turbine trip result in consequences more severe than the LOCV event with respect to RCS pressurization. The limiting single failure with respect to fuel performance is the loss of offsite power following a turbine trip. This event with a loss of offsite power results in an event similar to the loss of ac power which initiates the LOF event discussed in subsection 15.3.1. Results of the LOF event are directly applicable to the turbine trip event with a loss of offsite power.

15.2.2.4 Conclusions

For the turbine trip event and the turbine trip with a single failure, the RCS pressure remains below 2750 psia thus ensuring primary system integrity, and the minimum DNBR remains above the limit thus ensuring fuel cladding integrity.

15.2.3 LOSS OF CONDENSER VACUUM

15.2.3.1 Identification of Causes and Frequency Classification

A loss of condenser vacuum (LOCV) may occur due to, but not limited to, the failure of the circulating water system to supply cooling water to the condenser; failure of the main condenser evacuation system to remove non-condensable gases; failure of a condenser vacuum breaker; excessive in-leakage of air through a turbine gland packing; loss of power (LOP); or rupture of a condenser shell.

An LOCV is an Anticipated Operational Occurrence (AOO) and is classified as an incident of moderate frequency.

15.2.3.2 Sequence of Events and Systems Operation

The LOCV analyses are performed as separate cases for the primary and secondary peak pressure limits, since these events are not mutually conservative. The sequence of events for the moderate frequency LOCV event is presented in Table 15.2.3.1 for the primary peak pressure case and Table 15.2.3.2 for the secondary peak pressure case. The primary peak pressure case also analyzes the fuel integrity (minimum DNBR) for the LOCV event.

Condenser pressure will increase following an LOCV, causing a trip of the main turbine and closure of the Turbine Admission Valves (TAVs). The LOCV also causes the feedwater pumps to trip due to low suction pressure and disables the turbine bypass valves. The closure of the turbine stop valves and coastdown of main feedwater pumps result in a Reactor Coolant

(Primary) System (RCS) and Main Steam (Secondary) System heat up, and both system pressures increase rapidly. A reactor trip occurs on high pressurizer pressure (HPPT) occurs. The pressure increase in the primary and secondary system are limited by the primary safety valves (PSVs) and main steam safety valves (MSSVs).

If the Reactor Power Cutback System (RPCS) and the Steam Bypass Control System (SBCS) are in automatic mode of operation, a reactor power cutback may occur and the Nuclear Steam Supply System (NSSS) may continue to operate at a reduced power level. However, for the LOCV analysis, both the RPCS and SBCS are assumed to be in manual mode and credit is not taken for their functioning. Likewise, the Pressurizer Pressure Control System (PPCS) and Pressurizer Level Control System (PLCS), which may reduce over pressurization of the RCS, are assumed to be in manual mode and no credit is taken for their functioning.

A reactor trip on low steam generator level (LSGLT) could occur immediately following a LOCV, when a steam generator pressure spike causes the steam bubbles in the steam generator to collapse. However, this level trip is not credited in the analysis.

An auxiliary feedwater actuation signal (AFAS) on low steam generator level occurs as the plant begins to cooldown and depressurize. The auxiliary feedwater flow is automatically initiated after a time delay and begins to fill the steam generators until a normal level is reached.

The LOCV analysis does not credit operator action for the first thirty minutes following the event. Thirty minutes after initiation of the LOCV event, the operators commence a cooldown using the Atmospheric Dump Valves (ADVs).

Analytical setpoints and response times associated with the Reactor Protective System (RPS) trip functions and Engineered Safety Features Actuation System (ESFAS) functions are consistent with, or conservative with respect to, limiting numerical values that appear in the PVNGS UFSAR delineated in UFSAR Chapter 7.

The NRC's Standard Review Plan states that an incident of moderate frequency, such as the loss of condenser vacuum event, should not generate a more serious plant condition without other faults occurring independently. In addition, the Standard Review Plan states that an incident of moderate frequency, in combination with a single active component failure or single operator error, should not result in the loss of function of any barrier other than the fuel cladding.

A LOCV event will cause a termination of feedwater and main steam flow. The analysis does not model the time dependence in detail. Instead, the LOCV is assumed to abruptly and completely terminate both main steam and feedwater flow. In considering the peak pressure criteria, the only mechanisms for mitigation of the RCS and main steam system overpressurization are the PSVs, MSSVs and RCS flow. Table 15.0-0 is used to determine credible single failures for safety analysis. This table indicates that there are no credible failures that can

degrade the PSV and MSSV capacity. Technical Specification 3.7.1 places limits on reactor power and variable overpower trip (VOPT) setpoints when one or more MSSVs are inoperable, thereby ensuring secondary system peak pressure remains within 110% of secondary system design pressure. The LOCV is one of the transients analyzed for validating Technical Specification 3.7.1. A decrease in RCS to steam generator heat transfer due to reactor coolant flow coastdown can be caused by a LOP following a turbine trip. A Reactor Coolant Pump (RCP) coastdown results in a reactor trip that is generated by the Core Protection Calculators on RCP speed. Due to the rapid reactor trip, this failure reduces the peak pressure relative to the LOCV itself. The results of the parametric study show that a LOP coinciding or following the High Pressurizer Pressure Trip (HPPT) does not make the primary and secondary side pressures more adverse. In addition, it is assumed that the most reactive control rod fails to insert on scram.

Therefore, it was concluded that there is no single failure that would make the maximum primary and secondary pressure more limiting during a LOCV event.

A decrease in RCS flow is the only parameter which can significantly reduce the minimum DNBR during a LOCV event. The LOP is the only failure that may affect RCS flow. LOCV by itself, however, produces an increasing RCS pressure which compensates for the elevated RCS temperatures such that the available thermal margin does not degrade before the onset of the LOP. Thus, the overall DNBR degradation experienced during

an LOCV event with LOP would be bounded by that of the loss of RCS flow event of UFSAR Section 15.3.1.

Table 15.2.3-1
SEQUENCE OF EVENTS FOR THE LOCV
PRIMARY SIDE PEAK PRESSURE and FUEL PERFORMANCE (DNBR) EVENT

Time (sec)	Events
0.00	LOCV, turbine trip, main FW pump trip
0.00	Minimum DNBR occurs
7.05	Pressurizer pressure reaches HPPT setpoint
7.55	Reactor trip breakers open
8.16	Scram CEAs begin falling
8.69	PSVs open
8.99	MSSV Bank 1 opens[1]
9.60	Maximum RCS pressure reached
11.08	MSSV Bank 2 opens
12.93	PSVs close
13.35	Maximum steam generator pressure occurs
13.36	MSSV Bank 3 opens
16.81	Steam generator water level reaches AFAS Analytical setpoint
19.80	MSSV Bank 3 closes
31.39	MSSV Bank 2 closes
59.98	MSSV Bank 1 closes
62.90	Auxiliary Feedwater (AFW) flow initiated
1798.50	Maximum pressurizer water volume occurs
1800.0	Operator initiates plant cooldown

[1]Bank 1 MSSVs cycle throughout the 1800 seconds. Only the initial opening and closure are listed in the table.

Table 15.2.3-2
SEQUENCE OF EVENTS FOR THE LOCV
SECONDARY SIDE PEAK PRESSURE EVENT

Time (sec)	Event
0.00	LOCV, turbine trip, main feedwater pump trip occur
0.00	Minimum DNBR occurs
4.02	MSSV bank 1 opens[2]
5.65	MSSV bank 2 opens
6.89	Pressurizer pressure reaches HPPT setpoint
7.32	MSSV bank 3 opens
7.39	Reactor trip breakers open
8.00	Scram CEAs begin falling
9.50	PSVs open
9.83	Maximum RCS pressure occurs
11.50	PSVs close
12.09	Maximum pressurizer water volume
12.56	Steam generator water level reaches AFAS analytical setpoint
13.97	Maximum steam generator pressure occurs
22.62	MSSV bank 3 closes
34.77	MSSV bank 2 closes
58.56	AFW flow initiated
60.10	Pressurizer Pressure reaches SIAS analytical setpoint
64.10	MSSV bank 1 closes
90.10	High Pressure Safety Injection flow initiated
1800.0	Operator initiates plant cooldown

[2]Bank 1 MSSVs cycle throughout the 1800 seconds. Only the initial opening and closure are listed in the table.

15.2.3.3 Core and System Performance

A. Mathematical Model

The NSSS response to a LOCV was simulated using the CENTS computer program described in UFSAR Section 15.0.3.1.3.2. Parametric studies are performed using key design inputs to maximize primary and secondary side pressures. Inputs to the CENTS code such as moderator reactivity as a function of moderator density, Doppler reactivity as a function of effective fuel temperature, and shutdown rod worth were calculated using the two-dimensional ROCS code discussed in UFSAR Section 4.3.3.1.1.2. Shutdown rod worth assumes that the most reactive control rod fails to insert on scram. Input to the CENTS code may also be calculated using the SIMULATE-3 code discussed in UFSAR Section 4.3.3.1.1.5.

The initial and transient DNBR was calculated using the CETOP computer code (see UFSAR Section 4.4 and 15.0.3.1.6), which uses the CE-1 CHF correlation described in reference 2. The LOCV event does not present a challenge to the DNBR SAFDL because the RCS overpressurization tends to increase DNBR.

Since there is no power excursion during the transient, the LOCV event does not challenge the peak fuel centerline temperature SAFDL or the limit on linear heat generation rate (21 kW/ft).

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a LOCV from full power conditions are presented in Table 15.2.3-3. The initial conditions were varied within the ranges of steady state operation configurations (i.e., specified by the Technical Specifications, plant configuration, and design specifications) to determine the set of initial conditions that produce the most adverse consequences following a LOCV.

Parameters of interest include initial core inlet temperature, core inlet flow, pressurizer pressure, steam generator level, pressurizer water level, PSV and MSSV tolerances and blowdowns, Moderator Temperature Coefficient (MTC), Fuel Temperature Coefficient (FTC), fuel rod gap conductances, kinetics parameters, LOP, function of PLCS and PPCS and SG tube plugging. Starting from a base case, one parameter at a time is changed to establish the trends for the RCS and steam generator pressure.

C. Results

The response of key core parameters as a function of time is presented in Figures 15.2.3-1 through 15.2.3-3 and 15.2.3-14 through 15.2.3-17 for this moderate frequency event for the primary peak pressure case and the secondary peak pressure case, respectively. The sudden reduction in steam flow caused by the LOCV leads to a reduction of the

primary-to-secondary heat transfer and an increase in RCS temperature. The rapid heatup and volumetric expansion of the reactor coolant results in an increase in pressurizer pressure. When the pressurizer pressure reaches the HPPT setpoint, reactor trip occurs. The CEAs drop into the core initiating the decrease in core power from full power.

Table 15.2.3-3
ASSUMED INITIAL CONDITIONS FOR LOCV
PRIMARY PEAK PRESSURE/DNBR AND SECONDARY SIDE PEAK PRESSURE CASES

Parameter	Value	
	Primary Side Peak Pressure/DNBR Case	Secondary Side Peak Pressure Case
Initial core power (% of RTP)	102	102
Initial core inlet temperature (°F)	555	566
Initial pressurizer pressure (psia)	2100	2100
Initial RCS flow (% design)	116	95
Initial pressurizer water level (%)	24	24
Initial steam generator level (% WR)	60.7	60.7
Moderator Temperature Coefficient ($\Delta\rho$/°F)	0.0	0.0
Fuel Temperature Coefficient	Least negative	Most negative
SCRAM delay time (sec)	0.5	0.5
CEA holding coil delay (sec)	0.6	0.6
CEA worth at trip - WRSO (%$\Delta\rho$)	8.0	8.0
Fuel gap conductance (Btu/hr-ft^2-°F)	500	500
Plugged tubes (per steam generator)	1258	0
AFW flow (gpm/pump)	650	650
AFW delay time (sec)	46	46
PSV setpoint tolerance	+3%	+3%
PSV blowdown	5%	5%
MSSV Setpoint Tolerance	+3%	+3%
MSSV blowdown	5%	5%
Pressurizer heaters and sprays	Off	On
Charging and letdown flows (gpm)	139.5/29	46.5/46.5
LOP	No	No

Since there is no power excursion during the transient, the LOCV event does not challenge the peak fuel centerline temperature SAFDL or the limit on linear heat generation rate (21 kW/ft).

The minimum DNBR is greater than the DNBR SAFDL value of 1.34 and meets the acceptance criteria of the Standard Review Plan (see Figure 15.2.3-14). Therefore, fuel cladding damage is not predicted for this moderate frequency event.

15.2.3.4 Reactor Coolant System Barrier Performance

A. Mathematical Model

The computer codes that were employed to evaluate the RCS barrier performance for the limiting moderate frequency event are identical to those described in UFSAR Section 15.2.3.3.A.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions that were employed to evaluate the RCS barrier performance for the limiting moderate frequency event are identical to those described in UFSAR Section 15.2.3.3.B.

C. Results

The response of key RCS parameters as a function of time is presented in Figures 15.2.3-4 through 15.2.3-13 and 15.2.3-18 through 15.2.3-28 for this limiting moderate frequency event.

The PSVs open and a maximum RCS pressure of 2745 psia is reached, which is less than 110% (2750 psia) of RCS design pressure (2500 psia). For the secondary side peak pressure case, three banks of MSSVs open and the maximum secondary system pressure of 1390 psia is reached, which is less than 110% (1397 psia) of secondary system design pressure (1270 psia).

These primary and secondary side maximum pressures meet the acceptance criteria of Standard Review Plan 15.2.3.

15.2.3.5 Radiological Consequences and Containment Performance

LOCV is a moderate frequency event in which no fuel damage occurs. Therefore, radiological consequences are not calculated for this event and containment isolation is not credited.

15.2.3.6 Conclusions

For the loss of condenser vacuum event, the maximum RCS pressure remains below 110% of RCS design pressure(2750 psia), thus ensuring primary system integrity. Likewise, the maximum secondary system pressure remains below 110% of design pressure (1397 psia), thus ensuring secondary system integrity.

The minimum DNBR remains well above the SAFDL limit, thus ensuring fuel cladding integrity.

15.2.4 MAIN STEAM ISOLATION VALVE CLOSURE

15.2.4.1 Identification of Event and Causes

The main steam isolation valve closure event is initiated by the closure of all MSIVs due to a spurious closure signal.

15.2.4.2 Sequence of Events and Systems Operation

The closure of all MSIVs results in the termination of all main steam flow. The decreased heat removal results in increasing primary and secondary temperatures and pressure. Reactor trip occurs on high pressurizer pressure. The pressure increases in the primary and secondary systems are limited by the pressurizer and steam generator safety valves. The operator can initiate a controlled system cooldown using the steam bypass control system any time after reactor trip occurs.

15.2.4.3 Analysis of Effects and Consequences

The results of the MSIV closure event are no more limiting with respect to RCS pressurization than those of the LOCV event presented in subsection 15.2.3. The LOCV also results in the termination of all main steam flow. However, main steam flow is terminated more rapidly during the LOCV since the closure time for the turbine stop valves is much shorter than that for the MSIVs. The faster reduction in heat removal results in a higher peak RCS pressure for the LOCV event.

Like the LOCV, the DNBR increases during the MSIV closure event due to the increasing pressure. Thus, the initial DNBR is also the minimum DNBR for the MSIV closure event.

Due to the similarity with the LOCV event, there are no concurrent single failures which when combined with the MSIV closure event result in consequences more severe than the LOCV event with respect to RCS pressurization. The limiting single failure with respect to fuel performance is the loss of offsite power following a turbine trip. This event with a loss of offsite power results in an event similar to the loss of ac power which initiates the LOF event discussed in subsection 15.3.2. Results of the LOF event are directly applicable to the MSIV closure with loss of offsite power following a turbine trip.

15.2.4.4 Conclusions

For the MSIV closure event and the MSIV closure with a single failure, the RCS pressure remains below 2750 psia thus ensuring primary system integrity, and the minimum DNBR remains above the limit thus ensuring fuel clad integrity.

15.2.5 STEAM PRESSURE REGULATOR FAILURE

This event does not apply to the CESSAR SYSTEM 80 design and therefore is not presented.

15.2.6 LOSS OF NONEMERGENCY AC POWER TO THE STATION AUXILIARIES

15.2.6.1 Identification of Event and Causes

The loss of nonemergency ac power to the station auxiliaries (LOAC) may result from either a complete loss of power from the

transmission network or a loss of power to 13.8kV buses NAN-S01 and NAN-S02. The LOAC is presented as the initiating event for the four pump loss of flow event discussed in subsection 15.3.1.

15.2.6.2 Sequence of Events and Systems Operation

When all normal ac power is assumed to be lost to the plant, the turbine stop valves close, and it is assumed that the area of the turbine control valves is instantaneously reduced to zero. Also, the feedwater flow to both steam generators is instantaneously assumed to go to zero. The reactor coolant pumps coast down and the reactor coolant flow begins to decrease. A reactor trip will occur as a result of a low DNBR condition as the flow coastdown begins. The pressure increases in the RCS and steam generators are limited by the pressurizer and steam generator safety valves.

The loss of all normal ac power is followed by automatic startup of the standby diesel generators, the power output of which is sufficient to supply electrical power to all necessary engineered safety features systems and to provide the capability of maintaining the plant in a safe shutdown condition. Subsequent to the reactor trip, stored and fission product decay energy must be dissipated by the reactor coolant system and main steam system. In the absence of forced reactor coolant flow, convective heat transfer coolant flow occurs. Initially, residual water inventory in the steam generators is used as a heat sink, and the resultant steam is released to atmosphere by the spring-loaded steam generator safety valves.

With the availability of standby diesel power, auxiliary feedwater is automatically initiated on a low steam generator water level signal. Plant cooldown is operator controlled via the atmospheric dump valves.

15.2.6.3 Analysis of Effects and Consequences

The results of the LOAC event are identical to those of the loss of reactor coolant flow event presented in subsection 15.3.1, and are no more limiting with respect to RCS pressurization than the LOCV event discussed in subsection 15.2.3. During the LOCV event the plant experiences simultaneous losses of steam and feedwater flow and condenser availability. In addition, the plant experiences a complete loss of forced reactor coolant flow during the LOAC event. The loss of forced reactor coolant flow results in an earlier reactor trip for the LOAC event (on low RCP shaft speed) compared to the reactor trip for the LOCV event (on high pressurizer pressure). The earlier trip promotes a less severe primary-to-secondary heat imbalance and hence a lower peak RCS pressure for the LOAC event.

The fuel performance for the LOAC is no more limiting than that for the LOF event discussed in subsection 15.3.1. The LOAC is the initiating event for the LOF so the fuel performance results of the LOF event are directly applicable to the LOAC event.

15.2.6.4 Conclusions

For the LOAC event and the LOAC with a concurrent single failure, the RCS pressure remains below 2750 psia thus ensuring primary system integrity, and the minimum DNBR remains above the limit thus ensuring fuel cladding integrity.

15.2.7 LOSS OF NORMAL FEEDWATER FLOW

15.2.7.1 Identification of Event and Causes

The loss of normal feedwater flow (LFW) event may be initiated by losing one or both main feedwater pumps or by a spurious signal being generated by the feedwater control system resulting in a closure of the feedwater control valve(s).

15.2.7.2 Sequence of Events and Systems Operation

LFW results in decreasing water level and increasing pressure and temperature in the steam generators. The RCS pressure and temperature also rise until a reactor trip occurs either due to low steam generator water level or high pressurizer pressure. Assuming the SBCS is in the manual mode of operation, termination of main steam flow due to closure of the turbine stop valves following reactor trip temporarily causes steam generator and RCS pressurization. The decrease in core heat rate after insertion of the CEAs in combination with the main steam safety valves opening restores the RCS to a new steady state condition. Auxiliary feedwater flow is automatically initiated on a low steam generator water level, assuring sufficient steam generator inventory for core decay heat

removal and cooldown to shutdown cooling entrance conditions. The cooldown is operator controlled using the SBCS and the condenser.

15.2.7.3 Analysis of Effects and Consequences

The maximum RCS pressure for the LFW event is less than that for the LOCV event discussed in subsection 15.2.3. The LOCV event results in the termination of main steam flow prior to reactor trip in addition to the total loss of normal feedwater flow. This additional condition aggravates RCS pressurization by further reducing the rate of primary-to-secondary heat transfer below that of the LFW event.

Like the LOCV, the DNBR increases during the LFW event due to the increasing RCS pressure. Thus the initial DNBR is also the minimum DNBR for the LFW event.

There are no concurrent single failures which when combined with LFW result in consequences more severe than the LOCV event with respect to RCS pressurization.

The limiting single failure with respect to fuel performance is the loss of offsite power following turbine trip. For the LFW event, prior to turbine trip the DNBR increases due to the RCS pressure increase. DNBR then briefly decreases after turbine trip due to the reactor coolant flow coastdown on loss of offsite power. The DNBR decreases similar to the DNBR transient associated with the total loss of reactor coolant flow event shown in subsection 15.3.1; however, the DNBR decrease for LFW is not as severe due to the earlier reactor

trip relative to the initiation of the coolant flow coastdown. Therefore, the minimum DNBR remains above the limit.

15.2.7.4 Conclusions

For the loss of feedwater flow event and the loss of feedwater flow with a concurrent single failure the RCS pressure remains below 2750 psia thus ensuring primary system integrity, and the minimum DNBR remains above the limit ensuring fuel cladding integrity.

15.2.8 FEEDWATER SYSTEM PIPE BREAKS

Feedwater line breaks (FWLBs) may occur due to pipe failures in the main feedwater system (FWS). The pipe breaks in the FWS are evaluated to confirm that the reactor coolant system is maintained in a safe status for a range of break areas up to and including double-ended breaks of the largest feedwater line.

The FWLB transient that results from the postulated FWS line break is sensitive to the break discharge rate. Therefore, a range of break sizes are evaluated to determine the acceptance of the most limiting Nuclear Steam Supply System (NSSS) response. Depending on the break size, location, and the plant operating conditions at the time of break, the effects of the break could cause a Reactor Coolant System (RCS) heatup (due to reduced feedwater flow to the affected steam generator) or a RCS cooldown (due to excessive energy discharge through the break).

In order to discuss the possible effects, FWLBs are categorized as small if the associated discharge flow is within the capacity of the FWS, and otherwise as large. For analytical consideration, break sizes that are less than or equal to 0.2 ft^2 are considered as small breaks in FWLB analyses. Break locations are identified with respect to the feedwater line reverse flow check valves, which are located between the steam generator feedwater nozzles and the containment penetrations. Closure of these valves to reverse flow from the nearest steam generator maintains the integrity and would limit uncontrolled discharge of that generator in the presence of a break upstream of the valves.

Breaks upstream of the check valves can initiate one of the following transients. If the FWS is unavailable following the pipe failure, a total loss of normal feedwater flow (LOFW) results. With the FWS remaining in operation no reduction in feedwater flow occurs for small breaks, while large breaks impose either a partial LOFW or a total LOFW, if the break area is sufficient to discharge the entire feedwater pump flow capacity.

In addition to the possibility of partial or total LOFW events, breaks downstream of the check valves have the potential to establish reverse flow from the nearest steam generator (referred to as the "affected" generator) back through the break. Reverse flow occurs whenever the FWS is not operating subsequent to a pipe break or when the FWS is operating but without sufficient capacity to maintain pressure at the break

above the steam generator pressure. It is only these breaks developing reverse flow that are of interest in these analyses in order to maximize the transient effects.

Depending on the enthalpy of the reverse flow and the ruptured steam generator's heat transfer characteristics, the reverse flow may induce either a RCS heatup or cooldown. However, excessive heat removal through the break is not considered in this analysis, because the cooldown potential is less than that of the main steam line break events. The maximum break size is smaller for the feedwater line break events than for the Main Steam Line Break (MSLB) event. In addition, MSLBs have a greater potential for discharging high enthalpy fluid due to the location of steam piping above feedwater piping within the steam generator Furthermore, the FWLBs cause an instant reduction in feedwater flow, unlike MSLBs. Since FWLBs can cause a rapid depletion of the affected steam generator's liquid mass, reduced heat transfer capability and a rapid RCS heatup and pressurization, it is the heatup potential that is emphasized in the peak pressure analyses.

A general description of the FWLB event follows, assuming a break downstream of the check valves, unavailability of the FWS, and low enthalpy break discharge. The loss of subcooled feedwater flow to both steam generators causes increasing steam generator temperatures and decreasing liquid inventories and water levels. The rising secondary temperatures reduce the primary-to-secondary heat transfer and cause a heatup and pressurization of the RCS. The heatup becomes more severe as

the ruptured steam generator experiences a further reduction in its heat transfer capability due to insufficient liquid inventory as the break discharge continues. This initial sequence of events culminates with a reactor trip on high pressurizer pressure, low steam generator water level, or high containment pressure. RCS heatup can continue after the reactor trip due to a total loss of heat transfer in the ruptured steam generator as it empties. Eventually the decreasing core power following reactor trip reduces the core heat rate to the heat removal capacity of the unaffected steam generator.

15.2.8.1 Parametric Analysis for FWLBs

Sensitivity studies are used to establish the limiting set of initial operating and transient parameters for the FWLB events with respect to RCS pressurization, long term RCS heat removal capacity of the Auxiliary Feedwater (AFW) system and pressurizer fill using the CENTS computer code. These parameters include break size and steam generator mass interval over which heat transfer area ramps to zero ΔM, initial core power, initial RCS pressure, initial RCS flow, initial pressurizer liquid volume, pressurizer and main steam safety valve tolerance and blowdown, core physics conditions, fuel rod gap conductance, initial core inlet temperature, initial feedwater enthalpy, and initial steam generator inventory.

15.2.8.1.1 Parametrics on Key Parameters

For the parametric study on the key parameters, the FWLB with loss of offsite power (LOP) methodology that considers a coinciding High Pressurizer Pressure Trip (HPPT) and Low Steam Generator Level Trip (LSGLT) (occurring at 5500 lbm liquid mass inventory) with a constant break size is applied and the initial steam generator level is adjusted to match the trips. Selection of the parameters is based on the range specified by the Technical Specifications, plant configuration, and design specifications. Starting from a base case that is based on a set of configuration and assumptions, one parameter at a time is changed. The resulting pressures and levels shown in Figures 15.2.8-1 through 15.2.8-11 are used to establish the trends for the RCS peak pressure and the maximum pressurizer level for each parameter.

Initial pressurizer pressure affects the timing of HPPT, and is a parameter that is adjusted to result in coinciding HPPT and the LSGLT. Therefore, the effect of the initial pressurizer pressure on peak RCS and maximum pressurizer level is evaluated together with the initial steam generator inventory, the break size, and the initial temperature. The limiting initial pressurizer pressure is determined in conjunction with the determination of the limiting break size in UFSAR Section 15.2.8.1.2.

A higher initial core inlet temperature increases the initial steam generator pressure and reduces primary to secondary heat transfer. A higher temperature also results in higher RCS

energy content to be removed. Increased initial steam generator pressure due to higher temperature results in an earlier opening of the Main Steam Safety Valves (MSSVs), which increases the heat removal by the secondary system during the transient. Depending on the other conditions and time of trip, timing of these competing effects during the transient can make the peak pressure or pressurizer level more adverse or more benign. Therefore, a further study was conducted in conjunction with the break size and initial pressure in UFSAR Section 15.2.8.1.2.

15.2.8.1.2 Parametrics on Limiting Break Size and Steam Generator Heat Transfer Characteristics

In order to determine the sensitivity of the RCS pressurization to the ruptured steam generator heat transfer characteristics, the effective heat transfer area was conservatively assumed to decreased linearly (from the design value to zero) as the steam generator liquid mass decreased (from a selected value to zero). The mass interval over which the ramp down is assumed to occur is referred to as ΔM. Decreasing values of ΔM imply a more rapid loss of heat transfer in the ruptured steam generator.

After the most limiting key initial parameters are determined as described in UFSAR Section 15.2.8.1.1, the parametric study on break size and ΔM was performed. In addition to the break size and ΔM, different combinations of the initial pressurizer pressure and initial core inlet temperature are considered

since the combinations of these effect the primary to secondary heat transfer characteristics, break flow characteristics and the heat removal by Primary Safety Valves (PSVs) and MSSVs during the transient. The reactor trip is modeled to occur either on high pressurizer pressure trip or steam generator liquid mass. The trip will occur either on the LSGLT for larger break sizes since the steam generator empties faster, or on the HPPT for smaller break sizes since the RCS pressurization is steeper. Effects of initial pressurizer pressure and core inlet temperature are evaluated by starting the event at a minimum steam generator level. Results indicate that the current methodology of matching the HPPT with the LSGLT is limiting.

The limiting break size, and initial pressurizer pressure and core inlet temperatures are then evaluated for two heat transfer degradation assumptions per methodology; ΔM=0 for FWLBs with LOP, and ΔM=30,000 for small FWLBs without LOP and a single failure.

<u>ΔM =0 Case:</u>

For the instantaneous loss of heat transfer (ΔM =0), the most adverse peak pressure is obtained when the event starts from the maximum initial core inlet temperature and minimum initial pressurizer pressure (Figure 15.2.8-12). The limiting break size is the one that results in simultaneous trips on HPPT and LSGLT, which is chosen to occur when 5500 lbm liquid mass inventory is left in the steam generator.

If the LSGLT occurs much earlier than HPPT, as for larger break sizes, RCS pressure and temperature are lower at the time of trip. In addition, the larger break sizes provide additional heat removal by the energy release from the break. Thus, the complete loss of heat transfer in the affected steam generator has less severe effect for very large breaks since it is off-set by this additional energy removal through the break, resulting in lower RCS peak pressure.

If the trip on HPPT occurs much earlier than the LSGLT, as for smaller break sizes, the left over liquid inventory in the affected steam generator provides cooldown of the RCS through the break until the heat transfer is lost at low steam generator inventory. Furthermore, for smaller break sizes, additional cooling becomes available when the PSVs open. For very small break sizes, the cooldown by the PSVs become more effective than the cooldown by the break. The cooling effect of the PSVs can be seen by looking at the results for very small break sizes. Below a certain break size, the cooldown by the leftover steam generator inventory is not significant, and the peak RCS pressure is driven by the PSVs. The peak pressure occurs much earlier than the loss of heat transfer, and is not affected by the break sizes.

As illustrated in Figure 15.2.8-12, lower initial pressure results in later simultaneous trips, shifting the peak pressure vs. break size curve to the left. In other words, decreasing initial pressure (or smaller break size) results in higher peak pressure. Lower initial core inlet temperature causes

additional delay of the simultaneous trips, resulting in smaller break sizes for matching trips. However, this results in lower peak RCS pressure due to the decreased energy content of the primary system at lower inlet temperatures. Therefore, for peak pressure determination, the limiting break size is the smallest break size that would result in simultaneous trips for the event starting from highest core inlet temperature and lowest pressurizer pressure.

The effect of initial core inlet temperature and initial pressurizer pressure on maximum pressurizer level for different break sizes is shown in Figure 15.2.8-13. Simultaneous HPPT with LSGLT also produces the most adverse pressurizer level. Lower initial pressurizer pressure results in a later trip which provides more time for pressurizer inventory addition before trip. Although the parametric study for $\Delta M=0$ shows that the maximum initial core inlet temperature is more limiting, the pressurizer volume is also increased by decreasing temperatures for smaller break sizes. Since the pressurizer level is evaluated for the long term cooling scenario, the later peaks of maximum pressurizer level are more of a concern. In the long term cooling case, the primary system is cooled by the AFWS, relief from the PSVs, MSSVs, and energy release from the break following the steam generator dryout. For these cooling mechanisms, the lower temperature and smaller break combination results in less heat removal. This is because the higher core inlet temperature (or higher initial steam generator pressure) causes the MSSVs to open early, and larger breaks would discharge more energy. Also, a lower core inlet

temperature maximizes the swelling affect due to the density change in the RCS thus maximizing the pressurizer liquid volume increase in the long term. Considering these effects, it is determined that the minimum temperature and minimum break size would produce most adverse result in terms of the pressurizer level for the long term cooling case.

In conclusion, the parametrics have determined that for the ΔM=0 case, the smallest break size that would produce simultaneous HPPT and steam generator dryout combined with the lowest initial core inlet temperature and lowest initial pressurizer pressure is the most limiting case in terms of long term heat removal.

ΔM =30000 Case:

For the degradation of heat transfer over a mass range corresponding to ΔM =30,000, the most adverse peak pressure is obtained when the event starts from the maximum initial core inlet temperature and maximum initial pressurizer pressure (Figure 15.2.8-14). If the LSGLT (corresponding to 35,000 lbm) occurs much earlier than HPPT, the larger break sizes provide cooldown of the primary by the energy release from the break compensating for the heat transfer degradation. If the trip on HPPT occurs much earlier than the degradation of heat transfer, the cooldown by the PSVs and by the break is adequate enough to limit the RCS pressure prior to the heat transfer degradation. For smaller size breaks, PSVs may open earlier during the heat transfer degradation making the effect of reduced heat transfer insignificant. As illustrated in Figure 15.2.8-14, larger

break sizes result in higher peak pressure since the heat transfer degradation is faster and the PSVs open late, shifting the peak pressure vs. break size curve to the right. Competing effects of cooling by the PSVs and the heat transfer degradation can be seen by looking at the results for very small break sizes (Figure 15.2.8-15). Below a certain break size, the heat transfer degradation is not significant since it is slower than the pressure increase, and the peak RCS pressure is driven by the PSVs. The peak pressure occurs much earlier than the total loss of heat transfer. Also, for small break sizes, the maximum peak pressure occurs when the LSGLT approaches the HPPT. Therefore, the limiting break size is the largest break size that would give coinciding HPPT and LSGLT with the highest initial core inlet temperature and pressurizer pressure. The largest break size for small FWLBs is 0.2 ft^2, by definition.

Also in Figure 15.2.8-14, the effect of the initial core inlet temperature shows variation by break size. This is due to the additional cooldown provided by the opening of MSSVs. When the initial core inlet temperature is higher, the initial steam generator pressure is higher, which results in earlier opening of MSSVs.

The limiting combination of initial core inlet temperature and initial pressurizer pressure on maximum pressurizer level is the same for the $\Delta M = 0$ and the $\Delta M = 30000$ cases. The effect of lower core inlet temperature and the smaller break size is more noticeable in Figure 15.2.8-15.

15.2.8.1.3 Parametric Study on Single Failure for FWLB without LOP

The FWLB without LOP methodology assumes a single failure of one of the two fast bus transfer circuits resulting in a Failure to Fast Bus Transfer (FFBT). Normally, both fast bus transfer circuits are operable. However, there is no restriction on removing one or both circuits from service for a period of time during the normal operations. Therefore, the limiting single failure from Table 15.0-0 for the FWLB without LOP methodology was investigated. It was determined that there are no credible single failures (see Table 15.0-0) which, in combination with one or both fast bus transfer circuits blocked, would make the consequences of the event more severe. A two Reactor Coolant Pump (RCP) coastdown, assuming both fast bus transfer circuits are in service and a single failure on one of them occurs, is more limiting than either a total LOP (four RCP coastdown) or full fast bus transfer (no RCP coastdown).

15.2.8.2 Feedwater Line Break Event with Loss of Offsite Power

Analysis of the limiting FWLB event with a LOP was performed using the CENTS computer code along with several simplifying assumptions which, with respect to RCS overpressurization, conservatively model the break discharge flow and enthalpy and the ruptured steam generator water level and heat transfer.

Blowdown of the steam generator nearest the FWLB is modeled assuming frictionless critical flow as calculated by the Henry-

Fauske correlation (reference 4). Although the enthalpy of the blowdown depends on the location of the break and fluid conditions within the affected steam generator, it is assumed that saturated liquid is discharged until no liquid remains, at which time saturated steam discharge is assumed.

With respect to RCS overpressurization these assumptions result in conservatively high mass, low energy flow from the break, thereby minimizing the ruptured generator heat removal capacity.

No credit is taken for a LSGLT in the affected steam generator until the generator is emptied of liquid. This conservatively delays the time of reactor trip, prolonging the RCS heatup and overpressurization. Additionally, no credit is taken for the high containment pressure trip.

15.2.8.2.1 Identification of Causes and Frequency Classification

The FWLB event may occur due to a pipe failure in the FWS.

A FWLB with a LOP is classified as a limiting fault event.

15.2.8.2.2 Sequence of Events and Systems Operation

The sequence of events for the FWLB with LOP is presented in Table 15.2.8-1.

The FWLB event with LOP is initiated by a break with size as stated in Table 15.2.8-2, that is assumed to occur between the steam generator economizer feedwater nozzle and its associated feedwater line check valve.

An instantaneous total loss of main feedwater flow to both steam generators is assumed. Critical flow is established from the affected steam generator through the feedwater line break. In addition, it is assumed that the FWS is unavailable and that the break discharge enthalpy remains as saturated liquid until the affected steam generator empties, at which time saturated steam enthalpy is assumed. The loss of subcooled feedwater flow to both steam generators causes increasing steam generator temperatures and decreasing liquid inventories. This reduces the primary-to-secondary heat transfer rate, resulting in increased RCS temperature and pressure.

The affected steam generator is assumed to instantaneously lose all heat transfer capability due to total depletion of its liquid inventory by boil off and break discharge flow. This initiates a rapid heatup and pressurization of the RCS and depressurization of the steam generators. A reactor trip occurs on high pressurizer pressure, which is coincident with a trip signal (LSGLT) on low steam generator water level. A turbine trip on reactor trip occurs followed by a LOP and closure of the turbine admission valves (TAVs). The closing of the TAVs leaves the feedwater line break as the only steam discharge path. This results in steam generator pressurization which reduces the primary-to-secondary temperature difference and heat transfer rate, thus continuing the RCS heatup. In addition, the loss of reactor coolant flow following the LOP decreases the rate of heat removal in the steam generator tubes, resulting in a significant reduction of heat removal from the RCS.

The reduction of primary side heat removal causes RCS volumetric expansion that results in compression of the pressurizer steam volume due to insurge flow through the pressurizer surge line, which increases the pressurizer pressure above the primary safety valve (PSV) setpoint. When the pressurizer pressure reaches the PSV setpoint, the PSVs open. The maximum RCS pressure remains below 120% of design pressure. The primary side heatup rate lowers due to the decrease in core decay heat flux, which results in a decrease in RCS pressure.

The MSSVs open, limiting secondary side pressure and stabilizing the temperature. This allows a greater heat transfer rate to the unaffected steam generator. The unaffected steam generator maximum pressure, remains below 120% of design pressure.

As a result of steaming through the MSSVs, the unaffected steam generator water level decreases and initiates an auxiliary feedwater actuation signal (AFAS). During the transient, the pressurizer water volume remains below the PSV nozzle elevation.

The secondary side pressure decreases due to a cooldown attributed to auxiliary feedwater (AFW), PSV and MSSV action, and steam flow from the reverse direction through the affected steam generator and out the feedwater line break. A main steam isolation signal (MSIS) is generated on a low steam generator pressure, which closes the main steam isolation valves (MSIVs), and isolates the unaffected steam generator from the affected

steam generator. After the MSIVs close, the pressure difference between the affected and unaffected steam generators increases and reaches the AFW ΔP-lockout setpoint. At this time, the AFW is fully diverted to the unaffected steam generator, restoring its water level. The unaffected steam generator re-pressurizes, causing a reduction in heat transfer and subsequent primary system heatup and pressurization. The primary-to-secondary heat and pressure imbalance is eliminated shortly after the re-opening of the MSSVs. The NSSS enters a quasi-steady state with a gradual cooldown and depressurization due to decreasing core decay heat generation. After 1800 seconds the operators initiate a controlled cooldown to shutdown cooling entry conditions, using the atmospheric dump valves (ADVs).

The FWLB with LOP analysis conservatively assumes operator action is delayed until 30 minutes after the occurrence of the event.

Analytical setpoints and response times associated with the Reactor Protective System (RPS) trip functions and Engineered Safety Features Actuation System (ESFAS) functions are consistent with, or conservative with respect to, limiting numerical values that appear in the PVNGS Technical Specifications and UFSAR Chapter 7.

The NSSS is protected during this transient by the primary safety valves (PSVs) and the following trips:

- Steam Generator Low Level

- Steam Generator Low Pressure
- High Pressurizer Pressure
- Low Departure from Nucleate Boiling Ratio (DNBR)
- High Containment Pressure
- Variable Overpower Trip

Depending upon the initial conditions, any one of these trips may terminate this transient. The NSSS is also protected by MSIVs, feedwater line check valves, MSSVs, and the AFWS, all of which serve to maintain the integrity of the secondary heat sink following reactor trip.

In considering the peak pressure criteria for this event and a postulated worst single active component failure in a system required to mitigate the transient, UFSAR Table 15.0-0 was used. As a result of the evaluation method applied to this analysis, the only mechanisms for mitigation of the RCS and main steam pressurization are the PSVs, MSSVs, and RCS flow. The RCS flow and MSSVs influence the RCS-to-steam generator heat transfer rate.

There are no credible failures that can degrade the PSV or MSSV capacity. Technical Specifications place limits on reactor power and variable overpower trip (VOPT) setpoints when one or more MSSVs are inoperable, thereby ensuring primary and secondary system peak pressure remains within applicable maximum pressure limits. The FWLB event is one of the transients analyzed for validating Technical

Specification 3.7.1. A decrease in RCS-to-steam generator heat transfer due to reactor coolant flow coastdown can be caused by a FFBT following turbine trip or by a LOP following turbine trip (i.e., two RCP or four RCP coastdown, respectively). In this analysis a LOP is assumed to occur following a turbine trip, which results in a four pump coastdown. In addition, it is assumed that the most reactive control rod fails to insert on scram. Therefore, for the FWLB event with a reactor trip followed by a turbine trip and a LOP, there is no credible single failure to make the event consequences more adverse with respect to primary peak pressure.

The FWLB long term cooling event presented in UFSAR Section 15.2.8.4 evaluates the single failure of one auxiliary feedwater pump that results in reduced secondary side heat removal capacity.

Table 15.2.8-1
SEQUENCE OF EVENTS FOR THE FEEDWATER LINE BREAK EVENT WITH LOSS OF OFFSITE POWER FOR PEAK PRESSURE and FUEL PERFORMANCE

Time (sec)	Event(s)
0.0	FWLB occurs. Complete loss of normal feedwater to both steam generators occurs
36.04	High Pressurizer Pressure Trip Activated
36.18	Dryout of affected steam generator (5,000 lbm of liquid inventory). AFAS generated in affected SG[1]
36.54	Reactor trip breakers open
36.54	Turbine trip occurs
36.54	LOP occurs
36.73	Unaffected steam generator reaches Low Steam Generator Level Trip analytical setpoint
37.15	Scram CEAs begin falling
37.94	PSVs open
39.41	Maximum RCS pressure
43.98	PSVs close
44.44	MSSV bank 1 opens on unaffected steam generator
44.96	MSSV bank 1 opens on affected steam generator
45.21	Peak secondary pressure occurs
<1800	Long-term automatic plant system actions and NSSS response to this transient are similar to the long-term cooling FWLB event
1800.0	Operator initiates plant cooldown

[1] Although AFAS is assumed to occur when the steam Generator reaches dryout, no AFW flow is delivered to the steam generators during the 60 seconds of the transient analyzed because of the 46-second delay time, nor is a MSIS or AFW lockout generated. The responses of these systems are similar to Long-Term Cooling FWLB transient presented in UFSAR Section 15.2.8.4.

15.2.8.2.3 Core and System Performance

A Mathematical Model

The NSSS response to the FWLB with LOP was simulated using the CENTS computer code described in UFSAR Section 15.0.3.1.3.2. Inputs to the CENTS code such as moderator reactivity as a function of moderator density, Doppler reactivity as a function of effective fuel temperature, and shutdown rod worth were calculated using the two-dimensional ROCS code discussed in UFSAR Section 4.3.3.1.1.2. The shutdown rod worth assumes that the most reactive control rod fails to insert on scram. Input to the CENTS code may also be calculated using the SIMULATE-3 code discussed in UFSAR Section 4.3.3.1.1.5.

The DNBR for the core hot channel was calculated using the CETOP computer code (see UFSAR Sections 4.4 and 15.0.3.1.6) which uses the CE-1 critical heat flux (CHF) correlation (Reference 2). Transient dependent input to CETOP such as RCS pressure, coolant flowrate through the core, core inlet temperature, and core average heat flux are obtained from the transient response predicted by CENTS.

The methodology for FWLB with LOP applies to a whole spectrum of feedwater line breaks, occurring with a LOP resulting from a turbine trip and a limiting single failure. FWLB event with LOP and a single failure is subject to ASME Service Level C pressure limit (120% of

design pressure) due to the very low estimated frequency of occurrence.

The analysis methods address the influence of the four major controlling parameters:

- discharge enthalpy
- discharge flow
- low water level trip condition in the ruptured steam generator
- heat transfer characteristics of the ruptured steam generator.

The principal conservative assumptions and analytical methods utilized in the analysis of this event include:

- Conservative estimation of the break flow and enthalpy, i.e. discharge of saturated liquid until steam generator is dry (steam generator is considered dry when 5000 lbm or less of liquid inventory is left).
- Delay of heat transfer degradation in the affected steam generator until the liquid inventory is depleted and then assuming an instantaneous loss of heat transfer.
- Initializing key parameters such that a reactor trip occurs on high pressurizer pressure coinciding with LSGLT, which is delayed until liquid mass inventory in the affected steam generator is depleted.

- Delaying the AFAS until liquid mass inventory in the affected steam generator is depleted.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a FWLB with LOP from full power conditions are presented in Table 15.2.8-2. The input parameters and initial conditions are based on the parametric studies discussed in UFSAR Section 15.2.8.1, selected to maximize the consequences of the FWLB.

The input parameters used in this analysis include:

- Maximum initial core power - Maximum core power maximizes the heat content of the primary system and the amount of energy to be removed by the secondary system. This results in a larger heat up and pressurization of the primary and secondary systems.

- Maximum initial core inlet temperature - This maximizes the amount of energy to be removed from the primary system following a loss of heat sink, and increases the initial steam generator pressure. This results in a reduced primary to secondary heat transfer, and a higher RCS peak pressure.

- Maximum initial RCS flow - For a given core power and core inlet temperature, maximum RCS flow results in a lower hot leg temperature and thus a lower steam generator temperature. This results in decreased break flow and enthalpy. The decreased break flow and

enthalpy (i.e., decreased heat removal through the break) prior to trip increases the primary system pressurization.

- Minimum initial pressurizer pressure - Sensitivity studies show that the minimum pressurizer pressure and maximum initial core inlet temperature result in the limiting RCS pressurization.

- Minimum Initial Core Average Fuel Rod Gap Conductance - Minimum fuel rod gap conductance delays the heat transfer from the fuel to the reactor coolant. This increases the energy content of the primary system after trip, resulting in higher primary and secondary peak pressures.

- Maximum PSVs opening setpoint - This delays the pressure relief of primary system and heat removal through the PSVs, thus maximizing the peak primary pressure.

- Minimum initial pressurizer volume - This delays the HPPT due to steam cushioning effect, thereby resulting in a higher primary peak pressure.

- Minimum initial steam generator level - A lower initial steam generator inventory results in earlier degradation in heat transfer, earlier emptying of the affected and intact steam generators and a higher RCS pressure.

- Minimum initial feedwater enthalpy - This minimizes the heat removal capability of the affected steam generator, thereby contributing to primary side heatup and results in higher RCS pressure.
- Least negative (most positive) moderator temperature coefficient (MTC) - This reduces the negative reactivity insertion into the core due to coolant heat up during the event, thus resulting in a slower decrease in power and higher heat content of the primary.
- Maximum number of plugged steam generator tubes - Increasing the number of plugged steam generator tubes decreases the heat transfer from primary to secondary side due to the reduced steam generator heat transfer surface area. This contributes to RCS heatup and pressurization.
- Limiting break size - The limiting FWLB with LOP event break size is determined by parametric study discussed in UFSAR Section 15.2.8.1.2 and is stated in Table 15.2.8-2.

C. Results

The response of key core parameters as a function of time following a FWLB and LOP break are provided in Table 15.2.8-1 and Figures 15.2.8-16 through 15.2.8-18 and 15.2.8-31.

The FWLB transient DNBR values are dependent upon variations in RCS pressure, core inlet temperature, core flow and core heat flux. The immediate loss of feedwater results in increased RCS temperature and pressure. The increase in RCS temperature and pressure is initially gradual since the steam flow has not been immediately interrupted. The increasing RCS pressure tends to increase the DNBR value, however, the increasing RCS temperature tends to stabilize the DNBR and result in a rather flat trace as depicted in figure 15.2.8-31. The LOP and coastdown of the RCPs significantly reduces flow

Table 15.2.8-2
ASSUMED INITIAL CONDITIONS FOR THE FEEDWATER LINE BREAK EVENT WITH LOSS OF OFFSITE POWER PEAK PRESSURE AND FUEL PERFORMANCE EVENT

Parameter	Value
Initial core power(% of RTP)	102
Initial core inlet temperature (°F)	566
Initial pressurizer pressure, psia	2275
Initial RCS flow, (% of design)	116
Initial pressurizer level (%)	24
Initial steam generator level (% of WR)	80.7
Initial feedwater enthalpy (Btu/lbm)	426.7
Moderator Temperature Coefficient ($\Delta\rho$/°F)	-0.2 E-4
Fuel Temperature Coefficient	Least negative
SCRAM delay time (sec)	1.15
CEA holding coil delay (sec)	0.6
CEA worth of trip-WRSO (%$\Delta\rho$)	8.0
Fuel rod gap conductance (Btu/hr-ft^2-°F)	500
Plugged tubes per Steam Generator	1258
PSV setpoint tolerance	+3%
PSV Blowdown	5%
MSSV setpoint tolerance	+3%
MSSV Blowdown	5%
Single Failure	None
LOP	Yes
Feedwater pipe break area (ft^2)	0.162

to the core. This in conjunction with rising coolant temperature, positive MTC, reactivity feedbacks, and core power result in overcoming the effect of increased pressure on DNBR. The DNBR sharply decreases for a few seconds and reaches its lowest value, but remains above the Specified Acceptable Fuel Designed Limit (SAFDL) for DNBR of 1.34. The decrease in core heat flux after trip, increase in RCS pressure and stabilizing RCS temperature, results in a sharp increase in DNBR value.

Since there is no power excursion during the transient, the FWLB event does not challenge the peak fuel centerline temperature SAFDL or the limit on linear heat generation rate (21 kW/ft).

The FWLB with LOP transient minimum DNBR (see Figure 15.2.8-31) is greater than the DNBR SAFDL value of 1.34, and therefore meets the acceptance criteria documented in Reference 3. Fuel cladding damage does not occur for this limiting fault event.

15.2.8.2.4 Reactor Coolant System Barrier Performance

A. Mathematical Model

The computer codes that were employed to evaluate RCS barrier performance for this limiting fault event are identical to those described in UFSAR Section 15.2.8.2.3.A.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions that were employed in the computer codes to evaluate RCS barrier performance for this limiting fault event are identical to those described in UFSAR Section 15.2.8.2.3.B.

C. Results

The response of key RCS parameters as a function of time is presented in Figures 15.2.8-19 through 15.2.8-30 for this limiting fault event.

The FWLB with LOP assumes a loss of main feedwater to both steam generators resulting in a reduction of steam generator water inventory, pressurization of the secondary side, and a resulting heatup and pressurization of the primary side. The primary side heatup causes volumetric expansion and increase in pressurizer water level and pressure. A reactor trip occurs on a HPPT followed by a concurrent LOP on turbine trip. The turbine trip causes TAV closure. This reduction in primary to secondary heat transfer causes a rapid heatup of primary side coolant and the PSVs open to limit pressure. The MSSVs open to limit secondary side pressure.

For 3990 MWt, the maximum RCS pressure reaches 2745 psia, which is less than 120% (3000 psia) of RCS design pressure (2500 psia). The maximum secondary system pressure is 1313 psia, which is less than 120% (1524 psia) of the secondary system design pressure (1270 psia).

The maximum primary and secondary system pressures for this event meet the limiting pressure acceptance criteria of the Standard Review Plan.

As explained in UFSAR Section 15.2.8, FWLB is analyzed as a heat-up transient, and the cooldown potential of a FWLB is less than that of a MSLB. Therefore, the potential of reactor vessel being subject to brittle fracture (GDC 35) is bounded by the MSLB.

15.2.8.2.5 Radiological Consequences and Containment Performance

Fuel damage is not predicted for this limiting fault event. During this event, three sources of radioactivity contribute to the site boundary dose; the initial activity in the steam generator inventory, the activity associated with primary-to-secondary leakage from the steam generator tubes and releases from the reactor drain tank. These sources are assumed to be at 0.1 μCi/gm for the initial steam generator inventory, and at 1.0 μCi/gm dose equivalent I-131 for the RCS sources, respectively. Analysis methodologies are the same as those used in UFSAR Section 15.1.5.5 for the limiting fault MSLB event. The dose analysis for FWLB with LOP uses bounding MSLB release rates, determined independently of break size. Assuming all of the radioactivity is released to the atmosphere, the offsite dose due to the feedwater line break with loss of offsite power results in no more than 3.1 REM two-hour inhalation thyroid dose at the exclusion area boundary (EAB) and 1.7 REM eight hour inhalation thyroid dose at the low

population zone (LPZ) boundary. Whole body doses do not exceed 0.1 REM for either two-hour EAB or eight-hour LPZ. Since no fuel failure is predicted, no containment isolation is credited. In addition, the control room dose is bounded by the control room dose analyzed for events in UFSAR Section 6.4.7.3.

15.2.8.2.6 Conclusions

For the FWLB with a LOP resulting from a turbine trip, the maximum RCS pressure remains below 120% (3000 psia) of design pressure, thus ensuring primary system integrity. Likewise, the maximum secondary system pressure remains below 120% (1524 psia) of design pressure.

The minimum DNBR remains above the SAFDL limit, thereby ensuring fuel cladding integrity. All dose consequences are well within the 10CFR100 guidelines.

15.2.8.3 Feedwater Line Break Event With Offsite Power Available and Limiting Single Failure

The FWLB with LOP event presented in UFSAR Section 15.2.8.2 shows that the limiting break size, when combined with the LOP, produces the maximum primary and secondary pressures below 120% of the design values. The NRC has stated (Reference 3) that 120% of design maximum pressure criterion is appropriate for FWLB combined with the LOP. However, the NRC also stated in reference 3, that it must be shown that small break loss of feedwater inventory events with the limiting single failure and offsite power available meet the maximum pressure criterion of 110% of the design value. In order to demonstrate compliance

with this criterion, a conservative analysis method was developed for the FWLB, with a break size area less than or equal to 0.2 ft^2 with offsite power available. This is also referred to as a "small" feedwater line break event because of the analysis method assumed for the steam generator heat transfer characteristics.

15.2.8.3.1 Identification of Causes and Frequency Classification

The feedwater line break with a single failure and offsite power available may occur due to a pipe failure in the FWS.

The FWLB with a limiting single failure and offsite power available is classified as a limiting fault event.

15.2.8.3.2 Sequence of Events and Systems Operation

The sequence of events presented in Table 15.2.8-3 summarizes the important plant system responses for the FWLB with a limiting single failure and offsite power available.

The FWLB with single failure and offsite power available is initiated by a break with size as stated in Table 15.2.8-4, that is assumed to occur between the steam generator economizer feedwater nozzle and its associated feedwater line check valve and results in an instantaneous total loss of main feedwater flow to both steam generators. Critical flow is established from the affected steam generator through the feedwater line break. In addition, it is assumed that the FWS is unavailable and that the break discharge enthalpy remains as saturated

liquid until the affected steam generator empties, at which time saturated vapor enthalpy is assumed. The loss of subcooled feedwater flow to both steam generators causes increasing steam generator temperatures and decreasing liquid inventories. This causes a reduction in the primary-to-secondary heat transfer rate and an increase RCS temperature and pressure.

As a result of heat transfer degradation due to insufficient water inventory in the affected steam generator a rapid heatup and pressurization of the RCS occurs, generating a HPPT signal that is coincident with a LSGLT signal. The reactor trip breakers open followed by an assumed instantaneous turbine trip and closure of TAVs. The closure of the TAVs leaves the feedwater line break as the only steam discharge path. This results in steam generator pressurization and reduction in primary-to-secondary heat transfer rate, which causes a RCS heatup. Immediately following turbine trip, a FFBT is assumed and results in the coastdown of two RCPs. The two-pump loss of reactor coolant flow decreases the rate of heat removal in the steam generator tubes resulting in a significant reduction of heat removal from the RCS.

The reduction of primary side heat removal causes RCS volumetric expansion that results in compression of the pressurizer steam volume due to insurge flow through the pressurizer surge line that increases the pressurizer pressure above the PSV setpoint. When the pressurizer pressure reaches the PSV setpoint, the PSVs open and offset the pressurization by releasing steam. The maximum RCS pressure remains below

110% of design pressure. The primary side heatup rate lowers due to the decrease in core decay heat flux, which results in a decrease in RCS pressure.

The MSSVs open, stabilizing the secondary side temperature. This allows a greater heat transfer rate to the unaffected steam generator. The maximum unaffected steam generator pressure remains below 110% of design pressure.

As a result of steaming through the MSSVs, the unaffected steam generator water level decreases and initiates an AFAS.

The secondary side pressure decreases due to a cooldown attributed to AFW, PSV and MSSV action, and steam flow from the reverse direction through the affected steam generator and out the feedwater line break. A MSIS is generated on low steam generator pressure, which closes the MSIVs, and isolates the unaffected steam generator from the affected steam generator and the feedwater line break. After the MSIVs close, the pressure difference between the affected and unaffected steam generators increases and reaches the AFW ΔP lockout setpoint. At this time, the AFW is fully diverted to the unaffected steam generator, restoring its water level. The unaffected steam generator re-pressurizes, causing a reduction of heat transfer and subsequent primary system heatup and pressurization. The primary-to-secondary heat and pressure imbalance is eliminated shortly after the re-opening of the MSSVs. The NSSS enters a quasi-steady state with a gradual cooldown and depressurization due to decreasing core decay heat generation. After

1800 seconds the operators initiate a controlled cooldown to shutdown cooling entry conditions, using the ADVs.

The analysis of the FWLB with a single failure and offsite power available conservatively assumes operator action is delayed until 30 minutes after the occurrence of the initiating event.

Analytical setpoints and response times associated with the RPS trip functions and ESFAS functions are consistent with, or conservative with respect to, limiting numerical values that appear in the PVNGS Technical Specifications and UFSAR Chapter 7.

The NSSS is protected during the transient by the PSVs and the following trips:

- Steam Generator Low Level
- Steam Generator Low Pressure
- High Pressurizer Pressure
- Low Departure from Nucleate Boiling Ratio (DNBR)
- High Containment Pressure
- Variable Overpower Trip.

Depending upon the particular initial conditions, any one of these trips may terminate this transient. The NSSS is also protected by MSIVs, feedwater line check valves, MSSVs, and the AFWS which serve to maintain the integrity of the secondary heat sink following reactor trip.

In considering the peak pressure criteria for this event and a postulated active single component failure in a system required to mitigate the transient, Table 15.0-0 was used. As a result of the evaluation method applied to this analysis, the only mechanisms for mitigation of the RCS and main steam pressurization are the PSVs, MSSVs, and RCS flow. The RCS flow and MSSVs influence the RCS-to-steam generator heat transfer rate.

Table 15.0-0 indicates that there are no credible failures that can degrade the PSV or MSSV capacity. Technical specification 3.7-1 places limits on reactor power and VOPT setpoints when one or more MSSVs are inoperable, thereby ensuring primary and secondary system peak pressure remains within 110% of system design pressure. A decrease in RCS-to-steam generator heat transfer due to reactor coolant flow coastdown can be caused by a FFBT following turbine trip or LOP following turbine trip (i.e., two RCP or four RCP coastdown, respectively). Because offsite power is assumed to be available for this analysis, a fast bus transfer will occur following turbine trip if the transfer buses are available. Assuming both transfer buses are available, a FFBT is assumed following the turbine trip, which results in the coastdown of two RCPs in diagonally opposite loops. It has been determined by parametric analysis in UFSAR Section 15.2.8.1.3 that this plant configuration is limiting for the event. There is no other credible single failure, besides FFBT, to make the event consequences more adverse with respect to primary peak

pressure. In addition, it is assumed that the most reactive control rod fails to insert on scram.

The FWLB with LOP long term cooling event presented in UFSAR Section 15.2.8.4 evaluates the single failure of one AFW pump that results in reduced secondary side heat removal capacity.

15.2.8.3.3 Core and System Performance

A. Mathematical Model

The computer codes used to simulate the NSSS and core thermal-hydraulic response to the FWLB with single failure and offsite power available are the same as those described in UFSAR Section 15.2.8.2.3.A.

The methodology used in the analysis of FWLB with single failure and offsite power available, (small break loss of feedwater inventory events), is the same as that described and applied in UFSAR Section 15.2.8.2, with the exception of the treatment of steam generator heat transfer and reactor trip on steam generator low water level.

Table 15.2.8-3
SEQUENCE OF EVENTS FOR FEEDWATER LINE BREAK WITH LIMITING SINGLE FAILURE AND OFFSITE POWER AVAILABLE

Time (sec)	Event
0.0	FWLB occurs. A complete loss of normal feedwater to both steam generators occurs
27.41	Affected steam generator reaches Low Steam Generator Level Trip analytical setpoint
27.45	High Pressurizer Pressure Trip Activated
27.95	Reactor Trip breakers open
27.95	Turbine Trip occur and FFBT
28.56	Scram CEAs begin falling
30.67	PSVs open
31.21	Maximum RCS pressure occurs
31.54	MSSV bank 1 opens on unaffected steam generator
31.57	MSSV bank 1 opens on affected steam generator
34.06	PSVs close
34.69	Peak secondary pressure occurs
35.24	Affected steam generator dries out. AFAS is generated in affected steam generator[2]
48.69	MSSV bank 1 closes on affected steam generator
51.74	MSSV bank 1 closes on unaffected steam generator
< 1800	Long-term automatic plant system actions and NSSS response to this transient are similar to the long-term cooling FWLB event
1800.0	Plant cooldown is initiated

[2] Although AFAS is assumed to occur when the steam generator reaches dryout, no AFW flow is delivered to the steam generators during the 60 seconds of the transient analyzed because of the 46-second delay time, nor is a MSIS or AFW lockout generated. The responses of these systems are similar to Long-Term Cooling FWLB transient presented in UFSAR Section 15.2.8.4.

Predictions of steam generator heat transfer and level behavior are based on the model documented in references 5 through 8. As discussed below, this model is conservative when applied to the small break loss of feedwater inventory events.

Steam Generator Heat Transfer

RCS pressurization is largely a function of the rate of heat transfer decrease by the affected steam generator as its inventory is depleted. UFSAR Section 15.2.8.1.2 documents the sensitivity of RCS pressurization to steam generator heat transfer behavior. The study verified that RCS pressurization is maximized by underestimating the affected steam generator liquid mass corresponding to the initiation of heat transfer degradation (i.e., overestimating the rate of heat transfer decrease). The original methodology took a simplistic and clearly conservative approach by assuming heat transfer degradation was instantaneous upon steam generator dryout. However, this approach is modified in order to more realistically model the behavior for small breaks.

A gradual heat transfer reduction is expected as the steam generator tubes are exposed to increasing void fractions, which force the tubes from the normal nucleate boiling heat transfer regime into transition boiling and eventually into liquid deficient heat transfer. Transition boiling is anticipated when the local void fraction exceeds 0.9. Liquid deficient heat transfer

develops when local qualities approach 0.9. Under full power conditions and utilizing the steam generator model documented in references 3, 5 and 6, the onset of these heat transfer regimes corresponds to steam generator liquid inventories of approximately 70,000 lbm and 35,000 lbm, respectively, for the System 80 design. However, the referenced model conservatively ignores the transition boiling regime, thereby delaying heat transfer degradation until fluid conditions correspond to liquid deficient heat transfer. Therefore, the modified treatment of steam generator heat transfer behavior is conservative, since it underestimates the liquid mass associated with the initiation of heat transfer degradation.

Steam Generator Low Water Level Trip

As discussed in UFSAR Section 15.2.8.2, the original loss of feedwater inventory event method credited the LSGLT in the affected steam generator only after its liquid inventory had been depleted. This assured conservative treatment of low level trip even if the loss of feedwater inventory event caused rapid steam generator depressurization (i.e., large breaks) and consequent swelling of the downcomer level due to flashing of the downcomer liquid. However, for sufficiently small breaks the steam generator pressure remains constant or increases prior to reactor trip and no downcomer level swell will occur due to flashing. Therefore, in the analysis of small break loss of feedwater inventory events, the LSGLT

is modeled to occur with a larger liquid inventory remaining.

For the System 80 design steam generators, the low level trip setpoint corresponds to a downcomer liquid level of approximately 24 feet above the tube sheet and a liquid inventory of over 70,000 lbm under full power conditions (based on the reference steam generator model). However, the analysis of small break loss of feedwater inventory events conservatively delays low level trip until heat transfer degradation begins with approximately 35,000 lbm of liquid remaining in the affected steam generator.

The methodology was developed to meet the requirement that the analysis is of the FWLB with single failure and offsite power available will not result in exceeding 110% of primary and secondary system design pressures.

The method of analyses includes parametrics (sensitivity studies) to establish the limiting initial operating and transient parameters and break sizes with respect to RCS overpressurization during the small feedwater line break event (UFSAR Section 15.2.8.1).

The conservative assumptions made in this FWLB with single failure and offsite power available analysis include:

- Conservative estimation of the break flow and enthalpy by assuming discharge of saturated liquid until the steam generator is dry (steam generator is considered dry when 5000 lbm or less of liquid inventory remains).

- Conservative delay in crediting a reactor trip generated on low level by the affected steam generator. The LSGLT is delayed until the liquid mass inventory is at or below 35000 lbm.
- Conservative gradual heat transfer reduction. The affected steam generator heat transfer is gradually reduced until liquid deficient heat transfer begins at approximately 35000 lbm. This conservative treatment of steam generator heat transfer behavior effectively underestimates the liquid mass associated with the initiation of heat transfer degradation at which time the LSGLT is credited.
- The transient is initialized so that a reactor trip occurs on the HPPT simultaneously with a LSGLT signal (when 35000 lbm remains in affected steam generator).
- The AFAS is delayed until the liquid mass inventory in the affected steam generator is depleted.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a FWLB with single failure and offsite power available from full power conditions are presented in Table 15.2.8-4. The input parameters and initial conditions were selected in order to maximize the consequences of the FWLB with single failure and offsite power available.

The following input parameters used in the analysis are discussed:

- Maximum initial core power - Maximum core power maximizes the heat content of the primary system and maximizes the amount of energy to be removed by the secondary system. This results in a larger heat up and pressurization of the primary and secondary systems.
- Maximum initial core inlet temperature - This maximizes the amount of energy to be removed from the primary system following a loss of heat sink, and increases the initial steam generator pressure. This results in a reduced primary to secondary heat transfer, and a higher RCS peak pressure.
- Maximum initial RCS flow - For a given core power and core inlet temperature, maximum RCS flow results in a lower hot leg temperature and thus a lower steam generator temperature. This results in decreased break flow and enthalpy. The decreased break flow and enthalpy prior to trip (i.e., decreased heat removal through the break) increases the primary system pressurization.
- Maximum (adjusted) initial pressurizer pressure - Sensitivity studies show that the maximum pressurizer pressure and maximum initial core inlet temperature result in the maximum RCS pressurization.

- Minimum Initial Core Average fuel rod gap conductance - Minimum fuel rod gap conductance delays the heat transfer from the fuel to the reactor coolant. This increases the energy content of the primary system after trip, resulting in higher primary and secondary peak pressures.
- Maximum PSVs opening setpoint - This delays the pressure relief of primary system and heat removal through the PSVs, thus maximizing the peak primary pressure.
- Minimum initial pressurizer volume - This delays the HPPT due to steam cushioning effect, thereby resulting in a higher primary peak pressure.
- Minimum initial steam generator level - A lower initial steam generator inventory results in earlier degradation in heat transfer, earlier emptying of the affected and unaffected steam generators and a higher RCS pressure.
- Minimum initial feedwater enthalpy - This minimizes the affected steam generator's heat removal capability, thereby contributing to primary side heatup and results in higher RCS pressure.
- Least negative (most positive) MTC - This reduces the negative reactivity insertion into the core due to coolant heat up during the event, thus resulting in a

slower decrease in power and higher heat content of the primary.

- Maximum number of plugged steam generator tubes - Increasing the number of plugged steam generator tubes decreases the heat transfer from primary to secondary side due to the reduced steam generator heat transfer surface area. This contributes to RCS heatup and pressurization.

- Limiting break size - The limiting FWLB with single failure and offsite power available event break size is determined by parametric study presented in UFSAR Section 15.2.8.1 and is stated in Table 15.2.8-4.

Table 15.2.8-4
ASSUMED INITIAL CONDITIONS FOR FEEDWATER LINE BREAK
WITH LIMITING SINGLE FAILURE AND OFFSITE POWER AVAILABLE

Parameter	Value
Initial core power (% of RTP)	102
Initial core inlet temperature (°F)	566
Initial pressurizer pressure (psia)	2312
Initial RCS flow (% of design)	116
Initial pressurizer level (%)	24
Initial steam generator level (% of WR)	80.7
Initial feedwater enthalpy (Btu/lbm)	426.7
Moderator Temperature Coefficient ($\Delta\rho$/°F)	-0.2 E-4
Fuel Temperature Coefficient	Least negative
CEA worth of trip-WRSO (%$\Delta\rho$)	8.0
Fuel rod gap conductance (Btu/h-ft^2-°F)	500
Plugged tubes	1258
PSV setpoint tolerance	+3%
PSV Blowdown	5%
MSSV setpoint tolerance	+3%
MSSV Blowdown	5%
Single Failure	FFBT
LOP	No
Feedwater pipe break area, ft^2	0.199

C. Results

The response of key core parameters as a function of time following a FWLB with a limiting single failure and offsite power available are provided in table 15.2.8-3 and figures 15.2.8-32 through 15.2.8-34.

The FWLB transient DNBR and fuel centerline temperature or LHGR discussion in UFSAR Section 15.2.8.2.3.C is applicable to this event. The minimum DNBR calculated in UFSAR Section 15.2.8.2.3 for the peak pressure FWLB with LOP event that is initiated from low RCS pressure and high RCS temperature with the four pump coastdown on LOP is more limiting for degradation of DNBR. Therefore, it is concluded that fuel clad degradation would not occur following a FWLB with a single failure and offsite power available.

15.2.8.3.4 Reactor Coolant System Barrier Performance

A. Mathematical Model

The computer codes that were employed to evaluate RCS barrier performance for this limiting fault event are identical to those described in UFSAR Section 15.2.8.3.3.A.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions that were employed in the computer codes to evaluate RCS barrier performance for this limiting fault event are identical to those described in UFSAR Section 15.2.8.3.3.B.

C. Results

The response of key RCS parameters as a function of time is presented in Figures 15.2.8-35 through 15.2.8-41 for this limiting fault event.

The FWLB assumes a loss of main feedwater to both steam generators resulting in a reduction of steam generator water inventory, pressurization of the secondary side, and a resulting heatup and pressurization of the primary side. The primary side heatup causes volumetric expansion and an increase in pressurizer water level and pressure. A reactor trip occurs on the HPPT along with a turbine trip and TAV closure. Following the turbine trip, the FFBT occurs and results in the coastdown of two RCPs resulting in a reduction of heat removal from the RCS. This reduction in primary to secondary heat transfer causes a rapid heatup of primary side coolant which causes the PSVs to open to limit the RCS pressure increase. The MSSVs open to limit the secondary side pressure increase.

For 3990 MWt, the maximum RCS pressure reaches 2688 psia, which is less than 110% (2750 psia) of RCS design pressure (2500 psia). The maximum secondary system pressure reaches 1353 psia, which is less than 110% (1397 psia) of the secondary system design pressure (1270 psia). The maximum primary and secondary system pressures for this event meet the limiting pressure acceptance criteria of Reference 3.

15.2.8.3.5 Radiological Consequences and Containment Performance

Fuel damage is not predicted for this limiting fault event. The dose consequences for this event are no more limiting then the dose consequence assessment presented in UFSAR Section 15.2.8.2.5.

15.2.8.3.6 Conclusions

For the FWLB with a limiting single failure and offsite power available, with a break size less than or equal to 0.2 ft^2, the maximum RCS pressure remains below 110% of design pressure (2750 psia), thus ensuring primary system integrity. Likewise, the maximum secondary system pressure remains below 110% of design pressure (1397 psia).

The minimum DNBR remains above the SAFDL limit, thereby ensuring fuel cladding integrity. All dose consequences are within the 10CFR100 guidelines.

15.2.8.4 Feedwater Line Break with LOP and Single Failure for Long Term Cooling

The FWLB with LOP and SF transient is the most limiting transient with respect to long-term RCS heat removal capability. It bounds the FWLB without LOP and SF event discussed in 15.2.8.3. The adequacy of the auxiliary feedwater (AFW) system capacity to remove decay heat from the primary side following a FWLB event when considered with a LOP and a single failure (failure of one of the two AFW pumps to start)

is demonstrated in this section. This section also demonstrates that the largest increase in pressurizer water level occurs during this transient and remains below the primary safety valve (PSV) inlet nozzles. As a result, it demonstrates that part of UFSAR Chapter 18.II.D TMI Requirements regarding PSV operability are met; since the water level in the pressurizer remains below the PSV inlet nozzles and only steam is discharged through the PSVs. PSV design requirements are discussed in UFSAR Chapter 5.

15.2.8.4.1 Identification of Causes and Frequency Classification

A decrease in heat removal by the secondary system may be caused by a feedwater line break (FWLB) in the main feedwater system (FWS). The FWLB with a single failure and loss of offsite power is classified as a limiting fault.

15.2.8.4.2 Sequence of Events and Systems Operation

The sequence of events for the FWLB with a LOP resulting from turbine trip and a single failure (the active failure of an AFW pump) is presented in Table 15.2.8-5. This sequence of events was obtained by simulating the FWLB event with the computer codes identified in Section 15.2.8.3.A.

The postulated event is initiated by a pipe break that is assumed to occur between the steam generator economizer feedwater nozzle and its associated feedwater line check valve and results in an instantaneous total loss of main feedwater flow to both steam generators. Critical flow is established

from the affected steam generator through the feedwater line break. In addition, it is assumed that the break discharge enthalpy corresponds to that of saturated liquid until the affected steam generator empties, at which time saturated vapor enthalpy is assumed. The loss of subcooled feedwater flow to both steam generators causes increasing steam generator temperatures and decreasing liquid inventories, that reduce the primary-to-secondary heat transfer rate and increase RCS temperature and pressure.

The affected steam generator is assumed to instantaneously lose all heat transfer capability due to total depletion of its liquid inventory. As a result of steaming through the break, both the affected steam generator and the unaffected steam generator water level decreases and initiates an auxiliary feedwater actuation signal (AFAS). No credit is taken for the AFAS or the low steam generator level trip until steam generator dryout occurs. A reactor trip occurs on high pressurizer pressure, which is coincident with the affected steam generator dryout. Depending on the feedwater line break size, a containment pressure high trip and a containment high-high pressure Engineered Safety Features Actuation System (ESFAS) signal may also occur for an inside containment FWLB. In order to account for the containment pressure trip condition and coincident containment isolation actuation signal (CIAS), safety injection actuation signal (SIAS) and main steam isolation signal (MSIS), it is assumed that a containment pressure trip condition and CIAS/SIAS/MSIS occur at the same time as the high pressurizer pressure trip. In addition, the

containment spray actuation signal (CSAS) is assumed to activate coincident to the reactor trip and resulting ESFAS signals. The turbine trips following reactor trip and a loss of offsite power (LOP) occurs three seconds after turbine trip (see UFSAR Section 15.0.2.4). The closing of the turbine admission valves leaves the feedwater line break as the only steam discharge path. The loss of reactor coolant flow following the LOP decreases the rate of heat transfer in the steam generator tubes, resulting in a reduction o f heat removal from the RCS. This exacerbates the heatup and pressurization of the RCS and steam generators.

The reduction of primary side heat removal causes RCS volumetric expansion that results in compression of the pressurizer steam volume due to insurge flow through the pressurizer surge line, which increases the pressurizer pressure above the pressurizer safety valve (PSV) opening setpoints. The main steam safety valves (MSSVs) also open, limiting secondary side pressure and stabilizing temperature. This increases the heat transfer rate to the unaffected steam generator, which results in a decrease in RCS pressure.

One charging pump load sequences to the diesel generator and provides full flow after LOP and SIAS (see footnote h to UFSAR Table 8.3-3). The main steam isolation valves (MSIVs) close after the MSIS, isolating the unaffected steam generator from the break. After the MSIVs close, the reduction in heat transfer causes the unaffected SG to repressurize, the primary system to heat up the repressurize and additional pressurizer insurge occurs. The opening of the PSVs also results in

additional pressurizer insurge. The pressure difference between the affected and unaffected steam generator reaches the auxiliary feedwater ΔP-lockout setpoint prior to any auxiliary feedwater flow being initiated.

The auxiliary feedwater is fully diverted to the unaffected steam generator, restoring its water level. The secondary side pressure fluctuates around the MSSV opening and closing setpoints as they cycle. The PSVs will likewise cycle to relieve RCS pressure. The maximum liquid volume attained in the pressurizer during the FWLB event remains below the volume which results in water entrainment into the PSV nozzles when they are open (the PSV nozzles are at an elevation equivalent to 99.4% level). Thus, the pressurizer does not go solid at any time and RCS pressure control is maintained. The transient is terminated at 1800 seconds, when operators initiate a controlled cooldown, such as by using ADVs, to shutdown cooling entry conditions. The operator can take action to isolate the affected steam generator and refill the unaffected steam generator by manual control of AFW any time after the reactor trip occurs. However, the FWLB with LOP and Single Failure analysis does not credit any operator action for the first 20 minutes of the transient.

Analytical setpoints and response times associated with the Reactor Protective System (RPS) trip functions and Engineered Safety Features Actuation System (ESFAS) functions were chosen to be consistent with, or conservative with respect to, limiting numerical values that appear in the PVNGS Technical Specifications and UFSAR Chapter 7.

The NSSS is protected during this transient by the primary safety valves (PSVs) and the following trips:

- Steam Generator Low Level
- Steam Generator Low Pressure
- High Pressurizer Pressure
- Low Departure from Nucleate Boiling Ratio (DNBR)
- High Containment Pressure
- Variable Overpower Trip.

Depending upon the initial conditions, any one of these trips may terminate this transient. The NSSS is also protected by main steam isolation valves (MSIVs), feedwater line check valves, main steam safety valves (MSSVs), and the auxiliary feedwater system (AFWS) which serve to maintain the integrity of the secondary heat sink following reactor trip.

The peak pressure criteria for the FWLB with LOP and a postulated active single component failure (UFSAR, Table 15.0-0) in a system required to control the transient in accordance with the NRC’s Standard Review Plan (SRP) are presented in Section 15.2.8.2.2 and 15.2.8.2.3 for the FWLB with LOP and FWLB with single failure and offsite power available, respectively.

For the long term cooling aspect of the FWLB event, the mechanisms to mitigate the primary and secondary heatup and pressurization and to provide a heat sink for decay heat are the PSVs, MSSVs, RCS flow, and the AFW capacity. There is no

credible single failure that can degrade the PSV and MSSV capacity, and the rationale for the degradation of the RCS flow as a result of the LOP is the same as that discussed in Sections 15.2.8.2.2 and 15.2.8.2.3. The only active single failure that can reduce the long-term secondary side heat removal capacity is the failure of one of the two auxiliary feedwater pumps to start (Table 15.0-0).

In this analysis it is demonstrated that the FWLB with a loss of offsite power and the failure of one AFW pump to start provides adequate decay heat removal so that no loss of core cooling would result. It is further demonstrated in the analysis that the pressurizer does not go solid or pass water through the PSVs. Hence, no loss of control in the RCS pressure boundary occurs.

TABLE 15.2.8-5
SEQUENCE OF EVENTS FOR FEEDWATER LINE BREAK WITH
LOSS OF OFFSITE POWER AND SINGLE FAILURE EVENT

Time (sec.)	EVENT	Value
0	FWLB and complete LOFW to both SGs, break size (ft^2)	0.199
31.07	Pressurizer pressure reaches trip setpoint (psia). (1)	2450
31.07	HPPT signal generated. SIAS/CIAS/MSIS/CSAS signals generated	
31.15	PSVs open (psia).	2450
31.22	Dryout of affected SG (lbm of liquid inventory), AFAS generated in affected SG.	<5000
31.57	Reactor trip breakers open.	
31.57	Turbine trip occurs	
31.87	Maximum RCS pressure (psia).	2572
32.18	Scram CEAs begin falling.	
34.57	LOP occurs	
36.69	Main Steam Isolation Valves close	
37.26	MSSVs bank 1 open (psia) (2)	1303
38.77	MSSVs bank 2 open (psia)	1344
39.32	PSVs close (psia)	2102
43.19	Maximum SG Pressure (psia)	1367
43.96	AFW Lockout (psid)	270
59.64	MSSVs bank 2 close	1276
74.57	One charging pump restarts (gpm)	44
77.24	AFW initiated to SG #2 (one pump, gpm)	650
91.31	MSSVs bank 1 close (psia) (2)	1237
1200	Operator Action – Intact SG ADV opened (%)	10
1800	Maximum liquid volume of pressurizer (ft^3)	1683
1800	Operators initiate plant cool down	

Notes: 1 - The HPPT is coincident with the LSGLT.

2 - Only the first time the Bank 1 MSSV open and close is listed. The Bank 1 MSSVs continue to cycle as required to remove decay heat.

15.2.8.4.3 Core and System Performance

A. Mathematical Model

The NSSS response to the long-term heat removal FWLB with LOP and Single Failure event was simulated using the CENTS computer code described in UFSAR Section 15.0.3.

Reactivity/Physics related data were provided to the CENTS computer code via the same computer codes and methods discussed in Section 15.2.8.2.3.A.

The minimum DNBR for the core hot channel for the FWLB with LOP was calculated with the CETOP computer code (described in UFSAR Section 4.4) and is discussed in Section 15.2.8.2.3.

The method of analysis includes parametrics (sensitivity studies) used to establish the limiting initial operating and transient parameters and break sizes with respect to long term heat removal and pressurizer fill, as discussed in Section 15.2.8.1. The method of analysis is the same as the FWLB with LOP methodology discussed in Section 15.2.8.2 in addition to the following conservative assumptions:

- The single failure of one of the two safety-related auxiliary feedwater pumps.
- All auxiliary feedwater which is diverted to the affected steam generator is not credited for heat removal.

- The maximum value within the allowable range is assumed for auxiliary feedwater temperature.
- CIAS/SIAS/MSIS are initiated on high containment pressure at the time of reactor trip. This methodology does not change the timing of the reactor trip, or the methodology for matching the HPPT with dryout of the affected steam generator. Parametric analysis determined that the time of reactor trip is the most adverse time to initiate the CIAS/SIAS/MSIS. This methodology assumes that a CIAS/SIAS/MSIS occurs on high containment pressure, simultaneously with the high pressurizer pressure trip. Early MSIS (before SG low pressure occurs) is conservative with respect to pressurizer level criteria since it eliminates the unaffected SG cooldown through the break early in the transient. There is no effect on peak RCS pressure due to early MSIS, since the peak pressure occurs before the closure of the main steam isolation valves (MSIVs). A SIAS causes the charging pumps to load sequence to the diesel generator after LOP, depending on demand from the PLCS. This is a conservative assumption for pressurizer fill criteria since it adds inventory to the RCS.
- The pressurizer Level Control System is in the automatic mode with the plant operated on program Tavg at the start of the transient. This methodology provides justification for using the nominal cold leg

temperature as the initial cold leg temperature assumption for the event.

- CSAS initiated on high-high containment pressure at the time of reactor trip. This methodology does not change the timing of the reactor trip, or the methodology for matching the HPPT with dryout of the affected steam generator. It is conservative to assume that a Containment Spray Actuation Signal (CSAS) coincident with the CIAS signal. Since the containment peak pressure and temperature analysis did not explicitly analyze any feedwater line break events, [Chapter 6, Section 6.2.1.1.1.1] the exact amount of time that elapses from when the containment pressure reaches the high containment pressure trip setpoint to when it reaches the high-high containment pressure trip setpoint is unknown. Therefore it is conservative to assume that it reaches the high-high containment pressure trip setpoint at the same instant it reaches the high containment pressure trip setpoint. A review of Chapter 6, Table 6.2.4-2 determined that the activation of the CSAS isolates the CBO return to the VCT Instrument air, and nuclear cooling water penetrations into / out of containment and opens the spray header isolation valves. For this analysis the key effect is the isolating of the CBO return to VCT. This is a conservative assumption for pressurizer fill criteria since it adds inventory to the RCS.

- The PVNGS Emergency Operating Procedure (EOPs) contain explicit instructions to help the operator manage to ensure that the plant is placed in a stable, safe condition following an Excessive Steam Demand event Therefore, the analysis assumes operator action to open an ADV (on the intact steam generator) to preclude a direct challenge to the RCS Inventory Control and RCS Pressure Control Safety Functions twenty (20) minutes after the even initiation.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a FWLB with LOP and Single Failure event are summarized in Table 15.2.8-6. The parameters and conditions were selected in order to demonstrate adequacy of auxiliary feedwater capacity for primary side decay heat removal and to determine the maximum pressurizer water level for PSV operability. A full spectrum of break areas based on parametrics were considered up to a break size of the combined area of flow distribution nozzles in the feedwater ring in establishing the limiting break size.

The input parameters used in this analysis include:

- Maximum initial core power - Maximum core power maximizes the heat content of the primary system and the amount of energy to be removed by the secondary system. This results in a larger heat up and

pressurization of the primary and secondary systems and pressurizer level.

- Initial core inlet temperature – As determined by parametric analysis, a lower core inlet temperature results in a higher transient pressurizer level. However, the initial core inlet temperature is chosen based on the assumption that the plant is operated on program Tavg, corresponding to the pressurizer level control system program setpoint at hot full power conditions, at the start of the transient.

- Minimum initial RCS flow - For a given power and core inlet temperature, a lower RCS flow results in a higher core outlet temperature. This maximizes the energy stored in the RCS and the energy to be removed by the secondary system, resulting in higher pressurizer level.

- Minimum Initial Pressurizer Pressure - Parametric analysis shows that a minimum initial pressurizer pressure results in a maximum pressurizer water level during the long-term heat removal FWLB.

- Minimum Initial Core Average Gap - Minimum gap conductance delays the heat transfer from the fuel to the reactor coolant. This increases the energy content of the primary system after trip, resulting in higher primary and secondary peak pressures and higher pressurizer level.

- Least negative (most positive) moderator temperature coefficient (MTC) - This reduces the negative reactivity insertion into the core due to coolant heat up during the event, thus resulting in a slower decrease in power and higher heat content of the primary.

- Minimum Pressurizer Safety Valves (PSVs) opening setpoint - Earlier opening of the PSVs increases the surge line flow into the pressurizer, thus increasing the pressurizer level.

- Maximum initial pressurizer liquid level - Parametric study shows that initiating the transient from the maximum initial pressurizer level has no significant sensitivity. However, starting from this level results in the maximum pressurizer level during the transient.

- Minimum initial steam generator level - Parametric study shows that a minimum initial steam generator inventory results in earlier degradation in heat transfer and earlier emptying of the affected and intact steam generators. This increases the RCS pressurization and pressurizer level.

- Minimum initial feedwater enthalpy - This minimizes the heat removal capability of the affected steam generator, which results in higher RCS temperature and pressure and a greater demand on AFW decay heat removal capacity.

- Maximum number of plugged steam generator tubes - The parametric study shows that asymmetric tube plugging results in maximum pressurizer level. Increasing the number of plugged steam generator tubes decreases the heat transfer from primary to secondary side due to the reduced steam generator heat transfer surface area. This contributes to RCS heatup and pressurization and greater demand on AFW decay heat removal capacity.

- Limiting break size - The limiting FWLB long term cooling event break size is determined by parametric study discussed in Section 15.2.8.1.2.

Table 15.2.8-6
ASSUMED INITIAL CONDITIONS FOR FEEDWATER LINE BREAK WITH LOSS OF OFFSITE POWER AND SINGLE FAILURE EVENT

Parameter	Value
Initial core power (% of rated)	102
Initial average RCS temperature, Tavg (at 100% power and maximum pressurizer level) (°F)	585.6
Initial Pressurizer Pressure (psia)	2100
Initial RCS Flow (% of design)	95
Initial Pressurizer water level (ft)	23.9
Initial SG Water Level (ft)	35.8 (25% NR)
Moderator Temperature Coefficient ($x10^{-4}$ $\Delta\rho$/°F)	-0.2
Fuel Temperature Coefficient	least negative
Kinetics	Maximum β
CEA Worth of Trip-WRSO (%$\Delta\rho$)	8.0
Fuel Gap Gas conductance (Btu/hr-ft^2-°F)	500
SCRAM Delay Time (sec)	0.5
CEA Holding Coil Delay Time (sec)	0.6
Plugged SG Tubes	0%/10%
PSV Tolerance	-1%
PSV Blowdown	14.2%
MSSV Tolerance	+3%
MSSV Blowdown	5%
Single Failure	One AFW pump
LOP	Yes
FWLB Area (ft^2)	0.199
RCP seal control bleed-off flow rate (gpm/RCP)	0.0
Operator Action Time (minutes)	20.0

C. Results

The response of key core parameters as a function of time following a FWLB with a loss of offsite power and a single failure of an AFW pump is the same as those discussed in Section 15.2.8.2.3.C, since that event documents the fuel performance for the FWLB events.

The FWLB transient DNBR is discussed in Section 15.2.8.2.3.C and depicted in Figure 15.2.8-31. The FWLB transient DNBR and LHGR discussion in Section 15.2.8.2.4.C is applicable to FWLB long term cooling events. The minimum DNBR versus time as shown on this figure remains above the SAFDL throughout the transient. The minimum DNBR calculated in Section 15.2.8.2.4 for the peak pressure FWLB with LOP event that is initiated from low RCS pressure and high RCS temperature with the four pump coastdown on LOP is more limiting for degradation of DNBR. Therefore, it is concluded that fuel clad degradation would not occur following a long term FWLB with loss of offsite power and a single failure.

15.2.8.4.4 Reactor Coolant System Barrier Performance

A. Mathematical Model

The computer codes that were employed to evaluate RCS barrier performance for this limiting fault event are identical to those described in UFSAR Section 15.2.8.4.3.A.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions that were employed in the computer codes to evaluate RCS barrier performance for this limiting fault event are identical to those described in UFSAR Section 15.2.8.4.3.B.

C. Results

The response of key RCS parameters as a function of time is presented in Figures 15.2.8-42 through 15.2.8-51 for this limiting fault event.

The limiting peak pressure FWLB events are discussed in Sections 15.2.8.2 and 15.2.8.3.

For FWLB with LOP and a single failure, auxiliary feedwater actuation in the affected steam generator is delayed until affected steam generator dry-out. A main steam isolation signal on high containment pressure isolates the unaffected steam generator from the break early in the transient. Following the isolation, AFW delivery increases the level in the unaffected steam generator (Figure 15.2.8-48 and 50). The AFW flow provides sufficient inventory for heat removal to occur through the MSSVs such that RCS pressure control is maintained by the PSVs, and the RCS converges to a quasi steady state prior to 1200 seconds (Figure 15.2.8-44 and 46). Operator action is taken at 1200 seconds. This demonstrates the adequacy of RCS decay heat removal with the AFW system during the FWLB which satisfies SRP 10.4.9 and 15.2.8.

Throughout the transient (Figure 15.2.8-46) the pressurizer water level remains low enough so that only steam is discharged from the PSVs any time the PSVs are open, as required by UFSAR Chapter 5B and 18.II.D for meeting the NUREG-0737 Requirements.

15.2.8.4.5 Radiological Consequences and Containment Performance

Fuel damage is not predicted for this limiting fault event. The dose consequences for this event are no more limiting than the dose consequence assessment presented in section 15.2.8.2.5.

15.2.8.4.6 Conclusions

The auxiliary feedwater capacity is adequate to provide removal of the core decay heat until operator action is taken 20 minutes after event initiation.

The maximum pressurizer water level remains below the PSV inlet nozzles and only steam is discharged, thereby satisfying NUREG-0737 Requirements presented in UFSAR Chapter 5B and 18.II.D.

15.2.9 REFERENCES

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15.3 DECREASE IN REACTOR COOLANT FLOWRATE

15.3.1 TOTAL LOSS OF REACTOR COOLANT FLOW

15.3.1.1 Identification of Causes and Frequency Classification

A complete loss of forced reactor coolant flow (LOF) may result from the simultaneous loss of electric power to all four reactor coolant pumps (RCPs). The only limiting credible failure, which can result in a simultaneous loss of power to the four RCPs, is the complete loss of offsite power.

An LOF event is an Anticipated Operational Occurrence (AOO) and is classified as an incident of moderate frequency.

15.3.1.2 Sequence of Events and System Operation

A loss of electric power to all four reactor coolant pumps produces a reduction of coolant flow through the reactor core that causes an increase in core average coolant temperature, system pressure, and a decrease in margin to DNB. A total loss of forced reactor coolant flow will produce a minimum DNBR more adverse than any partial loss of forced reactor coolant flow event that involves the loss of electrical power to three or less RCPs. This is because the reactor will trip at the same time for both cases, however the partial loss of flow has a slower flow coastdown.

If credit is not taken for a reactor trip on turbine trip, then reactor protection is provided by a core protection calculator (CPC) generated trip initiated when any one of the four RCP shaft speeds drops to 95 percent of normal speed. The credited CPC trip ensures that the event induced minimum DNBR value will remain above the Specified Acceptable Fuel Design Limit (SAFDL) for DNBR.

The combination of loss of primary heat sink (due to loss of offsite power causing a loss of load on turbine, turbine trip and closure of turbine admission valves) with a reduction of reactor coolant flow results in an increase in RCS pressure that is limited by the primary safety valves(PSVs).

The steam bypass control system also becomes unavailable due to loss of offsite power, which results in a loss of condenser vacuum and termination of main feedwater to the steam generators. This sequence of system interactions leads to the opening of the main steam safety valves (MSSVs) which limits the secondary side pressure and removes heat stored in the core and the RCS.

The sequence of events for this moderate frequency LOF event are presented in Table 15.3.1-1. A low voltage on the 4.16 kV safety buses generates an undervoltage signal which starts the emergency diesel generators. The non-safety buses are automatically separated from the safety buses and all loads are shed (except for load centers). After each diesel generator set has attained operating voltage and frequency, its output breaker closes connecting it to its safety bus. Engineered safety feature equipment is then loaded in sequence onto this bus.

Analytical setpoints and response times associated with the Reactor Protective System (RPS) trip functions and Engineered Safety Features Actuation System functions were consistent with, or conservative with respect to, numerical values delineated in UFSAR Sections 7.2 and 7.3.

Following reactor trip and total loss of forced reactor coolant flow, stored and core decay heat removal occurs by means of natural circulation through the core with the steam generators providing primary to secondary side heat transfer.

An auxiliary feedwater actuation signal (AFAS) occurs as the steam generator levels decrease due to the pressure relief and mass discharge during cycling of MSSVs. Actuation of auxiliary feedwater system (AFW) system at a specific time (46 seconds after the AFAS is generated) has no impact on the event DNBR.

Plant operators may initiate cooldown 30 minutes after the event induced reactor trip occurs by utilizing the AFWS and atmospheric dump valves (ADVs).

The Standard Review Plan (Reference 1) states that an incident of moderate frequency, such as the loss of forced coolant flow, should not generate a more serious plant condition without other faults occurring independently. Furthermore, the Standard Review Plan states that an incident of moderate frequency, in combination with a single active component failure, or single operator error, should not result in the loss of function of any barrier other than the fuel cladding.

The loss of offsite power event plus a single failure will not result in a lower DNBR than that calculated for the loss of offsite power event alone. For decreasing reactor coolant flow events, the major parameter of concern is the minimum hot channel DNBR. This parameter establishes whether a fuel design limit has been violated and thus whether fuel damage might be

anticipated. Those factors which cause a decrease in local DNBR are:

- increasing coolant temperature
- decreasing coolant pressure
- increasing local heat flux (including radial and axial power distribution effects)
- decreasing coolant flow.

For the total loss of RCS flow event, the minimum DNBR occurs during the first few seconds of the transient and the reactor is tripped by the CPCs on low RCP shaft speed. Therefore, any single failure that would result in a lower DNBR during the transient would have to effect at least one of the above parameters during the first few seconds of the event. None of the single failures listed in table 15.0-0 will have any affect on the transient minimum DNBR during this period.

Additionally, none of the single failures listed in table 15.0-0 will have any effect on the peak primary system pressure. Nor will the loss of offsite power make unavailable any systems whose failure could affect the calculated peak pressure. For example, a failure of the steam dump and bypass system to modulate or quick open and a failure of the pressurizer spray control valve to open involve systems (steam dump and bypass system and pressurizer pressure control system) assumed to be in the manual mode as a result of the loss of offsite power and, hence, unavailable for at least 30 minutes.

For the reasons stated above, the loss of offsite power event with a single failure is no more adverse than the loss of offsite power event in terms of the minimum DNBR and peak primary system pressure.

Table 15.3.1-1

TYPICAL SEQUENCE OF EVENTS FOR TOTAL LOSS OF REACTOR COOLANT FLOW

Time sec)	Event
0.00	Loss of offsite power occurs
0.00	Turbine trip, Diesel generator starting signal, RCPs coast down and main feedwater is lost
0.60	Low RCP.shaft speed trip condition
0.90	Trip.breakers open
1.50	CEAs.begin to drop
2.85	Minimum.DNBR occurs
3.80	PSVs open (first occurrence)
4.25	Maximum RCS pressure
4.90	MSSVs open (first occurrence)
6.50	PSVs close (last occurrence)
11.30	Maximum steam generator pressure[1]
652.85	Low water level AFAS setpoint reached in steam generator 1
698.85	AFW begins entering steam generators
699.95	MSSVs close (last occurrence)
1800.0	Operator initiates plant cooldown

[1]The maximum steam generator pressure timing is obtained from peak secondary pressure case.

15.3.1.3 Core and System Performance

A. Mathematical Model

Several computer codes were employed to evaluate core and system performance for this moderate frequency event. The HERMITE computer code (see reference 2 and UFSAR Appendix 15D) is used to determine the reactor core response during the postulated RCS flow coastdown. The HERMITE LOF simulation, which includes thermal hydraulic data is transferred to the CETOP computer code (which uses the CE-1 CHF correlation that is described in UFSAR Sections 4.4 and 15.0.3) in order to determine thermal hydraulic conditions at time of minimum DNBR. The thermal hydraulic conditions at time of minimum DNBR are then input to the TORC computer code which also uses the CE-1 CHF correlation to calculate the value of the minimum DNBR during the LOF transient. The thermal margin to DNB for the event is calculated using the TORC computer code.

The CENTS computer code (see UFSAR Section 15.0.3.1.3.2) is used to simulate the Nuclear Steam Supply System (NSSS) response to the total loss of reactor coolant flow event.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a total loss of RCS flow are selected to minimize DNBR during the transient and are presented in Table 15.3.1-2.

The set of initial conditions selected for the analysis presented in this section is one of a very large number of combinations within the reactor operating space of steady state operational configurations, that would provide the minimum thermal margin required by the core operating limit supervisory system (COLSS). The COLSS (described in UFSAR Section 7.7) computes a Power Operating Limit that ensures the thermal margin available in the core is greater than that required to maintain a calculated LOF event minimum DNBR value that is equal to or greater than the DNBR SAFDL.

Parameters were chosen in a manner that minimizes reactor bulk saturation, which results in less void reactivity as determined in HERMITE, since minimizing negative feedback results in more adverse consequences and therefore, presents the limiting postulated LOF event. Results of parametrics show that for any axial power distribution, the most limiting Required Overpower Margin is attributed to the following: a) a minimum gap conductance, which delays the core heat flux decrease after reactor trip and results in a later DNBR turn-around and a lower RCS flow at the time of minimum DNBR. b) a maximum RCS pressure and minimum core inlet temperature, which removes the reactor core from bulk saturation conditions and minimizes void reactivity effects. c) a maximum core flow, which removes the core from bulk saturation conditions and minimizes void feedback effects.

The four pump LOF transient is characterized by the flow coastdown curve that bounds the coastdowns observed during startup testing. The consequences following a total LOF initiated from any one of these combinations of conditions would be no more adverse than those presented herein.

A bounding number of plugged steam generator tubes was assumed in the LOF analysis. The flow coastdown associated with the plugged steam generator tubes four-Pump LOF is more conservative since it causes a more rapid decrease in the RCS flow.

As shown in Table 15.3.1-2, the control element assemblies (CEAs) begin to drop into the core after loss of electrical power to the RCPs and after a conservative delay time that includes the largest possible delay times for sensor delays, CPC response time, and control element drive mechanism (CEDM) coil decay time.

C. Results

The typical response of key parameters as a function of time is presented in Figures 15.3.1-1 to 15.3.1-15 for this moderate frequency event. The loss of offsite power causes the plant to experience a simultaneous turbine trip, loss of main feedwater, condenser nonfunctionality, and a four RCP coastdown. As a result of the RCP coastdown, the CPC generates a trip signal and the CEAs start to drop into the core after a short conservative delay time.

Since there is no power excursion during the transient, the LOF event does not challenge the linear heat generation rate limit of 21 kw/ft and, consequently, the fuel temperature remains below the SAFDL.

The minimum DNBR is greater than the DNBR SAFDL value of 1.34 (see Figure 15.3.1-14) and meets the acceptance criteria of the Standard Review Plan.

Therefore, fuel cladding damage is not predicted for this moderate frequency event.

Table 15.3.1-2
ASSUMED INITIAL CONDITIONS FOR THE
TOTAL LOSS OF REACTOR COOLANT FLOW (DNBR Case)

Parameter	Value
Core power level (% of rated)	102
Core inlet coolant temperature (°F)	548
Pressurizer pressure (psia)	2325
Core mass flow (% of design)	116
Moderator temperature coefficient ($\Delta\rho$/°F)	-0.20E-4
Fuel temperature coefficient	Least negative
CEA worth for trip-WRSO (%$\Delta\rho$)	-8.0
Minimum Radial power peaking factor[1]	1.28
Fuel rod gap conductance (Btu/hr-ft^2-°F)	500
Number of plugged SG tubes	1258
Trip Delay Times (sec) a. Time for CPCs to detect low pump speed b. CPC delay to generate trip signal c. CEA holding coil delay TOTAL	 0.60 0.30 0.60 1.50

Note: The transient is insensitive to the pressurizer and steam generator levels. Nominal values were used in the analysis.

[1] This value corresponds to the lower limit on radial peaking for the "RANGE" trip in the CPC.

15.3.1.4 RCS Pressure Boundary Barrier Performance

A. Mathematical Model

The computer codes that were employed to evaluate fission product barrier performance (other than fuel cladding) for this moderate frequency event are identical to those described in UFSAR Section 15.3.1.3.A.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions relevant to barrier performance for this moderate frequency event are similar to those presented in Table 15.3.1-2 of UFSAR Section 15.3.1.3.B. The safety analysis performs parametrics on core inlet temperature, RCS mass flowrate and steam generator tube plugging for peak pressure cases. The results indicate that the maximum T-cold, maximum RCS flowrate and no SG tube plugging condition produces highest peak RCS pressure while the maximum T-cold, minimum RCS flowrate and no tube plugging condition produces highest secondary peak pressure.

The PSVs were modeled to maximize primary pressure. The maximum allowable setpoints (as allowed by Technical Specification 3.4.10) were used (2475 + 3% tolerance).

The MSSVs were also modeled to maximize pressure. The maximum allowable setpoints (as allowed by Technical Specification 3.7.1) were used (setpoint + 3% tolerance).

C. Results

The typical response of key parameters as a function of time is presented in Figures 15.3.1-1 to 15.3.1-13 for this moderate frequency event. The figures are representative of the transient.

The loss of steam flow due to closure of the turbine stop valves results in a rapid increase in the steam generator pressure. A sharp reduction in primary to secondary heat transfer follows, which, in conjunction with the loss of forced reactor coolant flow, causes a rapid heatup of the primary coolant. The primary safety valves (PSVs) open and cycle several times, and slightly later the main steam safety valves (MSSVs) open and cycle several times.

The maximum RCS pressure is 2664 psia, which is less than 2750 psia (110% of RCS system design pressure of 2500 psia). The maximum secondary-system pressure is 1363 psia, which is less than 1397 psia (110% of secondary system design pressure of 1270 psia).

These values meet the acceptance criteria of the Standard Review Plan (Reference 1).

15.3.1.5 Conclusions

The minimum DNBR remains above the SAFDL limit, thereby ensuring fuel cladding integrity. The initial margin required as a result of this analysis is preserved by the limiting condition of operation on DNBR margin.

The maximum RCS and secondary system pressures remain within 110% of their design values following the total LOF event.

Radiological consequences for this event are bounded. The consequences are the result of normal RCS releases at design source terms and are negligible. This event would not result in any releases of radioactive material above that of a normal reactor trip.

15.3.2 FLOW CONTROLLER MALFUNCTION CAUSING A FLOW COASTDOWN

This event is categorized as a boiling water reactor event in NRC Standard Review Plan 15.3.2 and will therefore not be analyzed.

15.3.3 SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER

A single reactor coolant pump (RCP) rotor seizure can be caused by seizure of the upper or lower thrust-journal bearings. A single reactor coolant pump rotor seizure with loss of offsite power (LOP) is classified as a limiting fault.

The sequence of events, system operations and plant response for the single RCP rotor seizure are almost identical to those

of a single RCP shaft break. Both events cause a rapid drop in core flow to the three pump RCS flow configuration.

The difference is that for the rotor seizure event, the reactor is tripped by the Core Protection Calculator (CPC) on a low RCP speed condition, whereas for the shaft break event, the reactor is tripped by the Reactor Protective System (RPS) on a steam generator differential pressure low flow trip. The seized rotor, having the greater resistance to the Reactor Coolant System (RCS) flow, has a slightly faster coastdown. The RCP shaft break allows a freewheeling coastdown of the impeller with the RCP motor continuing to rotate. The RCS flow coastdown is slightly slower, but because the RCP motor and shaft continue to turn the speed signals to the CPC do not decrease. Protection for this event is delayed until the RPS trip is generated.

Both the seized rotor and sheared shaft events were assessed with the LOP and it was found that the RCP shaft break resulted in slightly more fuel failure and higher radiological dose than the seized rotor event. Therefore, the results of the single RCP sheared shaft are more limiting than the seized rotor event.

15.3.4 REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER

15.3.4.1 Identification of Causes and Frequency Classification

A single reactor coolant pump sheared shaft could be caused by mechanical failure of the pump shaft. This is assumed to

result from a manufacturing defect in the shaft. A single active failure of an Atmospheric Dump Valve (ADV) to close is assumed upon opening of the ADVs after reactor trip. This ADV is assumed to remain open for the duration of the event. Following a turbine trip, a Loss of Offsite Power (LOP) caused by instability of the transmission network, triggered by the turbine trip is assumed. See UFSAR Section 15.0.2.4 for more information regarding the potential LOP following a turbine trip.

A single RCP sheared shaft is classified as a limiting fault.

15.3.4.2 Sequence of Events and Systems Operation

The shearing of the RCP shaft causes the core flow rate to rapidly decrease to a value that would occur with three reactor coolant pumps operating. The reduction in primary coolant flow rate causes an increase in the average coolant temperature in the core, a corresponding reduction in the margin to Departure from Nucleate Boiling (DNB) that may result in some fuel pins experiencing DNB, and an increase in the primary system pressure. Reactor protection is provided by a trip generated by rapid flow reduction that causes a pressure differential (Δr) across the steam generator primary side in the affected loop to decrease to a value below the Δr trip setpoint.

Analytical setpoints and response times associated with the Reactor Protective System (RPS) trip functions and Engineered Safety Features Actuation System (ESFAS) functions are consistent with, or conservative with respect to, numerical

values delineated in UFSAR Sections 7.2 (table 7.2-1) and 7.3. The RPS trip conservatively assumes the largest possible delay time for sensor delay, calculation period, Control Element Drive Mechanism (CEDM) dead time, and CEDM coil decay time. The RPS Steam Generator differential pressure trip is single failure proof.

The sequence of events for this limiting fault incident is presented for each evaluation performed. Approximately 3 seconds following turbine trip, an assumed LOP causes a loss of AC power to the onsite loads due to transmission network instability (see UFSAR Section 15.0.2.4 for more details on 3 second delay). This results in a simultaneous loss of feedwater flow, condenser unavailability, and a coastdown of all RCPs. Approximately 12 seconds after the LOP occurs, the emergency diesel generators start providing power to the two plant 4.16 kV safety buses.

The pressurizer can assist (but is not credited) in the control of the RCS pressure and volume changes during the transient by compensating for the initial expansion of the RCS fluid. The combination of loss of primary heat sink (due to LOP, which causes a loss of load on turbine and closure of turbine admission valves) with the reduction of reactor coolant flow, results in an increase in RCS pressure.

The unavailability of the steam bypass control system (SBCS) due to the LOP results in an increase in secondary pressure. If no operator action is taken to open the ADVs, the RCS pressure increase is limited by the primary safety valves

(PSVs) and the main steam safety valves (MSSVs) limit the secondary side pressure and remove heat stored in the core and the RCS.

The reactor heat removal takes place by means of natural circulation in the RCS, following the coastdown of the undamaged RCPs. The steam generators provide primary to secondary heat transfer. The water level in each of the steam generators begins decreasing immediately after the loss of main feedwater flow, and an auxiliary feedwater actuation signal (AFAS) is generated on low water level in a steam generator. The AFAS setpoint is first reached in the steam generator in the unaffected loop. This leads to the startup of the auxiliary feedwater (AFW) pumps.

For radiological evaluation it is assumed that the operators open the ADVs after reactor trip. Once the ADVs are opened, one valve is assumed to remain stuck open. This results in the eventual generation of a Main Steam Isolation Signal (MSIS) on low steam generator pressure. Once the main steam isolation valves are closed further blowdown of the unaffected steam generator is prevented. AFW is automatically terminated to the affected steam generator as a result of a high differential pressure signal between steam generators. Thirty minutes from the time of shaft shear, the operator is assumed to override the AFW lockout and divert all of the AFW flow to the affected steam generator, covering the tops of the U-tubes after 90 minutes. The operator then initiates cooldown of the RCS by using the ADVs and the AFWS on the unaffected steam generator, while maintaining the level on the affected steam generator.

The process of feeding with the AFWS and releasing steam with the ADVs continues until shutdown cooling entry conditions are reached. The operator may let the ESFAS regulate the feedwater flow by issuing and withdrawing AFAS-1 and/or AFAS-2 signals down to cold shutdown entry conditions. See UFSAR Section 10.4.9 for details of the AFW systems (interface requirements are given in UFSAR Section 5.1.4).

For the core and system performance evaluation, the major parameter of concern is the minimum hot channel Departure from Nucleate Boiling Ratio (DNBR). This parameter establishes whether fuel design limit has been violated and thus whether fuel damage could be anticipated. The factors that cause a decrease in local DNBR are:

- increasing coolant temperature
- decreasing coolant pressure
- increasing local heat flux (including radial and axial power distribution effects)
- decreasing coolant flow

For the single RCP shaft break event, the minimum DNBR occurs during the first one to four seconds. Therefore, any single failure that would result in a lower DNBR during the transient would have to affect at least one of the above parameters during the first one to four seconds of the event.

The single failures that have been postulated are listed in Table 15.0-0. Most of these failures affect the secondary system, and during the first one to four seconds they do not

affect the primary system parameters that determine the DNBR. The analysis does not credit non-safety related components for any mitigating purposes. The only failures, that could affect the RCS behavior during this interval, are:

- a loss of normal AC
- a failure of the pressurizer level control system
- a failure of the pressurizer pressure control system
- a failure of the reactor regulating system

The loss of normal AC power, which is assumed to occur three seconds after turbine trip, results in loss of power to the RCP, the condensate pumps, the circulating water pumps, the pressurizer pressure and level control systems, the reactor regulating system, and the feedwater control system.

Loss of function of the condensate and circulating water pumps and the feedwater control system initially affects only the secondary system, and thus does not affect DNBR in the first one to four seconds of the transient. Loss of power to the reactor regulating system and pressurizer level and pressure control systems renders those systems unavailable. This unavailability will have no significant impact on DNBR during the first one to four seconds. Loss of power to the RCPs is the only potentially significant failure with regard to DNBR that results from a loss of AC. However, as a result of a three second delay between the time of turbine trip and the time of loss of offsite power (see UFSAR section 15.0.2.4), there is no effect on minimum DNBR. Failure of the pressurizer

level control, pressure control, or reactor regulating systems has minimal affect on any of the four factors that determine DNBR during the first one to four seconds of the event. Thus, none of the single failures listed in Table 15.0-0 will result in a more adverse transient minimum DNBR than that predicted for the single RCP shaft break event.

For pressure boundary performance evaluations, there is no single failure in addition to the LOP which results in more limiting peak RCS or secondary side pressures.

For radiological evaluations, a single active failure of an ADV to close is assumed once the ADVs are opened and this ADV is assumed to remain open for the duration of the event. The stuck open ADV is assumed to cause all of the iodine contained in the affected steam generator to be released to the atmosphere. Thus, this failure in combination with the LOP maximizes the radiological consequences of the single RCP shaft break event. None of the other single failures listed in Table 15.0-0 in combination with a loss of AC will yield more severe radiological consequences.

15.3.4.3 Core and System Performance

A. Mathematical Model

Several computer codes were employed to evaluate core and system performance for the sheared shaft limiting fault event. The transient core response was simulated using the HERMITE computer code (Reference 2) and the CETOP computer code (described in UFSAR Section 4.4 and

15.0.3.1.6) to generate the limiting core thermal hydraulic conditions at the time of minimum DNBR. The time of occurrence and the value of the minimum DNBR were calculated by the CETOP code.

The thermal-hydraulic code, TORC (described in UFSAR Section 15.0.3.1.6), was used to calculate DNBR values at various integrated radial peaking factors (Fr) to form data pairs. TORC output was used to determine fuel failure using the statistical convolution technique (see UFSAR section 15.4.8.3.C).

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a single RCP sheared shaft are presented in Table 15.3.4-1. These initial conditions result in the most adverse core performance.

UFSAR Appendix 15D describes the RCP coastdown methodology.

The flow coastdown is shown in Figure 15.3.4-8. The flow coastdown curve was developed using the methodology in Appendix 15D.

Table 15.3.4-1
ASSUMED INITIAL CONDITIONS FOR THE SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP CORE AND SYSTEM PERFORMANCE

Parameter	**Value**
Core Power Level	100%
Core Average Heat Flux	Maximum
Core inlet coolant temperature deg F	548
Core inlet pressure psia	2415
Core mass flow (% of design)	116
Moderator Temperature Coefficient $\Delta\rho$/deg F	-0.20×10^{-4}
Fuel Temperature Coefficient	Least Negative
CEA worth for trip - WRSO (%$\Delta\rho$)	-8.0
Maximum radial peaking factor	2.0
Fuel rod gap conductance (Btu/hr-ft2-deg F)	Minimum
Kinetics Parameters	BOC
Axial Power Distribution	-0.3
Loss of Offsite Power	Yes

The limiting initial conditions selected for the analysis have the core as far from bulk saturation conditions as possible and yet represents reasonable initial plant conditions from an operational standpoint. The results of parametrics show that the sheared shaft event initiated from top peaked initial conditions, away from saturation conditions lead to the most conservative transient simulations. Since the minimum DNBR for this event occurs

so quickly in the transient (< 3 seconds), the analysis is rather insensitive to the system responses when compared to the initial core parameters.

That is why the core parameters are discussed in detail in this section. The following analysis initial conditions tend to maximize the calculated fuel damage:

- Maximum rated core power (from a Power Operating Limit): Maximum allowable power results in more fuel failure.
- Minimum core inlet temperature: Maximizes initial core wide subcooling.
- Maximum core inlet pressure: Maximizes initial core wide subcooling.
- Maximum RCS flow: Maximizes initial core wide subcooling.
- Full power core average heat flux: Maximum Core Average Heat Flux results in more fuel failure.
- Top peaked power distribution (most negative Axial Shape Index limit): Since minimum DNBR occurs prior to CEA insertion, top peaked power distribution results in more limiting DNBR values.
- Maximum radial peaking factor (Fr): A maximum unrodded peaking factor promotes core wide subcooling and corresponds to a more limiting pin power distribution.

An unrodded pin power distribution also results in a larger number of failed fuel pins.

- Most positive (least negative) Moderator Temperature Coefficient: Increases the positive reactivity insertion due to moderator temperature feedback during the flow coastdown.

- Least negative (most positive) Fuel Temperature Coefficient (FTC): FTC has minimal impact on the analysis due to the event being short (< 4 seconds). Any reactivity feedback from the fuel in this period has a benign effect mainly because the fuel temperature does not change significantly during the time of interest.

- Maximum delayed neutron fraction: A maximum delayed neutron fraction, β, consistent with beginning of cycle conditions delays the core power decrease after reactor trip.

- Slower CEA drop time (scram position versus time) and CEDM Coil Delay time: Delays the core power decrease after reactor trip which results in a later DNBR turnaround and a lower flow at the time of minimum DNBR.

- Minimum gap conductance: Delays the core heat flux decrease after trip: resulting in a later DNBR turnaround and a lower flow at time of minimum DNBR.

C. Sequence of Events

The Sequence of Events for the Core and System Performance Analysis is shown in Table 15.3.4-2: below.

Table 15.3.4-2
SEQUENCE OF EVENTS FOR THE SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP FOR CORE AND SYSTEM PERFORMANCE

Time (sec)	**Event**
0.0	Reactor Coolant Pump Shaft Break occurs
2.5	Minimum DNBR Occurs
2.5	Reactor trip on low RCS flow, based on SG $\Delta\rho$
2.5	Reactor Trip Breakers Open, Turbine Generator Trip
3.1	CEAs begin to drop into the core
5.5	Loss of Offsite Power Occurs
10.0	Event Terminated

D. Results

During the first few seconds of the transient, the combination of decreasing flow rate and increasing RCS temperature results in a decrease in the DNBR of the fuel pins. The transient minimum DNBR is below the Specified Acceptable Fuel Design Limit (SAFDL) for DNBR. Figure 15.3.4-12 shows the variation of the minimum DNBR with time. The negative CEA reactivity inserted after

reactor trip causes a rapid power and heat flux decrease, which causes DNBR to increase. The amount of predicted failed fuel is determined with the statistical convolution technique (see UFSAR Section 15.4.8.3.C). The limiting fuel failure is discussed in UFSAR Section 15.3.4.6 ("EAB/LPZ Radiological Consequences and Containment Performance") and as long as the Fr (radial peaking factor) and fuel failure combination results in a bounding (2-hour site boundary) thyroid dose of less than 260 REM, the consequences remain within 10 CFR 100 guideline values.

DNB Propagation is evaluated by verifying that the bounding fuel clad strain evaluation is still applicable. The absolute minimum time in DNB required to reach NRC imposed strain limit of 29.3% is 4.5 seconds. This minimum time is based on the following conditions:

- Fuel Rod to RCS Differential Pressure < 1200 psid
- Local Heat Flux < 0.7E6 BTU/hr-ft2
- Local Mass Flux > 1.4 E6 lbm/hr-ft2
- Local Quality > -0.1

The analysis verifies the local conditions are within the specified ranges and that the overall time in DNB is less than 4.5 seconds. Therefore, DNB propagation will not occur.

15.3.4.4 RCS Pressure Boundary Barrier Performance

A. Mathematical Model

The CENTS computer code (see UFSAR Section 15.0.3.1.3.2) was used to simulate the secondary and Nuclear Steam Supply System thermal hydraulic response to a single RCP shaft break with a LOP resulting from turbine trip

B. Input Parameters and Initial Conditions

The input parameters and initial conditions relevant to barrier performance for this limiting fault event are presented in Table 15.3.4-3.

Table 15.3.4-3
ASSUMED INITIAL CONDITIONS FOR THE SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP FOR PRESSURE BOUNDARY PERFORMANCE

Parameter	**Value**
Core Power Level	102%
Core inlet coolant temperature deg F	548
Pressurizer Pressure (psia)	2325
Core mass flow (% of design)	116
Moderator Temperature Coefficient $\Delta\rho$/deg F	-0.18×10^{-4}
Fuel Temperature Coefficient	Least Negative
CEA worth for trip - WRSO (%$\Delta\rho$)	-8.0
Fuel rod gap conductance (Btu/hr-ft2-deg F)	Minimum
Kinetics Parameters	BOC
AFAS Setpoint (%WR)	20%
MSSV Setpoints	Minimum
MSSV Tolerance	+3%
PSV Setpoints	Maximum
PSV Tolerance	+3%
Number of plugged SG Tubes	1258
Loss of Offsite Power	Yes
Single Failure	None

The PSVs were modeled to maximize primary pressure. The maximum allowable setpoints (as allowed by Technical Specification 3.4.10) were used (2475 + 3%).

The MSSVs were also modeled to maximize primary and secondary pressure. The maximum allowable setpoints (as allowed by Technical Specification 3.7.1) were used (setpoint + 3% tolerance).

C. Sequence of Events

The Sequence of Events for the pressure boundary performance analysis are shown in Table 15.3.4-4 below.

Table 15.3.4-4
SEQUENCE OF EVENTS FOR THE SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP FOR PRESSURE BOUNDARY PERFORMANCE[a]

Time (sec)	**Event**
0.0	Reactor Coolant Pump Shaft Break occurs
1.7	Main Steam Isolation Signal on low SG pressure
2.5	Reactor trip on low RCS flow, based on SG $\Delta\rho$
2.5	Reactor Trip Breakers Open, Turbine Generator Trip
3.1	CEAs begin to drop into the core
5.5	Loss of Offsite Power Occurs
6.4	PSVs open
6.6	Peak RCS Pressure occurs
7.8	PSVs close
17.2	Peak SG pressure occurs
17.2	MSSVs open first time
72.7	MSSVs close[b]
807.0	AFAS generated in SG #1
853.0	AFW flow delivered to SG #1
964.3	AFW Reset in SG #1[b]
1301.9	AFAS generated in SG #2
1301.9	AFW flow delivered to SG #2
1373.2	AFW Reset in SG #2[c]
1800	Operators begin plan cooldown. Event Terminated

a. The exact diesel generator sequencing time is not critical for this event and was not specifically modeled since the diesel generator will be available to power AFW “A” well before AFAS is reached.

b. MSSVs cycle open and closed throughout the transient.

c. AFW actuation may occur and reset more than once.

D. Results

The typical transient response of key NSSS parameters as a function of time is presented on Figures 15.3.4-1 to 15.3.4-12 for this limiting fault event.

The shearing of the RCP shaft causes a reactor trip to occur on a steam generator Δr low RCS flow trip that results in a reactor trip followed by a concurrent turbine trip, which causes turbine admission valve closure. Furthermore, a reduction of flow in the affected RCS loop is compounded by the occurrence of a LOP three seconds later. The steam bypass control system, condenser and main feedwater system become unavailable, resulting in a rapid increase in secondary side pressure and temperature. The reduction in primary-to-secondary heat transfer causes a rapid heatup of the primary side coolant. No operator action is assumed for 30 minutes. The PSVs open to limit pressure and slightly later the main steam safety valves open.

The RCS pressure reaches a maximum of 2614 psia (see Figure 15.3.4-4), which is less than 2750 psia (110% of RCS system design pressure of 2500 psia). The secondary system pressure reaches a maximum of 1303 psia (see Figures 15.3.4-9 and 15.3.4-10), which is less than 1397 psia (110% of secondary design pressure of 1270 psia).

These event primary and secondary pressure values meet the acceptance criteria of the Standard Review Plan.

15.3.4.5 NSSS Response for Control Room Dose Consequences

A NSSS response evaluation is performed to determine the time of Control Room Essential Filtration Actuation and secondary mass releases due to the MSSVs and the stuck open ADV for input into the control room dose analysis presented in UFSAR 6.4.7.3.

A. Mathematical Model

The CENTS computer code (see UFSAR Section 15.0.3.1.3.2) was used to simulate the secondary and Nuclear Steam Supply System (NSSS) thermal hydraulic response to a single RCP shaft break with a LOP resulting from turbine trip.

B. Input Parameters and Initial Conditions

Input parameters and initial conditions are established to maximize secondary side releases and delay the Safety Injection Actuation Signal, which starts the control room essential filtration. Initial conditions are shown below in Table 15.3.4-5.

Table 15.3.4-5
ASSUMED INITIAL CONDITIONS FOR THE SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP AND A STUCK OPEN ADV

Parameter	**Value**
Core Power Level	102%
Core inlet coolant temperature deg F	548
Pressurizer Pressure (psia)	2325
Core mass flow (% of design)	116
Moderator Temperature Coefficient $\Delta\rho$/deg F	$-4.4\text{x}10^{-4}$
CEA worth for trip - WRSO (%$\Delta\rho$)	-8.0
SIAS Setpoint (psia)	1750
Initial SG Level (%WR)	42%
MSIS Setpoint (psia)	1005
AFAS Setpoint (%WR)	20%
AFW SG DP Lockout Setpoint (psid)	130
MSSV Setpoints	Minimum
MSSV Tolerance	-3%
Loss of Offsite Power	Yes
Single Failure	Stuck Open ADV

C. Sequence of Events

The Sequence of Events for the NSSS Response for Control Room Dose are shown in Table 15.3.4-6 below.

Table 15.3.4-6

SEQUENCE OF EVENTS FOR THE SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP WITH A STUCK OPEN ADV

Time (sec)	**Event**
0.0	Reactor Coolant Pump Shaft Break occurs
2.5	Reactor trip on low RCS flow, based on SG $\Delta\rho$
2.5	Reactor Trip Breakers Open, Turbine Generator Trip
3.1	CEAs begin to drop into the core
5.5	Loss of Offsite Power Occurs
7.4	Main Steam Safety Valves Open
15.3	Steam Generator Water Level Reaches AFAS setpoint in SG #1
18.8	Steam Generator Water Level Reaches AFAS setpoint in SG #2
61.4	Auxiliary Feedwater Initiated to SG #1
61.4	Auxiliary Feedwater Initiated to SG #2
63.9	Main Steam Safety Valves Close
122.5	Operator initiates plant cooldown by opening one ADV on each steam generator. ADV on SG #1 instantly fails full open
152.5	MSIS actuated on low SG pressure
172.4	SG $\Delta\rho$ causes AFAS lockout on SG #1, AFW to SG #1 terminated
242.5	Operator shuts ADV on SG #2
396.9	AFAS reset on high SG level in SG #2
290.3	SIAS Setpoint reached on low pressurizer pressure
330.3	SI flow initiated
447.0	SG #1 reaches dryout conditions
1800.	Operators take manual control of AFW and begin filling SG #1. AFW in SG #2 is terminated.
5291.5	SG #1 level reaches the physical location of the top of the SG U-tubes (14% NR)
5400.4	SG #1 level reaches the top of the SG U-tubes considering EOP Uncertainties (43% NR)
5401.4	Event Terminated.

D. Results

The shearing of the RCP shaft causes a reactor trip to occur on a steam generator $\Delta\rho$, low-RCS-flow trip that results in a reactor trip followed by a concurrent turbine trip, which causes turbine admission valve closure. Furthermore, a reduction of flow in the affected RCS loop is compounded by the occurrence of a LOP three seconds later. The steam bypass control system, condenser and main feedwater system become unavailable, resulting in a rapid increase in secondary side pressure and temperature. The reduction in primary-to-secondary heat transfer causes a rapid heatup of the primary side coolant. After reactor trip the operator opens ADVs on both steam generators. Once the ADVs are opened, one valve is assumed to remain stuck open. This results in the eventual generation of a Main Steam Isolation Signal (MSIS) on low steam generator pressure. Once the main steam isolation valves are closed, further blowdown of the unaffected steam generator is prevented. AFW is automatically terminated to the affected steam generator as a result of a high differential pressure signal between steam generators. Thirty minutes from the time of shaft shear, the operator overrides the AFW lockout and diverts all of the AFW flow to the affected steam generator, covering the tops of the U-tubes after 90 minutes.

Table 15.3.4-7

TIME OF SIAS AND SECONDARY MASS RELEASES FOR THE SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER AND STUCK OPEN ADV

Time of SIAS (sec)	**Total MSSV Release (lbm)**	**Total ADV Release from SG #1 (lbm)**	**ADV Release for 600 seconds from SG #1 (lbm)**
290.3	12.238×10^4	4.196×10^5	1.108×10^5

15.3.4.6 EAB/LPZ Radiological Consequences/Containment Performance

A. Physical Model and Assumptions

To evaluate the consequences of the single reactor coolant pump shaft break with a LOP event, it is assumed that the condenser is not available for the entirety of the transient. After reactor trip occurs, an MSIS is generated, the steam generators are isolated and the pressure in the steam generators rises quickly to the MSSV setpoint. Sometime after the reactor trip, the operators will open an ADV on each steam generator to stop the MSSVs from cycling. When they open the ADVs, one is assumed to cycle to a fully-opened position and stick there. At this point, the operators close the ADV on the unaffected steam generator. The exact timing of these operator actions does not affect the calculated offsite doses since the dose calculation makes the simplifying assumption that the iodine contained in the affected steam generator is

released to the atmosphere at the initiation of the event. At thirty minutes the operators divert all of the AFW flow to the affected steam generator until the tops of the U-tubes are covered and then proceeds with the controlled cooldown using the ADVs on the unaffected steam generator and the AFWS while maintaining the level in the affected steam generator.

The U-tubes for the unaffected steam generator remain covered by water throughout the event so a Decontamination Factor (DF) of 100 is used for releases from this steam generator.

Peak containment pressure is not calculated for these events and would be bounded by the LOCA and MSLB events. Containment integrity will not be challenged. In the case of the sheared shaft event, the actual time the PSV is opened is less than 3 seconds.

B. Calculational Methods and Parameters

Even for identical core average and hot channel conditions for a given transient event, the number of fuel pins that experience DNB, will vary from cycle to cycle. The calculated amount of fuel failure is sensitive to fuel loading pattern (i.e. pin power distribution). Therefore, it would be difficult to bound the calculated fuel failure of all future reloads based upon any one transient response. In order to accommodate the potential variability between cycles, the calculated dose was expressed as a function of the product of the radial

peaking factor and the fuel failure fraction. The values of this product just corresponding to the limit (i.e., thyroid dose of 260 REM) were determined.

A cycle-specific analysis ensures that the product of the failure (based upon actual core loading) and the maximum cycle radial peaking factor do not exceed these limit products. As long as the product for the cycle is less than the product corresponding to the respective limit, the doses for the cycle will be less than the limits and the radiological consequences for a 2-hour, site-boundary thyroid doses will be within 10 CFR 100 guideline values.

Since an ADV is assumed to stick open, the containment barrier is not credited. Operators take action to close all system boundary valves to minimize flow/discharge to the environment.

The major assumptions, parameters, and inputs to calculational methods used to evaluate the radiological consequences of the single RCP shaft break are presented in Table 15.3.4-8. Additional clarification is provided as follows:

1. The RCS equilibrium activity is based on long term operation at 102% of Rated Thermal Power (RTP) with a technical specification limit on primary activity, expressed in Dose Equivalent I-131 (DEQ I-131) of 1.0μCi/gm.

The RCS activity is calculated to determine the total amount of activity leaked into the secondary system during the duration of the accident due to a 0.5 gal/min primary-to-secondary leak per steam generator. The primary-to-secondary leakage of 1 gal/min is assumed to continue to the steam generators for the entire event. The activity in the fuel clad gap is 10% of the iodines and 10% of the noble gases accumulated in the fuel at the end of core life, assuming continuous full power operation. All of the activity in the fuel gap for fuel rods that are calculated to experience DNB is assumed to be uniformly mixed with the reactor coolant. This assumption is consistent with Regulatory Guide 1.77.

2. The steam generator equilibrium activity is assumed to be 0.1 μCi/gm DEQ I-131 prior to the accident. This is the technical specification limit for steam generator activity.

3. Offsite power is not available. When the operators open the ADVs following the reactor trip, one is assumed to cycle to a fully-opened position and stick there. At this point, the operators close the ADV on the unaffected steam generator. The exact opening time of the stuck open ADV does not matter for the calculated EAB or LPZ doses since the simplified dose calculation model assumes all of the iodine contained in the affected steam generator is released to the

atmosphere instantaneously at the initiation of the event. At 1800 seconds, the operators begin flooding the affected steam generator and cover the tubes by 5400 seconds. The operators control the cooldown using the ADVs and the AFWS on the unaffected steam generator, while maintaining the level in the affected steam generator.

4. For the fluid leaked from primary to secondary, iodine is assumed to be released to the atmosphere with a DF of 1.0 in the affected steam generator when the tubes are uncovered. The DF is increased to 100 when the tubes are recovered at about 90 minutes.

5. Mass releases are based on the heat that must be removed from the RCS and they include the decay heat and the stored heat in the primary coolant and in the metal masses. Table 15.3.4-9 shows the releases for this analysis.

6. No credit for radioactive decay in transit to dose point is assumed.

7. The atmospheric dispersion factor used in this analysis is listed in Table 2.3-31.

8. The mathematical model used to analyze the activity released during the course of the accident is described in UFSAR Section 15.0.4 ("Radiological Consequences").

9. Since the PSVs lift for this event, the dose calculation conservatively takes into account the activity released to containment, even though the Reactor Drain Tank is sized to remain intact from the PSV discharge.

The uncertainties and conservatisms in the assumptions used to evaluate the radiological consequences of the single RCP shaft break with a LOP are as follows:

1. A conservative primary-to-secondary leakage of 1 gpm is used. This corresponds to 1440 gallons per day (gpd). Operation with a primary-to-secondary leak of 1 gpm is not allowed. Technical Specification 3.4.14 limits primary-to-secondary leakage through any one steam generator to less than 150 gpd.
2. The meteorological conditions assumed to be present at the site during the course of the accident are based on 5% level χ/Q values. Meteorological conditions will be less severe 95% of the time. This results in conservative values of atmospheric dispersion calculated for the EAB or LPZ outer boundary. Furthermore, no credit has been taken for the transit time required for activity to travel from the point of release to the EAB or LPZ outer boundary.
3. The dose calculations conservatively use the maximum cooldown rate of 100°F/hr allowed by Technical Specifications. This approach was independent of whether the charging system could compensate for the accompanying rate of shrinkage.

4. The dose calculations use a conservatively low steam generator liquid mass constant value of 160,600 lbm for the intact steam generators. This lower value is conservative as it will increase the steam generator DEQ I-131 concentration from which releases to the site boundary evolve.

DECREASE IN REACTOR

COOLANT FLOWRATE

Table 15.3.4-8

TYPICAL PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP
(Sheet 1 of 2)

Parameter	Value
A. Data and assumptions used to evaluate the radioactive source term	
a. Power level (% RTP)	102
b. Percent of fuel calculated to experience DNB and fail (%).	17.0 at FR=1.72[2]
c. Reactor coolant activity before event, based on Technical Specifications (μCi/gm)	1.0
d. Secondary system activity before event (μCi/gm)	0.1
e. Minimum primary system liquid inventory (excluding mass in pressurizer), lbm	510,000
f. Minimum steam generator inventory, lbm per steam generator	160,600
B. Data and assumptions used to estimate activity released from the secondary system	
a. Primary to secondary leak (gpm)	0.5 per SG
b. Total mass release through the MSSVs and ADVs based on boiling off inventory to remove decay heat and stored heat.	
• Decay heat based on	1979 ANS Standard with a 2σ uncertainty.
• Specific heat for RCS metal masses.	Maximum
C. Atmospheric dispersion factors (sec/m^3)	
• EAB (0-2 hours)	2.3×10^{-4}
• LPZ (0-8 hours)	6.4×10^{-5}

[2] These values were used in the Control Room Dose calculation and are more restrictive than those used for the EAB dose. As long as the product of the Fr and fuel failure fraction (= 29.24%) does not increase, the Control Room Dose calculations will remain bounding and the EAB dose will remain within acceptance criteria.

DECREASE IN REACTOR

COOLANT FLOWRATE

Table 15.3.4-8

TYPICAL PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP
(Sheet 2 of 2)

Parameter	Value
D. Health Physics Parameters	
1. Dose conversion assumptions	Refer to UFSAR Section 15.0.4
2. Control room design parameters	Refer to Appendix 15B and UFSAR Section 6.4
E. Percent of core fission products assumed to be available for release to reactor coolant	10
F. Iodine DF for the unaffected steam generator	100
G. Iodine partition coefficient for the affected steam generator for first 90 minutes[3]	1
H. Credit for radioactive decay in transit to dose point	No
I. Loss of offsite power	Yes
J. RCS Iodine and Noble Gas Source Terms after event initiation.	
Isotope	Ci/MWt
I-131	2.51×10^{4}
I-132	3.81×10^{4}
I-133	5.62×10^{4}
I-134	6.57×10^{4}
I-135	5.10×10^{4}
Kr-83m	4.15×10^{3}
Kr-85	4.40×10^{2}
Kr-85m	1.30×10^{4}
Kr-87	2.15×10^{4}
Kr-88	3.20×10^{4}
Xe-131m	2.60×10^{2}
Xe-133m	1.38×10^{3}
Xe-133	5.62×10^{4}
Xe-138	4.97×10^{4}

[3] The U-tubes in the affected steam generator are assumed to be re-covered by water after this time.

Table 15.3.4-9

TYPICAL SECONDARY SYSTEM MASS RELEASE TO THE ATMOSPHERE FOR THE SINGLE REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

Time	Integrated Primary-to-Secondary Leakage (gallons)	Secondary System Mass Release (lbm)
2 hr	120	9.54×10^5
8 hr	480	2.42×10^6

15.3.4.7 Conclusions

The maximum RCS and secondary side pressures due to a single RCP shaft break in combination with a LOP resulting from turbine trip remain less than 110% of their design values.

In the event of a single RCP shaft break or rotor seizure event, the 2-hour EAB doses will be less than 260 REM for a RTP of 3990 MWt. This exposure is within 10 CFR 100 limits. The NRC changed the acceptance criteria for this event in CESSAR SER Supplement 2 as a result of the assumptions made (LOP, ADV sticks open). The acceptance criteria were changed from the guidelines in the Standard Review Plan (Reference 1) to the limits given in 10 CFR Part 100.

15.3.5 REFERENCES

1. "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Sections 15.3.3 - 15.3.4: Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break," NUREG-0800 Rev. 1, July 1981.

2. "HERMITE A Multi-Dimensional Space-Time Kinetics Code for PWR Transients," CENPD-188, March 1976 (Proprietary).

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

15.4.1 UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL FROM A SUBCRITICAL OR LOW (HOT ZERO) POWER CONDITION

15.4.1.1 Identification Cause and Frequency Classification

An uncontrolled withdrawal of control element assemblies (CEAs) is postulated to occur as a result of a single failure in the control element drive mechanism (CEDM), control element drive mechanism control system, reactor regulating system or as a result of operator error.

These initiating events are Anticipated Operational Occurrences (AOOs), as discussed in Table 3.9-1 and are classified as incidents of moderate frequency.

The uncontrolled CEA withdrawal (CEAW) from subcritical and low (hot zero) power conditions are presented in this section.

15.4.1.2 Sequence of Events and Systems Operation

The withdrawal of CEAs from subcritical or low (hot zero) power conditions adds reactivity to the reactor core, causing both the core power level and the core heat flux to increase, followed by corresponding increases in reactor coolant temperatures and reactor coolant system (RCS) pressure. The withdrawal of CEAs also produces a time-dependent redistribution of core power. These transient variations in core thermal parameters may result in the system’s approach to the specified acceptable fuel design limits (SAFDLs) and RCS and secondary system pressure limits, thereby requiring the protective action of the reactor protective system (RPS).

The reactivity insertion rate accompanying the uncontrolled CEA withdrawal is dependent primarily upon the CEA withdrawal rate and the CEA worth since, at subcritical or Hot Zero Power (HZP) conditions, the normal reactor feedback mechanisms do not occur until power generation in the core is large enough to cause changes in the fuel and moderator temperatures. The reactivity insertion rate determines the rate of approach to the fuel design limits. Based on the reactivity insertion rate and the system initial conditions, the limiting moderate frequency uncontrolled CEAW transient is terminated by a high logarithmic power level trip (HLPT) for the subcritical initial condition, or an RPS variable overpower trip (VOPT) for the HZP initial condition. Depending on the reactivity insertion rate and the system initial conditions, the CPC VOPT, CPC Low DNBR, or high LPD trips may terminate the transient, as well.

The uncontrolled CEA withdrawal from subcritical or HZP conditions causes subcritical multiplication to increase core power resulting in a reactor trip. The brief power excursion which results in a slight increase in RCS temperature, is terminated when the CEAs begin to insert. The RCS pressure remains below the pressurizer pressure safety relief valve setpoint. The secondary side pressure increases slightly following reactor trip and is limited by the steam generator safety valves. The atmospheric dump valves are used to cool the RCS to shutdown cooling entry conditions. The feedwater flow rate is operated in manual mode and is very low because it matches the steam flow rates. RCS heat is removed via the steam bypass control system until the shutdown cooling system (SCS)

is manually actuated at a time when the RCS temperature and pressure have been reduced to approximately 350°F and 400 psia. The SCS provides sufficient cooling flow to cool the RCS to cold shutdown.

The sequence of events for the limiting moderate frequency CEA withdrawal transient from subcritical and HZP conditions are presented in Table 15.4.1-1. Analytical setpoints and response times associated with the RPS trip functions are consistent with, or conservative with respect to, numerical values delineated in UFSAR Section 7.2. A conservative CEA coil decay time of 0.6 seconds was used in simulating the uncontrolled CEAW transients.

Table 15.4.1-1

SEQUENCE OF EVENTS FOR SUBCRITICAL AND HOT ZERO POWER CASES

Time (seconds)		**Event**
Subcritical	**HZP**	
0.0	0.0	CEAs begin uncontrolled withdrawal
71.86	24.89	Core power reaches RX trip setpoint (% RTP)
72.36	25.34	Trip breakers open and CEA withdrawal stops
72.96	25.94	CEAs begin to drop
72.97	25.95	Peak power reached (% RTP)
73.16	26.18	Minimum DNBR occurs
73.17	26.19	Peak heat flux reached (% RTP)
73.75	30.12	Withdrawn CEAs are assumed to be fully inserted to its original position for the Subcritical event while all the CEAs except the most Worth Rod Stuck Out (WRSO) are assumed fully inserted for HZP case

15.4.1.3 Core and System Performance

A. Mathematical Model

Several computer codes are employed to evaluate core and system performance for the limiting uncontrolled CEAW moderate frequency transients. The CENTS computer code (see UFSAR Section 15.0.3.1.3.2) is used to simulate the Nuclear Steam Supply System (NSSS) response to these events by modeling the neutronics, thermal hydraulics and plant systems during transient conditions. The CETOP computer code (see UFSAR Section 4.4 and 15.0.3.1.6), uses thermal hydraulic and heat flux data from CENTS to simulate fluid conditions within the reactor core in order to calculate the time and numerical value of the fuel pin minimum departure from nucleate boiling ratio (DNBR).

A steady state peak linear heat rate of 21 kW/ft has been established as the Limiting Safety System Setting (LSSS) to prevent fuel centerline melting during normal steady state operation. Following design basis AOOs, the transient linear heat rate may exceed 21 kW/ft provided the fuel centerline melt temperature is not exceeded. However, if the transient linear heat rate does not exceed 21 kW/ft, then the fuel centerline melt temperature is also not exceeded. The calculated transient value of Linear Heat Generation Rate (LHGR) exceeds the nominal steady state LSSS of 21 kW/ft for a short period of time during the

transient. Therefore, a hand calculation is made on the amount of energy rise and deposition in the fuel, i.e., an adiabatic deposited energy calculation is performed. This is done to ensure that the fuel temperature (i.e., fuel enthalpy) remains below the melting point and no fuel failure occurs.

B. Input Parameters and Initial Conditions

Important input parameters and initial conditions used to analyze the NSSS response to a CEA withdrawal from subcritical and HZP conditions are delineated in Table 15.4.1-2. These parameters have been determined to comprise the limiting set of conditions from which an uncontrolled CEA withdrawal could be initiated from subcritical or low HZP conditions and produce the limiting moderate frequency events. A maximum initial core gap conductance is used to minimize Doppler feedback and maximize core power.

Parametric analyses have indicated that the lowest initial power and the highest reactivity insertion rates result in the highest peak core power and the most limiting thermal and hydraulic conditions for DNBR. For the subcritical event, the initial subcritical power level that results from a conservative neutron source strength is assumed. The initial minimum power, 5E-10% RTP, is calculated based on this source strength and the subcriticality imposed by the withdrawn bank, and subcriticality

multiplication. For the low power event, the lowest initial power is determined based on the High Log Power Trip (HLPT) bypass removal setpoint.

The maximum reactivity insertion rates are based on the maximum CEA withdrawal rate of the CEA drive system, 30 inches/min. For the subcritical event, only the withdrawal of regulating CEAs are evaluated since the PVNGS Technical Specifications requires adequate shutdown margin to prevent going critical by withdrawal of shutdown CEAs, and the out-of-sequence withdrawal of CEAs would result in immediate trip by CPCs due to high penalty applied. In addition, plant startup procedures instructs sequential withdrawal of CEAs in the following order, first the shutdown CEAs, then the part strength CEAs, and finally regulating CEAs. Based on the calculated maximum CEA worths, and the maximum CEA withdrawal rate, the reactivity insertion has a maximum expected rate of 2.835E-4 delta rho/sec for a CEA withdrawal from subcritical condition. The low (HZP) power maximum reactivity insertion rate is determined by performing a parametric study on the CEA bank worth, CEA positions, and axial power shapes to establish bounding bank worth and bounding axial shape. Based on the bounding bank worth and the bounding axial shape, bounding differential rod worths are determined using the HERMITE code. The maximum reactivity insertion rate of 1.7E-4 delta rho/sec is used

corresponding to the bounding differential rod worth and the maximum withdrawal speed of 30 inches/min for a CEA withdrawal from low power conditions.

For the subcritical CEA withdrawal (CEAW), the High Log Power Trip (HLPT) occurs at a setpoint of 0.1% RTP. For the CEAW at low power conditions, the analysis RPS VOPT occurs at a setpoint of 11%. The evaluation used a 12% trip setpoint to conservatively envelope the RPS VOPT band and increase rates described in UFSAR Section 7.2.

The initial conditions that result in the most rapid approach to the fuel design limits for the subcritical and HZP events are a core inlet temperature of 572°F, based on the Technical Specification in Mode 1 and operating procedures limiting temperature in lower modes, and minimum RCS flow based on four pump operation. These yield reduced heat removal, resulting in higher fuel temperatures and lower DNBRs. A minimum pressurizer pressure was used for the subcritical and HZP event conditions to obtain a conservative minimum DNBR and to minimize the initial negative reactivity feedback margin for greater fuel enthalpy production. The most positive moderator temperature coefficient (MTC) of $+0.5 \times 10^{-4}$ $\Delta\rho$/°F is assumed for this analysis. Also, the least negative in cycle Doppler coefficient was used for both uncontrolled CEA withdrawal transients.

Table 15.4.1-2

INPUT PARAMETERS AND INITIAL CONDITIONS
FOR THE LIMITING MODERATE FREQUENCY UNCONTROLLED
CEA WITHDRAWAL ANALYSES

PARAMETER	VALUE	
	Subcritical Analysis	Low (Hot Zero) Power Analysis
Initial core power (% of RTP)	5.0×10^{-8}	1.9×10^{-5}
Initial core inlet temperature (°F)	572	572
Initial pressurizer pressure (psia)	1785	2100
Initial RCS flow[a] (lbm/sec)	43278	43278
MTC ($\Delta\rho$/°F)	0.5×10^{-4}	0.5×10^{-4}
FTC[b]	Least negative	Least negative
Maximum peaking factor (F_q)	13.8	10.5
Maximum reactivity insertion rate ($\Delta\rho$/inch)	5.67×10^{-4}	3.4×10^{-4}
CEA worth at trip[c], (%$\Delta\rho$)	-1.60	-6.5 (WRSO)
Trip Setpoint[d] (% of RTP)	0.1	11.0[e]
SCRAM delay (sec)	0.5	0.45
CEA holding coil delay (sec)	0.6	0.6
Fuel rod gap conductance (Btu/hr-ft^2-°F)	6530	6530

a. This corresponds to 95% of the original design flow of 164.0 Mlbm/hr.

b. The fuel temperature coefficients used are found in the unit- and cycle-specific analyses.

c. For Subcritical CEAW only the withdrawn CEA is reinserted whereas for the Hot Zero Power case, the withdrawn CEA along with all the other CEAs except for the Worst Rod Stuck Out (WRSO) is reinserted.

d. For the CEAW from subcritical, the trip setpoint is for the HLPT. For the CEAW from HZP, the trip setpoint is for the RPS analog VOPT.

e. Note in the computer runs this is conservatively set at 12%.

C. Results

The responses of key parameters as a function of time are presented in Figures 15.4.1-1 through 15.4.1-16, typical for the uncontrolled CEAW transient from subcritical condition and the HZP condition.

The uncontrolled CEA withdrawal from a subcritical condition resulted in a reactor trip on HLPT. The minimum DNBR calculated for this event that was initiated from the conditions of Table 15.4.1-2, was 2.24 which is greater than the design limit of 1.34.

The peak LHGR was calculated to be 56.20 kW/ft, which exceeds the LSSS but the highest fuel centerline temperature reached was 1570°F, which is less than the fuel melt temperature which is based on burnup and erbia content.

The uncontrolled CEAW from HZP conditions resulted in a reactor trip on the RPS analog VOPT. The minimum DNBR calculated for this event, initiated from the conditions of Table 15.4.1-2, was 1.67 which is greater than the design limit of 1.34.

The calculated peak LHGR was 40.52 kW/ft, which exceeds the LSSS, but the fuel centerline temperature was bounded by 2600°F, which is less than the fuel melt temperature which is based on burnup and erbia content.

Therefore, fuel and/or cladding damage is not predicted for these limiting moderate frequency events and the acceptance criteria delineated in Section 15.4.1 of the Standard Review Plan (Reference 1) are met.

15.4.1.4 Reactor Coolant System Barrier Performance

A. Mathematical Model

The computer codes that were employed to evaluate fission product barrier performance for the limiting moderate frequency events are described in UFSAR Section 15.4.1.3.A.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions that were employed to evaluate fission product barrier performance for the limiting moderate frequency events are described in UFSAR Section 15.4.1.3.B.

C. Results

The response of key parameters as a function of time is presented in Figures 15.4.1-1 through 15.4.1-16 for these limiting moderate frequency events. The peak RCS pressure for the CEA withdrawal from a subcritical condition presented in Figure 15.4.1-3 is less than that of the CEA withdrawal from the HZP condition presented in Figure 15.4.1-11. The calculated peak RCS pressure was 1881 psia for the CEAW from

subcritical (see Figure 15.4.1-3) and 2225 psia for the CEAW from HZP (see Figure 15.4.1-11), both of which are less than the design limit of 2750 psia.

The calculated secondary side peak pressures were 1246 psia for the CEAW from subcritical and 1260 psia for the CEAW from HZP, both of which are less than the design limit of 1397 psia.

It should be noted that these peak pressures were obtained from the cases for which the initial and transient conditions were selected to maximize heat transfer degradation and fuel centerline temperature for demonstration of this event being not a peak pressure event because of the small amount of heat transferred to the RCS from fuel during the transient. Furthermore, the peak pressure is not a SRP review criterion for this event, however, the evaluation results are reported herein.

15.4.1.5 Radiological Consequences and Containment Performance

Fuel damage is not predicted for the limiting moderate frequency uncontrolled CEA withdrawal events, and therefore there are no radiological consequences from these events. These events would not result in any release of radioactive material above that of a normal reactor trip.

15.4.1.6 Conclusions

For the postulated events involving an uncontrolled CEA withdrawal from subcritical or HZP conditions, the PVNGS design meets the relevant requirements of Standard Review Plan (Reference 1).

15.4.2 UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL AT POWER

15.4.2.1 Identification of Causes and Frequency Classification

An uncontrolled CEA withdrawal (CEAW) at power is assumed to occur as a result of a single failure in the control element drive mechanism (CEDM), control element drive mechanism control system, the reactor regulating system, or as a result of operator error.

An uncontrolled CEAW from power conditions is an Anticipated Occupational Occurrence (AOO), as discussed in Table 3.9-1 and is classified as an incident of moderate frequency.

15.4.2.2 Sequence of Events and Systems Operation

The uncontrolled withdrawal of a Control Element Assembly (CEA) from full power conditions adds reactivity to the core, causing both the core power level and the core heat flux to increase, followed by corresponding increases in reactor coolant temperatures and reactor coolant system (RCS) pressure. The withdrawal of CEAs also produces a time-dependent redistribution of core power. These transient variations in core thermal parameters may result in an approach to the

specified acceptable fuel design limits (SAFDLs) on DNBR and fuel centerline melt temperature, thereby requiring the protective action of the reactor protective system (RPS).

The net reactivity insertion rate accompanying the uncontrolled CEAW is dependent upon the CEA withdrawal rate and reactivity feedback mechanisms present at the time of the CEAW from full power conditions. The net reactivity insertion rate determines the rate of approach to the fuel design limits. Depending on the reactivity insertion rate and the system initial conditions, the uncontrolled CEAW transient from full power is terminated by a Core Protection Calculator (CPC) Variable Overpower Trip (VOPT) or the High Pressurizer Pressure Trip (HPPT).

Table 15.4.2-1 gives a sequence of events from the time the CEAs start to withdraw until the operator initiates a cooldown of the Nuclear Steam Supply System (NSSS). This typical sequence of events was obtained by simulating the event with the computer codes identified in UFSAR Sections 15.4.2.3 and 15.4.2.4. Figures 15.4.2-1 through 15.4.2-11[2] depict the response of key NSSS parameters during this event. The withdrawal of CEAs causes a positive reactivity change, resulting in an increase in the core power and core heat flux (Figures 15.4.2-1 and 15.4.2-2, respectively). Following the generation of a turbine trip on reactor trip, main feedwater flow reduces to 5% of nominal, full flow. The steam bypass

[2] Figures are typical representation of the transient.

control system (SBCS) is assumed to be in manual mode with all the bypass valves closed, resulting in the main steam safety valves (MSSVs) opening (Figure 15.4.2-10) to limit secondary system pressure and remove stored heat transferred from the core and the RCS. After the reactor trip and turbine trip, there is a brief power mismatch between the primary and secondary sides of the steam generator until the MSSVs open, resulting in an increase in RCS pressure and temperature (Figures 15.4.2-3 and 15.4.2-5, respectively). The RCS pressure (Figure 15.4.2-3) remains below the PSV setpoint. The analysis does not credit the actuation of the pressurizer pressure control system and level control systems. However, for RCS control and recovery following the opening of the MSSVs, the pressurizer heaters are adjusted to maintain pressure around 2100 psia. The operator initiates cooldown 30 minutes following the initiation of the event utilizing the main feedwater and the SBCS.

Table 15.4.2-1 does not reflect the event time line beyond 1800 seconds. The cooldown proceeds with the operator reducing the main steam isolation actuation setpoint to prevent the inadvertent generation of a Main Steam Isolation Signal (MSIS). When steam pressure decreases to a point where the main feedwater pumps can no longer be used, the operator secures the main pumps. Cooldown is continued by utilizing one auxiliary feedwater pump SBCS until the shutdown cooling system is manually actuated at a time when the RCS temperature and pressure have been reduced to approximately 350°F and 400 psia.

Table 15.4.2-1

SEQUENCE OF EVENTS FOR THE
SEQUENTIAL CEA WITHDRAWAL EVENT AT FULL POWER

Time (sec)	Event
0.00	CEAs begin withdrawing
13.1	CPC's trip signal generated
13.85	Reactor trip breakers open
13.85	Turbine trip occurs
14.0	Minimum DNBR occurs
14.2	Maximum core power occurs
14.45	Scram CEAs begin to drop into the core
14.7	Maximum core average heat flux occurs
16.8	Maximum RCS pressure
21.2	Maximum secondary pressure
21.3	MSSV bank open and begins to cycle open and closed
1800	Operator initiates cooldown

Analytical setpoints and response times associated with the RPS trip functions were consistent with, or conservative with respect to, numerical values delineated in UFSAR Section 7.2. A conservative CEA coil decay time of 0.6 seconds was used in simulating the uncontrolled CEAW at power transient.

15.4.2.3 Core and System Performance

A. Mathematical Model

The NSSS response to a CEA group withdrawal at full power conditions was simulated using the CENTS computer code described in UFSAR Section 15.0.3.1.3.2. The thermal margin on DNBR in the reactor core was simulated using the CETOP computer code (described in UFSAR Sections 4.4 and 15.0.3.1.6) with the CE-1 CHF correlation that is also described in UFSAR Section 4.4. If the calculated transient value of Linear Heat Generation Rate (LHGR) exceeds the conservative, steady-state limit of 21 kW/ft for a short period of time during the transient, an additional, conservative, hand calculation is performed to confirm that the fuel temperature remains below the melting point. The SAFDL requires the calculated fuel temperature not exceed the fuel melting temperature, but states that showing the LHGR remains below 21 kW/ft guarantees no fuel melting. The fuel temperature is calculated based on the amount of energy deposited in the fuel over time. This is done to ensure that the fuel temperature (i.e., fuel

enthalpy) remains below the melting point and no fuel failure occurs.

B. Input Parameters and Initial Conditions

The assumptions and input parameters that are unique to this event analysis are discussed below and are listed in Table 15.4.2-2.

These initial conditions (i.e., radial power peak, core flow, and inlet temperature) were chosen such that a reactor trip on low DNBR is actuated prior to or at the same time as the HPPT or the VOPT would be initiated. The selection of these parameters in this manner minimizes the hot channel minimum DNBR.

The initial conditions and NSSS characteristics used in this analysis yield the minimum DNBR for any CEA group withdrawal incident. Parametric studies were performed on core inlet temperature, fuel rod gap conductance, and core flow. The studies indicated that minimum DNBR during the CEA withdrawal is most sensitive to initial core inlet temperature. Thus, the minimum allowable core inlet temperature was assumed. The minimum initial pressurizer pressure, which has a negligible impact on the event was selected to avoid a HPPT actuation. Thus, the conditions chosen yield the minimum DNBR for a CEA withdrawal at power.

Table 15.4.2-2

ASSUMPTIONS AND INITIAL CONDITIONS
FOR THE SEQUENTIAL CEA WITHDRAWAL ANALYSIS

Parameter	Value **RTP 3990 MWt**
Initial core power (% of RTP)	102
Initial core inlet temperature (°F)	548
Initial pressurizer pressure (psia)	2100
Initial RCS flow (% of design)	95
Moderator temperature coefficient ($\Delta\rho$/°F)	0.0
Doppler fuel temperature coefficient[4]	Least negative
Kinetics[5]	Minimum β
Maximum radial peaking, (Fr)	2.0
Differential reactivity insertion (%$\Delta\rho$/in)	0.008
CEA withdrawal speed (inches/min)	30.0
CEA worth at trip (%$\Delta\rho$)	8.0
Fuel rod gap conductance (Btu/hr-ft^2-°F)	6527
Number of Plugged Steam Generator Tubes	0
Single failure	None
Loss of Offsite Power (LOP)	No

[4]The fuel temperature coefficient used is found in the unit- and cycle-specific analyses.

[5]The kinetics parameters used are found in the unit- and cycle-specific analyses.

The maximum power level from which the withdrawal is initiated was assumed to be 102% of licensed power. Minimum DNBR during the CEA withdrawal is more sensitive to high initial power levels. The initial core average axial power distribution for this analysis is a shape characterized by an axial shape index equal to -0.3. This distribution is assumed because it minimizes the DNBR.

Other input parameters that are important to this analysis are moderator temperature coefficient (MTC) and fuel temperature coefficient (FTC) of reactivity. The MTC assumed in this analysis corresponds to beginning-of-life core conditions. This MTC has the smallest impact on retarding the rate of change of power, coolant temperature, and DNBR. A FTC corresponding to beginning-of-life conditions was used in the analysis, since this FTC causes the least amount of negative reactivity change for mitigating the transient increases in core power, heat flux, and the reactor coolant temperatures.

The regulating CEA position from which the CEA withdrawal is initiated corresponds to 25% insertion of the first regulating bank. This particular insertion was selected based on the calculated CEA worth and associated uncertainties to produce the worst transient. A corresponding maximum differential worth of 0.008% $\Delta\rho$ per inch of rod motion was

conservatively assumed in the present analysis. This corresponds to a maximum reactivity withdrawal rate of $0.4 \times 10^{-4}\ \Delta\rho$ per second based on the maximum CEA withdrawal speed of 30 inches per minute, including all uncertainties.

All the control systems, except the SBCS, were assumed to be in the automatic mode since these systems have no impact on the minimum DNBR obtained during the transient. The SBCS is assumed to be in manual mode because this minimizes DNBR during the transient.

C. Results

The dynamic behavior of key NSSS parameters following a CEAW at power are presented in Figures 15.4.2-1 to 15.4.2-11.

The minimum DNBR calculated by CETOP is 1.55, which is greater than the DNBR SAFDL of 1.34, and occurs at 14.0 seconds into the transient as shown in Figure 15.4.2-4.

The peak LHGR reached during this transient is less than 15 kW/ft as shown in Figure 15.4.2-7. This computed LHGR is well below that for the LSSS of 21 kW/ft and, as discussed above, the peak fuel temperatures during this transient are below that of centerline melt.

Therefore, the results of the uncontrolled CEAW from full power conditions show that for the limiting

event, the acceptance criteria for the DNBR SAFDL and fuel centerline melt temperature limit are met.

15.4.2.4 Reactor Coolant System Barrier Performance

A. Mathematical Model

The computer codes that were employed to evaluate fission product barrier performance for this moderate frequency event are the same as those described in UFSAR Section 15.4.2.3.A.

B. Input parameters and Initial Conditions

The input parameters and initial conditions that were employed to evaluate fission product barrier performance for this moderate frequency event are the same as those described in UFSAR Section 15.4.2.3.B.

C. Results

The uncontrolled CEAW from full power results in an increase in RCS pressure and the secondary pressure.

The maximum RCS pressure is 2338 psia (see Figure 15.4.2-3), which is below the primary side limit of 2750 psia (110% of the design pressure of 2500 psia). The secondary side pressure reaches 1230 psia (see Figure 15.4.2-6), which is below the secondary side limit of 1397 psia (110% of the design pressure of 1270 psia).

Figure 15.4.2-10 gives the MSSVs flow versus time for the uncontrolled CEAW from full power.

15.4.2.5 Radiological Consequences and Containment Performance

Fuel cladding degradation is not predicted for this moderate frequency event, and therefore there are no calculated offsite dose radiological consequences for this event. This event would not result in any releases of radioactive material above that of a normal reactor trip.

15.4.2.6 Conclusions

Evaluation of the moderate frequency uncontrolled CEAW from full power shows that:

- The fuel cladding integrity will be maintained with the minimum DNBR remaining above the SAFDL, the maximum LHGR remaining below the value that causes peak centerline melt temperature.
- The RCS pressure remains below 110% of its design value (i.e., 110% of 2500 psia, or 2750 psia).
- The secondary side pressure remains below 110% of its design value (i.e., 110% 0f 1270 psia, or 1397 psia).
- Fuel cladding degradation is not anticipated and there are no radiological consequences resulting from the event. This event would not result in any releases of radioactive material above that of a normal reactor trip.
- For the postulated uncontrolled CEAW from full power, the PVNGS design meets the relevant requirements of the Standard Review Plan.

15.4.3 SINGLE FULL-STRENGTH CONTROL ELEMENT ASSEMBLY DROP

The 4-finger Control Element Assembly (CEA) drops are ensured acceptable results by the initial thermal margin preserved by the Limiting Conditions of Operation (LCOs), and do not rely upon CEA position-related (i.e., power distribution) penalty factors contained within the calculations in the Core Protection Calculators (CPCs).

The CEA position-related penalty factors for downward deviations of 12-fingered CEAs are calculated such that the CPCs will provide a trip when necessary. A part-strength Power Dependent Insertion Limit (PDIL) also restricts the part-strength CEA insertion to less than 25% for power levels greater than 50%. From these initial conditions, the part-strength single or subgroup drop inserts only negative reactivity (similar to a full-strength single or subgroup drop event). For CEA subgroup drops, the CEA position-related penalty factors for downward deviations are used by the CPCs to provide a trip when necessary.

15.4.3.1 Identification of Causes and Frequency Classification

A single full-strength CEA drop (FSCEAD) results from an interruption in the electrical power to the control element drive mechanism (CEDM) holding coil of a single full-strength CEA. This interruption can be caused by a holding coil failure or loss of power to the holding coil. The limiting case is the FSCEAD that does not cause a reactor trip to occur but results

in an approach to the Specified Acceptable Fuel Design Limit (SAFDL) on the Departure from Nucleate Boiling Ratio (DNBR).

The FSCEAD event is an Anticipated Operational Occurrence (AOO) as discussed in Table 3.9-1 and is classified as an incident of moderate frequency.

15.4.3.2 Sequence of Events and Systems Operation

Table 15.4.3-1 presents a chronological list of events that occur during the FSCEAD transient, from initiation to the attainment of steady state conditions.

The transient is initiated by the release and subsequent drop of a single full-strength CEA. This initiates a reduction in core power and a primary to secondary side power to load mismatch. This mismatch results in a cooldown of the RCS due to excess heat removal by the secondary system. In the presence of a negative Moderator Temperature Coefficient (MTC), the cooldown adds positive reactivity and the core power tends to return to its pre-drop level.

The resultant increase in the hot pin radial peaking factor coupled with a return to initial power (following a temporary power depression) results in a power distribution distortion that increases with time as xenon redistributes and a minimum DNBR that remains above the DNBR SAFDL value of 1.34 at 900 seconds following the drop event.

The bounding analysis conservatively assumes that the operator begins to reduce power at 900 seconds if the CEA has not been

re-aligned. Operation at reduced power is allowed for a limited period to allow the CEA to be re-aligned.

15.4.3.3 Core and System Performance

A. Mathematical Model

Hand calculations are performed to verify acceptable results for a FSCEAD. This is acceptable since the major effect considered to degrade thermal margin comes from the radially distorted power. A maximum radial distortion factor including 15 minutes of Xenon redistribution resulting from a FSCEAD is obtained from the physics calculation. The ratio of pre- and post- drop radial distortion is converted to the equivalent power ratio (the required margin) by the quasi partial derivative of the Power Operating Limit (POL) with respect to radial distortion factor. A bounding value of the POL partial derivative within LCO parameters is used to maximize the required margin, which must be reserved by COLSS, CPCS or other LCOs. Bounding partial derivatives were developed by varying one input parameter while the remaining parameters were kept unchanged. As long as the assumptions used in the development of these derivatives remain valid, their values will remain unchanged. For the derivation of the quasi partial derivatives of the POL with respect to radial distortion factor, it is assumed that the coolant inlet temperature, core flow, Fr, and pressure are at

their initial pre-transient values. This is conservation because the decrease in DNBR in the transient caused by decreasing RCS pressure is more than offset by the decreasing coolant temperature and reduced core average power.

The same methodology is used to analyze a subgroup CEA drop when both CEA calculators (CEACs) are out of service. These margin analyses (calculation of cycle specific distortion factors to ensure they are bounded by the assumed distortion values) are performed each cycle as part of the reload analysis.

The CETOP-D computer code (see UFSAR Section 15.0.3.1.6) which uses the CE-1 critical heat flux correlation (see UFSAR Section 4.4) is used to calculate the thermal margin preserved by the TS LCOs for RCS pressure, temperature, flow and ASI.

Several computer codes are employed to create a typical sequence of events. The CENTS computer code (see UFSAR Section 15.0.3.1.3.2) is used to simulate the Nuclear Steam Supply System (NSSS) response to this event. The CETOP-D computer code (see UFSAR Section 15.0.3.1.6) which uses the CE-1 critical heat flux correlation (see UFSAR Section 4.4) is used to calculate the equivalent power change corresponding to the axial and radial power distortion when the minimum DNBR is kept unchanged at the SAFDL.

B. Input Parameters and Initial Conditions

Hand Calculation Methodology

The initial conditions are set by the thermal margin reserved in COLSS or CPCS via TS 3.2.4. Since COLSS and CPCS perform an online calculation of DNBR and use measured input values, there are infinite combinations of power, pressure, temperature, coolant flow rate, radial peaking factors, and axial power distribution for any given thermal margin requirement. However TS 3.2.4 ensures a minimum thermal margin which can be converted into a maximum allowable radial distortion which is then verified to be conservative for each core design.

Sequence of Events

For the purposes of creating a sequence of events, Table 15.4.3-2 lists the assumptions and initial conditions used for the FSCEAD event. The initial conditions of power, pressure, temperature, and coolant flow rate were typical values. The axial power distribution was a limiting shape, and the radial peaking factor was chosen such that a minimum initial thermal margin was obtained. This was done so that the DNBR would be minimized.

The negative reactivity inserted by a dropped CEA causes the power to initially decrease everywhere in the core. With no reactor trip, the coolant inlet temperature and pressure will gradually decrease.

Concurrently, the radial peaking factor will increase to an asymptotic post drop value. The decreasing coolant temperature combined with the negative doppler and moderator temperature coefficients causes a positive reactivity insertion which brings the core back to the initial power.

There is no single power level or plant configuration COLSS In Service (IS)/Out of Service (OOS) and CEACSs IS/OOS that is clearly most limiting. Rather, all conditions and power levels must be considered. To generate a typical sequence of events, the heat flux is based on the 95% power conditions and the asymptotic radial peaking factor existing at that time. This particular power was chosen based on its historically limiting condition for other events and precedence in licensing submittals.

Table 15.4.3-1

SEQUENCE OF EVENTS FOR THE
SINGLE FULL-STRENGTH CEA DROP EVENT

Time (sec)	Event
0.0	CEA begins to drop into core
4.0	CEA reaches fully inserted position
4.05	Core power level reaches minimum and begins to increase due to reactivity feedback
30.0	Minimum pressurizer pressure
50.0	Core power returns to maximum value
900.0	Minimum DNBR is reached
900.0	Operator begins a power reduction if the dropped CEA is not re-aligned[6]

[6] The effects of xenon on radial power distortion at 15 minutes (900 seconds) are conservatively assumed in the bounding analysis.

Table 15.4.3-2

TYPICAL ASSUMPTIONS AND INITIAL CONDITIONS
FOR THE SINGLE FULL-STRENGTH CEA DROP

Parameter	Value
Core thermal power (% of RTP)	95
Thermal margin	117%
Axial Shape	-2.0 ASI
Initial core inlet temperature (°F)[7]	558
Initial pressurizer pressure (psia)[8]	2250
Initial RCS flow rate, (lbm/sec)[9]	48086
MTC ($\Delta\rho$°/F)	-4.4×10^{-4}
Fuel Temperature Coefficient (FTC)[10]	Least negative
Dropped CEA worth (%$\Delta\rho$)	-0.15
Pre CEA drop radial peaking distortion factor	1.6150
Post CEA drop radial peaking distortion factor	1.8146
CEA drop radial peaking distortion factor @ 15 mins	1.8609
CEA drop time (sec)	4.0
Fuel rod gap conductance (Btu/hr-ft^2-°F)	1620
Number of plugged steam generator tubes	0
Single failure	None
Loss of offsite power	No

[7] Since the purpose of the transient analysis was to provide a representative sequence of events, the inlet temperature was set to a representative value.

[8] Since the purpose of the transient analysis was to provide a representative sequence of events, the pressure was set to a representative value.

[9] Since the purpose of the transient analysis was to provide a representative sequence of events, the RCS flow was set to a representative value. The flow represents the actual value used in the runs.

[10] The fuel temperature coefficient used is found in the unit- and cycle-specific analyses.

For this event, the choice of mode for the reactor regulating system is inconsequential because there would be no regulating bank motion if the system were in manual mode; and in the automatic mode, the CEA withdrawal prohibit, actuated on the CEAC based rod deviation, prevents the motion of any regulating bank that could cause the CPC calculated minimum DNBR to approach the DNBR SAFDL.

C. Results

Table 15.4.3-1 presents the sequence of events for the full-strength CEA drop event initiated at the conditions described in Table 15.4.3-2.

A minimum CE-1 DNBR of greater than the DNBR SAFDL is obtained at 900 seconds, as determined from the initial radial power peaking increase following CEA drop plus 15 minutes of xenon redistribution at the final coolant conditions. The operator is conservatively assumed in the bounding analysis to take action at this time to begin reducing power if the misaligned CEA has not been realigned.

The fuel centerline melt temperature is not exceeded if the transient Linear Heat Generation Rate (LHGR) does not exceed 21 kW/ft. The limiting initial power is 95%.

Based on the bounding radial peaking distortion, the maximum allowable initial LHGR that could exist as an initial linear heat condition without exceeding

21.0 kW/ft during this transient exceeds 15 kW/ft (21 kW/ft/Maximum Distortion Factor = maximum allowable initial LHGR). This amount of margin is assured because the linear heat rate LCO is based on the more limiting allowable LHGR for LOCA.

Therefore, the results of the FSCEAD analysis show that for the limiting event, the acceptance criteria for the DNBR SAFDL and peak fuel centerline temperature limit are met.

15.4.3.4 Reactor Coolant System Barrier Performance

A. Mathematical Model

CENTS and CETOP computer codes (see UFSAR Sections 15.0.3.1.3.2 and 15.0.3.1.3.6) are used to simulate the Nuclear Steam Supply System (NSSS) response to this event to create a typical sequence of events.

The computer codes that were employed to evaluate fission product barrier performance for this moderate frequency event are the same as those described in UFSAR Section 15.4.3.3.A.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions that were employed to evaluate fission product barrier performance for this moderate frequency event are the same as those described in Section 15.4.3.3.B.

C. Results

The barrier performance parameters following a FSCEAD would be less adverse than those following the CEA withdrawal events from subcritical, HZP, or at power (see UFSAR Sections 15.4.1 and 15.4.2).

This event is initiated with a nominal pressurizer pressure of 2250 psia. The RCS pressure decreases as a result of the FSCEAD and remains well below the 110% primary side design limit of 2750 psia. The secondary side pressure also remains below the 110% secondary side design limit value of 1397 psia.

The single FSCEAD event does not result in a reactor and turbine trip and therefore, there are no resultant event related steam releases to the atmosphere.

15.4.3.5 Radiological Consequences and Containment Performance

Fuel cladding degradation is not predicted for this moderate frequency event, and therefore there are no offsite dose radiological consequences for this event. This event would not result in any releases of radioactive material above that of a normal reactor trip.

15.4.3.6 Conclusions

Evaluation of the moderate frequency FSCEAD event shows that:

- The fuel cladding integrity will be maintained with the minimum DNBR remaining above the SAFDL, the maximum fuel

centerline temperature remaining below the fuel melt temperature.

- The RCS pressure remains below 110% of its design value (i.e., 110% of 2500 psia, or 2750 psia).
- The secondary side pressure remains below 110% of its design value (i.e., 110% 0f 1270 psia, or 1397 psia).
- Fuel cladding degradation is not anticipated and there are no radiological consequences resulting from the event.
  - For the postulated single full-strength CEA drop event initiated from the Technical Specification LCOs, the PVNGS design meets the relevant requirements of the Standard Review Plan (Reference 1).

15.4.4 STARTUP OF AN INACTIVE REACTOR COOLANT PUMP

15.4.4.1 Identification of Event and Causes

The startup of an inactive reactor coolant pump (SIRCP) is presented here with respect to potential loss of subcriticality. This event is also evaluated with respect to Reactor Coolant System (RCS) pressure and fuel performance criteria.

Administrative procedures govern the starting of RCPs and reduce the effects of RCP starts.

15.4.4.2 Sequence of Events and Systems Operation

SIRCP can either raise or lower core average coolant temperature. The average temperature can be lowered by

increased heat transfer to the steam generators, caused by increased core coolant flow and by colder primary system water in the steam generators being forced into the core. The core average temperature can be raised by increased heat transfer from the steam generators to the RCS, as a result of increased core coolant flow and by hotter primary system water in the steam generators being forced into the core.

The SIRCP event which lowers the core average temperature (the cooldown event), combined with a negative isothermal temperature coefficient (ITC), produces a positive reactivity insertion. The SIRCP event which increases core average temperature (the heatup event), combined with a positive ITC, produces an increase in RCS pressure and a positive reactivity insertion.

15.4.4.3 Analysis of Effects and Consequences

SIRCP can cause either a heatup or cooldown of the primary system depending on the primary to secondary ΔT.

SIRCP was examined in Modes 3 through 6, since plant operation with less than four RCPs running is only permitted in these modes.

A. Mathematical Models

The reactivity added to the core during a heatup or cooldown SIRCP event was determined using conservative isothermal temperature coefficients (ITCs) with a maximum uncertainty applied. These ITCs were used with the maximum core temperature increase or decrease

to determine the maximum reactivity inserted during SIRCP. This reactivity insertion is compared to the total amount of subcriticality.

B. Input Parameters and Initial Conditions

The initial conditions considered for this event ranged from a positive to a negative temperature difference between the secondary and primary system. Assuming primary system temperature higher than the secondary temperatures (a positive temperature difference) would result in cooling down the RCS. Assuming secondary system temperature initially higher than the primary temperature (a negative temperature difference) would result in heating up the RCS. Cooling the RCS would increase reactivity if there is a negative ITC. Heating the RCS would increase reactivity and RCS pressure if there is a positive ITC.

To conservatively calculate the reactivity added to the core during SIRCP, the most negative or positive ITCs are used with uncertainties applied in the most conservative direction. The initial core average moderator temperature during SIRCP is assumed to be at the temperature corresponding to the most positive ITC for the heatup event, or the most negative ITC for the cooldown event.

The following assumptions are made:

1. Prior to SIRCP all reactor coolant pumps are off. Normally at least one RCP must be running (or one shutdown cooling train during shutdown cooling operation). The Technical Specifications allow operation without any pumps running for up to one hour. This assumption maximizes the change in temperature during SIRCP.

2. Following SIRCP the core average temperature either (1) drops to the temperature of the coldest steam generator, for the cooldown event, or (2) increases to the temperature of the hottest steam generator, for the heatup event. This conservatively bounds the maximum change in core temperature that can occur during this event, by ignoring coolant mixing that would occur in the reactor coolant system.

15.4.4.4 Results

The results show that the maximum temperature change during SIRCP when used with the most conservative ITCs does not result in a loss of subcriticality.

When the RCS is above the conditions requiring low temperature overpressure (LTOP) protection, the SIRCP event that results in a heatup of the RCS will not result in a peak pressure greater than 110% of design pressure. While the RCS is in the LTOP mode, the shutdown cooling system (SCS) relief valves will

prevent violation of RCS integrity limits. (See section 5.2 for a general discussion of RCS integrity.)

Since subcriticality is not lost during the event, there is no increase in heat flux and therefore no decrease in minimum departure from nucleate boiling ratio (DNBR).

15.4.4.5 Conclusions

The SIRCP does not result in a loss of subcriticality. The increase in pressure during this event will not result in peak pressures above the applicable limits. There is no increase in core heat flux and therefore no decrease in minimum DNBR.

15.4.5 FLOW CONTROLLER MALFUNCTION CAUSING AN INCREASE IN BWR CORE FLOW

This event is not applicable to pressurized water reactors and, therefore, is not included in this FSAR.

15.4.6 INADVERTENT DEBORATION

15.4.6.1 Identification of Event and Causes

The Inadvertent Deboration (ID) event is presented here with respect to the time available for operator corrective action prior to the reactor achieving criticality. Fuel integrity is not challenged by this event.

The ID event may be caused by improper operator action or by a failure in the boric acid makeup flow path, which reduces the flow of borated water to the charging pump suction. Either cause can produce a boron concentration of the charging flow

which is below the concentration of the reactor coolant. The ID event is classified as an incident of moderate frequency as defined in Reference 1 of UFSAR Section 15.0.

This evaluation shows that Mode 5 (cold shutdown) with the Reactor Coolant System (RCS) drained down results in the least time available for detection and termination of an ID event. The combination of lowered RCS volume and three operating charging pumps results in a small dilution time constant and the fastest dilution rate, and therefore yields the shortest time interval between initiation of an ID event and the reactor achieving criticality.

Since RCS boron concentration is maintained under strict procedural controls, the probability of a sustained and erroneous dilution due to operator error is very low.

15.4.6.2 Sequence of Events and Systems Operation

An ID event occurs when charging flow into the RCS has a lower boron concentration than the fluid within the RCS. The resulting decrease in RCS boron concentration adds positive reactivity to the core. Assuming dilution continues at the maximum possible rate with unborated charging flow, the operator has at least 15 minutes in Modes 1 through 5, and 30 minutes in Mode 6, between the receipt of an alarm from the Boron Dilution Alarm System (BDAS) and the reactor achieving criticality. The mechanism to notify the operator of an ID event when the BDAS is inoperable is chemical surveillance of

the RCS boron concentration, in accordance with the unit-specific Core Operating Limits Report (COLR).

The success path for reactivity control is as follows: The operator is alerted to a decrease in the RCS boron concentration either through a high neutron flux alarm on the startup flux channel, sampling, reactor make-up flow rate, or boric acid flow rate. The operator turns off the charging pump(s) in order to halt further dilution. Next, the operator increases the RCS boron concentration by implementing the emergency boration procedure.

When the reactor is critical (Modes 1 and 2) an ID event will result in a slow increase in core power and RCS temperature. This event is slower than other reactivity excursions analyzed (e.g., CEA withdrawals), and the reactor will trip in time to prevent violation of any safety limit. This trip ensures a second dilution period (Mode 3 or lower with All Rods In (ARI) or in an N-1 configuration), during which the operator must be notified of any ongoing deboration at least 15 minutes before the reactor achieves criticality. Therefore, Modes 1 and 2 do not have to be analyzed further with respect to an ID event.

If the reactor is subcritical with trippable CEAs withdrawn from the core (All Rods Out (ARO) in Modes 3 through 5), the high log power trip must be active. Shutdown Margin (SDM) is assumed to be at the minimum value consistent with Technical Specification limits. If the operator is not notified of the ID event with sufficient time to prevent criticality, the high log trip will actuate and insert the withdrawn CEAs into the

core. The trip will alert the operator to the ID event and ensure a second dilution period during which the operator will have at least 15 minutes to respond before the reactor achieves criticality. Thus ARO configurations in Modes 3 through 5 do not need to be analyzed further with respect to an ID event.

If the reactor is subcritical without trippable CEAs (ARI or N-1 configuration in Modes 3 through 5), an ID event will result in degradation of SDM and an increase in subcritical multiplication. SDM is assumed to be at the minimum value consistent with Technical Specification limits. The operator must be notified of the ID event at least 15 minutes before the reactor achieves criticality, so that corrective actions may be implemented. Either the BDAS, or chemical surveillance of RCS boron concentration (when BDAS is not operable), will alert the operator to the ID event.

If the reactor is in Mode 6, an ID event will result in degradation of SDM. In this instance the operator must be notified of the ID event at least 30 minutes before complete loss of subcriticality. The mechanisms to notify the operator are the same as above for Modes 3 through 5 (BDAS or chemical sampling). In Mode 6, the CEAs may be totally removed from the core, thus the ARO configuration is the most limiting and is the only configuration analyzed.

The indications and/or alarms available to alert operators to an ID event in each of the operational modes are outlined below.

A. In Modes 1 and 2, a high power trip or, for some sets of conditions, a high pressurizer pressure trip in Mode 1 or a high log power trip in Mode 2 will provide indication of any boron dilution event. Furthermore, a high T_{AVE} alarm may also occur prior to trip.

B. In Modes 3 and 4 with CEAs withdrawn, the high logarithmic power level trip and pre-trip alarm, and a high neutron flux alarm (BDAS alarm) will provide an indication to alert the operator of an inadvertent boron dilution.

C. In Modes 3, 4, and 5 with CEAs fully inserted except the worst rod stuck out and in Mode 6, a high neutron flux alarm (BDAS alarm) will provide indication of any boron dilution event.

D. In Mode 5 with the RCS partially drained for system maintenance, the primary coolant volume available for mixing consists of only the volume of the reactor vessel up to the level of the coolant legs and the volume of the shutdown cooling system. Similarly, in Modes 4 or 5 when cooling the RCS with the shutdown cooling system, the active volume may consist of only the volume of the reactor vessel (excluding the upper head region) and the volume of the shutdown cooling system. In these conditions a high neutron flux alarm (BDAS alarm) will provide indication of any boron dilution event.

Operational procedure guidelines, in addition to these indications and/or alarms, will assure detection and termination of an ID event before the reactor achieves criticality.

15.4.6.3 Analysis of Effects and Consequences

The time interval between the onset of an ID event and the reactor achieving criticality may be calculated for each possible set of initial conditions (operating mode, mixing volume, charging flow, SDM, and, if applicable, stuck rod worth). These time intervals are conservatively translated into required boron concentration surveillance intervals in the COLR, for use when BDAS is inoperable.

A. Mathematical Model

Assuming complete mixing of boron in the RCS, the rate of change of boron concentration during dilution is described by the following equation:

$$M\left(\frac{dC}{dt}\right) = -WC \qquad (1)$$

Where:

M = RCS mass

C = RCS boron concentration

t = time

W = Charging mass flow rate of unborated water

and dC/dt is maximized by maximizing W and minimizing M.

Assuming: W = constant, equal to the maximum possible value; and

M = constant, equal to the minimum value occurring during the boron dilution incident,

the solution of equation (1) can be written

$$C(t) = C_0 e^{-t/T} \qquad (2)$$

Where: $C(t)$ = Boron concentration at time t

C_0 = Initial boron concentration at time t = 0

T = M / W = Boron dilution time constant

The time T_{crit} that is required to dilute to criticality (from the start of the ID event at time t = 0) is given by:

$$T_{crit} = T \ln\left(\frac{C_0}{C_{crit}}\right) \qquad (3)$$

Where: C_{crit} = Critical boron concentration

Furthermore, the relationship between the alarm time and the BDAS alarm setpoint (i.e., the SRM ratio, or the ratio of the source range flux signal at a

particular time to the initial source range flux signal) is given by:

$$\frac{ICRR(C_0 - C_{CRIT})}{ICRR(C_0 e^{-a/T} - C_{CRIT})} \qquad (4)$$

Where: SRM_{ratio} = BDAS alarm setpoint (limiting value of 2.2)

ICRR = Inverse count rate ratio which is an empirically determined fraction of the difference between the measured boron concentration and the calculated critical boron concentration.

B. Input Parameters and Initial Conditions

It is assumed that the ID event proceeds at the maximum possible rate. For this to occur, all charging pumps must be on, the reactor makeup water pump must be on, letdown flow must be diverted from the volume control tank, and a failure in the boric acid makeup water flow path (e.g., flow control valve FV-210Y failing in the closed position) must terminate borated water flow to the charging pump suction. Specific input parameters and initial conditions for Mode 5 with the RCS partially drained, and for Mode 6, are described in the sections below.

C. Mode 5 Drained Down Boron Dilution Event

Evaluation of ID events initiated during each of the six plant operational modes (defined in the Technical Specifications) shows that Mode 5 (cold shutdown) in the drained-down configuration results in the shortest available time for detection and termination of the event. Therefore, the initial conditions and analysis parameters are chosen for the cold shutdown operational mode to minimize the interval from initiation of dilution to the time at which criticality is reached. The following are the analysis assumptions for the Mode 5 ID event:

1. Complete mixing of boron within the RCS is assumed.

2. The event is initiated at the ARI condition with reactor trip breakers open.

3. The primary coolant volume, including only the volumes for Mode 5 drained conditions as described above, is 4500 ft^3. A conservatively low reactor coolant mass was assumed by using the cold RCS internal volume. Assuming a coolant temperature of 210°F, the Technical Specification upper limit for cold shutdown, the resulting mass is 269,461 lbm.

4. All three charging pumps are assumed to be operating at a rate of 45 gpm per pump, for a

total of 135 gpm. The corresponding mass flow rate, assuming cold liquid flow, is 18.78 lbm/sec.

5. The critical boron concentration (with ARI) and the IBW are 1150 ppm and 85.6 ppm/%$\Delta\rho$, respectively, including uncertainties for the cold shutdown conditions. For Mode 5 ARI with the RCS drained to the middle of the hot legs, a value of 3.0% $\Delta\rho$ (1.0% $\Delta\rho$ Technical Specification SDM + 2.0% $\Delta\rho$ Stuck Rod Worth) is used for initial subcriticality. The initial subcritical boron concentration is found by adding the product of the IBW and the initial subcriticality (i.e., 3.0% $\Delta\rho$) to the critical boron concentration. The resulting initial boron concentration in the Mode 5 ARI configuration is therefore 1407 ppm. Thus the change in boron concentration from 3.0% $\Delta\rho$ subcritical to a critical condition is 247 ppm.

The parameters discussed above are summarized in table 15.4.6-1.

Table 15.4.6-1

ASSUMPTIONS FOR THE MODE 5 INADVERTENT DEBORATION ANALYSIS

Parameter	Assumed Value
Cold RCS volume (excluding pressurizer and surge line), ft^3	4,500
RCS mass (excluding pressurizer and surge line), lbm	269,461
Volumetric charging rate, gpm	135
Mass charging rate, lbm/sec	18.78
Dilution time constant, T, sec	14,351
Initial boron concentration, C_o, ppm	1,407
Critical boron concentration, C_{crit}' ppm	1,150

D. Mode 6 Boron Dilution Event

If the reactor is in Mode 6 an ID will result in degradation of SDM. In this instance the operator must be notified of the ID event at least 30 minutes before the reactor achieves criticality. In Mode 6, the CEAs may be totally removed from the core. Therefore, the ARO configuration is the most limiting and is the only configuration analyzed. The following are the analysis assumptions for the ID event:

1. Complete mixing of boron within the RCS is assumed.

2. The event is initiated at the ARO condition.

3. The primary coolant volume is conservatively set to the values assumed for Mode 5 drained conditions. A coolant temperature of 135° F is assumed for Mode 6, however, with a resulting mass of 276,583 lbm.

4. All three charging pumps are assumed to be on at a rate of 45 gpm per pump, for a total of 135 gpm. The corresponding mass flow rate, assuming cold liquid flow, is 18.78 lbm/sec.

5. Initial and critical boron concentrations are conservatively established at 3000 ppm (the minimum refueling boron concentration allowed by the COLR) and 2204 ppm, respectively.

The parameters discussed above are summarized in table 15.4.6-2.

Table 15.4.6-2

ASSUMPTIONS FOR THE MODE 6 INADVERTENT DEBORATION ANALYSIS

Parameter	Assumed Value
Cold RCS volume (excluding pressurizer and surge line), ft^3	4,500
RCS mass (excluding pressurizer and surge line), lbm	276,583
Volumetric charging rate, gpm	135
Mass charging rate, lbm/sec	18.78
Dilution time constant, T, sec	14,731
Initial boron concentration, C_o, ppm	3,000
Critical boron concentration, C_{crit}' ppm	2,204

15.4.6.4 Results

Using the conservative parameters described above in equations (3) and (4), sufficient time is available to assure the detection and termination of an ID event. Numerous indications of improper operation and the high neutron flux alarm on the startup flux channel will alert the operator of an ID event with at least 15 minutes (30 minutes in mode 6) remaining before the core becomes critical.

15.4.6.5 Conclusions

The ID event will result in acceptable consequences. Sufficient time is available for the operator to detect and to terminate an ID event if it occurs. Fuel integrity is not challenged during this event.

15.4.7 INADVERTENT LOADING OF A FUEL ASSEMBLY INTO THE IMPROPER POSITION

15.4.7.1 Identification of Events and Causes

The inadvertent loading of a fuel assembly into the improper position event is initiated by interchanging two fuel assemblies. The likelihood of an error in core loading is considered to be extremely remote because of the strict procedural control used during core loading.

15.4.7.2 Sequence of Events and System Operation

The fuel enrichment within a fuel assembly is identified by a coded serial number marked on the exposed surface of the top end plate of the fuel assembly. This serial number is used as a means of positive identification for each assembly in the plant. A tag board is provided in the main control room showing a schematic representation of the reactor core and spent fuel storage area. During the period of core loading, the location of each fuel assembly, and source will be shown on this tag board by a tag carrying its identification number.

The tag board in the main control room will be constantly updated by a designated member of the reactor engineering staff whenever a fuel assembly is being moved. The reactor engineering representative will be in constant communication with each area where this is occurring. All core alterations shall be observed and directly supervised by either a licensed senior reactor operator or a senior reactor operator limited to fuel handling who has no other concurrent responsibilities

during this operation. Fuel assemblies will not be moved unless these lines of communication are available. In addition to these precautions, annual inventories of the spent fuel and new fuel storage areas will be performed in addition to post refueling reactor core mapping. These inventories will be used as the basis for setting up the tag board for use during fuel movement. At the completion of core loading, the exposed surfaces of the top end plates are inspected to verify that all assemblies are correctly located. These precautions are included in the core loading procedures which are to be reviewed by appropriate plant personnel.

15.4.7.3 Analysis of Effects and Consequences

If, in spite of the extreme precautions described above, it is postulated that a fuel assembly is misloaded, several situations may be postulated. The misloading of a fuel assembly may affect the core power distribution only slightly, for example, if assemblies of similar enrichments and reactivities are misloaded. Alternatively, the core power distribution may be affected enough so that the core performance would be affected if assemblies having different enrichments or reactivities are misloaded. In the unlikely event that two assemblies of significantly different initial reactivities would be interchanged, most misloadings would be detected using either the incore or excore neutron detectors during the power ascension physics testing. Misloadings that result in significant azimuthal tilt would be detected by the differences in signals between the four excore detectors during

routine monitoring of their signals during the initial power ascension. In addition, analysis has shown that if all the incore detectors in the vicinity of the misload are operational, then most of the misloads that may result in a significant increase in power peaking will be detected during the power ascension testing. If several of the incore detectors in the vicinity of the misloaded assembly are nonfunctional, then some of the misloads that result in substantial increase in core power peaking may not be detected during the initial power ascension physics testing. Of this small class certainly the worst case that can be envisioned is the interchange of a fresh assembly with a once-burned assembly in the interior of the core. Although this type of misload may result in high local power peaking, it may not be detectable if most of the incore detectors in the vicinity of the misload are nonfunctional since it produces essentially no core wide global power tilt during the power ascension physics testing. Figure 15.4.7-1 shows a representative power distribution at the time of maximum ROPM for a worst case misload of this type.

For PVNGS, operation with an undetectable misload may result in a potential non-conservatism of the COLSS and CPC online margin assessment due to the potential non-conservatism of the measurement of local power peaking for the misloaded core. If the CECOR measured values for the radial peaking factors are conservative then safety limits will not be exceeded even during operation with an undetectable misload, since these peaking factors are used by COLSS and CPC to calculate margin to the SAFDLs.

If all the ICIs in the vicinity of the misload are functional then most of the impact of the misload on power peaking will be accounted for. However, if some of the ICIs in the vicinity of the misload are nonfunctional, then the CECOR measurement radial peaking factor may be significantly non-conservative for a core with an undetectable misload. However, even in this case the SAFDL will not be exceeded provided that the overpower margin associated with the error in measured peaking factor does not exceed the minimum (required) overpower margin (ROPM) reserved by COLSS. Thus, the analysis of this event determines the ROPM that must be reserved by COLSS to assure that the DNB SAFDLs is not violated due to a fuel assembly misloading.

The methodology used for the assembly misloading analysis is summarized as follows:

- Several candidate worst case misloads are selected for analysis. The selection of the representative worst undetectable misload was based on the reactivities and fissile content of the assemblies as well as reactivities of other assemblies in the vicinity of the misloaded assembly.
- A determination is made as to whether the misload is detectable during the startup tests. This is done by using the 3D nuclear design code (ROCS, Reference 4.3.4-5) to calculate the signal at each of the ICI locations for the fuel symmetry verification test for each postulated assembly misloading. These signals were then used by CECOR to infer the “measured” power distribution. These

CECOR cases consider several different configurations of failed instruments in the vicinity of the high-power misloaded assembly consistent with the requirements for ICI functionality.

- If the misload is judged detectable then it is eliminated from further consideration.
- Of the misloads judged undetectable several of the worst candidates are selected for analysis under full power operating conditions. The worst candidates are defined as those having the highest CECOR decalibration factor (DF).
- For each of the assembly misloadings selected for full power analysis the power distribution was calculated by both the 3D nuclear design code and CECOR at several different burnup points. The CECOR cases consider several different configurations of failed instruments consistent with the ICI functionality criteria. The design code and CECOR core power distributions are then used to establish the maximum CECOR Decalibration Factor during full power operation.
- The power distributions calculated by the 3D nuclear design code and CECOR for the burnup point corresponding to the maximum CECOR DF is used to calculate the minimum DNBR and ROPM using the CETOP code for the worst case misload.
- The largest value of ROPM calculated for the worst undetectable misload is compared to the ROPM installed in COLSS to assure that the DNB SAFDL will not be violated under any allowed operating condition. Table 15.4.7-1

shows that if all the incore detectors in the vicinity of the misloaded assembly are operational, then the misload will be detected during power ascension physics testing since it would exceed the physics startup test acceptance criteria for the maximum power difference between any assembly and its symmetric assembly average or the maximum difference between predicted and measured assembly power. If all the incore instruments within one assembly pitch of the misload are nonfunctional, then the misload may not fail the power ascension test acceptance criteria and operation under a misloaded condition at power may occur.

Table 15.4.7-2 shows the cycle maximum power peaking factors associated with the misload. If all of the incore detectors in the vicinity of the misload are functional then the error in measured power peaking (using the CECOR code, Reference 17 of Section 4.3) due to the misload will be 11%. Since the measured power peaking is used by COLSS to determine the available overpower margin and since the minimum COLSS available overpower margin under any condition is at least 17%, including allowances for uncertainties, no fuel damage is expected. If all the incore instruments within one assembly pitch of the misload are nonfunctional, then the error in measured power peaking due to the misload will be 16%. This corresponds to an overestimate in the available COLSS overpower margin of 17% which is still less then minimum COLSS overpower margin, which is always greater than 17%. Furthermore, since it is very improbable that all the incore detectors in the immediate vicinity of the misload would be nonfunctional, it is

highly likely that the misload will be detected during power ascension or early in the cycle before a significant decrease in operating margin occurs.

Based on these results:

- If all the ICIs in the vicinity of the misload are operational, then the ROPM associated with the representative worst case undetectable misload is expected to be <11%.
- With the current TRM requirement of 1 functional ICI in every 4-by-4 array of fuel assemblies, the worst undetectable misload will not result in fuel failure under any allowed operating condition even with up to 25% failed ICIs.
- The MDNBR at nominal core conditions for the representative worst case undetectable misload including allowance for physics calculational uncertainties is significantly greater than 1.34. In addition, the peak linear heat generation rate (PLHGR) for this worst undetectable misload is also well below the LHR SAFDL for fuel centerline melt.

Table 15.4.7-1

Maximum Difference in Measured Symmetric Instrument Power For Representative Worst Case Undetectable Misload During Power Ascension Testing

Case	Maximum Difference (%)
Nominal (no misload)	~0
Measured by CECOR for Representative Worst Case Undetectable Misload assuming all ICIs in vicinity of misload are functional	13.5
Measured by CECOR assuming all ICIs within one assembly pitch of the misload are nonfunctional	9.2

Table 15.4.7-2

Maximum Power Peaking Factors Occurring For Representative Worst Case Undetectable Misload

Case	Cycle Max Radial Peaking Factor
Nominal (no misload)	1.38
Representative Worst Case Undetectable Misload	1.65
Measured by CECOR for Representative Worst Case Undetectable Misload assuming all ICIs in vicinity of misload are functional	1.49
Measured by CECOR assuming all ICIs within one assembly pitch of the misload are nonfunctional	1.42

15.4.7.4 Conclusion

The inadvertent misloading of a fuel assembly into the improper position events have been analyzed and shown to be highly improbable. The fuel handling procedures and core instrument system more than adequately assure that there is not possibility of a misloaded fuel assembly event proceeding to a

point that would fail fuel, and hence meets the 10CFR 100 requirements.

15.4.8 CONTROL ELEMENT ASSEMBLY EJECTION

15.4.8.1 Identification of Cause and Frequency Classification

A Control Element Assembly (CEA) ejection (CEAE) event is postulated to occur as a result of a mechanical failure that causes an instantaneous circumferential rupture of the control element drive mechanism (CEDM) housing or its associated nozzle. This results in the reactor coolant system pressure ejecting the CEA and drive shaft to the fully withdrawn position.

The CEDM housings are capable of withstanding throughout their design life all normal operating loads including the steady state and transient operating conditions specified for the reactor vessel. Hence, the occurrence of such a failure is considered to be incredible, and the CEAE is classified as a limiting fault event.

15.4.8.2 Sequence of Events and Systems Operation

The sequence of events that occur during the fuel performance aspect of the CEAE initiated from full power Beginning-of-Cycle (BOC) conditions is presented in Table 15.4.8-1. Likewise, the sequence of events that occur during the peak pressure aspect of the CEAE is presented in Table 15.4.8-5.

The postulated mechanical failure of the CEDM causes the ejection of a CEA which adds positive reactivity to the core

that results in a rapid increase in reactor core power for a short period of time. This power excursion is terminated by the combination of delayed neutron and Doppler feedback effects. Closely following the CEAE, reactor shutdown is initiated by a core protection calculator (CPC) and/or reactor protective system (RPS) variable overpower trip (VOPT) on high neutron power. The reactor power decreases rapidly as the shutdown CEAs drop into the reactor core.

The reactor core is therefore protected against severe fuel damage by restrictions on CEA patterns and/or power dependent insertion limits during operation; and by a reactor trip. These factors combine to limit the acceptable values for fuel enthalpy, fuel and clad temperatures, and reactor coolant system (RCS) and secondary side pressures during the transient.

The sequence of events that occurs during the CEA ejection initiated from full power BOC conditions for the peak RCS pressure event is presented in Table 15.4.8-5.

The limiting secondary steam releases for the CEAE event are based on a full-power, BOC analysis[11], with the sequence of events summarized in Table 15.4.8-1. These steam releases are applied to the CEAE event radiological consequences assessment presented in UFSAR Section 15.4.8.5. The analysis assumed that the ejected CEA results in a hole at the top of the reactor

[11] The system response for the calculation of the limiting steam releases used the CESEC computer code (see UFSAR Section 15.0.3.1.3.1).

vessel head. In the analysis, secondary side steaming was maximized by assuming a loss of offsite power (LOP) following the turbine trip. This caused a 4 pump Reactor Coolant Pump (RCP) coastdown, main feedwater pump trip, loss of condenser vacuum and loss of the steam bypass control system. This results in increased primary and secondary side pressures due to decreased heat removal by the steam generators with the subsequent opening of the primary and secondary safety valves to relieve pressure and dissipate energy. A safety injection actuation signal (SIAS) was generated, adding additional boron postulated break in the primary system, caused the RCS pressure and temperature to decrease to below that of the steam generators. The analysis also assumed that operator action was delayed until 30 minutes after event initiation. Plant cooldown was accomplished by using the Auxiliary Feedwater (AFW) system in conjunction with the atmospheric dump valves (ADVs) until shutdown cooling entry conditions were reached.

Section 15.4.8 of the Standard Review Plan (Reference 1) does not require the evaluation of the 4 pump RCP coastdown for this event with respect to fuel performance. However, Regulatory Guide 1.77, Appendix B, indicates that release of fission products from the secondary system should be evaluated with the assumption of a coincident loss of offsite power.

Table 15.4.8-1

TYPICAL SEQUENCE OF EVENTS FOR THE CEA EJECTION EVENT FROM FULL POWER CONDITIONS (FUEL ENTHALPY AND TEMPERATURE CASE)

Time (sec)	Event
0.00	Mechanical failure of CEDM causes CEA to eject
0.04	Core power reaches CPC VOPT analysis setpoint
0.05	CEA is fully ejected
0.07	Maximum core power occurs
0.79	CPC VOPT signal is generated
0.79	Trip breakers open
0.79	Turbine trip occurs
1.39	CEAs begin to drop
3.33	Maximum clad surface temperature in the hot node occurs
3.33	Maximum fuel centerline temperature in the hot node occurs
~5.57	CEAs fully inserted; core power reduced to below 10% of full power

15.4.8.3 Core and System Performance

A. Mathematical Model

The Nuclear Steam Supply System (NSSS) response to a CEAE was simulated using the method of analysis described in Reference 3. The procedure outlined in Figure 2.1 of Reference 3 was used to determine the energy deposition in the fuel rod. The number of fuel pins predicted to experience departure from nucleate boiling was calculated using the STRIKIN-II computer program described in UFSAR Section 15.0.3.1.5 with the CE-1 correlation described in UFSAR Chapter 4.4. A matrix relating the initial and ejected CEA peaking factors to a pin census edit was obtained from Step 6 of the C-E synthesis method (Reference 3) and used to calculate the number of fuel pins experiencing DNB. Further conservatism was introduced by assuming that clad failure occurs when fuel rods experience DNB.

The CENTS computer code described in UFSAR Section 15.0.3.1.3.2 was used to determine the peak RCS and secondary side pressures and the overall NSSS response to the event. The inputs to CENTS were selected so that the ejected rod power excursion that resulted, maximized the time-dependent energy deposition into the RCS.

B. Input Parameters and Initial Conditions

Important input parameters and initial conditions used to analyze the NSSS response to a CEAE are delineated in

Table 15.4.8-2. A spectrum of initial reactor states (including conditions characteristic of the beginning and end of the fuel cycle) was considered. Table 15.4.8-3 lists the initial CEA Bank configurations considered as separate initial reactor states and gives the maximum worth for a CEA ejected from the state as well as the maximum post-ejection radial peaking enhancement factor. The initial conditions for the principal process variables were varied within the reactor operating space of steady state operational configurations to determine the set of conditions that produce the most adverse consequences following a CEAE. Various combinations of initial core inlet temperature, core inlet flow rate, pressurizer pressure, and axial power distribution were considered. The initial pressurizer and steam generator water levels, as controlled within the operating space, have an insignificant effect on the consequences of the CEAE analysis.

For all cases analyzed, an axial power distribution was chosen to maximize the energy content in the hottest fuel pellet. The remaining parameters were chosen based on the results shown in Chapter 4 of Reference 3. These parameters were varied in the most adverse direction until a COLSS power operating limit was achieved.

Table 15.4.8-2

TYPICAL ASSUMPTIONS USED FOR THE CEA EJECTION ANALYSIS
FULL POWER BEGINNING OF CYCLE INITIAL CONDITIONS
(FUEL ENTHALPY AND TEMPERATURE CASE)

Parameters	Values[12]
Initial core power (% of RTP)[13]	102
Initial Core inlet temperature (°F)	569
Initial RCS flow rate (lbm/sec)[14]	43277
Initial pressurizer pressure (psia)	2100
Moderator temperature coefficient (Δρ/°F)	0.0
Maximum Ejected CEA worth (%Δρ)	0.131
Fuel Temperature Coefficient[15]	Least negative
Kinetics[16]	Minimum β
Pre-ejection 3-D fuel pin peaking factor	2.005
Post-ejection 3-D fuel pin peaking factor	3.8095
CEA worth at trip, WRSO (%Δρ)	5.5
Fuel Rod gap conductance (Btu/hr-ft^2-°F)	Minimum[17]
Postulated time to eject CEA (sec)	0.05
CEA coil delay time (sec)	0.6
Axial shape index	-0.2

[12] Values are for the bounding CEAE analysis.

[13] The case was simulated for maximizing the fuel centerline temperature.

[14] This corresponds to 95% of the original design flow.

[15] The fuel temperature coefficients used are found in the unit- and cycle-specific analyses.

[16] The kinetics parameters used are found in the unit- and cycle-specific analyses.

[17] The STRIKIN-II code, using the FATES runs, solves the 1-D, radial heat conduction equation for each axial region along the hot rod. The conduction model explicitly represents the gap region and dynamically calculates the gap conductance in each axial region. This results in the smallest gap conductance so that heat transfer to the coolant is minimized.

Table 15.4.8-3

TYPICAL INITIAL REACTOR STATES CONSIDERED
FOR THE TYPICAL CEA EJECTION EVENT

Initial Rod Configuration	Ejected Rod Worth, $\%\Delta\rho$	Ejected Radial Peaking Factor
Bank 5 inserted (95% power)	0.131	1.9
Banks 4 & 5 inserted (50% power)	0.300	2.4
Banks 3, 4 & 5 inserted (20% power)	0.404	2.7

The key input parameters and initial conditions used in analysis of the CEA ejection peak RCS pressure event is presented in UFSAR Section 15.4.8.4.B. The assumptions and initial conditions used in the analysis that determined the CEA ejection secondary side steam releases are discussed in UFSAR Section 15.4.8.5.

C. Results

A spectrum of initial reactor states, shown in Table 15.4.8-3, was analyzed to show that each case met the criteria established in Regulatory Guide 1.77. All cases resulted in a radial average fuel specific enthalpy less than 280 cal/gram at the hottest axial location of the hot fuel pin. The case that resulted in the greatest potential for offsite dose consequences (i.e., the case resulting in the largest number of postulated fuel failures) was identified as the case initiated from full power beginning of cycle (BOC) initial conditions.

The following paragraphs describe this event in detail. Table 15.4.8-1 contains the sequence of events that occur during a CEAE initiated from full power. Refer to Table 15.4.8-2 for the initial conditions and assumptions used for this analysis. Figures 15.4.8-1 through 15.4.8-5 show the reactor core power, peak core power density, core average heat flux, peak hot

channel heat flux, and clad and fuel temperatures during the significant portion of transient.

Ejection of a CEA causes the core power to increase rapidly due to the almost instantaneous addition of positive reactivity. However, the rapid increase in core power is terminated by a combination of Doppler feedback and delayed neutron effects. This increase in power results in a high power trip and the reactor power begins to decrease as the CEAs enter the core. Reactivity effects are shown in Figure 15.4.8-6.

In the hot channel, the increase in heat flux is such that DNB is calculated to occur, resulting in:

- a rapid decrease in the surface heat transfer coefficient
- a rapid decrease in heat flux
- a rapid increase in clad temperature.

The heat flux continues to decrease for the remainder of the transient.

The calculated radially averaged fuel enthalpy and fuel centerline enthalpy of the hottest fuel pellet for the limiting case remains below the criterion of 280 cal/gm and the fuel centerline temperature is less than the fuel melt temperature. These results show that the CEAE accident will not result in a radial average fuel enthalpy greater than 280 cal/gm at any

axial location in any fuel rod, and that no fuel rod exceeds fuel centerline melt temperature.

NRC Regulatory Guide 1.77 recommends that the onset of DNB be used as the basis for predicting clad failure for the postulated CEA ejection event. For PVNGS, the number of fuel rods that experience DNB is calculated with a statistical convolution technique, which is discussed in UFSAR Section 15E.3.3 and described in Reference 4. The statistical convolution technique involves the summation, over the reactor core, of the number of fuel rods with a specific DNBR value, multiplied by the probability of DNB at that DNBR value. However, to provide a conservative assessment of radiological consequences, a bounding number of fuel rods is assumed to suffer clad failure in the 3954 MWt evaluation, as shown in Table 15.4.8-6. In the 4070 MWt evaluation, the allowable clad failure percentage is a function of the product of clad failure percentage and maximum fuel radial peaking factor as discussed in Section 15.4.8.5D. This limitation on clad failure is compared to a unit cycle specific fuel pin census performed for each reload analysis using the statistical convolution technique in order to predict that the number of fuel rods that experience DNB will result in less than assumed fuel rod failure in dose calculations.

15.4.8.4 Reactor Pressure Boundary Barrier Performance

The CEAE peak RCS pressure event initiated from full power BOC conditions is presented in this section.

The reactor coolant discharged through the CEA break to containment and the steaming mass release through the MSSVs and ADVs are discussed in UFSAR Section 15.4.8.5.

A. Mathematical Model

The CENTS computer code described in UFSAR Section 15.0.3.1.3.2 was used to determine the RCS and secondary side peak pressures and the overall NSSS response to the CEAE event.

The CESEC computer code described in UFSAR Section 15.0.3.1.3.1 was used in determining the barrier performance aspect of the CEAE analysis that deals with secondary side releases to atmosphere that are used in the radiological consequence UFSAR Section 15.4.8.5.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used in determining barrier performance for the peak RCS pressure during the CEA ejection accident from full power BOC conditions are presented in Table 15.4.8-4. The following assumptions were made in the analysis:

- Initial conditions for the key process variables were varied within the ranges of steady state operational configurations including the

uncertainties to determine the set of initial conditions and input variables that would produce the most adverse consequences.

- It was conservatively assumed that there was no pressure boundary breach or leakage in the CEDM area of the reactor vessel head and no pressure reduction caused by the failure of the control element mechanism housing for the primary peak pressure case.

- Only the high pressurizer pressure trip (HPPT) was credited. Although the CPC or RPS VOPT trip may occur on high neutron power much earlier than the HPPT making the event more benign, no credit was taken for these trips.

- The CEAE was assumed to result in almost immediate Turbine Admission Valve (TAV) closure (valve closes in 0.2 seconds). In addition, main feedwater was ramped to zero flow in 1.0 seconds.

- The operator may cool the NSSS by using manual operation of the AFW system and the ADVs anytime after the trip occurs. However, no credit is taken for the operator action for the first 30 minutes of the event.

The assumptions and initial conditions used in determining the secondary side steaming releases for the CEAE event are summarized in Table 15.4.8-6.

Table 15.4.8-4

TYPICAL ASSUMPTIONS USED FOR THE CEA EJECTION ANALYSIS
FOR RCS PEAK PRESSURE EVENT FROM FULL POWER
BEGINNING OF CYCLE INITIAL CONDITIONS

Parameters	Value
	RTP 3990 MWt
Initial core power (% of RTP)	102
Initial core inlet temperature (°F)	548
Initial RCS flow (lbm/sec)[18]	52845
Initial pressurizer pressure (psia)	2100
Initial pressurizer water level (ft)	11.4
Initial steam generator water level (ft)	25.7
MTC ($\Delta\rho$/°F)	0.0
Fuel Temperature Coefficient[19]	Least negative
Kinetics[20]	Minimum β
SCRAM worth at Trip, N-2 (%$\Delta\rho$)	5.5
Fuel rod gap conductance (Btu/hr-ft^2-°F)	6984
Ejected CEA worth (%$\Delta\rho$)[21]	0.157
Postulated CEAE time (sec)	0.05
SCRAM delay time (sec)	0.75
CEA holding coil delay time (sec)	0.6
Plugged steam generator tubes	0
PSV Tolerance	+3%
MSSV Tolerance	+3%
Single Failure	None
LOP	No

[18] This corresponds to 116% of original design flow.

[19] The fuel temperature coefficient used is found in the unit- and cycle-specific analyses.

[20] The kinetics parameters used are found in the unit- and cycle-specific analyses.

[21] The ejected rod worth is limited to 0.131 %$\Delta\rho$ from the fuel enthalpy and temperature case (see Table 15.4.8-2) and use of 0.157 %$\Delta\rho$ is conservative for the peak pressure case.

C. Results

The sequence of events for CEAE peak RCS and main steam pressures for barrier performance is shown in Table 15.4.8-5. The CEAE with a postulated turbine trip and loss of main feedwater results in a peak RCS pressure of 2702 psia (see Figure 15.4.8-7) that is eventually stopped by the PSVs and by the HPPT. The reactor trip causes the closure of the turbine admission valves, which causes a rapid rise in secondary-side pressure to peak pressure of 1349 psia (see Figure 15.4.8-10). The MSSVs open to relieve secondary-side pressure and dissipate energy. Typical NSSS pressure responses to the CEAE transient are presented in Figures 15.4.8-7 through 15.4.8-11[22].

The maximum RCS pressure is less than 120% (3000 psia) of RCS design pressure (2500 psia). The maximum primary pressure for this event meets the limiting pressure acceptance criteria of the Standard Review Plan (Reference 1).

[22] Figures 15.4.8-7, 15.4.8-8 and 15.4.8-10 for RCS and Secondary pressures are from the CENTS runs using the PSV opening area of 0.021602 ft^2, which is the main purpose of this event simulation. Figures 15.4.8-9 and 15.4.8-11 are from a CENTS run at 3876 MWt using a slightly larger PSV area of 0.0301 ft^2. The figures represent typical responses for the transient simulation.

Table 15.4.8-5

TYPICAL SEQUENCE OF EVENTS FOR
CEA EJECTION PEAK RCS PRESSURE EVENT

Time (sec)	Event
RTP 3990 MWt	
0.00	Mechanical failure of CEDM causes CEA to eject
0.05	CEA fully ejected
0.07	Maximum core power
19.60	HPPT reached
20.35	HPPT reactor trip, turbine trip, main feedwater trip
20.95	Scram CEAs begin to drop
21.62	PSVs open
22.16	Peak RCS pressure occurs
24.71	PSVs close
24.81	MSSVs open
27.89	Maximum steam generator pressure occurs
32.70	Steam generator level drops to auxiliary feedwater actuation signal setpoint
< 1800	Long-term automatic plant system actions and NSSS response to this transient are similar to the control element assembly withdrawal at power
1800.0	Operator initiates cooldown

15.4.8.5 Radiological Consequences and Containment Performance

A. Mathematical Model

The number of fuel pins predicted to experience departure from nucleate boiling was calculated using the STRIKIN-II computer program described in section 15.0 with the CE-1 correlation described in chapter 4. A matrix relating the initial and ejected CEA peaking factors to a pin census edit is obtained from Step 6 of the C-E synthesis method and is used to calculate the number of fuel pins experiencing DNB. The time-dependent energy deposition in the NSSS was determined from the above analysis and input into the CESEC III computer program to determine the overall NSSS response to this event.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used for the fuel evaluation portion of a CEA ejection analysis are delineated in UFSAR Tables 15.4.8-2, 15.4.8-3 and 15.4.8-4.

For all cases analyzed, an axial power distribution was chosen to maximize the energy content in the hottest fuel pellet. The remaining parameters were chosen based on the results shown in Chapter 4 of reference 3. These parameters were varied in the most adverse direction until a COLSS power operating limit was achieved.

C. Results

The spectrum of initial reactor states contained in table 15.4.8-3 was analyzed to show that each case met the criteria established in Regulatory Guide 1.77. All cases resulted in a radial average fuel specific enthalpy less than 280 cal/gram at the hottest axial location of the hot fuel pin. The case that resulted in the greatest potential for offsite dose consequences (i.e., the case resulting in the largest number of postulated fuel failures) was identified as the case initiated from full power (FP) beginning of cycle (BOC) initial conditions. The following paragraphs describe this event in detail. Refer to table 15.4.8-4 for the initial conditions and assumptions used for this analysis.

Figures 15.4.8-1 through 15.4.8-5 show the reactor power, heat flux, and clad and fuel temperatures during the significant portion of transient. Table 15.4.8-1 contains the sequence of events that occur during a CEA ejection initiated from full power BOC initial conditions.

Ejection of a CEA causes the core power to increase rapidly due to the almost instantaneous addition of positive reactivity. However, the rapid increase in core power is terminated by a combination of Doppler feedback and delayed neutron effects. This increase in power results in a high power trip and the reactor

power begins to decrease as the CEAs enter the core. Reactivity effects are shown in figure 15.4.8-6.

In the hot channel, the increase in heat flux is such that DNB is calculated to occur, resulting in:

- a rapid decrease in the surface heat transfer coefficient
- a rapid decrease in heat flux
- a rapid increase in clad temperature.

The transient behavior of the NSSS following a postulated CEA ejection is as follows. The steam generator pressure increases rapidly due to the closure of the turbine control valve following reactor and turbine trip. The steam bypass control system is inoperable on loss of offsite power and therefore is unavailable.

Subsequently, the reduced reactor power following the reactor trip, in addition to the postulated break in the primary system, causes the RCS pressure and temperature to decrease.

The steam generator pressure decreases slowly until the main steam safety valves close. The total mass released through the safety valves is approximately 164,160 lbm in the 3954 MWt analysis and 165,528 lbm in the 4070 MWt analysis.

NRC Regulatory Guide 1.77 recommends that the onset of DNB be used as the basis for predicting clad failure for the postulated CEA ejection event. For PVNGS, the number of fuel rods that experience DNB is calculated with a statistical convolution technique, which is discussed in UFSAR Section 15E.3.3 and described in Reference 4. The statistical convolution technique involves the summation, over the reactor core, of the number of fuel rods with a specific DNBR value, multiplied by the probability of DNB at that DNBR value. However, to provide a conservative assessment of radiological consequences, 19% of the fuel rods are assumed to suffer clad failure in the 3954 MWt analysis, as shown in Table 15.4.8-6. This assumed value is greater than the percentage of fuel rods that the statistical convolution technique predicts will experience DNB.

The activity released to the containment (through the ruptured CEDM pressure housing), is assumed to be mixed instantaneously throughout the containment and is available for leakage to the atmosphere. Activity released to the containment building is the activity in primary coolant that is discharged through the CEA break. The activity in the primary coolant consists of primary coolant concentration prior to the accident and fuel-clad gap activity from the fuel rods that experience DNB. Activity is released from the containment building through the power access purge

until the purge system release path is isolated by a Containment Isolation Actuation Signal (CIAS) due to a low pressurizer pressure for the 3954 MWt analysis and due to high radiation levels at the purge monitors for the 4070 MWt analysis. Following isolation of the containment power access purge, airborne activity in containment is released via containment structural leakage.

The activity released from the secondary system is the activity released to the atmosphere from the main steam safety valves and from the atmospheric dump valves during cooldown.

Another source of activity release to the environment is due to ESF recirculation leakage outside the containment building, which is assumed to start at 20 minutes after the event. The iodine activity concentration in the recirculating water is determined assuming that 50% of the total reactor coolant system iodine activity is diluted in a containment sump water volume composed of the combined minimum water volumes of the refueling water tank, the reactor coolant system, and the safety injection tanks. The fraction of radioactive iodine in the leakage water that becomes airborne and available for release is based on the flashing fraction.

Assumptions and parameters that were unique to the evaluation of a CEA ejection event are itemized in

table 15.4.8-6. The following paragraphs provide additional clarification to some of the items contained in the table.

Activity available for release from containment at time zero.

The activity available for leakage from containment is based on the following Regulatory Guide 1.77, Appendix B assumptions:

1. The activity in the fuel clad gap is 10% of the iodines and 10% of the noble gases accumulated in the fuel at the end of core life (infinite cycle length is assumed for short lived isotopes (i.e., all isotopes other than Kr-85) per TID 14844 methodology), assuming continuous maximum full power operation. The ORIGEN computer code was used to obtain source term activities for long-lived isotopes (such as I-129 and Kr-85) using a conservative burnup as summarized in Tables 15.4.8-6 (for the 3954 MWt analysis) and 15.4.8-6A (for the 4070 MWt analysis). All of the activity in the fuel gap for fuel rods that are calculated to experience DNB is assumed to be instantaneously available for release from containment.

Table 15.4.8-6
PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION
ANALYZED CORE POWER OF 3954 MWt WITH ORIGINAL STEAM GENERATORS
(Sheet 1 of 5)

Parameter	Value
A. Data and assumptions used to evaluate the radioactive source term	
1. General	
a. Power level, MWt	3954
b. Burnup	infinite
Short lived fission product (I, Xe, Kr other than Kr-85)	(TID 14844)
Long lived fission product (Kr-85)	44.93 GWD/MTU (EOL)(ORIGEN)
c. Fuel assumed to experience DNB, %	19
d. Fuel calculated to experience incipient centerline melt, %	0.0
e. Maximum fuel radial peaking factor	2.0
f. Secondary system activity before start of the event, uCi/gm I-131 Dose equivalent	0.1
g. Primary system liquid inventory, lbm	571,776
h. RCS activity before start of the event	uCi/gm
I-131	3.0
I-132	0.83
I-133	4.4
I-134	0.52
I-135	2.5

Table 15.4.8-6
PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION
ANALYZED CORE POWER OF 3954 MWt WITH ORIGINAL STEAM GENERATORS
(Sheet 2 of 5)

		Parameter	Value
A.1	h.	RCS activity before start of the event (cont'd)	uCi/gm
		Kr-83m	0.013
		Kr-85	6.1
		Kr-85m	1.3
		Kr-87	1.0
		Kr-88	2.8
		Kr-89	0.076
		Xe-131m	5.9
		Xe-133m	0.34
		Xe-133	360
		Xe-135m	0.74
		Xe-135	7.7
		Xe-137	0.17
		Xe-138	0.63
B.	1.	Dose Conversion Factor for iodine inhalation (Thyroid) are based on ICRP 30, Rem/Ci	Rem/Ci
		I-131	1.08+6
		I-132	6.44+3
		I-133	1.80+5
		I-134	1.07+4
		I-135	3.13+4
	2.	Whole body and beta skin Dose Conversion Factors for all other isotopes are based on Reg. Guide 1.109.	Table 15B-2
C.		Metrological data (based on 1986 through 1991 weather data).	
	1.	EAB X/Q, 0-2 hr. sec/m^3	Table 2.3-31
	2.	LPZ X/Q, sec/m^3	
		0-8 hr	Table 2.3-31
		8-24 hr	
		24-96 hr	
		96-720 hr	

Table 15.4.8-6
PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION
ANALYZED CORE POWER OF 3954 MWt WITH ORIGINAL STEAM GENERATORS
(Sheet 3 of 5)

Parameter	Value
D. Data and assumptions used to estimate Containment release	
1. Containment leakage	
a. Containment net volume, ft^3	2.62E+6
b. Containment leak rate, % vol containment	
0-24 hr	0.1
24 hr – 30 day	0.05
2. Gap activity (of core inventory)	
Iodine	10
Noble gases	10
3. Activity discharged to containment, % RCS activity	100
4. Core gap activity available for release	Ci
I-131	9.92E+07
I-132	1.50E+08
I-133	2.22E+08
I-134	2.59E+08
I-135	2.01E+08
Kr-83M	1.64E+07
Kr-85	1.36E+06
Kr-85M	5.14E+07
Kr-87	8.50E+07
Kr-88	1.26E+08
Kr-89	1.63E+08
Xe-131M	1.02E+06
Xe-133M	5.45E+06
Xe-133	2.22E+08
Xe-135M	7.19E+07
Xe-135	2.11E+08
Xe-137	2.10E+08
Xe-138	1.96E+08

Table 15.4.8-6
PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION
ANALYZED CORE POWER OF 3954 MWt WITH ORIGINAL STEAM GENERATORS
(Sheet 4 of 5)

Parameter	Value
5. Activity release from secondary system	
a. Primary to secondary leak rate, gal/min	1.0
b. Steam mass released through MSSVs, lbm	164,160
c. Steam mass released through ADVs	1,144,000
d. Partition factor	
Iodine[1]	0.01
Noble gases	1
E. Power access purge parameters	
1. Number of valves	2
2. Nominal size of valves, inch	8
3. Time to isolation (start event to isolation), sec	77
4. Total RCS mass discharge to containment for 77 sec, lbm	45,742
F. ESF leakage parameters	
1. Total volume of water in ESF sumps post event, ft^3	6.98E+04
2. Fraction of RCS activity retained by ESF sumps, %	
a. Iodine	50
b. Noble gases	0.0

[1] Justification for the iodine partition factor of 0.01 is provided in Westinghouse Letter LTR-OA-02-86.

Table 15.4.8-6
PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION
ANALYZED CORE POWER OF 3954 MWt WITH ORIGINAL STEAM GENERATORS
(Sheet 5 of 5)

Parameter	Value
F. ESF leakage parameters (cont'd)	
3. RAS actuation time (conservative), min	20
4. Safety injection system leakage, ml/hr	3000
5. Flashing fraction for iodine, %	10
G. Control room parameters[a]	
1. Control room essential HVAC	
a. Normal HVAC Isolation time (CPIAS), sec	119

[a]Refer to UFSAR Section 6.4 and Appendix 15.B for parameters related to control room volume and operation of the essential HVAC system and to UFSAR Appendix 15.B for control room dispersion coefficients, occupancy factors and breathing rate. The bounding unfiltered infiltration rate to the control room is presented in UFSAR Section 6.4.7.

Table 15.4.8-6A
PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION ANALYZED CORE POWER
OF 4070 MWt WITH REPLACEMENT STEAM GENERATORS
(Sheet 1 of 5)

Parameter	Value
A. Data and assumptions used to evaluate the radioactive source term	
1. General	
a. Power level, MWt	4070
b. Burnup	infinite
Short lived fission product (I, Xe, Kr other than Kr-85)	(TID 14844)
Long lived fission product (Kr-85)	70.00 GWD/MTU (EOL)(ORIGEN)
c. Fuel calculated to experience incipient centerline melt, %	0.0
d. Secondary system activity before start of the event, uCi/gm I-131 Dose equivalent	0.1
e. Primary system liquid inventory, lbm	606,083
f. RCS activity before start of the event	uCi/gm
I-131	3.0
I-132	0.83
I-133	4.4
I-134	0.52
I-135	2.5

Table 15.4.8-6A
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL
CONSEQUENCES OF A CEA EJECTION ANALYZED CORE POWER OF
4070 MWt WITH REPLACEMENT STEAM GENERATORS
(Sheet 2 of 5)

		Parameter	Value
A.1	f.	RCS activity before start of the event (cont'd)	uCi/gm
		Kr-83m	0.013
		Kr-85	6.1
		Kr-85m	1.3
		Kr-87	1.0
		Kr-88	2.8
		Kr-89	0.076
		Xe-131m	5.9
		Xe-133m	0.34
		Xe-133	360
		Xe-135m	0.74
		Xe-135	7.7
		Xe-137	0.17
		Xe-138	0.63
B.	1.	Dose Conversion Factor for iodine inhalation (Thyroid) are based on ICRP 30, Rem/Ci	Rem/Ci
		I-131	1.08+6
		I-132	6.44+3
		I-133	1.80+5
		I-134	1.07+4
		I-135	3.13+4
	2.	Whole body and beta skin Dose Conversion Factors for all other isotopes are based on Reg. Guide 1.109.	Table 15B-2
C.		Metrological data (based on 1986 through 1991 weather data).	
	1.	EAB X/Q, 0-2 hr. sec/m^3	Table 2.3-31
	2.	LPZ X/Q, sec/m^3	
		0-8 hr	Table 2.3-31
		8-24 hr	
		24-96 hr	
		96-720 hr	

Table 15.4.8-6A
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION ANALYZED CORE POWER OF 4070 MWt WITH REPLACEMENT STEAM GENERATORS
(Sheet 3 of 5)

Parameter	Value
D. Data and assumptions used to estimate Containment release	
1. Containment leakage	
a. Containment net volume, ft^3	2.62E+6
b. Containment leak rate, % vol containment	
0-24 hr	0.1
24 hr – 30 day	0.05
2. Gap activity (of core inventory)	
Iodine	10
Noble gases	10
3. Activity discharged to containment, % RCS activity	100
4. Core activity available for release (based on 4070 MWt power level)	Ci
I-131	1.02E+08
I-132	1.55E+08
I-133	2.29E+08
I-134	2.68E+08
I-135	2.08E+08
Kr-83m	1.69E+07
Kr-85	1.79E+06
Kr-85m	5.28E+07
Kr-87	8.77E+07
Kr-88	1.30E+08
Kr-89	1.69E+08
Xe-131m	1.06E+06
Xe-133m	5.63E+06
Xe-133	2.29E+08
Xe-135m	7.39E+07
Xe-135	2.18E+08
Xe-137	2.17E+08
Xe-138	2.02E+08

Table 15.4.8-6A
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION ANALYZED CORE POWER OF 4070 MWt WITH REPLACEMENT STEAM GENERATORS
(Sheet 4 of 5)

Parameter	Value
5. Activity release from secondary system	
a. Primary to secondary leak rate, gal/min	1.0
b. Steam mass released through MSSVs, lbm	165,528
c. Steam mass released through ADVs	1,260,000
d. Partition factor	
Iodine[1]	0.01
Noble gases	1
E. Power access purge parameters	
1. Number of valves	2
2. Nominal size of valves, inch	8
3. Time to isolation (start event to isolation), sec	48
F. ESF leakage parameters	
1. Total volume of water in ESF sumps post event, ft^3	7.023E+04
2. Fraction of RCS activity retained by ESF sumps, %	
a. Iodine	50
b. Noble gases	0.0

[1] Justification for the iodine partition factor of 0.01 is provided in Westinghouse Letter LTR-OA-02-86.

Table 15.4.8-6A
PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION
ANALYZED CORE POWER OF 4070 MWt WITH
REPLACEMENT STEAM GENERATORS
(Sheet 5 of 5)

Parameter	Value
F. ESF leakage parameters (cont'd)	
3. RAS actuation time (conservative), min	20
4. Safety injection system leakage, ml/hr	3000
5. Flashing fraction for iodine, %	10
G. Control room parameters[a]	
1. Control room essential HVAC	
a. Normal HVAC Isolation time (CPIAS), sec	90

[a] Refer to UFSAR Section 6.4 and Appendix 15.B for parameters related to control room volume and operation of the essential HVAC system and to UFSAR Appendix 15.B for control room dispersion coefficients, occupancy factors and breathing rate. The bounding unfiltered infiltration rate to the control room is presented in UFSAR Section 6.4.7.

2. The nuclide inventory of the fraction of fuel which reaches or exceeds the initiation temperature of fuel melting at any time during the transient is to be calculated; 100% of the noble gases and 25% of the iodines in this fraction of fuel are assumed to be instantaneously available for release from the containment.

   None of the fuel was calculated to reach or exceed initiation temperature for fuel melting.

Activity release from the secondary system.

Activity released from the secondary system is based upon the secondary activity initially in the steam generators plus primary activity resulting from a 1 gpm steam generator tube leak. A steam generator decontamination factor of 100 is applied to radioactive iodine in the 1 gpm primary to secondary leakage. Supporting documentation for applying a steam generator decontamination factor of 100 to radioactive iodine is provided in Reference 7.

Activity released in secondary system steam includes activity in steam released through the Main Steam Safety Valves (MSSVs) and the Atmospheric Dump Valves (ADVs). Main steam is released via the MSSVs for 30 minutes following accident initiation. From 30 minutes after the accident initiation until shutdown cooling is established, main steam releases are via the ADVs. The mass of steam released through

the MSSVs and the ADVs is given in Table 15.4.8-6 for the 3954 MWt analysis and Table 15.4.8-6A for the 4070 MWt analysis. The Westinghouse (Old CE) CESEC III computer code was used to determine MSSV and ADV secondary system steam releases. It is indicated in Reference 8 that the CESEC III computer code underestimates the decay heat which will cause an under prediction of the steam release. MSSV and ADV steam releases were adjusted to compensate for the CESEC III under prediction of steam release. Steam releases were also adjusted to reflect RSG and power uprate for the 4070 MWt analysis.

Reactor coolant system activity after event.

The RCS activity after the event was based on the assumptions given above. The reactor coolant activity after the event is equal to the reactor coolant activity prior to the event plus the increase in activity due to fuel clad gap activity from the fraction of the fuel that experiences DNB.

Table 15.4.8-7
REACTOR COOLANT RELEASE TO CONTAINMENT AND CONTAINMENT PRESSURE AND TEMPERATURE VERSUS TIME
ANALYZED CORE POWER OF 3954 MWt WITH ORIGINAL STEAM GENERATORS

Reactor Coolant Blowdown		Containment Pressure and Temperature		
Time (sec)	Leak Rate (lbm/sec)	Time (sec)	P (psia)	T (°F)
0.0	0.00E+00	0.0	14.2	100.0
4.0	1.12E+03	4.4	14.4	103.4
8.0	1.08E+03	9.4	14.8	110.3
12.0	1.05E+03	14.4	15.3	116.6
16.0	1.02E+03	19.4	15.6	122.5
20.0	9.88E+023	24.4	16.0	127.9
24.0	9.62E+02	29.4	16.3	132.9
28.0	9.38E+02	34.4	16.6	137.5
32.0	9.31E+02	39.4	16.9	141.8
36.0	9.29E+02	44.4	17.2	146.0
40.0	9.28E+02	49.4	17.5	150.0
44.0	9.27E+02	59.4	18.0	157.0
48.0	9.26E+02	69.4	18.5	163.4
52.0	9.25E+02	79.4	19.0	169.2
56.0	9.23E+02	89.4	19.4	174.6

Table 15.4.8-7A
REACTOR COOLANT RELEASE TO CONTAINMENT AND CONTAINMENT PRESSURE AND TEMPERATURE VERSUS TIME ANALYZED CORE POWER OF 4070 MWt WITH REPLACEMENT STEAM GENERATORS

Reactor Coolant Blowdown		Containment Pressure and Temperature		
Time (sec)	Leak Rate (lbm/sec)	Time (sec)	P (psia)	T (°F)
0.0	0.00E+00	0.0	14.2	100.0
4.0	1.17E+03	4.4	14.4	104.3
8.0	1.13E+03	9.4	14.9	111.8
12.0	1.09E+03	14.4	15.2	117.7
16.0	1.06E+03	19.4	15.6	122.6
20.0	1.03E+03	24.4	15.9	126.5
24.0	1.00E+03	29.4	16.1	129.9
28.0	9.75E+02	34.4	16.4	132.9
32.0	9.59E+02	39.4	16.6	135.5
36.0	9.56E+02	44.4	16.8	137.9
40.0	9.55E+02	49.4	17.0	140.1
44.0	9.53E+02	59.4	17.4	144.1
48.0	9.50E+02	69.4	17.8	147.5
52.0	9.47E+02	79.4	18.1	150.6
56.0	9.44E+02	89.4	18.4	153.3

Although it is unlikely that the entire radioactivity noted in table 15.4.8-6 would be instantly released from the core and the RCS, measures have been incorporated in the PVNGS design to keep offsite doses below 10CFR100 limits should such a release take place. Credit for iodine removal by sprays has not been assumed. Leakage from recirculation components outside the containment, as well as containment leakage and containment purge releases, have been assumed.

Table 15.4.8-8 presents the estimated offsite doses at the exclusion area and low population zone boundaries.

D. Conclusions: Radiological Consequences

Table 15.4.8-8 presents offsite doses at the exclusion area and low population zone boundaries.

<u>Analyzed Core Power of 3954 MWt</u>

The EAB and LPZ radiological consequences of a CEA Ejection accident are presented in Table 15.4.8-8. Thyroid and whole body doses in Table 15.4.8-8 are representative of the parameters presented in Table 15.4.8-6 for a reactor core power level of 3954 MWt with original steam generators. Control room doses are due to a CEA Ejection accident are addressed in Section 6.4.7.3.

Analyzed Core Powe of 4070 MWt

CEA Ejection analyses for a reactor core power level of 4070 MWt with replacement steam generators determine allowable combinations of accident generated failed fuel percentage (Ff) and fuel radial peaking factor (Fr) such that the total design basis offsite dose values, presented in Table 15.4.8-8, are maintained. The limiting dose associated with a CEA Ejection accident is the control room dose. It is indicated in Section 6.4.7.3 and Table 6.4.7-1 that the CEA Ejection accident is the limiting accident for the control room dose. The limiting product of Ff and Fr for the control room accident is 0.30. Fuel cycle characteristics are controlled such that the product of Ff and Fr does not exceed 0.30 following a design basis CEA Ejection accident. This will ensure that the offsite doses are within the design basis dose values presented in Table 15.4.8-8.

Table 15.4.8-8

RADIOLOGICAL CONSEQUENCES OF A CONTROL ELEMENT ASSEMBLY EJECTION ACCIDENT[a]

Dose	Thyroid Dose[c] (rem)	Whole Body Dose (rem)
Exclusion area boundary (EAB)		
2-hour consequences		
Containment contribution (purge system and boundary)	70.2	2.20
ESF contribution leakage	0.059	2.59×10^{-4}
Secondary contribution	6.68	1.51
Total[b]	77	3.71
Low population zone (LPZ)		
30-day consequences		
Containment contribution (purge system and boundary)	148.0	0.83
ESF contribution leakage	0.05	1.2×10^{-5}
Secondary contribution	2.20	0.47
Total[b]	151	1.30

a. Assumes no credit for containment sprays or non-ESF HVAC filtration.

b. Values have been rounded up.

c. The bounding control room thyroid dose is given in Section 6.4.7.

15.4.8.6 Conclusions

The rupture of a CEDM nozzle or housing and the subsequent ejection of a CEA will not result in a radial average fuel enthalpy greater than 280 cal/gram at any axial location in any fuel rod. The fuel centerline temperature will be less than fuel melt temperature. For dose consequences, refer to UFSAR Section 15.4.8.5 for details.

The peak RCS pressure for the CEAE event is less than Service Limit C, 3000 psia (120% of the design pressure of 2500 psia), as defined in the ASME code.

For the postulated event involving a CEAE, the PVNGS design meets the relevant requirements of the Standard Review Plan (Reference 1).

15.4.9 REFERENCES

1. "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, Section 15.4.8 - Spectrum of Rod Ejection Accidents (PWR) and Section 15.4.8, Appendix A - Radiological Consequences of a Control Rod Ejection Accident (PWR)," NUREG-0800 Rev. 1, July 1981.

2. Intentionally deleted.

3. "C-E Method for Control Element Assembly Ejection Analysis," CENPD-190-A, January 1976.

4. "C-E Methods for Loss of Flow Analysis," CENPD-183-A, June 1984.

5. "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Regulatory Guide 1.109, Revision 1, October 1977.

6. DiNunno, J.J. et al., Calculation of Distance Factors for Power and Test Reactor Sites, TID-14844, March 23, 1962.

7. Westinghouse Letter No. LTR-OA-02-86, "Transmittal of Justification Documentation Factor for PVNGS CEA Ejection Analysis," dated June 17, 2002.

8. Westinghouse (Old ABB-CE), TID-97-005, "CESEC III Error Notification C-97-002," dated April 8, 1997.

15.5 INCREASE IN RCS INVENTORY

15.5.1 INADVERTENT OPERATION OF THE ECCS

15.5.1.1 Identification of Event and Causes

The inadvertent operation of the emergency core cooling system (ECCS) is assumed to actuate the two high pressure safety injection (HPSI) pumps and open the corresponding discharge valves. This operation occurs as a result of a spurious signal to the system or operator error.

15.5.1.2 Sequence of Events and Systems Operation

Inadvertent operation of the ECCS is only of consequence when it occurs below the HPSI pump shutoff head pressure. Above that pressure there will be no injection of fluid into the system. Below the HPSI pump shutoff head pressure, when the shutdown cooling system is isolated the HPSI flow will increase reactor coolant system (RCS) inventory and pressure until the pressure reaches the pump shutoff head pressure. During shutdown cooling system operation the increase in RCS inventory and pressure will be mitigated by the shutdown cooling system relief valves.

15.5.1.3 Analysis of Effects and Consequences

Plant operation above the HPSI pump shutoff head pressure will not be impacted by the inadvertent operation of the ECCS. Below the HPSI pump shutoff head pressure when the shutdown cooling system is isolated, there will be an RCS inventory and pressure increase. This increase will be terminated when the pressure rises above the shutoff head pressure. Due to the

pressure increase caused by this transient at low RCS temperatures, there is an approach to the brittle fracture limits of the RCS. Examination of the Technical Specifications RCS pressure-temperature limitations shows that the brittle fracture limits will not be violated for this transient. Should the ECCS inadvertently actuate during shutdown cooling operation, the shutdown cooling relief valves will mitigate the pressure transient so that the temperature-pressure limits are not exceeded. The shutdown cooling relief valves can be isolated when the RCS temperature is above the pressure-temperature limits for brittle fracture of the RCS (See UFSAR Section 5.2.2.11).

15.5.1.4 Conclusion

The peak pressurizer pressure reached during the inadvertent operation of the ECCS is well within 110% of design pressure. Additionally, the pressure-temperature limits for brittle fracture of the RCS are not violated by this transient. The fuel integrity is not challenged by this event.

15.5.2 CVCS MALFUNCTION-PRESSURIZER LEVEL CONTROL SYSTEM MALFUNCTION WITH LOSS OF OFFSITE POWER

15.5.2.1 Identification of Event and Causes

All events and events plus single failures which cause an increase in RCS inventory as a result of failure or misoperation of the CVCS were examined with respect to the RCS pressure and fuel cladding performance. The Pressurizer Level

Control System (PLCS) malfunction was the most limiting event and is more limiting than the UFSAR Chapter 15.5.1 event.

The failure of the PLCS is an Anticipated Operational Occurrence (AOO) and is classified as an incident of moderate frequency. In combination with a single failure, the PLCS malfunction is an infrequent event.

15.5.2.2 Sequence of Events and Systems Operation

The PLCS Malfunction analyses are performed as separate cases for the primary and secondary peak pressure limits, since these events are not mutually conservative. The sequence of events is presented in Table 15.5.2.2-1.

When in the automatic mode, the PLCS responds to changes in pressurizer level by changing charging and letdown flows to maintain the program level. Normally, one charging pump is running with two charging pumps available for automatic startup when a low level setpoint is reached. If the pressurizer level controller fails low or the level setpoint generated by the reactor regulating system fails high, a low level signal can be transmitted to the controller. In response, the controller will start all the charging pumps and close the letdown control valve to its minimum opening, resulting in the maximum mass addition to the RCS.

The event initiates at the most limiting conditions allowed per Technical Specifications. The simulated malfunction of the PLCS results in the reduction of letdown to a minimum and the increase in charging to a maximum. The mismatch in charging and letdown will result in a slow, continuous in surge of RCS

coolant into the pressurizer. The RCS liquid entering the pressurizer will displace the steam above the liquid. The steam space being compressed will result in increasing RCS pressure. With the Pressurizer Pressure Control System (PPCS) in manual, the pressurizer sprays will not open and the RCS pressure will increase. The event proceeds until a reactor trip occurs on high pressurizer pressure (HPPT).If the Steam Bypass Control System (SBCS) is in automatic mode of operation, primary and secondary peak pressures should remain below relief valve setpoints. However, for the PLCS malfunction analysis, the SBCS is assumed to be in manual mode and credit is not taken for their functioning. The pressure increase in the primary and secondary systems are limited by the Primary Safety Valves (PSVs) and the Main Steam Safety Valves (MSSVs). The maximum RCS pressure occurs in the first two to five seconds following reactor trip.

As steam and energy is relieved in the Steam Generators (S/Gs) through the MSSVs, the level in the S/Gs will drop. An auxiliary feedwater actuation signal (AFAS) on low steam generator level occurs. The auxiliary feedwater flow is automatically initiated after a time delay and supplies water from the condensate storage tank (CST) to the Steam Generators.

The PLCS malfunction analysis does not credit operator action for the first thirty minutes following the event. Thirty minutes after initiation of the event, the operators stabilize the plant by securing excess charging and/or balance letdown with charging. The operators commence a cooldown using the safety grade Atmospheric Dump Valves (ADVs) and/or non-safety grade SBCS depending on system availability.

Analytical setpoints and response times associated with the Reactor Protective System (RPS) trip functions and Engineered Safety Features Actuation System (ESFAS) functions are consistent with, or conservative with respect to, limiting numerical values that appear in the PVNGS UFSAR delineated in UFSAR Chapter 7.The NRC's Standard Review Plan states that an incident of moderate frequency, such as the PLCS malfunction event, should not generate a more serious plant condition without other faults occurring independently. In addition, the Standard Review Plan states that an incident of moderate frequency, in combination with a single active component failure or single operator error, should not result in the loss of function of any barrier other than the fuel cladding.

The PLCS malfunction with pressurizer sprays in manual or off causes a reactor trip on high pressurizer pressure. The limiting criteria[1] for this event are peak pressure and secondary pressure which occur within the first two to five seconds after the high pressure reactor trip. Therefore, any single failure which would result in a higher RCS pressure during the transient would have to have an effect during the first two to five seconds following reactor trip.

The single failures that have been postulated are listed in table 15.0-0. The failures which affect the RCS behavior during this interval are:

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[1]Primary integrity can not be compromised (i.e., neither can the primary go solid nor the PSVs pass water

- Loss of Normal AC
- Failure of the Pressurizer Pressure Control System
- Failure of the Steam Bypass Control System
- Failure of the Reactor Regulating System
- Failure of the Feedwater Control System.

Although these non-class systems would not normally be credited, the difference is the loss of RCP flow. Decreased RCP flow has the effect of decreasing heat transfer to the secondary and therefore would by itself increase primary pressure; however, loss of power to the RCPs reduces the RCP head and has a larger effect and reduces peak RCS pressure. Computer simulation has determined that a loss of power is not limiting. The de-energizing of the RCPs has the effect of reducing peak pressure in the primary and secondary. De-energizing the RCPs reduces pump flow and pump head. The CENTS code explicitly models the RCS pressures in each node and has determined that the maximum flow with RCPs running results in higher peak primary and secondary pressure. Consequently, peak RCS pressure occurs with offsite power being available and RCPs running. Peak secondary pressure also occurs with RCPs running which maximizes the heat transfer to the secondary.

Table 15.0-0 is used to determine credible single failures for safety analysis. This table indicates that there are no credible failures that can degrade the PSV and MSSV capacity. Technical Specification 3.7.1 places limits on reactor power and variable overpower trip (VOPT) setpoints when one or more MSSVs are inoperable, thereby ensuring secondary system peak

pressure remains within 110% of secondary system design pressure. The LOCV is one of the transients analyzed for validating Technical Specification 3.7.1. A decrease in RCS to steam generator heat transfer due to reactor coolant flow coastdown can be caused by a LOP following a turbine trip. However, the results of the parametric study show that a LOP coinciding or following the High Pressurizer Pressure Trip (HPPT) does not make the primary and secondary side pressures more adverse. In addition, it is assumed that the most reactive control rod fails to insert on scram.

Other single failures were examined such as operator action or equipment failure resulting in an inadvertent dilution; however, none were identified as credible. No credible single failure has been identified that makes the consequences worse than as specified under the limiting conditions described for this event. This is similar to conclusion in UFSAR 15.2.3.2 where no credible single failure was identified.

Therefore, it was concluded that there is no single failure that would make the maximum primary and secondary pressure more limiting than the LOCV event.

Regarding the approach to the fuel design limit, the major parameter of concern is the minimum hot channel Departure from Nucleate Boiling Ratio (DNBR). The major factors which cause a decrease in local DNBR are:

- Increasing Coolant Temperature
- Decreasing Coolant Flow
- Decreasing RCS Pressure, and

- Increasing Local Heat Flux (including radial and axial power distribution effects).

A decrease in RCS flow is the only parameter which can significantly reduce the minimum DNBR during the event. The PLCS malfunction with pressurizer sprays in manual or off causes a reactor trip. The heat flux starts to drop in the first five seconds. The single failures that have been postulated are listed in table 15.0-0. The failures which affect the RCS behavior during this interval are:

- Loss of Normal AC
- Failure of the Pressurizer Pressure Control System
- Failure of the Steam Bypass Control System
- Failure of the Reactor Regulating System
- Failure of the Feedwater Control System.

The loss of normal AC power results in Loss of Power to the:

- Reactor Coolant Pump,
- Condensate Pumps,
- Circulating Water Pumps,
- Pressurizer Pressure and Level Control System,
- Reactor Regulating System,
- Feedwater Control System, and
- Steam Bypass Control System.

The effect of losing normal ac power on the PLCS malfunction is as follows. Loss of power to the condensate and circulating water pumps and the feedwater control system initially effects

only the secondary system and thus does not affect DNBR in the first five seconds of the transient. Loss of power to the reactor regulating system pressurizer level and pressure control systems renders those systems inoperable. Failure of the pressurizer pressure control system or reactor regulating system cannot appreciably affect any of the major factors which determine DNBR during the first five seconds of the event. This inoperability will have no significant impact on DNBR during the first five seconds. Thus, none of the single failures listed in table 15.0-0 will result in a lower DNBR than that predicted for the PLCS malfunction with a loss of offsite power following turbine trip. Loss of power to the reactor coolant pumps is the only significant failure with regard to DNBR which results from a loss of normal ac power.

No single failure was identified from table 15.0-0 which would have a significant effect on DNBR prior to the reactor trip.

Therefore, any single failure which would result in a lower DNBR during the transient would have to affect at least one of the above parameters during the first five seconds of the event. The LOP is the only failure that may affect RCS flow. PLCS malfunction by itself, however, produces an increasing RCS pressure which compensates for the elevated RCS temperatures such that the available thermal margin does not degrade before the onset of the LOP. Thus, the overall DNBR degradation experienced during an PLCS malfunction event with LOP would be bounded by that of the loss of RCS flow event of UFSAR Section 15.3.1.

Table 15.5.2.2-1 presents a chronological sequence of events for the peak primary case which occur during PLCS malfunction from the initial malfunction until the operator stabilizes the plant and initiates plant cooldown.

Table 15.5.2.2-1 Sequence of Events

Time (sec)	Event
0	Charging flow maximized and letdown flow minimized
296.1	Pressurizer pressure reaches reactor trip analysis setpoint[a]
296.1	High pressurizer pressure trip signal generated
296.1	Turbine trip
296.6	Trip breakers open
297.2	Control rods start inserting
299.0	PSVs open
299.4	Maximum RCS[b] pressure
300.6	MSSVs first open and continue to cycle during the event
301.1	PSVs close[c]
308	Maximum steam generator pressure
357	AFW enters the steam generators
1800	Operator initiates plant cooldown

a. The time of event initiation is highly dependent on initial conditions (e.g., initial pressurizer level) that have little impact on peak primary or secondary pressure. The relative times from reactor trip until breakers opening, control rods inserting, PSVs opening and peak pressure are reasonably invariant.

b. Maximum RCS pressure includes RCP and elevation head in addition to pressurizer pressure.

c. When and how often PSVs cycle is highly dependent on initial conditions (e.g., initial pressurizer level RCS temperature) that have little impact on peak primary or secondary pressure.

15.5.2.3 Core and System Performance

A. Mathematical Model

The nuclear steam supply system (NSSS) response to PLCS malfunction with a reactor trip and a turbine trip was simulated using the CENTS computer program described in subsection 15.0.3.

B. Input Parameters and Initial Conditions

This event was not analyzed for fuel failure. Fuel failure as a result of DNB or peak linear heat rate is not of concern for this event. Pressure is increasing in this event and no power peaking or low RCS flow would occur that would not already be bounded by loss of flow.

C. Results

Since this transient causes an increase in RCS pressure due to an increase in primary coolant inventory, the DNBR increases. Therefore, the acceptance criterion regarding fuel performance is met.

15.5.2.4 Primary and Secondary Barrier Performance

A. Mathematical Model

The nuclear steam supply system (NSSS) response to PLCS malfunction with a reactor trip and a turbine trip was simulated using the CENTS computer program described in subsection 15.0.3.

B. Input Parameters and Initial Conditions

The initial conditions are set conservatively with respect to allowable TS limits, plant design, operating procedures, and instrument uncertainties. The initial conditions were varied within the ranges of steady state operation configurations (i.e., specified by the Technical Specifications, plant configuration, and design specifications) to determine the set of initial conditions that produce the most adverse consequences.

Parameters of interest include initial core inlet temperature, core inlet flow, pressurizer pressure, pressurizer water level, steam generator level, Moderator Temperature Coefficient (MTC), Fuel Temperature Coefficient (FTC), fuel rod gap conductances, kinetics parameters, LOP, and SG tube plugging. Starting from a base case, one parameter at a time is changed to establish the trends for the RCS and steam generator pressure.

For peak primary pressure and peak secondary pressure, neither the net charging rate nor the initial level have a significant impact. Although not discussed in detail, the PLCS malfunction with the sprays in automatic was analyzed and determined to be not limiting with respect to overfilling the pressurizer.

For this scenario, total charging flow due to all three pumps is 132 gal/min. Although a conservative bleedoff of 2 gpm per pump could be credited, no credit for this bleedoff has been taken. The minimum letdown flow is 30 gal/min.

Table 15.5.2.4-1

Limiting Initial Conditions for PLCSM Peak Primary and Secondary Pressure

Parameter	Value	
	Primary Peak Pressure	Secondary Peak Pressure
Initial core power (% of RTP)	102	
Initial core inlet temperature (°F)	566[a]	
Initial pressurizer pressure (psia)	2325[b]	
Initial RCS flow (% design)	116	95
Initial pressurizer water level (%)	23.9	
Pressurizer heaters	On	
Pressurizer sprays	Off	
Charging and letdown flows (gpm)	135/30	
MTC ($\delta\rho$/°F)	-0.0002[b.]	
β	Maximum [b.]	
FTC ($\delta\rho$/°F)	Most negative [b.]	
Prompt neutron lifetime (l*)	Min [b.]	Max [b.]
Fuel gap conductance (Btu/hr-ft2-°F)	500	
SCRAM delay time (sec)	0.5	
CEA holding coil delay (sec)	0.6	
CEA worth at trip - WRSO (%$\delta\rho$)	8.0	
Plugged tubes (per steam generator)	0	
Initial steam generator level (% WR)	28.22	28.22
AFW flow (gpm/pump)	650	
AFW delay time (sec)	46	
PSV setpoint tolerance	+3%	
PSV blowdown	5%	
MSSV Setpoint Tolerance	+3%	
MSSV blowdown	5%	
LOP	No	

a. The sensitivity of this parameter from minimum to maximum on peak primary pressure is much smaller than the uncertainties.

b. The sensitivity of this parameter from minimum to maximum on peak primary and secondary pressure is much smaller than uncertainties. Use of nominal values or other changes would have a negligible effect.

Table 15.5.2.4-2

Initial Conditions with Significant Impact on Peak Primary and Secondary Pressure for PLCSM

Parameter	Value	
	Peak Pressure	
	Primary	Secondary
Initial core power (% of RTP)	102	
Initial RCS flow (% design)	116	95
Fuel gap conductance (Btu/hr-ft2-°F)	500	
β	Maximum	
SCRAM delay time (sec)	0.5	
CEA holding coil delay (sec)	0.6	
CEA worth at trip - WRSO (%δρ)	8.0	
Plugged tubes (per steam generator)	0	
PSV setpoint tolerance	+3%	
Inlet temperature (°F)		566
MSSV Setpoint Tolerance		+3%

C. Results

The dynamic behavior of NSSS parameters for a PLCS malfunction with a reactor and turbine trip turbine trip is presented in figure 15.5.2-2 to 15.5.2-11. Note that the peak secondary pressure occurs for maximum primary temperature so that the figures represent both peak and primary pressure and peak secondary transient.

Failure of the PLCS causes an increase in reactor coolant system inventory initiated by the startup of the third charging pump coupled with the decrease in letdown flow to its minimum. With the PPCS in the manual mode and the proportional sprays turned off, increase in RCS inventory results in a pressurizer pressure increase to the reactor trip analysis setpoint.

Since the SBCS is conservatively assumed in the manual mode and the rate of closure of the turbine stop valves is faster than the rate of control rod insertion, pressurizer pressure increases which opens the primary safety valves. Peak primary pressure is 2681 psia which is less than 110% of the design pressure (2500 psia) or 2750 psia.

The unavailability of the SBCS causes the steam generator pressure to increase, causing the MSSVs to open. The decreasing core power and the safety valves function to limit the peak steam generator pressure to 1382 psia which is less than 110% of the design pressure (1270 psia) or 1397 psia.

At 1800 seconds, the operator stabilizes the plant and initiates plant cooldown using ADVs or SBCS.

This event has also been evaluated for peak pressurizer level (overfill) to assess the impact on the operability of the pressurizer safety valves. However, the limiting transient is discussed in section 18.II.D in accordance with NUREG-0737.

15.5.2.5 Radiological Consequences and Containment Performance

PLCSM is a moderate frequency event in which no fuel damage occurs. As noted above, the steam is discharged by the PSVs. That steam is directed to the Reactor Drain Tank (RDT). If a second lift of the PSVs occurs, the RDT rupture disk will rupture. The steam would be released to the containment. Since fuel failure will not occur as a result of not exceeding any Specified Acceptable Fuel Design Limits (SAFDLs), the dose and effluents will be controlled to the limits specified in 10CFR20. Therefore, radiological consequences are not

calculated for this event and containment isolation is not credited.

15.5.2.6 Conclusion

For the PLCS malfunction following turbine trip event, the maximum RCS pressure remains below 110% of RCS design pressure (2750 psia), thus ensuring primary system integrity. Likewise, the maximum secondary system pressure remains below 110% of design pressure (1397 psia), thus ensuring secondary system integrity.

Since this transient causes an increase in RCS pressure due to an increase in primary coolant inventory, the DNBR increases. Therefore, the acceptance criterion regarding fuel performance is met.

15.6 DECREASE IN REACTOR COOLANT SYSTEM INVENTORY

15.6.1 INADVERTENT OPENING OF A PRESSURIZER SAFETY/RELIEF VALVE

The inadvertent opening of a pressurizer safety valve event as described in NRC Standard Review Plan 15.6.1 is evaluated in the emergency core cooling systems analyses (section 6.3).

15.6.2 DOUBLE-ENDED BREAK OF A LETDOWN LINE OUTSIDE CONTAINMENT

15.6.2.1 Identification of Causes and Frequency Classification

Direct release of reactor coolant may result from a break or leak outside containment in a letdown line, instrument line, or sample line. The double-ended break of the Chemical and Volume Control System (CVCS) letdown line outside containment upstream of the letdown line control valve (DBLLOCUS) was selected for this analysis because it is the largest line, and results in the largest release of reactor coolant outside the containment.

The single active failure of an isolation valve was not considered in the analysis because the letdown line includes two isolation valves in series situated inside the containment. Hence, failure of one isolation valve does not make the consequences of the event more severe.

A letdown line break can range from a small crack in the piping to a complete double-ended break. The cause of the event may be attributed to corrosion which forms etch pits, or to fatigue cracks resulting from vibration or inadequate welds. In order to bound all break sizes,

forms and locations, a double-ended guillotine break of the letdown line just outside containment upstream of the control valve is evaluated.

The letdown line break is classified as a limiting fault event whose occurrence is not expected, but is postulated because its consequences include the potential for release of significant amounts of radioactive material. Two cases were analyzed: in the first case, the initial conditions were selected as shown in Table 15.6.2-3 to minimize DNBR (see figure 15.6.2-16) while in the second case the initial conditions were selected as shown in Section 15.6.2.4B with the exception of conservatively setting pressurizer heaters ON to maximize the blowdown flow (see figure 15.6.2-1 to 15.6.2-15). These will be discussed below.

15.6.2.2 Sequence of Events and Systems Operation

A double-ended break of the letdown line outside containment upstream of the letdown line control valve releases primary fluid to the auxiliary building as shown in figure 15.6.2-7. This discharge rate, as shown in figure 15.6.2-8, is more than twice the maximum expected letdown flow. The event will set off a number of alarms. Table 15.6.2-1 lists the alarms that would be noted by the reactor operator in the control room.

Table 15.6.2-1
ALARMS THAT WILL BE
ACTUATED FOR THE DBLLOCUS EVENT

1. Regenerative heat exchanger high exit temperature alarm
2. Letdown line low pressure alarm
   (downstream of the break)
3. Letdown line process radiation monitor loop low flow alarms
4. Auxiliary building high radiation alarm
5. Auxiliary building high temperature alarm
6. Pressurizer level deviation alarm
7. Auxiliary building sump high level alarm
8. Pressurizer low level alarm

The first three alarms listed in table 15.6.2-1 (the regenerative heat exchanger (RHX) high exit temperature alarm, the letdown line low pressure alarm, and the low flow alarm in the process radiation monitor loop) will immediately alert the operator after the initiation of the event. The high RHX outlet temperature alarm, in addition to sounding the alarm, also initiates isolation of the letdown line by closing one of the two letdown line isolation valves inside the containment. However, no credit is taken for this isolation action in the analysis. Secondly, the high radiation and high temperature alarms in the auxiliary building are expected to be triggered within a few seconds after the event initiation. Thirdly, the pressurizer level deviation alarm is expected to alert the operator approximately one minute after the initiation of the event. Next, the auxiliary building sump high level alarm is expected to be triggered within a few minutes after the initiation of the event. Lastly, the pressurizer low level alarm will occur in approximately 10 minutes after the initiation of the event.

For most nominal starting configurations, the makeup system will be able to restore VCT level before the VCT low level alarm is actuated.

The analysis assumes that the operator isolates the letdown line 10 minutes after the first three alarms resulting from the DBLLOCUS, thereby terminating any further release of primary flow to the auxiliary building. Subsequently, the operator is assumed to take appropriate steps for a controlled reactor

shutdown. The assumption of operator action within 10 minutes after the first few alarms are triggered is based on an ANS/ANSI Standard (Reference 1). The 10 minutes is the minimum time for the letdown line break event category that shall elapse from the time of the alarm until operator actions can be considered for initiation of safety functions.

Table 15.6.2-2 presents a sequence of events which occur following a double-ended break of the letdown line until the operator takes action to terminate the primary system fluid loss 10 minutes after the initiation of the event.

Table 15.6.2-2
SEQUENCE OF EVENTS FOR THE DOUBLE-ENDED BREAK
OF A LETDOWN LINE OUTSIDE CONTAINMENT
UPSTREAM OF THE LETDOWN CONTROL VALVE

Time (sec)	Event	Setpoint/Value
0.0	Letdown Line Ruptures (Break Area, ft^2)	0.01556
0.0	Maximum Break Flow Rate (lbm/sec)	48.9
600	Maximum Break Quality	0.4064
600	Maximum Integrated Mass Release, Flashed (lbm)	11,700
600	Minimum DNBR occurs	1.47
600	Operator isolates the letdown line break and takes steps for a controlled shutdown of the reactor.	10 Minutes

The operator diagnoses the event based on alarms specified in table 15.6.2-1, and may generate a manual reactor trip after isolating the letdown line. If a trip occurs, the control element assemblies (CEAs) fall into the core to provide a negative reactivity insertion. The boron concentration is adjusted to ensure that a proper negative reactivity shutdown margin is achieved prior to cooldown by manually controlling the chemical and volume control system (CVCS).

The turbine automatically trips on the manual reactor trip. The steam bypass control system (SBCS) automatically actuates and opens the steam bypass valves to dump steam to the condenser. The main feedwater control system (FWCS) responds to the reactor trip and generates a reactor trip override signal which reduces feedwater flow to a value commensurate with the decay heat load. The plant cooldown is controlled by manual operation of the SBCS. The main feedwater pumps are manually controlled and continue to supply feedwater until the operator starts the auxiliary feedwater pump and secures the main feedwater pumps.

The shutdown cooling system (SCS) is manually actuated when reactor coolant system (RCS) temperature and pressure have been reduced to approximately 350F and 400 psia. This system provides sufficient cooling flow to cool the RCS to cold shutdown.

15.6.2.3 Core and System Performance

A. Mathematical Model

The nuclear steam supply system (NSSS) response to a DBLLOCUS was simulated with the CENTS computer program (see UFSAR Section 15.0.3). The analysis assumes critical flow through the break and accounts for letdown line and regenerative heat exchanger (RHX) losses to calculate the break discharge. The pressurizer pressure control system (PPCS) and the pressurizer level control system (PLCS) are assumed normally operating unless lack of operation would make the consequences of the event more adverse. In such cases, the PPCS and PLCS are assumed to be inoperative, or in the most adverse mode, until the time of operator action.

The CETOP-D computer code (see UFSAR Section 4.4), which uses the CE-1 CHF correlation, was used to calculate the initial conditions corresponding to the DNBR SAFDL. CETOP-D was also used to calculate transient DNBR values and thermal-hydraulic conditions at the time of the minimum DNBR.

B. Input Parameters and Initial Conditions

Table 15.6.2-3 lists the assumptions and initial conditions used for the letdown line break core performance analysis. These conditions were chosen to minimize the DNBR for DBLLOCUS, within the allowable operating range specified by the Technical Specifications, plant configuration, design specifications, and instrument uncertainties.

The break, just outside the containment penetration, is assumed to be the full cross sectional area (double-ended) of the 2-inch letdown line pipe corresponding to a break area of 0.01556 ft^2 to maximize the depressurization and thus minimize the transient DNBR. In similar manner, conservatively no credit is taken for the pressurizer heaters to slowdown the depressurization.

The break is assumed to be isolated at the end of the transient, i.e., at 600 seconds (10 minutes).

C. Results

The discharge in the primary system causes the RCS pressure to decrease around 250 psi during the 10-minute transient with depressurization rate of approximately 0.40 psi/sec.

The minimum departure from nucleate boiling ratio (DNBR) decreases solely as a result of the pressure degradation, however, remains well above the SAFDL value of 1.34 during the transient (see Figure 15.6.2-16). The core power remains constant during the transient thus the linear heat generation rate remains unaffected ensuring fuel integrity.

Therefore, no fuel failure occurs during the DBLLOCUS event.

15.6.2.4 RCS Pressure Boundary and Barriers Performance

A. Mathematical Model

The mathematical model used for evaluation of barrier performance is described in section 15.6.2.3 A.

Table 15.6.2-3

ASSUMED INPUT PARAMETERS AND INITIAL CONDITIONS FOR THE DOUBLE-ENDED BREAK OF A LETDOWN LINE OUTSIDE CONTAINMENT UPSTREAM OF THE LETDOWN CONTROL VALVE

Parameter	Value
Initial Core Power Level (% of Rated)	102
Initial Core Inlet Temperature, °F	572
Initial Pressurizer Pressure, psia	2325
Initial RCS Flow (% of design lbm/hr)	95%, $155.8x10^{6}$
Initial Pressurizer Water Level, %	59
Moderator Temperature Coefficient (MTC)	nominal
Fuel Temperature (Doppler) Coefficient	nominal
Kinetics Parameters	nominal
CEA Worth at Trip	no reactor trip
Gas Gap Conductance	nominal
Number of Plugged Tubes per SG	0
Number of Running Charging Pumps	3
Pressurizer Heaters	OFF
Break Size (double-ended), ft^2	0.01556

B. Input Parameters and Initial Conditions

The input parameters and initial conditions relevant to barrier performance for the limiting fault event are the same as those presented in table 15.6.2-3 for a letdown line break from full power conditions with the exception of conservatively setting pressurizer heaters ON.

These conditions were chosen to maximize the primary system flashed mass release into the auxiliary building atmosphere for DBLLOCUS, within the allowable operating range specified by the Technical Specifications, plant configuration, design specifications, and instrument uncertainties. This, in turn, leads to the most conservative predictions of radiological releases.

Some of the initial conditions and NSSS characteristics used in this analysis of the maximum total flashed mass release for the letdown line break were based on parametric studies. The parameters evaluated were initial core inlet temperature, initial power level, initial pressurizer pressure, initial core inlet flow rate, initial pressurizer liquid inventory, MTC, RHX heat transfer, PLCS operation, and line friction loss (K-Factor) effect.

Of these parameters, the initial core power does not directly affect the break release, however, the allowed higher core inlet temperature at lower powers increases the flashed mass release from the break. On the other hand, the RCS coolant activity may be lower at lower power levels. Thus, the maximum core power with the maximum allowable core inlet temperature

for all operating power levels are conservatively used together for bounding initial conditions. A larger initial pressurizer pressure (driving head), a higher initial pressurizer level (static head), and a lower core flow(low pressure drop in the RCS loop), increase the RCS pressure at the letdown line exit resulting in a higher break release. Similarly, a lower pressure drop in the letdown line, due to line friction loss, maximizes the break discharge. The heat transfer in the RHX reduces the letdown coolant enthalpy at the break location, thus results in a lower flashed mass release at the break. As a modeling simplification, conservatively no heat transfer in the RHX is assumed in the bounding case.

The core physics parameters including the MTC have negligible to no effect on the break release since the fuel and moderator temperature remains essentially constant during the event and no power changes throughout the core occurs.

All control systems are assumed to be in the automatic mode unless lack of automatic operation would make the consequences of the event more adverse to maximize the total primary mass releases. Since no RHX heat transfer is conservatively assumed, the PLCS operation mode has insignificant effect on the break release. The heaters conservatively left at the full-on mode to maintain high pressurizer pressure thus increase the break release, during the transient.

C. Results

The response of key parameters as a function of time are presented in Figures 15.6.2-1 to 15.6.2-15 for the DBLLOCUS.

The decrease in the primary system mass causes the pressurizer pressure to decrease around 100 psi during the 10-minute transient with depressurization rate of approximately 0.20 psi/sec. Also, during the same time period the pressurizer level decreases about 10 feet (29%) to a new level of approximately 30%.

At 10 minutes into the transient the operator isolates the letdown line, terminating the release of primary fluid outside the containment. The amount of total and flashed reactor coolant released into the Auxiliary Building is shown in Figure 15.6.2-7. The break flow rate varies between 48.9 lbm/sec and 46.9 lbm/sec, as shown in Figure 15.6.2-8. The break quality varies between 0.4060 and 0.4064 during the transient, as shown in Figure 15.6.2-9. With the total mass release of about 28,800 lbm and the maximum break flow quality of about 0.4064, the total flashed release from the break during 10-minute transient is less than 11,700 lbm.

The double-ended break of a letdown line outside containment upstream of the letdown line control valve results in gradual depressurization of the reactor coolant system thus does not challenge the RCS pressure safety limit. The secondary system pressure does not increase above its initial condition value during the transient and does not challenge the 110% of the design limit ensuring integrity of the main steam system.

15.6.2.5 Radiological Consequences and Containment Performance

A. Mathematical Model

The DBLLOCUS event is indicated by several non-Q1E alarms listed in table 15.6.2-1. The first three alarms are expected to take place immediately following initiation of the event. Ten minutes after the initiating event, the letdown line is isolated by the reactor operator.

The methodology to determine the most adverse dose results includes multiplying the amount of primary coolant released into the auxiliary building by the maximum flashing fraction. The flashing fraction is based on the enthalpy and pressure of the primary coolant at the break location. Both the mass released and enthalpy values are obtained from the CENTS code.

The mathematical model used to analyze the activity released during the course of the accident is described in section 15.0.4 (Radiological Consequences) and control room doses are discussed in section 6.4.7 (Bounding System Unfiltered Air Inleakage for Radiological Design).

B. Assumptions and Parameters

The letdown line break outside containment results in the discharge of radioactivity to the environment. Worst case or conservative assumptions are:

1. The initial activity level of the primary coolant is assumed to be 3.81 μCi/gm dose equivalent I-131(DEQ I-131) as calculated using ICRP-30 iodine dose conversion factors.

This corresponds to the maximum equilibrium value with 1% failed fuel.

2. A concurrent iodine activity spike with a spiking factor of 500 for the GIS is assumed to occur coincident with initiation of the transient.

3. The quantity of steam (coolant times maximum flashing fraction) released outside containment is maximized by assuming the most adverse initial conditions and by assuming critical flow through the break.

4. The blowdown decontamination factor (DF) is calculated to determine how much iodine contained in the released primary mass is assumed to be airborne. This is based on the fraction of primary fluid that flashes to steam in the auxiliary building, based on the enthalpy of the escaping fluid.

5. No credit is taken for the retention within the auxiliary building and filtration system.

6. No credit is taken for ground deposition of the activity that escapes the auxiliary building or of decay in transit to the exclusion area boundary.

7. The meteorological conditions assumed to be present at the site during the course of the accident are based on χ/Q values which are expected to be conservative 95% of the time. This condition results in the poorest values of atmospheric dispersion calculated for the EAB or low population zone (LPZ) outer boundary. Furthermore, no

credit has been taken for the transit time required for activity to travel from the point of release to the EAB or LPZ outer boundary. Hence, the radiological consequences evaluated under these conditions are conservative. The PVNGS site specific χ/Q value used for this analysis is discussed in section 2.3.4.

8. Parametrics performed in the dose calculation concluded that all 3 charging pumps in operation prior to initiation of the line break resulted in the highest doses. The higher assumed charging flow maximizes the Iodine source in the primary and bounds all possible modes of operation.

C. Results

The radiological consequences resulting from the occurrence of a postulated letdown line rupture have been conservatively analyzed using assumptions and models described in the preceding subsections. The thyroid inhalation dose and whole body dose have been analyzed for the two-hour dose at the exclusion area boundary. The two-hour thyroid inhalation dose and whole body dose values remain less than a small fraction of 10 CFR 100 guidelines (10% of 10 CFR 100 limits) as listed in table 15.6.2-4. The containment barrier is not challenged since no releases to containment occur during this event.

Table 15.6.2-4
RADIOLOGICAL CONSEQUENCES FOR THE DBLLOCUS

Target Organ, Evaluation Period, Location	Dose (REM)	SRP Limit (REM)
Thyroid, 0-2 hrs at EAB	10.45	30
Whole Body, 0-2 hrs at EAB	0.021	2.5

15.6.2.6 Conclusions

The double-ended break of letdown line outside containment upstream of the letdown line control valve results in gradual depressurization of the reactor coolant system. The peak secondary pressure does not increase during the transient and remains below 110% of design ensuring integrity of the main steam system. The minimum DNBR remains above the SAFDL value, thereby ensuring fuel cladding integrity. The amount of coolant assumed to be released in the dose calculation is 11,900 lbm. The event generated iodine spikes (GIS) radiological releases results in a two-hour thyroid inhalation dose and whole body dose that are a small fraction of 10 CFR 100 guidelines (10% of 10 CFR 100 limits).

For the postulated event involving a letdown line break from full power conditions, the PVNGS design conforms with the applicable requirements of 10 CFR Part 50 Appendix A, General Design Criterion 55 (Reactor Coolant Pressure Boundary Penetrating Containment), as described in the NRC Standard Review Plan (Reference 2).

15.6.3 STEAM GENERATOR TUBE RUPTURE

The Steam Generator Tube Rupture (SGTR) accident is a penetration of the barrier between the Reactor Coolant System (RCS) and the main steam system, and results from a double ended guillotine break of a steam generator U-tube.

A SGTR is classified as a limiting fault event, whose occurrence is not expected during the lifetime of the plant, however, the event is postulated because the consequences include the potential for the release of significant amounts of radioactivity to the environment (i.e., an ANSI N18.2-1973 Condition IV event). Acceptance criteria for SGTR safety analyses are established on the basis of radiological dose consequences, whose acceptance limits vary with the analytical assumptions used for the SGTR event combination under consideration (e.g., availability of offsite power, iodine spiking, single failure, etc.).

SGTR event combinations are also evaluated to ensure that Emergency Operating Procedure (EOP) mitigation strategies provide sufficient direction to plant operators to prevent the occurrence of steam generator overfill. These evaluations are performed in accordance with 10 CFR 50, Appendix B, Criterion III (Design Control) processes. Prevention of steam generator overfill is not an acceptance criterion for SGTR analyses in NRC Standard Review Plan (NUREG-0800) Section 15.6.3.

15.6.3.1 Steam Generator Tube Rupture Without a Loss of Offsite Power

The SGTR with a LOP and an additional Single Failure (SF) presented in UFSAR Section 15.6.3.2 bounds all SGTR events, including the SGTR without a LOP, with respect to offsite dose consequences. The LOP causes the plant to experience a loss of turbine load, loss of normal feedwater flow and loss of condenser vacuum that results in direct steaming to the atmosphere via stuck-open Atmospheric Dump Valve (ADV), the most limiting SF, and the Main Steam Safety Valves (MSSVs). Based on the loss of the condenser vacuum and the direct steaming through the stuck-open ADV, the SGTR with LOP and a single failure is more limiting than the SGTR with respect to radiological consequences.

Additionally, operator action in conformance with Emergency Operating Procedures (EOPs) will prevent overfilling of the steam generators following a SGTR event. Steam generator level control is afforded primarily by controlling the delivery of feedwater (or auxiliary feedwater) to the steam generators, and by releasing steam through the Steam Bypass Control System (SBCS) or the Atmospheric Dump Valves (ADVs).

However, SRP Section 15.6.3 requires that the following two criteria must be met for the SGTR with no LOP:

- For the SGTR event with a pre accident iodine spike, the calculated dose should not exceed the 10 CFR 100 limits, i.e., 300 REM for the thyroid.

- For the SGTR event with an accident generated iodine spike, the calculated dose should not exceed a small part of 10 CFR 100, i.e., 30 REM to the thyroid.

In order to evaluate the dose consequence for the SGTR event, explicit modeling of the transient is not performed. The NSSS response for the SGTR with LOP event presented in UFSAR Section 15.6.3.2 was conservatively assumed to apply for the SGTR event. The dose calculation for the loss of offsite power event was modified with the assumption that the start of the cooldown at 2081 seconds (as depicted in Table 15.6.3-1), is conducted with the Steam Bypass Control System (SBCS) to the condenser instead of the ADVs for the SGTR with LOP event. The activity released to the environment is through the condenser with a DF of 100. With the exception of the performance of radiological consequences, the details outlined below for the SGTR with LOP event including the assumptions applies for the SGTR event. Thus only the radiological consequences are reported below.

15.6.3.1.1 Radiological Consequences

A. Results

The reported values for the 2-hour EAB and the 8-hour LPZ thyroid inhalation doses for the PIS and the GIS cases are presented in Table 15.6.3-1a.

Table 15.6.3-1a
RADIOLOGICAL CONSEQUENCES FOR THE SGTR EVENT

Event Case	Evaluation Period & Location	Dose (REM)
GIS	0-2 hrs at EAB	2.9
	0-8 hrs at LPZ	0.9
PIS	0-2 hrs at EAB	6.2
	0-8 hrs at LPZ	1.8

15.6.3.1.2 Conclusions

The radiological releases calculated for the SGTR event were demonstrated to be within the SRP Section 15.6.3 guidelines. Specifically, the calculated dose for the GIS does not exceed 30 REM (small part of 10 CFR 100 limit) for the thyroid.

15.6.3.2 Steam Generator Tube Rupture With a Loss of Offsite Power and a Single Failure

15.6.3.2.1 Identification of Causes and Frequency Classification

The SGTR with a LOP and a SF event is initiated by the rupture of a steam generator tube, resulting in a failure of the barrier between the RCS and the main steam system. It employs the conservative assumptions of the Standard Review Plan as described in Reference 2 (e.g., loss of offsite power, accident meteorology, iodine spiking, etc.). However, it also assumes that the challenge to the plant is enhanced by actions and failures beyond those postulated by Part 15.6.3 of the Standard Review Plan (Reference 9), as described below.

The analysis of the event postulates that the operators open the ADVs on both steam generators, at which time the ADV on affected steam generator runs to the full open position and sticks full open for the duration of the transient. This ADV is presumed to remain full open despite the availability of control systems that would close the ADV as well as a hand wheel which could be used by the operators to manually close the ADV.

A SGTRLOPSF is classified as a limiting fault event, whose occurrence is not expected during the lifetime of the plant, however, the event is postulated because the consequences include the potential for the release of significant amounts of radioactive materials. These releases cannot result in radiological doses that exceed the 10 CFR 100 limits.

15.6.3.2.2 Sequence of Events and Systems Operation

Integrity of the barrier between the RCS and main steam system is significant from a radiological release standpoint. The radioactivity from the leaking steam generator tube mixes with the shell-side water in the affected steam generator. Prior to turbine trip, the radioactive water is transported through the turbine to the condenser as steam, where the non-condensable radioactive materials are released via the condenser air removal pumps. Following the reactor trip and turbine trip followed by the postulated LOP, the condenser is unavailable. As a result, the radioactive fluid is released through the MSSVs or ADVs.

Table 15.6.3-1 provides a sequence of events for the SGTRLOPSF, from the initiation of the break to the attainment of SDC entry conditions.

The double-ended break of a steam generator tube results in a primary-to-secondary leak rate that exceeds the capacity of the charging pumps. The automatic operation of the PLCS reduces the letdown flow to a minimum value less than a minute into the event.

As a result of the inventory loss, pressurizer level (See Figure 15.6.3-5) and RCS mass gradually decreases from its initial value (See Figure 15.6.3-7). The RCS pressure also decreases (See Figure 15.6.3-2). The backup heaters are energized by the action of the PPCS to mitigate against further depressurization and the PLCS starts the third charging pump.

Following the rupture of the steam generator tube, coolant begins leaking from the RCS into the steam generators (See Figure 15.6.3-10) and the RCS continues to depressurize (See Figure 15.6.3-2). The decrease in RCS pressure typically results in a CPC trip on margin to hot-leg saturation. The auxiliary trip in the CPC (Primary Pressure out of Analyzed Range - Low) and the Low Pressurizer Pressure Trip in the Plant Protection System could also occur. Sensitivity studies for trip times showed an early trip produces more adverse radiological consequences, principally because the early trip results in the ADVs being opened sooner by the operators. A manual trip at 100 seconds was assumed in order to bound

automatic trip time, estimated to occur somewhat later in the transient.

The reactor trip causes the power to drop rapidly (See Figure 15.6.3-1). It also causes the turbine to trip and the main feedwater flow to drop rapidly to zero. When the reactor and turbine trips occur, with the SBCS in manual mode, the secondary system begins to pressurize (See Figure 15.6.3-8) until the MSSVs open[1], mitigating further secondary system pressure increases and releasing steam directly to the atmosphere. The LOP occurs three seconds after the turbine trip and the plant loses the turbine load, normal feedwater flow, forced reactor coolant flow, condenser vacuum and steam generator blowdown capability. Heat removal is initially achieved by steaming directly to atmosphere through the MSSVs and ADVs (See Figure 15.6.3-14) and AFW flow (See Figure 15.6.3-9), which is automatically initiated to both steam generators. Non-condensable material released from the condenser and the steam releases directly to the atmosphere from the MSSVs contribute to the dose consequences.

[1] Figure 15.6.3-8 does not display the peaks of the secondary pressure spikes just after the LOP that result in the opening of the MSSVs. This is a result of a lower frequency of data recording (50 second interval) for plot files for the long-term response and the fact that these pressure spikes are only about 20 seconds long.

Based on the standard post-trip procedure for PVNGS, as the pressure in the steam generators rises above the allowable range, the operator opens one ADV in each steam generator after the trip to minimize cycling of the MSSVs. Earlier opening of the ADVs results in more adverse dose consequences since it increases the release to the atmosphere. The time between the trip and operator action to open the ADVs is assumed to be 2 minutes to bound operating experience and simulator scenarios. The ADV on the affected steam generator is assumed to go to a full open position, causing an increased blowdown of the affected steam generator.

The continued decrease in RCS and pressurizer pressure results in a SIAS, and HPSI flow to the RCS begins. The pressurizer empties due to the primary-to-secondary leakage and post-trip RCS liquid shrinkage. Decreasing steam generator pressure due to flow through the ADVs results in a MSIS on low steam generator pressure being generated. The MSIS results in the closure of the MSIVs, causing a pressure differential to grow between the two steam generators as the flow through the fully-open ADV on the affected steam generator drives its pressure down faster than that of the unaffected steam generator due to the lower flow through the partially-open ADV on that steam generator. As the pressure differential increases between the two steam generators, the AFW to the affected steam generator is terminated by the ΔP lockout.

The LOP and the RCS flow coastdown result in the reduction of flow to the reactor vessel upper head region. This region

becomes thermal-hydraulically de-coupled from the rest of the RCS, and due to flashing caused by the depressurization and boil off from the metal structure-to-coolant heat transfer, voids begin to form in this region (See Figure 15.6.3-6) as the saturation pressure falls below the fluid temperature (See Figure 15.6.3-4). HPSI flow delivery to the RCS halts further RCS shrinkage and depressurization and the voids eventually collapse.

The remainder of the transient is determined by the diagnostic and mitigating operator actions, which are based on the EOP instructions for SGTR and the Functional Recovery Procedures. Timing those operator actions is consistent with or conservative to the times described in ANSI/ANS-N58.8-1984 (Reference 3).

The operator first diagnoses the excessive steam demand and closes the ADVs to prevent excessive cooldown. It is assumed that the ADV on the affected steam generator sticks open while the ADV on the unaffected steam generator closes. Diagnosis of a SGTR with Excess Steam Flow is facilitated by any or all of the following monitors and alarms:

- Rise in Condenser Off-Gas Monitor or alarm
- Rise in Steam Generator Blowdown Monitor or alarm
- Rise in Main Steam Line Monitor or alarm
- Rise in Main Steam Line N-16 Monitor or alarm
- Rise in activity in Steam Generator liquid sample

- Mismatch between feed flow and steam flow

The major post-trip EOP operator actions considered are discussed below in detail.

A. Manual Reactor Trip

Although the reactor trip by CPCs on margin to hot-leg saturation or on low pressure, or by RPS on low pressurizer pressure, is expected due to RCS depressurization during a SGTR event, an operator action to manually trip the reactor at an earlier time is assumed in order to bound the timing of automatic reactor trips, which are estimated to occur later in the transient. This is an adverse operation action, principally because the earlier trip results in the ADVs being opened sooner by the operators.

B. Opening of ADVs

In order to preclude a direct challenge to the MSSVs, the operators open the ADVs (on both steam generators) after the reactor trip, as instructed in the procedures, to relieve the pressure on the steam generators since, because of the LOP, the SBCS is not available. This is also an adverse action since an earlier opening of the ADVs results in increased release to the atmosphere, and thus, more adverse dose consequences. A bounding value of 2 minutes for the time after trip to manually open the ADVs is assumed based on operating experience and simulator scenarios.

C. Diagnose the Event and Stabilize the Plant

The operators first diagnose the Excess Steam Demand (ESD) and take action to close the ADVs to prevent excessive cooldown. This action is assumed to occur approximately seven minutes after the reactor trip and is consistent with expected operator action to ensure adequate RCS heat removal. The analysis assumes that a diagnosis of a SGTR with a continued ESD caused by the stuck-open ADV, will take approximately 15 minutes after indication of double ended guillotine break of a steam generator tube by any of the alarms and monitors listed above, after which operator actions follow guidance from the appropriate PVNGS procedure.

D. Functional Recovery Strategy

At 15 minutes post-trip, the operators are assumed to override the AFAS on the affected steam generator, which has blocked flow to the affected steam generator based on the pressure difference between the two steam generators, and establish dedicated flow from both AFW pumps to the affected steam generator until the steam generator level recovers above 40% NR. This action is consistent with the procedural strategy in response to indications of a SGTR with an ESD (due to uncontrolled steaming to atmosphere from the affected steam generator). The total AFW flow specified in the EOP for a SGTR with an ESD is between 1360 and 1600 gpm. The lower value was used to delay covering the steam generator tubes thereby maximizing the radiological releases when AFW is in manual.

E. Post-Tube Covering Strategy

After the affected steam generator level is above 40% NR, the operators are assumed to initiate a conservatively low AFW flow of 500 gpm to the unaffected steam generator. In accordance with the EOPs, the operator maintains the affected steam generator level between 40% and 60% NR, thus covering the U-tubes, for the remainder of the event by adjusting AFW flow as necessary. The operator is assumed to shift the control of heat removal to the unaffected steam generator when the affected steam generator U-tubes are covered.

F. Cooldown and Depressurize RCS to SDC Entry Conditions

The cooldown and depressurization of the RCS is predominantly due to the stuck-open ADV. However, the analysis assumes operator actions to minimize the cooldown and depressurization to remain within the restriction of EOP guidelines. Specifically, adequate SCM is maintained by utilization of HPSI pumps and pressurizer class back-up heaters.

In addition to maintaining adequate subcooling, the operator is simultaneously responsible for assuring adequate RCS inventory is maintained. Specifically, the EOPs require the operator to retain specified levels in the pressurizer and the upper head before throttling back the HPSI flow. Accordingly, the pressurizer level and the SCM (See Figure 15.6.3-15) in the analysis are maintained above the level required by the EOPs.

Table 15.6.3-1
SEQUENCE OF EVENTS FOR THE LIMITING SGTRLOP SINGLE FAILURE EVENT (3990 MWt RTP with RSG) (Page 1 of 2)

Time (sec)	Event
0	SGTR occurs
43	Letdown control valve throttled to minimum
79	Backup pressurizer heaters energized
100	Manual reactor trip
100	Reactor trip breakers open
100	Turbine trip occurs
100.6	SCRAM CEAs begin falling
102	MSSVs open
104	LOP occurs
105	Maximum steam generator pressure
109	Steam generator level reaches AFAS setpoint in unaffected steam generator
110	Steam generator level reaches AFAS setpoint in affected steam generator
155	AFW initiated to unaffected steam generator
156	AFW initiated to affected steam generator
162	MSSVs close
220	Operator initiates plant cooldown by opening one ADV on each steam generator. The ADV on one steam generator (affected) instantaneously opens fully
245	Pressurizer pressure reaches SIAS setpoint
245	SI flow initiated with no delay
251	MSIS actuation, secondary pressure

Table 15.6.3-1
SEQUENCE OF EVENTS FOR THE LIMITING SGTRLOP SINGLE FAILURE EVENT (3990 MWt RTP with RSG) (Page 2 of 2)

Time (sec)	Event
268	AFAS 1 lockout on high ΔP
317	Voids begin to form in the upper head
520	Operator shuts ADV on the unaffected steam generator to prevent excessive cooldown
608	AFAS 2 reset on high steam generator level
847	Voids collapsed in the upper head
1000	Operator overrides the ΔP lockout and initiates dedicated AFW flow of 1360 gpm to affected steam generator
1900	Operator opens pressurizer head vent
2716	HPSI flow throttled to maintain SCM less than the limit
2779	With level in the affected steam generator above the top of U-tubes, the operator secures AFW flow to affected steam generator and initiates AFW to unaffected steam generator
12610	Class back-up heaters energized to maintain target harsh SCM criteria
26014	ADV opened in the unaffected steam generator in preparation of approaching SDC entry conditions
26260	SDC entry conditions reached in the affected loop
28800	Operator activates SDC system

Although SDC entry conditions may be reached in less than 8 hours, the event was simulated for 8 hours to maximize the dose consequences.

15.6.3.2.3 Core and System Performance

A. Mathematical Model

The thermal-hydraulic response of the NSSS to the SGTRLOPSF was simulated using the CENTS computer code (described in UFSAR Section 15.0.3.1.3.2). The features incorporated in the analytical model include the following:

- secondary releases from both the MSSVs and ADVs
- early operator action for manual trip
- early operator action to open the ADVs
- a series of operator actions to cover the steam generator tubes
- time delays for operator functional recovery actions
- delay in reaching shutdown cooling (chosen to maximize 8-hour steam release)

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a SGTRLOPSF are listed in Table 15.6.3-2. The initial conditions for several process variables were varied parametrically in order to determine the values or assumptions that would produce the most adverse radiological consequences. The initial condition choices that would contribute to a higher

calculated radiological release to atmosphere are discussed below.

- Maximum rated core power - Maximizes the initial heat content of the primary system and maximizes the energy removed from the secondary system. This leads to an increased heat up and pressurization of the primary and secondary systems, which increases the secondary system releases.

- Maximum core inlet temperature - Maximizes the initial secondary system pressure, which increases the steaming through the MSSVs, and maximizes the amount of heat that must be removed during the 2- and 8-hour cooldown intervals by steam releases.

- Minimum RCS flow rate - Maximizes the temperature differential across the core, which maximizes the energy that must be removed by steaming through the steam generators. This increases the activity releases through the MSSVs and ADVs.

- Maximum pressurizer pressure - Maximum initial pressurizer pressure increases the leak rate from the RCS to the affected steam generator, which increases the releases from the secondary system.

- Initial steam generator mass - Low initial steam generator water mass contributes to more adverse radiological consequences by allowing the specific activity in the

steam generators to increase more rapidly because of the leak.

- Minimum scram worth at hot full power – Minimizes the rate of decreasing core power after the reactor trip and therefore increases the heat load to be removed by secondary system releases.

- Safety Injection – Maximizing the HPSI flow will result in higher RCS pressures and increased leakage to the affected steam generator. The SIAS setpoint was set high to provide an early delivery of HPSI flow. No delay time was applied to this signal. In addition, two HPSI pumps were assumed to be available, thus maximizing the flow delivered to the RCS upon SIAS signal.

The SGTRLOPSF transient is not sensitive to the values of MTC and FTC, with regards to radiological consequences, as there are no changes in the fuel or moderator temperatures prior to reactor trip. The most negative MTC and the least FTC were used.

The major assumptions regarding systems operation during the event are summarized below.

- After reactor trip, the main feedwater flow is ramped down to zero in one second.

- Subsequent beneficial operator actions are delayed by times that are also consistent with the ANSI Standard (Reference 3).

- MSSV setpoints are set at their lowest lift pressure in order to make the MSSVs open and release steam to the atmosphere early.
- After the LOP and RCPs coast down, charging pumps are de-energized, letdown is isolated and heaters and sprays are lost.
- The LOP also causes loss of condenser vacuum, loss of steam bypass control valves, and loss of forced flow (RCP coastdown).
- When the ADVs are opened on both steam generators, one of the ADVs is assumed to fail wide open. Most of the cooldown comes about by steaming from the affected steam generator, with the unaffected steam generator being used to control cooldown to SDC entry conditions.
- The AFW system is activated at 20% level wide range and shuts off at 30% level wide range prior to operator action.
- Two AFW pumps are assumed to be available to supply feedwater to either steam generator. No credit is taken for the third 1E-powered AFW train.
- Two HPSI pumps are assumed to be available subsequent to the generation of a SIAS. The SIAS comes from a low pressurizer pressure signal and has no time delay, so that it results in maximum HPSI flow.

Table 15.6.3-2

PARAMETERS USED FOR THE LIMITING SGTRLOP SINGLE FAILURE EVENT
(3990 MWt RTP with RSG Case)

PARAMETER	Value
Initial core power (% of RTP)	102
Initial core inlet temp (°F)	568
Initial pressurizer pressure (psia)	2325
Initial RCS flow (% of design)	95
Initial pressurizer level (%)	53
Initial steam generator level (% WR)	41
MTC ($\Delta\rho$/°F)	-4.0×10^{-4}
FTC	Least negative
Kinetics	Minimum β
CEA worth at trip - WRSO (%$\Delta\rho$)	-8.0
Fuel rod gap conductance (Btu/hr-ft^2-°F)	518
Plugged steam generator tubes	0
SGTR break location	at the tube sheet
Single failure	Stuck-Open ADV (at full open position)
LOP	Yes

- The pressurizer 250 kW class 1E backup heaters are cycled as necessary to maintain adequate SCM.
- The pressurizer head vent system is manually controlled by the operators, as necessary, to depressurize the RCS during the event.
- The SBCS is assumed to be in the manual mode initially.

The event is simulated so that the SDC entry conditions are reached at about 8 hours after initiation of the double-ended rupture of the steam generator U-tube.

C. Results

Table 15.6.3-1 presents a typical sequence of events for the SGTRLOPSF event. Typical transient response of key NSSS parameters as a function of time is presented in Figures 15.6.3-1 to 15.6.3-15 for this limiting fault event.

The calculated transient minimum DNBR is greater than the DNBR SAFDL value of 1.34. Therefore, fuel cladding damage is not predicted for the limiting fault SGTRLOPSF event.

15.6.3.2.4 RCS Pressure Boundary Barrier Performance

A. Mathematical Model

The computer codes that were employed to evaluate fission product barrier performance (other than fuel cladding) for this limiting fault event are identical to those described in UFSAR Section 15.6.3.2.3.

B. Input Parameters and Initial Conditions

The input parameters and initial condition relevant to barrier performance for this limiting fault event are the same as those presented in Table 15.6.3-2 of UFSAR Section 15.6.3.2.3.

C. Results

Due to depressurization of the primary system, the RCS pressures during the event do not exceed the initial pressure

which is less than 110% (2,750 psia) of RCS system design pressure (2,500 psia). The secondary pressures reach maxima around 1300 psia just after the turbine trip and opening of the MSSVs. Thus, the maximum pressure is less than 110% (1,397 psia) of secondary design pressure (1,270 psia).

Steam generator overfill does not occur because of the single failure of the stuck open ADV on the affected steam generator, and manual control of the ADV on the unaffected steam generator.

15.6.3.2.5 Containment Performance and Radiological Consequences

A SGTRLOPSF is classified as a limiting fault. Offsite radiological dose consequences are limited to 10 CFR Part 100 guideline values. Additionally, radiation exposure for control room personnel are subject to the limits specified in General Design Criterion (GDC) 19 of 10 CFR 50 Appendix A.

Control room radiological assessments for bounding unfiltered in-leakage are presented in UFSAR Section 6.4.7. The evaluation of offsite radiological dose consequences associated with the SGTRLOPSF event is discussed below.

Peak containment pressure is not calculated for this event and would be bounded by the Design Basis Accidents, Loss-of-Coolant Accident and the Main Steam Line Break events (see UFSAR Section 6.2). Since this event results in the depressurization of the primary system, the pressurizer safety valves do not lift. The impact of the releases by the pressurizer vent

system to the containment is small enough that the impact of the radiological release from the containment to the atmosphere has negligible impact on the EAB, LPZ or Control Room doses.

A. Mathematical Model

The mathematical model employed in the evaluation of the radiological consequences resulting from the SGTRLOPSF is based on the general modeling in UFSAR Section 15.0.4 and is described below.

The SGTRLOPSF predicts that steam or liquid will be released from the RCS or main steam system and radioactive material will be present in these discharges. As a result, the SGTRLOPSF is anticipated to result in radiological dose consequences for the off-site general public. Appendix 15B describes a generic activity release model for assessing the radiological consequences of postulated accidents.

To analyze the radiological consequences of the SGTRLOPSF, the steam releases to the environment are extracted from the CENTS simulations of the event. Estimated releases are utilized in the radiological dose analyses, for the purpose of determining thyroid doses at the EAB and at the outer boundary of the LPZ.

The evaluation of the radiological consequences of the SGTRLOPSF assumes a double-ended, guillotine break at the hot side tube sheet of a steam generator U-tube while the reactor is operating at full power. Occurrence of the accident leads to an increase in contamination of the secondary system due to reactor coolant leakage through the ruptured tube. An early

reactor trip is assumed, which causes the turbine to trip and leads to a LOP three seconds after the turbine trip. Prior to LOP, the activity is released to the environment through the condenser. Following the closure of turbine admission valves, the steam generator pressure increases rapidly, resulting in opening of MSSVs and steam discharge as well as activity release through the MSSVs. Venting from the affected steam generator by the MSSVs continues until the closure of MSSVs when the secondary system pressure drops below the MSSV blowdown setpoint. Two minutes after the trip, the operator partially opens one ADV on each steam generator to minimize further challenges to the MSSVs and to stabilize RCS temperature. At this point, one of the ADVs (on affected steam generator) is assumed to open fully and remain open for the remainder of the transient.

For most of the event, the heat extraction occurs through the affected steam generator while the unaffected steam generator releases very little steam. The open ADV dumps the inventory of the affected steam generator and the leakage from the primary loop flashes and is released directly. When operator action to divert all AFW to the affected steam generator is taken, the inventory begins to increase until the U-tubes are eventually covered by liquid. At this point the release rate drops dramatically as the iodine is “scrubbed” by the water. Boil-off of the inventory in the affected steam generator, which is maintained by the operators, and controlled cooling by feeding and bleeding of the unaffected steam generator provides the cooling for the event.

The tube leak in the affected steam generator is minimized when primary-to-secondary pressure differential is reduced with a target of keeping it within 50 psid, in accordance with EOP guidance. For this event, the SDC entry conditions are reached in the affected loop prior to 8 hours. However, the transient is simulated for 8 hours in order to maximize dose consequences.

The analysis of the radiological consequences of a SGTRLOPSF considers the most severe release of secondary activity as well as primary system activity leaked from the tube break. The inventory of iodine and noble gas fission product activity available for release to the environment is a function of primary-to-secondary coolant leakage rate, the iodine spiking factor, the initial condition of the fuel in the core and the mass of steam discharged to the environment. Conservative assumptions are made for all these parameters.

B. Input Parameters and Initial Conditions

The assumptions and parameters used to determine the activity releases and offsite doses for a SGTRLOPSF are discussed below.

1. Accident doses are calculated for two different iodine spiking assumptions: (a) an event-Generated Iodine Spike (GIS) coincident with the initiation of the event and (b) a Pre-accident Iodine Spike (PIS).

2. Technical Specification limits for the initial primary system (1.0 μCi/gm) and secondary system activity (0.1 μCi/gm) concentrations are assumed. Transient

primary system specific activity is calculated using the dilution from HPSI flow.

3. A spiking factor of 335 is employed for the GIS at the time of event initiation.

4. A CVCS purification efficiency of 100% is assumed based on the bounding purification flow rate of 150 gpm.

5. The I-131 decay constant is 9.97×10^{-7} sec^{-1}.

6. For the PIS condition, a PIS factor of 60 for the primary system activity concentration is employed.

7. Total allowable primary-to-secondary leakage of 1 gpm is conservatively assumed to be in the unaffected steam generator for the duration of the transient, instead of 0.5 gpm per steam generator.

8. In the unaffected steam generator, the primary-to-secondary is released to the atmosphere with the Decontamination Factor (DF) of 100.

9. In the affected steam generator, the portion of the leaking primary fluid that flashes to steam upon entering to the steam generators is assumed to be released to the atmosphere with a DF of 1.0, while unflashed portion is assumed to mix with the steam generator inventory and released to the atmosphere with a DF of 100.

10. The portion of the leaking primary fluid that flashes to steam is calculated based on the enthalpy of the leak

(See Figure 15.6.3-12). During periods of U-tube uncovery, the flashing fraction is set to 1.0.

11. The atmosphere dispersion factors employed in the analyses are 2.3 x 10^{-4} sec/m^3 for the EAB and 6.4 x 10^{-5} sec/m^3 for the LPZ.
12. The Dose Conversion Factors (DCFs) for dose equivalent Iodine are derived from ICRP-30 (Reference 4).
13. The primary-to-secondary leakage through the tube rupture (See Figure 15.6.3-11), secondary mass inventory (See Figure 15.6.3-13), and secondary system releases from ADVs (See Figure 15.6.3-14) and MSSVs are calculated from the transient simulation of the event.
14. Prior to LOP, the activity is released to the environment through the condenser with a DF of 100.

C. Results

The reported values for the 2-hour EAB and the 8-hour LPZ thyroid inhalation doses for the PIS and the GIS cases are presented in Table 15.6.3-3. The calculated EAB and LPZ doses are within the values of 10 CFR 100. These results bound PVNGS Units operating at a RTP of 3990 MWt or less.

Table 15.6.3-3

RADIOLOGICAL CONSEQUENCES FOR THE LIMITING SGTRLOPSF EVENT

Event Case	Evaluation Period & Location	Dose (REM)
GIS	0-2 hrs at EAB	124
	0-8 hrs at LPZ	84
PIS	0-2 hrs at EAB	294
	0-8 hrs at LPZ	91

15.6.3.2.6 Conclusions

The dynamic behavior of important NSSS parameters during a typical event was presented in Figures 15.6.3-1 through 15.6.3-15. The radiological releases calculated for the limiting SGTR event (SGTR with a loss of offsite power and a fully stuck open ADV) were demonstrated to be within the 10 CFR 100 guidelines.

The RCS and secondary system pressures were shown to be below 110% of the design pressure limits, thus assuring the integrity of these systems.

Additionally, it was demonstrated that there would be no violation of the fuel thermal limits, since the minimum DNBR remains above the DNBR SAFDL value throughout the duration of the event.

15.6.4 RADIOLOGICAL CONSEQUENCES OF MAIN STEAM LINE FAILURE OUTSIDE CONTAINMENT (BWR)

Not applicable.

15.6.5 LOSS-OF-COOLANT ACCIDENTS

Refer to subsection 6.3.3 and paragraphs 6.2.1.5, 6.3.3.2.1, and 6.3.3.3 for loss-of-coolant accident (LOCA) performance evaluations of reactivity control, reactor heat removal, primary system integrity, and secondary system integrity. Also refer to the above sections for LOCA analysis of effects and consequences as they pertain to releases from the primary, secondary, and safety injection systems.

The auxiliary feedwater system is described in subsection 10.4.9. A SIAS will actuate control room and fuel building essential ventilation systems. See sections 6.4 and 9.4 for details and sections 18.II.E.1.1 and 18.II.E.1.2 for reevaluation of the auxiliary feedwater system with respect to TMI lessons learned. A CIAS or CPIAS will terminate the containment power access purge, as described in section 9.4.

15.6.5.1 Identification of Event and Causes - Small Break LOCA

Refer to subsection 6.3.3.

15.6.5.2 Sequence of Events and Systems Operation - Small Break LOCA

Seven breaks were analyzed to characterize the radiological consequences. The spectrum of seven SBLOCA break sizes

included span of the limiting break size for ECCS (0.05 ft^2) with most limiting peak cladding temperature, to break size with no core uncovery (0.01 ft^2 or less), to a 1 inch diameter break (0.005 ft^2). These analyses are specifically done for radiological assessment of SBLOCA and include the effect of ZIRLO fuel, which is bounding for both ZIRLO and Zircaloy-4 clad fuel.

15.6.5.2.1 Evaluation Model

The C-E computer codes CEFLASH - 4AS for primary coolant system thermal hydraulics, CONTRANS2 for containment pressure evaluation, and Bechtel computer code LOCADOSE for dose assessment are used for this Evaluation Model.

15.6.5.2.2 Release Pathways

The release of radioisotopes is postulated through the following pathways.

- Through containment leakage which results from release of primary coolant to the containment from the ruptured pipe. This pathway includes:
    - unfiltered discharge through the power access purge lines until such time as the valves are closed due to generation of CIAS or CPIAS,
    - Leakage through the containment structure at Technical Specification leak rates.

- Release of contaminated steam from the secondary system. This pathway includes:
    - Release of steam contaminated by leakage of primary coolant to the secondary side. The primary-to-secondary leakage is assumed to be at a rate of 1 gpm, and
    - Release from the secondary system inventory [feedwater] at Technical Specification concentration of 0.1 uCi/gm Dose Equivalent I-131.
    - Release of contaminated sump inventory from leakage of ESF components outside containment during recirculation phase.

15.6.5.2.3 Description of Results

The results of these analyses show that all SBLOCA transients achieved containment isolation and containment spray actuation before core uncovery, that is before the possibility of large radioactive release resulting from fuel cladding damage that core uncovery may cause. The 0.03 ft^2 break was determined to be the smallest size break that would exhibit cladding rupture behavior. Table 15.6.5-1 sheet one provides a summary of calculated times to core uncovery, CIAS, CSAS and core recovery. This information is used in the dose assessment evaluation to determine the magnitude of source term and

duration of release from containment power access purge prior to containment isolation.

The following are assumptions used to evaluate the RCS and containment behavior during SBLOCA:

- ALL breaks are in RCS cold leg; potential hot leg breaks are less limiting.
- Loss of offsite power at time of reactor trip.
- Isolation of Main Steam and Main feed at time of reactor trip.
- RCP trip on loss of offsite power.
- SIAS on low pressurizer pressure.
- Single failure: Loss of one diesel
- Auxiliary feedwater actuation to maintain RCS heat removal.
- Containment power purge is operating at start of this event and these valves would be isolated at initiation of CIAS (for hydraulic analysis).
- SI spillage from broken cold leg is assumed to have insignificant effect on containment responses.
- No operator action has been assumed.

Radiological consequences associated with a spectrum of small break LOCAs have been evaluated using computer code LOCADOSE in accordance with the guidelines of Regulatory Guide 1.4, Regulatory Guide 1.77, and SRP Section 15.6.5. This evaluation

is partitioned in to two groups: break sizes that would result in core uncovery and breaks that would not result in core uncovery. The limiting break's thyroid dose due to inhalation and whole-body gamma dose due to immersion are presented in table 15.6.5-1. Two break sizes were evaluated 0.03 ft^2 and 0.005 ft^2 Fuel-clad failure was postulated for the first case, fuel-clad rupture was not predicted for the 0.005 ft^2 break. Doses are calculated using ICRP-30 iodine inhalation dose conversion factors and regulatory guide 1.109 dose conversion factors for all other path ways and isotopes.

The following are a list of assumptions used to evaluate the consequences of the spectrum of SBLOCA,

- Core power was set at an elevated level of 102% of uprated licensed power (3990 MWt).
- The core activity level was based on the "bounding" source term using TID-14844 methodology.
- The initial primary system activity level was based on the maximum activity in the reactor coolant due to continuous full power operation with 1% failed fuel, with iodine at a pre-existing iodine spike level of 60 uCi/gm DEQ I-131.
- Fuel-clad failure was assumed for the case where core uncovering was observed [0.03 ft^2 break].
- For the case where fuel failure was postulated [0.03 ft^2 break]; all gaseous constituents in the fuel-clad gap were released into the primary coolant. The amount of activity

accumulated in the fuel-clad gap was assumed to be 10% of the core iodine and noble gases [Reg. Guide 1.77].

- The offsite [EAB & LPZ] and the control room atmospheric dispersion parameters [X/Qs] were based on the updated site specific meteorological data [refer to section 2.3-31],
- The containment power access purge closed within 8 seconds (8 seconds includes: instrument response time, ESF loop delay time and valve closure time) upon receipt of a containment isolation actuation signal (CIAS) or CPIAS. Time to generate an isolation signal is conservatively set to the elapsed time from the initiating event to time for containment pressure to reach 5 PSIG.
- Control room essential filtration system was activated within 50 seconds upon receipt of a SIAS.
- Spray water was delivered to the containment atmosphere in 92 seconds upon receipt of a containment spray actuation signal (CSAS). The time for the containment pressure to reach a CSAS setpoint ranged from 282 to 10,000 seconds depending upon the size of the break.
- Containment leakage rate was set at value of 0.1 vol% per day for the first 24 hours, and at half of that rate thereafter per regulatory guide 1.4.
- Primary-to-secondary leakage rate was set at value of 1.0 gpm (total). Duration of 3 hours was assumed for the break size

of 0.03 ft^2. For 0.005 ft^2 break a value of 8 hours was assumed based on natural circulation cooldown.

- ESF component leakage rate during recirculation phase was conservatively set at a constant rate of 3,000 ml/hr. This pathway only applies to the fuel-clad failure case because the smaller break does not result in sump recirculation.

15.6.5.3 Analysis of Effects and Consequences

For the break for which fuel cladding failure was postulated (0.03 ft^2), the main dose contributor was the primary fluid that leaked to the secondary side, following the release of 100 percent of the gas gap activity into the primary.

For a 0.005 ft^2 break, fuel-clad rupture was not predicted. Although the source term was based on design RCS activity level, with pre-existing iodine spike, a relatively higher thyroid dose for control room was noted which was due to extended release through the mini-purge and a fairly long isolation time for the control room.

For all cases analyzed (refer to table 15.6.5-1), the offsite doses remained bounded by the large break LOCA doses that are presented in table 15.6.5-2 and the control room doses were below GDC 19 exposure limits.

Table 15.6.5-1
RADIOLOGICAL CONSEQUENCES OF A SMALL BREAK LOCA
Summary of Calculated Time[1] vs. Break Size

Break size (ft^2)	CIAS on 5 PSIG (sec)	React or Trip (sec)	CSAS on 10 PSIG (sec)	Core uncovery (sec)	Core recovery (sec)
0.07	75	155	282	610	2480
0.05	119	217	442	772	2970
0.03	256	360	1190	1400	5000
0.01	2596	970	6770	No uncovery	No uncovery
0.008	3826	1200	9370	No uncovery	No uncovery
0.006	6242	1565	>10000	No uncovery	No uncovery
0.005	8945	1860	>10000	No uncovery	No uncovery

[1]Duration provided is approximate from the outputs of CEFLASH and CONTRANS2.

Table 15.6.5-1 (cont'd)
RADIOLOGICAL CONSEQUENCES OF A SMALL BREAK LOCA
Summary of input parameters for radiological consequences

	Parameter	Value
A. Source Term Data		
1	Core Activity (curies):	
	I-131	1.02E+08
	I-132	1.55E+08
	I-133	2.29E+08
	I-134	2.68E+08
	I-135	2.08E+08
	Kr-83m	1.69E+07
	Kr-85	1.79E+06
	Kr-85m	5.28E+07
	Kr-87	8.77E+07
	Kr-88	1.30E+08
	Kr-89	1.69E+08
	Xe-131m	1.06E+06
	Xe-133m	5.63E+06
	Xe-133	2.29E+08
	Xe-135m	7.39E+07
	Xe-135	2.18E+08
	Xe-137	2.17E+08
	Xe-138	2.02E+08
2	RCS specific activity concentration prior to event:	uCi/gm
	I-131	3.0
	I-132	0.83
	I-133	4.4
	I-134	0.52
	I-135	2.5
	Kr-83m	0.013
	Kr-85	6.1
	Kr-85m	1.3
	Kr-87	1.0
	Kr-88	2.8
	Kr-89	0.076
	Xe-131m	5.9
	Xe-133m	0.34
	Xe-133	360
	Xe-135m	0.74
	Xe-135	7.7
	Xe-137	0.17
	Xe-138	0.63

Table 15.6.5-1 (cont'd)
RADIOLOGICAL CONSEQUENCES OF A SMALL BREAK LOCA
Summary of input parameters for radiological consequences

	Parameter	Value
3	Fuel-Clad failure 0.03 ft^2 break 0.005 ft^2 break	 Yes No
4	Activity accumulated in the fuel-gap, in percent of core: Iodine Noble Gases	 10% 10%
5	Iodine composition: Elemental Particulate Organic	 91% 5% 4%
6	Percent of the accumulated fission products in the fuel-gap that would be released into the primary coolant due to event-induced fuel-clad failure	100%
B. Containment Power Access Purge (Mini-Purge) Data		
7	Source Terms Iodine [assuming pre-existing iodine spike, Dose Equivalent I-131] Noble gases	 60 uCi/gm RCS normal
8	Purge valve type Purge valve size, inch Number of valves (0.03 ft^2 break)	Butterfly 8 2
9	Effective purge flow rates, cfm 0.03 ft^2 break 0.005 ft^2 break (Maximum)	Calculated by LOCADOSE 2,200
10	Total containment power access purge isolation time [duration of release to environment in sec] Break sizes 1. 0.03 ft^2 2. 0.005 ft^2	 265 1869

Table 15.6.5-1 (cont'd)
RADIOLOGICAL CONSEQUENCES OF A SMALL BREAK LOCA
Summary of input parameters for radiological consequences

	Parameter	Value
C. Containment Leakage Data		
11	Source Terms 0.03 ft2 breaks 0.005 ft2 break	 RCS_{normal}+ Gap activity RCS_{normal} with iodine spike
12	Percent of the discharged primary coolant activity which is released to the containment atmosphere [airborne]: Iodine Noble gases	 25% 100%
13	Containment net free volume, ft^3	2.62E+6
14	Containment leak rate, vol.%/day 0-24 hr > 24 hr	 0.1 0.05
15	Containment region volumes, ft^3: Main spray region Auxiliary spray region Unsprayed region	 2.27E+6 2.00E+5 1.50E+5
16	Transfer rate between sprayed and unsprayed regions, in terms of unsprayed volume change per hour	$3.3\ hr^{-1}$ [8,250 cfm]
17	Air transfer rates between the containment regions, cfm: Main sprayed and unsprayed regions auxiliary sprayed and unsprayed regions	 7,582 668
18	Total instrumentation and pump response time (w/LOP) for containment spray pump (DG start, ESFAS, sequencer and pump response time) seconds	33

Table 15.6.5-1 (cont'd)
RADIOLOGICAL CONSEQUENCES OF A SMALL BREAK LOCA
Summary of input parameters for radiological consequences

	Parameter	Value
19	Iodine removal by spray, during injection phase: Main sprayed region: Elemental Organic Particulate Auxiliary sprayed region: Elemental Organic Particulate Spray elemental-iodine decontamination Factor	 Coefficients 19.6 hr^{-1} 0 0.32 hr^{-1} 6.05 hr^{-1} 0 0.09 hr^{-1} DF 6.51
20	Elemental iodine removal by plate-out [wall deposition]: Main sprayed region Auxiliary sprayed region unsprayed region Elemental-iodine decontamination facTor	 Coefficients 2.14 hr^{-1} 14.4 hr^{-1} 14.4 hr^{-1} DF 100
21	Duration of containment leakage	30 days
D. Primary-to-Secondary Leakage Data		
22	Primary-to-secondary leak rate (steam generator tube leakage), total	1 gpm
23	Source Terms 0.03 ft^2 breaks 0.005 ft^2 break	 RCS_{normal}+ Gap activity RCS_{normal} with iodine spike
24	Duration of leakage 0.03 ft^2 breaks 0.005 ft^2 break	 3 hrs 8 hrs
25	Steam Generator Partition Factors Iodine noble gases	 0.01 1

Table 15.6.5-1 (cont'd)
RADIOLOGICAL CONSEQUENCES OF A SMALL BREAK LOCA
Summary of input parameters for radiological consequences

	Parameter	Value
E. Secondary Steam Release Data		
26	Source Terms Secondary coolant activity concentration prior to onset of the event	0.10 uCi/gm DEQ I-131
27	Total mass release through the main steam safety valves (MSSVs) and through the atmospheric dump valves (ADVs) Steam generator iodine partition factor	374,400 lbm (total secondary volume) 1.0
F. ESF Recirculation Data		
28	Sump volume (ft^3), Reduced RWT volume of 400,000 gal RCS volume, including Pzr & CVCS Safety injection tanks [SITs]	 53,476 ft^3 9,177 ft^3 4 x 1,750 ft^3
29	Sump activity of iodine, as a percent post-accident reactor coolant activity	50%
30	Recirculation start time	20 minutes, post accident
31	Credit assumed for radioactive decay of iodine prior to recirculation	yes
32	Total ESF component leakage rate [two trains]	3,000 ml/hr
33	Percent of the iodine in the leaked water which is assumed to become volatile [flashing fraction]	10%
34	Duration of ESF leakage	30 days
G. Control Room Data - refer to section 6.4.7[(b)]		
H. Transport Data		
35	EAB X/Q, 0-2 hr, sec/m^3 LPZ X/Q, sec/m^3: 0-8 hr 8-24 hr 24-96 hr 96-720 hr	2.3E-4 6.4E-5 4.8E-5 2.6E-5 1.1E-5

Table 15.6.5-1 (cont'd)
RADIOLOGICAL CONSEQUENCES OF A SMALL BREAK LOCA
Summary of input parameters for radiological consequences

	Parameter	Value
36	Offsite Breathing Rates, m^3/sec: 0-8 hr 8-24 hr > 24 hr	 3.47E-4 1.75E-4 2.32E-4
37	Credit for depletion of the effluent plume of radioactive iodine due to deposition on the ground	Not Assumed
38	Credit for radiological decay in transit	Not Assumed
I. Dose Calculation Data		
39	Dose Conversion Factors (DCFs): Inhalation Thyroid DCFs, rem/Ci I-131 I-132 I-133 I-134 I-135	**NRC-ICRP-30** 1.08E+6 6.44E+3 1.80E+5 1.07E+3 3.13E+4
40	Immersion [Beta Skin & Whole-Body] DCFs	Reg. Guide 1.109

Table 15.6.5-1 (cont'd)
RADIOLOGICAL CONSEQUENCES OF A SMALL BREAK LOCA
Summary of Input Parameters for Radiological Consequences

Location	**EAB (rem) (0-2hr)**		**LPZ (rem)(0-30day)**		**Control room[a] (rem)(0-30day)**		
Dose Contributor	Whole Body	Thyroid	Whole Body	Thyroid	Whole Body	Beta skin	Thyroid[(b)]
Break size 0.03 ft.^{2} Limiting break with fuel rupture							
Containment Air Lkg:							
Mini-Purge	4.30E-3	8.89E+0	1.20E-3	2.47E+0	7.72E-4	1.61E-2	3.78E+0
Containment Bldg.	2.53E-1	6.76E+0	1.90E-1	9.55E+0	1.27E-1	2.62E+0	1.10E+0
Steam Release:							
Primary-Sec. Lkg	3.84E+0	1.60E+1	1.24E+0	5.75E+0	7.87E-1	1.52E+1	6.11E-1
Secondary Steam	3.41E-4	1.46E+0	9.48E-5	4.07E-1	1.99E-5	1.47E-4	1.74E+0
ESF Comp. Lkg	7.05E-4	1.58E-1	1.22E-03	1.03E+0	4.49E-5	8.55E-4	1.03E-1
Total	**4.10E+0**	**3.33E+1**	**1.43E+0**	**1.92E+1**	**9.15E-1**	**1.78E+1**	**7.33E+0**
Break size 0.005 ft.^{2} Limiting event without fuel rupture							
Containment Air Lkg:							
Mini-Purge	1.18E-2	1.35E+1	3.28E-3	3.76E+0	2.93E-3	6.21E-2	1.42E+1
Containment Bldg.	2.41E-5	2.07E-2	1.38E-4	1.21E-1	8.32E-5	2.01E-3	1.30E-2
Steam Release:							
Primary-Sec. Lkg	5.01E-4	2.08E-2	3.47E-4	1.64E-2	3.73E-4	8.42E-3	7.81E-3
Secondary Steam	3.41E-4	1.46E+0	9.48E-5	4.07E-1	1.99E-5	1.47E-4	1.74E+0
Total	**1.27E-2**	**1.50E+1**	**3.86E-3**	**4.31E+0**	**3.41E-3**	**7.27E-2**	**1.59E+1**

a. Whole body doses do not included contribution from direct/ scatter shine (containment, outside cloud and piping/filter dose). SBLOCA direct and scatter doses are bounded by Large LOCA see table 15.6.5-2.

b. The bounding leakage and thyroid dose is given in section 6.4.7.

15.6.5.4 Identification of Event and Causes - Large Break LOCA

Refer to subsection 6.3.3.

15.6.5.5 Sequence of Events and Systems Operation - Large Break LOCA Dose Calculation

Containment power access purge through an 8-inch penetration will be terminated within 12 seconds after generation of CIAS CPIAS as described in subsection 6.5.3.1.

A SIAS will initiate a switch to the filtered recirculation and filtered makeup mode of control room ventilation as discussed in section 6.4. A SIAS will initiate filtered ventilation of the lower region (below 100-foot elevation) of the auxiliary building as discussed in section 9.4. Since recirculation loop equipment and piping for safety injection and containment sprays in the auxiliary building is located below the 100-foot elevation, leakage from active recirculation equipment is filtered prior to release to the environment.

For the limiting large break LOCA, the reactor trip will result in a turbine trip, and a subsequent loss of offsite power will result in the loss of main feedwater flow. As result of the loss of feedwater and due to fast depressurization of RCS as result of the initiating event, high containment pressure would generate a CIAS and then MSIS actuation. At this time the primary coolant and containment environment would be at lower pressure than the secondary side of the steam generators and the secondary would become a heat source for the primary system. The steam generators would then quickly depressurize

due to containment spray system and possible use of ADVs. During this time the leakage would change direction from the primary coolant to the secondary side of the steam generators. This would result in a leakage path from containment to the environment.

15.6.5.6 Analysis of Effects and Consequences - Large Break LOCA Dose Calculation

It is assumed that there is a preexisting RCS iodine spike of 60 μCi/cc dose equivalent I-131 since there will not be any fuel cladding rupture within the 20 seconds after initiation of the large break LOCA. This activity is instantaneously mixed with the containment atmosphere and available for release via the power access purge. The containment airborne radioactivity inventory will be affected by four factors: leakage, radioactive decay, plateout and sprays. No credit has been taken for spray removal of organic iodine. Refer to section 6.5 for a discussion of spray effectiveness. It is assumed that the containment leaks at the maximum rates allowed by the Technical Specifications, i.e., 0.1 vol %/d for the first 24 hours and half of that rate thereafter. This leakage, when combined with initial releases, will result in potential doses offsite and in the control room. Contribution from the containment leakage through the steam generators is evaluated. The offsite and control room doses are calculated with a single failure of a GDC 57 valve or a stuck open ADV. The leakage from containment environment through the primary system to the secondary system is conservatively assumed to be containment

atmosphere at post large break LOCA conditions. The flowrate is calculated as that produced by leaking through a steam generator tube fault equivalent in size to that which would allow the 1 gpm RCS liquid at normal operating plant conditions. This rate is used for the first 24 hours. The leakage rate is assumed to be half that for the duration of the analysis. The analysis does not take any credit for iodine partition factors or operator action to flood the steam generator. The doses are listed in table 15.6.5-2.

Additionally, there will be exposure offsite and in the control room from the filtered release of recirculation leakage. The calculated leakage is based on the containment sump inventory as per table 15.6.5-2. The doses from recirculation releases are listed in table 15.6.5-2. The total combined doses to an individual offsite and to control room operators following a postulated large break LOCA are also presented in table 15.6.5-2.

The release of radioisotopes, due to LOCA, is postulated through the following pathways:

1- The containment leakage which results from the release of primary coolant to the containment from the postulated break. This pathway includes: (1) unfiltered discharge through the power access [mini-purge] intake and exhaust lines until such time the valves are closed due to generation of a CIAS, (2) leakage through the containment structure at Technical Specification leak rates, and (3)

release of containment air through depressurized secondary system.

2- release of contaminated sump inventory due to leakage from ESF systems outside containment during the recirculation phase. This pathway includes: (1) ESF component leakage outside containment, and (2) back-leakage of recirculating sump water to refueling water storage tank during long term cooling, post RAS due to check valve CH-V-305 and CH-V-306 leakage or any other SI system leakage to the refueling water storage tank [IN 91-56].

In addition to the above contributors, control room doses are evaluated for radiological exposure due to direct dose from containment, ESF piping, shine from outside cloud and dose due to accumulation iodine on essential control room HVAC filtration filters. Table 15.6.5-2 provides detailed information on key parameters used to evaluate the consequences of LOCA and a summary of integrated doses at different locations.

15.6.5.7 Conclusions

Based on use of very conservative assumptions regarding spray effectiveness, containment ventilation, and leakage, as well as conservative fuel failure models, the offsite doses presented in table 15.6.5-2 for LOCA are substantially below 10CFR100 limits.

Table 15.6.5-2
Large break LOCA radiological analysis parameters and results

	Parameter	Value (3954 MWt)	Value (4070 MWt)
Source Term Data			
1	Core Activity (curies)	Ci	Ci
	I-131	9.92E+07	1.02E+08
	I-132	1.51E+08	1.55E+08
	I-133	2.22E+08	2.29E+08
	I-134	2.60E+08	2.68E+08
	I-135	2.02E+08	2.08E+08
	Kr-83m	1.64E+07	1.69E+07
	Kr-85	1.37E+06	1.79E+06
	Kr-85m	5.14E+07	5.28E+07
	Kr-87	8.50E+07	8.77E+07
	Kr-88	1.27E+08	1.30E+08
	Kr-89	1.64E+08	1.69E+08
	Xe-131m	1.03E+06	1.06E+06
	Xe-133m	5.46E+06	5.63E+06
	Xe-133	2.22E+08	2.29E+08
	Xe-135m	7.20E+07	7.39E+07
	Xe-135	2.12E+08	2.18E+08
	Xe-137	2.10E+08	2.17E+08
	Xe-138	1.97E+08	2.02E+08
2	RCS specific activity concentration prior to event:	uCi/gm	uCi/gm
	I-131	60 DEQ I-131	60 DEQ I-131
	I-132	---	---
	I-133	---	---
	I-134	---	---
	I-135	---	---
	Kr-83m	0.013	0.013
	Kr-85	6.1	6.1
	Kr-85m	1.3	1.3
	Kr-87	1.0	1.0
	Kr-88	2.8	2.8
	Kr-89	0.076	0.076
	Xe-131m	5.9	5.9
\	Xe-133m	0.34	0.34
	Xe-133	360	360
	Xe-135m	0.74	0.74
	Xe-135	7.7	7.7
	Xe-137	0.17	0.17
	Xe-138	0.63	0.63

Table 15.6.5-2 (cont'd)
Large break LOCA radiological analysis parameters and results

	Parameter	Value 3954(MWt)	Value (4070 MWt)
3	Primary coolant weight Primary coolant specific volume @ 70F	571,776lbm 0.01605 ft^3/lbm	606,083 lbm 0.01605 ft^3/lbm
4	Iodine composition: Elemental, Organic, Particulate	91%, 4%, 5%	91%, 4%, 5%
Containment Data			
5	Containment Net Free Volume	2.62E+6 ft^3	2.62E+6 ft^3
6	Initial Pressure Initial Temperature Post-LOCA Peak Pressure Post-LOCA Peak Temperature	16.7 psia 120 °F 66.1 psia 251 °F	16.7 psia 120 °F 74.7 psia 308°F
Power Access Purge (mini-purge) Model			
7	Source Terms Iodine, (Dose Equivalent I-131) Noble gases	60 uCi/gm RCS Normal	60 uCi/gm RCS Normal
8	Purge valve type Purge valve size, inch Number of release flow paths	Butterfly 8 2	Butterfly 8 2
9	Containment power access purge total isolation time [duration of release to environment]	12 sec	12 sec
10 11	Percent of the primary coolant mass released to the containment during the first 12 seconds Source Terms [fraction of core activity	100%	100%
Containment Leakage Model			
	initially airborne in the containment]: Iodines Noble gases	25% of core 100% of core	25% of core 100% of core
12	Containment leak rate, vol.%/day 0-24 hr >24 hr	0.1 0.05	0.1 0.05
13	Containment air leak rate through the depressurized secondary system, cfm	0.9 cfm	0.9 cfm

Table 15.6.5-2 (cont'd)
Large break LOCA radiological analysis parameters and results

	Parameter	Value (3954 MWt)	Value (4070 MWt)
14	Duration of containment leakage	30 days	30 days
15	Containment region volumes, ft^3: Main spray region Auxiliary spray region Unsprayed region total [containment net free volume]	 2.27E+6 0.20E+6 0.15E+6 2.62E+06	 2.27E+6 0.20E+6 0.15E+6 2.62E+06
16	Transfer rate between sprayed and unsprayed regions, in terms of unsprayed Volume change per hour	3.3 hr^{-1} [8,250 cfm]	3.3 hr^{-1} [8,250 cfm]
17	Air transfer rated between the containment regions, cfm: Main sprayed and unsprayed regions Auxiliary sprayed and unsprayed regions	 7,582 668	 7,582 668
18	Spray flow start time, second - Time to reach High-High containment pressure setpoint [to generate CSAS] - Total instrument response time - Time to fill spray header total [assumes loss of offsite power]	 <1 sec 33 sec 58 sec 92 sec	 <1 sec 33 sec 58 sec 92 sec
19	Spray Iodine Removal Coefficients, λ_s, (during injection phase): Main sprayed region: Elemental Organic Particulate Auxiliary sprayed region: Elemental Organic Particulate Spray elemental-iodine decontamination factor	 Coefficients 19.6 hr^{-1} 0 0.32 hr^{-1} 6.05 hr^{-1} 0 0.09 hr^{-1} DF 6.51	 Coefficients 19.6 hr^{-1} 0 0.32 hr^{-1} 6.05 hr^{-1} 0 0.09 hr^{-1} DF 6.51
20	Removal of elemental iodine by plate-out [wall deposition], λ_p: Main sprayed region Auxiliary sprayed region unsprayed region Elemental-iodine decontamination factor	Coefficients 2.16 hr-1 14.6 hr-1 14.6 hr-1 DF 100	Coefficients 2.14 hr-1 14.4 hr-1 14.4 hr-1 DF 100
ESF Recirculation Leakage Model			
21	Source Term: Sump activity of iodine, as a percent of total core activity	50% of core	50% of core

Table 15.6.5-2 (cont'd)
Large break LOCA radiological analysis parameters and results

	Parameter	Value (3954 MWt)	Value (4070 MWt)
22	Sump volume (ft^3): RWT volume RCS volume, including PZR & CVCS Safety injection tanks [SITs] total, Input to LOCADOSE	 5.35E+04 ft^3 9.18E+03 ft^3 7.16E+03 ft^3 6.98E+04 ft^3	 5.35E+04 ft^3 9.73E+03 ft^3 7.00E+03 ft^3 7.023E+04 ft^3
23	Recirculation start time	20 minutes, post accident	20 minutes, post accident
24	Credit assumed for radioactive decay of iodine prior to recirculation	yes [20 minutes]	yes [20 minutes]
25	Total ESF component leakage rate	3,000 ml/hr	3,000 ml/hr
26	Percent of iodine in the leaked water which is assumed to become volatile [flashing fraction]	10%	10%
27	Fuel building/low aux essential filtration Filter efficiency, 2 inch Charcoal (iodine): Elemental Organic Particulate	 95% 95% 95%	 95% 95% 95%
28	Duration of ESF leakage	30-days	30-days
29	Partition coefficient of iodine in RWT	1000	1000
RWT Backleakage Model			
30	Dilution volume RWT volume Fuel building Volume	 1.15E+5 7.45E+5	 1.15E+5 7.45E+5
Control Room Data refer to section 6.4.7[(b)]			
Transport Data			
31	EAB X/Q, 0-2 hr, sec/m^3 LPZ X/Q, sec/m^3: 0-8 hr 8-24 hr 24-96 hr 96-720 hr	2.3E-4 6.4E-5 4.8E-5 2.6E-5 1.1E-5	2.3E-4 6.4E-5 4.8E-5 2.6E-5 1.1E-5
32	Offsite Breathing Rated, m^3/sec: 0-8 hr 8-24 hr > 24 hr	 3.47E-4 1.75E-4 2.32E-4	 3.47E-4 1.75E-4 2.32E-4

Table 15.6.5-2
Large break LOCA radiological analysis parameters and results

	Parameter	Value (3954 MWt)	Value (4070 MWt)
33	Credit for depletion of the effluent plume of radioactive iodine due to deposition on the ground	Not Assumed	Not Assumed
34	Credit for radiological decay in transit	Not Assumed	Not Assumed
Dose Calculation Data			
35	Thyroid Inhalation DCFs, rem/Ci	**ICRP-30**	**ICRP-30**
	I-131	1.08E+6	1.08E+6
	I-132	6.44E+3	6.44E+3
	I-133	1.80E+5	1.80E+5
	I-134	1.07E+3	1.07E+3
	I-135	3.13E+4	3.13E+4
36	Immersion [Beta Skin & Whole-Body] DCFs	LOCADOSE [Reg. Guide 1.109]	LOCADOSE [Reg. Guide 1.109]

Table 15.6.5-2 (cont'd)
Radiological Consequences of Large leak LOCA[c]

	0-2 hr EAB, rem		30-day LPZ, rem		30-day Control room, rem		
Contributor	Thyroid	Whole-Body	Thyroid	Whole-Body	Thyroid[b]	Whole-Body	Beta Skin
Power Access [mini] Purge	1.03 (1.09)	4.96E-04 (5.25E-04)	2.81E-01 (3.02E-01)	1.38E-04 (1.46E-04)	5.40E-01 (3.88E-01)	8.75E-05 (9.26E-05)	1.68E-03 (1.78E-03)
Containment Lkg	37.6 (38.8)	2.693 (2.52)	9.22E+01 (9.52E+01)	1.939 (1.90)	5.95 (6.14)	1.10 (1.10)	1.72E+01 (1.71E+00)
Containment Lkg via Depressurized Secondary System	18.6 (19.2)	1.33 (1.25)	4.57E+01 (4.71E+01)	9.59E-01 (9.39E-01)	2.94 (3.04)	5.46E-01 (5.42E-01)	8.50 (8.44)
ESF Component Leakage	1.53 (1.57)	6.84E-03 (6.99E-03)	9.93 (10.2)	1.18E-02 (1.21E-02)	5.38E-01 (5.50E-01)	4.09E-04 (4.19E-04)	8.07E-03 (8.26E-03)
RWT Back-Leakage [@ 43 gpm][a]	2.16E-02 (2.34E-02)	1.10E-04 (1.14E-04)	7.54 (7.72)	4.67E-03 (4.81E-03)	5.08E-01 (3.36E-01)	5.23E-05 (5.38E-05)	1.05E- (1.08E-03)
Contribution from containment direct shine	NA	nil (nil)	NA	nil (nil)	NA	0.071 (0.10)	NA
Contribution from out side cloud to control-room	NA	nil (nil)	NA	nil (nil)	NA	0.205 (0.215)	NA
Contribution from control room essential filtration system	NA	nil (nil)	NA	nil (nil)	NA	0.061 (0.065)	NA
Total	**58.75 (60.63)**	**4.03 (3.77)**	**155.66 (160.50)**	**2.91 (2.86)**	**10.48 (10.45)**	**1.99 (2.03)**	**25.69 (25.53)**

a. Contribution from IN 91-56

b. The bounding leakage and thyroid dose is given in section 6.4.7.

c. Values shown are for licensed power of 3954 MWt, values in parentheses are for licensed power of 4070 MWt.

15.6.6 REFERENCES

1. "Time Response Design Criteria for Safety-Related Operator Actions," ANS 58.8, ANSI N660, Rev. 2, 1981.

2. "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," NUREG-75/087, December 31, 1978.

3. "Time Response Design Criteria for Safety - Related Operator Actions," ANSI-N660/ANS-58.8, 1984.

4. "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity," International Commission on Radiological Protection (ICRP), Publication 30, Supplement to Part 1, 1980.

5. "χ/Q Based on 1986-1991 Meteorological Data," 13-NC-XX-0204, Rev. 01, A. Karimi, July 30, 1996.

6. "Calculation of Distance Factors for Power and Test Reactor Sites," TID 14844, DiNunno, J.J., et al, March 1962.

7. PVNGS Technical Specification, Amendment Nos. 75, 61, and 47 for Units 1, 2, and 3 respectively, May 16, 1994.

8. PVNGS Technical Specification, Amendment Nos. 109, 101, and 81 for Units 1, 2, and 3 respectively, October 23, 1996.

9. "Safety Evaluation Report Related to the Final Design of the Standard Nuclear Steam Supply Reference System CESSAR

System 80,” Section 15.3.7, “Steam Generator Tube Rupture,” NUREG-0852, Supplement 2, September 1983.

15.7 RADIOACTIVE MATERIAL RELEASE FROM A SUBSYSTEM OR COMPONENT

15.7.1 WASTE GAS SYSTEM FAILURE

15.7.1.1 Identification of Event and Causes

The most limiting waste gas system accident is defined as an uncontrolled release to the atmosphere of the contents of one waste gas decay tank. The gaseous radwaste system is described in section 11.3.

This accident is considered a limiting fault and is analyzed to define the worst consequences of a gaseous release that could result from any malfunction in the gaseous radwaste system. The accident as described assumes a combined failure of the waste gas decay tank and of the normal (non-ESF) radwaste building ventilation (filtration) system described in section 9.4.

15.7.1.2 Sequence of Events and System Operation

A sequence of events diagram for this accident is provided as figure 15.7.1-1. The event is characterized as a rapid release of the contents of a single waste gas decay tank to the environment (Puff model). It is postulated that the tank contains its maximum inventory and that no action is taken to mitigate the consequences of the event.

15.7.1.3 Analysis of Effects and Consequences

The instantaneous release of the waste gas decay tank inventory will result in the radiological consequences shown in table 15.7.1-1. No credit has been taken for control room essential HVAC System.

RADIOACTIVE MATERIAL RELEASE

FROM A SUBSYSTEM OR COMPONENT

Table 15.7.1-1

ASSUMPTIONS AND RADIOLOGICAL CONSEQUENCES OF

WASTE GAS SYSTEM FAILURE

	Parameter	Value
1.	System parameters RCS mass [lbm] Control room air volume [ft3]	571,776 1.61E+05
2.	Control room normal air handling unit: maximum outside air flow rate [cfm][(a)]	1,200
3.	Control room in-leakage (ingress/ egress)[scfm]	10
4.	Control room essential air handling unit (AHU) and recirculating charcoal filter unit	no credit
5.	Iodine species fractions (after discharge) elemental organic particulate	 0.91 0.04 0.05
6.	Atmospheric dispersion factor (χ/Q) [sec/m^3]	Refer to section 2.3.4
7.	Control room accident χ/Q[sec/m^3]	Refer to Appendix 15B,table B-5
8.	Breathing rate [m^3/sec] 0-720 hour offsite 0-720 hour control room	 3.47E-04 3.47E-04
9.	Iodine removal efficiency due to RCS degassing by gas-stripper iodines noble gases	 0.1 1.0
10.	Pre-holdup ion exchanger decontamination factor (DF) iodines noble gases	10 1
11.	Primary coolant letdown flow Rate through the gas stripper [gpm]	140

RADIOACTIVE MATERIAL RELEASE

FROM A SUBSYSTEM OR COMPONENT

Table 15.7.1-1

ASSUMPTIONS AND RADIOLOGICAL CONSEQUENCES OF

WASTE GAS SYSTEM FAILURE

	Parameter	Value
12.	Control room accident χ/Q for adjacent unit [sec/m3]	
	0-8 hr	4.80E-04
	8-24 hr	3.41E-04
	24-96 hr	1.37E-04
	96-720 hr	2.76E-05
13.	Source term, Max GRS Activity [Ci]:	
	Kr-83m	1.53E-01
	Kr-85m	9.54E+01
	Kr-85	1.59E+03
	Kr-87	3.01E+00
	Kr-88	1.00E+02
	Xe-131m	1.50E+03
	Xe-133m	7.94E+01
	Xe-133	8.95E+04
	Xe-135m	7.01E-08
	Xe-135	1.07E+03
	Xe-138	6.16E-09
	I-131	7.57E+00
	I-132	1.81E-01
	I-133	8.72E+00
	I-134	2.08E-03
	I-135	2.76E+00

a. The bounding inleakage is given in Section 6.4.7.

RADIOACTIVE MATERIAL RELEASE

FROM A SUBSYSTEM OR COMPONENT

Table 15.7.1-1

ASSUMPTIONS AND RADIOLOGICAL CONSEQUENCES OF

WASTE GAS SYSTEM FAILURE

	Parameter	Value
	Results	rem
	EAB (0-2hr)	
	Thyroid	7.85E-01
	Whole Body	2.19E-01
	LPZ (0-30 days)	
	Thyroid	
	Whole Body	2.18E-01
		6.11E-02
	Control room (effected unit)(0-30 day)	
	Thyroid	
	Whole Body	5.22E-02
		1.42E-01
	Control room (adjacent unit)(0-30 day)	
	Thyroid	1.61E-02
	Whole Body	2.18E-02

15.7.1.4 Conclusions

As noted in table 15.7.1-1, the radiological consequences are less than 1% of 10CFR100 limits even assuming coincident failure of the normal (non-ESF) radwaste building ventilation system.

15.7.2 RADIOACTIVE LIQUID WASTE SYSTEM LEAK OR FAILURE (RELEASE TO ATMOSPHERE)

The most limiting liquid waste system leak or failure would be the failure of the representative outside liquid storage tank. Refer to subsection 15.7.3.

15.7.3 POSTULATED RADIOACTIVE RELEASES DUE TO LIQUID-CONTAINING TANK FAILURES

15.7.3.1 Identification of Event and Causes

The most limiting radioactive liquid tank failure would be the uncontrolled release of liquid from a representative outside liquid storage tank. The representative outside liquid storage tank is a hypothetical tank that bounds all possible outside liquid storage tank ruptures under the absolute worst case conditions. The tank is assumed to contain the Technical Specification maximum allowable curie content, with the mixture of isotopes representative of the isotopic mixture present in RCS fluid at 600 EFPD, no gas stripping, and with 1% failed fuel. The use of the RCS source terms are intended to remove any uncertainty based on operational considerations in the liquid processing systems that feed the outside liquid storage tanks that are part of the chemical and volume control system (CVCS) as described in subsection 9.3.4, or are part of the liquid radwaste system (LRS) as described in section 11.2. In addition to use of the RCS isotopic inventory mixture, noble gases are included in the representative outside liquid storage tank inventory and are available for release. This

conservative practice will bound all possible outside liquid storage tank ruptures under the worst case conditions.

A nonmechanistic failure that instantaneously releases 100% of the tank's contents to the environment is postulated.

15.7.3.2 Sequence of Events and System Operation

A sequence of events diagram for this accident is provided as figure 15.7.3-1. The event is characterized as a rapid release of the representative outside liquid storage tank contents to the environment. It is postulated that no action is taken to mitigate the consequences of the event. Dose modeling methodology is described in subsection 15B.6.5.

15.7.3.3 Analysis of Effects and Consequences

The radiological consequences of the representative liquid storage tank rupture are described in table 15.7.3-1. The instantaneous release of the representative liquid storage tank gaseous inventory will result in radiological consequences less than waste gas system failure as described section 15.7.1.3.

Table 15.7.3-1

RADIOLOGICAL CONSEQUENCES OF A REPRESENTATIVE LIQUID STORAGE TANK FAILURE

Parameter	Value
Results	Rem
EAB (0 - 2 hr) Thyroid	1.184E-02
EAB (0 - 2 hr) Whole Body	4.594E-03
LPZ (0 - 8 hr) Thyroid	3.293E-03
LPZ (0 - 8 hr) Whole Body	1.278E-03

15.7.3.4 Conclusions

As noted in table 15.7.3-1 the radiological consequences of gaseous release from a Representative Liquid Storage Tank are less than 1% of 10CFR100 limits even though nonmechanistic instantaneous failure of the tank was postulated.

15.7.4 RADIOLOGICAL CONSEQUENCES OF FUEL HANDLING ACCIDENTS

The fuel handling accident is considered to occur at two locations at PVNGS: outside the containment building in the fuel building, and inside the containment. The events at each location are independent of each other. The failure modes for fuel handling equipment inside and outside containment are non-mechanistic and therefore the initiating events in the two buildings are independent. The analyses described herein are based on movement of only one fuel assembly.

15.7.4.1 Fuel Handling Accident Outside Containment

15.7.4.1.1 Identification of Event and Causes

The fuel handling accident that is considered results from the dropping of a single fuel assembly during fuel handling.

15.7.4.1.2 Sequence of Events and Systems Operation

A sequence of events diagram for this accident is provided as figure 15.7.4-1. The radiation monitoring system (RMS), described in section 11.5, will provide prompt notification of high airborne radiation levels in the fuel building which may develop as a result of a fuel handling accident. Additionally,

the safety-related monitors of the RMS will initiate generation of the fuel building essential ventilation actuation signal (FBEVAS). Engineered safety features equipment functions following a FBEVAS are described in section 9.4. The FBEVAS logic is described in section 7.3.

By reducing building exhaust rates and initiating exhaust filtration, ESF actions will substantially reduce potential offsite radiological exposures in the event of a fuel handling accident.

15.7.4.1.3 Analysis of Effects and Consequences

If a dropped assembly were damaged to the extent that one or more fuel rods were broken, the accumulated fission gases and iodines in the fuel rod gaps would be released to the surrounding water. Release of the solid fission products in the fuel would be negligible because of the low fuel temperature during refueling. The fuel assemblies are stored within the spent fuel racks resting on the bottom of the spent fuel pool. The tops of the racks extend above the tops of the stored fuel assemblies. A dropped fuel assembly could not strike more than one fuel assembly in the storage rack. [1] Impact could occur only between the ends of the

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1. In Unit 2 Spent Fuel Pool Storage Location A38, Element P2F003 and surrounding support apparatus are undergoing long term storage. Due to structural damage and additional height provided by the support apparatus, Element P2F003 protrudes 2.59 inches above the upper surface of the storage rack. This condition makes it possible for an element dropped near vertically to strike one element seated in storage location and then rotate to strike the top of Element P2F003.

involved fuel assemblies, with the lower end fitting of the dropped fuel assembly impacting against the upper end fitting of the stored fuel assembly.

A. Vertical Fuel Assembly Drop

Analytical methods used to calculate the impact velocity and the resulting impact stress in Zircaloy-4 and ZIRLO fuel rod cladding for the vertical drop are described below.

The analysis of the fuel assembly vertical drop employed a summation of the forces acting on the fuel assembly in the vertical direction to determine the equation of motion of the fuel assembly. The resulting equation of motion is given below:

$$F_{vert} = M \times a = F_d + F_b - F_w$$

where:

M = mass of a fuel assembly

a = acceleration

F_d = drag force of a fuel assembly (drag coefficient x (velocity)^2)

F_b = buoyant force of a fuel assembly

F_w = weight (dry) of a fuel assembly

The analysis assumed the fuel assembly drop distance was sufficient for the fuel assembly to reach its terminal velocity (acceleration equals zero in the above equation), thus making the results conservative or applicable for any drop height. For this worst

case, the terminal velocity, and therefore the assumed impact velocity of the fuel assembly, is 254.4 and 240 inches per second for Zircaloy-4 and ZIRLO fuel, respectively, and the resulting stress in the fuel rod cladding is 24,000 psi for Zircaloy-4 and 22,320 psi for ZIRLO.

The equation employed in calculating the above impact stress in the fuel rod clad is as follows:

$$S_i = V_i \sqrt{(E/\upsilon)}$$

where:

S_i = impact stress

V_i = impact velocity

E = modulus of elasticity

υ = specific volume

The yield stress of the fuel rod cladding is 49,000 psi for Zircaloy-4 and 81,785 psi for ZIRLO. This is the minimum yield stress value for unirradiated fuel and is conservative for irradiated fuel. Thus, for the fuel assembly vertical drop, the impact stresses which result from absorbing the kinetic energy of the drop are below the yield stress of the clad for both the Zircaloy-4 and ZIRLO fuel assembly, and no fuel rod failures will occur.

B. Horizontal Fuel Assembly Drop

Horizontal impact of a fuel assembly could result from a dropped fuel assembly falling in the horizontal

position, or from a vertical fuel assembly rotating to the horizontal position. This event assumes that all fuel rods in the dropped fuel assembly fail, which is consistent with Regulatory Guide 1.25 assumptions. Thus, the dose analysis is bounding for the Zircaloy-4 and ZIRLO fuel assembly horizontal drop analyses.

C. Input Parameters and Initial Conditions for the Radiological Analysis

For the radiological consequences of a fuel handling accident evaluation, cladding failure was assumed to occur for all fuel rods in an assembly. The reactor was assumed to operate at a power level of 3990 MWt, and the earliest time at which a spent fuel assembly can be moved is considered to be 72 hours after shutdown.

Assumptions and parameters used in evaluating the fuel handling accident are listed in table 15.7.4-1. The calculational methods and assumptions described in Regulatory Guide 1.25 apply since the dropped fuel assembly meets all of the requirements of Regulatory Guide 1.25, except as discussed below.

Based on the plant specific fuel cycle design and core, the maximum fuel rod discharge pressure would exceed the Regulatory Guide 1.25 limit of 1200 psig. Therefore, a site specific methodology for addressing fuel rod pressure has been developed and is implemented herein with prior NRC approval. This

methodology (Reference 3) determines the peak assembly average fuel pin pressure rather than the maximum fuel pin pressure and demonstrates that it is less than the Regulatory Guide 1.25 limit of 1200 psig.

The peak assembly average fuel pin pressure is determined by first determining the maximum fuel rod pressure based on worst case fuel cycle parameters using computer code FATES 3B. The fuel pin internal gas pressure is based on the FATES 3B analysis for the hot rod in the hot assembly and is performed and verified for each core reload. Pressure in a fuel rod in the spent fuel pool or the refueling pool is obtained by adjusting the FATES 3B results for the temperature of the water in the spent fuel pool. This methodology is independent of individual fuel rods (or fuel assembly since all rods in an assembly are assumed to be at maximum pressure) and fuel rod core location and results in a peak rod internal pressure for the fuel type analyzed by FATES 3B.

Each type of fuel is analyzed in the same manner. Then the maximum peak assembly average fuel pin pressure is calculated by averaging the pressure for the different types of fuel pins in an assembly.

$$\text{Average Pin Pressure} = \frac{\text{Sum of Individual Pin Pressures}}{\text{Number of Pins in Assembly}}$$

$$<1200 \text{ psig}$$

Table 15.7.4-1
PARAMETERS USED IN EVALUATING THE RADIOLOGICAL
CONSEQUENCES OF A FUEL HANDLING ACCIDENT

Parameter	Reg. Guide 1.25 Assumptions	Calculational Assumption
Fuel Assy. Data: [1] Radial peaking factor Burnup, MWD/MTU Max. fuel pin pressure, psig (average pressure for 236 fuel rods in peak assembly)	1.65 25,000 1,200	1.7 70,000 Peak assembly average fuel pin pressure is < 1200 when fuel is being moved[2]
Decay time, hours	None	72
Number of failed pins	All fuel rods in an assembly	All fuel rods in assembly (236)
Fraction of fission product gases contained in the gap region of fuel rods, % Kr-85 Xe-133 Other noble gases Iodine	 30 10 10 10	 30[3] 16[3] 15[3] 15[3]
Iodine gap chemical composition, % Organic iodine compounds Inorganic iodine compounds	 0.25 99.75	 0.25 99.75
Percentage of gap activity released to pool	100	100
Peak assembly shutdown gap activity, for key isotopes (Ci):	Not quantified beyond 100% of gap inventory	I-131 ---------- 1.08E+05 Xe-131m -------- 1.12E+03 Xe-133 --------- 2.58E+05 Kr-85 ---------- 3.78E+03
Minimum water depth, Fuel Pool surface to top of damaged fuel rods, feet	23	22.5
Fuel Building filter efficiencies, % Filter eff., organic iodine Filter eff., inorganic iodine	 70 90	 70 90
Pool decontamination factors: Iodine Noble gases	 100 1	 100 1

RADIOACTIVE MATERIAL RELEASE

FROM A SUBSYSTEM OR COMPONENT

Parameter	Reg. Guide 1.25 Assumptions	Calculational Assumption
Composition of iodine in atmosphere above pool, %: Organic iodine compounds Inorganic iodine compounds	 25 75	 25 75
Time for radioactive material to escape from fuel bldg., hours	99.9% in 2 hours	>99.9% in 2 hours
Filter system effluent dilution factor	Typically none; direct passage to exhaust system. (Evaluated on individual basis.)	All activity escaping the water surface in Fuel Bld./Cont. immediately & homogeneously mixed throughout building volume of 7.36E+05 ft^3
Atmospheric diffusion factors --Inside Containment --Outside Containment	Interim factors provided until site meteorological data obtained; licensee directed to use site specific data when available	 See Table 15B-5 2.24E-04 sec/m^3

1) Fuel data valid only for oxide fuels with:

a) Highest power assy. peak linear power density no greater than 20.5 kW/ft.;

b) Highest power assy. center-line operating temp. <4,500 F.

2) FATES 3B computer code.

3) Methodology conservatively assumed to be bounding for Zircaloy-4 and ZIRLO fuel; exceeds values calculated by ANSI/ANS 5.4-1982.

The releases from the spent fuel pool are calculated in accordance with Regulatory Guide 1.25. The top of the highest damaged fuel rod would be at elevation 115 feet.[2] The spent fuel pool low water level alarm and high water level alarm setpoints are at elevations 137 feet 6 inches and 138 feet 2 inches, respectively. As such, there is a nominal 23 feet of water over the damaged fuel pins. Even if the pool water level were at the low level alarm point, there would be a minimum of 22 feet 6 inches of water over the damaged fuel pins.

Gap activities at reactor shutdown in the fuel assembly damaged as a result of a fuel handling accident in accordance with Regulatory Guide 1.25 are given in table 15.7.4-1. This activity is assumed to be instantaneously released to the fuel building subsequent to evolution from the spent fuel pool.

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2 In Unit 2 Spent Fuel Pool Storage Location A38, Element P2F003 and surrounding support apparatus are undergoing long term storage. Due to structural damage and additional height provided by the support apparatus, Element P2F003 protrudes 2.59 inches above the upper surface of the storage rack. In the most conservative case of an element falling onto and being supported by this Element P2F003, the highest point on the supported element would be at elevation 115' 5.18". An administratively controlled minimum Spent Fuel Pool water level of 138' ensures at least 22'6" of water coverage of all parts of the dropped element. This is only required during fuel movement within the administrative restricted area surrounding fuel element P2F003.

The fuel building essential ventilation system will actuate on high radiation, which would minimize the releases to the environment.

The offsite doses at the exclusion area boundary and low population zones for a fuel handling accident outside containment are presented in table 15.7.4-3.

15.7.4.1.4 Conclusions

As noted in table 15.7.4-3, the radiological consequences of a fuel handling accident outside containment are within SRP limits and well within (25%) 10CFR100 limits, and are in all cases bounded by the postulated fuel handling accident inside containment doses. Control room doses are discussed in Section 6.4.7.3. The operator doses are within the limits set by 10CFR50 Appendix A GDC 19.

Table 15.7.4-3

RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT OUTSIDE CONTAINMENT

	Dose (rem)	
	Thyroid	Whole Body
2-hour exclusion area boundary	25.1	2.88×10^{-1}
30-day low population zone	7.9	1.11×10^{-1}

15.7.4.2 Fuel Handling Accident Inside Containment

15.7.4.2.1 Identification of Event and Causes

Refer to paragraph 15.7.4.1.1.

15.7.4.2.2 Sequence of Events and Systems Operation

A sequence of events diagram for this accident is provided as figure 15.7.4-2. The RMS, described in section 11.5, will provide prompt notification of high airborne radiation levels in the containment which may develop as a result of a fuel handling accident.

15.7.4.2.3 Analysis of Effects and Consequences

The analysis presented in paragraph 15.7.4.1.3 for a fuel handling accident outside containment is also applicable to this section and as paragraph 15.7.4.1.3 assumes acceleration is zero at the terminal velocity. Thus, the consequences of a fuel handling accident in the containment are no more severe in terms of activity released from the fuel element than a fuel handling accident outside containment.

The releases from the refueling pool are calculated in accordance with the assumptions of Regulatory Guide 1.25.

It is also assumed that, for the postulated accident, this activity is instantaneously released to the containment and released to the outside atmosphere within two hours.

The 2-hour doses at the exclusion area boundary and 30 day low population zone doses are presented in table 15.7.4-5.

15.7.4.2.4 Conclusions

As shown in the results of the analyses in table 15.7.4-5, the radiological consequences of a fuel handling accident inside containment are within SRP limits and well within (25%) 10CFR100 limits. Control room doses are discussed in Section 6.4.7.3. The operator doses are within the limits set by 10CFR50 Appendix A GDC 19.

Table 15.7.4-5

RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT INSIDE CONTAINMENT (WITHOUT REFUELING PURGE ISOLATION)

	Dose (rem)	
	Thyroid	Whole Body
2-hour exclusion area boundary	74.7	4.16×10^{-1}
30-day low population zone	20.8	1.16×10^{-1}

15.7.5 SPENT FUEL CASK DROP ACCIDENT

The probability of fuel handling accidents in the fuel building that result from dropping either a TSC/TFR containing spent fuel or other heavy load from the single failure proof Cask Handling Crane is sufficiently small that they are not credible events, and therefore do not require analysis. The Cask Handling Crane, the TSC, the TFR, and the associated lifting

devices used for dry fuel storage handling in the fuel building meet the applicable criteria of NUREG-0612 Section 5.1.6 (Single-Failure-Proof Handling Systems). Transport of loaded casks to the ISFSI storage location is performed within the bounds of the NAC-UMS Certificate of Compliance (CoC) (Docket no, 72-1015) and the NAC-UMS® FSAR. Refer to the NAC-UMS® and the ISFSI 72.212 Evaluation Report for details of fuel handling accidents during these operations. Interlocks and procedural and administrative controls involved in fuel handling are described in subsection 9.1.4.

15.7.6 REFERENCES

1. "Verification of the Acceptability of a 1-Pin Burnup Limit of 60 MWD/kgU for Combustion Engineering 16x16 PWR Fuel," CEN-386-P-A, August 1992.

2. "Report on the Implementation of a 1-Pin Burnup Limit of 60 MWD/kgU at PVNGS," CEN-427-(V)-P, November 1995.

3. Technical Specification for "Palo Verde Nuclear Generating Station, Units 1, 2, and 3 – Issuance of Amendments RE: Internal Fuel Pin Pressure (TAC Nos. MC0620, MC0621, and MC0622)," NRC letter dated September 27, 2004 (Amendment 153).

APPENDIX 15A

RESPONSES TO NRC REQUESTS FOR INFORMATION

CONTENTS

CONTENTS (cont)

CONTENTS (Cont)

TABLES

FIGURES

FIGURES (Cont)

QUESTION 15A.1 DELETED

QUESTION 15A.2 (NRC Question 450.10) (15.6.2)

In evaluating the double-ended break of the letdown line outside containment, provide the following:

(1) summary of primary system's iodine activity, including the potential increase in iodine release rate (iodine spiking) above the equilibrium value during the accident and its effect on the accident doses; and

(2) valve closure time and maximum permissible leakage rate of the letdown line isolation valve.

RESPONSE: The response will be provided on the CESSAR docket.

QUESTION 15A.3 (NRC No. 450.11) (15.7.3)

In evaluating the radioactive liquid waste system leak or failure, provide data, assumptions and methodology used in analyzing the radiological consequences of fission gases released to the atmosphere.

RESPONSE: The response is provided in revised paragraph 15.7.3.2.

QUESTION 15A.4 (NRC Question 460.19) (15.7)

We are currently evaluating the liquid radwaste tank failure accident for Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3. Based on our evaluation, we have concluded that the tank most likely to result in the highest levels of concentrations in the release in the event of tank failure is

the concentrate monitor tank which is located in the radwaste building at elevation 100 feet (on grade) and has a capacity of 4000 gallons when filled to 80% of its capacity (see engineering drawing 13-P-OOB-003, FSAR, PVNGS for location). Our calculations show that either a dilution factor of 3 x 10^8 or a transit time of approximately 718 years will be required in order to ensure that the radionuclide concentrations at the applicable location are well below the 10CFR Part 20 limits. Please indicate whether such values can be expected at the applicable location for PVNGS and if not what dilution factor and transit time can be expected at the applicable location.

RESPONSE: The concentrate monitor tanks are located inside the radwaste building. In the event of tank failure, all leakage would be contained by curbs and floor drains and pumped (by sump pumps) for holdup and/or processing. Accordingly, no ground contamination would occur.

The concentrate monitor tank gaseous inventory is expected to be very small (refer to table 12.2-5). Thus, radiological impact due to concentrate tank failure is projected to be less than that of the refueling water tank (RWT) as noted in subsections 15.7.2 and 15.7.3. The RWT has the highest liquid and gaseous inventories and concentrations of any outside tank. Dilution factors and transit times for the perched water and regional aquifer for failure of the RWT are presented in paragraph 2.14.13.3.

<u>QUESTION 15A.5</u> (NRC Question 450.13) (15.6.3)

The radiological consequences of the steam generator tube rupture accident are presented in CESSAR Section 15.6.3 for only the exclusion area boundary. This does not fully comply with the guidelines of 10CFR Part 100 which requires a radiological consequence evaluation be performed at a low population zone for the duration of the accident. It is the staff position that CE provide the assumed LPZ envelope and provide the estimated radiological consequences at the assumed LPZ boundary for the duration of the accident.

RESPONSE: The response will be provided on the CESSAR docket.

<u>QUESTION 15A.6</u> (NRC Question 450.14) (15.6.3)

The amount of steam released from the affected and unaffected steam generators presented in FSAR subsection 15.6.3 are based upon the assumption of recovery of offsite power and condenser during the accident. This is contrary to the staff position of assuming that offsite power is lost for the duration of the accident and therefore the condenser is never available for steam dump. Because the staff uses the applicant's values or curves of the steam release estimates in its radiological consequence calculations, it is not possible to complete our review until appropriate steam release values are received. Provide the estimates of steam release to the environment assuming that the condenser is not available for the accident duration.

RESPONSE: The response will be provided on the CESSAR docket.

QUESTION 15A.7 (NRC Question 450.15) (15.6.3)

The analysis of the radiological consequences presented in FSAR subsection 15.6.3 does not appear to consider the steam release pathway occurring from the steam jet air ejectors (SJAEs) to the environment prior to assumed loss of the condenser. Because the condenser is available for a significant period prior to condenser trip and the primary to secondary leakage is greatest prior to the loss of the condenser, it is the staff position that the steam release pathway through the SJAEs to the environment needs to be considered in the radiological consequence analysis. Provide the amount of steam released through the SJAEs to the environment prior to the loss of the condenser.

RESPONSE: The PVNGS design does not include SJAEs. Air is removed via the condenser air removal system. This pathway is monitored for radioactivity prior to release and is filtered by charcoal and HEPA filters in the event of high effluent radioactivity. (Refer also to CESSAR Section 15.6.3)

QUESTION 15A.8 (NRC Question 450.16) (15.6.3)

The radiological consequence evaluation provided in CESSAR Section 15.6.3 are based upon assumptions which vary greatly from previous staff practice in the following areas:

1) The evaluations were performed using values which are less than the proposed technical specification limits for normal operation.

   This is not acceptable to the staff because the technical specifications define the operating envelope under which the plant can operate without restriction. Analyses using values less than the Technical Specifications do not verify that at the Technical Specification limits the plant would operate safely and that the radiological consequences would not exceed the staff acceptance criteria on radiological exposures.

2) The radiological consequence analysis of a steam generator tube rupture makes no mention of iodine spiking in the CESSAR document, and the Palo Verde docket uses a spiking factor of only 100.

   The staff position on an acceptable spiking factor is provided in SRP Section 15.6.3. This section states that a spiking factor of 500 times the normal release rate of iodine from the fuel should be used.

3) The iodine transport in the steam generator is determined using CENPD-180 and its supplement.

   The staff position on iodine transport in the steam generator is defined in SRP Section 15.6.3 and is that the iodine transport should be determined using the methods and models described in NUREG-0409. The CESSAR and Palo Verde dockets do not discuss the

differences in the methods used to those proposed in NUREG-0409.

Based upon the above discussion, the staff position is that the applicant provide an analysis of the radiological consequences of the steam generator tube rupture which assumes operation at the proposed technical specification values and describes the differences between the models used and those presented in the staff Standard Review Plan.

RESPONSE: The response will be provided on the CESSAR docket.

QUESTION 15A.9 (NRC Question 450.17) (15.6.2)

In the evaluation of the double-ended break of the letdown line outside containment-upstream of the letdown line control valve (CESSAR Section 15.6.2), the staff has calculated the dose in accordance with SRP 15.6.2. The result shows the EAB, 0-2 hours, thyroid dose to be 85 rems. This value is more than twice the acceptable limit of 30 rems as defined in SRP 15.6.2. The staff position is that the maximum equilibrium fission product concentration given in the technical specification be reduced from 4.7 μci/cc to the standard 1 μci/cc. This measure will correspondingly reduce the dose to within acceptable levels. State your intent regarding compliance with our position.

RESPONSE: The response will be provided on the CESSAR docket.

QUESTION 15A.10 (NRC Question 450.19) (15.7.4)

In order to complete our evaluation of the fuel handling accident analysis we request that you provide the following information:

(1) Location of RMS detector used to isolate containment refueling purge system and air flow transit time between detector and valve based on normal flowrates.

(2) Specify if the RMS detector used to isolate containment refueling purge system is ESF grade and redundant and, if so, include location of redundant detector.

(3) Location of RMS detector used to isolate fuel handling building in the event of a fuel handling accident and air flow transit line between detector and damper based on normal flowrates.

(4) Specify if RMS detector used to isolate fuel handling building, in the event of a fuel handling accident, is ESF grade and redundant and, if so, include location of redundant detector.

RESPONSE: As noted in paragraphs 15.7.4.1 and 15.7.4.2, offsite doses due to fuel handling accidents will be a small fraction of 10CFR100 limits even without isolation or filtration of containment or fuel building exhausts. Protective action is not required. The design, however, does include radiation monitors to sense the occurrence of an accident and initiate protective action.

1) The PAPA area radiation monitors isolate the containment refueling purge upon high radiation. They are located just outside the containment between the refueling purge exhaust ducting and the power access purge ducting as shown on engineering drawing 13-N-RAR-004. Air flow transit time is less than 1/4 second.

2) There are two redundant, ESF-grade monitors, 13-J-SQA-RU-37 and 13-J-SQB-RU-38. Refer to section 11.5.

3) Area radiation monitor 13-J-SQA-RU-31 is located on the east wall of the fuel building adjacent to the spent fuel pool. The detector will register the evolution of airborne radioactivity from the pool within 1/4 second.

4) 13-J-SQA-RU-31 is ESF grade. The redundant ESF monitor has two channels, low range and high range (13-J-SQB-RU-145 and 13-J-SQB-RU-146). It is located just below the roof level and samples the exhaust downstream of the dampers. The sample transit time is less than 10 seconds between duct and monitor.

QUESTION 15A.11 (NRC Question 440.32) (15.0)

Expand table 15.0-6, the list of single failure considered in transient and accident analyses, to include the following:

1. One primary safety valve stuck closed

2. One secondary safety valve fail to open or fail to close

3. Loss of offsite power

4. failure of one diesel to operate (for the events with loss of offsite power being treated as a consequential result of the event).

5. failure to achieve fast transfer

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

NOTE: Subsequent to the docketed response, it was determined that the single failure of a fast bus transfer was no longer a limiting single failure for any of the UFSAR Chapter 15 accident analyses. As noted in UFSAR Section 15.0.2.4, this single failure is bounded by the postulated loss of offsite power following a turbine trip.

QUESTION 15A.12 (NRC Question 440.33) (15.0)

For all analyses of transients with concurrent single failures, provide a reference to the sensitivity study which shows that the failure selected is the worst case single failure.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.13 (NRC Question 440.34) (15.0)

Confirm that during the preoperational or startup test phase you intend to verify the valve discharge rates and response times (such as opening and closing times for main feedwater, auxiliary feedwater, turbine and main steam isolation valves, and steam generator and pressurizer relief and safety valves)

to show that they have been conservatively modeled in the chapter 15 analyses.

RESPONSE: PVNGS intends to verify response times during a preoperational test to show that they have been conservatively modeled in chapter 15 analyses as described in CESSAR chapter 14 for valves within the CESSAR scope, and in PVNGS FSAR chapter 14 for valves outside the CESSAR scope.

<u>QUESTION 15A.14</u> (NRC Question 440.35) (15.0)

The method that you have used for calculating the amount of failed fuel after an accident has not been approved. It is our position that fuel failures be recalculated using the criteria that any fuel rod which has a CE-1 DNBR less than the minimum DNBR value determined in section 4.4 fails. Radiological consequences should be calculated accordingly.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

<u>QUESTION 15A.15</u> (NRC Question 440.36) (15.0)

Verify that for each transient analyzed in chapter 15, if operator action is not discussed then no operator action is required. In particular, consider events in which the ECCS is actuated or RCP trip would be required based on present procedures.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.16 (NRC Question 440.37) (15.0)

For each accident, discuss nonsafety grade equipment which was assumed to operate and could result in the transient becoming more severe or verify that no nonsafety grade equipment operating would produce a more severe transient. For example, the pressurizer heaters being energized for a transient resulting in high RCS pressures could tend to worsen the effects of the transient. Likewise, pressurizer spray could be detrimental for a transient resulting in low RCS pressure.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.17 DELETED

QUESTION 15A.18 (NRC Question 440.39) (15.0)

One of the key parameters in LOCA analyses is peak clad temperature. For non-LOCA transients, minimum DNBR (departure from nucleate boiling ratio) is of primary importance. For those transients analyzed in chapter 15 of the FSAR, provide graphical output of the DNBR as a function of time.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.19 (NRC Question 440.40) (15.0)

As part of the CESEC review, the NRC intends to perform audit evaluations of feedwater line breaks, steam line breaks, and large- and small-break LOCAs (as part of the FSAR and TMI Action Plan Item II.K.3.30 and II.K.3.31 reviews). In order to

perform these audits, we require the following data, as outlined in the "PWR Information Request Package."

RESPONSE: The response will be provided on the CESSAR docket.

QUESTION 15A.20 (NRC Question 440.41) (15.0)

The current CESEC model does not properly account for steam formation in the reactor vessel. Therefore, for all events in which (a) the pressurizer is calculated to drain into the hot leg, or (b) the system pressure drops to the saturation pressure of the hottest fluid in the system during normal operation, we require the applicant to reanalyze these events with an acceptable model or otherwise justify the acceptability of Palo Verde chapter 15 analyses conclusions performed with CESEC.

RESPONSE: The response was provided in CESSAR Amendment 6.

QUESTION 15A.21 (NRC Question 440.42) (15B)

Figure 15B-19 shows the primary system pressure exceeding 110% of the design pressure. This figure also indicates a substantial pressure differential between the pressurizer and reactor vessel. The standard review plans typically limit the pressurization of the RCS to 110% of the design pressure. However, the ASME pressure vessel code permits exceeding the 110% limit to approximately 120% for very low probability events. The NRC will accept the limiting pressurization transient (i.e., feedwater line break) as calculated for System 80 if we can be assured that the analysis performed is

conservative and that a small break in the feedwater line is a very low probability event.

As such, we request the following information be provided:

(1) Verification of CESEC to predict pressurization transients. This should include the developed pressure differential across the pressurizer surge line.

(2) Demonstrate that the probability of a small break in the feedwater system is not significantly more probable than the large break. Include the consideration of ancillary line breaks.

(3) Section 15B.3 references a sensitivity study for RCS overpressurization transient to plant initial conditions. Provide the results to this study in graphical form. Specifically, include DNBR and pressure as a function of time.

(4) It is expected that increasing the break area for a feedwater line break would increase the degree of primary system pressurization. A larger break area should result in an earlier loss of heat sink and corresponding higher decay heat for system pressurization. Figure 15B-1 indicates that the limiting feedwater line break is not a double-ended guillotine break (1.4 square feet), but a 0.2-square foot break. Provide greater details as to why this occurs. Is this behavior considered realistic or a consequence of a modeling assumption? Provide additional graphical explanations, including heat transfer coefficient, heat flow, secondary side inventory, all secondary side flow rates, and any additional data

required to demonstrate the reasons for the 0.2-square foot break begin the limiting break size.

(5) Figure 15B-10 provides the relationship between the maximum RCS pressure to initial steam generator inventory. Provide additional information which explains in detail functional behavior of this curve.

Page 15B-5 states: "...the initial RCS pressure can be adjusted to provide simultaneous reactor trip signals from high pressurizer pressure and low water level in the intact steam generator and hence the plateau of maximum RCS pressure." Provide greater details of the analyses and assumptions made in order to achieve coincident trip signals from the pressurizer and SG.

(6) For figure 15B-11 (and page 15B-6), how does raising the degree of feedwater subcooling increase the maximum RCS pressure? It would appear that raising the degree of subcooling would result in a larger heat sink, and, therefore, a lower peak pressure.

(7) What decay heat model does CESEC use? Does this model assume infinite irradiation?

(8) Provide details of the core and steam generator heat transfer models used in CESEC.

(9) Utilizing a one-node representation of the steam generator secondary side, how is the low liquid level trip analyzed?

(10) Provide verification of the CESEC <u>pressurizer</u> model for pressurization transients (resulting in the opening of a safety valve or PORT) with data from experiments and

operating plant transients. Of interest is level and pressure as a function of time. Document the assumptions made in analyzing these tests.

(11) Document the sensitivity of a feedwater line break with and without loss of offsite power.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions and CESSAR Amendment 6.

QUESTION 15A.22 (NRC Question 440.43) (15B)

For the feedwater line break analysis, provide the pressurizer liquid and mixture level as a function of time.

Provide detailed plots for the following parameters during the initial 50 seconds of the transient:

1. Pressurizer pressure
2. Surge line flow
3. Pressurizer mixture level
4. Pressurizer safety valve flow and quality

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.23 (NRC Question 440.44) (15.0)

We require additional information regarding the steam generator behavior during a feedwater line break. Provide the steam generator secondary side coolant inventory, mixture level, heat transfer coefficients, energy removed by each steam generator (Btu) and secondary side flow as a function of time.

It is our understanding that the limiting heat transfer modeling technique utilized in CESEC assumes an approximately constant heat transfer coefficient between the primary and secondary systems until all the liquid mass in the secondary system is depleted (i.e., WM = 0). It is not clear why the limiting modeling technique was not the case where the heat transfer was degraded as the secondary side inventory began uncovering the tubes. Please explain.

Discuss differences in the steam generator secondary heat transfer modeling between a feedwater line break and a steam line break.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.24 DELETED

QUESTION 15A.25 (NRC Question 440.46) (15.0)

Accidents resulting in containment isolation also isolate the component cooling water to the reactor coolant pumps. This can potentially lead to RCP seal damage which may result in a LOCA. Address the time available for the operators to restore the coolant to the seals. Has consideration been given to not isolating component cooling water to the RCP seals on containment isolation? If pump seal integrity cannot be maintained, evaluate the consequential failure of the pump seals for the limiting accident.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.26 DELETED

QUESTION 15A.27 (NRC Question 440.48) (15.0)

Provide a list of transients which result in opening of the pressurizer safety valves.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.28 (NRC Question 440.49) (15.0)

The staff has been informed that the CESEC-III computer program is best suited to analyze transients which void the upper head of the reactor vessel. As such, we request that the following information be provided:

(1) Documentation of the CESEC-III code. As part of the documentation, address the differences between the different versions of CESEC (I, II, and III).

(2) Provide comparative analyses with the different versions of the CESEC programs (used for licensing) to demonstrate the adequacy of previous analyses.

(3) Provide verification of CESEC-III against plant and experimental data for pressurization and depressurization transients (such as the AN0-2 experiments and the St. Lucie I cooldown experience).

(4) For those transients which result in primary system voiding, provide graphical output of the upper head mixture level as a function of time. Discuss operator actions/guidelines for detecting and mitigating primary system void formation.

(5) Show, by analysis or otherwise, that the allowable cooling rate (for cold shutdown conditions) will not result in primary system voiding.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.29 DELETED

QUESTION 15A.30 DELETED

QUESTION 15A.31 DELETED

QUESTION 15A.32 DELETED

QUESTION 15A.33 DELETED

QUESTION 15A.34 (NRC Question 440.55) (15.6)

For small-break LOCAs, containment isolation may occur. It is our understanding that component cooling water to the RCP seals will be isolated upon containment isolation. Demonstrate that the RCP seals will remain intact and maintain the pressure boundary for the duration of the accident. Address expected RCP operation. If seal integrity cannot be maintained, seal failure must be assumed. Discuss the maximum seal leakage rates based on operating experience. If the consequences of seal failure are assumed to be covered by the analyzed break spectrum, justify the differences in the break locations from the locations analyzed.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.35 DELETED

QUESTION 15A.36 (NRC Question 440.58) (15.6.3)

The analysis for a steam generator tube rupture does not address tube leakage in the unaffected steam generator. Provide an interface requirement for the allowable steam generator tube leakage and reference the technical specification limit. Confirm the analyses were performed using this allowable limit or provide justification why this leakage term can be excluded from the analyses.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.37 (NRC Question 440.59) (15.6.3)

The analysis for a steam generator tube rupture is for a double-ended rupture. Provide the analyses used to determine that this is the limiting ease. If a partial area break is considered, such that the steam generator relief valves open at a longer time into the transient is more primary coolant leaked to the secondary and out the SRVs, resulting in an increased dose rate.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.38 (NRC Question 440.60) (15.6.3)

SRP 15.6.3 acceptance criteria requires that this event be analyzed with a concurrent loss of offsite power. Provide an analysis for the limiting case which includes a concurrent loss of offsite power.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.39 (NRC Question 440.61) (15.6.3)

For the SGTR event, what prevents steam from the affected steam generator being used to drive the steam-driven auxiliary feedwater pump and exhausted to the environment? If operator action is required, confirm that no credit for operator action was given for 30 minutes, consider with your assumption for isolation of the affected steam generator. If credit was given for operator action in less than 30 minutes, provide justification why this credit can be given, or reanalyze the event assuming steam from the faulted steam generator is used to drive the steam-driven AFW pump and is exhausted to the environment.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.40 (NRC Question 440.62) (15.6.3)

Provide a description of the CESEC model used to model the CVCS from the reactor coolant system to the break point. Include a description of the environmental conditions at the break point (pressure, enthalpy, break flow model used).

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.41 (NRC Question 440.63) (15.6.3)

Discuss the single failure assumed for these analyses. What analyses/evaluations were performed to justify that the single failures chosen were the most limiting?

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.42 (NRC Question 440.64) (15.0)

In this section, you have selected the turbine trip without a single failure as the limiting reactor coolant system pressure and the limiting radiological release event for the moderate frequent event category in the decreased heat removal by secondary system group. However, these limiting cases were not selected by a qualitative comparison of similar initiating events specified in SRP 15.2.1 through SRP 15.2.7 (e.g., loss of external load, turbine trip, loss of condenser vacuum, steam pressure regulator failure, loss of normal AC power and loss of normal feedwater flow). Provide a qualitative analysis in the FSAR for each of the initiating events in the same group per the SRP, and identify the limiting cases for the group. Provide a detail quantitative analysis for each of the limiting cases including the limiting RCS pressure, limiting fuel performance, and the limiting radiological release.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

<u>QUESTION 15A.43</u> (NRC Question 440.65) (15.2)

In this section, you have provided the loss of condenser vacuum with a fast transfer failure and technical specification steam generator tube leakage as the limiting RCS pressure and the limiting radiological release event for the limiting fault event category in the decreased heat removal by secondary system group. Although, these limiting cases may be the candidates for the limiting cases for the infrequent event category in the group, they were not selected by a qualitative comparison of similar initiating events plus a single failure specified in SRP 15.2.1 through 15.2.7. Provide a qualitative analysis in the FSAR for each of the initiating event plus a single failure in the same group per the SRP, and identify the limiting cases for the group. Provide a detailed quantitative analysis for each of the limiting cases including the limiting RCS pressure, limiting fuel performance, and the limiting radiological release. Confirm that the results of the analyses meet the acceptance criteria for these events per SRP 15.2.1.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

NOTE: Subsequent to the docketed response, it was determined that the single failure of a fast bus transfer was no longer a limiting single failure for any of the UFSAR Chapter 15 accident analyses. As noted in UFSAR Section 15.0.2.4, this single failure is bounded by the postulated loss of offsite power following a turbine trip.

QUESTION 15A.44 (NRC Question 440.66) (15A)

Provide tabulations of the sequence of events, disposition of normally operating systems, utilization of safety systems, and a transient curve of primary system pressure for the total loss of primary coolant flow event. Also provide an analysis of the total loss of primary coolant flow with a single failure event. Confirm that the results of these analyses meet the acceptance criteria for these events per SRP 15.3.1.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.45 (NRC Question 440.67) (15.3)

In subsection 15.3.5 you have provided the single reactor coolant pump shaft seizure with loss of offsite power following turbine trip and with technical specification tube leakage as the limiting RCS pressure and radiological release event for the limited fault event category. This postulated event is classified as an infrequent event per SRP 15.3.3. Confirm that the results of the analysis meet the acceptance criteria for these events per SRP 15.3.3, using the criteria stated in Question 440.35 to calculate the amount of failed fuel in this event. State the amount of failed fuel in the results of the analysis. Radiological consequences should be calculated accordingly.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions and CESSAR Amendment 6.

<u>QUESTION 15A.46</u> (NRC Question 440.68) (15.0)

Provide results of an analysis of the reactor coolant pump shaft break as required by SRP 15.3.4 for staff review. The event should consider loss of offsite power following turbine trip and with technical specification steam generator tube leakage. The criteria stated in Question 440.35 should be used for the calculation of the amount of failed fuel for this event. State the amount of failed fuel in the results of the analysis. Radiological consequences should be calculated accordingly. Confirm that the results of the analysis meet the acceptance criteria for these events per SRP 15.3.4 which classifies this event as an infrequent event.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

<u>QUESTION 15A.47</u> (NRC Question 440.69) (15.5)

In this section, you have provided the pressurizer level control system malfunction (PLCSM) with a fast transfer failure and the PLCSM with a loss of offsite power at turbine trip with Technical Specification steam generator tube leakage as the limiting RCS pressure and radiological release event for the limiting fault event category in the increase in reactor coolant system inventory group. However these limiting cases were not selected by a qualitative comparison of similar initiating events plus a single failure specified in SRP 15.5.1 (e.g., inadvertent operation of high pressure ECCS or a malfunction of the CVCS). Provide a qualitative analysis in the FSAR for each of the initiating events (with and without a single active failure) in the same group per the SRP, and

identify the limiting cases for the group. Provide a detailed quantitative analysis for each of the limiting cases including the limiting RCS pressure, limiting fuel performance, and the limiting radiological release. Confirm that the results of the analyses meet the acceptance criteria for these events per SRP 15.5.1.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions

NOTE: Subsequent to the docketed response, it was determined that the single failure of a fast bus transfer was no longer a limiting single failure for any of the UFSAR Chapter 15 accident analyses. As noted in UFSAR Section 15.0.2.4, this single failure is bounded by the postulated loss of offsite power following a turbine trip.

QUESTION 15A.48 (NRC Question 440.70) (15.0)

Provide tabulations of the sequence of events, disposition of normally operating systems, utilization of safety systems, and all necessary transient curves for the startup of an inactive reactor coolant pump event. The comparison to peak RCS pressure acceptance criteria should be included in the analysis. Also provide the results of an analysis of this event with a single failure. Confirm that the results of these analyses meet the acceptance criteria for these events per SRP 15.4.4.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.49 (NRC Question 440.71) (15D)

You have provided, in CESSAR Appendix 15D, the results of an inadvertent boron dilution event without a single failure under plant cold shutdown conditions. This information is not sufficient. You should provide results of analyses for all possible boron dilution events under various plant operational modes (e.g., refueling, startup, power operation, hot standby and cold shutdown). Also provide the results of analyses of these events with a single failure. Confirm that the results of these analyses meet the acceptance criteria for these events per SRP 15.5.1. In particular, the available times per operator action between time of alarm and time of loss of shutdown margin should be shown to meet the SRP guidelines. The results of the analyses should be presented in the FSAR including tabulations of sequence of events, disposition of normally operating systems, utilization of safety systems, and all necessary transient curves for the events.

In your analysis, indicate for all modes of operation what alarms would identify to the operators that a boron dilution event was occurring. Consider the failure of the first alarm. Provide the time interval from this alarm to when the core would go critical. If a second alarm is not provided, show that the consequences of the most limiting unmitigated boron dilution event meet the staff criteria and are acceptable.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.50 DELETED

QUESTION 15A.51 (NRC Question 440.73) (15D)

Several recent LERs indicate there has been a deficiency in the inadvertent boron dilution analysis at some plants. Provide an analysis of the dilution event when the RCS is drained to the hot leg.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.52 (NRC Question 440.74) (15D)

Recently, an operating PWR experienced a boron dilution incident due to inadvertent injection of NaOH into the reactor coolant system while the reactor was in a cold shutdown condition. Discuss the potential for a boron dilution incident caused by dilution sources other than the CVCS.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

QUESTION 15A.53 (NRC Question 440.75) (15.6)

Discuss the transient resulting from a break of an ECCS injection line. In particular, describe the flow splitting which will occur in the event of a single failure and verify that the amount of flow actually reaching the core is consistent with the assumptions used in the analysis.

RESPONSE: The response was provided on the CESSAR docket. See CESSAR FSAR Responses to NRC Questions.

<u>QUESTION 15A.54</u> (NRC Question 440.76) (15.8)

The NRC is currently considering what actions may be necessary to reduce the probability and consequences of anticipated transients without scram (ATWS). Until such time as the Commission determines what plant modifications are necessary, we have generally concluded that pressurized water plants can continue to operate because the risk from anticipated transient without scram events in a limited time period is acceptably small. However, in order to further reduce the risk from anticipated transient without scram events during the interim period before completing the plant modifications determined by the Commission to be necessary, we have required that the following actions be taken:

1. Develop emergency procedures to train operators to recognize anticipated transient without scram events, including consideration of scram indicators, rod position indicators, flux monitors, pressurizer level and pressure indicators, pressurizer relief valve and safety valve indicators, and any other alarms annunciated in the control room with emphasis on alarms not processed through the electrical portion of the reactor scram system.

2. Train operators to take actions in the event of an anticipated transient without scram, including consideration of manually scramming the reactor by using the manual scram button, prompt actuation of the auxiliary feedwater system to assure delivery to the full capacity of this system, and initiation of turbine trip. The operator should also be trained to initiate boration by

actuation of the high pressure safety injection system to bring the facility to a safe shutdown condition.

Describe how you will meet the above requirements, and provide a schedule for submittal of the ATWS procedures for staff review.

RESPONSE: Procedures will be developed to cover emergencies and off-normal events. These procedures will provide sufficient guidance to ensure that correct action is taken by the operator. ATWS events will be covered in these procedures. PVNGS will provide training on ATWS events and emergency and off-normal procedures. Sufficient information will be provided so that the operator can determine if his actions are effective. Should the operator's actions not be effective, the procedure will contain additional action that can be taken by the operator to ensure the parameter and/or condition is restored to acceptable values.

Procedures will be available for NRC review at least 60 days prior to fuel load.

<u>QUESTION 15A.55</u> (NRC Question 440.82) (15.0)

Section 15D.2.2.2 of the CESSAR System 80 FSAR states that the loss of instrument air event impact on the plant systems and components will be addressed in the applicant's FSAR. Discuss the loss of instrument air for Palo Verde showing that it meets the appropriate acceptance criteria for a moderate frequency event. Causes and potential systems interactions should be addressed and the loss of instrument air should be considered

during all phases of reactor operation. Also, present your plans and capability for preoperational or startup tests to substantiate the analyses.

RESPONSE: The nitrogen supply system will support the required ESF air-supplied components normally supplied from instrument air system for one hour on loss of instrument air. This is accomplished by providing an automatic control valve connecting the nitrogen system to the instrument air system. Depletion of the nitrogen system will not affect any safety-related systems.

The following list shows the systems which would be affected on loss of instrument air and depletion of the nitrogen supply. Also shown is the position of the air (or nitrogen supply valve upon depletion of the nitrogen supply.

SYSTEM	VALVE POSITION
RCP Seal Injection	Open
RCS Letdown	Closed
CVCS Charging	Closed
Boric Acid Concentrator	Closed
Suction to RDPs	Closed
Gas Stripper	Closed
Pressurizer Sprays	Closed
Steam Bypass to Condenser	Closed
Main Steam Line Drains	Closed
Nitrogen Charging to SITs	Closed
Sulfuric Acid to ESPs	Closed

Letdown Hx Cooling Water	Closed
Turbine Cooling Water	Open
Normal Chilled Water	Closed
Auxiliary Steam System	Closed

Instrument air loss would not incapacitate any safety-related systems or equipment needed for safe shutdown. It would affect the above systems by fail-safe closing or opening (as indicated) of air-operated valves upon air failure and depletion of nitrogen supply.

QUESTION 15A.56 (SGTR Question 1)[a] (15.6.3)

In the SGTR analysis for Palo Verde units submitted by your letter dated January 27, 1984, the acceptability of the radiological consequences is heavily dependent on the operator's action on controlling the cooldown rate. It is assumed in the analysis that the operator has to open one ADV in each steam generator at a 10.5% opening position to ensure a maximum cooldown rate of 75F. The staff notes that the ADVs have no device to limit their opening to the assumed 10.5%, and other calculations have shown that an opening of slightly less than 12% would result in exceeding the 10CFR Part 100 guideline values. Also, there are no specific limits in either the technical specifications or procedures to restrict opening of the ADV to less than the 10.5% assumed. There is only the

a. Letter from G. W. Knighton, NRC, to E. E. Van Brunt, Jr., APS, dated April 27, 1984.

maximum cooldown rate limit of 75F/hr, a value that we believe is difficult for the operator to determine during a complicated event like the SGTR. Discuss what positive measures will be taken to ensure that the assumed ADV opening position and cooldown rate will not be exceeded.

RESPONSE: The January 27, 1984, analysis of the SGTR with the loss of offsite power and the failure of the stuck open ADV event assumed that, once the operator identified and pursued isolating the affected steam generator, all auxiliary feedwater flow ceased to that generator. This approach was chosen to maximize radiological consequences pursuant to direction from the Regulatory Staff. This arbitrary restriction results in the hypothetical radiological consequences being very sensitive to valve opening position because of the subsequent tube uncovery.

Further review of this nondesign basis accident calculation has indicated that it is unnecessarily conservative to assume tube uncovery. Accordingly, the PVNGS Emergency Operating Procedures will include direction to feed the affected steam generator in order to keep the tubes covered and maintain the iodine partition coefficient. This is not a deviation from the CE Emergency Procedure Guidelines (CEN-152). Rather, it is an additional consideration to be used to mitigate the consequences of a SGTR, and provides substantial benefits for the instances where the ruptured steam generator cannot be isolated from the atmosphere (e.g., stuck open ADV). This multiple failure event, SGTR and a fully stuck

open ADV, was not contemplated by CEN-152, just as it is not considered by the NRC's Standard Review Plan.

This modification to the PVNGS Procedure will be incorporated before fuel load of PVNGS Unit 1. Training of the operators will commence soon after approval of the procedure modification, and will require approximately 3 months to train all of the Unit 1 shifts. This training should be complete by initial criticality. Training will include simulator time and will emphasize the reduction of offsite releases and the potential for overfill of the affected steam generator.

Including this additional procedure into the analysis leads to a revised 0 to 2 hour thyroid dose of 200 rem including a fully (100%) open atmospheric dump valve and a preexisting iodine spike. This is the highest dose (refer to table 15A-1 for the complete dose results) and is well within Part 100 criteria.

It should be noted that a stuck, fully open ADV is not considered a credible event as there is no single failure that can cause the valve to run full open and stay there. Refer also to the response provided for Question 15A.58.

Table 15A-1

RADIOLOGICAL CONSEQUENCES OF THE STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND FULLY STUCK OPEN ADV

Location	Offsite Doses, Rem	
	GIS	PIS
1. Exclusion area boundary 0-2 hours thyroid	40	200
2. Low population zone outer boundary 0-8 hours thyroid	20	41

QUESTION 15A.57 (SGTR Question 2)[a] (15.6.3)

The SGTR analysis also assumes a cooldown rate of 30F per hour at 30 minutes after the attempted closing of the affected steam generator ADV. Describe how the operator monitors the plant conditions to prevent the cooldown rate exceeding 30F/hr during this time period.

RESPONSE: The long-term cooldown rate of 30F per hour was chosen for the January 27, 1984, analysis so that shutdown cooling conditions were reached 8 hours after the event. This maximized the 0-8 hour dose. A more rapid, or a slower, cooldown would release less steam from the ruptured steam generator.

This assumption is not used in the revised analysis presented in the response to Question 15A.56.

QUESTION 15A.58 (SGTR Question 3)[a] (15.6.3)

Since the ADVs at Palo Verde do not have upstream block valves, there would be virtually no way of isolating a stuck open ADV. The staff believes from an overall plant safety standpoint, Palo Verde should install block valves upsteam of the ADVs, per the interface requirement stated in the CESSAR System 80 FSAR. Discuss your technical justification for a lack of the block valves, especially in light of industry experience suggesting that stuck open steam system valves are not an uncommon occurrence.

a. Letter from G. W. Knighton, NRC, to E. E. Van Brunt, Jr., APS, dated April 27, 1984.

Additionally, the Palo Verde SGTR analysis should either assume an ADV stuck in the full open position, or the applicant should provide positive assurance that the ADV cannot be opened beyond the assumed 10.5%.

RESPONSE: The analysis presented in the response to Question 15A.56 assumes an ADV stuck in the full open position. Nevertheless, this is not considered a credible single failure.

The PVNGS ADVs are air-operated hydraulic valves. The valves are spring loaded to fail closed on loss of air. Additionally, they may be closed by air or by an integral handwheel, if necessary. In order for the valve to open, an air supply must be provided. Two parallel sets of fail closed, three-way solenoid valves (four total) provide the air supply. In the closed position, the valves isolate the air supply and bleed air off of the ADV. The solenoid valves are powered by two channels of essential dc power. Each set of solenoid valves is controllable from the Control Room. Closure of any one set of valves is sufficient to terminate the air supply and close the ADV. The control schematic is provided as figure 15A-1.

Should all four solenoid valves fail by remaining energized, the operator can regulate the air supply by using the valve positioner and controller. These will also be able to close the ADV. In short, for the ADV to open and remain open, there must be six failures involving two channels of dc power. This is considered an incredible event.

Mechanical binding of the valve was also considered. In order to remain open, the valve would need to seize up so firmly that neither air pressure, spring nor manual handwheel operation would be able to close the valve. This would result in the valve sticking at the operating range. As noted in the January 27, 1984, analysis, offsite dose exposure is less than 150 rem even with the tubes uncovered. Under the revised analysis of Question 15A.56, with the tubes covered, the dose is 41 rem (table 15A-1).
The analysis of the steam generator tube rupture with a loss of offsite power and a fully stuck open atmospheric dump valve (ADV) follows:

Identification of Event and Causes

This transient is similar to that described in CESSAR Appendix 15D. It assumes that the plant is challenged by a steam generator tube rupture that includes additional events and failures beyond those postulated by the NRC Standard Review Plan 15.6.3. In addition to the conservative assumptions of the SRP (loss of offsite power, accident meteorology, iodine spiking, etc.), this analysis postulates that the operators open an ADV on the affected steam generator and that it both runs to the full open position and that it sticks full open for the duration of the transient. The ADV is presumed to remain open despite the availability of two redundant and independent safety grade valve control systems and a manual handwheel to close the ADV.

<u>Sequence of Events and Systems Operation</u>

Table 15A-2 presents a chronological list of events that are assumed to occur during the steam generator tube rupture event with a loss of offsite power from the time of the double-ended rupture of a steam generator U-tube to the attainment of shutdown cooling entry conditions.

The C-E Emergency Procedure Guidelines, CEN-152, contain guidance to the operator for controlling a steam generator tube rupture. Recognizing that the coincident occurrence of the limiting (conservative) assumptions of the SRP is unlikely, CEN-152 proposes that, should offsite power and the steam bypass control system be unavailable, the operator opens an ADV on each steam generator (ruptured or not) in order to preclude a challenge to the main steam safety valves (MSSVs). This action presupposes that the ADVs are reliable and can be closed after the RCS is cooled to a temperature which precludes a challenge to the MSSVs. It also presupposes that the MSSVs have not opened. However, due to the coincident conservative assumptions of the SRP, the MSSVs open early in the transient. Furthermore, Palo Verde procedures are oriented towards diagnosing the event and stabilizing the plant prior to initiating cooldown.

Because of the PVNGS emphasis on proper diagnosis prior to operator action, it is unlikely that the operator would open the ADV once the diagnosis indicated an SGTR.

Nevertheless, this scenario assumes that once an operator diagnoses a SGTR, he opens an ADV (as suggested in

CEN-152). To recover from this scenario, the plant specific Palo Verde Steam Generator Tube Rupture Procedure includes direction to the operator to maintain steam generator level such that the steam generator tubes are covered.

Table 15A-2

SEQUENCE OF EVENTS FOR A STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND FULLY STUCK OPEN ADV (Sheet 1 of 4)

Time (Sec)	Event	Setpoint or Value	Success Path or Comment
0.0	Tube rupture occurs	--	--
40	Third charging pump started, feet below program level	-0.75	Primary system integrity
40	Letdown control valve throttled back to minimum flow, feet below prgram level	-0.75	Primary system integrity
47	CPC hot leg saturation trip signal generated	--	Reactivity control
47.15	Trip breakers open	--	Reactivity control
48	Turbine trip	--	Secondary system integrity
51	Loss of offsite power	--	--
52	LH main steam safety valves open, psia	1265	Secondary system integrity
52	RH main steam safety valves open, psia	1265	Secondary system integrity
56	Maximum steam generator pressures both steam generators, psia	1330	--
121	Steam generator water level reaches auxiliary feedwater actuation signal (AFAS) analysis setpoint in unaffected generator, percent wide range level	25	Secondary system integrity

Table 15A-2

SEQUENCE OF EVENTS FOR A STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND FULLY STUCK OPEN ADV (Sheet 2 of 4)

Time (Sec)	Event	Setpoint or Value	Success Path or Comment
122	AFAS generated	--	--
131	Steam generator water level reaches AFAS analysis setpoint in the affected generator, percent wide range level	25	Secondary system integrity
132	AFAS generated	--	--
167.0	Auxiliary feedwater initiated to unaffected steam gnerator	--	Secondary system integrity
177.0	Auxiliary feedwater initiated to affected steam generator	--	Secondary system integrity
460	Operator initiates plant cooldown by opening one ADV on each SG - ADV of the affected SG instantaneously opens fully	--	Removal heat removal
484	Pressurizer empties	--	--
513	MSIS actuation, secondary pressure, psia	919	Secondary system integrity
535	Automated isolation of AFW to affected SG, ΔP SGs, psi	185	Secondary system integrity
581	Pressurizer pressure reaches safety injection actuation signal (SIAS) analaysis setpoint, psia	1578	Reactivity control

Table 15A-2

SEQUENCE OF EVENTS FOR A STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND FULLY STUCK OPEN ADV (Sheet 3 of 4)

Time (Sec)	Event	Setpoint or Value	Success Path or Comment
581	Safety injection actuation signal generated	--	--
581	Safety injection flow initiated	--	Reactivity control
655	Operator overrides the AFW isolation signal and starts feeding the affected SG with AFW	--	--
775	Operator takes manual control of the AFW system, feeds affected SG with both AFW pumps	--	--
895	Operator shuts the ADV of the unaffected steam generator	--	--
1015	Operator initiates auxiliary spray to the pressurizer	--	--
1385	Level in the affected SG above the top of U-tubes, percent wide range	71.5	--
2040	Pressurizer level, percent	50	--
2400	Operator controls HPSI flow, backup pres-surizer heater output, and auxiliary spray flow to control RCS pressure and sub-cooling, F	20	--

Table 15A-2

SEQUENCE OF EVENTS FOR A STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND FULLY STUCK OPEN ADV (Sheet 4 of 4)

Time (Sec)	Event	Setpoint or Value	Success Path or Comment
28,800	Shutdown cooling entry conditions are reached RCS pressure, psia/ temperature, F	400/350	--
28,800	Operator activates shutdown cooling system	--	--

As is evident, the multiple failure scenario being postulated is not internally consistent. However, for analytical purposes, the sequence of events described in table 15A-2 serves to bound the scenario by projecting the adverse operator action (full opening of the ADV on the ruptured generator) and the nonmechanistic ADV failure to occur at the earliest possible time consistent with ANSI Standard N660. Subsequent beneficial operator actions are delayed by times that are also consistent with the ANSI standard.

Accordingly, an analytical model was developed from the bounding assumptions. The model features include:

- secondary releases from both the MSSVs and ADVs
- early operator action to open the ADVs
- one potential series of operator actions to cover the S/G tubes
- time delays for operator recovery action
- delay in reaching shutdown cooling (chosen to maximize 8-hour steam release)

The disposition of normally operating systems for the SGTR event are the same as those presented in Table 15D-2 of CESSAR. The utilization of safety systems during the event is the same as that presented in Table 15D-3 of CESSAR.

The major assumptions regarding systems operation during the event are summarized below.

1) The auxiliary feedwater system (AFWS) is activated at 25% level wide range and shuts off at 30% level wide range prior to operator action.

2) Two AFW pumps are assumed to be available to supply feedwater to either steam generator. No credit is taken or the third 1E powered AFW train. An AFW flowrate of 650 gallons per minute per pump is assumed to be delivered to the steam generators at a SG pressure of 1270 psia.

3) The response times of ADVs, MSIVs, AFW control valves, and AFW flow isolation valves are assumed to be instantaneous.

4) After the loss of offsite power subsequent to reactor trip, no credit is taken for charging. One charging pump is assumed available for auxiliary spray in the pressurizer.

5) Two high pressure safety injection (HPSI) pumps are assumed to be available subsequent to the generation of a safety injection actuation signal.

RADIOLOGICAL CONSEQUENCES

The physical model is the same as that discussed in CESSAR Section 15D.3.2 except that the ADV of the affected steam generator opens fully. In order to reduce the radiological releases, the operator takes appropriate actions to recover the U-tubes of the affected steam generator. Actions assumed in this analysis included overriding the automatic isolation of AFW flow to the

affected steam generator and diverting the flow of both AFW pumps of the affected steam generator.

The assumptions and conditions employed for the evaluation of radiological releases are the same as those discussed in CESSAR Section 15D.3.2.B with the exceptions of assumptions 7, 9, and 10. They are:

7. During the period when the water level in the affected steam generator is above the top of the U-tubes, that portion of the leaking primary fluid which flashes to steam upon entering the steam generator is assumed to be released to the atmosphere with a decontamination factor (DF) of 1.0. The portion of the leaked fluid that does not flash, mixes with the liquid in the steam generator and is released to the atmosphere with a DF of 100. During the period when the water level is below the top of the U-tubes, it is assumed that all the leaking primary fluid escapes to the atmosphere with a DF of 1.0. No credit is taken for the presence of steam separators and dryers which would retain a part of the escaping primary liquid in the steam generator.

9. The 0-2 hour and 2-8 hour primary-to-secondary leakage through the rupture are 285,400 lbm and 516,700 lbm, respectively.

10. The atmospheric dispersion factors employed in the analyses are: 3.1×10^{-4} sec/m^3 for the exclusion area boundary and 5.1×10^{-5} sec/m^3 for the low population zone.

The mathematical model is as described in CESSAR Section 15D.3.2.C.

The 2-hour exclusion area boundary (EAB) and the 8-hour low population zone (LPZ) boundary inhalation doses for both the GIS and the PIS are presented in table 15A-1. The calculated EAB and LPZ doses are well within the acceptance criteria.

CONCLUSIONS

The dynamic behavior of important NSSS parameters during the event is presented in figures 15A-2 through 15A-15.

The radiological releases calculated for the SGTR event with a loss of offsite power and a fully stuck open ADV are well within the 10CFR100 guidelines. The RCS and secondary system pressures are well below the 110% of the design pressure limits, thus assuring the integrity of these systems. Additionally, no violation of the fuel thermal limits occurs, since the minimum DNBR remains above the 1.19 value throughout the duration of the event.

QUESTION 15A.59 (SGTR Question 1)[a] (15.6.3)

In the response to Question 15A.56, it states that feeding the affected steam generator is not a deviation from CEN-152. Our position is that since the Palo Verde SG isolation strategy is different from the approved generic CEN-152 strategy, this is a deviation which should be justified.

a. Letter from G. W. Knighton, NRC, to E. E. Van Brunt, Jr., APS, dated November 28, 1984.

RESPONSE: The PVNGS procedure for mitigating a steam generator tube rupture (SGTR) has been augmented to include direction to the operator to feed the affected steam generator in order to keep the tubes covered and maintain the iodine partition coefficient. APS acknowledges that this is a deviation from CEN-152, and our justification is provided below.

By directing the operator to feed the affected steam generator, to cover the tubes, the iodine partition coefficient is maintained. By maintaining the iodine partition co-efficient, offsite doses will be reduced. With this new procedural consideration, offsite doses will be reduced for any postulated SGTR. That is, a reduction in offsite doses would be realized for those scenarios which do not include a full open atmospheric dump valve failure.

This modification to the PVNGS procedure will be incorporated before fuel load of PVNGS Unit 1. Training of the operators will commence soon after approval of the procedure modification, and will require approximately 3 months to train all of the Unit 1 shifts. This training should be complete by initial criticality. Training will include simulator time and will emphasize the reduction of offsite releases and the potential for overfill of the affected steam generator.

We believe this justifies the deviation from CEN-152, for the PVNGS SGTR procedure.

As shown in figure 15A-4, the operator action to feed the affected steam generator in combination with the stuck open ADV may result in a primary system cooldown rate in excess of the Technical Specification maximum cooldown rate of 100F per hour. Although this operator action may result in exceeding a Technical Specification requirement, the action is justified by the need to maintain offsite doses as low as possible during a SGTR event.

<u>QUESTION 15A.60</u> (SGTR Question 2)[a] (15.6.3)

For a steam generator tube rupture, initially the secondary side of the affected steam generator will be fed by both the primary-to-secondary side leak and feedwater. This influx of water creates the potential for overfilling the steam generator. Discuss the information available to the operator to prevent overfilling the steam generator and the sensitivity of the time period from the start of the accident to the time when there could be an overfill problem, assuming the operator does not take any action to prevent overfilling. Alternately, show that the consequences of SG overfill are not significant.

RESPONSE: For a SGTR with loss of offsite power and a fully stuck open ADV, the steaming rate through the stuck open ADV is significantly higher than the primary-to-secondary side leak during the entire reported period of the transient. Therefore, the influx of leak flow from the primary system

a. Letter from G. W. Knighton, NRC, to E. E. Van Brunt, Jr., APS, dated November 28, 1984.

alone will not create the potential for overfilling the steam generator. The operator, after taking manual control of the auxiliary feedwater system, first raises the affected SG level above the top of the U-tubes. Thereafter, the auxiliary feedwater flow is throttled to maintain the level above the top of the SG U-tubes at about 71.5% wide range. This level prevents any overfilling of the affected steam generator. The operator will continuously rely on the SG level measurements (12 Class 1E indicators per SG) for information all through the transient to keep the level below the acceptable limit of about 90% wide range in both generators. There are audio and visual alarms that actuate when it appears that the SG is being overfilled. It is these alarms and MSIS actuation which would provide overfill protection assuming no operator action. If at anytime there is a concern regarding SG overfill, the auxiliary feedwater to the affected steam generator will be temporarily terminated.

Combustion Engineering Emergency Procedure Guidelines (CEN-152) provides suggestions regarding steam generator overfill during a SGTR event mitigation. These suggestions include draining to radwaste system and steaming the generator.

<u>QUESTION 15A.61</u> (SGTR Question 3)[a] (15.6.3)

Evaluate the sensitivity of the time period the SG tubes could be uncovered to the increase in radiological consequences.

a. Letter from G. W. Knighton, NRC, to E. E. Van Brunt, Jr., APS, dated November 28, 1984.

Relate this study to the amount of tube uncovery without credit for manual SG level control.

RESPONSE: In the analysis of a SGTR with loss of offsite power and a fully stuck open ADV, the first operator action taken to recover the level in the affected SG was assumed to occur 2 minutes after isolation of the auxiliary feedwater flow to the affected SG. The action consisted of overriding the auxiliary feedwater isolation signal in order to start feeding the affected steam generator again. Two minutes subsequent to this action the operator takes manual control of the auxiliary feedwater system and starts feeding the affected steam generator with both auxiliary feedwater pumps. The actions were taken to raise the level in the affected SG above the top of the U-tubes as quickly as allowed by the emergency operating procedure since the magnitude of the offsite radiation dose is sensitive to the duration of SG tube uncovery.

In order to limit the doses within acceptable limits the operator needs to take timely actions. The current analysis assumed the operator takes manual control of the auxiliary feedwater system approximately 5 minutes after opening the ADV on each SG or 2 minutes after overriding the auxiliary feedwater system isolation signal. Calculations performed indicate that to limit the offsite doses to 10CFR100 guidelines, the operator will need to take manual control of the auxiliary feedwater system no later than approximately 12 minutes after opening of the ADV on each generator. The time interval between overriding the auxiliary feedwater isolation signal and taking manual control of the system is

again 2 minutes. Therefore, within the constraints and conservatisms inherent in the current model, the operator can delay taking manual control of the SG level by approximately 12 minutes after the opening of the ADVs, and still limit the offsite doses to 10CFR100 guidelines.

QUESTION 15A.62 (SGTR Question 4)[a] (15.6.3)

In your discussion of the steam generator tube rupture (Appendix); it states that 460 seconds (about 7-1/2 minutes) is the earliest possible time that the operator can take an adverse action. The bases for this statement was given as reference to ANSI Standard N660. Since the purpose of ANSI Standard N660 is not to determine the earliest time for operator to take "adverse" actions, our position is that inadequate bases have been provided to justify that the operator could not have opened the ADV earlier than 460 seconds. Therefore, determine the radiological consequences of the steam generator tube rupture with loss of offsite power assuming the operator opens an ADV on each steam generator at the earliest time possible that would result in the maximum radiological consequences.

RESPONSE: The largest contribution of the offsite dose during the event occurs in the time period between the opening of the ADVs and the time of recovery of the affected SG level above the U-tubes. This time period is greatly influenced by the inventory in the affected steam generator at the time that the ADVs are opened. In the current

a. Letter from G. W. Knighton, NRC, to E. E. Van Brunt, Jr., APS, dated November 28, 1984.

analysis the auxiliary feedwater flow to the affected SG is actuated on low SG level at about 177 seconds. Thereafter, the level is maintained in the narrow band between 25 and 30% wide range by the automatic operation of the auxiliary feedwater system. The SG level in the affected generator will be higher than 25% wide range prior to the auxiliary feedwater system actuation. Hence, opening of the ADVs at a prior time (that is, before 177 seconds) results in the inventory in the affected steam generator being higher than that calculated for the current analysis at the time the ADVs were opened. This means quicker recovery of the level in the affected steam generator since the inventory will be less depleted than for the current analysis.

Opening the ADV at an earlier time, when primary system pressure is higher, also causes increased primary-to-secondary flow through the postulated tube rupture. This offsets the level effects described above. Therefore, the overall impact on offsite doses is expected to be minimal. Analysis has verified that the most limiting offsite dose (preexisting iodine spike) is increased by less than 5%. For the offsite dose with an event generated iodine spike, analysis has verified an increase of approximately 8%. This assumes that the sequence of events between the opening of the ADVs and the operator taking manual control of the auxiliary feedwater system is the same for both cases. Therefore, even if the operator was to open the ADVs at a time prior to that assumed in the analysis, resulting offsite doses would still be within 10CFR100 guidelines.

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APPENDIX 15B

DOSE MODELS USED TO EVALUATE THE ENVIRONMENTAL CONSEQUENCES OF ACCIDENTS

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TABLES

FIGURES

APPENDIX 15B

DOSE MODELS USED TO EVALUATE THE ENVIRONMENTAL CONSEQUENCES OF ACCIDENTS

15B.1 INTRODUCTION

This appendix identifies the models used to calculate control room and offsite radiological doses, not calculated in CESSAR, that would result from releases of radioactivity due to various postulated accidents.

15B.2 ASSUMPTIONS

The following assumptions are basic to the model for the whole-body dose due to immersion in a cloud of radioactivity and to the model for the thyroid dose due to inhalation of radioactivity:

A. All radioactive releases are treated as ground level releases regardless of the point of discharge.

B. The dose receptor is a standard man, as defined by the International Commission on Radiological Protection (ICRP), (reference 1).

C. No credit is taken for cloud depletion by ground deposition and radioactive decay during transport to the exclusion area boundary (EAB) or the outer boundary of the low population zone (LPZ).

D. Radionuclide data, including decay constants and decay energies presented in table 15B-1, are taken from references 2 through 6.

APPENDIX 15B

Table 15B-1

RADIONUCLIDE PARAMETERS

Nuclide	Decay Constant (sec-1)	MeV/Disintegration (gamma)	Average MeV/Disintegration (beta)
I-131	9.97E-7	0.381	0.194
I-132	8.42E-5	2.333	0.519
I-133	9.21E-6	0.608	0.403
I-134	2.2E-4	2.529	0.558
I-135	2.91E-5	1.635	0.475
Kr-83m	1.05E-4	0.002	0.037
Kr-85m	4.29E-5	0.159	0.253
Kr-85	2.05E-9	0.002	0.251
Kr-87	1.51E-4	0.793	1.324
Kr-88	6.78E-5	1.950	0.375
Kr-89	3.63E-3	1.712	1.001
Xe-131m	6.81E-7	0.02	0.143
Xe-133m	3.66E-6	0.0416	0.190
Xe-133	1.52E-6	0.0454	0.135
Xe-135m	7.38E-4	0.432	0.095
Xe-135	2.11E-5	0.247	0.316
Xe-137	3.02E-3	0.194	1.642
Xe-138	8.15E-4	1.183	0.606

15B.3 WHOLE-BODY GAMMA AND BETA SKIN DOSE

The whole-body gamma dose delivered to an offsite dose receptor is calculated by assuming the receptor to be immersed in a hemispherical radioactive cloud that is infinite in all directions above the ground plane; i.e., a semi-infinite cloud. The concentration of radioactive material within this cloud is

uniform and equal to the maximum centerline ground level concentration that would exist in the cloud at the appropriate distance from the point of release.

The gamma dose to an offsite receptor due to gamma radiation for a given time period is:

$$D_{wb} = \chi / Q \bullet \sum_{i} DCF_{wbi} \bullet Q_i \qquad (1)$$

where:

D_{wb} = whole-body dose to an offsite receptor from gamma radiation, (rem)

χ / Q = site atmospheric dispersion factor effective during the time period at the point of exposure, (s/m^3)

DCF_{wbi} = whole body dose conversion factor for the semi-infinite cloud model for nuclide i, ($rem\text{-}m^3/Ci\text{-}s$). (See table 15B-2)

Q_i = total activity of nuclide i released during the time period, (Ci)

The gamma dose to the control room personnel is calculated assuming a finite hemispherical cloud model. The gamma dose due to gamma radiation in the control room for a given time period is:

$$D_{wb} = \frac{(CRVOL)^{0.338}}{1173} \sum_{i} DCF_{wbi} \frac{(IQ_i)\ (3600)\ (CRO)}{(CRVOL)\ (0.02832)} \qquad (2)$$

where:

D_{wb} = whole-body gamma dose to control room personnel from gamma radiation, (rem)

CRO = the control room occupancy factor ≤1

APPENDIX 15B

Table 15B-2

WHOLE-BODY GAMMA AND BETA SKIN IMMERSION DOSE CONVERSION FACTORS

Radionuclide	Beta Skin DCF (rem – m^3/Ci – sec)	Whole-Body Gamma DCF (rem – m^3/Ci – s)
I-131	3.17E-2	8.72E-2
I-132	1.32E-1	5.13E-1
I-133	7.35E-2	1.55E-1
I-134	9.23E-2	5.32E-1
I-135	1.29E-1	4.21E-1
Kr-83m	0	2.40E-6
Kr-85	4.24E-2	5.102E-4
Kr-85m	4.62E-2	3.7E-2
Kr-87	3.08E-1	1.88-1
Kr-88	7.51E-2	4.65E-1
Kr-89	3.2E-1	5.26E-1
Xe-131m	1.508E-2	2.89E-3
Xe-133m	3.15E-2	7.95E-3
Xe-133	9.69E-3	9.32E-3
Xe-135m	2.25E-2	9.89E-2
Xe-135	5.89E-2	5.74E-2
Xe-137	3.86E-1	4.50E-2
Xe-138	1.31E-1	2.80E-1

3600 = conversion factor, s/h

0.02832 = conversion factor, ft^3/m^3

CRVOL = control room volume, ft^3

IQ_i = total integrated activity for nuclide i in control room for the time period, (Ci-hr)

DCF_{wbi} = the semi-infinite cloud whole-body gamma dose conversion factor for nuclide i, (rem-m^3/Ci-s). (See table 15B-2)

The expression $\frac{(\mathrm{CRVOL})^{0.338}}{1173}$ is a geometrical correction factor to ratio a finite cloud to infinite cloud[7].

The beta skin dose to control room personnel is calculated assuming a tissue depth of 7 mg/cm^2. The beta skin dose to control room personnel for a given time period is:

$$D_{\beta s} = \frac{\mathrm{CRO}}{(\mathrm{CRVOL})\,(0.02832)} \sum_i D_{\beta si} \bullet IQ_i \qquad (3)$$

where:

$D_{\beta si}$ = the beta skin dose conversion factor for nuclide i, (rem-m^3/Ci-h). (See table 15B-2 for factor)

and all other parameters are as previously defined.

15B.4 THYROID INHALATION DOSE

The thyroid dose to an offsite receptor for a given time period is obtained from the following expression:

$$D = x / Q \bullet B_i \bullet \sum (Q_i \bullet DCF_i) \qquad (4)$$

where:

D = thyroid inhalation dose, (rem)

x/Q = site atmospheric dispersion factor during the time period, (s/m^3)

B = breathing rate during the time period, (m^3/s). (See table 15B-3)

Q_i = total activity of nuclide i released during time period, (Ci)

DCF_i = thyroid dose conversion factor for nuclide i, (rem/Ci inhaled). (See table 15B-4)

The radionuclide data are given in table 15B-1. The atmospheric dispersion factors used in the analysis of the environmental consequences of accidents are given in section 2.3.

Breathing rates and dose conversion factors for radioactive iodines required for computing thyroid inhalation doses are tabulated in Tables 15B-3 and 15B-4, respectively.

Table 15B-3

BREATHING RATES[a]

Time After Accident	m^3/s
0 to 8 hours	3.47(-04)
8 to 24 hours	1.75(-04)
1 to 30 days	2.32(-04)

a. From Regulatory Guide 1.4

Table 15B-4

IODINE DOSE CONVERSION FACTORS

Iodine Isotope	Rem -Thyroid/Curie Inhaled	
	TID-14844[a]	ICRP-30[b]
I-131	1.48(+06)	1.08(+06)
I-132	5.35(+04)	6.44(+03)
I-133	4.00(+05)	1.80(+05)
I-134	2.50(+04)	1.07(+03)
I-135	1.24(+05)	3.13(+04)

a. See reference 8
b. See reference 9

15B.5 CONTROL ROOM DOSE

During the course of an accident, control room personnel may receive doses from the following sources:

A. Direct whole-body gamma dose from the radioactivity present in the containment building

B. Direct whole-body gamma dose from the radioactive cloud surrounding the control room

C. Whole-body gamma, thyroid inhalation, and beta skin doses from the airborne radioactivity present in the control room.

In calculating the exposure to control room personnel, occupancy factors were obtained from reference 7 as follows:

0 to 24 hours: occupancy factor = 1

1 to 4 days: occupancy factor = 0.6

4 to 30 days: occupancy factor = 0.4

The dose model for each of the radiation sources is discussed below:

A. Direct whole-body gamma dose from the radioactivity present in the containment building (direct containment dose).

Time integrated (0 to 30 days) radionuclide concentrations in the containment are calculated. For conservatism, no credit is taken for reduction of the containment activity by means other than radioactive decay. The containment is modeled by an equivalent volume cylindrical source having a diameter of 146

feet and a height of 155 feet. The radioactivity present in the containment is assumed to be uniformly distributed in the cylindrical source. Shielding is provided by the 4-foot concrete containment walls, 120 feet of air separating the containment building from the control building, and 2-foot thick control room walls.

No credit is taken for any shielding that would be provided by the auxiliary building.

B. Direct whole-body gamma dose from the radioactive cloud surrounding the control room (outside cloud dose). Leakage from the containment building, or any building, will result in the formation of a radioactive plume. For conservatism it is assumed that this plume forms a cloud surrounding the control room. Gamma radiation from this cloud, although attenuated, can penetrate the control room roof and walls resulting in a whole-body gamma dose to control room personnel. The radius of the cloud is computed using a mass balance of the radioactivity released due to leakage and the volume of the cloud; therefore, the radioactive cloud is time variant and expands for the duration of the accident.

Radioactivity concentration (Ci/m^3) in the radio-active cloud surrounding the control room is the product of the building leak rate (Ci/s) and the control room atmospheric dispersion factor, χ/Q (s / m^3. Exclusion area boundary and low population zone χ/Q's are

presented in section 2.3. A tabulation of control room χ/Q's is presented in table 15B-5.

Credit is taken for concrete shielding provided by the control room walls and ceiling.

Table 15B-5

ATMOSPHERIC DISPERSION FACTORS

(1986 – 1991)

Time Period	Control Room χ/Q (s/m^3)
0 to 8 hours	1.56(-3)
8 to 24 hours	1.08(-3)
1 to 4 days	4.15(-4)
4 to 30 days	1.03(-4)

C. Dose from the airborne radioactivity present in the control room (occupancy dose).

Airborne radioactivity will be drawn into the control room due to the intake of outside air required to maintain a positive pressure in the control room. This contributes to the whole-body gamma, thyroid inhalation, and beta skin doses. The major parameters of the control room ventilation system are presented in table 15B-6.

The whole-body gamma dose is computed using a finite cloud model. The calculational model is an equivalent volume hemisphere of 42-foot radius.

A thyroid inhalation dose results from the radioactive iodine present in the control room. The control room

habitability system, designed to remove iodine from the air, is described in table 15B-6.

15B.6 ACTIVITY RELEASE MODELS

15B.6.1 GENERAL EQUATION

The activity released from a postulated accident is calculated by using the following matrix equation for each isotope and each species of iodine:

$$\frac{d\bar{A}}{dt} + \bar{C}\ \bar{A} = \bar{S}\text{; Initial Condition } \bar{A}(t_o) = \bar{A}_o \qquad (5)$$

$$\bar{Q} = \bar{L} \times \overline{AI}$$

where:

$\bar{A}(T)$ = ${}_i(a\ (t))$

a_i = the activity in the ith node, (Ci)

$\bar{C}$ = (C_{ij}) matrix

C_{ij} = the transfer rate from the ith node to the jth node, (s^{-1})

$\bar{S}$ = (S_i) vector

S_i = the production rate in the ith node (Ci/sec)

$\bar{Q}$ = the activity released to the environment over the time period t_o to t_i, (Ci)

$\bar{L}$ = (ℓ_i) matrix

ℓ_i = the leak rate from the ith node to environment (/sec)

$\overline{AI}$ = $\int_{t_o}^{t_1} \bar{A}(t)\ dt$ (Ci-sec)

APPENDIX 15B

Table 15B-6

CONTROL ROOM ESSENTIAL VENTILATION SYSTEM PARAMETERS[(a)]

Parameter	Assumption
Number of emergency ventilation systems operating	1
Maximum filtered intake rate, (SCFM)	1,000
Unfiltered intake rate, (SCFM)	0
Unfiltered intake for egress/ingress (SCFM)	See Section 6.4.7
Intake clean filter efficiency	
Iodine, elemental,%	95
Iodine, organic,%	95
Iodine, particulate%	99
Minimum Recirculation rate, standard ft3/min	25,740
Recirculation cleanup filter efficiency	
Iodine, elemental, %	95
Iodine, organic. %	95
Iodine, particulate %	99
Leak rate, standard ft3/min (out leakage)	1,010
Control room volume, standard ft3	161,000

a. There are two completely redundant emergency control room ventilation systems.

For a more detailed description of this system, refer to subsection 9.4.2. The dose model employed in this analysis is consistent with the thyroid inhalation model discussed in section 15B.4.

The beta skin dose model is consistent with the "infinite hemispherical cloud" model described in section 15B.3.

Each node represents a volume where activity can be accumulated. The environment and the control room are each represented by a node. To ensure that the system of differential equations has constant coefficients, the time scale is broken up into time intervals over which all parameters are constant. Thus, all coefficients and sources are assumed to be representable by step functions.

The matrix equation is solved using matrix techniques. The particular solution is obtained by Gaussian elimination. The homogenous solution is obtained by solving for the eigenvectors and the eigenvalues of the coefficient matrix C. They are determined by using QR transformation techniques.

The following sections describe how the coefficient matrix and the source vector are calculated for the different accident calculations.

15B.6.2 THE MODEL FOR CONTAINMENT LEAKAGE

The model for LOCA containment leakage is shown in figure 15B-1. The system of differential equations for estimating the released activity is as follows:

$$\frac{dA_1}{dt} + \lambda_d A_1 - L_{21}A_2 - L_{31}A_3 - L_{41}A_4 = 0 \qquad (6a)$$

$$\frac{dA_2}{dt} + (\lambda_d + \lambda_s + L_{21} + L_{24})\ A_2 - L_{42}A_4 = 0 \qquad (6b)$$

$$\frac{dA_3}{dt} + (\lambda_d + \lambda_s + L_{31} + L_{34})A_3 - L_{43}A_4 = 0 \qquad (6c)$$

$$\frac{dA_4}{dt} - L_{24}A_2 - L_{34}A_3 + (\lambda_d + L_{41} + L_{42} + L_{43})A_4 = 0 \qquad (6d)$$

$$\frac{dA_5}{dt} - \frac{X}{Q}\left(L_u+(1-f_L)L_f\right) L_{21}A_2 - \frac{X}{Q}\left(L_u+(1-f_L)L_f\right)L_{31}$$

$$-\frac{X}{Q}\left(L_u+(1-f_L)L_f\right) L_{41}A_4 + \left(L_f + L_u + f_rR_c + \lambda_d\right) A_5 = 0 \qquad (6e)$$

$$Q = \int_{t_0}^{t_1} \left(L_{21}A_2 + L_{31}A_3 + L_{41}A_4\right) dt \qquad (7)$$

where:

$A_1(t)$ = activity in the environment, (Ci)

$A_2(t)$ = activity in the sprayed main region of the containment, (Ci)

$A_3(t)$ = activity in the auxiliary sprayed region of the containment (Ci)

$A_4(t)$ = activity in the unsprayed region of the containment, (Ci)

$A_5(t)$ = activity in the control room, (Ci)

λ_d = radioactive decay constant, (s^{-1})

$L_{21} = \dfrac{T_{21}}{(100)(24)(3600)}$, (s^{-1})

T_{21} = leak rate from the main sprayed volume to the environment, (%/day)

$L_{31} = \dfrac{T_{31}}{(100)(24)(3600)}$, (s^{-1})

T_{31} = leak rate from the auxiliary sprayed volume to the environment, (%/day)

$L_{41} = \dfrac{T_{41}}{(100)(24)(3600)}$, (s^{-1})

T_{41} = leak rate from the unsprayed volume to the environment (%/day)

λ_s = the spray removal constant, (s^{-1})

$L_{24} = \frac{T_{24}}{(V_2)(60)}$, ($s^{-1}$)

T_{24} = transfer rate from the main sprayed region to the unsprayed region, (ft^3/min)

V_2 = volume of the main sprayed region, (ft^3)

$L_{42} = \frac{T_{42}}{(V_4)(60)}$, ($s^{-1}$)

T_{42} = transfer rate from the unsprayed region to the sprayed region, (ft^3/min)

V_4 = volume of the unsprayed region, (ft^3)

$L_{34} = \frac{T_{34}}{(V_3)(60)}$, ($s^{-1}$)

T_{34} = transfer rate from the auxiliary sprayed region to the unsprayed region (ft^3/min)

V_3 = volume of the auxiliary sprayed region (ft^3)

$L_{43} = \frac{T_{43}}{(V_4)(60)}$, ($s^{-1}$)

T_{43} = transfer rate from the unsprayed region to the auxiliary sprayed region, (ft^3/min)

$L_u = \frac{T_u \cdot (0.3048)^3}{60}$, ($m^3$/s)

Tu = unfiltered inleakage into the control room, ft^3/min)

L_f = $\frac{T_f\ (0.3048)^3}{60}$, ($m^3$/s)

f = filtered air intake rate into the control room, (ft^3/min)

f_L = filter efficiency of the filters on the intake units

x/Q = atmospheric dispersion factor for the control room, (s/m^3)

R_c = $\frac{T_r}{(V_c)\ (60)}$, (s^{-1})

T_R = filtered recirculation rate in the control room, (ft^3/min)

V_c = control room free volume, (ft^3)

f_R = filter efficiency of the filter on the recirculation unit

Q = activity released to the environment, (Ci)

The coefficient matrix is:

$\bar{C}$ =

$$\begin{bmatrix} \lambda_d & -L_{21} & -L_{31} & -L_{41} & 0 \\ 0 & \lambda_d+\lambda_s+L_{21}+L_{24} & 0 & -L_{42} & 0 \\ 0 & 0 & \lambda_d+\lambda_s+L_{31}+L_{34} & -L_{43} & 0 \\ 0 & -L_{24} & -L_{34} & \lambda_d+L_{41}+L_{42}+L_{43} & 0 \\ 0 & -x/Q(L_u+(1-f_L)L_f)L_{21} & -x/Q(L_u+(1-f_L)L_f)L_{31} & -x/Q(L_u+(1-f_L)L_f)L_{41} & L_f+L_u+f_rR_c+\lambda_d \end{bmatrix}$$

After solving for A(t), the integrated activity in each node can then be calculated. From the integrated activity, the offsite doses and the doses to the operators in the control room can be calculated using the dose models given in sections 15B.3 and 15B.4.

15B.6.3 THE MODEL FOR RECIRCULATION LOOP LEAKAGE

The model for LOCA leakage in recirculation loops outside containment is shown in figure 15.B-2. The activity released due to the operational leakage of the engineered safety feature (ESF) components during the recirculation mode of the postulated LOCA is calculated from the following equations:

$$\frac{dA_1}{dt} + \lambda_d A_1 - (1-f)L_{21}\ A_2 = 0 \qquad (8a)$$

$$\frac{dA_2}{dt} + (+\lambda_d+L_{21})\ A_2 = S_2 \qquad (8b)$$

$$Q = \int_{t_o}^{t_1} (1-f)\ L_{21}\ A_2\ dt \qquad (9)$$

where:

A_1 = the activity in the environment, (Ci)

A_2 = the activity in the ESF component rooms, (Ci)

λ_d = decay constant, (s^{-1})

L_{21} = filtered leak rate to the environment, (ESF room vol/s)

f = filter efficiency of the filters on the ESF room purge units

$$S_2 = P \bullet \frac{A_o T_s}{V_s}$$

A_o = activity in the recirculation water, (Ci)

P = iodine partition factor

T_s = twice the maximum operational leak rate, (cm^3/s)

V_s = total volume of recirculation water, (cm^3)

Q = activity released to the environment, (Ci)

The coefficient matrix is:

$$\bar{C} = \begin{bmatrix} \lambda_d & -(1-f)L_{21} \\ O & (\lambda_d + L_{21}) \end{bmatrix}$$

The source vector is

$$\bar{S} = \begin{bmatrix} O \\ \\ S_2 \end{bmatrix}$$

15B.6.4 THE MODEL FOR THE FUEL HANDLING ACCIDENT IN THE FUEL BUILDING WITH ESF SAFEGUARDS ACTUATION

The model for the release of activity from the fuel building during a postulated fuel handling accident is shown in figure 15B-3. The activity released to the environment is estimated from the following equations:

$$\frac{dA_1}{dt} + \lambda_d A_1 - (1-f)L_{21}A_2 = 0 \qquad (10a)$$

$$\frac{dA_2}{dt} + (\lambda_d + L_{21})A_2 = 0 \qquad (10b)$$

$$Q = \int_{t_o}^{t_1} L_{21}A_2 dt \qquad (11)$$

where:

A_1 = activity in the environment, (Ci)

A_2 = activity in the fuel building atmosphere, (Ci)

λ_d = decay constant, (s^{-1})

L_{21} = purge rate to the environment, (s^{-1})

f = filter efficiency of the filters on the ventilation unit

Q = activity released to the environment, (Ci)

The resultant coefficient matrix is:

$$\bar{C} = \begin{bmatrix} \lambda_d & -(1-f)L_{21} \\ 0 & (\lambda_d + L_{21}) \end{bmatrix}$$

15B.6.5 OTHER ACCIDENT MODELS

Other accidents can be conservatively modeled as simulated instantaneous releases to the environment. This is simulated as a large transfer rate to the environment. The model is shown in figure 15B-3. The system of differential equations is:

$$\frac{dA_1}{dt} + \lambda_d A_1 - L_{21} A_2 = 0 \tag{12a}$$

$$\frac{dA_2}{dt} + (\lambda_d + L_{21}) A_2 = 0 \tag{12b}$$

$$Q = \int_{t_o}^{t_1} L_{21} A_2 \, dt \tag{13}$$

where:

A_1 = activity in the environment, (Ci)

A_2 = activity to be released to the environment, (Ci)

λ_d = decay constant, (s^{-1})

L_{21} = very large transfer rate to the environment, (s^{-1})

Q = activity released to the environment, (Ci)

The resultant coefficient matrix is:

$$\bar{C} = \begin{bmatrix} \lambda_d & -L_{21} \\ & \\ O & (\lambda_d + L_{21}) \end{bmatrix}$$

15B.7 REFERENCES

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9. "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity", International Commission on Radiological Protection (ICRP), Publication 30, Supplement to Part 1, 1980.

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APPENDIX 15C

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APPENDIX 15D

ANALYSIS METHODS FOR LOSS OF PRIMARY COOLANT FLOW

CONTENTS

FIGURES

APPENDIX 15D
ANALYSIS METHODS FOR LOSS OF PRIMARY COOLANT FLOW

15D.1 INTRODUCTION

This appendix provides a description of methods used in the analysis of the nuclear steam supply system (NSSS) response to a loss of primary coolant flow (LOF) event. An LOF could occur as a result of a loss of electrical power to the four reactor coolant pumps (RCPs). The conclusions and results presented in subsection 15.3.1 were obtained using the methods described here. This method will hereafter be referred to as Space-Time Kinetics LOF (ST-LOF).

The computer codes used in the ST-LOF method are described in section 15D.2. The principal time-dependent parameters calculated are the primary coolant flow rate, reactor core power, hot bundle heat flux, and limiting channel departure from nucleate boiling ratio (DNBR). A comparison of present analysis methods with previous methods is given in section 15D.3. The analysis assumptions are listed in section 15D.4.

15D.2 COMPUTER CODES

15D.2.1 DATA TRANSFER

Given the postulated initiating event, the COAST code is used to compute the core inlet volumetric flow rate as a function of time. These data are then input to the CESEC or CENTS code which predicts the overall system response. CESEC or CENTS calculates plant protection system responses and valve actuations for assessing the long term consequences of the LOF.

CESEC or CENTS also computes the time-dependent core inlet mass flux, core inlet coolant temperature, and reactor coolant system (RCS) pressure (note that no credit is taken for pressure increases when computing the DNBR transient effects). These parameters can later be used as input to the HERMITE code. For those cases where a reactor trip occurs so rapidly that only the coolant flow rate changes, CESEC or CENTS is bypassed and the flow coastdown is input directly to HERMITE.

HERMITE is used to predict the reactor core response during a LOF. HERMITE calculates the transient core power, core average heat flux, and hot bundle heat flux. The time-dependent core average heat flux along with the core inlet coolant mass flux, core inlet coolant temperature, and RCS pressure are input to the CETOP code. This code computes the limiting channel coolant conditions and the limiting channel DNBR. Figure 15D-1 depicts the transfer of data between the computer codes used.

The entire data transfer highlighted in figure 15D-1 is not repeated for each cycle reload since nothing in the early steps changes from cycle to cycle. The later steps (specifically, HERMITE and CETOP executions) are repeated with each cycle because of changes in fuel parameters (e.g., core average heat flux and hot bundle heat flux).

15D.2.2 COAST

The COAST code is used in the same manner as described in CENPD-183.[1] COAST analyzes reactor coolant flow under any combination of active and inactive pumps in a two-loop, four pump plant. The equation of conservation of momentum is written for each of the flow paths of the COAST model assuming

unsteady one-dimensional flow of an incompressible fluid. The equation of conservation of mass is written for the appropriate nodal points. Pressure losses due to friction, bends, and shock losses are assumed proportional to the flow velocity squared. Pump dynamics are modeled using a head flow curve for a pump at full speed and using four quadrant curves, which are parametric diagrams of pump head and torque on coordinates of speed versus flow, for a pump at other than full speed.

The COAST code has been verified by comparison to measurements taken during the initial startup test program of the PVNGS units. A further description of COAST is contained in CENPD 98.[2]

15D.2.3 CESEC III OR CENTS

The CESEC III or CENTS code is used to determine the long term response of the NSSS to primary coolant flow reductions resulting from postulated LOF events. The CESEC III or CENTS code may also be used to predict the change in core inlet coolant temperature if this parameter changes before the time of minimum DNBR.

CESEC III or CENTS computes key system parameters during a transient including core heat flux, pressures, temperatures, and valve actions. A partial list of the dynamic functions included in this NSSS simulation includes:

- point kinetics neutron behavior
- Doppler and moderator reactivity feedback
- boron and control element assembly (CEA) reactivity effects

- multi-node average channel reactor core thermal hydraulics
- reactor coolant pressurization and mass transport
- RCS safety valve behavior
- steam generation
- steam generator water level
- main steam bypass
- secondary safety and turbine valve behavior
- alarm, control, protection, and engineered safety feature system actions.

Initial steam generator feedwater enthalpy and flow rate are typically set to match the initial power for transient simulations. For a further description of CESEC III or CENTS, see section 15.0.

15D.2.4 HERMITE

One application of the HERMITE code is to determine the reactor core response during postulated LOF events. HERMITE can accept as input the transient boundary conditions of coolant flow rate, inlet coolant temperature, RCS pressure, and CEA position. In this application, HERMITE solves the few-group, space- and time-dependent neutron diffusion equation including feedback effects of fuel temperature, coolant temperature,

coolant density, and control element motion for a one dimensional average fuel bundle. The fuel temperature model explicitly represents the pellet, gap, and clad regions of an average fuel pin and representative hot bundle fuel pin. The

hot bundle fuel pin power density is related to the average fuel pin power density by time-dependent planar radial power peaking factors. For the calculation of heat flux, heat conduction equations are solved by a finite difference method. Continuity and energy conservation equations are solved in order to determine the coolant temperature and density for the average and hot bundles. A further description of HERMITE is given in CENPD-188-A.[3]

The hot bundle fuel pin power density is equal to the core average fuel pin power density multiplied by the planar radial power peaking factor, $F_{(xy)}(z)$. For times prior to the insertion of CEAs, and for regions of the core that the CEAs have not entered, the $F_{(xy)}(z)$ is equal to a conservatively chosen initial value. As the CEAs pass a plane of the core, the radial power peaking factor of that plane is increased as a function of time from the initial value. The increase in $F_{(xy)}(z)$ calculated by HERMITE is limited so that the power at a hot spot within a given plane of the core will not rise faster than for the average of that plane. If the power in the average channel of the plane has fallen since the last time step, the $F_{(xy)}(z)$ increase is limited so that the power in the hot spot for that plane does not increase.

The synthesis of the axial power distribution and the planar radial power peaking factors provides a conservative representation of the hottest fuel assembly during the LOF transient, including maximum three dimensional power peaking effects. This technique yields a conservative prediction of the minimum DNBR which can occur as a result of the LOF transient.

15D.2.5 CETOP

The CETOP code uses the CE-1 critical heat flux correlation described in CENPD-162-P[4] to calculate the limiting channel DNBR transient. CETOP receives the core average fuel bundle heat flux, core inlet coolant mass flux, core inlet coolant temperature, and RCS pressure at selected times during the LOF transient. The code is used to perform static calculations of the axial coolant enthalpy distribution and DNBR at these times. No credit is taken for RCS pressure increases in calculating the DNBR. The CETOP code is also discussed in section 15.0.

15D.3 COMPARISON WITH PREVIOUS METHODS

CENPD-183, Appendix A[3] describes the methodology used to predict the consequences of postulated LOF events for many previous Combustion Engineering NSSS designs. This section summarizes the fundamental differences between the ST-LOF method and that described in CENPD-183.

The primary difference between these methods is in the calculation of the core power. The CENPD-183 method uses the QUIX code to compute reactivity as a function of CEA position assuming the neutron flux and delayed neutron precursors are in equilibrium. Combining CEA position versus time data with the reactivity versus CEA position data produces the time-dependent reactivity function which is input to the CESEC or CENTS point kinetics equations.

The ST-LOF method uses HERMITE to calculate the core power directly from CEA position versus time. HERMITE calculates the

time-dependent neutron flux in one dimension (axially) with the few group diffusion equation explicitly accounting for fission, absorption, and transport cross-section variations.

Other differences exist in the calculation of the hot channel heat flux. In the CENPD-183 methodology, it is assumed that the hot channel normalized heat flux decay is equivalent to the core average normalized heat flux decay for computing the time of minimum DNBR. Furthermore, it is assumed that the axial heat flux distribution is constant in time. The minimum DNBR value calculated with the CENPD-183 methodology assumes no decay of the hot channel heat flux.

In the ST-LOF method it is assumed that the hot bundle normalized power decay is equivalent to the core average normalized power decay prior to the insertion of the CEAs. As the CEAs are inserted in the core, the planar radial peaking factors are increased so that the hot channel power decreases less rapidly than core average power for the rodded planes. The hot bundle and core average axial heat flux distributions are each time-dependent. The minimum DNBR value calculated with the ST-LOF method is based on the decay heat flux calculated by HERMITE at the time of minimum DNBR.

CENPD-183 describes both static and dynamic methods for computing the DNBR. The ST-LOF method uses the static method for calculating the DNBR as described in CENPD-183, Appendix A except that CETOP is used in place of COSMO.

15D.4 ANALYSIS ASSUMPTIONS

A number of conservative assumptions are made in the LOF analysis. These assumptions are:

- RCS pressure increase during the transient is not credited for in DNBR calculations
- a conservative (most positive) moderator temperature coefficient (MTC) is assumed
- a conservative time of the pump speed trip is assumed
- a conservative (minimum) scram bank reactivity rod worth is assumed.

15D.5 REFERENCES

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3. "HERMITE Space-Time Kinetics," CENPD-188-A, July 1976.
4. "CE Critical Heat Flux - Critical Heat Flux Correlation for CE Fuel Assemblies with Standard Space Grids," CENPD-162-P, April 1975 (Proprietary).

APPENDIX 15E

LIMITING INFREQUENT EVENT

APPENDIX 15E

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LIMITING INFREQUENT EVENTS

15E.1 IDENTIFICATION OF CAUSES AND FREQUENCY CLASSIFICATION

This event is a composite event that is evaluated to bound all infrequent events, including Anticipated Operational Occurrences (AOOs) in combination with a single active failure, with respect to the degradation in the Departure from Nucleate Boiling Ratio (DNBR). In general, all combinations of infrequent events including AOOs with single active failures need to be evaluated. To avoid evaluating all the potential AOOs as initiating events and single failures, the composite event assumes that an unspecified initiating event degrades all the thermal margin preserved by the COLSS and brings the core conditions to the DNBR SAFDL. Therefore, this event is initiated by any AOO (moderate frequency events). The composite event, by definition, is an infrequent event and includes moderate frequency events in combination with an active single failure.

Note that this composite event bounds all infrequent events including AOOs with single failure with respect to the DNBR degradation. The limiting AOO with respect to Fuel Centerline Melt Temperature (or Peak Linear Heat Rate) is CEA Bank Withdrawal event that is evaluated in UFSAR Chapter 15.4.

15E.2 SEQUENCE OF EVENTS AND SYSTEM OPERATIONS

The composite event assumes that an unspecified initiating event degrades all the thermal margin preserved and brings the

core conditions to the DNBR SAFDL. This assumption is conservative since the AOOs are specifically analyzed to ensure that the SAFDLs are not violated and the necessary thermal margin is preserved by the LCOs. The active single failure is assumed to further aggravate the DNBR degradation. The most limiting active single failure for DNBR degradation is determined to be LOP, which in turn, result in the coastdown of all four RCPs. Therefore, the most limiting infrequent event with respect to the DNBR degradation can be described as The Loss of Flow (LOF) from the SAFDL.

The composite event then is simply modeled as a LOF, using the LOF methodology (References 1 and 2), with the conditions at the beginning of the flow coastdown corresponding to SAFDL conditions. Starting from SAFDL conditions, the LOP results in an RCP coastdown that leads almost immediately to a reactor trip by the Core Protection Calculator (CPC) DNBR function, as the reduction in Reactor Coolant System (RCS) flow degrades DNBR below the initial SAFDL conditions. Within ~3.5 seconds of event initiation (~3 seconds after reactor trip), the local and average core heat fluxes have decreased sufficiently so that no pins remain in DNB. Hence, DNB propagation is not predicted to occur. Figure 15E-1 provides the transient DNBR response for the event.

15E.3 CORE AND SYSTEM PERFORMANCE

A set of initial conditions corresponding to the DNBR SAFDL was calculated with the CETOP-D code. This is a bounding assumption, since the CPC DNBR trip will provide a trip prior to the core conditions reaching the DNBR SAFDL conditions with

a very high probability. The SAFDL conditions include an assumed, pre-existing power of 116%, representing the undefined limiting AOO. The LOF methodology models only the core average and the hot channel using the HERMITE computer code (Reference 3). The core average and hot channel response to the LOF event from these initial conditions was simulated using the 1-D HERMITE code. The transient DNBR values were calculated using the CETOP-D code, which uses the CE-1 CHF correlation. Input parameters and initial conditions were selected to maximize the DNBR degradation. Using the conditions at the time of minimum DNBR, a more accurate DNBR is calculated using the more detailed TORC code for several different values of radial peaking.

Although a LOP would not occur for at least three seconds following a turbine trip, this evaluation conservatively assumes a coincident turbine trip and LOP. The RCP coastdown leads to a CPC DNBR reactor trip. RCS flow coastdown degrades DNBR below the initial SAFDL conditions. DNBR degradation is terminated when the mitigating effects of the SCRAM Control Element Assembly (CEA) insertion dominate the flow coastdown.

15E.3.1 Mathematical Models

The Limiting Infrequent Event was analyzed with respect to core performance with the following mathematical models:

- The one-dimensional HERMITE space-time computer code was used to calculate the core average and hot channel response to a LOF event from the DNBR SAFDL. The HERMITE computer code is described in UFSAR Section 4.3 and in an

NSSS vendor topical report (Reference 3). HERMITE was also used to determine the boron concentration at the Moderator Temperature Coefficient (MTC) value selected for this analysis.

- The CETOP-D computer code, which uses the CE-1 Critical Heat Flux correlation, was used to calculate the initial and transient DNBR values. The CETOP-D computer code is described in UFSAR Section 4.4 and in NSSS vendor topical reports (References 4, 5, and 6). CETOP-D was also used to determine initial Power Operating Limit (POL) conditions for this event (see UFSAR Section 15.1.3.3.2 for additional information on POL conditions).

- The TORC computer code, which uses the CE-1 CHF correlation, was used to calculate the minimum DNBR value using the conditions corresponding to the time minimum DNBR was predicted by the CETOP-D code. The TORC computer code is described in UFSAR Section 4.4 and in NSSS vendor topical reports (References 8 and 9).

- Because the models in the CETOP-D code are not as detailed as those in TORC, DNBR predictions from CETOP-D are typically adjusted by penalty factors to ensure conservatism. Use of the more detailed TORC computer code removes the requirement for penalty factors and provides a more accurate prediction of the DNBR value than the CETOP-D code.

- Fuel failure calculations use a statistical convolution technique that is described in Reference 1. This technique involves the summation, over the reactor core,

of the number of fuel pins at a specific DNBR value, multiplied by the probability of DNB occurring at that DNBR value.

15E.3.2 Input Parameters and Initial Conditions

Table 15E-1 summarizes the key input parameters and initial conditions utilized in the core performance safety analysis for the limiting infrequent event. Since the average NSSS response is not applicable for this event, the parameters that are not input to the HERMITE or CETOP/TORC are not listed in the table.

The following assumptions are made in this analysis:

- The Rated Thermal Power (RTP) was set to the maximum, 3990 MWt.
- The most limiting event would occur from full power operation. The initial power level used in the core performance safety analysis was increased to 116% of RTP (to represent the ROPM for an unspecified limiting AOO).
- The initial core inlet temperature, and pressurizer pressure are selected to maximize the DNBR degradation, and RCS flow rate was determined with the CETOP-D code, corresponding to DNBR SAFDL conditions at the assumed initial core power. For the purpose of computing SAFDL conditions, the radial peaking factor, F_R, was set to a maximum value when obtaining the SAFDL conditions.
- The LOF involves a reduction in reactor coolant flow rate, which decreases the coolant mass flux and increases the coolant temperature in the core region. Use of a negative

MTC value during this heatup would add negative reactivity, which in turn would tend to reduce reactor power and core heat flux. Therefore, for conservatism, the least negative MTC allowed by the Technical Specifications at Hot Full Power (HFP) was used in the analysis.

- The least negative Doppler fuel temperature coefficient curve, at Beginning of Cycle (BOC), was assumed. Least negative values minimize the addition of negative reactivity caused by increasing fuel temperature.

- BOC values were chosen to model delayed neutron kinetics. The delayed fraction is larger at BOC values and results in a slower power response. This delays the decrease in core power during the flow coastdown and following the reactor trip causing the heat flux decreasing more slowly and causes a later turn-around of DNBR. Since the flow is decreasing with time, delaying the heat flux results in a lower flow rate at the time of minimum DNBR.

- If power generation in the core is shifted toward the bottom, the insertion of negative reactivity following reactor trip will be somewhat delayed until the CEAs have inserted farther into the core. The scram reactivity curve was therefore based on a positive ASI representing a bottom-peaked core. The time versus scram reactivity curve was adjusted to account for a 0.6-second CEA holding coil time delay following opening of the reactor trip breakers, and normalized to model 90% CEA insertion at 4.0 seconds after power is removed from the Control Element

Drive Mechanism (CEDM) coils (see UFSAR Section 3.9.4). In addition, the insertion of reactivity was delayed to account for the response time of the Reactor Protective System (RPS). This delay accounts for the time interval between when the CPCs would detect a low DNBR condition to the time at which electrical power to the CEDM coils would be interrupted.

- The CEA worth at trip represents the minimum scram worth for HFP conditions at BOC, assuming the most reactive CEA remains stuck out of the core following reactor trip. This is more limiting (less scram worth) than the anticipated scram reactivity worth at other times during the operating cycle for HFP conditions.
- Parametric studies with the HERMITE code for a LOF event show that, for any given axial power distribution, the most limiting ROPM occurs with lower core inlet temperatures, higher pressures, higher core flow rates and lower fuel rod pellet-to-clad gap conductance. A low value for gap conductance, which delays the decay of the heat flux, was therefore selected for this analysis, corresponding to the maximum core average linear heat rate.
- For the limiting infrequent event, an additional single active component failure involving a LOP was modeled for the core performance safety analysis.
- There was no operator action for the first 30 minutes of the event.

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TABLE 15.E-1

PARAMETERS USED FOR THE LIMITING INFREQUENT EVENT

PARAMETER	Value
Rated Thermal Power (MWt)	3990
Initial core power (% of RTP)	116
Initial core inlet temp (°F)	548
Initial pressurizer pressure (psia)	2325
Initial RCS flow (% of design)	108.8
MTC ($\Delta\rho$/°F)	-0.2E-4
FTC	Least negative
Kinetics	Maximum β
CEA worth at trip - WRSO (%$\Delta\rho$)	-8.0
Fuel rod gap conductance (Btu/hr-ft^2-°F)	Minimum Local
Plugged SG tubes	N/A
Single failure	None
LOP	Yes

NOTE 1: The Local Minimum Fuel Rod Gap conductance (Hgap) is determined using the FATES code and is documented in a reload analyses calculation.

15E.3.3 Results

The Standard Review Plan provides a specific acceptance criterion for all AOOs with a single failure as:

> An incident of moderate frequency in combination with any single active component failure, or single operator error, should not result in loss of function of any barrier other than the fuel cladding. A limited number of fuel rod cladding perforations are acceptable.

The safety analysis shows that the calculated minimum DNBR would approach a value of 1.17 at approximately 2.1 seconds following the LOP, which is well below the DNBR SAFDL of 1.34. Figure 15E-1 depicts a representative hot channel DNBR transient for this limiting event. Within ~3.5 seconds, local and average core heat flux has decreased enough such that no pins experiencing DNB remain. Hence, DNB propagation is not predicted to occur.

The radial peaking factor used to calculate the minimum DNBR was 1.9243 for this limiting case. This corresponds to an initial peaking of 1.91 and reflects the peaking increase in the heat fluxes caused primarily by the coolant heat-up during the flow coast-down. Additional TORC cases were run to assess the sensitivity of the minimum DNBR value to changes in the radial peaking factor. The results of these additional cases, all of which used the same thermal-hydraulic conditions at the time of minimum DNBR predicted by CETOP-D, are shown in Table 15E-2.

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Table 15E-2

TYPICAL MINIMUM DNBR VERSUS RADIAL PEAKING FACTOR FOR THE LIMITING INFREQUENT EVENT CORE PERFORMANCE SAFETY ANALYSIS

Radial Peaking Factor, F_R, at the Time of Minimum DNBR	Minimum DNBR
1.9243	1.17
1.7	1.44
1.5	1.74
1.3	2.11

Minimum DNBR versus F_R data pairs similar to Table 15E-2 are calculated in cycle-specific reload analyses to provide a prediction of the DNBR propagation and amount of fuel failure for any proposed reload core design pin census (i.e., the distribution of power generation among fuel pins in a core). Such fuel failure calculations use a statistical convolution technique that is described in Reference 2. This technique involves the grouping of fuel rods with respect to radial peaking factors; calculating the minimum DNBR in each radial pealing group; and then determining the probability of experiencing DNB corresponding to each minimum DNBR value. The number of fuel rods damaged within a radial peaking group is given by the number of fuel rods in that group, multiplied by the probability of experiencing DNB at that group's minimum DNBR value. Finally, summing up the damaged fuel rods in all radial peaking groups yields the total number of fuel rods damaged in the core.

NRC approval is based upon the use of conservative analytical assumptions, including a hot channel flow factor that does not exceed 73% of the core average assembly inlet flow. A hot channel flow factor of 70%, which includes additional voluntary conservatism beyond that required by the PVNGS licensing basis, was utilized to obtain the minimum DNBR versus F_r data pairs in Table 15E-2.

15E.4 RCS PRESSURE BOUNDARY BARRIER PERFORMANCE

The purpose of the analysis of this event is to bound DNBR degradation for infrequent events, including AOOs with active single failure. Thus, it does not address the reactor pressure boundary performance. Reactor pressure boundary barrier performance for infrequent events and AOOs with or without a single failure is addressed in their respective UFSAR sections.

15E.5 CONTAINMENT PERFORMANCE AND RADIOLOGICAL CONSEQUENCES

Offsite radiological consequences for limiting infrequent event were calculated for 2 hours at the Exclusion Area Boundary (EAB) and for 8 hours for the Low Population Zone (LPZ). The offsite dose calculation assumed 10% fuel failure to bound future fuel cycles.

The release path for iodine and noble gas activity consisted of releases by the MSSVs and controlled steaming through the Atmospheric Dump Valves (ADVs) on both steam generators during the cooldown. Due to a LOP, the condenser was unavailable and MSSVs and ADVs were employed to remove decay heat and cool down the RCS.

It was assumed that plant operators would not initiate a plant cooldown to SDC entry conditions for at least 30 minutes following event initiation.

Since this is an infrequent event, offsite radiological dose consequences are limited to a small fraction, or 10%, of 10 CFR Part 100 guideline values. Additionally, radiation exposures for control room personnel are subject to the limits specified in General Design Criterion 19 of 10 CFR 50 Appendix A.

Control room radiological assessments for bounding unfiltered in-leakage are presented in UFSAR Section 6.4.7. The results presented in that UFSAR section for a postulated RCP Sheared Shaft event with a stuck open ADV bound the anticipated control room exposure for the limiting infrequent event including AOOs with an active single failure. The RCP Sheared Shaft event was predicted to result in a higher percentage of fuel failure than the limiting infrequent event and, in combination with a stuck open ADV, the RCP Sheared Shaft event would result in a correspondingly higher control room dose than the limiting infrequent event.

The offsite radiological dose consequences associated with the limiting infrequent event are evaluated below.

15E.5.1 Mathematical Models

For the offsite radiological dose assessment, activity in the RCS was calculated on the basis of the pre-event radioiodine and noble gas activity levels (which are limited by Plant Technical Specifications), to which was added the anticipated post-event increase in activity levels due to fuel pin

failures. The increase in activity levels due to fuel pin failures is dependent upon the radial peaking factor, which affected the radionuclide inventory in the fuel rod gap, as well as the fuel failure fraction, which defined the number of pins that release radionuclides to the RCS coolant.

Once the activity level in the RCS was determined, the amount of activity carried over to the steam generators by primary-to-secondary leakage was calculated. Activity that leaks into the steam generators was assumed to mix with that steam generators' secondary inventory. The level of activity in the generator increased as the event proceeded. The activity released from the steam generators to the environment was determined, based on a steaming rate that removed decay heat and the stored heat in the plant to successfully cool down the NSSS to SDC entry conditions. Once activity releases were quantified, the thyroid and whole body doses at the Exclusion Area Boundary (EAB) and Low Population Zone (LPZ) were calculated as a function of the radial peaking factors and fuel failure fraction.

15E.5.2 Input Parameters and Initial Conditions

Offsite radiological dose consequences associated with the limiting infrequent event were analyzed under the assumptions listed in Section 15.0.4 and the following conditions:

1. Isotope inventories were based on a core power level of 102% of RTP.

2. Based on Technical Specification limits, the initial assumed contamination in the NSSS was:

- RCS Dose Equivalent (DEQ) I-131 1.0 µCi/gm
- RCS Noble Gas (DEQ) Xe-133 550 µCi/gm
- Secondary System DEQ I-131 0.10 µCi/gm

3. A RCS liquid mass of 555,000 lbm of water was used in the analysis, including 45,000 lbm of water in the pressurizer. Additionally, 4,500 lbm of steam was assumed to be in the pressurizer. Although the RCS may hold more mass, these values were selected to increase the iodine concentration following postulated fuel failures, which conservatively increases offsite dose consequences.

4. A steam generator liquid mass of 160,600 lbm per steam generator was used in the analysis. Although the steam generators can hold more mass, this value was selected to increase the iodine concentration in the unaffected steam generator, which conservatively increases offsite dose consequences.

5. A primary-to-secondary leak rate of 0.5 gpm (720 gallons per day) per steam generator was assumed. This is consistent with the PVNGS Technical Specification 5.5.9.

6. It was assumed that 10% of the iodine and noble gas inventories in the fuel pins were resident in the fuel rod pellet-to-clad gap, and available for release upon clad rupture.

7. All of the activity in the fuel rod gap was assumed to be released to the RCS coolant upon fuel pin failure.

8. Iodines associated with leakage to the steam generators were assumed to be released to the environment during steaming with a Decontamination Factor (DF) of 100.

9. It was assumed that plant operators would not initiate a plant cooldown to SDC entry conditions for at least 30 minutes following event initiation. However, it should be noted that a faster RCS cooldown rate would increase steam releases during the first two hours following the event, which would produce more severe thyroid doses at the EAB. On the other hand, a slower RCS cooldown rate would allow radionuclide concentrations to build up in the secondary system, which would produce more severe 8-hour doses at the LPZ. Therefore, radiological dose calculations were performed using two different cooldown rates:

   - A maximum Technical Specification cooldown rate of 100°F/hr, initiated at 30 minutes into the event sequence.
   - A slower cooldown rate of 40°F/hr, initiated at 30 minutes into the event sequence, which would bring the RCS to SDC entry conditions at approximately 8 hours following event initiation.

10. Decay heat during the 8-hour period following the event was based on a 1979 ANS decay heat curve increased by an amount corresponding to the 2σ of the uncertainty.

11. A value of 740,000 BTU/°F was used to represent the specific heat capacity of the RCS, the RCS clad and the

steam generators. Use of a large value increases the amount of steam that must be released to the environment during the cooldown.

12. The χ/Q atmospheric dispersion factors used in the analysis are the short-term factors shown in Table 2.3-31.

13. Since the PSVs lift for this event, the dose calculation conservatively takes into account the activity released to containment, even though the Reactor Drain Tank is sized to remain intact from the PSV discharge.

15E.5.3 Results

The results of the limiting infrequent event radiological dose analysis are shown in Table 15E-3 for radial peaking of 1.72 and a fuel failure fraction of 10.0%. These results bound RTP of 3990 MWt or less.

Table 15E-3

RADIOLOGICAL CONSEQUENCE OF LIMITING INFREQUENT EVENT RADIOLOGICAL ANALYSIS (F_R = 1.72, 10% FUEL FAILURE)

Thyroid Dose (REM)		Whole Body Dose (REM)	
2 Hour EAB	8 Hour LPZ	2 Hour EAB	8 Hour LPZ
4.5	11.7	0.96	1.11

15E.6 CONCLUSIONS

The limiting infrequent event (i.e., AOO with active single failure) results in a limited number of fuel pins predicted to be in DNB for a few seconds. DNB propagation is not predicted to occur. Offsite doses remained below the acceptance criteria for this category of event. Specifically, a small fraction of

10 CFR Part 100 guidelines (i.e., 30 REM thyroid, 2.5 REM whole body).

15E.7 REFERENCES

1. "C-E Methods for Loss of Flow Analysis," CENPD-183, July 1975.
2. "C-E Methods for Loss of Flow Analysis," CENPD-183-A, June 1984.
3. Combustion Engineering, "HERMITE, A Multi-Dimensional Space-Time Kinetics Code for PWR Transients," CENPD-188-A, March 1976.
4. Combustion Engineering, "Responses to First Round Questions on the Statistical Combination of Uncertainties Program: CETOP-D Code Structure and Modeling Methods," CEN-139(A)-P, March 1981.
5. Combustion Engineering, "Responses to First Round Questions on the Statistical Combination of Uncertainties Program: CETOP-D Code Structure and Modeling Methods," CEN-124(B)-P, Part 2, May 1981.
6. Combustion Engineering, "CETOP-D Code Structure and Modeling Methods for San Onofre Nuclear Generating Station Units 2 and 3," CEN-160(S)-P, September 1981.
7. Intentionally Left Blank.
8. Combustion Engineering, "TORC Code: A Computer Code for Determining the Thermal Margin of a Reactor Core," CENPD-161-P-A (proprietary), CENPD-161-A (non-proprietary), April 1986.

9. Combustion Engineering, "TORC Code Verification and Simplified Modeling Methods," CENPD-206-P-A (proprietary), CENPD-206-A (non-proprietary), June 1981.

10. International Commission on Radiation Protection, Publication No. 30, Supplement to Part 1, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity," 1980.

11. Nuclear Regulatory Commission, "Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 120 to Facility Operating License No. NPF-41, Amendment No. 120 to Facility Operating License No. NPF-51, and Amendment No. 120 to Facility Operating License No. NPF-74, Arizona Public Service Company, et al., Palo Verde Nuclear Generating Station, Units 1, 2, and 3, Docket Nos. STN 50-528, STN 50-529, and STN 50-530," August5, 199530," August 5, 1999.

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16. PVNGS TECHNICAL SPECIFICATIONS

The Technical Specifications for Unit 1 are incorporated in the Facility Operating License, NPF-41, as Appendix A.

The Technical Specifications for Unit 2 are incorporated in the Facility Operating License, NPF-51, as Appendix A.

The Technical Specifications for Unit 3 are incorporated in the Facility Operating License, NPF-74, as Appendix A.

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CHAPTER 17

QUALITY ASSURANCE

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TABLES

FIGURES

17. QUALITY ASSURANCE

17.1 QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION (HISTORICAL)

NOTE: Construction is complete for the three units of the Palo Verde Nuclear Generating Station (PVNGS). Sections 17.1 through 17.1C describe quality assurance during the design and construction (project phase) and will not be updated. This information is maintained as a historical reference only.

This section describes the quality assurance (QA) program which has been established by the applicant, Arizona Public Service Company (APS), to provide assurance that the engineering, design, procurement and construction of the Palo Verde Nuclear Generating Station (PVNGS) conforms with applicable regulatory requirements and with the design bases specified in the license application. The QA program described in section 17.1 is applicable to each unit during the design and construction phases. The QA program for the startup and operational phase activities of PVNGS is described in section 17.2, and will be implemented for each unit in turn as described in paragraph 17.2.2.4.

The APS QA program for the engineering design, procurement, and construction of PVNGS is described in section 17.1A of this chapter. APS shall be responsible for the implementation of this QA program. Certain work, however, has been and will be delegated to other organizations for the engineering design, procurement, and construction of the PVNGS. The major participating organizations are the Bechtel Power Corporation, Los Angeles Power Division, (Bechtel), and Combustion

Engineering, Inc. (C-E). The QA programs for Bechtel and C-E are described in sections 17.1B and 17.1C of this chapter, respectively.

The APS QA program, as well as the QA programs of Bechtel, C-E, and other suppliers, comply with the requirements of NRC Regulation 10CFR Part 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants (10CFR50, Appendix B).

Changes to the QA program description included or referenced in sections 17.1A, 17.1B, and 17.1C of this chapter shall be submitted to the NRC in accordance with 10CFR50.55(f). Changes that do not reduce the commitments in the program are submitted within 90 days after implementation. Changes that do reduce the commitments shall be submitted to the appropriate NRC Regional Office, to the Resident Inspector, and to the Document Control Desk, U.S. NRC for approval prior to implementation.

17.1A APS QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

The APS QA program is documented by written policies and directives contained in the APS QA Manual for the Design, Procurement and Construction of PVNGS (hereafter referred to as the "APS QA Manual").

The APS QA program complies with the requirements of NRC Regulation 10CFR Part 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants. In addition, the APS QA program is structured in accordance with the NRC Regulatory Guides listed in paragraph 17.1A.2.6.

Definitions used are in accordance with ANSI N45.2.10, Quality Assurance Terms and Definitions, as endorsed by Regulatory Guide 1.74. Exceptions and additional terms and definitions applicable to matters relating to PVNGS are included in the APS QA Manual.

17.1A.1 ORGANIZATION

17.1A.1.1 General

Arizona Public Service Company, as the applicant, is solely responsible for the establishment and execution of the APS QA program. Bechtel, acting as the agent for APS, has been delegated the responsibility for establishing and executing major portions of the APS QA program as described in this chapter. Combustion Engineering (C-E) is responsible for nuclear steam supply system as defined in chapter 17 and maintains QA responsibility for this work. APS, however, recognizes and acknowledges the ultimate responsibility for the

APS QA program and provides QA surveillance and audits activities to assure that the requirements of the APS QA program are satisfied. An interface organization chart is given in figure 17.1A-1.

17.1A.1.2 Responsibility and Authority

Figures 13.1-1 and 13.1-2 show the organizational structure and relationships to corporate management of individuals and groups within APS with project management responsibility and responsibility for management of the APS QA program during design and construction. The authority and specific responsibilities of individuals within APS who perform QA functions are established and delineated in writing in the APS QA Manual. These authorities and responsibilities are described in the following paragraphs.

17.1A.1.2.1 President and Chief Operating Officer

As shown in figure 17.1A-1, the president and chief operating officer of APS has the overall responsibility for the engineering, design, procurement, construction, and operation of PVNGS. Execution of these responsibilities is delegated to the vice president, nuclear production, through the executive vice president, Arizona Nuclear Power Project (ANPP). The responsibilities for establishing the policies and practices set forth in the APS QA Manual and assuring conformance with the requirements of the APS QA program are delegated to the director, Corporate QA/QC, through the executive vice president, ANPP. The president and chief operating officer

shall retain the responsibility, however, for assuring the independence of the director, Corporate QA/QC, from schedules and costs and for providing the director, Corporate QA/QC, the authority to direct and control the APS QA program, to assure conformance to the quality requirements of that program.

17.1A.1.2.2 Executive Vice President, Arizona Nuclear Power Project

The executive vice president, ANPP, reports directly to the president and chief operating officer and has the responsibility for establishing and maintaining the APS QA program for the PVNGS. Day-to-day responsibilities for design and construction have been delegated to the vice president, nuclear production. The responsibilities for developing the policies and practices set forth in the APS QA Manual and assuring conformance with the requirements of the APS QA program are delegated to the director, Corporate QA/QC. The executive vice president, ANPP, reserves the authority to conduct, or order, the auditing of any activity at any time to determine the effectiveness of the policies and requirements set forth in the APS QA Manual and to determine compliance with the provisions of the APS QA Manual. The executive vice president, ANPP, is responsible for instituting a formal review of the APS QA program at least annually.

17.1A.1.2.3 Vice President, Nuclear Production, ANPP Project Director

The vice president, nuclear production, through the executive vice president, ANPP, has been designated by the president and chief operating officer of APS as the responsible corporate officer, for implementation of APS QA program requirements during the performance of activities relating to the engineering, design, procurement, and construction of PVNGS. The vice president, nuclear production's responsibilities for implementing the QA program are delegated to the director, technical services. The vice president, nuclear production, was the focal point for all formal communications pertaining to PVNGS during the design and construction phase. When PVNGS Unit 1 entered the operations phase, director/manager level personnel were made responsible for formal communication within their respective areas of responsibility.

17.1A.1.2.4 Director, Corporate QA/QC

The director, Corporate QA/QC, is responsible for managing the APS QA program. The director, Corporate QA/QC, reports directly to the executive vice president, ANPP. He is responsible for the implementation of the APS QA program and for advising the executive vice president, ANPP; the president and chief operating officer; and the chairman and chief executive officer of the program's effectiveness. The director, Corporate QA/QC, has been given the authority by the president and chief operating officer to have stopped, by established procedures, unsatisfactory work or further

processing of unsatisfactory material which is not in conformance with specified quality requirements and/or the provisions of the APS QA program.

The director, Corporate QA/QC, is responsible for assuring the adequacy of the APS QA program and the QA programs of those contractors assigned the obligation of establishing and implementing portions of the APS QA program. This responsibility will be exercised through periodic surveillance and audits of the QA programs of those organizations performing the work.

The director, Corporate QA/QC, has the authority and organizational freedom to identify quality problems. He may initiate, recommend, or provide solutions to the director, technical services. He verifies implementation of solutions.

Specific duties and responsibilities of the director, Corporate QA/QC, include the following:

A. Develop and implement the APS QA program.

B. Prepare and control the APS QA Manual including revisions and its distribution.

C. Formulate QA policies for use by APS.

D. Review QA programs of Bechtel and C-E for compliance with regulatory requirements and use his delegated authority to ensure that deficiencies in their QA programs are corrected. Changes made to C-E's QA program for editorial or administrative purposes only do not require review.

E. Perform audits and surveillances of Bechtel's and C-E's QA programs, advise management of the status of program implementation and take corrective action as deemed necessary.

F. Review specifications, drawings, and procedures for conformance to APS quality requirements, applicable industry standards, and regulatory requirements.

G. Manage the QA staff in the performance of their activities and responsibilities.

H. Have audited the permanent QA records.

I. Establish liaison with the PVNGS plant manager; director, technical services; manager, transition; and the nuclear safety manager and maintain a current status of quality-related and other activities as they pertain to the PVNGS.

J. Maintain communication with the QA organizations of Bechtel and C-E with respect to QA activities.

K. Review correspondence from the NRC Office of Inspection and Enforcement and direct the preparation of inspection report responses.

L. Inform APS management of QA activities through distribution of audit reports and other quality-related information.

M. Report potential significant quality-related matters both verbally and in writing to the vice president, nuclear production.

N. Assist in preparation of significant deficiency reports to the NRC in accordance with the provisions of 10CFR50.55(e) and 10CFR Part 21.

O. Assist the assistant vice president, nuclear production; the PVNGS plant manager; the director, technical services; the transition manager; and the nuclear safety manager in preparation of quality-related procedures controlling the activities of ANPP personnel.

17.1A.1.2.5 APS Corporate QA Department

The APS Corporate QA Department is under the supervision and direction of the director, Corporate QA/QC, for the execution of the QA program. Their specific responsibilities include the following:

A. Maintain surveillance of QA requirements, practices, and experiences throughout the nuclear power industry.

B. Develop procedures that employ recent data and developments from the nuclear power industry, which are used to assure quality in engineering, design, procurement, and construction of the PVNGS.

C. Audit Bechtel's and C-E's QA programs to provide assurance that they are maintained current with new standards, criteria, and codes.

D. Review the project "Q" list of components (see table 3.2-1), equipment, structures, and systems to ascertain that the list is kept current.

E. Review drawings, procurement documents, and procedures to provide assurance that QA requirements are being incorporated.

F. Audit the design, manufacturing, testing, and construction activities of Bechtel and C-E and their subcontractors to provide assurance that quality practices are being maintained.

G. Utilize the assistance of technical services personnel in review and audit activities.

H. Review changes to Bechtel's prequalified bidders' list and provide concurrence as deemed appropriate.

The APS Corporate QA Department is organized into departments as shown in the organization chart in figure 17.2-1.

Responsibilities of the APS Corporate QA Department include QA functions relating to engineering, design, procurement, and construction of PVNGS. Therefore, these APS Corporate QA Departments are described below.

17.1A.1.2.5.1 Quality Systems and Engineering. The Quality Systems and Engineering Department, through the quality systems and engineering manager, has the responsibility to assist the director, Corporate QA/QC, in the implementation of the APS QA program. The quality systems and engineering manager reports

directly to the director, Corporate QA/QC. He is responsible to:

A. Develop, maintain, issue, review, and/or control programs and procedures required for the implementation of the APS QA program, including the Operations Quality Assurance Criteria Manual, and the APS QA Manual.

B. Review quality documents as necessary for incorporation and adequacy of quality requirements.

17.1A.1.2.5.2 Procurement Quality Department. The Procurement Quality Department, through the procurement quality manager, has the responsibility to assist the director, Corporate QA/QC, in the implementation of the APS QA program by monitoring the procurement activities of Bechtel and C-E. The procurement quality manager reports directly to the director, Corporate QA/QC. The responsibilities of the procurement quality manager include monitoring or auditing procurement, receiving, inspection, and storage activities.

17.1A.1.2.5.3 Quality Audits and Monitoring Department. The Quality Audits and Monitoring Department, through the quality audits and monitoring manager, has the responsibility to assist the director, Corporate QA/QC, in the implementation of the APS QA program for home office and site construction activities. He is also responsible for auditing and/or monitoring the implementation of the APS QA program by the APS technical services departments; and the implementation of the Bechtel

quality program for construction activities; as well as design and engineering activities by Bechtel and C-E. The quality audits and monitoring manager reports directly to the director, Corporate QA/QC.

17.1A.1.2.6 Director, Technical Services

The director, technical services, has the responsibility for engineering, construction, records management, nuclear fuels management, and licensing, and for proper implementation of the APS QA program for these functions. The director, technical services, has the assistance of technical units as shown in figure 13.1-7.

The director, technical services, has the authority to stop Technical Services Department activities that are not accomplished in compliance with applicable regulatory or QA requirements. The director, technical services, reports directly to the vice president, nuclear production.

17.1A.1.2.6.1 Nuclear Engineering (NE) Manager. The nuclear engineering manager, through the director, technical services, has been delegated responsibility for engineering, design, and procurement of the PVNGS. The nuclear engineering manager has the assistance of technical units as shown in figure 13.1-8 in fulfilling his responsibilities. The nuclear engineering manager has overall control of work performed on the project including:

A. The right to review and comment on all documents including drawings, specifications, analyses,

computations, and procurement documents prepared by contractors in performance of all work

B. The acceptance or rejection of all plans which govern the conduct of work, the assignment of responsibilities among and the coordination of activities of Bechtel, C-E, the nuclear engineering staff, suppliers, subcontractors, and consultants employed by Bechtel or APS

C. The right to inspect either directly or through his designated representative all work performed by contractors. The nuclear engineering manager shall have the responsibility and the authority to reject any material or workmanship that does not meet the requirements specified in agreements with contractors

D. The authority to accept all work performed by Bechtel subject to the concurrence of the Corporate QA manager indicating that the provisions of the APS QA program have been satisfied.

The nuclear engineering manager shall be responsible for the preparation of the nuclear engineering department procedures and instructions which shall delineate the responsibilities of the technical groups in the Nuclear Engineering Department organization and the administrative procedures and controls over the work performed by Nuclear Engineering Department personnel during the engineering design and procurement of the PVNGS.

For a complete description of the Nuclear Engineering Department including personnel qualifications, refer to subsection 13.1.1.

17.1A.1.2.6.2 Nuclear Construction Manager. The nuclear construction manager through the director, technical services, has the delegated responsibility for the construction of PVNGS. He has the assistance of several technical groups in fulfilling his responsibilities. The nuclear construction manager directs the APS field construction engineering personnel at the power plant site to ensure that the project contractors and subcontractors comply with all applicable construction codes, standards, procedures, and specifications.

The nuclear construction manager has overall control of work performed by contractors at the site including:

A. The right to evaluate the specification and purchase order of field-purchased equipment and services

B. The acceptance or rejection of all construction plans which govern the conduct of work, the assignment of responsibilities among and the coordination of activities of BPC, C-E, contractors, and consultants employed by BPC or APS.

C. The right to inspect either directly or through his designated representative all work performed by contractors. The nuclear construction manager shall have the responsibility and authority to reject any material or workmanship which does not meet the

requirements specified in agreements with contractors.

17.1A.1.2.6.3 Nuclear Records Management Manager. The nuclear records management manager, through the director, technical services, has the delegated responsibility for the receipt, microfilming, indexing, storage, control, and retrieval of records for PVNGS. The nuclear records management manager directs the technical and administrative activities within the Nuclear Records Management Department which is comprised of five units as follows: NPRM administration, RMS computer system, PVNGS drawing and document control, drawing and document control (offsite), and micrographics (onsite and offsite).

The Nuclear Records Management Department provides onsite and offsite support for design, engineering, construction, startup, and operation in the areas of documentation, drawing control, and associated reference informational material by the means of hard copy, micromedia, and/or computer-assisted retrieval.

17.1A.1.2.7 Bechtel Power Corporation

Bechtel is responsible to perform engineering, design, construction, cost engineering, procurement, QA, assistance in startup and preoperational testing, and project management coordination work requisite to the construction of three separate and complete nuclear power electric generating units. The organizational structure for QA which will direct Bechtel is described in section 17.1B.

17.1A.1.2.8 Combustion Engineering, Inc.

Combustion Engineering is responsible to APS for the engineering, design, and procurement of the nuclear steam supply system (NSSS). The organizational structure for QA within C-E and the responsibilities of individuals and groups within that organization are described in section 17.1C.

17.1A.1.3 Project Quality Assurance Interface Control

Arizona Public Service Company has overall responsibility for interface control as it applies to the engineering, design, procurement, construction, and testing of the PVNGS. This responsibility rests primarily with the vice president, nuclear production and the APS director, Corporate QA/QC. Additional responsibilities for controlling project interfaces rest with Bechtel and C-E. The responsibilities and methods used by these organizations for maintaining effective lines of communication between their QA organizations and the organizations of contractors performing work under their control are described in sections 17.1B and 17.1C, respectively. A primary responsibility of the APS director, Corporate QA/QC, is the verification of compliance with these interface measures as well as their effectiveness for controlling project interfaces.

Lines of communication between APS and its contractors shall be primarily through Bechtel. In this regard, the primary communication line between Bechtel and APS has been between the Bechtel project manager and the vice president, nuclear production. Upon issuance of the operating license for PVNGS

Unit 1, formal interfaces were established between director/manager APS personnel, and Bechtel and C-E, in areas where the individual director/manager had responsibility. The APS director, Corporate QA/QC, shall have direct access to the QA organizations within Bechtel and contractors. In general, however, this access has been through the Bechtel project QA manager.

17.1A.1.4 Personnel Qualifications

The director, Corporate QA/QC, is responsible for managing and directing the APS QA program. The director, Corporate QA/QC, shall satisfy the following minimum qualification requirements:

A. Graduate of a 4-year accredited engineering or science college or university.

B. Minimum of 5 years' experience in quality assurance, including testing or inspection (or both) of equivalent manufacturing, construction, and installation activities. At least 2 years of this experience should be associated with nuclear facilities; or if not, the individual shall have training sufficient to acquaint him thoroughly with the safety aspects of a nuclear facility.

C. In lieu of a degree, a high school graduate plus 10 years of experience in general QA or engineering of equivalent manufacturing, construction, and installation activities. Five years of this experience is required in QA, including testing or

inspection (or both) of equivalent manufacturing, construction, and installation activities. At least 2 years of this experience should be associated with nuclear facilities; or if not, the individual shall have training sufficient to acquaint him thoroughly with the safety aspects of a nuclear facility.

The director, Corporate QA/QC, shall have broad experience and formal training in the performance of QA and quality control activities, including inspection and testing. He must be capable of planning and providing supervision to QA personnel who will be engaged in inspecting, testing, reviewing, evaluating, and auditing the adequacy of activities to accomplish QA objectives.

The director, Corporate QA/QC, shall be responsible for having reviewed the qualifications of Bechtel, C-E, and their subcontractor personnel, and for the review of indoctrination and training programs established by those contractors for personnel who perform activities affecting quality.

17.1A.2 QUALITY ASSURANCE PROGRAM

17.1A.2.1 General

Arizona Public Service Company is responsible under the ANPP Participation Agreement to manage the construction, operation, and maintenance of PVNGS in accordance with the rules and regulations of the NRC, the construction permits, operating licenses, and SNM licenses issued for the PVNGS units by the NRC, and the applications for such permits and licenses, and in

such a manner as to provide for the protection of the health and safety of the public. The importance of QA in contributing to this safety, as well as contributing to station reliability, is also recognized.

In accordance with this philosophy, the APS QA program has been developed and establishes the policies and practices for quality assurance for the engineering, design, procurement, and construction of PVNGS. Disagreements or differences of opinion in QA matters that originate with or are brought to the attention of the director, Corporate QA/QC, are expected to be resolved jointly by him and the director, technical services, as appropriate. Where such resolution is not achieved within a reasonable period of time, unresolved differences shall be referred to the vice president, nuclear production, or executive vice president, ANPP, as appropriate.

It is the policy of APS to utilize qualified and trained personnel in all responsible project positions and job assignments. Personnel shall receive formal indoctrination in QA, including basic principles; 10CFR Part 50, Appendix B; and the contents of the APS QA Manual.

17.1A.2.2 Program Description

The APS QA program consists of three elements, which are described below. The first element is a documented system of administrative controls over activities affecting quality. The second element is quality verification, and the third element is QA.

17.1A.2.2.1 Administrative Controls

The APS QA program requires preparation of appropriate documents, including procedures, drawings, and specifications, which prescribe the measures that have been established to control all activities affecting quality. Compliance with this requirement is the responsibility of each and every organization or group with responsibility for the engineering, design, procurement, and construction of the PVNGS. The measures which are established to control work must be detailed to the extent necessary to ensure that adequate controls have been incorporated. This establishes a documented system of controls which will guarantee confidence in the acceptability or quality of the work activities governed by those documents.

17.1A.2.2.2 Quality Verification

Quality is achieved through the use of skilled personnel, adequate planning, use of suitable tools and procedures, proper definition of job requirements, and appropriate supervision and technical direction. Quality is verified through surveillance, inspection, testing, checking, and review of work activities and documentation. Quality verification is the basic responsibility of the organization or group performing the activity. Quality verification is performed, however, by individuals other than those who did the work.

17.1A.2.2.3 Quality Assurance

The QA function consists of review, surveillance, and audit. Auditing is assigned to the APS Corporate QA Department, which

is independent of the organizations responsible for the work. The APS Corporate QA Department is responsible for formulating or reviewing general quality policies; review of QA and control activities; monitoring and auditing program activities to assure compliance with established controls and requirements; and for measuring the overall effectiveness of those controls.

17.1A.2.3 Responsibilities

The organization and responsibilities of the principal parties involved in the engineering, design, procurement, and construction of the PVNGS are described in subsection 17.1A.1. The responsibilities of these organizations with respect to the elements of the APS QA program are described below.

17.1A.2.3.1 Arizona Public Service Company

Arizona Public Service Company has overall responsibility for the QA program. Responsibility for establishing and implementing a system of administrative controls over quality affecting activities rests with the director, technical services, and the director, Corporate QA/QC. These controls are described in the ANPP Administrative Policies and Procedures Manual, the corresponding ANPP department instruction manuals, and the APS QA Manual. These manuals contain the administrative procedures which control the activities of the Nuclear Engineering Department personnel, Nuclear Construction Department personnel, and Nuclear Records Management Department personnel.

The APS Corporate QA Department is primarily responsible for QA audit activities which are described in subsection 17.1A.18. The audit responsibility of the APS Corporate QA Department includes audits of contractors and the compliance of nuclear engineering, nuclear construction, and nuclear records management personnel with the provisions of the administrative procedures which control their activities.

17.1A.2.3.2 Bechtel Power Corporation

Bechtel is responsible for complying with the requirements of the APS QA program. The procedures, instructions, manuals, and other documents which delineate activities carried out by Bechtel engineering, procurement, construction, scheduling, and QA are described in section 17.1B. Bechtel is responsible to APS for the engineering, design, procurement, and construction of PVNGS. Consistent with this delegated responsibility, Bechtel is responsible for both quality verification and QA activities with respect to suppliers of equipment, material, and services including C-E.

17.1A.2.3.3 Suppliers

Arizona Public Service Company requires that suppliers of equipment, materials, and services that could affect the quality of safety-related structures, systems, and components establish and implement QA programs. These programs shall include provisions that are consistent with the APS QA program. Arizona Public Service Company responsibilities with respect to these programs will be exercised through surveillance and audit

by the APS Corporate QA Department either in conjunction with or independent of Bechtel QA. Bechtel is responsible for performing quality verification for Bechtel activities and QA for Bechtel and supplier activities.

17.1A.2.4 Program Documentation

Arizona Public Service Company QA program policies and practices are contained in the APS QA Manual and the ANPP Administrative Policies and Procedures Manual. The APS QA Manual consists of QADs, listed in table 17.1A-1, which are approved by the director, Corporate QA/QC. Requirements for preparation, review, approval, revision, and issuance and distribution of QADs are delineated in the APS QA Manual. Table 17.1A-1 includes a cross-reference of the requirements of 10CFR Part 50, Appendix B, to the QADs contained in the APS QA Manual. More detailed cross-references to implementing procedures of APS nuclear projects, Bechtel, and C-E are incorporated into various QADs in the APS QA Manual. Other documents that include instructions, procedures, and manuals delineating activities to be performed by APS, Bechtel and CE are identified in the APS QA Manual, including the ANPP Administrative Policies and Procedures.

The director, Corporate QA/QC, and the director, technical services, have the right to review and comment on all documents, including QA manuals and procedures, drawings, specifications, analyses, computations, and procurement documents prepared by Bechtel.

The document control procedures for Bechtel and C-E are identified in sections 17.1B and 17.1C, respectively.

17.1A.2.5 Management Reviews

The executive vice president, ANPP, reviews the status and adequacy of the APS QA program at least annually. The executive vice president, ANPP, requires the director, Corporate QA/QC, to make formal recommendations with regard to the adequacy of the policies and practices contained in the APS QA Manual and the compliance with those policies and practices. The recommendations become the formal record of effectiveness of the APS QA program.

The intent of the management review is to assess the scope, implementation, and effectiveness of the QA program to assure that the program effectively complies with APS policy and the requirements of 10CFR50, Appendix B. The review includes results of audits of quality affecting activities to maintain an overall awareness of the effectiveness of the APS QA program and the implementation of APS policy directives.

Additionally, and on a routine basis, the executive vice president, ANPP, reviews appropriate QA records, including but not limited to reports of audits and corrective action, and other QA summary reports.

17.1A.2.6 Applicability of Codes, Standards, and Regulatory Guides

The APS QA program has been developed, to the extent practical, in accordance with approved NRC regulatory guides and ANSI

standards. Bechtel is responsible to APS for maintaining control over the list of codes, standards, and regulatory guides which are applicable to the engineering, design, procurement, and construction of the PVNGS. This list is included in the Project Design Criteria Manual for the PVNGS, which is maintained by Bechtel. All changes to this list are reviewed by the APS director, Corporate QA/QC, and the director, technical services, prior to implementation in procurement documents.

The director, technical services, has overall responsibility for determining the applicability of codes, standards, and regulatory guides and for implementing the provisions of those requirements. The director, Corporate QA/QC, is responsible for verifying that codes, standards and regulatory guides accepted for use during the design, procurement, and construction of the PVNGS are implemented. The director, Corporate QA/QC, will coordinate this effort with the Bechtel project QA manager as necessary to take full advantage of the codes and standards reviews conducted by Bechtel.

The APS QA program is structured in accordance with the following regulatory guides with the exceptions as described in section 1.8:

A. Regulatory Guide 1.28: Quality Assurance Program Requirements (Design and Construction)

B. Regulatory Guide 1.37: Quality Assurance Requirements for Cleaning of Fluid Systems and

Associated Components of Water-Cooled Nuclear Power Plants

C. Regulatory Guide 1.38: Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants

D. Regulatory Guide 1.39: Housekeeping Requirements for Water-Cooled Nuclear Power Plants

E. Regulatory Guide 1.30: Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment

F. Regulatory Guide 1.94: Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants

G. Regulatory Guide 1.58: Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel

H. Regulatory Guide 1.116: Quality Assurance Requirements for Installation, Inspection and Testing of Mechanical Equipment and Systems

I. Regulatory Guide 1.88: Collection, Storage and Maintenance of Nuclear Power Plant Quality Assurance Records

J. Regulatory Guide 1.64: Quality Assurance Requirements for the Design of Nuclear Power Plants

K. Regulatory Guide 1.144: Auditing of Quality Assurance Programs for Nuclear Power Plants

L. Regulatory Guide 1.123: Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants

M. Regulatory Guide 1.146: Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

17.1A.2.7 Safety-Related Structures, Systems, and Components Controlled by the Program

Table 3.2-1 identifies the structures, systems, and components to which the APS QA program applies and is called the Q-list. It is a tabulation of safety-related items; i.e., those items that contribute to the prevention or mitigation of the consequences of postulated accidents which could cause undue risk to the health and safety of the general public; generally, QA-related functions performed on Q-list items during the engineering, design, procurement, inspection, and testing phases are the responsibility of the organization (Bechtel or C-E) primarily responsible to supply the item.

17.1A.2.8 Personnel Indoctrination and Training

Arizona Public Service Company QA program provides for the indoctrination and training of personnel performing activities affecting quality as necessary to assure that suitable proficiency is achieved and maintained. The APS QA Manual identifies the procedures that have been established by APS for

indoctrination and training, as well as the personnel qualification requirements. Personnel indoctrination and training procedures assure that:

A. Personnel responsible for performing quality activities are instructed as to the purpose, scope, and implementation of the quality-related manuals, instructions, and procedures.

B. Personnel performing quality-related activities are trained and qualified in the principles and techniques of the activity being performed.

It is the responsibility of managers to assure that their personnel are aware of QA requirements. This is achieved through a planned training program.

Personnel designated to participate in audits shall have or will be given training and orientation in methods for performing audits. One or more of the following methods will be employed in developing personnel:

A. Training to provide personnel with working knowledge and understanding of both ANSI N45.2, Quality Assurance Program Requirements for Nuclear Power Plants, and
ANSI N45.2.12, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants.

B. Training programs designed to provide general and specialized training in audit performance. General training will include fundamentals, objectives,

characteristics, organization, performance, and results of quality auditing. Specialized training will include methods of examining, questioning, evaluating, and documenting specific audit items, methods of identifying and following up on corrective items, and methods of closing out audit findings.

C. On-the-job training, guidance, and counseling under the direct supervision of an experienced, qualified auditor. Such training will include planning, performing, reporting, and followup action involved in conducting audits.

D. Orientation of technical specialists by the audit team leader. Such orientation will include familiarization with audit principles and procedures.

Auditors' proficiency may be maintained through one or more of the following methods:

A. Regular, active participation in the audit process.

B. Review and study of codes, standards, procedures, and instructions related to QA programs and program auditing.

C. Participation in training or orientation programs.

Training requirements and procedures for Bechtel and C-E project personnel whose work activities affect quality are delineated in sections 17.1B and 17.1C, respectively.

17.1A.3 DESIGN CONTROL

17.1A.3.1 General

The design of structures, systems, equipment, and components is controlled by the various contractor organizations to assure safe and reliable performance of products and services provided to APS. The control processes are documented by procedures and checklists which establish the responsibilities and interfaces of each contractor that has an assigned design responsibility. The procedures and checklists include means to assure that quality requirements and standards are specified in design and procurement documents; that suitable materials, parts, components, and processes are applied; and that the designs are verified for adequacy by persons other than those performing the original design. Design changes are controlled to the same level as was applied to the original design, including review and approval by the same organization that performed the original review and approval, unless otherwise designated by Bechtel with concurrence by APS. Design documents and revisions thereto shall be distributed to responsible individuals in a timely manner and controlled to prevent inadvertent use of superseded material. Errors and deficiencies in design that adversely affect safety-related structures, systems, and components are documented and appropriate corrective action is taken in accordance with subsections 17.1A.15 and 17.1A.16.

Bechtel has been delegated the responsibility for the engineering design, procurement, and construction of PVNGS. They have responsibility for the QA audit of the design control

measures and their implementation by the NSSS and other contractors performing design work. Bechtel's design control procedures are described in section 17.1B.

Combustion Engineering has responsibility for performing the design of the NSSS and/or review and approval of work performed by their subcontractors. Combustion Engineering's design control procedures are described in section 17.1C.

Arizona Public Service Company has overall responsibility for the control of the design of PVNGS. Arizona Public Service Company will review documents submitted by Bechtel, C-E, and their subcontractors. This review, in conjunction with QA audits, will provide assurance that contractor's design control measures are in conformance with the requirements of the APS QA Manual.

17.1A.3.2 Design Control Procedures

Bechtel and C-E design organizations have established and implemented design control procedures that delineate the responsibilities, authority, reporting, and methods of communication of the design organization. These procedures include provisions for the following:

A. Design Process Control

The implementation of design process control methods has been delegated to Bechtel and C-E subject to review by APS technical services and audit by Corporate QA. Design process control methods shall be applied to: analyses, such as thermal, hydraulic,

stress, and accident; core physics and design; material selection and compatibility; accessibility for both maintenance and repair and inservice inspection; and delineation of acceptance criteria for tests (construction and preoperational) and inspections.

B. Design Standards

Design documents and specifications developed for Quality Class Q structures, systems, equipment, and components shall be prepared and reviewed by Bechtel and C-E to ascertain inclusion of the following:

1. Engineering requirements
2. NRC design criteria
3. NRC QA criteria
4. NRC regulatory guide conformance or applicability
5. Applicability of industry codes and standards, i.e., ASME, IEEE, ANS, and ANSI
6. Conformance with the Safety Analysis Report
7. Interface requirements including internal interfaces.

C. Design Interface Control

Bechtel QA reviews interface control procedures to verify that implementing procedures are being properly used with design documents prepared by

Bechtel. Bechtel's design interface control is described in section 17.1B. Bechtel maintains interface control with the subcontractors and with APS. The APS Corporate QA Department will perform audits to verify that interface controls are maintained between APS and Bechtel and between Bechtel and their subcontractors, including C-E.

D. Design Verification

Bechtel and C-E are responsible for developing and implementing a design verification or checking method prior to issuance of Bechtel and C-E design, engineering, and specification documents. This will include design review, alternate calculations where applicable, and qualification testing.

Bechtel and C-E will document significant deficiencies which may adversely affect safety-related structures, equipment, systems, or components in the design process and shall take appropriate corrective action and document same. When a test program is specified to verify adequacy of the design, qualification testing of a prototype unit subjected to the most adverse design conditions shall be used. Materials, parts, equipment, and components which are considered "off-the-shelf" shall be reviewed and selected based on their suitability of application when such items are employed or related to Quality Class Q systems, structures, equipment, or components.

E. Design Change Control

Bechtel and C-E have developed and implemented design change control procedures which are commensurate with those used for the original design. Final results, upon incorporation of all design changes, are documented in final as-built drawings and specifications.

F. Field Change Control

Upon receipt of material, equipment, and components, and during the construction and preoperational test phase, field changes may be required.

Field changes shall be approved by the project engineer and shall be subject to the same design change control procedures described in paragraph 17.1A.3.2, listing C.

Field changes shall be documented and subject to design control procedures implemented by Bechtel.

Arizona Public Service Company shall be notified of each change and may review proposed changes as deemed necessary. Bechtel/C-E shall submit supporting documentation for all changes. The field changes shall be reflected in the appropriate drawings and specifications.

G. Control of Significant Deficiencies

Significant deficiencies that are safety-related shall be reported in accordance with the NRC Code of Federal Regulations -- 10CFR50.55(e).

H. Design Records

Bechtel and C-E contractors are responsible for the collection, storage, distribution, maintenance, and subsequent turnover to APS of design documents, design reviews, records, and changes thereto. The system shall be maintained in a systematic and controlled manner subject to audit by APS.

17.1A.4 PROCUREMENT DOCUMENT CONTROL

As the PVNGS units enter the operations phase, APS may directly procure material, equipment, and services in accordance with the applicable provisions of section 17.2. Material, equipment, and services so obtained may be utilized for corresponding construction phase applications. In such cases, procurement document control measures shall be established and implemented in accordance with subsection 17.2.4, in lieu of this section.

Bechtel is responsible for the preparation and submittal of procurement documents, in compliance with the QA requirements, to APS for review and comment. This review is coordinated by the director, technical services. The awarding of contracts is by APS. Contracts will be managed by Bechtel.

Combustion Engineering is responsible for procurement of NSSS components. Bechtel audits C-E procurement activities for compliance with C-E QA requirements.

Procedures established and implemented by both Bechtel and C-E delineate the preparation and the review of procurement documents by cognizant and qualified personnel, to assure that applicable regulatory requirements, design bases, and quality requirements are properly included or referenced; that these requirements can be inspected or controlled; that there are adequate acceptance/rejection criteria; and that all of these QA requirements have been complied with by the procurement documents.

The procurement documents identify the requirements for the QA program to be implemented by vendors and contractors. The QA requirements are in accordance with the Q-list, table 3.2-1. The procurement documents document the supplier's or contractor's acceptance of obligation to implement the QA program in accordance with 10CFR50, Appendix B.

Procurement documents include or reference, as applicable, basic technical requirements including regulatory requirements, component and material identifications, drawings, specifications, codes and industrial standards with applicable revision dates, tests and inspection requirements, and special process instructions and requirements for such activities as designing, fabrication, cleaning, erecting, packaging, handling, shipping, field storage, and inspecting.

Procurement documents include provisions for right of access to vendors facilities and records for source inspection and audit by Bechtel, C-E, APS, and/or regulatory agencies.

Procurement documents include, as appropriate, documentation requirements, identifying the documents to be prepared, maintained, submitted, or made available for review and comment, such as: drawings, specifications, procedures, procurement documents, manufacturing and inspection plans, inspection and test records, personnel and procedure qualifications, as well as material, chemical, and physical test results. Instructions on record retention and disposition are provided.

Changes made to procurement documents shall be subject to the same degree of control as was used in the preparation of the original documents, consistent with the requirements of ANSI N45.2.11, Paragraph 7.2. Minor changes, such as inconsequential editorial corrections or changes to commercial terms and conditions, may not require that the revised document receive the same review and approval as the original documents.

Procurement documents for spare parts or replacement parts comply with all of the foregoing requirements.

Procurement documents include provisions for extending applicable requirements of the procurement documents to the suppliers lower tier suppliers, including right of access if necessary to facilities and records by Bechtel, C-E, APS, and/or regulatory agencies.

APS has overall responsibility for the control of the procurement of PVNGS items and services. This control is exercised through reviews of procurement document control measures conducted by technical services and APS Corporate QA Departments. Audits are conducted by the APS Corporate QA Department to verify that the measures have been established and implemented.

Descriptions of Bechtel's and C-E's procurement document control measures are discussed in sections 17.1B and 17.1C, respectively.

17.1A.5 INSTRUCTIONS, PROCEDURES, AND DRAWINGS

The APS QA program requires that activities affecting quality be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances, and accomplished in accordance with such documents. These documents include appropriate quantitative and qualitative criteria for determining whether or not an activity has been satisfactorily accomplished.

A contractor, or supplier, responsible for an activity affecting quality is required to provide the necessary instructions, procedures, or drawings to appropriately prescribe the activity. These documents must be reviewed and approved by responsible personnel prior to accomplishing the activity.

Bechtel, and/or APS, may require the submittal of such documents for review and acceptance, prior to the undertaking

of an activity. Such a requirement shall be identified in procurement documents.

The APS Corporate QA Department verifies that activities affecting quality have been performed in accordance with instructions, procedures, or drawings and that required documentation exists for verification.

The APS QA Manual contains an identification of the controlled procedures, instructions, manuals, and other documents which delineate activities carried out by APS.

These documents form the basis for control over the activities which could affect the quality of Quality Class Q structures, systems, and components of the PVNGS during engineering, design, procurement, and construction.

The APS QA Manual identifies the originating authority; the responsibility for document review for APS QA policy compliance; the responsibility for review, comment, and acceptance within APS; and the responsibility for approval for the controlled documents used by APS. The APS Corporate QA Department will perform audits to verify that these documents are being utilized in the proper manner. Bechtel and C-E documents are identified in sections 17.1B and 17.1C, respectively.

17.1A.6 DOCUMENT CONTROL

The APS QA program requires that organizations with responsibility for documents which prescribe activities affecting quality establish and implement document control

measures. The procedures which have been established by APS to implement the requirements for document control are identified in the APS QA Manual. These procedures identify the format and content requirements for documents; the responsibilities for preparation, review, approval, and revision to documents; the document identification systems used by APS; the measures to control issuance and distribution, receipt, filing and storage, use, and disposition. Documents include drawings, design specifications, calculations, engineering studies, vendor data, test procedures, design criteria, Q-list, PSAR/FSAR, and QA programs and procedures.

The procedures which have been established by Bechtel and C-E to implement the requirements for document control are described in sections 17.1B and 17.1C.

The director, Corporate QA/QC, is responsible for the maintenance, issuance, and control of the APS QA Manual. The director, Corporate QA/QC, is also responsible for the issuance of instructions which delineate the performance of activities by APS Corporate QA personnel.

The director, technical services, is responsible for the preparation of document control procedures for the Technical Services Departments, where there is responsibility for the issuance, review, and/or acceptance of documents. Such activities include review and comment on design documents issued by Bechtel; review and comment on procurement documents prepared by Bechtel; review and comment on field design and procurement documents; review of acceptance and qualification test procedures; review and comment on construction plans; and

review and comment on changes to previously accepted documents. These document control procedures identify the individuals or groups responsible for each activity.

Bechtel has the responsibility for engineering, design, procurement, and construction document control for the project. Bechtel is responsible for the issuance of design documents to the site prior to commencement of work; the coordination and control of interface documents with various suppliers and contractors; the control of changes to design documents; coordination of documents with APS; the review and acceptance of procedures submitted by suppliers; project QA program documents; and distribution and control of design documents released for construction. Document control procedures require that only proper and current documents are provided and are used by contractors performing an activity; that superseded documents are properly controlled; that current and updated distribution lists are established; and that supervision monitors for compliance with document control requirements.

Suppliers and contractors are responsible for maintaining prescribed document control procedures as part of their own QA program. The document control measures which are adopted by an organization must be designed to assure that only currently approved documents are used by those performing an activity; that there are means for determining the status of a document; that the use of outdated or inappropriate documents is precluded; and that changes are included in all documents affected by the change.

The document control procedures require that an organization prescribe measures to preclude inadvertent use of outdated or superseded documents.

Bechtel is responsible to APS for a comprehensive system of planned and documented audits to verify compliance with all aspects of the APS QA program for document control. These audits shall be performed by personnel not having direct responsibilities in the areas being audited.

Bechtel shall conduct internal and external audits to assure that both its document control program and the programs of other organizations are being implemented and are satisfactory. Arizona Public Service Company shall ensure the adequacy of suppliers' document control measures by evaluating their QA programs as required per subsections 17.2.4 and 17.2.7.

The APS director, Corporate QA/QC, is responsible for having conducted surveys and audits to verify compliance with the requirements for the control of documentation. This includes the audit of the audit programs carried out by each organization as necessary to determine their effectiveness. The director, Corporate QA/QC, is responsible to ensure Bechtel audit schedules and results are reviewed on a routine basis to verify that appropriate corrective action and timely followup action, including reaudit of deficient areas, is taken where indicated by the audit findings.

17.1A.7 CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES

As the PVNGS units enter the operations phase, APS may directly procure material, equipment, and services in accordance with the applicable provisions of section 17.2. Material, equipment, and services so obtained may be utilized for corresponding construction phase applications. In such cases, control of purchased material, equipment, and services shall be in accordance with subsection 17.2.7, in lieu of this section.

The APS QA program requires that procedures be implemented that delineate the methods and responsibilities for assuring that material, equipment, and services, procured by Bechtel or other suppliers and contractors, conform to the requirements of the procurement documents.

The procurement procedures of Bechtel, its suppliers, and contractors require that quotations to furnish material, equipment, and services be solicited only from a prequalified bidders' list, which is prepared by Bechtel. Criteria for prequalification are delineated in the procedures, and take into consideration previous experience with the bidder including the bidder's reputation and experience with utilities and the nuclear industry, his QA capability, and other factors. Arizona Public Service Company reviews changes to the Bechtel prequalified bidders' list.

Addition of bidders to the prequalified bidders' list requires a detailed and documented evaluation by qualified personnel, which includes assessment of bidders' management capabilities, financial resources, plant facilities, technical capabilities,

and QA programs. Visits to suppliers or contractors' facilities are made, to assist in the evaluation process.

Bechtel QA is responsible for approving the acceptance criteria for the bidders' QA program. Bechtel Procurement Supplier Quality Department is responsible for evaluating and accepting bidders' programs and manuals.

Procurement documents delineate the documentation which a successful bidder is required to furnish as evidence of compliance with the procurement document requirements.

Suppliers are required to furnish Bechtel with information concerning their manufacturing and inspection plans in order that Bechtel may plan and implement a source surveillance plan. Bechtel QA coordinates the establishment of surveillance plans with APS to permit APS participation in supplier surveillance. The surveillance plan includes inspection of items, witnessing of processes or tests, and audits of the suppliers' QA programs.

Prior to release for shipment, material and equipment requiring source inspection must be inspected for conformance to procurement document requirements by C-E representatives, and/or Bechtel procurement supplier quality representatives. Verification is made that quality documentation exists and is complete. Documentation of this verification will constitute acceptable evidence of compliance with all procurement requirements. A copy of this verification document is sent to the Bechtel field quality control engineer.

Items that have been source-inspected are examined, upon receipt, for shipping damage, correctness of identification, and proper quality documentation. Inspection status is described in subsection 17.1A.14. Documentary evidence showing that Q-list items or materials conform to procurement requirements shall be available at the site prior to installation of such items or use of such material, except as discussed in subsections 17.1A.15 and 17.1A.17. Items found by receiving inspection to be nonconforming shall be segregated and/or controlled as described in subsection 17.1A.15.

Documentary evidence is sufficient to identify the specific requirements, such as codes, standards, and specifications met by the procured item. This requirement can be satisfied by having available at the site copies of the purchase specification, purchase order and any changes, and written certification of conformance to procurement requirements. These documents shall be maintained by the project field quality control engineer. Bechtel QA shall verify by audit the validity of the certifications of conformance.

The procedures which have been established by APS to implement the requirements for procurement control are identified in the APS QA Manual. These requirements are based on Appendix B to 10CFR Part 50. The procedures which have been established by Bechtel and C-E to implement the requirements for procurement control are described in sections 17.1B and 17.1C.

The APS director, Corporate QA/QC, is responsible for having audits conducted to verify compliance with all aspects of the requirements described in the referenced procedures and QA

manuals. This includes the audit of the audit programs carried out by each involved organization. The director, Corporate QA/QC, is responsible for having reviews of Bechtel's audit schedules and results on a routine basis and for verifying that corrective action and followup action, including reaudit of deficient areas, are taken.

17.1A.8 IDENTIFICATION AND CONTROL OF MATERIALS, PARTS, AND COMPONENTS

The APS QA program requires that vendors and contractors establish and implement procedures for the identification and control of materials, parts, and components (including partially fabricated subassemblies) to assure the use or installation of only accepted items.

Bechtel is responsible for assuring that onsite procedures exist and are being implemented for the identification and control of materials, parts, and components.

Bechtel and C-E shall require in their procurement documents that equipment be identified at the source, prior to shipping, in accordance with the established plant identification system. In addition, traceability of materials, parts, or components to the supplier's quality documentation is specified in the procurement documents.

Source and receiving inspection planning shall include the verification of the correct identification of items and their records and shall note these as a condition for acceptance.

Physical identification shall be used, to the maximum extent possible, for relating an item at any stage of work to an applicable drawing, specification, and/or other pertinent technical document. Where physical identification is impractical or would affect the function or quality of the item, physical separation, procedural control, or other means shall be employed.

Material storage areas at supplier's shops and at the site shall be controlled to assure identification of materials.

The APS director, Corporate QA/QC, is responsible for having audits conducted to verify compliance with the procedures and measures for identification and control of materials, parts, and components. Audits conducted by the Corporate QA Department will evaluate the effectiveness of the controls which Bechtel is exercising over suppliers.

17.1A.9 CONTROL OF SPECIAL PROCESSES

Special processes are defined as those metallurgical, chemical, or other processes where assurance of the process quality is dependent largely on the inherent skill of the operator, and on the control of process parameters. It cannot be assured by direct inspection of work alone. These include, but are not limited to, welding, heat-treating, chemical cleaning, and nondestructive examination (NDE).

The APS QA program requires that contractors and suppliers identify, in their submittals, the special processes they intend to employ. Contractors and suppliers must assure that

in performing these processes, qualified procedures, equipment, and personnel are used under controlled conditions and in accordance with the requirements of applicable codes and standards.

Personnel, equipment, and procedures utilized in the performance, control, and inspection of special processes shall be qualified prior to use, in accordance with applicable codes and standards. Special processes shall be performed under controlled conditions by qualified personnel in accordance with written process sheets, shop procedures, checklists, travelers, or equivalent. Evidence of verification shall be documented.

For special processes not covered by existing codes or standards, or where quality requirements exceed the requirements of established codes and standards, the procedures for qualifying personnel, procedures, or equipment shall be defined in the procurement documents and shall be submitted for review prior to use.

Documentation of procedures and personnel qualification shall be kept current by the contractor or supplier. The documentation shall be subject to APS or Bechtel QA audit. Audits of special processes shall include verification that qualified personnel and procedures are used, and that there is compliance with the requirements of applicable codes and standards.

The APS director, Corporate QA/QC, shall have audits conducted which evaluate the effectiveness of the control over special processes exercised by Bechtel's QA organization. The specific

measures for control over special processes shall be identified prior to commencement of any activities by Bechtel or other contractors or suppliers performing special processes.

17.1A.10 INSPECTION

The APS QA program requires that suppliers establish, prior to manufacture, a specific inspection program for activities affecting quality, which is designed to verify compliance with the quality requirements identified in the procurement documents.

Bechtel is responsible for establishing and implementing an inspection program which meets the requirements of 10CFR50, Appendix B.

Bechtel QA has responsibility for the audit of the Bechtel inspection program and its implementation by Bechtel personnel, and other contractors and suppliers' inspection programs relative to Q-list items. Arizona Public Service Company is responsible to perform similar audits of suppliers.

Audits may be conducted by the APS Corporate QA Department to verify that inspection plans, instructions, and procedures have been established, are acceptable, and are being implemented. These audits supplement those audits conducted by Bechtel and C-E QA personnel.

Inspections shall be performed by individuals other than those who performed the activity and who are qualified. They should be from a group independent of those having direct responsibility for manufacture. If such independent inspection

personnel are not available, additional inspection shall be provided by Bechtel or other independent contractors.

The supplier shall maintain integrated manufacturing and inspection plans that clearly identify the items and activities to be inspected. The plans must include the specific inspections required by the procurement documents or those in the referenced codes and standards.

Inspections shall include the monitoring of processes and personnel when inspection of the finished product is impractical or inconclusive; inspection and process monitoring shall be utilized for adequate control.

Inspections shall be performed in accordance with procedures, instructions, and/or checklists, which shall contain the following as applicable:

A. Identification of quality characteristics to be inspected

B. Identification of those individuals or the organization responsible for performing the inspection operation

C. Acceptance/rejection criteria

D. Calibration requirements

E. A description of the methods of inspection

F. Evidence of completion and certification of inspection operation

G. Record of the results of the inspection operation

H. Record of reinspection results.

The supplier inspection plans shall include the following as applicable:

A. Identification of materials

B. Dimensional checks

C. Material test reports

D. Fitup of parts

E. Assembly of components

F. Process parameters

G. Examination of work

H. Cleanliness of parts and work area

I. Use of correct documentation

J. Monitoring of processes

K. Handling, cleaning, packaging, and storage procedures

L. Documenting of activities.

Inspections shall be satisfactorily completed and documented prior to releasing equipment for shipment, or special control established over a part or subassembly which has not completed satisfactory inspection.

Arizona Public Service Company shall review the integrated manufacturing and inspection plans of suppliers, establish a set of mandatory inspection holdpoints. Required mandatory holdpoints, beyond which work may not proceed without APS approval, shall be included in the supplier's inspection plans,

or otherwise controlled to ensure that work does not proceed without acceptance. Arizona Public Service Company shall monitor supplier's activities in accordance with paragraph 17.2.7.

Combustion Engineering and other suppliers who procure equipment from subsuppliers shall be responsible for assuring that their suppliers establish and implement a satisfactory inspection program. They shall determine that there is compliance with the quality requirements specified in the procurement documents.

Contractors at the site shall be required to establish and implement inspection programs that are in accordance with contract requirements and the applicable codes and standards. These programs are subject to review and acceptance by Bechtel.

A contractor's planned inspections shall be performed by inspection personnel, independent from the individual or group performing the activity being inspected. Bechtel shall review the contractors' inspection plans and establish notification points for their witness. Mandatory holdpoints may be established beyond which work may not proceed without Bechtel release; mandatory holdpoints shall be identified in the contractors' inspection plans.

The work of contractors who do not have inspection responsibility shall be inspected by APS or Bechtel. Inspection plans shall be based on design document requirements, the applicable codes and standards, and the work procedures adopted by the contractor. They shall provide the

contractor with the inspection program to coordinate the scheduled inspection activities. Inspections shall be documented by checklists or reports.

The inspection activities of Bechtel, and all suppliers and contractors, are subject to auditing by the APS Corporate QA Department to verify compliance with specified requirements.

17.1A.11 TEST CONTROL

The APS QA program requires that a documented test program be implemented to assure that required testing be identified and properly performed to demonstrate that Q-listed structures, systems, and components will perform satisfactorily in service. Identification of the required testing shall be based on design considerations and regulatory requirements. Testing will be in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design and procurement documents.

Proof and performance testing of components shall be performed and documented by suppliers as required in procurement documents. Suppliers may also be required to perform prototype qualification tests. The performance of supplier testing may be witnessed by Bechtel and/or APS. Notification and mandatory holdpoints shall be incorporated in the suppliers' manufacturing and test plans.

The procedures which have been established by Bechtel and C-E to implement the requirements for test control are described in sections 17.1B and 17.1C.

The director, Corporate QA/QC, shall have audits of Bechtel and C-E conducted to verify that documents specify the applicable tests to demonstrate that structures, systems, and components perform satisfactorily in service. Audits of the Bechtel QA program to ensure that suppliers are satisfactorily performing tests in accordance with design requirements will also be conducted.

The program for testing of structures, systems, and components, to demonstrate their satisfactory performance in service, is described in chapter 14.

17.1A.12 CONTROL OF MEASURING AND TEST EQUIPMENT

The APS QA program requires that procedures be implemented for the control, calibration, and periodic adjustment of tools, gauges, instruments, and other measuring and test equipment used to obtain and/or verify conformance to established quality requirements.

Suppliers and contractors, as part of their QA program, shall implement written procedures for the control and calibration of tools and measuring and testing equipment. Contractors shall maintain documentation of the calibration status and records of tools and gauges utilized. Assurance of supplier and contractor performance shall be obtained by evaluating their procedures, and during periodic in-process audits of records by both Bechtel and APS Corporate QA Department.

Inspection, test, and work procedures shall include provisions assuring that tools, gauges, instruments, and other inspection,

measuring, and testing equipment, and devices used in activities affecting quality, are of the proper range, type, and accuracy. To assure its accuracy, inspection, measuring, and test equipment shall be calibrated, adjusted, and maintained, prior to first use and at prescribed intervals thereafter, with calibration performed against equipment certified to have known valid relationships to nationally recognized standards or performed on some other documented basis. The acceptance criteria for principal contractor's calibrating procedures will include the requirement that the degree of uncertainty of the calibrating standards shall be less than the error of the equipment being calibrated. Control measures shall prevent the use by unauthorized personnel of calibrated tools, gauges, instruments, and other measuring and test equipment. Special calibration and control measures are not required for devices when normal commercial practices provide adequate accuracy.

The calibration status, date of calibration, and recalibration date shall be displayed prominently on each device, whenever possible, or on records traceable to the device. The records shall contain all elements necessary for control and verification of past calibration activities.

Inspection, test, and work procedures shall include the requirement that, whenever inspection, test, or measuring equipment is found to be out of calibration, the acceptability of all items inspected, tested, or measured since the last documented calibration must be evaluated.

The APS director, Corporate QA/QC, shall be responsible for having audits conducted to verify compliance with the procedures and measures for controlling measuring and test equipment. These measures shall be identified prior to commencement of any activities by suppliers or contractors which require the use of measuring and test equipment.

17.1A.13 HANDLING, STORAGE, AND SHIPPING

The APS QA program requires that procedures be established and implemented to control the handling, storage, and shipping (including cleaning, packaging, and preservation of material and equipment) to assure the maintenance of quality from source through installation or use.

Arizona Public Service Company or Bechtel shall review procurement documents to assure that they either provide, or require that suppliers provide, instructions on handling, storage, shipping, cleaning, and preservation for the product supplied. Instructions shall be provided for marking, labeling, packaging, shipping, and storing of items. Marking shall identify the shipment and special handling or storage requirements, including indications of the presence of special environments, or the need for special control.

Arizona Public Service Company shall establish a surveillance plan to assess and document onsite compliance with handling, storage, cleaning, and preservation procedures.

Combustion Engineering is responsible for verifying that requirements of procurement documents are satisfied, prior to release of an NSSS component for shipment to the site.

Bechtel shall review C-E's requirements and procedures for handling, storage, and shipping.

Bechtel has responsibility for handling, storing, and preserving materials and equipment at the site. The responsibility may be delegated to a responsible contractor, e.g., electrical equipment and materials to the electrical contractor.

Special coverings, equipment, and protective environments (such as inert gas atmosphere), specific moisture content levels, and temperature levels shall be provided and maintained for given materials and components as specified in manufacturers' instructions, supplemented by additional requirements as specified by Bechtel.

Special handling tools and equipment necessary to assure safe and adequate handling of critical, sensitive, or perishable items shall be provided and controlled. Special handling tools and equipment shall be inspected and tested by qualified personnel in accordance with written procedures, at specified times, to verify that the tools and equipment are maintained and suitable for the intended task.

Cleaning of components or systems at the site shall be performed in accordance with procedures prepared by the supplier of the equipment. The procedures shall be reviewed by APS or Bechtel. Cleaning operations may be monitored by APS or

Bechtel. The APS Corporate QA Department will conduct audits to verify that handling, storage, and shipping procedures are being implemented. These audits may be conducted through Bechtel's QA Department.

17.1A.14 INSPECTION, TEST, AND OPERATING STATUS

The APS QA program requires that written procedures be prepared and implemented which delineate the requirements, methods, and responsibilities for:

A. Indicating the status of inspections and tests performed on individual items during the procurement and construction phases of the project, to preclude inadvertent bypassing of such inspections and testing.

B. Indicating the operating status of installed structures, systems, and components during the construction testing phase, to prevent inadvertent operation of equipment or hazard to plant personnel.

These procedures shall be provided and implemented by suppliers or contractors who fabricate or assemble materials or equipment in their shops, by site contractors having responsibility for inspection of their work, and by Bechtel for onsite indication of inspection and test status of the items they inspect.

Prior to the start of preoperational testing, APS shall establish procedures, based on current practices, for the control of test and operating status indicators, including the

authority for application and removal of tags, markings, labels, and stamps.

The inspection and test status of items shall be indicated by the use of markings such as stamps, tags, labels, routing cards, or other suitable means, and shall be noted in records traceable to the item. The procedures shall delineate the authority for application and removal of status markings.

The operating status of installed structures, systems, and components shall be indicated by the operating panel readouts or equivalent. When such readouts are incomplete or inoperable and for systems and components not having such readouts, operating status shall be indicated by such means as tagging of valves and switches.

During construction testing, written procedures shall be implemented for controlling abnormal electrical or mechanical arrangements such as bypassed interlocks, installed jumpers, and piping bypasses.

Identification of abnormal operating status shall always include placing such identification at control locations where the system or component can be actuated, started, or controlled. Items whose status is nonconforming, inoperative, or malfunctioning shall be so indicated, as required by subsection 17.1A.15.

Bechtel is responsible for audits which assure that the foregoing requirements are complied with by all responsible organizations. The APS Corporate QA Department is responsible

for audits of delegated activities, and for internal audits for compliance by APS groups participating in acceptance testing.

17.1A.15 NONCONFORMING MATERIALS, PARTS, OR COMPONENTS

The APS QA program requires that procedures be prepared and implemented which describe the methods of controlling material, parts, or components that do not conform to defined requirements, to prevent their inadvertent use or installation.

All suppliers, contractors, and subcontractors who furnish, fabricate, erect, or install materials or equipment shall implement, as part of their QA program, acceptable procedures for the control of nonconforming items. These procedures shall include methods for identification, segregation, documentation, evaluation, and disposition of items that do not conform to the requirements of the design or procurement documents, including the pertinent QA programs.

Upon identification of a nonconformance, the supplier or contractor shall suspend the affected work until the nonconformance has been evaluated if:

A. The continuance of the work would conceal the nonconformance and make corrective action difficult or impossible.

B. The nonconformance is due to the work procedure and continuing its use would increase the extent or severity of the nonconformance.

Nonconforming items, where practical, shall be segregated from acceptable material in a controlled access location; when this

is not possible, control shall be maintained by tagging, marking, or other clear means of identification. Installation of nonconforming items into plant systems will be permitted only when established procedures are implemented which assure that the component or system will not be operated unsafely. As a general rule, nonconforming items are not to be used or installed. However, this requirement will not preclude reasonable exceptions such as those situations where nonconforming conditions relate only to the need for minor repairs or replacement of easily accessible parts, or lack of actual documentation at the site, and where the nonconformance can be readily resolved. In such cases, the decision to proceed on installation of nonconforming items must be supported by appropriate engineering evaluations.

Justification for use and installation of a nonconforming item will be generally limited to avoidance of unreasonable schedule delays or prevention of equipment or component placement which would otherwise seriously block access to placement areas.

Nonconformance reports justifying installation or use of nonconforming items will be produced prior to installation or use and will be approved in accordance with established procedures. The procedures will provide for an established system of nonconformance identification and for timely completion of prescribed corrective action. These items will be tagged "hold" with reference on the tag to the documentation described above.

A final check of the documentation verifying the quality of a particular system and acceptance of nonconformances that have

not been dispositioned will be required before construction tests can be made.

All identified nonconformances shall be documented. When the disposition consists of repair or correction by existing approved procedures, documentation on appropriate forms is acceptable. When the disposition consists of repair by procedures requiring approval, or by design change requiring waiver or other approval, the documentation shall be by appropriate written report of the nonconformance and its resolution, inspection, and approval.

Identified nonconformances shall be evaluated and a recommended disposition proposed by the supplier or contractor performing the work in question. Identified nonconformances, when so resolved by the supplier or contractor, shall be repaired or reworked in accordance with documented procedures. The affected items shall be reinspected for acceptance in accordance with applicable procedures and codes.

Dispositions involving special repair procedures or design changes shall be made and approved by the responsible design organization, or by Bechtel, and reviewed by Bechtel. The evaluation and disposition of the nonconformance shall be controlled by written procedures.

Before equipment is released for shipment, the inspectors (Bechtel, C-E, and others) shall determine that proper disposition has been made of the nonconformance and the necessary documentation is complete and accurate.

Documentation for items that have been repaired or accepted as-is shall describe the change, waiver, or nonconformance which has been accepted, identify the accepting party, and denote the as-built condition. The documentation for all such nonconforming items shall be filed as part of the QA records. These nonconformances are reported to management as described in subsection 17.1A.16.

Bechtel has responsibility for the disposition of nonconformances identified by Bechtel and APS and the review of nonconformance reports of contractors, including C-E. Procedures developed to implement nonconformance systems require that appropriate levels of engineering, QA, and project management are authorized to approve nonconformances. Resolutions of nonconformances requiring "repair" or "accept-as-is" must be approved by the engineering organization that specified the original criteria. The procedures established by Bechtel include requirements to keep the APS Corporate QA Department informed as to the nature and status of identified nonconformances. Arizona Public Service Company requires that BPC and other contractors notify the APS Corporate QA Department immediately when a condition adverse to quality is discovered and appears to be reportable. This shall include immediate notification of all deficiency evaluation reports initiated by BPC.

Arizona Public Service Company has the ultimate responsibility to determine if a nonconformance initiated by APS or by any contractor borders on or meets conditions stated in 10CFR Part 50.55(e) or 10CFR Part 21. Arizona Public Service Company

management, including the PVNGS plant manager; director, technical services; director, Corporate QA/QC; and vice president, nuclear production shall, decide what action is to be taken with regard to formally notifying the NRC and resolving the nonconformance or deficiency.

The APS Corporate QA Department shall periodically review the trend report of nonconforming reports maintained by Bechtel. This review shall concentrate on the types of nonconformances which are occurring on the project and which may indicate trends.

The APS Corporate QA Department shall conduct audits to verify that established procedures are being complied with in the disposition of nonconforming items.

17.1A.16 CORRECTIVE ACTION

The APS QA program requires that procedures be established and implemented to assure that conditions adverse to quality and items discussed in subsection 17.1A.15 are promptly identified and corrected, and that the cause is determined and corrective action is taken to preclude repetition.

Conditions adverse to quality, such as design deficiencies, failures, malfunctions, and nonconformances, shall be promptly identified and reported by cognizant Bechtel or C-E personnel. The report shall be directed to the person, or organization, responsible for correction of these conditions. The reports on conditions adverse to quality may be in the form of inspection reports, audit reports, or by formal letter.

The report shall include a determination of the underlying causes of a problem. Implementation of corrective action shall be verified by reaudit or reinspection, including a determination as to whether the underlying causes of the problem have been adequately corrected to preclude repetition. In these cases, the adverse condition, its cause, and the corrective action taken shall be documented and reported to appropriate levels of management, including Bechtel and APS.

Suppliers and contractors shall be required, in procurement documents and contracts, to have, as part of their QA program, a system for corrective action when conditions adverse to quality are identified, either at their facility or on material and equipment for which they are responsible. If the deficiencies or deviations are discovered at the site, responsible management of the affected supplier or contractor shall be promptly notified and advised of the problem. Followup by Bechtel will assure that the required corrective action is taken. Bechtel shall resolve the technical aspects of problems, or concur with solutions proposed by suppliers or contractors. Nonconformances to approved project procedures shall be reported to Bechtel QA.

17.1A.17 QUALITY ASSURANCE RECORDS

The APS QA program requires that records be provided and maintained to furnish documentary evidence of the quality of items and of activities affecting the quality of items and systems of PVNGS, and that written procedures be implemented

delineating the methods and requirements for receiving, identifying, storing, and preserving these records.

The records required for each safety-related item include the following: design records; as-built data; results of reviews, inspections, tests, work performance monitoring, and materials analyses; operating logs; and closely related data such as qualifications of personnel, procedures, and equipment.

The design records shall include the following information: design basis, drawings, specifications, and design changes. The records shall include deviations and their disposition.

Inspection records and test records shall include the following information: date of the inspection or test; identification of the item inspected or tested; identity of the inspector, data recorder, and/or evaluator; type of observation; results of the inspection or test; acceptability; and action taken in connection with any deficiencies noted.

The specific QA records which suppliers and contractors are required to provide shall be specified in procurement or contract documents, and shall comply with applicable regulatory requirements, codes, standards, and specifications. Quality verification documentation is to be provided prior to or with each shipment of material to the site. If these objectives cannot be met, procedures have been developed to allow the shipment to and receipt at the site of items or equipment that may lack some of the quality verification documents called for in the procurement specification. Procedures provide a

tracking system to ensure that required documentation is received.

Organizations which do work on the design, fabrication, erection, or testing of the structures, systems, or components important to safety are responsible for submitting records of those activities as required by the procurement documents, applicable codes and standards.

Bechtel is responsible for obtaining, processing, and adequately storing and protecting the QA records for the project until these records are turned over to APS on completion of each unit of the station.

Suppliers or contractors who exercise the option to retain QA records beyond the construction phase shall meet APS's requirements on retention, including storage, preservation, and safekeeping. These records shall be made available on demand for use by APS, or its agent.

Arizona Public Service Company is responsible for the permanent storage, protection, and maintenance of the records during the life of the unit, including periodic verification of the availability of such records stored for APS by other organizations.

A record storage facility will be located so as to provide convenient access to information necessary for operations, maintenance, inservice inspection, problem solving, or engineering of station modifications. The record storage facility shall meet the requirements of Regulatory Guide 1.88 as described in section 1.8.

Station orders and procedures are prepared by the station operations staff, as part of the operational QA program. This is discussed in section 17.2.

Bechtel shall carry out a comprehensive system of planned and documented audits to verify compliance with all aspects of the QA program for records management. These audits shall be performed by personnel not having direct responsibilities in the areas being audited. Bechtel shall conduct internal and external audits to assure that both its records management program and the programs of other organizations, including C-E, are being implemented and are satisfactory.

The APS director, Corporate QA/QC, shall be responsible for having audits conducted to verify compliance with the requirements for the management and control of the QA records. This shall include the audit of the audit programs carried out by each responsible organization to determine their effectiveness. The director, Corporate QA/QC, shall ensure Bechtel's audit schedules and results are reviewed on a routine basis and verify that corrective action and followup action, including reaudit of deficient areas, have been taken where indicated by the audit findings.

17.1A.18 AUDITS

The APS QA program requires that a comprehensive system of planned and documented audits be established and implemented to verify compliance with all aspects of the QA program, and to assess its effectiveness.

All organizations which are required to have and implement a QA program are required to conduct audits of their program and the programs of their subcontractors.

Bechtel has the responsibility for audits of vendors and contractors during the design, procurement, and construction phases of the project, as well as for internal audits of its own activities as described in subsection 17.lB.18. AS PVNGS units enter the operations phase, APS has assumed responsibility for vendor audits, and conducts these audits in accordance with subsections 17.2.7 and 17.2.18.

Arizona Public Service Company shall monitor the implementation of the audit program by Bechtel by informal observation and by documented periodic audits. As part of the auditing of Bechtel, APS shall participate in a sampling of the audits conducted by Bechtel. In addition, APS will audit its own project activities, including the QA function itself.

The director, Corporate QA/QC, is responsible for keeping APS management informed on QA matters and for necessary action to correct deficiencies when action by management is needed. He discharges his responsibilities by conducting independent periodic audits of the APS QA program, and by reporting his findings to: management, the executive vice president, ANPP, and others who have corporate responsibility for the areas audited.

Audits shall be performed in accordance with written procedures, or checklists, by trained personnel having no direct responsibilities in the area audited. Audits may be

conducted by QA engineers and/or other qualified personnel, such as technical specialists from other departments, designated by the appropriate QA manager.

The purpose of audits is the evaluation of work areas, activities, processes, items, and documentation, to provide an objective evaluation of compliance with established requirements, methods or procedures; to assess progress in assigned tasks; to determine adequacy of QA program performance; and to verify implementation of recommended corrective action. Audit results shall be documented and reviewed with management responsible for the area audited, who shall take necessary action to correct reported deficiencies.

Audits shall be conducted at either planned, periodic intervals, or on a random unscheduled basis. The director, Corporate QA/QC, shall maintain a schedule for the audits. Audits will selectively cover each of the various elements of APS and Bechtel QA programs, at the beginning of the project activity involving those elements, and at regular intervals thereafter. The scheduled frequency of audits may be changed by the director, Corporate QA/QC, as circumstances dictate; e.g., changes in level of activity, importance of activity, previous findings, changes in organization or procedures, or occurrence of problems.

Audits may be used to determine the acceptability of suppliers' or contractors' QA programs prior to awarding of a purchase order or contract; followup audits shall be used to assure that suppliers and contractors properly implement their QA programs.

Suppliers and contractors shall be required, in procurement and contract documents, to perform internal auditing of their own QA program. Compliance with these requirements shall be verified by APS and/or Bechtel audits.

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17.1B BECHTEL QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

The Bechtel quality assurance (QA) program for the Palo Verde Nuclear Generating Station (PVNGS) complies with the applicable provisions of section 1.8 and the following:

A. 10CFR50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Processing Plants

B. 10CFR50, Licensing of Production and Utilization Facilities

C. Section 17 of NRC Regulatory Guide 1.70, Revision 3, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants

D. Quality assurance requirements of Section III, ASME Boiler and Pressure Vessel Code for items covered by the Code

   Bechtel is the holder of an ASME Certification of Authorization--"N" Stamp

E. American National Standards Institute (ANSI) given in the listing below, except for the noted exceptions or alternatives as described in section 1.8.

   1. ANSI N45.2-1971, Quality Assurance Program Requirements for Nuclear Plants (Regulatory Guide 1.28)

   2. ANSI N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During the Construction Phase of Nuclear Power Plants (Regulatory Guide 1.37)

3. ANSI N45.2.2-1972, Packaging, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants (During the Construction Phase) (Regulatory Guide 1.38)

4. ANSI N45.2.3-1973, Housekeeping During the Construction Phase of Nuclear Power Plants (Regulatory Guide 1.39)

5. ANSI N45.2.4-1972 (IEEE-336), Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations (Regulatory Guide 1.30)

6. ANSI N45.2.5-1974, Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (Regulatory Guide 1.94)

7. ANSI N45.2.6-1978, Qualifications of Inspection, Examination and Testing Personnel for the Construction Phase of Nuclear Power Plants (Regulatory Guide 1.58)

8. ANSI N45.2.8-1975, Supplementary Quality Assurance Requirements for Installation, Inspection and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants (Regulatory Guide 1.116)

9. ANSI N45.2.9-1974, Requirements for Collection, Storage and Maintenance of Quality Assurance Records for Nuclear Power Plants (Regulatory Guide 1.88)

10. ANSI N45.2.10-1973, Quality Assurance Terms and Definitions (Regulatory Guide 1.74)

11. ANSI N101.4-1972, Quality Assurance for Protective Coating Applied to Nuclear Facilities (Regulatory Guide 1.54)

12. ANSI N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants (Regulatory Guide 1.64)

13. ANSI N45.2.12-1977, Requirements for Auditing Quality Assurance Programs for Nuclear Power Plants (Regulatory Guide 1.144)

14. ANSI N45.2.13-1976, Requirements for Control of Procurement of Equipment, Materials and Services for Nuclear Power Plants (Regulatory Guide 1.123)

15. ANSI N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants (Regulatory Guide 1.146)

The program described herein is applied by Bechtel Western Power Corporation (BWPC) and Bechtel Construction Inc. (BCI) to those safety-related structures, systems, and components (Q-list items) identified in table 3.2-1 for which Bechtel

Power Corporation has responsibility under its contract with the Arizona Public Service Company (hereafter referred to as "APS").

The Bechtel Power Corporation scope of work is: To perform engineering, design, construction, cost engineering, procurement, QA, quality control (QC), assist in startup and preoperational testing, and project management coordination work requisite to the construction of three separate and complete nuclear power electric generating units. The construction scope was assigned by Bechtel Power Corporation to BCI. The remaining scope was subcontracted to BWPC.

The term "quality assurance" is defined as all those planned or systematic actions necessary to provide adequate confidence that an item or facility will perform satisfactorily in service.

The term "quality control" is defined as all those QA actions that provide a means to control and measure the characteristics of an item, process, or facility to established requirements.

"Quality" is achieved through the use of planning and procedures, suitable tools, proper definition of job requirements, skilled personnel, and supervision and technical direction.

Quality is verified through surveillance, inspection, testing, checking, and review of work activities and documentation. It is Bechtel policy that QC and verification are the responsibility of the organization or group that performs the activity; i.e., engineering, procurement, or construction.

Quality verification is performed by individuals other than those who performed the work.

The Bechtel QA functions consisting of review, surveillance, and auditing is assigned to the Quality Assurance Group, which is independent of the organizations responsible for the work. The QA Group is responsible for formulating and/or reviewing general quality policies; coordination of QA, control and verification activities; and for monitoring and auditing program activities to verify compliance with established requirements, and to measure program effectiveness. When the term "quality assurance" is applied to personnel titles or procedures, it refers to the personnel and practices of the QA Group. The overall Bechtel QA program, which includes the activities of the organizations performing work as well as QC and QA, is referred to as the Bechtel quality program.

For the purpose of clarity, the QA terms used in this section are the definitions from ANSI N45.2.10 and Regulatory Guide 1.74, Quality Assurance Terms and Definitions, supplemented by the following additional terms and definitions:

A. BPC -- Bechtel Power Corporation

B. BWPC -- Bechtel Western Power Corporation

C. BCI -- Bechtel Construction, Inc.

D. Bechtel QA program -- a jointly developed and applied quality assurance program for BWPC and BCI for the Palo Verde project.

E. Administrative direction (administrative supervision) -- responsible for hiring, salary review, and assignment of an individual

F. Coordination -- bringing together and ensuring communication between independent groups, including responsibility for identification of interface problems, reconciling a position, and arriving at agreement

G. Formulate -- responsibility for coordination of effort by affected organizations in preparation of documentation describing or defining a policy or procedure

H. Monitor -- to watch over, observe, or examine a work operation, (results of the observations and examination may be recorded; however, signoff responsibility is not included.)

I. Project direction -- directions or instructions concerned with project operations includes coordination and day-to-day direction of the project entities receiving technical direction from others, but does not include authority to overrule prescribed procedures or technical decisions of such entities

J. Project home office -- the home office assigned responsibility for management of the project

K. Q-List items -- safety-related systems, components, and structures to which this program applies (refer to table 3.2-1)

L. Quality Assurance Group -- the QA Group consists of the manager of QA, QA manager of projects, project QA manager, and the QA personnel (refer to paragraph 17.1B.1.5.1).

M. Review -- to examine any form of documentation for the purpose of establishing acceptability relative to requirements of the function represented by the reviewer. (Reviews may range from a thorough investigation to a spot check. Reviews are generally not hold points, but signoff on documents or records traceable to the documents is required.)

N. Surveillance -- a broad term pertaining to and including both monitoring and witnessing

O. Technical direction -- instructions and directions defining technical requirements for an activity. (This may include furnishing prescribed procedures, technical requirements, design approaches, specifications, and design details.)

P. Technical guidance -- providing advice representing a preferred method or approach to a function or activity. (This may include establishing general requirements or policy, but not specific procedures or instructions.)

Q. Witness -- to watch over, observe, or examine a specific test or work operation, which includes signoff responsibility for conformance to procedures or specifications

BECHTEL QUALITY ASSURANCE DURING

DESIGN AND CONSTRUCTION

17.1B.1 ORGANIZATION

17.1B.1.1 Bechtel Group, Inc.

Figure 17.1B-1 illustrates the organizational chart of the Bechtel group of companies. The Bechtel group includes: Bechtel Western Power Corporation, Bechtel Eastern Power Corporation, and Bechtel Construction Inc., plus others.

Bechtel Western Power Corporation as a subcontractor of Bechtel Power Corporation is responsible for design and procurement activities associated with PVNGS. Bechtel Construction Inc. by assignment from Bechtel Power Corporation is responsible for construction activities associated with PVNGS as addressed in paragraphs 17.1B.1.5.3 and 17.1B.1.6.4.

17.1B.1.2 Bechtel Western Power Corporation

Members of the BWPC management team are responsible for coordination of, and technical guidance to, activities within their disciplines. Bechtel Western Power Corporation provides quality-related services in the area of design, engineering, procurement, and QA to BCI.

The BWPC president approves basic quality policies for all BWPC projects. The BWPC manager of quality assurance is responsible for technical direction of the Bechtel QA program. He formulates or reviews overall quality policies for BWPC, provides technical guidance to the BWPC QA managers, and evaluates the effectiveness of the total BWPC and BCI quality program. The following is a specific list of the primary responsibilities of the BWPC manager of QA:

A. Formulate or review overall quality policies for use in BWPC and recommend them for approval by the BWPC president

B. Review QA policies and QA procedures prior to release for compliance with BWPC policies

C. Review, obtain concurrence and approval for compliance with BWPC quality policy, quality manuals from Bechtel centralized functions.

D. Formulate and direct audit programs to assure BWPC management that the overall quality program conforms with policy and that the program as implemented is effective.

E. Provide reports to the BWPC president evaluating the effectiveness of the quality program and any problems requiring special attention

F. Coordinate the quality program of centralized functions, i.e., the Procurement Supplier Quality Department, and the Materials and Quality Services (M&QS) Department

G. Conduct quality program coordination meetings with responsible BWPC managers, managers of QA, QC, and engineering.

17.1B.1.3 Materials and Quality Services

The M&QS is a centralized function reporting to Bechtel National, Inc. through the Bechtel Research and Development

vice president and general manager (figure 17.1B-1). The M&QS manager is responsible for furnishing specialized chemical, metallurgical, process evaluations, and procedures. They also assist in auditing of suppliers of ASME Section III materials and/or services to Bechtel. The M&QS quality functions for power projects are coordinated by the BWPC manager of QA.

The M&QS responsibilities include:

A. Develop and qualify welding and nondestructive examination (NDE) procedures

B. Train and qualify Bechtel NDE personnel

C. Support engineering procedures and qualifications of personnel

D. Provide technical guidance to field welding engineers

E. Review supplier and subcontractor welding, nondestructive examination, protective coating procedures, and QC manuals for ASME components and metal structures applications

F. Prepare and maintain the Bechtel QA Manual for ASME Nuclear Components (BQAM-ASME III) and provide liaison with the ASME and authorized inspection agencies in matters associated with compliance with the ASME Code BQAM-ASME, and the control of the ASME nuclear symbol stamps

G. Participate in audits of field construction, which include compliance with the QA Manual for ASME, Nuclear Code Section III, components, and BCI and

subcontractor field welding and NDE and protective coatings programs

H. Participate in surveys and audits of materials and component suppliers and subcontractors, as required

I. Consult with engineering, procurement, construction, QA, and QC on failure analysis problems involving materials, welding, protective coatings, and nondestructive examination

J. Support engineering in the preparation of specifications for components, piping, metal structures, and protective coatings and in the selection of materials.

17.1B.1.4 Procurement

Procurement, as a service organization, does not establish technical or quality requirements contained in procurement documents nor does it approve changes thereto; these functions are the responsibility of the engineering departments.

The quality functions of procurement are supplier surveys, quality program verification, surveillance inspection, and audit of supplier activities for implementation of quality programs. These functions are the responsibility of the manager of supplier quality. The procurement supplier quality function is independent of purchasing and expediting functions. The procurement supplier quality department program as applied to power projects is established by the manager of supplier quality and is coordinated by the BWPC manager of QA. The

manager of supplier quality is responsible for assuring that BWPC purchased items and associated quality verification records subject to source inspection comply with requirements contained in procurement documents. Manager of supplier quality responsibilities are as follows:

A. Prepare and maintain the Procurement Supplier Quality Manual and associated procedures thereto

B. Train and qualify BWPC procurement supplier quality personnel

C. Survey and audit potential suppliers for conformance to 10CFR50, Appendix B, and ANSI N45.2, as applicable, and perform periodic audits and quality program verification activities of selected suppliers and offsite subcontractors as required

D. Prepare source inspection plans

E. Perform progressive surveillance inspection of items and review of quality verification documentation in accordance with the Procurement Supplier Quality Manual and associated procedures and the procurement document requirements.

F. Release items for shipment.

The field services manager directs the operation of source inspectors. He is independent of project-assigned personnel. He is responsible for the quality of the inspectors' performance in implementing the designated source inspection plans for PVNGS (see figure 17.1B-4). The inspection plans are

designated by the project from a book of standard plans (the Procurement Supplier Quality Department Surveillance Inspection Plans) and augmented by the Procurement Supplier Quality Manual requirements. Plans unique to PVNGS or changes to previously approved PVNGS plans must be approved by the project QA manager, as provided by the Project Quality Program Manual. Neither the inspector nor anyone above him in the chain of command is responsible for the cost/schedule impact of project delays or expense caused by deficiencies the inspector may discover in inspected materials. The performance of the inspector is evaluated solely by the field services manager and/or his staff.

17.1B.1.5 Bechtel Western Power Corporation Management

Figure 17.1B-2 illustrates the BWPC organization chart. The BWPC management team, under the direction of the BWPC president, provides effective management direction, administration, and functional guidance to BWPC entities and individuals.

The management team includes the president, vice president and manager of the Los Angeles Office, vice president and manager of International Business Development and Operations, vice president and manager of Domestic Marketing and Business Development Operations, vice president and manager of the San Francisco Office, vice president and manager of the Houston Office, manager of QA, legal counsel, and manager of public relations. Managers have direct responsibility and authority for the functions of their organizations.

17.1B.1.5.1 BWPC Quality Assurance

The BWPC manager of QA is responsible for planning, controlling and managing the QA program. He reports to and receives authority from the BWPC president.

He controls the application and effectiveness of the Bechtel QA program through QA management and project audits of BWPC engineering, procurement supplier quality, procurement, and BCI construction.

The BWPC manager of QA is responsible for assuring that QA has approved the procedures describing the functions, training, and qualification requirements of individuals performing procurement, inspection, and construction QC activities.

The BWPC manager of QA prepares reports of project quality status for distribution to the BWPC president and management. These reports include important quality events, significant items, a comprehensive analysis of problem areas, and the actions taken in their regard.

The project QA manager (PQAM) for the Palo Verde project is assigned by and receives technical and administrative direction from the BWPC manager of QA and the QA manager of projects. The PQAM is responsible for directing and managing the PVNGS quality program.

The Procurement Supplier Quality Manual, describing the functions, training, and qualifications of personnel in procurement inspection, is approved by the BWPC manager of QA.

The quality control training program for the project describing the functions, training, and qualifications of personnel in BCI construction quality control is approved by the BCI chief construction QC and training engineer, after review and acceptance by the project QC engineer (PQCE).

The adequacy of the Procurement Supplier Quality Manual and the quality control training program are selectively evaluated by performing an in-depth review of:

- Basis for determining inspection level and sequence
- Adequacy of inspection methods

The BWPC manager of QA is assisted by the QA manager of projects and is responsible for providing overall management pertaining to QA technical direction to the project. Figure 17.1B-5 illustrates the BWPC QA organization.

The BWPC manager of QA provides technical and administrative direction to the BWPC QA Group which has the following responsibilities:

A. Formulate or review BWPC QA policies for use where necessary to implement or supplement basic QA policy and recommend these for approval by the vice president and general manager

B. Approve QA procedures and instructions that define responsibilities and functions of QA personnel

C. Review, prior to release, quality-related procedures and manuals prepared by departments and projects for conformance to QA policies

D. Formulate audit programs and conduct audits and reviews to assure BWPC management and APS that the QA program conforms with policies and requirements of BWPC, BCI, and APS. Identify the need for corrective action and assure followup

E. Provide periodic reports to the vice president and general manager evaluating the effectiveness of the BWPC quality program and advise of any problems requiring special attention

F. Provide and maintain a qualified and suitably trained staff of QA engineers to carry out required project and staff functions

G. Formulate programs for maintaining the professional competence of personnel within his organization and provide assistance in training and indoctrination programs for BWPC management and engineering personnel whose activities affect quality

H. Participate in quality coordination meetings with responsible BWPC and BCI managers and supervisors of QA and QC.

I. Coordinate the QA, QC, and quality engineering programs within BWPC

The PQAM prepares reports of project QA status. These reports include important QA events, significant items, a comprehensive analysis of problem areas, and the actions taken in their regard. Appropriate action based on the status of project QA activities is taken by the BWPC manager of QA.

17.1B.1.5.2 Bechtel Western Power Corporation Engineering

Figure 17.1B-6 illustrates the BWPC Engineering Organization. The BWPC manager of engineering reports to the vice president and manager of functional operations and provides technical and administrative direction to the Engineering Department. The BWPC manager of engineering is assisted by managers of engineering, engineering managers, chief engineers, and the supervisor of quality engineering. Engineering managers are responsible for the management and technical direction of assigned projects, and for assuring that the projects are provided with adequate personnel and are following prescribed procedures for conduct of engineering activities. Engineering managers provide administrative direction to the project engineering manager (PEM).

The chief engineers are responsible for the technical adequacy of engineering design performed for their respective disciplines. They are responsible for assigning the engineers, designers, and draftsmen required to perform engineering functions within their respective disciplines on projects, and for maintaining an adequate staff of specialists and other support personnel to provide technical guidance to the projects and to perform independent reviews of selected engineering design work. Chief engineers provide administrative and technical direction to the engineers in their respective disciplines.

The supervisor of quality engineering supports the Engineering Department in the preparation and conduct of quality program

functions within the Engineering Department. He provides technical and administrative direction to the quality engineering staff and quality engineers assigned to projects. The supervisor of quality engineering has the following responsibilities:

A. Assists the manager of engineering in preparation of Engineering Department procedures related to the quality program and reviews for compliance to program requirements

B. Provides technical and administrative direction to quality engineers

C. Prepares procedures for conduct of quality engineering functions

D. Provides appropriate indoctrination and training programs for Engineering Department personnel to assure implementation of Engineering Department procedures related to the quality program

E. Represents the Engineering Department in quality coordination meetings.

17.1B.1.5.3 Bechtel Construction, Inc.

Figure 17.1B-7 illustrates the BCI Construction Organization. The BCI manager of construction reports to the BCI president and provides technical and administrative direction to the Construction Department. He is assisted by the construction managers, construction manager services, chief construction engineer, and chief construction QC and training engineer.

Construction managers are responsible for providing overall construction management and technical direction to assigned projects, and for ensuring that projects are provided with adequate personnel and are following prescribed BCI practices and procedures for conduct of construction activities. The chief construction engineer is responsible for providing technical support to the projects.

The BCI chief construction QC and training engineer reports to and receives administrative direction from the BCI manager of construction, and is responsible for planning, directing, and controlling the BCI construction QC program and QC activities in support of project QA program requirements.

The BCI PQCE reports to and receives technical and administrative direction from the BCI chief construction QC and training engineer. Field QC engineers are functionally and administratively responsible to the PQCE. They are responsible for quality witness and inspection verifications of construction and test activities using approved quality control procedures and instructions.

The chief construction QC and training engineer has responsibilities to:

A. Prepare and maintain the Construction Quality Control Manual

B. Approve any special field QC procedures and instruction for the project

C. Hire and assign field QC engineers to the projects

D. Train and certify field QC engineers per ANSI N45.2.6

E. Prepare and/or approve field inspection planning

F. Provide technical and administrative direction to field QC engineers

G. Provide periodic reports to management on the status and effectiveness of the QC program

The activities of BCI construction QC and BWPC QA personnel are independent of construction cost and schedule influences.

The PQAM at the construction site is responsible for directing and managing the project QA program, including the approval of BCI construction QC procedures and instructions prior to use, and the review of QA verification records of compliance to requirements of approved construction inspection instructions and procedures. He is assisted in these responsibilities by QA engineers at the design office and construction site.

17.1B.1.5.4 Bechtel Western Power Corporation Procurement

Figure 17.1B-3 identifies the organization of BWPC procurement. The BWPC manager of procurement reports to the BWPC manager of functional operations and is responsible for providing management of purchasing and administrative direction to procurement supplier quality in accordance with BWPC policies and procedures. The supplier quality supervisor and the procurement operations manager report to the BWPC manager of procurement.

7.1B.1.6 Project Organization and Functions

17.1B.1.6.1 Project Manager

The project manager (PM) reports to the vice president and manager of domestic operations and is responsible for project direction based on the combined BWPC and BCI scope of work, APS requirements, and BWPC policies and procedures. The project manager is the leader of the combined BWPC and BCI project team consisting of the project engineering manager (PEM), the PQAM, the project procurement manager (PPM), the project cost and scheduling supervisor, the field construction manager, and representatives from other Bechtel companies, as required. He provides the necessary direction to the project team to ensure satisfactory performance. Figure 17.1B-8 illustrates the project management organization.

The PM is responsible for the application of the project quality program by the designated departments and for coordinating the activities of project QA and QC to assure that the quality program is implemented in conformance with the quality policies and procedures approved for his project.

The PM is the primary interface with APS and major client vendors. The interface at the project management level concerns matters of establishing, maintaining, and changing the Bechtel scope of work, the project schedule, project costs, and coordinating the quality program. Authority for interface at the project function level concerning technical and QA matters related to the performance of project functions is delegated by the PM to the project team.

17.1B.1.6.2 Project Quality Assurance

The project QA program is implemented through the PQAM. The PQAM is responsible for managing and directing the Palo Verde QA program at the construction site and the design office. The PQAM is assigned by and receives technical and administrative direction from the QA manager/projects. He coordinates with and represents the PM in QA matters. The PQAM supervises the project QA staff, which includes those at the jobsite and at the project home office.

In order to assure that the quality program is sufficiently addressed, the PQAM's duties and responsibilities for the PVNGS include:

A. Review and approval of:

- Material requisitions and specifications for purchase orders and subcontracts
- Subcontractors' QA programs and manuals
- Bid evaluations/selection of project approved suppliers
- Purchase orders and subcontracts
- Selected single-line drawings and P&IDs
- Vendor inspection planning
- Construction work plans and procedures
- Site inspection planning

- Review for reportability and concurrence of nonconformance descriptions and dispositions

B. Coordinate the establishment of the project quality program

C. Overall surveillance of the project quality program and coordination of its implementation

D. Coordinate project quality-related activities of engineering, procurement, and construction and provide necessary interface during audits or inspections by off-project entities of M&QS, ANI, NRC, or regulatory agencies

E. Conduct project surveillance and audit of project quality-related functions and advise management of the status of program implementation

F. Review and provide quality program compliance signoff on project documents described in the Project Quality Program Manual (PQPM), including QA descriptions in safety analysis reports (SARs), subcontractor QA programs, and selected quality verification records packages prior to transfer for prerequisite test, or release for APS preoperational testing.

G. The PQPM delegates the authority to stop work to the PQAM. Stop work action is immediately implemented by verbal notification to the cognizant superintendent and project construction manager. Stop work action is documented on a stop work order, which delineates:

1. Reasons for stopping work

2. Description of the condition that precipitated the stop work action

Distribution of the stop work order includes, as a minimum, the QA manager/projects, project construction manager, PM, and APS. The cognizant superintendent and project construction manager are responsible for implementing the stop work order. Quality assurance verifies that the work has stopped. Activities may proceed after disposition to proceed and/or corrective action has been approved by the PQAM.

H. Identify quality problems, initiate, recommend, or provide solutions and verify implementation of solution through established procedures.

I. Conduct trend analysis program responsive to repetitive problems indicative of ineffective prior corrective action implemented as a result of audit/surveillance findings or SDDR/NCR conditions.

J. Prepares reports for BWPC and BCI management review of PVNGS project quality status. These reports include important quality events, significant items, a comprehensive analysis of problem areas and the actions taken in their regard. Appropriate action based on the status of project QA activities is taken by the manager of division QA.

17.1B.1.6.3 Project Engineering

The PEM provides project direction to the discipline groups and is responsible for the conduct of engineering on the project. He is responsible for ensuring that engineering work under BWPC cognizance is carried out in accordance with the project direction received from the PM and the technical direction received from the engineering manager. Figure 17.1B-9 shows the Project Engineering Organization.

The engineering group supervisors (EGSs) are responsible for the quality and technical adequacy of the engineering work performed under their guidance. The group supervisors receive their technical direction in these matters from the chief engineers for their respective disciplines.

The EGSs are assigned a team of engineers, designers, and draftsmen from their respective chief engineers. The PEM, project engineer (PE), assistant project engineers (APEs), project quality engineer (PQE), EGSs, engineers, designers, and draftsmen comprise the Bechtel project engineering team. This team is responsible for all BWPC engineering design work performed by the project and for checking functions performed on the project. Special design support is furnished to the project by specialty groups. The PE is responsible for coordination of such special design work performed by other than project personnel and for requiring that it be subjected to the same degree of checking and control as that conducted on the project. The PEM is assisted in implementation of the

engineering quality program by the PQE. The project engineering team has the following responsibilities:

A. Prepare calculations, drawings, and specifications which constitute the engineering designs

B. Ensure that drawings, specifications, procedures, and instructions conform to APS requirements and applicable BWPC standards, applicable industry standards, regulatory agency requirements, and the design bases as defined in SARs

C. Prepare specifications for proposed supplier and subcontractor QA programs

D. Establish the need for supplier inspection and review results of same

E. Review and approve design changes and approve non-conformances which include "repair" or "use-as-is" disposition

F. Review drawings, specifications, procedures, test data, manuals, and reports submitted to engineering by suppliers and subcontractors

G. Prepare licensing documents for SAR

H. Conduct work in accordance with Engineering Department procedures authorized for the project

I. Establish the test program requirement where necessary to demonstrate that supplied or procured items will perform satisfactorily in service

17.1B.1.6.4 Project Construction

A BCI project construction manager reports to the construction manager and is responsible for the PVNGS project field construction performance. He is responsible for ensuring that construction work under BCI cognizance is carried out in accordance with the project direction received from the PM. He also is responsible for ensuring that the quality of the work complies with the PVNGS QA program requirements and is properly verified and documented.

The project construction team includes: Superintendents who are in direct charge of the craft; field engineers who perform field engineering, validate nonconformance reports for other than Quality Class Q, and provide technical guidance including in-process control inspection of construction work; field procurement personnel who are responsible for purchase of field procured items and control of materials prior to release for construction; the field contracts administrator who coordinates activities in field subcontracts; the project QA engineer, assigned by and administratively and technically responsible to the PQAM, who is responsible for coordinating the QA program; and PQCE, assigned by and administratively and technically responsible to the BCI chief construction QC and training engineer. The PQCE is responsible for the field QC program, including performance of all quality verification inspection. Project QC is coordinated by the project field construction manager. Figure 17.1B-10 shows the organization of the project construction team.

Project QC is the responsibility of the BCI PQCE whose responsibilities include:

A. Perform all jobsite quality verification inspection

B. Prepare jobsite QC documentation and maintain construction QC records

C. Perform surveillance of subcontractors' quality programs and review of subcontractor's quality verification documentation

D. Provide technical direction to testing laboratories and inspection subcontractors

E. Administer the nonconforming material control systems, validate nonconformance reports for Quality Class Q, and verify acceptance of rework and repairs in accordance with nonconformance dispositions

F. Review supplier quality verification documentation package(s) for completeness and traceability to the item(s)

The PQCE is assigned the responsibility for effective execution of the quality control program at the construction site. The chief construction QC and training engineer, who receives administrative direction from the BCI manager of construction, provides technical and administrative direction to the PQCE for work performance and verification. The PQCE coordinates work scheduling with the project construction manager but does not take direction from him. At no time is the PQCE subjected to

pressures of schedules and cost impact of his inspection findings.

Contractors are assigned first-level responsibility for the quality of their work. Their performance is coordinated and monitored by the BCI field organization. The BCI field QC organization performs the degree of quality verification/surveillance inspection of contractor and documentation performance appropriate for the individual contractor scope of work.

17.1B.1.6.5 Project Procurement

The PPM reports to the PM and provides project direction for procurement activities and coordinates with the project supplier quality supervisor.

Figure 17.1B-11 shows the organization of the project procurement team.

The PPM and project supplier quality supervisor are responsible for:

A. Purchasing

   1. Develop prequalified bid lists

   2. Primary interface with prospective vendors for performing vendor qualification when required

   3. Primary interface with bidders prior to award and, after award, with the vendor concerning matters resulting in purchase order and contract changes

4. Bidding activities, including preparation of the commercial evaluation of bid proposals

B. Procurement Supplier Quality

1. Definition of procurement supplier quality scope of work as required by engineering

2. Coordination of procurement supplier quality inspection services with project requirements

3. Coordinate audits with procurement supplier quality technical services in the conduct of post-award audits of the implementation of suppliers QA/QC programs

4. Preaward surveys of supplier's facilities and QA/QC programs

17.1B.1.6.6 Project Startup Testing

The startup test program is described in section 14.2. The startup test program is conducted in accordance with the QA program described in section 17.2.

17.1B.2 QUALITY ASSURANCE PROGRAM

17.1B.2.1 Scope

The program described in this section is applied to those structures, systems, and components (Q-list items) whose satisfactory performance is required to prevent accidents that may cause undue risk to the health and safety of the public, or to mitigate the consequences of such accidents if they do

occur. These items are defined as safety-related and are identified in table 3.2-1.

17.1B.2.2 Policy

The Bechtel quality program complies with NRC regulations and practices prescribed by ANSI, APS requirements, and BWPC policies. The program assigns the responsibility for quality to the organization performing the work, and includes, as a basic requirement, that individuals responsible for verifying and checking are independent of the individual or group responsible for performing the work. Additionally, independent reviews, audits, and surveillance are provided by individuals who are independent of the organizations responsible for performing the work.

Overall quality policy of the BWPC, approved by the BWPC president, is formulated or reviewed by the BWPC manager of QA, who is independent of individuals responsible for direction or coordination of engineering, procurement, and construction activities, and who reports to management of the BWPC. Quality assurance practices for individual projects are implemented through the PQAM who receives technical and administrative direction from manager of BWPC QA and the QA manager of projects. Project department and BWPC quality practices are subject to audit by QA at various levels.

Design verification includes checking within the project by individuals other than those who perform the original design and review and verification of technical adequacy of designs by

the chief engineers or their technical staff who are independent of the project.

Supplier and subcontractor QC requirements are specified in the procurement specifications by engineering, which requires suppliers and subcontractors to execute appropriate quality programs. Verification of supplier/subcontractor compliance is provided by source surveillance and inspection at suppliers facilities by the Procurement Supplier Quality Department, or by field quality control for onsite subcontractors or by APS personnel or their agent. Also, surveillance and audit of these activities by QA personnel, the Procurement Supplier Quality Department staff, or APS personnel or their agent.

Inspection of construction activities performed directly by BCI includes in-process controls and inspection of the work by formal QC verification inspection activities and audits by QA, supplemented by M&QS personnel as required.

When disputes arise from a difference of opinion between QA/QC personnel and other department personnel (engineering, procurement, QC, and construction personnel) regarding project quality program matters, the final authority rests with the PQAM, subject only to appeal to the BWPC manager of QA by the PM. The PM will assure that the functional department heads are informed of this disagreement and have adequate opportunity to present their position. If the PM agrees with the PQAM, the functional department heads will be informed of the decision and have adequate opportunity to present their position to the manager of BWPC QA.

17.1B.2.3 Program Documentation

The PQPM contains or references the procedures and manuals that comprise the project quality program. This manual is controlled and maintained by the PQAM.

Quality program policy, procedures, and instructions are contained in the documents listed in table 17.1B-1. Copies of Bechtel program documents are available for review by regulatory authorities and APS. Controlled copies of those designated by footnote in the table are available upon request to cognizant regulatory bodies. Controlled copies of project manuals and procedures are made available to APS and, through them, to regulatory authorities when required.

The BWPC and department standard procedures and practices form the basis for the QA program on each nuclear project. These procedures and instructions are contained in standard manuals, modified to meet specific project requirements, and supplemented where necessary by specific inspection plans, work instructions, and check lists.

The method for controlling the distribution of the listed documents is established in each manual. Records shall be maintained identifying the document, the document recipient, and acknowledgment of the receipt of the original issue and subsequent revisions.

These controls require that procedures and revisions are transmitted by letters giving instructions pertaining to the procedures or revisions. This letter also serves as a form to acknowledge receipt. A master file is maintained for records

associated with the procedures, and followup action is taken in 30 days if delinquent manual holders have not responded.

The PQPM is approved by the BWPC manager of QA and PM. The manuals and procedures described in table 17.1B-1 are the basic quality program documents for the project. These manuals are distributed to appropriate personnel who have quality-related responsibilities.

Table 17.1B-2 provides a list of 18 procedures directly related to the 18 criteria of 10CFR50, Appendix B. The total quality program is described in the PQPM.

The project team (refer to paragraph 17.1B.1.6) has the responsibility for preparing and maintaining documentation defining project design criteria and applicable codes, standards, and regulatory requirements. Further, the project team has the responsibility for preparing and maintaining organization charts and documentation defining interface responsibilities among various Bechtel groups and other major non-Bechtel project participants, such as APS and C-E.

17.1B.2.4 Personnel

Responsibilities, education, and experience requirements of individuals involved in quality program-related activities are formally documented in job descriptions that are approved and periodically reviewed by BWPC management. Requirements for education, experience, and proficiency levels are commensurate with the degree of importance of the job assignment (refer to table 17.1B-3).

Bechtel QA and QC personnel participating in the quality program are provided with indoctrination and training covering the standards, policies, and procedures that apply to the specific portions of the work they are performing to assure that suitable proficiency is achieved and maintained.

Table 17.1B-1

BECHTEL QUALITY PROGRAM DOCUMENTS (Sheet 1 of 2)

Document	Originating Authority	Review for QA Policy Compliance	Authorizing Approval	Content
Bechtel QA Manual - ASME Nuclear Components (BQAM-ASME III)[a]	M&QS	BWPC manager of QA	President Bechtel National, Inc. and appropriate authorized code inspection agency	Policies and procedures for overall Bechtel program applicable to ASME work
Procurement Supplier Quality Manual[a]	BWPC manager of Supplier Quality	BWPC manager of QA	BWPC manager of supplier quality	Procurement inspection procedures and standard supplier inspection plans
Nuclear Quality Assurance Manual	BWPC manager of QA	BWPC mana-ger of QA	BWPC president	BWPC policy supplementing and implementing quality policy
BWPC QA Department Procedures Manual	BWPC manager of QA	BWPC manager of QA	BWPC manager of QA	Procedures for conducting BWPC QA activities

a. Available on request to appropriate regulatory bodies.

Table 17.1B-1

BECHTEL QUALITY PROGRAM DOCUMENTS (Sheet 2 of 2)

Document	Originating Authority	Review for QA Policy Compliance	Authorizing Approval	Content
Engineering Department Procedures	Designated individuals	BWPC manager of QA	BWPC manager of engineer-ing	Definition of responsibilities and procedures for conduct of design, design review, and document control in the engineering departments
Project Quality Program Manual	Cognizant project team members	Project QA manager	Project manager, BWPC manager of QA	References to appropriate Bechtel standard procedures and practices, revised and supplemented if necessary to meet specific project requirements
Construction Work Plan Procedures and Quality Control Instructions Manual	Construction/ PQCE	Project QA manager	Project field engineer, project QA manager, PQCE	Responsibilities and practice for construction activities (how the work is performed, inspected, and accepted)
Internal Procedures Manual	Project engineering manager	BWPC manager of QA	Engineering manager	Project design/ interface procedures

Table 17.1B-2

PROJECT QUALITY PROGRAM MANUAL PROCEDURES (Sheet 1 of 5)

Matrix -- Relation to U.S. Nuclear Regulatory Commission 10CFR50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants and American National Standard ANSI N45.2 Quality Assurance Requirements for Nuclear Power Plants PVNGS Units 1, 2 and 3 Job No. 10407			Project Quality Program Manual Procedures									
App. B Sec. No.		ANSI Sec. No	1.0 Project Organization I	2.0 Project Quality ssurance Program Procedures (PQPM) II	3.0 Design Control III	4.0 Procurement Document Control IV	5.0 Instructions, Procedures, and Drawings V	6.0 Document Control VI	7.0 Control of Purchased Matl. Equip. and Serv. VII	8.0 Identification and Cont. of Matl., Parts, and comp. VIII	9.0 Control of Special Processes IX	10.0 Inspection X
I	Organization	3	X						X			
II	Quality assurance program	2	X	X	X	X	X		X			
III	Design control	4			X			X	X	X		
IV	Procurement document control	5				X			X			
V	Instructions, procedures, and drawings	6			X	X	X		X			
VI	Document control	7			X		X	X	X			
VII	Control of purchased material, equipment and services	8				X	X	X	X			X
VIII	Identification and control of materials, parts, and components	9							X	X	X	X
IX	Control of special processes	10							X		X	X
X	Inspection	11							X	X	X	X
XI	Test control	12							X		X	X
XII	Control of measuring and test equipment	13							X		X	X
XIII	Handling, storage and shipping	14							X	X		X
XIV	Inspection, test and operating status	15							X			X
XV	Nonconforming material, parts, or components	16							X			
XVI	Corrective action	17							X			
XVII	Quality assurance records	18			X				X		X	X
XVIII	Audits	19			X			X	X			

BECHTEL QUALITY ASSURANCE DURING

DESIGN AND CONSTRUCTION

Table 17.1B-2

PROJECT QUALITY PROGRAM MANUAL PROCEDURES (Sheet 1 of 5 continued)

Matrix -- Relation to U.S. Nuclear Regulatory Commission 10CFR50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants and American National Standard ANSI N45.2 Quality Assurance Requirements for Nuclear Power Plants

PVNGS Units 1, 2 and 3
Job No. 10407

			Project Quality Program Manual Procedures									
			11.0 Test Control	12.0 Calibration and Cont. of Meas. and Test Equip.	13.0 Handling, Storage, Shipping, and Preserv.	14.0 Inspection, Test, and Operating Status	15.0 Nonconforming Matl., Parts, and Comp.	16.0 Corrective Action	17.0 Quality Assurance Records	18.0 Audits	19.0 Glossary of Terms and Definitions	20.0 QA Requirements for Fire Protection Systems
App. B Sec. No.		ANSI Sec. No	XI	XII	XIII	XIV	XV	XVI	XVII	XVIII	XIX	XX
I	Organization	3						X	X	X	X	
II	Quality assurance program	2					X	X	X	X	X	X
III	Design control	4					X	X	X	X	X	X
IV	Procurement document control	5						X	X	X	X	X
V	Instructions, procedures, and drawings	6						X	X	X	X	X
VI	Document control	7						X	X	X	X	X
VII	Control of purchased material, equipment and services	8			X	X	X	X	X	X	X	X
VIII	Identification and control of materials, parts, and components	9				X	X	X	X	X	X	
IX	Control of special processes	10					X	X	X	X	X	
X	Inspection	11			X	X	X	X	X	X	X	X
XI	Test control	12	X			X	X	X	X	X	X	X
XII	Control of measuring and test equipment	13		X			X	X	X	X	X	
XIII	Handling, storage and shipping	14			X		X	X	X	X	X	
XIV	Inspection, test and operating status	15				X	X	X	X	X	X	X
XV	Nonconforming material, parts, or components	16					X	X	X	X	X	X
XVI	Corrective action	17					X	X	X	X	X	X
XVII	Quality assurance records	18			X	X	X	X	X	X	X	X
XVIII	Audits	19					X	X	X	X	X	X

Table 17.1B-2

PROJECT QUALITY PROGRAM MANUAL PROCEDURES (Sheet 2 of 5)

Procedure No. and Title	Substance
1.0 Project Organization	Describes the organizational structure and responsibilities for the Bechtel quality program during design, procurement, and construction of PVNGS
2.0 Project Quality Assurance Program Procedures (PQPM)	Describes the procedures and guidelines that facilitate control of: quality program procedures; classification of systems, components, and structures; training of personnel whose activities affect quality; and reporting the effectiveness of the quality program to management
3.0 Design Control	Describes the design process consisting of preparation, review, approval, change control, and distribution of design documents. The process provides for independent review to assure design adequacy, inspectability, testability, and compatibility with the Safety Analysis Report. Also described are the review requirements for the FSAR and ER, and quality- related functions and responsibilities of the project field engineering group
4.0 Procurement Document Control	Describes the method of controlling the quality of supplier furnished material or services

Table 17.1B-2

PROJECT QUALITY PROGRAM MANUAL PROCEDURES (Sheet 3 of 5)

Procedure No.	and Title	Substance
5.0	Instructions Procedures, and Drawings	Defines the governing documents that delineate the responsibilities of engineering, construction, QA, procurement supplier quality, procurement (field), and startup, and the system used as an extension of the Project Quality Program Manual when interpretation of policy/requirements necessitates more detailed procedural instructions
6.0	Document Control	Describes measures for maintaining control of design documents for PVNGS
7.0	Control of Purchased Material, Equipment, and Services	Describes the QA requirements for BWPC and BCI subcontractors and suppliers of materials or services.
8.0	Identification and Control of Material, Parts, and Components	Defines the system of material identification and control for assuring that Quality Class 1 and 2 materials, parts, appurtenances, components, and systems are of the proper configuration, and, when required, are traceable to supporting quality documentation
9.0	Control of Special Processes	Describes the system for the control of special processes, equipment, and personnel
10.0	Inspection	Defines the requirements for supplier and jobsite inspection programs. These requirements apply to structures, systems, and components designated Quality Class Q

Table 17.1B-2

PROJECT QUALITY PROGRAM MANUAL PROCEDURES (Sheet 4 of 5)

Procedure No. and Title		Substance
11.0	Test Control	Describes a system for control of testing for conformance with design disclosures
12.0	Calibration and Control of Measuring and Test Equipment for Construction and Startup	Describes a system of periodic calibration to assure the accuracy of instruments, gages, and measuring devices used in the construction and startup of PVNGS
13.0	Handling, Storage, Shipping, and Preservation	Defines responsibilities to assure adequate handling, storage, shipping, and preservation instructions and procedures are provided for safety-related items
14.0	Inspection, Test, and Operating Status	Describes the requirements and responsibilities of suppliers to identify the inspections, tests, and operating status performed on Quality Class Q materials and equipment
15.0	Nonconforming Materials Parts, and Components	Defines the procedure for identification, control, and disposition of material, equipment, or supplies that do not conform to controlling documents
16.0	Corrective Action	Describes the system that pro-vides corrective action for deficiencies discovered during monitoring of the QA program
17.0	Quality Assurance Records	Defines the controls for design, procurement, supplies, and construction quality-related records

BECHTEL QUALITY ASSURANCE DURING
DESIGN AND CONSTRUCTION

Table 17.1B-2

PROJECT QUALITY PROGRAM MANUAL PROCEDURES (Sheet 5 of 5)

Procedure No. and Title		Substance
18.0	Audits	Defines the procedure for conducting audits of engineering, procurement, construction sup-pliers, and subcontractors' activities performed by or for BWPC
19.0	Glossary of Terms and Definitions	Delineates definitions and terms used in this manual as applicable to PVNGS
20.0	QA Requirements for Fire Protection Systems	Defines the procedures for design, installation, and testing of BWPC or BCI/subcontractor activities consistent with regulatory guidelines and intent of NRC BTP APCSB 9.5-1, Appendix A

Table 17.1B-3

QUALIFICATION AND EXPERIENCE LEVELS

Title	Required Background
BWPC Manager of QA	Advanced degree with 5 or more years of related experience, or engineering degree with 8 or more years of related experience.
QA Manager/ Projects	Advanced degree with 2 to 4 years of related experience, or undergraduate degree with 5 to 7 years of related experience, or no degree with 8 or more years of related experience
Project QA Manager	Advanced degree with 2 to 4 years of related experience, or undergraduate degree with 5 to 7 years of related experience, or no degree with 8 or more years of related experience
Project QA Engineer	Advanced degree with less than 2 years of related experience, or undergraduate degree with 2 to 4 years of related experience, or no degree and 5 to 7 years of related experience
QA Engineer	Advanced degree with less than 2 years of related experience, or undergraduate degree with 2 to 4 years of related experience, or no degree and 4 to 6 years of related experience

NOTE: Qualifications and experience levels described above are to be considered as guidelines and are not absolute when other demonstrated capabilities and managerial characteristics prevail.

Personnel performing inspection, examination, and testing activities to verify quality are qualified in accordance with the established project requirements. Procurement supplier quality personnel are required to meet the requirements established in the Procurement Supplier Quality Manual. Quality assurance personnel and others participating in audits are required to be trained and qualified in accordance with documented procedures. Personnel performing pressure boundary and structural welding and nondestructive examinations are required to meet applicable qualification requirements of the ASTM Code and other appropriate codes and standards.

Personnel assigned to projects are provided with specific indoctrination and training covering project procedures applicable to their work. This is accomplished by general discussion of specific procedures and individual training by project supervisors and staff specialists. Similar programs are employed for indoctrination of individuals assigned to staff and specialist groups.

Formal qualification requirements are applied as follows:

A. Quality Control Personnel

Project QC engineers and home office QC staff and supervision will be qualified in accordance with the project established requirements of ANSI N45.2.6 or SNT-TC-1A, as applicable.

B. Quality Assurance Personnel

Personnel performing audits will be qualified in accordance with the appropriate requirements of ANSI N45.2.23.

C. Procurement Supplier Quality Representatives

A formal training program developed by the Procurement Supplier Quality Department is required for shop inspectors with assigned nuclear plant purchase orders. This program is defined in the Bechtel Procurement Supplier Quality Manual (PSQM) and conforms to requirements equivalent to those of ANSI N45.2.6.

17.1B.2.5 Management Review

Management reviews of the status and adequacy of the QA program are accomplished through periodic reports and presentations by QA management personnel to their respective managers, and through review of QA management audit reports. Meetings at BWPC are conducted by the BWPC manager of QA.

Also, the overall Bechtel program is reviewed annually by individuals outside the QA function. These reviews are performed by or for Bechtel management. The results of these reviews are documented.

17.1B.3 DESIGN CONTROL

The Bechtel design control program is based upon the requirements of ANSI N45.2.11.

Engineering Department policies, design criteria, design guides, standards, procedures, and instructions are employed for control of engineering design work to meet technical and regulatory requirements. These controls identify responsibilities and procedures necessary to ensure that design requirements are correctly translated into the final design. The controls also provide for appropriate documentation to permit review of the process used and results obtained. The controls also specify appropriate quality standards for control of changes and design interfaces.

Design criteria are assembled by the project on a discipline basis during the initial stages of design. These criteria include the criteria contained in SARs and project requirements. The design criteria are maintained current and serve as a basis for preparation of the final design. Departures from BWPC engineering discipline standards require approval by the PEM and appropriate BWPC chief engineer.

The design control program incorporates measures for identification and control of design interfaces among the various engineering disciplines on the project, between the project and technical support groups within BWPC, and of such external interfaces as C-E, APS, other equipment suppliers, and con-tractors performing design work. These measures include identification of technical responsibilities of the various design groups and coordination of design documents among them.

Engineering documents are prepared by project personnel and include drawings, specifications, design analyses, system descriptions, and technical reports. Engineering documents are

checked or reviewed in accordance with project procedures by personnel having technical capabilities commensurate to those of the originating engineer or designer. Engineering group supervisors are responsible for approval of the above engineering documents prepared within their groups. Design work of specialists external to the project is checked, reviewed, and accepted by project personnel qualified in the originating engineering discipline in accordance with project procedures. Design work may also be reviewed/accepted by members of the specialist group qualified in the originating engineering discipline, in accordance with specialist group procedures, and must be accepted by responsible project personnel.

Selected design documents are specified in the Engineering Department Procedures Manual for an additional level of review. This review is the responsibility of the cognizant chief engineer and his staff and is performed by personnel independent of the project team in accordance with Engineering Department procedures. Identification of documents requiring this additional level of control is provided by checklists or matrices prepared by the project during the initial design phase and approved by the cognizant chief engineer. Reviews may take the form of periodic in-process single or multidisciplinary reviews, final review meetings, independent detailed checks, comparison of results with those of the alternate simplified analysis, or comparison with proven standard designs. The specific review employed in each case is determined by the chief engineer and his staff, based upon the

importance of the item to safety, the specific attribute to safety, or its similarity with previously proven designs. Verification of the design review/approval program is provided through appropriate signature on the documents and approval records.

In accordance with ANSI N45.2, Section 4.3, design verification may be provided by tests. The specific test programs and results are reviewed by project and technical staff personnel.

Design changes, including changes recommended by field personnel, are subjected to design control measures commensurate to those applied to the original design. The BWPC policy requires that proposed changes to the design require review and approval by the engineering group that was responsible for the original design. Specifically, changes to design requirements or completed designs produced by project engineering, which may be proposed by vendors, contractors, BCI or others, must be reviewed and accepted by project engineering prior to implementation.

Materials, parts, equipment, and components that are considered "off-the-shelf" are reviewed and selected based on their suitability of application when such items are employed or related to Q-list systems, structures, equipment, or components.

Suppliers are not allowed to make changes from BWPC design or BWPC-approved supplier design documents without approval by BWPC project engineering.

Construction site requests or proposed changes in engineering design are documented by means of change notices or change requests which require authorization by project engineering.

The project engineer may give written authorization to the field engineer to make routine changes.

Design documents, design reviews, records, and changes thereto are distributed to responsible personnel and are filed and maintained through the document control centers as described in subsection 17.1B.6.

Design analyses such as physics, stress, materials, thermal, hydraulic, radiation, and accident are performed when applicable. Accessibility for inservice inspection, maintenance, and repair, as well as delineation of acceptance criteria for inspections and tests, is included.

The Design Criteria Manual is the base design document for the project. It includes BWPC engineering standards, industry standards and accepted design practices, and regulatory agency requirements. The design criteria are maintained current and serve as a basis for preparation of the final design. Design criteria and significant departures from BWPC discipline engineering standards require approval by appropriate division chief engineers, project personnel, and APS.

The QA program provides that design errors and deficiencies which adversely effect safety-related systems, structures, and components are documented and that appropriate corrective actions are taken. The documents used to report deficiencies are:

1. A document review notice (DRN) is used to provide objective evidence of the document review and approval process. It also provides for documenting the resolution of comments.

2. Corrective action requests (CARs), quality audit reports, and nonconformance reports (NCRs) are used to document deficiencies detected during design, procurement, and construction. These documents provide objective evidence for problem identification and corrective action.

3. A deficiency evaluation report (DER) is used to document significant reportable deficiencies, as defined in 10CFR50, Appendix B, Criterion XVI, 10CFR50.55(e), and 10CFR Part 21. The DER provides objective evidence for problem identification and corrective action.

4. A supplier deviation disposition request (SDDR) is used to document deviations from the procurement specifications or contract.

17.1B.4 PROCUREMENT DOCUMENT CONTROL

All procurement actions for Q-list items, or services, include technical specifications and QA requirements established by the project engineering team.

Project engineering is responsible for ensuring that applicable regulatory requirements, design bases, and other requirements such as supplier QA program requirements that are necessary to

obtain and verify quality are included or referenced in the procurement documents. The PQAM reviews and audits procurement documents for conformance to the QA program.

Procurement documents include specific technical specifications for the equipment and services to be furnished by the supplier or subcontractor. The specific codes, standards, tests, inspections, and records to be applied or furnished are included. The procurement documents define requirements for the supplier's QA program by incorporating the appropriate sections and elements of 10CFR50, Appendix B, and the ASME Boiler and Pressure Vessel Code. The procurement document also establishes requirements for source inspection and audit and provides for extension of the applicable requirements to subtier procurements. Requirements for control and approval of supplier nonconformances, and for preparation and delivery of documentation that must be submitted for review and approval are also included.

Changes and/or revisions to procurement documents and procurement documents for spares or replacement parts are reviewed to the same requirements as the original.

The PQAM reviews procurement documents for approval. Disagreements concerning procurement documents are resolved between the PQAM, the PPM, and/or the PE.

Final authority for quality program matters concerning procurement documents rests with the PQAM subject only to the appeal of the PM to the BWPC manager of QA.

The PQPM requires a review of procurement specifications by the PQAM to determine:

A. That the quality requirements are clear and unambiguous

B. That adequate acceptance and rejection criteria have been defined

C. The procurement document has been prepared, reviewed and approved in accordance with the QA program requirements.

(Review and approval is documented by signature on the DRN and retained in the project files.)

Project procedures require that procurement documents for Q items include the applicable requirements for supplier's QA programs consistent with pertinent provisions of 10CFR50, Appendix B, including provisions for preparation, retention, control, maintenance, and delivery of documentation.

Controls and QA requirements for spare or replacement parts for both design office and field procurement are equivalent to those applied to the original equipment procurement. The extent of the controls imposed will be determined by the individual spare part purchased.

17.1B.5 INSTRUCTIONS, PROCEDURES, AND DRAWINGS

The documented instructions and procedures governing the program are identified in subsection 17.1B.2 and table 17.1B-2.

Written, formal instruction from project engineering to construction contractors and suppliers is in the form of engineering specifications and addenda, specification change notices, drawings, drawing change notices, design change packages, and supplier engineering documents. These documents contain references to required procedures and instructions as appropriate and provide necessary acceptance criteria. These documents, when approved by project engineering, provide authorization for construction work.

The requirements, procedures, and instructions for construction QC activities are contained in the Work Plan Procedures/Quality Control Instructions (WPP/QCI) Manual. The elements of this manual include qualifications, indoctrination, certification and training; inspection examination and test control; control of nonconforming items; BCI field procurement control; control of measuring and test equipment; documentation and records control; final inspection and turnover; contractor and subcontractor control.

Bechtel Western Power Corporation procurement documents require suppliers and contractors to submit specified documents to BWPC for review and/or approval prior to start of fabrication or construction. Bechtel Western Power Corporation review of these documents is performed to determine that interfacing design features are compatible with overall design and installation requirements, and that procedures are acceptable.

Verification that work is accomplished in accordance with approved instructions, procedures, and drawings is obtained

through the various levels of surveillance, inspection, and audit described in subsection 17.1B.7.

17.1B.6 DOCUMENT CONTROL

The program documents identified in table 17.lB-1 include requirements for document control. This includes procedures that provide engineering, purchasing, procurement inspection, and preoperational testing control for review, approval, and release of documents and changes thereto.

Document control centers for the project are set up in the project engineering office and the jobsite. Controlled documents (drawings, specifications, vendor data) are released, received, controlled, and distributed through these centers.

Document control centers contain approved drawings and specifications prepared by project engineering. These documents are issued to organizations responsible for performing the work and to those responsible for inspection. Control registers identifying the drawings and specifications and their current status are issued periodically. Bechtel Western Power Corporation procurement supplier quality representatives receive copies of transmittal notices listing applicable documents and their approval status. These lists are used to verify current status of supplier documents. Transmittal forms are employed to forward drawings and specifications which require that signed acknowledgment receipts must be returned to the document control centers.

Changes made to approved documents are reviewed and approved in accordance with established procedures which provide that changes which affect the design of safety-related structures, systems, or components are reviewed and approved in the same manner as the original issue or by assigned alternate qualified personnel.

Changes may not be implemented without appropriate documented approvals. The methods for implementing approved changes into design and construction documents are defined in project design control procedures. Controlled change notices are used to identify and implement design changes. Incorporation of approved change notices into the governing base document is performed at the direction of APS.

Vendor-submitted documents such as drawings, specifications, procedures, manuals, and other data are controlled through the use of the control logs which provide identification and status of vendor documents. Transmittal forms used to return documents to the vendor show approval status of the evaluated vendor documents. BWPC shop inspectors are informed as to the current status of vendor documents and copies of applicable vendor documents are formally transmitted to the construction site with provision for receipt acknowledgment.

The project construction organization at the jobsite employs standard prescribed procedures for control of the distribution of approved drawings, specifications, and other documents. These procedures include provisions for field receipt, review, and distribution of approved documents and for appropriate marking or destruction of obsolete documents.

The transmittal of drawings and specifications is controlled in accordance with procedures which include provisions to prevent inadvertent use of obsolete or superseded documents.

Documents such as instructions, procedures, specifications, drawings, procurement documents, inspection plans, inspection records, supplier manuals, nonconformance reports, supplier deviation disposition requests, corrective action reports, memoranda, and correspondence are included in document control.

As part of their quality verification inspection program, field QC ensures that construction work is not performed if current approved design documents are not available.

Control of documents in the engineering and construction offices are regularly audited by project QA personnel.

17.1B.7 CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES

Bechtel Western Power Corporation may obtain material from APS that has been purchased, received, and stored by APS in accordance with section 17.2. In these cases the material will be considered acceptable based on APS's procurement, control, receipt inspection, and storage control without further receipt inspection, document review, etc., by BWPC.

17.1B.7.1 Supplier Evaluation and Selection

Suppliers shall be evaluated to ensure their capability to meet technical and quality requirements of the procurement document in accordance with paragraph 17.2.7.2. Procedures and instructions within BWPC assure that only vendors that are

determined to be qualified in accordance with this process are selected for procurement of safety-related material, equipment, and services.

17.1B.7.2 Supplier Inspection

Project engineering identifies commodities requiring source inspection and audit. Procurement or QA may recommend additional items when justified. Manufactured or fabricated Q-list items such as vessels, heat exchangers, pumps, piping subassemblies, valves and electrical panels are included in source inspection and audit programs. Items that are typically excluded from the source inspection program include materials and standard manufactured products (catalog items) where required quality can be adequately determined by receipt inspection or post-installation checkout or test. Also excluded are materials where important physical and chemical properties are independently verified on samples taken at the supplier's facilities or at the jobsite.

APS is responsible to coordinate source inspection and surveillance activities. When source inspection is a requirement of a safety-related purchase order, it shall be conducted in accordance with an APS-approved inspection plan. This plan shall provide for identification of witness and hold points and identify the examination and tests which are selected to be witnessed. The source inspection or surveillance will be performed by qualified personnel.

Reports documenting inspections performed, tests witnessed, and discrepancies observed are prepared by the source

inspection/surveillance personnel and distributed to appropriate project personnel. Source inspection/surveillance personnel are responsible for assuring that inspected material, equipment, and specified documentation conform to the requirements of the procurement documents prior to releasing inspected items for shipment. The source inspection surveillance personnel has the authority to refuse release of nonconforming material.

17.1B.7.3 Receiving Inspection

All items are examined on receipt at the jobsite for identification, quantity, and damage. These examinations are performed by the field QC engineers with the assistance of field engineering and the field procurement group. For items not subject to source inspection, appropriate examinations or tests are performed. Examinations and tests are performed in accordance with WPP/QCIs under the supervision of field QC.

Documentary evidence that the item conforms to procurement documents is on file and available to those concerned.

Items received without certifications of conformance and other required supporting documentation are judged nonconforming and are withheld, identified as nonconforming, and segregated until documentation is received. Items determined to have discrepancies are reported on an NRC processed in accordance with applicable WPP/QCIs.

Where complete documents verifying acceptance or certification cannot be sent to the jobsite with shipment, documentation will

be available at the site which allowed shipment without the specified documentation. This equipment will be properly identified as "nonconforming," and may be conditionally released for installation providing that an approved "interim" disposition on an NCR identifies the limitations and conditions for locating the item in place.

Complete quality verification record packages are requested for delivery prior to or with the shipment. Documented control measures, with provisions for followup, are provided to expedite receipt of quality verification packages which are delayed beyond the time of shipment. Completed quality verification record packages received at the construction site are checked for completeness and traceability by QC and are audited by QA. Project engineering may elect to have selected quality verification documentation delivered to the design office for review by so specifying in procurement documents.

17.1B.7.4 Supplier Audits

Audits of suppliers shall be coordinated by APS and conducted in accordance with requirements established in section 17.2.

17.1B.8 IDENTIFICATION AND CONTROL OF MATERIALS, PARTS, AND COMPONENTS

Identification requirements are determined by engineering during the design process and are included in the Technical Specifications and drawings. Items that require traceability are so designated. Procurement documents also provide requirements for identification of purchased items.

Parts, components, subassemblies, equipment, and partially fabricated items may be identified by markings such as stenciled or etched markings, strip marking, imprinted tape, color coding, and tags. Large quantities of small items may be identified to heat, batch, lot, or specification by applying markings to bags, bins, tanks, or other suitable containers.

Identification of installed or assembled items may be transferred to inspection records or as-built documents as required. Markings which are hidden or subject to obliteration during fabrication or installation shall be included on as-built records.

Organizations receiving materials, parts, or components verify that they are properly identified and are accompanied by appropriate documentation. Provisions are made for handling and storing items to retain identification.

17.1B.9 CONTROL OF SPECIAL PROCESSES

Special processes requiring procedures and/or personnel qualification beyond those required by the ASME Code are identified in specifications by reference to appropriate industry codes and standards, where available, or by specific identification in the specification. Supplier and subcontractor special process qualification data are subject to review and/or approval by BWPC.

Special processes performed by BCI, including welding, nondestructive examination, protective coating, and cleaning and flushing, are performed by qualified personnel in

accordance with qualified special process procedures. The requirements for welding and nondestructive examination comply with applicable portions of the ASME Boiler and Pressure Vessel Code, AWS Standards, and SNT-TC-1A and supplements, as applicable. Cleaning and flushing procedures and personnel qualifications conform to the requirements of ANSI N45.2.1.

Other special processes or work operations identified by the nuclear steam system supplier or project engineering are properly qualified and performed by trained personnel in accordance with specified technical requirements.

Current qualification records of procedures, equipment, and personnel are maintained at the jobsite. Controls are provided to ensure that personnel qualification records are regularly reviewed and appropriate requirements for requalification are implemented. Implementation of these controls is verified by field QC personnel and is audited by QA with the assistance of the M&QS Department.

17.1B.10 INSPECTION

As described in subsection 17.1B.7, supplier and subcontractor programs are subject to source inspection as applicable. The inspection of BCI construction work includes inprocess surveillance, examination, and inspection by field engineering personnel who are independent of direct construction craft supervision, and formal quality verification inspection and testing by field QC personnel who are independent of field engineering and craft supervision. Field engineering receives day-to-day supervision from the project construction manager.

Field QC engineers are assigned by and receive technical direction from the chief construction QC and training engineer in the division or area office. The overall inspection program is monitored and audited by resident construction site QA personnel.

Project field engineering provides technical guidance and surveillance of construction work which includes in process examination. The field engineer does not perform acceptance inspection or provide inspection results to QC inspection. Field QC is responsible for quality verification inspection and testing of safety-related, Q class equipment, systems and installations.

Inspection and testing activities are performed in accordance with procedures contained in the Project WPP/QCI Manual. Inspection planning is prepared for receiving inspection, construction and installation inspection, and testing. Inspection planning considers:

- Suitable environmental conditions
- Quality characteristics to be inspected
- Individual or groups responsible for performing the inspection
- Acceptance and rejection criteria
- Suitable equipment for inspections
- Description of the method of inspection

- Evidence of completion and certification of inspection operation
- Results of the inspection operation
- Verification that all inspection operations are complete and acceptable

Inspection of modifications, repairs, and replacements is performed in accordance with the original design and inspection requirements, or acceptable alternatives.

The Construction WPP/QCI Manual includes procedures for certifying all grades of inspectors, including specified renewal periods. The procedure is administered by the PQCE, monitored by the chief construction QC and training engineer, and audited by the PQAM.

The Procurement Supplier Quality Manual provides for a formal system of certifying all grades of BWPC source inspectors, including specified renewal periods. This system is administered by the Procurement Supplier Quality Department and audited by the PQAM.

17.1B.11 TEST CONTROL

Tests required to verify acceptance of completed installations, equipment or systems are defined in engineering drawings, specifications, or test procedures. Construction tests are an extension of construction inspection procedures. Construction testing is conducted to demonstrate that the equipment installation is complete and that the electrical systems are

properly wired. Test plans or procedures, test reports, and records are used to demonstrate that completed tests have met test objectives. Written test procedures include:

A. Instructions for conducting the test and test equipment to be used

B. Test prerequisites which include, but are not limited to, the following:

   1. Calibrated instrumentation

   2. Adequacy of the test equipment

   3. Requirement for trained, qualified, and/or licensed/certified personnel

   4. Preparation, condition, and completeness of item to be tested

   5. Suitable environmental conditions

   6. Where applicable, mandatory inspection hold points, for witness by APS, contractor, or authorized inspector

   7. Provisions for data collection and storage

   8. Acceptance and rejection criteria

   9. Methods of documenting or recording test results

System cleaning, flushing, instrument and control settings, and performance demonstration are part of the startup prerequisite test program. Prerequisite/preoperational testing is under the control of APS. Bechtel Western Power Corporation startup

engineers provide assistance to APS as described in subsection 14.2.1.

17.1B.12 CONTROL OF MEASURING AND TEST EQUIPMENT

The BCI field QC program provides for calibration, maintenance, and control of measuring and test equipment used in the construction, testing, and QC inspection activity. Calibration is conducted using certified equipment having known valid relationship to nationally recognized standards. Procedures provide for unique identification of each measuring or test equipment item requiring calibration or checking. Calibration schedules are established based upon the amount of usage, accuracy, and type of equipment. Procedures provide for identification of calibration status by tags, labels, or markings applied to the item.

The identification of measuring and test equipment used in performing tests is entered in the test records when the validity of the test result is dependent on the accuracy of the test equipment. Also, whenever inspection, test, or measuring equipment is found to be uncalibrated or out of calibration limits, all items that have been inspected, tested, or measured since the last recorded calibration of the equipment will be evaluated to determine acceptability.

The evaluation of performance and effectiveness of the control of measuring and test equipment is verified by supplier surveys and audits performed by BWPC procurement supplier quality or APS personnel. In addition, field QA surveillance and audit of subcontractors and BCI are performed. Field QC is responsible

for verifying the current calibration status and proper functioning of equipment prior to use.

17.1B.13 HANDLING, STORAGE, AND SHIPPING

The requirements for packaging, marking, and shipping are included in procurement documents for Q-list items, which meet the intent of ANSI N45.2.2.

Procedures for equipment and system cleaning, flushing, and cleanness control are contained in WPP/QCIs which conform to the appropriate requirements of ANSI N45.2.1.

Special handling, storage, shipping, and preservation requirements are identified in technical specifications that provide, or require suppliers or subcontractors to provide, the required procedures and instructions. The packaging, handling, and shipping practices of the suppliers are subject to review prior to shipment, to verify compliance with requirements defined in procurement documents.

Materials and equipment received at the construction site are inspected, stored, and maintained in accordance with standard field procedures supplemented by special procedures and requirements issued by project engineering or furnished by suppliers. Materials and equipment are physically inspected upon arrival at the jobsite, and moved into prescribed storage areas or to the installation site if adequate protection is available. Direct movement to the installation site is permitted, to eliminate multiple handling provided direct installation is compatible with the construction schedule.

Special environmental conditions such as inert gas, specific moisture content levels, and temperature levels prescribed in procedures or specifications are controlled at the site.

Procedures are provided, as appropriate, for handling special items and for the care and maintenance of material handling equipment. Otherwise, standard material handling methods are used to ensure care and protection from physical damage. Special handling instructions and procedures for major or special items are included in procedures reviewed by project engineering or BCI specialists. Personnel responsible for handling major or special items are qualified to the extent required by these special handling instructions and procedures. Preparation and performance of rigging operations involving major equipment such as reactor vessels, steam generators, and pressurizers are witnessed by BCI rigging specialists.

Appropriate requirements are achieved through these approved procedures, through inspection planning and QC instructions.

Assurance that special handling and cleaning is accomplished as specified is provided by engineering review and approval of procedures, field QC inspection of special handling, and cleaning and audits of these activities by QA.

17.1B.14 INSPECTION, TESTS, AND OPERATING STATUS

Construction procedures and inspection plans provide for identification of inspection status of receipt inspection or work-in-process by using work sequence plans, inspection records, tags, markings, or other devices compatible with the

item, system, or operation being inspected or tested. Progress of work is entered in records, and status identification is changed to reflect current conditions. At the completion of construction, a tagging system is employed to visually indicate the operating status of equipment and systems that are in test or rework. Records of test results are recorded and maintained in the site document control center.

Procedures and instructions include identification of the individuals or groups responsible for application and removal of status indicators.

Work is performed and inspected according to prescribed sequences to assure quality. Tests, inspection points, or other critical operations may be bypassed only when the element can be inspected at a later time in the sequence and a later hold point exists. Bypassed inspections/operations or tests are concurred with by the signature approvals consistent with the original approvals. In these cases, the inspection point is picked up at a later date. If physical control of the item is required to prevent its inadvertent use or installation beyond the point where the inspection can be performed, the item is tagged as nonconforming and conditionally released with limit placed on future work operations.

Procedures and instructions include identification of individuals or groups responsible for application and removal of status indicators, and for documenting the bypassing of inspections, tests, or other operations. Participation of QA personnel is as follows:

A. Quality assurance reviews and accepts QC instructions, receiving, and construction inspection planning and changes thereto.

B. Quality assurance assures, through audits, that the status of items is correct and maintained throughout construction and inspection activities.

C. Quality assurance assures, through audits, that required inspections of test operations are performed, test results are recorded, and that the construction, installation, and inspection status of items is known and current at all times.

Nonconformances discovered are clearly identified and controlled as described in subsection 17.1B.15. Nonconforming items are required to be identified, tagged, and/or segregated. No further work can proceed on any nonconforming item until an approved disposition is implemented. Suppliers and subcontractors are required to have a BWPC-approved program for handling nonconformances. Activities at the site will comply with standard QC procedures which assure adequate control of nonconformances. Both supplier and subcontractor activities regarding nonconformances will be audited by BWPC QA.

17.1B.15 NONCONFORMING MATERIAL, PARTS, OR COMPONENTS

Suppliers and subcontractors are required to advise BWPC of all nonconformances from procurement documents or BWPC-approved designs for which the recommended disposition is "repair" or "use-as-is." Bechtel Western Power Corporation reserves the

right to accept or reject the disposition. Bechtel Western Power Corporation requires suppliers to submit proposed repair procedures for nonconformances for approval by project engineering and review by the project QA engineer prior to their use. Reports of nonconforming conditions are prepared by the supplier, BWPC procurement supplier quality representatives, or project engineering to ensure complete and adequate documentation. Copies of completed NRCs are forwarded to the jobsite prior to, or included with, the documentation submitted with the equipment. Inspection or surveillance personnel verify inclusion of approved NCRs at the time of equipment release when source inspection/surveillance is required.

Nonconformances discovered during receiving inspection or construction activities (jobsite) are controlled and documented in accordance with standard project QC procedures. The procedures provide for identification, documentation, and control of the nonconforming item. The authority for approval of the proposed resolution and documentation of reinspection results is also provided.

Important elements of the procedure include requirements for:

A. Tagging and segregation whenever practical due to size, quantity, and complexity of the item

B. Determination of interim disposition by project engineering and field QC

C. Approval by project engineering of "repair" or "use-as-is" dispositions prior to correcting significant or unique nonconformances

D. Advising project engineering after implementation of standard approved repair procedures

E. Monthly review of completed NCRs by QA to trend analysis requirements established by the PQPM, which prescribes conditions significant to quality that require corrective action

F. Participation of ASME-authorized inspector for nonconformance disposition on code-covered items

G. Providing the quality systems and engineering manager copies of all "repair" or "use-as-is" NCRs

Repair and reinspection instructions must be prepared and submitted for project engineering approval before repair may proceed. These repair and reinspection instructions will be reviewed to assure that the acceptability of repair is verified by field QC reinspection of the item as originally inspected or by a method at least equivalent. Suppliers are contacted when necessary to provide input to the reinspection instructions as required. Quality assurance will audit for compliance.

Quality assurance periodically reviews and monitors supplier, onsite subcontractor, and BCI NCRs for the identification of significant conditions adverse to quality, the cause of the condition, and corrective action taken.

These are documented and reported to appropriate levels of management. Verification by the PQAM that corrective action to preclude recurrence has been taken is reported to QA management and project management for impacts on other phases of the project.

Nonconformance reports are reviewed by project engineering and QA to determine if the nonconforming condition is potentially reportable under the requirements of Federal Regulations 10CFR50.55(e) or 10CFR Part 21. Project procedures provide for reporting of significant deficiencies to the licensee and substantial safety hazards to the Nuclear Regulatory Commission.

17.1B.16 CORRECTIVE ACTION

The corrective action program provides procedures for prompt identification of conditions adverse to quality that may require corrective action.

Within the Bechtel program, the identification of situations that may need corrective action is accomplished through review of nonconformance reports, procurement supplier quality audits of supplier activities, and QA surveillance and audit program. Corrective action is controlled by project procedures and documented by means of corrective action reports. The procedures provide for the following:

A. Identifying and reporting by any member of the project team those conditions that warrant corrective action including proposed recommended actions

B. Determination of cause and identification of corrective action to be taken by the responsible organization

C. Reporting cause and corrective action to BWPC and APS management

D. Final verification by the PQAM that corrective action has been taken

E. Review by QA management, project management, and project engineering of the implication or effect on other work

F. Consideration for "stop work" by the PQAM, when continued operations will result in unsafe conditions/further nonconforming work or extensive evaluation.

This program also provides for evaluation of conditions reported by project management and APS that may require reporting to the NRC by APS in accordance with the requirements of 10CFR50.55(e).

17.1B.17 QUALITY ASSURANCE RECORDS

Records produced as a result of the quality program are prepared and maintained by BWPC, BCI, suppliers, and subcontractors as their work is being performed. The types of records include approved procedures, procurement records, specifications, drawings, qualifications, quality verification records, operating logs, results of reviews, inspections, tests, audits, and material analyses.

Project engineering records are retained by the project engineering document control centers as design work is performed. It is normal practice to microfilm documents at regular intervals, unless duplicate copies are available at an alternate location. Provisions for collection of completed records in the design office, or at the jobsite, and the criteria for storage and retention recommended in ANSI N45.2.9 are applied to permanent quality records.

Documentation of the design review process is prepared and maintained in accordance with subsections 17.1B.3 and 17.1B.6. Design changes may be issued on an interim basis by means of change notices. However, these are ultimately incorporated in revisions to the governing documents, unless the change is a limited waiver (e.g., "use-as-is" on an NRC) which does not generally apply to the design document. Copies of released drawings, specifications, technical reports, and similar documents are placed in engineering or construction document control center files, and submitted to the client. At the completion of engineering, final copies of these records are provided to the client. At a specified time, mutually agreed to by APS and BWPC, control of original design calculations and analyses will be turned over to APS. APS will maintain and retain the original documentation in accordance with the APS QA operations program for document control and retention. Bechtel Western Power Corporation will no longer be responsible for control of released documents.

Supplier records which identify "as-built" status and verify the quality of their work are requested from the supplier and

are placed in construction site quality record files. In some instances, with the agreement of BWPC and APS, suppliers are permitted to retain custody of certain records, if retention procedures and storage facilities are adequate and access is provided to APS.

Completed quality verification records including NRCs for "repair" and "use-as-is" dispositions are placed in quality record files. Appropriate regulatory groups and APS are provided access to these files while they remain in BWPC custody. At the completion of BWPC and BCI assignments, these files are turned over to APS Nuclear Records Management Group in accordance with procedures established by the client.

The requirements and guidelines for receipt, control, and retention of permanent QA records contained in ANSI N45.2.9 are employed for the control of construction site quality record files. The recommended retention periods of ANSI N45.2.9 or the requirements of ASME Boiler and Pressure Vessel Code, Section III, as applicable, are followed for BWPC and BCI-produced or acquired records. Supplier's nonpermanent records are generally retained by the supplier. Retention periods for these records will be established based upon the date of shipment or acceptance of the item and not the commercial operating date of the power plant.

The BCI WPP/QCI Manual will require that the following listed information be noted in inspection and/or test records:

- A description of the type of operation

- Evidence of completion of each construction inspection, or test operation
- The results of the inspection or test
- Information related to nonconformance(s)
- Inspector or data recorder
- Date
- Acceptance or nonconformance report number

Quality assurance will audit for compliance during their review of these documents.

For suppliers, source inspection/surveillance personnel, during source inspection, will assure that suppliers' inspection and test records contain the listed information. Examples of these reports and records are submitted with the supplier's QA program. Quality assurance engineers will audit suppliers records to assure they contain the listed information.

17.1B.18 AUDITS

A comprehensive program of audits is conducted by BWPC covering the various activities of the QA program.

The BWPC audit program includes scheduled or unscheduled audits conducted by project QA personnel at the construction site or home office as well as periodic team audits performed by personnel independent of project activities. Audit activities include the following:

A. Audits of project engineering activities by office QA personnel assigned to the project. These audits are planned, scheduled, and documented. Results are reported to the PEM, PM, PQAM, and the QA manager of projects. Audit results are also submitted to APS.

B. Audits of BCI field construction, and BWPC resident engineering. and subcontractor activities by resident field QA personnel assigned to the project. These audits are planned, scheduled, and documented. Results are reported to the site construction manager, PM, QA manager of projects, and to APS.

C. Audits of suppliers are coordinated by ANPP and conducted in accordance with requirements established in section 17.2.

D. Audits of project engineering, design, procurement, construction, and QC activities at the jobsite by QA audit teams under the direction of the BWPC manager of QA, assisted by M&QS specialists and others, as required. These audits are conducted at least annually and results are reported to the management of the function audited, cognizant project management, BWPC management, and the BWPC manager of QA.

E. Audits of BWPC Engineering Technical Staff and services activities are performed on an annual basis under the direction of the BWPC manager of QA. These audits cover those groups doing design and/or review

outside of direct control of the project engineer. Results of these audits are reported to the manager or supervisor of the function audited, affected project management, BWPC management, and BWPC manager of QA.

F. Audits of procurement and M&QS are conducted annually by QA personnel under the direction of the BWPC manager of QA. Results of these audits are reported to cognizant management of the audited group, BWPC management, and the BWPC manager of QA.

Audit programs include provisions for identification of deficiencies, determination that corrective action is defined, and followup to verify that corrective action has been taken and is effective. Audits include selective review of procedures, work practices, and examination of items and records. Records of audits are available to projects.

In accordance with the provisions of ANSI N45.2.12, the audit program is carried out to verify compliance with all aspects of the QA program which is defined in documents listed in table 17.1B-1. Specifically, the audit program includes audits of:

A. BCI construction subcontractor and BWPC resident engineering site activity which affect plant safety

B. The preparation, review, approval, and control of designs and specifications

C. Request for proposals and evaluations of bids

D. The preparation, review, approval, and control of procurement documents

E. The preparation, review, approval, and control of instructions, procedures (including test procedures), and drawings

F. Indoctrination and training programs

Audit data are derived from project design office QA audits, procurement supplier quality audits of suppliers, QA audits of construction, and subcontractor activity at the site.

The PQAM is responsible for analysis of Bechtel audit data to determine the effectiveness of the QA program. The results will be reported to QA management and project manager. The data are also reviewed to determine if a quality trend has been established which requires corrective action.

Audit results are sent to and reviewed by responsible management. Corrective action is taken by the management of the group audited. Project audit programs include provisions that corrective action is defined and scheduled completion dates determined. Reaudits are conducted to verify that corrective action has been taken and is effective.

17.1C COMBUSTION ENGINEERING (C-E) QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

The Combustion Engineering Quality Assurance Program is described in topical report CENPD-210A Revision 3, “Quality Assurance Program” dated November 1977.

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17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

Quality Assurance requirements for the Operations Phase are described in the PVNGS Operations Quality Assurance Program Description (QAPD).

CHAPTER 18

TMI-2 LESSONS LEARNED IMPLEMENTATION REPORT

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18. TMI-2 LESSONS LEARNED IMPLEMENTATION REPORT

The Palo Verde Nuclear Generating Station Lessons Learned Implementation Report (LLIR) addresses those TMI-related items approved for implementation by the Commission as published in the "Clarification of TMI Action Plan Requirements," NUREG-0737, November 1980 and Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability", December 17, 1982 (Generic Letter 82-33).

Each recommendation is addressed, as it applies to the Palo Verde Nuclear Generating Station (PVNGS) design and operation, in the following manner:

(1) Responses reference the existing PVNGS design as presented in the PVNGS Final Safety Analysis Report (FSAR) as amended, the Combustion Engineering, Inc. (C-E) Standard Safety Analysis Report - Final Safety Analysis Report (CESSAR) as amended, and the PVNGS Emergency Plan.

(2) Future work performed and modifications installed will be summarized as revisions to this report.

(3) This report includes requirements from NUREG-0737 and Supplement 1 to NUREG-0737 related to PVNGS.

(4) The NRC positions presented herein are from NUREG-0737 and Supplement 1 to NUREG-0737 unless otherwise noted.

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18.I OPERATIONAL SAFETY

18.I.A OPERATING PERSONNEL

18.I.A.1.1 SHIFT TECHNICAL ADVISOR

NRC Position

Each licensee shall provide an on-shift technical advisor to the shift supervisor. The shift technical advisor (STA) may serve more than one unit at a multiunit site if qualified to perform the advisor function for the various units.

The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and shall have received specific training in the response and analysis of the plant for transients and accidents. The STA shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the STAs that pertain to the engineering aspects of assuring safe operations of the plant, including the review and evaluation of operating experience.

PVNGS Evaluation

Two STAs will be provided onsite in accordance with the requirements of UFSAR Section 18.I.A.1.3, as advisory technical support to the shift manager (shift manager is equivalent to the shift supervisor position referred to in the NRC position above) in the areas of thermal hydraulics, reactor engineering, and plant analysis with regards to operational safety (see Technical Specification 5.2.2.f).

Normal duties of the STA shall include:

- The diagnosis of accidents and plant transients to determine how they may affect the engineered aspects of plant design and safety features
- The review and evaluation of applicable operating experience
- Other functions as assigned, or requested by the shift manager, which pertain to control room activities and engineering aspects that ensure safe operation of the plant.

Organizationally, the STA will report through the STA section leader for STA functions to the department leader, operations support.

The STAs shall have, as a minimum, a Bachelor's Degree in an engineering or science discipline.

The STA training program is discussed in subsection 13.2.1.

18.I.A.1.2 SHIFT MANAGER ADMINISTRATIVE DUTIES

NRC Position (NUREG-0694)

Review the administrative duties of the shift supervisor and delegate functions that detract from or are subordinate to the management responsibility for assuring safe operation of the plant to other personnel not on duty in the control room.

PVNGS Evaluation

The responsibility and authority of the unit shift manager (shift manager is equivalent to the shift supervisor position referred to in the NRC position above) is delineated in paragraph 13.1.2.6.1. The administrative duties of the unit

shift manager are defined in the PVNGS Station Manual and are in accordance with the guidance of the November 9, 1979, NRC letter from D. B. Vassallo to all pending construction permit applicants. Administrative functions which detract from or are subordinate to plant operational safety are assigned to other personnel who do not direct operational functions.

Additionally, the PVNGS operations organization includes a senior licensed unit control room supervisor for each unit, in addition to the assigned unit shift manager. The unit control room supervisor performs many of the administrative functions which typically would be performed by the unit shift manager.

The PVNGS operations organization also includes available personnel during the day shift on week days whose function is to assume administrative functions that might otherwise detract from the ability of shifts organization to devote full attention to the operation of the plant. Refer to subsection 18.I.C.3 for a further discussion of unit shift manager responsibilities.

18.I.A.1.3 SHIFT MANNING

NRC Position

(1) Limit Overtime

Administrative procedures shall be established to limit maximum work hours of all personnel performing a safety-related function.

(2) Minimum Shift Crew

The minimum shift crew for a unit shall include three operators, plus an additional three operators when the

unit is operating. Shift staffing may be adjusted at multiunit stations to allow credit for operators holding licenses on more than one unit.

In each control room, including common control rooms for multiple units, there shall be at all times a licensed reactor operator for each reactor loaded with fuel and a senior reactor operator licensed for each reactor that is operating. There shall also be onsite at all times an additional relief operator licensed for each reactor, a licensed senior reactor operator who is designated as shift supervisor, and any other licensed senior reactor operators required so that their total number is at least one more than the number of control rooms from which a reactor is being operated.

PVNGS Evaluation

(1) Limit Overtime

The following discussion related to operations overtime is historical in nature. 10 CFR 26, *Fitness for Duty Programs*, was amended by a Final Rule published March 31, 2008 in the Federal Register (73FR16966). The Final Rule superseded the NUREG-0737 based operator overtime controls.

PVNGS administrative controls to limit personnel fatigue reflect the additional requirements of the Final Rule, which applies to the operating staff, security and other personnel who perform duties identified in the rule (10 CFR 26.205, *Work hours*).

In accordance with NRC Generic Letter No. 82-02 PVNGS administrative procedures are in effect that limit the maximum hours to be worked by personnel performing safety-related functions. The personnel affected by this requirement include senior reactor operators, reactor operators, radiation protection technicians, auxiliary operators, and key maintenance personnel. Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a nominal 40-hour week while the plant is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance, or major plant modifications, on a temporary basis, the following guidelines shall be followed (this excludes the STA and PVNGS Fire Department working hours):

1) An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.

2) An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any 7-day period, all excluding shift turnover time.

3) A break of at least 8 hours should be allowed between work periods, including shift turnover time.

4) Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Recognizing that very unusual circumstances may arise requiring deviation from the above guidelines, such deviation shall be authorized in advance by personnel at the director level or designees in accordance with approved administrative procedures and with documentation of the basis for granting the deviation. The paramount consideration in such authorization shall be that significant reductions in the effectiveness of operating personnel would be highly unlikely.

Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the personnel assigned responsibility for authorizing deviations from the working hour guidelines. This review is to ensure that excessive hours have not been assigned and that routine deviation from the working hour guidelines do not occur.

In addition, procedures encourage licensed operators at the controls to be periodically relieved, when conditions permit, and assigned other duties while away from the control board.

Staff working hours are also addressed in the administrative Technical Specification.

(2) Minimum Shift Crew

The minimum requirements for shift crew per unit are identified in table 18.I.A-1.

Table 18.I.A-1

MINIMUM SHIFT CREW COMPOSITION

Position	Number of Individuals Required to Fill Position	
	Mode 1, 2, 3, or 4	Mode 5 or 6
SM	1	1
SRO	1	None
RO	2	1
AO	2	1
STA	(a)	None

(a) A minimum of two STAs are required for the site. See NRC SER dated March 19,2004.

SM - shift Manager (shift manager is an equivalent position to the shift supervisor position referred to in the NRC position above) with a senior reactor operator's license

SRO - Individual with a senior reactor operator's license

RO - Individual with a reactor operator's license

AO - Nuclear Auxiliary Operator or Sr.

STA - Shift technical advisor

Except for the shift manager, the composition of the shift crew may be one less than the minimum of table 18.I.A-1 for a period not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members, provided immediate action will be taken to restore the shift crew composition to within the minimum requirements of table 18.I.A-1. This provision does not permit any shift crew

position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

At least one licensed Reactor Operator shall be in the Control Room when fuel is in the reactor. In addition, while the reactor is in MODE 1, 2, 3, or 4, at least one licensed Senior Reactor Operator shall be in the Control Room.

During any absence of the shift manager from the control room while the unit is in Mode 1, 2, 3, or 4, an individual (other than the shift technical advisor) with a valid senior operator license shall be designated to assume the control room command function. During any absence of the shift manager from the control room while the unit is in Mode 5 or 6, an individual with a valid senior operator or operator license shall be designated to assume the control room command function. This control room command function is normally delegated to a designated control room supervisor who holds a valid senior reactor operator license.

Normal staffing as discussed in paragraph 13.1.2.6 and PVNGS administrative procedures meet or exceed NUREG-0737 minimum requirements.

18.I.B OVERALL ORGANIZATION

18.I.B.1.2 INDEPENDENT SAFETY ENGINEERING GROUP

NRC Position

Each applicant for an operating license shall establish an onsite independent safety engineering group (ISEG) to perform independent reviews of plant operations.

The principal function of the ISEG is to examine plant operating characteristics, NRC issuances, licensing information service advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety. The ISEG is to perform independent review and audits of plant activities, including maintenance, modifications, operational problems, and operational analysis, and aid in the establishment of programmatic requirements for plant activities. Where useful improvements can be achieved, it is expected that this group will develop and present detailed recommendations to corporate management for such things as revised procedures or equipment modifications.

Another function of the ISEG is to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practicable. The ISEG will then be in a position to advise utility management on the overall quality and safety of operations. The ISEG need not perform detailed audits of plant operations and shall not be responsible for sign-off functions such that it becomes involved in the operating organization.

PVNGS Evaluation

The program and related procedures for review of operating experience described at UFSAR 18.I.C.5 are the primary method used at PVNGS to review and act upon internal and external operating experience.

To augment the program and related procedures described at 18.I.C.5, the Director, Nuclear Assurance, is responsible to monitor and assess operational activities to provide assurance that activities important to safety are performed satisfactorily. Specific functions of the Nuclear Assurance staff are described in the Operations Quality Assurance Program Description (QAPD).

18.I.C OPERATING PROCEDURES

18.I.C.1 GUIDANCE FOR THE EVALUATION AND DEVELOPMENT OF PROCEDURES FOR TRANSIENTS AND ACCIDENTS

NRC Position

1. Requirements (from NUREG-0737, Supplement No. 1)

   a. The use of human factored, function oriented, emergency operating procedures (EOPs) will improve human reliability and the ability to mitigate the consequences of a broad range of initiating events and subsequent multiple failures or operator errors, without the need to diagnose specific events.

   b. In accordance with NUREG-0737, Item I.C.1, reanalyze transients and accidents and prepare technical guidelines. These analyses will identify operator tasks, and information and control needs. The analyses also serve as the basis for integrating upgraded emergency operating procedures and the control room design review and verifying the SPDS design.

   c. Upgrade EOPs to be consistent with technical guidelines and an appropriate procedure writer's guide.

   d. Provide appropriate training of operating personnel on the use of upgraded EOPs prior to implementation of the EOPs.

   e. Implement upgraded EOPs.

2. Documentation and NRC Review

   a. Submit technical guidelines to the NRC for review. The NRC will perform a preimplementation review of the technical guidelines. Within 2 months of receipt of the technical guidelines, the NRC will advise the licensees of their acceptability.

   b. Each licensee shall submit to the NRC a procedures generation package at least 3 months prior to the date it plans to begin formal operator training on the upgraded procedures. The NRC approval of the submittal is not necessary prior to upgrading and implementing the EOPs. The procedures generation package shall include:

      (i) Plant-Specific Technical Guidelines -- plant-specific guidelines for plants not using generic technical guidelines. For plants using generic technical guidelines, a description of the planned method for developing plant specific EOPs from the generic guidelines, including plant specific information.

      (ii) A writer's guide that details the specific methods to be used by the licensee in preparing EOPs based on the technical guidelines.

      (iii) A description of the program for validation of EOPs.

(iv) A brief description of the training program for the upgraded EOPs.

c. All procedures generation packages will be reviewed by the staff. On an audit basis for selected facilities, upgraded EOPs will be reviewed. The details and extent of this review will be based on the quality of the procedures generation packages submitted to NRC. A sampling of upgraded EOPs will be reviewed for technical adequacy in conjunction with the NRC reactor inspection program.

PVNGS Evaluation

Arizona Public Service Company (APS) has participated in C-E Owner's Group activities, conducted since the Three Mile Island (TMI) accident, to develop improved emergency procedure guidelines and associated supporting analyses. The initial C-E Owner's Group analysis of inadequate core cooling is documented in Report CEN-117, "Inadequate Core Cooling - A Response to NRC IE Bulletin 79-06C, Item 6 for Combustion Engineering Nuclear Steam Supply Systems." The initial C-E Owner's Group analyses of transients and accidents (non-LOCA) are documented in Report CEN-128, "Response of Combustion Engineering Nuclear Steam Supply Systems to Transients and Accidents."

The emergency procedure technical guidelines for Combustion Engineering pressurized water reactors were submitted to the NRC by the Combustion Engineering Owner's Group as CEN-152, "Combustion Engineering Emergency Procedure Guidelines," Revision 1, dated November 22, 1982. APS has developed an

emergency procedure generation package (PGP) for PVNGS based on the C-E emergency procedure guidelines and has submitted the PGP to the NRC on July 15, 1983. The PVNGS PGP contained the following information as required by Supplement No. 1 to NUREG-0737:

(i) Plant-specific technical guidelines

(ii) Procedure writer's guide

(iii) Description of the EOP verification and validation program

(iv) Description of the operator training program for the EOPs.

Since the initial issue of EOPs based on the PGP, APS has revised the EOPs to maintain them in accordance with the current revision of the C-E emergency procedure guidelines. Operators have received training as needed on the revisions to the EOPs.

PVNGS EOPs are discussed in the Operations Quality Assurance Program Description (QAPD).

18.I.C.2 SHIFT RELIEF AND TURNOVER PROCEDURES

<u>NRC Position (November 9, 1979 Letter from NRC to All Construction Permit Holders)</u>

The licensees shall review and revise as necessary the plant procedure for shift and relief turnover to assure the following:

1. A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift

supervisor to complete and sign. The following items, as a minimum, shall be included in the checklist.

a. Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).

b. Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transient and accidents by a check of the control console. (What to check and criteria for acceptable status shall be included on the checklist.)

c. Identification of systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement (this shall be recorded as a separate entry on the checklist).

2. Checklists or logs shall be provided for completion by the offgoing and ongoing auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that, by themselves, could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist.); and

3. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedure (for example, periodic independent verification of system alignments).

PVNGS Evaluation

Detailed administrative procedures have been developed that meet the guidance of the November 9, 1979, NRC letter from D. B. Vassallo to All Licensees of Plants Under Construction, for shift relief and turnovers to ensure that current plant conditions and system status is conveyed to the oncoming shift. The procedures have been developed for shift relief and turnover for the shift manager (shift manager is an equivalent position to the shift supervisor position referred to in the NRC position above), control room supervisors, nuclear operators, radwaste technicians, and radiation protection technicians.

The procedure for the operations staff includes the use of checklists and logs to ensure that there is a proper turnover of command functions and current operating conditions. Turnover and relief includes a review of tagouts, abnormal conditions, jumpers/bypasses, surveillance testing, and conditions affecting Technical Specifications. Annunciator panels, visual displays, and key operating parameters will also be monitored to verify system status and equipment condition.

18.I.C.3 SHIFT MANAGER RESPONSIBILITIES

NRC Position (NUREG-0694) (NRC Letter, D. B. Vassallo to All Pending Construction Permit Applicants, dated November 9, 1979)

(1) The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the shift supervisor for safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.

(2) Plant procedures shall be reviewed to assure that the duties, responsibilities, and authority of the shift supervisor and control room operators are properly defined to affect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room relative to other plant management personnel. Particular emphasis shall be placed on the following:

(a) The responsibility and authority of the shift supervisor shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times when on duty in the control room. The idea shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.

(b) The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons

authorized to relieve the shift supervisor shall be specified.

(c) If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.

(3) Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and the management function the shift supervisor is to provide for assuring safety.

(4) The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for assuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

PVNGS Evaluation

The primary onshift responsibility for safe operation of the plant belongs to the unit shift manager (shift manager is an equivalent position to the shift supervisor position referred to in the NRC position above), whose lines of authority and duties are described in section 13.1.2 and in the PVNGS administrative and operating procedures. The unit shift manager shall maintain a broad perspective of all of the operational conditions affecting the safety of the plant. The

unit shift manager should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room. Additionally, the control room supervisor provides a backup to the shift manager and supervises shift personnel in conduct of unit operations, as assigned. The unit shift manager or control room supervisor shall remain in the control room until properly relieved during emergency conditions.

The administrative duties of the unit shift managers will be periodically reviewed by a senior officer of APS. Administrative functions that detract from or are subordinate to the management responsibility for assuring the safe operation of the plant will be delegated to other operations personnel.

18.I.C.4 CONTROL ROOM ACCESS

NRC Position (NRC Letter, D. B. Vassallo to All Pending Construction Permit Applicants, dated November 9, 1979)

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support the operation, and to predesignated NRC personnel. Provisions shall include the following:

(1) Develop and implement administrative procedures that establishes the authority and responsibility of the person in charge of the control room to limit access, and

(2) Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current senior reactor operator's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside of the control room.

PVNGS Evaluation

(1) An administrative procedure has been developed to limit access to the control room. This procedure is contained in the PVNGS Station Manual. The unit shift manager (shift manager is an equivalent position to the shift supervisor position referred to in the NRC position above), and the unit control room supervisor have the responsibility to control access to those personnel who are required, or are requested, to support the operation of the plant.

(2) Procedures have been developed which establish clear lines of authority and communication during all plant conditions, including startups, normal, off-normal, and emergency conditions. These procedures clearly establish the line of succession for the individual in charge of the control room. Additionally, a procedure has been developed to clearly define the lines of communication and authority for plant personnel not in direct command of operations during an emergency.

18.I.C.5 PROCEDURES FOR FEEDBACK OF OPERATING EXPERIENCE TO PLANT STAFF

NRC Position

In accordance with Task Action Plan I.C.5, Procedures for Feedback of Operating Experience to Plant Staff (NUREG-0660), each applicant for an operating license shall prepare procedures to assure that operating information pertinent to plant safety originating both within and outside the utility organization is continually supplied to operators and other personnel and is incorporated into training and retraining programs. These procedures shall:

(1) Clearly identify organizational responsibilities for review of operating experience, the feedback of pertinent information to operators and other personnel, and the incorporation of such information into training and retraining programs;

(2) Identify the administrative and technical review steps necessary in translating recommendations by the operating experience assessment group into plant actions (e.g., changes to procedures, operating orders);

(3) Identify the recipients of various categories of information from operating experience (i.e., supervisory personnel, shift technical advisors, operators, maintenance personnel, health physics technicians) or otherwise provide means through which such information can be readily related to the job functions of the recipients;

(4) Provide means to assure that affected personnel become aware of and understand information of sufficient importance that should not wait for emphasis through routine training and retraining programs;

(5) Assure that plant personnel do not routinely receive extraneous and unimportant information on operating experience in such volume that it would obscure priority information or otherwise detract from overall job performance and proficiency;

(6) Provide suitable checks to assure that conflicting or contradictory information is not conveyed to operators and other personnel until resolution is reached; and,

(7) Provide periodic internal audit to assure that the feedback program functions effectively at all levels.

PVNGS Evaluation

An operating experience review program has been implemented for PVNGS. This program establishes the responsibilities and methodologies for reviewing the operating experience of PVNGS and other nuclear facilities. The Performance Improvement Department under direction of the Director, Performance Improvement, has the primary responsibility for implementing the operating experience review program. Additionally, PVNGS participates in the Institute of Nuclear Power Operations (INPO) Significant Event Evaluation and Information Network (SEE-IN) as discussed in NRC Generic Letter No. 82-04. The operating experience review program and implementing procedures have been developed in accordance with the requirements of NUREG-0737, Item I.C.5.

18.I.C.6 GUIDANCE ON PROCEDURES FOR VERIFYING CORRECT PERFORMANCE OF OPERATING ACTIVITIES

NRC Position

It is required (from NUREG-0660) that licensees' procedures be reviewed and revised, as necessary, to assure that an effective system of verifying the correct performance of operating activities is provided as a means for reducing human errors and improving the quality of normal operations. This will reduce the frequency of occurrence of situations that could result in or contribute to accidents. Such a verification system may include automatic system status monitoring, human verification of operations and maintenance activities independent of the people performing the activity (see NUREG-0585, Recommendation 5), or both.

Implementation of automatic status monitoring, if required, will reduce the extent of human verification of operations and maintenance activities but will not eliminate the need for such verification in all instances. The procedures adopted by the licensees may consist of two phases -- one before and one after installation of automatic status monitoring equipment, if required, in accordance with Item I.D.3.

PVNGS Evaluation

Paragraph 7.5.1.1.6 describes the safety equipment status panel, designed to implement Regulatory Guide 1.47, which displays the availability of selected equipment important to

nuclear safety. The presence of this system will reduce the extent of human verification of operations and maintenance activities. The following additional requirements have been implemented to ensure safety system reliability:

A. Permission to release equipment or systems for maintenance shall be granted by designated operating personnel who currently hold or have held a senior reactor operator license at Palo Verde. Prior to granting permission, such operating personnel shall verify that the equipment or system can be released, and determine how long it may be out of service. Granting of such permission shall be documented. Attention shall be given to the potentially degraded degree of protection when one subsystem of a redundant safety system has been removed for maintenance.

B. After permission has been granted to remove the system for service, it shall be made safe to work on. Measures shall provide for protection of equipment and workers. Equipment and systems in a controlled status shall be clearly identified. Strict control measures for such equipment shall be enforced.

C. Conditions to be considered in preparing equipment for maintenance, in addition to requirements of the Technical Specifications, include, for example: shutdown margin; method of emergency core cooling; establishment of a path for decay heat removal; temperature and pressure of the system; valves between work and hazardous material; venting, draining and flushing; entry into closed vessels; hazardous

atmospheres; handling hazardous materials; and electrical hazards. When entry into a closed system is required, control measures shall be established to prevent entry of extraneous material and to assure that foreign material is removed before the system is reclosed.

D. Procedures shall be provided for control of equipment, as necessary, to maintain personnel and reactor safety and to avoid unauthorized operation of equipment. These procedures shall require control measures such as locking or tagging to secure and identify equipment in a controlled status. The procedures shall require independent verifications, where appropriate, to ensure that necessary measures, such as tagging equipment, have been implemented correctly.

E. Temporary modifications, such as temporary bypass lines, electrical jumpers, lifted electrical leads, and temporary trip point settings, shall be controlled by approved procedures which shall include a requirement for independent verification by either a second person or by a functional test which conclusively proves the proper installation or removal of the temporary modification. A log, or other documented evidence, shall be maintained of the current status of such temporary modifications.

F. When equipment is ready to be returned to service, operating personnel shall place the equipment in operation and verify and document its functional acceptability. Attention shall be given to

restoration of normal conditions, such as removal of jumpers or signals used in maintenance or testing and returning valves, breakers or switches, or proper startup or operating positions from "test" or "manual" positions, and assuring that all alarms which are indicative of inoperative status are extinguished. For safety-related equipment, proper alignment shall be independently verified by a second person unless alignment is proven by functional testing.

18.I.C.7 NSSS VENDOR REVIEW OF PROCEDURES

NRC Position (NUREG-0694)

(1) Low Power Test Program

Obtain nuclear steam supply system (NSSS) vendor review of low-power testing procedures to further verify their adequacy.

(2) Power Ascension and Emergency Procedures

Obtain NSSS vendor review of power ascension test and emergency procedures to further verify their adequacy.

PVNGS Evaluation

Subsection 14.2.5 describes the review process for the test procedures of the low-power and power ascension test programs. The NSSS vendor representative is included on the test results review group to ensure the review of test procedures pertaining to or interfacing with the NSSS vendor-supplied systems.

The NSSS vendor has reviewed the emergency operating procedures that involve the NSSS vendor scope of supply.

18.I.C.8 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES FOR NEAR-TERM OPERATING LICENSE APPLICANTS

NRC Position (NUREG-0694)

Correct emergency procedures, as necessary, based on the NRC audit of selected plant emergency operating procedures (e.g., small-break LOCA, loss of feedwater, restart of engineered safety features following a loss of ac power, steam line break, or steam generator tube rupture).

PVNGS Evaluation

NRC staff review and approval of the PVNGS Emergency Operating Procedures will be done in accordance with TMI-2 Task Action Plan, Item I.C.1, as stated in Supplement 6 to the staff's Safety Evaluation Report related to the operation of PVNGS Units 1, 2, and 3 dated October 1984. Therefore, a pilot monitoring review of selected plant emergency operating procedures is not required. Please refer to subsection 18.I.C.1.

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18.I.D CONTROL ROOM DESIGN

Note: The revised 10 CFR 50.59 rule became effective March 13, 2001. This revision of the rule eliminated the term "unreviewed safety question". In accordance with the guidance provided in NRC Regulatory Issue Summary 2001-03, "Changes, Tests and Experiments", dated January 23, 2001, Issue 7, any future application of the information contained in NUREG-0737 to proposed changes, tests or experiments should be reviewed in the context of the revised 10 CFR 50.59 rule. The information presented in this section is historical and has been preserved in its original context.

18.I.D.1 DETAILED CONTROL ROOM DESIGN REVIEWS (SUPPLEMENT 1 TO NUREG-0737)

NRC Position

1. Requirements

   a. The objective of the control room design review is to "improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them" (from NUREG-0660, Item I.D.1). As a complement to improvements of plant operating staff capabilities in response to transients and other abnormal conditions that will result from implementation of the safety parameter display system (SPDS) and from upgraded emergency operating procedures, this design review will identify any modifications of control room configurations that would contribute to a significant reduction of risk

and enhancement in the safety of operation. Decisions to modify the control room would include consideration of long-term risk reduction and any potential temporary decline in safety after modifications resulting from the need to relearn maintenance and operating procedures. This should be carefully reviewed by persons competent in human factors engineering and risk analysis.

b. Conduct a control room design review to identify human engineering discrepancies. The review shall consist of:

(i) The establishment of a qualified multi-disciplinary review team and a review program incorporating accepted human engineering principles.

(ii) The use of function and task analysis (that had been used as the basis for developing emergency operating procedures technical guidelines and plant specific emergency operating procedures) to identify control room operator tasks and information and control requirements during emergency operations. This analysis has multiple purposes and should also serve as the basis for developing training and staffing needs and verifying SPDS parameters.

(iii) A comparison of the display and control requirements with a control room inventory to identify missing displays and controls.

(iv) A control room survey to identify deviations from accepted human factors principles. This survey will include, among other things, an assessment of the control room layout, the usefulness of audible and visual alarm systems, the information recording and recall capability, and the control room environment.

c. Assess which human engineering discrepancies are significant and should be corrected. Select design improvements that will correct those discrepancies. Improvements that can be accomplished with an enhancement program (paint-tape-label) should be done promptly.

d. Verify that each selected design improvement will provide the necessary correction, and can be introduced in the control room without creating any unacceptable human engineering discrepancies because of significant contribution to increased risk, unreviewed safety questions, or situations in which a temporary reduction in safety could occur. Improvements that are introduced should be coordinated with changes resulting from other improvement programs such as SPDS, operator training, new instrumentation (Regulatory Guide 1.97, Rev. 2), and upgraded emergency operating procedures.

PVNGS Evaluation

The purpose of the PVNGS detailed control room design reviews (DCRDR) was to review the control room design provided to the operator and implement changes that would improve the ability

of the PVNGS control room operator to prevent accidents or cope with accidents. Results of this control room design review (CRDR) identified several modifications to the PVNGS control room configuration that enhanced the safety of plant operation. Only those modifications that provided a control room design improvement to the operators were implemented.

The PVNGS DCRDR was conducted to identify human engineering discrepancies (HEDs). The review performed at PVNGS consisted of:

(1) establishing a qualified multidisciplinary review team,

(2) the use of function and task analysis to identify control room operator tasks and information and control requirements during emergency operations,

(3) a comparison of the displays and control requirements with a control room inventory to identify missing displays and controls,

(4) a control room survey to identify deviations from accepted human factors principles,

(5) an assessment of HEDs to determine which are significant and should be corrected,

(6) a selection of control room design improvements that will correct significant discrepancies,

(7) a verification that each of the selected control room design improvements will provide the necessary corrections of HEDs and will not introduce new HEDs into the control room, and will not result in an

increased risk, unreviewed safety questions, or temporary reduction in safety, and

(8) ensuring that improvements that are introduced to the PVNGS control room are coordinated with changes resulting from other improvement programs such as the PVNGS SPDS, the PVNGS operator training programs, new instrumentation of Regulatory Guide 1.97, Rev. 2, "Instrumentation for Light Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident" (Regulatory Guide 1.97) and the PVNGS emergency operating procedure (EOP).

The above eight issues as they apply to the PVNGS DCRDR are discussed in detail by a letter submitted to the NRC dated August 30, 1985 (ANPP-33302).

Additionally, as part of the licensing of PVNGS Unit 2, the NRC staff required that:

(1) any differences between the Units 1 and 2 control rooms be identified,

(2) evaluate the differences to determine if any HEDs exist, and

(3) propose actions and schedules to correct the HEDs.

In response to this new requirement, ANPP conducted an evaluation which consisted of evaluating the preplanned control room differences between Units 1 and 2, evaluating the temporary differences due to design change packages being implemented at different times between the units, and a walkdown of the control rooms and comparison of the findings. The results of this evaluation identified no new HEDs.

18.I.D.2 PLANT SAFETY PARAMETER DISPLAY SYSTEM

Note: The revised 10 CFR 50.59 rule became effective March 13, 2001. This revision of the rule eliminated the term "unreviewed safety question". In accordance with the guidance provided in NRC Regulatory Issue Summary 2001-03, "Changes, Tests and Experiments", dated January 23, 2001, Issue 7, any future application of the information contained in NUREG-0737 to proposed changes, tests or experiments should be reviewed in the context of the revised 10 CFR 50.59 rule. The information presented in this section is historical and has been preserved in its original context.

NRC Position

1. Requirements - Supplement 1 to NUREG-0737

   a. The safety parameter display system (SPDS) should provide a concise display of critical plant variables to the control room operators to aid them in rapidly and reliably determining the safety status of the plant. Although the SPDS will be operated during normal operations as well as during abnormal conditions, the principal purpose and function of the SPDS is to aid the control room personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether abnormal conditions warrant corrective action by operators to avoid a degraded core. This can be particularly important during anticipated transients and the initial phase of an accident.

b. Each operating reactor shall be provided with a SPDS that is located convenient to the control room operators. This system will continuously display information from which the plant safety status can be readily and reliably assessed by control room personnel who are responsible for the avoidance of degraded and damaged core events.

c. The control room instrumentation required (see General Design Criteria 13 and 19 of Appendix A to 10CFR50) provides the operators with the information necessary for safe reactor operation under normal, transient, and accident conditions. The SPDS is used in addition to the basic components and serves to aid and augment these components. Thus, requirements applicable to control room instrumentation are not needed for this augmentation (e.g., GDC 2, 3, 4 in Appendix A; 10CFR Part 100; single-failure requirements). The SPDS need not meet requirements of the single-failure criteria and it need not be qualified to meet Class 1E requirements. The SPDS shall be suitably isolated from electrical or electronic interference with equipment and sensors that are in use for safety systems. The SPDS need not be seismically qualified, and additional seismically qualified indication is not required for the sole purpose of being a backup for SPDS. Procedures which describe the timely and correct safety status assessment when the SPDS is and is not available will be developed by the licensee in parallel with the SPDS. Furthermore, operators

should be trained to respond to accident conditions both with and without the SPDS available.

d. There is a wide range of useful information that can be provided by various systems. This information is reflected in such staff documents as NUREG-0696, NUREG-0835, and Regulatory Guide 1.97. Prompt implementation of an SPDS can provide an important contribution to plant safety. The selection of specific information that should be provided for a particular plant shall be based on engineering judgment of individual plant licensees, taking into account the importance of prompt implementation.

e. The SPDS display shall be designed to incorporate accepted human factors principles so that the displayed information can be readily perceived and comprehended by SPDS users.

f. The minimum information to be provided shall be sufficient to provide information to plant operators about:

   (i) Reactivity control

   (ii) Reactor core cooling and heat removal from the primary system

   (iii) Reactor coolant system integrity

   (iv) Radioactivity control

   (v) Containment conditions

   The specific parameters to be displayed shall be determined by the licensee.

2. Documentation and NRC Review

a. The licensee shall prepare a written safety analysis describing the basis on which the selected parameters are sufficient to assess the safety status of each identified function for a wide range of events, which include symptoms of severe accidents. Such analysis, along with the specific implementation plan for SPDS, shall be reviewed as described below.

b. The licensee's proposed implementation of an SPDS system shall be reviewed in accordance with the licensee's technical specifications to determine whether the changes involve an unreviewed safety question or change of Technical Specifications. If they do, they shall be processed in the normal fashion with prior NRC review. If the changes do not involve an unreviewed safety question or a change in the Technical Specifications, the licensee may implement such changes without prior approval by NRC or may request a pre-implementation review and approval. If the changes are to be implemented without prior NRC approval, the licensee's analysis shall be submitted to NRC promptly on completion of review by the licensee's offsite safety review committee. Based on the results of NRC review, the director of IE or the director of NRR may request or direct the licensee to cease implementation if a serious safety question is posed by the licensee's proposed system, or if the licensee's analysis is seriously inadequate.

PVNGS Evaluation

The plant system performing the function of the SPDS at PVNGS is integrated into the emergency response facility data acquisition and display system (ERFDADS). This system takes plant process information coming from plant instrumentation, organizes it, applies it to a hierarchy of displays, and presents it to the control room personnel via visual displays in the control room, technical support center, satellite technical support center, and emergency operations facility. The ERFDADS consists of the following major subsystems:

(a) a data acquisition system in each unit's power block,

(b) a computer system in each Unit's power block, and

(c) visual displays and keyboards.

The SPDS portion of ERFDADS presents leading safety parameter display (SPD) information to control room personnel on the leading parameters associated with the plant critical safety function groups.

This information is presented on visual displays using digital readouts, bar graphs, trend charts, and x-y plots. Color coding is used to high-light serious conditions and indicate data quality.

The principal purpose of the SPDS is to aid the control room personnel during normal, abnormal, and emergency conditions for determining the safety status of the plant and addressing whether abnormal conditions warrant corrective actions to avoid a degraded core. At PVNGS, the SPDS is designed to fulfill this purpose by alerting the control room personnel to possible

problem areas so they can be handled by using qualified instrumentation and the applicable procedures.

The PVNGS SPDS was described in the Safety Analysis Report submitted to the NRC on February 27, 1985 (ANPP-32008) and as amended by a letter submitted to the NRC on August 19, 1985 (ANPP-33235).

In response to Generic Letter (GL) 89-06, APS certified in letter 161-02242 that the SPDS would be modified to meet the requirements of NUREG-0737. The NRC Staff responded on April 25, 1990, acknowledging our certification.
Letter 102 03139, SPDS Certification, dated September 30, 1994, informed the NRC of the completion of the implementation requirements of GL 89-06.

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18.I.G PREOPERATIONAL AND LOW-POWER TESTING

18.I.G.1 TRAINING DURING LOW-POWER TESTING

NRC Position NUREG-0694

(1) Propose Tests

Define and commit to a special low-power testing program approved by the NRC to be conducted at power levels no greater than 5% for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training.

(2) Submit Analysis and Procedures

(3) Training and Results

Supplement operator training by completing the special low-power test program. Tests may be observed by other shifts or repeated on other shifts to provide training to the operators.

PVNGS Evaluation

(1) See Chapter 13.2 for information pertaining to training of PVNGS personnel.

(2) See Chapter 14.2.12 for information pertaining to pre-operational testing.

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18.II SITING AND DESIGN

18.II.B CONSIDERATION OF DEGRADED OR MELTED CORES IN SAFETY REVIEW

18.II.B.1 REACTOR COOLANT SYSTEM VENTS

NRC Position

Each applicant and licensee shall install reactor coolant system (RCS) and reactor vessel head high point vents remotely operated from the control room. Although the purpose of the system is to vent noncondensable gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a loss-of-coolant accident (LOCA) or a challenge to containment integrity. Since these vents form a part of the reactor coolant pressure boundary, the design of the vents shall conform to the requirements of Appendix A to 10CFR Part 50, General Design Criteria. The vent system shall be designed with sufficient redundancy that assures a low probability of inadvertent or irreversible actuation.

Each licensee shall provide the following information concerning the design and operation of the high point vent system:

(1) Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for LOCA initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10CFR50.46.

(2) Submit procedures and supporting analysis for operator use of the vents that also include the information available to the operator for initiating or terminating vent usage.

PVNGS Evaluation

PVNGS Units 1, 2, and 3 have installed a reactor coolant gas vent system (RCGVS). A description of the design is as follows:

A. System Design Basis

The RCGVS is designed to be used to remotely vent gases from the reactor vessel head and pressurizer steam space during post-accident situations when large quantities of noncondensable gases may collect in these high points. Although primarily designed to be available during post-accident conditions, the system can also be used to aid in the RCS venting procedures following a maintenance outage.

The design criteria for the vent system are as follows:

1. The system shall permit remote (control room) venting from the reactor vessel head vent or the pressurizer.

2. The vent flowrate capability shall be based upon the following considerations:

   a. The vent rate should be sufficient to preclude the gas accumulation from interfering with core cooling.

b. Coolant loss through the vent should not exceed makeup capacity.

c. The vent mass rate should not result in heat loss from the RCS in excess of the pressurizer heater capacity.

d. Depressurization

1.0 The RCGVS shall be capable of venting non-condensable gases from the reactor coolant system, as a back-up to the Auxiliary Pressurizer Spray system, to control RCS pressure following a steam generator tube rupture (SGTR) event.

2.0 The RCGVS shall be capable of venting non-condensable gases from the reactor coolant system, as a back-up to the Auxiliary Pressurizer Spray system, to control pressure during natural circulation cool down following a loss of offsite power (LOP) event.

3. The vents shall conform to the applicable requirements of 10CFR50, Appendix A, General Design Criteria. In particular, these vents shall be safety grade and satisfy the single failure criterion and the requirements of IEEE-279 in order to ensure a low probability of inadvertent action.

4. The design shall minimize modification of currently installed safety class equipment and piping which

may be radioactive or require major reactor coolant system hydrostatic testing after installation.

5. The system shall be analyzed to determine effects of pipe breakage and the results should be demonstrated acceptable in accordance with the acceptance criteria of 10CFR50.46.

6. The vent system shall be capable of selectively venting to either the containment or the reactor drain tank.

7. The vent system shall be designed to vent superheated steam, steam water mixtures, water, fission gases, helium, nitrogen, and hydrogen at pressures and temperatures as high as 2500 psig and 700F.

8. Control room position indication shall be provided for all power-operated valves.

9. The system shall be designed not to interfere with refueling maintenance activities

The reactor coolant gas vent system is designed to vent noncondensable gases from the reactor coolant system during post-accident conditions. The purpose of venting is to prevent possible interference with core cooling. Small amounts of gas can be vented to the reactor drain tank and thus not enter the containment atmosphere. Larger volumes will require venting to the containment -- either through the ruptured reactor drain tank rupture disk or directly -- where the hydrogen concentration will be controlled by the containment hydrogen

recombiner. Pressure instrumentation is included in the design to monitor system performance.

Although designed for accident conditions, the system may be used to aid in the refueling venting of the reactor coolant system.

Although venting of the CEDMs and RCPs will still be necessary, pressurizer and reactor vessel venting can be accomplished with the system if desired. Vent flow may be directed to the reactor drain tank or the containment sump for this operation to prevent inadvertent release of radioactive fluid.

B. System Description

The Reactor Coolant Vent System (RCGVS) Vent Path originates from two points in the reactor coolant system.

1.0 The reactor vessel head via existing 3/4” head vent pipe.

2.0 The pressurizer steam space via existing 3/4” steam sample/vent lines.

The vent lines are fabricated from 1”, 304 or 316 austenitic stainless steel and have welded connections except where disassembly for maintenance, particularly refueling operations, is required. The reactor vessel head vent line has two remote operated valves, in parallel, that are powered from alternate power sources to assure a vent path exists in the event of a single failure. In addition, upstream of the parallel lines,

the vent path has a 1/4” x 1.25” stainless steel flow restricting orifice provided to limit reactor leakage to less than the capacity of the minimum number of functional charging pumps in the event of a line break or inadvertent valve operation.

The pressurizer steam space vent line also splits into two parallel paths, one path consists of two, class one, seismic one remotely operated solenoid valves powered by the same power source. The two class one, seismic one valves in series are redundant such that in the event of a single failure, the line could still be isolated by the other valve. The other path has one remotely operated solenoid valve and a 7/32” x 1” orifice. The solenoid valve in this line is powered from an alternate source from the valves in the parallel path. The orifice limits flow as described above in the event of a line break or inadvertent valve operation.

The vent lines from the reactor vessel and pressurizer steam space come together then split into two flow paths, one to the reactor drain tank (RDT) and the other to the containment atmosphere. Both lines are isolated by remotely operated solenoid valves which are supplied by alternate power sources to assure a vent path is available in the event of a single failure. The vent path to the RDT enters the tank at a point underwater to cool the steam and gases from the vent line. The vent path into containment is located in an open area near steam generator one.

SITING AND DESIGN

1. System Parameters

The components in the RCGVS consist of piping, valves, and instrumentation to direct vented gas flow from existing components to an existing tank as shown on figure 18.II.B-1. The main design parameters for the vent line are:

Design Flow	500 standard cubic feet per minute
Design Temperature	700F
Design Pressure	2500 psig
Line Size	1 inch

2. Descriptive Summary

The system permits the main control room operator to remotely vent the pressurizer and reactor vessel head. The pressurizer vent ties into an existing 3/4 inch vent line. The reactor vessel head vent ties into the existing 3/4 inch reactor vessel vent and will be flanged to permit head removal for refueling. The vent line is connected to the pressurizer relief valve common discharge header, which terminates in the reactor drain tank, entering below the water level. An existing reactor drain tank penetration is thus utilized. The capability to vent directly to containment is also provided should the operator not desire to allow the rupture disc on the reactor drain tank to rupture when large quantities of gas must be

vented. This line terminates at an open area near steam generator number 1. This area is not restricted in any way. This occurs at the north side of containment at elevation 158 feet 6 inches, above the operating deck. There is adequate ventilation to promote good mixing within the containment, and there is no equipment in the area of the discharge that could be affected by system operation.

The normal vent paths are from either the pressurizer or reactor vessel head to the reactor drain tank. These paths are powered from emergency power sources, Seismic Category I, and of the appropriate quality class to conform to existing standards. The vent flow is directed into the reactor drain tank below the water level to remove energy from the steam and to cool the gas itself. If large quantities of gas must be vented, the reactor drain tank will pressurize and eventually rupture its rupture disc providing a path to containment to continue the venting process. If the rupture is deemed undesirable by the operators, venting can be remotely shifted directly to the containment upon actuation of the reactor drain tank high pressure alarm, which annunciates in the main control room. This path is powered from emergency power sources, Seismic Category I, and of the appropriate quality class to conform to existing standards. No single active failure can

prevent the RCGVS from performing its design function.

For cases when the vented gas is not highly radioactive and containment isolation has not occurred, the gas delivered to the reactor drain tank can be routed to the gaseous radwaste system surge tank. Although unavailable during accident conditions, this path will allow processing of gas removed by the vent system if the system is used to aid in RCS venting for refueling operations.

To preclude inadvertent opening of any one of seven solenoid-operated vent valves, they are placed in their locked-closed position via key lock switches in the main control room. Opening of any solenoid-operated vent valve requires deliberate operator action. To minimize the possibility of common mode failure of solenoid operated valves to shut when deenergized, the operation procedure for the RCGVS will require that when both trains A and B are available, one valve powered from train A and one valve powered from train B will be used to complete a vent path.

The location of the solenoid-operated valves was reviewed on the plant model and it was found that there were no credible missile hazards from them, and no safety-related equipment in their area.

3. Operation

The operator can vent noncondensable gases from the reactor coolant by the following flow paths using the remotely operable vent system:

a. Reactor vessel head vent to the reactor drain tank

b. Pressurizer vent to the reactor drain tank

c. Reactor vessel or pressurizer vent to containment directly

d. Reactor vessel head or pressurizer vent to the gaseous radwaste system surge tank via the reactor drain tank.

Accident events with large gas generation may demand rapid response by the operator to remove the gases and to establish stable plant conditions in a controlled manner. Maintaining core water cover establishes and maintains core cooling which is of primary importance. Other events that may not cause the core to uncover permit a slower response.

Operating considerations for each flow path are given as follows:

a. Reactor Vessel Head Vent to the Reactor Drain Tank

Venting the reactor vessel to the reactor drain tank is accomplished by opening one of two reactor vessel head vent solenoid isolation valves and the solenoid-operated

valve to the reactor drain tank. System pressure integrity is confirmed by vent line pressure indication.

Integrity of the reactor drain tank is confirmed by monitoring tank pressure, temperature, and level. Continuous venting to the reactor drain tank may eventually result in rupture of the rupture disk, particularly if a substantial amount of noncondensable gases are generated in the reactor vessel. In this instance, direct venting to the containment would be preferable. The operator has the capability to monitor the hydrogen levels in containment and start the hydrogen recombiner.

b. Pressurizer Vent to the Reactor Drain Tank

If the operator desires to degas the reactor coolant system or remove accumulated gases in the pressurizer, the pressurizer vent can be aligned to the reactor drain tank. This is accomplished by opening one of two pressurizer vent paths (one path has two solenoid isolation valves and the other has a single solenoid isolation valve and an orifice) and the solenoid-operated valve to the reactor drain tank. System pressure integrity is confirmed by vent line pressure indication. Reactor drain tank conditions are monitored by

pressure, level, and temperature instruments. Continuous venting to the reactor drain tank may lead to failure of the rupture disc. In this case, the precautions noted in sublisting a above are to be followed.

c. Reactor Vessel Head or Pressurizer Vent to Containment Directly

Extended venting from either source to the reactor drain tank may eventually rupture the rupture disc. While this may be of no real consequence during a major accident, there may be times when the operator would desire to maintain the rupture disc intact. In this event, the venting may be directed to the containment directly by opening the solenoid-operated containment vent isolation valve. If this path is used, the precautions with respect to hydrogen in the containment noted in a. item must be followed.

d. Reactor Vessel Head or Pressurizer Vent to the Gaseous Radwaste System

This path may be used if the gases are known to be low in activity (i.e., will not exceed gaseous radwaste system (GRS) Technical Requirements Manual values), normal power is available, low removal rates are acceptable, and adequate storage space is available in the GRS. Alignment of this path is accomplished

by initiating vent flow from the pressurizer or reactor vessel head to the reactor drain tank as in sublistings a or b. Gases directed to the reactor drain tank can be sent to the GRS and collected in the gas surge tank for eventual storage in the gas decay tanks.

This mode of operation is intended for use when the vented gas is not highly radioactive and containment isolation has not occurred.

Consistent with NRC requirements, procedural guidelines for the system will be provided including information relative to initiating or terminating vent system usage.

4. Maintenance

System maintenance is limited to inservice inspection of the system valves. Adequate test connections are provided in the system design to accomplish the requisite testing. To avoid interferences with refueling operations, specific consideration was given to the layout and attachment of the vent system piping and valves to the reactor vessel head. The system is designed not to interfere with the reactor head removal procedures.

C. System Controls

The system is designed to be controlled remotely from the main control room. All valves and instrumentation are powered from Class 1E power sources. Position

indication is provided for all remotely operated valves (open/shut) and displayed in the control room. Pressure instrumentation is also provided to monitor system performance and displayed in the control room. In addition, reactor drain tank pressure, temperature, and level indication is provided in the control room.

D. LOCA Analysis

Consistent with NRC requirements, the system design is acceptable in accordance with 10 CFR 50.46.

The reactor coolant gas vent system is described in Section B above, including a description of the orificed and non-orificed lines. In the event of a line break downstream of the orifice in either the head vent line or pressurizer vent line, or inadvertent valve operation in either of the orificed lines, the orifice would limit reactor leakage to less than the capacity of the minimum number of functional charging pumps. Therefore, the event consequences are bounded by the small line break analysis in UFSAR 9.3.4.4.11, which demonstrates compliance with the requirements of GDC 33 of 10 CFR 50, Appendix A.

A break located at or upstream of the orifices, or inadvertent valve operation in the non-orificed pressurizer vent path, would be bounded by the spectrum of analyzed small break LOCAs in UFSAR 6.3.3. Since the inside diameter of the vent lines from the RCS are less than 3/4 inch, the corresponding cross-sectional area of the lines would be less than 0.003 square feet which is

much smaller than the 0.05 square foot break in the RCS cold leg or the 0.03 square foot break at the top of the pressurizer evaluated in UFSAR 6.3.3.3. Furthermore, a break in the head vent line (i.e., downstream of the core outlet) would result in a more benign plant response than the previously analyzed break in the RCS cold leg (i.e., upstream of the core inlet). Therefore, the emergency core cooling system would meet the acceptance criteria of 10 CFR 50.46 for any postulated breaks or inadvertent valve operations in the reactor coolant gas vent system.

18.II.B.2 DESIGN REVIEW OF PLANT SHIELDING AND ENVIRONMENTAL QUALIFICATION OF EQUIPMENT FOR SPACES/SYSTEMS WHICH MAY BE USED IN POST-ACCIDENT OPERATIONS

NRC Position

With the assumption of a post-accident release of radioactivity equivalent to that described in Regulatory Guides 1.3 and 1.4 (i.e., the equivalent of 50% of the core radioiodine, 100% of the core noble gas inventory, and 1% of the core solids are contained in the primary coolant), each licensee shall perform a radiation and shielding design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The design review should identify the location of vital areas and equipment, such as the control room, radwaste control stations, emergency power supplies, motor control centers, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be

unduly degraded by the radiation fields during post-accident operations of these systems.

Each licensee shall provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or post-accident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas throughout the facility.

PVNGS Evaluation

A radiation and shielding design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials has been conducted.

General design considerations to keep post-accident exposures ALARA are described in paragraph 12.1.2.4. A summary of the shielding design review results is provided in paragraph 12.3.2.3, and a description of the source terms used in the post-accident shielding review is provided in subsection 12.2.3. Post-accident radiation zones are discussed in paragraph 12.3.1.3, and presented as engineering drawings 13-N-RAR-018 through 13-N-RAR-038.

The qualification of safety-related equipment is provided in paragraph 3.11.5.2.

The function, operation and design of the radiation monitoring system are described in section 11.5.

18.II.B.3 POST-ACCIDENT SAMPLING CAPABILITY

NRC Position

A design and operational review of the reactor coolant and containment atmosphere sampling line systems shall be performed to determine the capability of personnel to promptly obtain (less than 1 hour) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18-3/4 rem to the whole-body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3 or 1.4 release of fission products. If the review indicates that personnel could not promptly and safely obtain the samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (in less than 2 hours) certain radionuclides that are indicators of the degree of core damage. Such radionuclides are noble gases (which indicate cladding failure), iodines and cesiums (which indicate high fuel temperatures), and nonvolatile isotopes (which indicate fuel melting). The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxiliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment,

then design modifications or equipment procurement shall be undertaken to meet the criteria.

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses assuming a highly radioactive initial sample (Regulatory Guide 1.3 or 1.4 source term). Both analyses shall be capable of being completed promptly (i.e., the boron sample analysis within an hour and the chloride sample analysis within a shift).

Clarification

The following items are clarifications of requirements identified in NUREG-0578, NUREG-0660, or the September 13 and October 30, 1979, clarification letters.

(1) The licensee shall have the capability to promptly obtain reactor coolant samples and containment atmosphere samples. The combined time allotted for sampling and analysis should be 3 hours or less from the time a decision is made to take a sample.

(2) The licensee shall establish an onsite radiological and chemical analysis capability to provide, within the 3-hour time frame established above, quantification of the following:

    (a) certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases, iodines and cesiums, and nonvolatile isotopes);

(b) hydrogen levels in the containment atmosphere;

(c) dissolved gases (e.g., H_2), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids;

(d) Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.

(3) Reactor coolant and containment atmosphere sampling during post-accident conditions shall not require an isolated auxiliary system [e.g., the letdown system, reactor water cleanup system (RWCUS)] to be placed in operation in order to use the sampling system.

(4) Pressurized reactor coolant samples are not required if the licensee can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or H_2 gas inreactor coolant samples is considered adequate. Measuring the 0_2 concentration is recommended, but is not mandatory.

(5) The time for a chloride analysis to be performed is dependent upon two factors: (a) if the plant's coolant water is seawater or brackish water and (b) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions the licensee shall provide for a chloride analysis within 24 hours of the sample being taken. For all other cases, the licensee shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

(6) The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding the criteria of GDC 19 (Appendix A, 10CFR Part 50) (i.e., 5 rem whole-body, 75 rem extremities). (Note that the design and operational review criterion was changed from the operational limits of 10CFR Part 20 (NUREG-0578) to the GDC 19 criterion (October 30, 1979, letter from H. R. Denton to all licensees).

(7) The analysis of primary coolant samples for boron is required for PWRs. (Note that Revision 2 of Regulatory Guide 1.97, when issued, will likely specify the need for primary coolant boron analysis capability at BWR plants.)

(8) If inline monitoring is used for any sampling and analytical capability specified herein, the licensee shall provide backup sampling through grab samples, and shall demonstrate the capability of analyzing the samples. Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per day for 7 days following onset of the accident and at least one sample per week until the accident condition no longer exists.

(9) The licensee’s radiological and chemical sample analysis capability shall include provisions to:

(a) Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding

to the source terms given in Regulatory Guide 1.3 or 1.4 and 1.7. Where necessary and practicable, the ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite liquid sample analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately 1 μCi/g to 10 Ci/g.

(b) Restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be accomplished through the use of sufficient shielding around samples and outside sources, and by the use of ventilation system design which will control the presence of airborne radioactivity.

(10) Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the reactor coolant systems.

(11) In the design of the post-accident sampling and analysis capability, consideration should be given to the following items:

(a) Provisions for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the RCS or containment,

for appropriate disposal of the samples, and for flow restrictions to limit reactor coolant loss from a rupture of the sample line. The post-accident reactor coolant and containment atmosphere samples should be representative of the reactor coolant in the core area and the containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from containment. The residues of sample collection should be returned to containment or to a closed system.

(b) The ventilation exhaust from the sampling station should be filtered with charcoal adsorbers and high efficiency particulate air (HEPA) filters.

Further Clarification

The following summary is from the NRC notice of availability for referencing in license amendment applications - Model Safety Evaluation of Technical Specification Improvement to Eliminate Requirements on Post Accident Sampling Systems using the Consolidated Line Item Improvement Process. The notice was published in the Federal Register on page 65018, Volume 65, Number 211, dated Tuesday October 31, 2000.

SUMMARY: Notice is hereby given that the staff of the Nuclear Regulatory Commission (NRC) has prepared a model safety evaluation (SE) relating to the elimination of requirements on post accident sampling imposed on licensees through orders, license conditions, or technical specifications. The NRC staff has also prepared a model no significant hazards consideration

(NSHC) determination relating to this matter. The purpose of these models is to permit the NRC to efficiently process amendments that propose to remove requirements for the Post Accident Sampling System (PASS). Licensees of nuclear power reactors to which the models apply may request amendments, in accordance with Section 50.90 of Title 10 to the Code of Federal Regulations, confirming the applicability of the SE and NSHC determination to their reactors and providing the requested plant-specific verifications and commitments.

PVNGS Evaluation

APS has eliminated PASS as documented in CE-NPSD-1157, as accepted by NRC in Safety Evaluation Report dated May 16, 2000 for CEOG Topical Report CE-1157 Revision 1. NRC letter dated September 28, 2001 documented acceptance of the request to remove PASS from the licensing and technical basis of the plant.

Additional Information

The procedure to be utilized at PVNGS to estimate the degree of core damage was developed from the "Revised Core Damage Assessment Procedure Guidelines," CE-NPSD-241, Revision 1," Combustion Engineering Owner's Group Task 1072, dated July, 1999. The PVNGS procedure uses isotopic analysis data obtained from grab samples, core exit thermocouple readings, containment radiation readings, and hydrogen production estimates. Early core damage estimates can be provided using the core exit thermocouple and containment radiation methods, and upgraded later using the hydrogen production.

The means for sampling reactor coolant, containment sump and containment atmosphere will be by grab sample. Provisions will be maintained for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump and containment atmosphere.

The capability for classifying fuel damage events at the Alert level threshold will be maintained in the PVNGS Emergency Plan implementing procedures. This level of core damage is associated to radioactivity levels of 300 μCi/cc dose equivalent iodine.

The capability to monitor radioactive iodines that have been released to the offsite environs will be maintained in the PVNGS Emergency Plan implementing procedures.

18.II.D REACTOR COOLANT SYSTEM RELIEF AND SAFETY VALVES

18.II.D.1 PERFORMANCE TESTING OF BOILING WATER REACTOR AND PRESSURIZED WATER REACTOR RELIEF AND SAFETY VALVES

NRC Position

Pressurized water reactor and boiling water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system (RCS) relief and safety valves under expected operating conditions for design basis transients and accidents.

PVNGS Evaluation

A qualification testing program of reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents was undertaken on an industry-wide generic basis. The Electric Power Research Institute (EPRI) conducted the qualification testing program.

By letter dated December 17, 1979, Mr. Williams J. Cahill, Jr., Chairman of the EPRI Safety and Analysis Task Force, submitted "Program Plan for the Performance Verification of PWR Safety/Relief Valves and Systems," December 13, 1979. As an activity for the C-E Owner's Group, Combustion Engineering (C-E) developed input to this program plan which included System 80 valve design data, piping diagrams, and steam leakage acceptance criteria.

By letter dated December 15, 1980, R. C. Youngdahl of Consumers Power Company provided, on EPRI's behalf, the current pressurized water reactor (PWR) Utilities' positions on NUREG-0737, Item II.D.1, clarifications.

On December 20, 1982, CEN-227 was submitted which provided evidence of pressurizer safety valve operability based on the EPRI test results for C-E plants. The approach applied by the C-E Owner's Group was to select the particular EPRI tests which closely matched the plant-specific conditions and then apply the test results to the plant-specific evaluation.

Arizona Public Service Company (APS) considers CEN-227 to provide the required information on safety valve operability for PVNGS as was stated in a letter to the NRC dated January 31, 1983.

CEN-227 provided two combinations of safety valve adjusting ring settings for PVNGS, demonstrated by the EPRI test results, that would result in satisfactory operation. The ring settings described in CEN-227 for PVNGS with Dresser 31709NA safety valves are (-48, -20, 0) and (-48, -60, 0). The ring settings used for the pressurizer safety valves at PVNGS are (-48, -60, 0). Thus, APS concluded that the present ring settings would result in satisfactory safety valve operability. This was intended to satisfy APS' responsibility to demonstrate safety valve operability in response to Item II.D.1 of NUREG-0737.

On December 18, 1984, a letter from PVNGS to the NRC was submitted for review. The letter contained proposed CESSAR amendments which dealt in part with changes to be incorporated, based upon the results of CEN-227. In response, the NRC transmitted a letter on March 12, 1985, to PVNGS that requested additional information in a five-question format. Contained within these five questions was a concern about pressurizer

safety valve (PSV) blowdown that became PVNGS Unit 1 license condition 2.C(22).

ANPP met with C-E and the NRC on April 3, 1985, to discuss proposed responses to the five NRC questions. A letter from PVNGS on April 12, 1985 (ANPP-32381), formally provided the responses to the NRC. In Section 5.2.2 of Supplement 8 to the PVNGS Safety Evaluation Report (NUREG-0857) dated May 1985, the NRC staff concluded that the proposed safety valve blowdown changes were acceptable. In addition, on March 23, 1987, the NRC transmitted a letter to PVNGS, requesting additional information about the PSVs' installed configuration and structural analyses, so that the NRC's contractor (Idaho National Engineering Laboratory) could complete its review of PVNGS design with respect to Item II.D.1. The NRC issued its endorsement of the contractor's review on 04/25/1988. This was documented in a letter from NRC to APS, "Performance Testing of Relief and Safety Valves for Palo Verde Units 1, 2 and 3 (TAC No. 61841)," April 25, 1988, stating that PVNGS has ". . . provided an acceptable response to TMI Item II.D.1, reconfirming that General Design Criteria 14, 15 and 30 of Appendix A to 10 CFR Part 50 were met. . . ." The contractor's report notes that CE reanalyzed the Loss of Load Event assuming 20% blowdown, and goes on to state that the ". . .20% blowdown is conservative since the maximum blowdown observed in the applicable EPRI tests was 14.2%. . . ." The contractor also states that " . . .only steam discharge was calculated for FSAR type transients. . ." which is consistent with the 14.2% maximum blowdown test results. The contractor also compares the range of pressure peaks in the tests (2505 psia to

2697 psia) to the peak pressurizer pressure reported for the LFWLB and documents the range of pressurization rates during testing was 2.9 to 322 psi/s, compared to the calculated rates of 14 to 105 psi/s. This letter from NRC discusses plant conformance to the GDCs and provides a license basis of 14.2% maximum blowdown for steam-only discharges for UFSAR events. No additional information was requested for pressurizer fill analyses in this letter. Therefore, another part of satisfying Chapter 18.II.D requirements is to demonstrate that the range of test parameters documented in the PSV tests, CEN-227, is valid for the limiting transients for peak pressurizer pressure (LFWLB) and rate of pressurization (LOCV).

On May 16, 1994 NRC issued TS Amendments 75, 61 and 47 for PVNGS Units 1, 2 and 3 respectively. These amendments involve increasing the pressurizer safety valve (PSV) setpoint tolerance from +/-1% to +3% and –1%. The analysis performed by PVNGS to support the TS Amendments 75, 61 and 47 demonstrated that the pressurizer would not fill for the limiting transient (LOCV event) and that the PSVs would discharge only steam.

Since the performance of CEN-227 and PSV setpoint tolerance changes, PVNGS has changed some plant operating conditions (i.e. 10°F reduction in the core inlet temperature, and 2% increase in nominal power level combined with 2°F additional reduction in the core inlet temperature) which affected the initial conditions used in the CEN-227 analysis. Increased initial power level and lower RCS temperature result in larger swelling of the RCS during a heatup transient. Therefore, an analysis was performed by PVNGS using a blowdown of 14% below the minimum PSV set pressure of 2450 psia (2475 psia –

1% tolerance) and initial conditions set to maximize the pressurizer liquid level. The analysis demonstrates that, for the limiting transient (LFWLB with LOP), the maximum pressurizer liquid level for PVNGS units remains below the PSV nozzles and subcooling is maintained during the period when the PSVs are open.

In summary, analyses demonstrate that a blowdown of 14% below the minimum PSV set pressure of 2450 psia is acceptable and that the pressurizer will not fill and pass only steam for the limiting transient.

18.II.D.3 DIRECT INDICATION OF RELIEF AND SAFETY VALVE POSITION

NRC Position

Reactor coolant system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve-position detection device or a reliable indication of flow in the discharge pipe.

PVNGS Evaluation

PVNGS does not utilize power-operated relief valves. The PVNGS primary code safety valves, located at the top of the pressurizer, are headered into the reactor drain tank (RDT) inside containment. Upstream of the common header each code safety valve is monitored for seal leakage by an in-line resistive-temperature detector (RTD) (refer to engineering drawings 01, 02, 03-M-RCP-001, -002 and -003).

Indirect indication of code safety valve leakage is provided by an increase of RDT pressure and a decrease of pressurizer

pressure and pressurizer level, monitored by safety grade instrumentation.

Positive indication of safety valve position is provided in the control room. Monitoring is provided by an acoustic monitoring system consisting of an accelerometer (acoustic sensor) mounted downstream of each valve. The sensing instrumentation is environmentally qualified to function in a post-LOCA environment in accordance with Regulatory Guide 1.89. A plant annunciator alarm is provided to alarm valve opening. The acoustic monitoring system is powered from a reliable instrument bus with Class 1E backup power. The system is designed to meet the requirements of Revision 2 to Regulatory Guide 1.97.

Installation of positive pressurizer safety valve position indication and development of emergency procedures are completed prior to fuel loading for each of the PVNGS units.

18.II.E SYSTEM DESIGN

18.II.E.1.1 AUXILIARY FEEDWATER SYSTEM EVALUATION

NRC Position

The Office of Nuclear Reactor Regulation is requiring reevaluation of the auxiliary feedwater (AFW) systems for all PWR operating plant licensees and operating license applications. This action includes:

(1) Perform a simplified AFW system reliability analysis that uses event-tree and fault-tree logic techniques to determine the potential for AFW system failure under various loss of main feedwater transient conditions. Particular emphasis is given to determining potential failures that could result from human errors, common causes, single-point vulnerabilities and test and maintenance outages;

(2) Perform a deterministic review of the AFW system using the acceptance criteria of Standard Review Plan Section 10.4.9 and associated Branch Technical Position ASB 10-1 as principal guidance; and

(3) Reevaluate the AFW system flowrate design bases and criteria.

PVNGS Evaluation

An auxiliary feedwater system review was conducted on August 21 and 22, 1980, and included NRC participation.

This review included a review of the PVNGS auxiliary feedwater system reliability analysis. A transcript of this review was provided to the NRC on October 17, 1980. Responses to open

items of the review were provided to the NRC on March 6, 1981. The PVNGS auxiliary feedwater system reliability analysis was performed in response to the NRC letter of March 10, 1980, from D. F. Ross, Jr., to All Pending Operating License Applicants of Nuclear Steam Supply Systems Designed by Westinghouse and Combustion Engineering. The final analysis was submitted to the NRC by APS letter dated February 10, 1981, from E. E. Van Brunt, Jr., to the Director of Nuclear Reactor Regulation. The final analysis (formerly Appendix 10B) has been archived as historical information-only in PVNGS engineering calculation 13-NC-AF-200, "Auxiliary Feedwater System (AFS) Reliability Analysis."

18.II.E.1.2 AUXILIARY FEEDWATER SYSTEM AUTOMATIC INITIATION AND FLOW INDICATION

Part 1: Auxiliary Feedwater System Automatic Initiation

NRC Position

Consistent with satisfying the requirements of General Design Criterion 20 of Appendix A to 10CFR Part 50 with respect to the timely initiation of the auxiliary feedwater system (AFWS), the following requirements shall be implemented in the short-term:

(1) The design shall provide for the automatic initiation of the AFWS.

(2) The automatic initiation signals and circuits shall be designed so that a single failure will not result in the loss of AFWS function.

(3) Testability of the initiating signals and circuits shall be a feature of the design.

(4) The initiating signals and circuits shall be powered from the emergency buses.

(5) Manual capability to initiate the AFWS from the control room shall be retained and shall be implemented so that a single failure in the manual circuits will not result in the loss of system function.

(6) The ac motor-driven pumps and valves in the AFWS shall be included in the automatic actuation (simultaneous and/or sequential) of the loads onto the emergency buses.

(7) The automatic initiating signals and circuits shall be designed so that their failure will not result in the loss of manual capability to initiate the AFWS from the control room.

In the long-term, the automatic initiation signals and circuits shall be upgraded in accordance with safety grade requirements.

Part 2: Auxiliary Feedwater System Flowrate Indication NRC Position

Consistent with satisfying the requirements set forth in General Design Criterion 13 to provide the capability in the control room to ascertain the actual performance of the AFWS when it is called to perform its intended function, the following requirements shall be implemented:

(1) Safety grade indication of auxiliary feedwater flow to each steam generator shall be provided in the control room.

(2) The auxiliary feedwater flow instrument channels shall be powered from the emergency buses consistent with satisfying the emergency power diversity requirements of the auxiliary feedwater system set forth in Auxiliary Systems Branch Technical Position 10-1 of the Standard Review Plan, Section 10.4.9.

PVNGS Evaluation

A. Automatic Initiation

1. The AFWS shown in engineering drawings 01, 02, 03-M-AFP-001 consists of two Seismic Category I pumps and their associated flow paths and valves and one non-Seismic Category I pump and its associated flow paths and valves.

   The feedwater trains of the AFWS are provided to automatically initiate residual heat removal capability during emergency conditions, such as a steam line rupture, loss of normal feedwater, or loss of offsite and normal onsite power.

   The feedwater trains of the AFWS are automatically actuated by an auxiliary feedwater actuation signal (AFAS) from the engineered safety features actuation system (ESFAS). The AFAS is initiated for each steam generator by a low steam generator level coincident with a "not ruptured" calculated signal for that steam generator (refer to CESSAR Figure 7.3-1d).

The AFAS logic determines whether a steam generator is not intact in the event of a secondary system break by sensing:

- The steam generator has initiated a low water level trip.
- The steam generator pressure is less than the other by a predetermined value.
- The other steam generator has been calculated as not being ruptured.

The startup train portion of the AFWS is provided for normal nonemergency operation during startup, cooldown, and hot standby.

2. The emergency feedwater trains of the AFWS are composed of components in two separate and independent load groups (i.e., load group 1 and load group 2). Each of the four emergency feedwater valves associated with each steam generator is automatically actuated in such a manner that no single failure can prevent either the supply of AFW to an intact steam generator or the isolation of AFW from a ruptured steam generator. Load group 2 powers the emergency motor-driven AFW pump and its associated valves and controls. Load group 1 supplies dc power to the steam-driven turbine controls and the valves associated with the emergency turbine-driven AFW pump. No ac power is required for support of the turbine-driven emergency feedwater train. The

instrumentation and controls of the components and equipment in load group 1 are physically and electrically separate and independent of the instrumentation and controls of the components and equipment in load group 2. This separation is maintained such that both trains are not terminated on common logic circuits.

3. Provisions are made to permit periodic testing of the AFW initiation signals and circuitry. These tests cover the trip actions from sensor input through the protection system and actuation devices. The system test does not interfere with the system protection function. The testing system meets the criteria of IEEE 338-1971, IEEE Trial-Use Criteria for Periodic Testing of Nuclear Power Generating Station Protective Systems, and Regulatory Guide 1.22, Periodic Testing of Protection System Actuator Functions. Testing is performed in accordance with the surveillance test requirements of the PVNGS Technical Specifications.

4. AFAS circuits are a part of the ESFAS. The initiating signals and circuits are powered from Class 1E buses in separate load groups as discussed in sublisting 2. The initiating sensors are powered from separate and redundant Class 1E instrumentation channels, each of which is supplied by either offsite power, or the associated diesel generator when offsite power is

not available and is backed up by a Class 1E battery.

5. Manual initiation capability for each AFW train exists in the control room. Control of individual AFWS components is also available in the control room. No single failure in the manual initiation portion of the circuit can result in the loss of AFWS function.

6. The Seismic Category I ac motor-driven pump and power-operated valves in its train are automatically and sequentially loaded on the associated diesel generator bus upon loss of offsite power.

7. Failure of the AFAS and circuits will not result in the loss of manual capability to control AFWS components from the control room.

8. AFAS circuits are Class 1E.

The PVNGS AFWS complies with the recommendations of NUREG-0737, November 1980.

B. Flow Indication

1. The PVNGS design includes monitoring of AFW flow to both steam generators. These flow indicator channels are displayed on the main control boards. The flow indication system is environmentally qualified. Class 1E (safety grade) pressure indicators located upstream of the manual block valves and Class 1E steam generator level indicators are also provided.

Pressure indicator PI-18A monitors the train A turbine-driven AFW pump discharge pressure and flow indicators FI-40A and FI-41A will monitor flow to steam generator 1 (refer to engineering drawings 01, 02, 03-M-AFP-001). Pressure indicator PI-17A monitors the train B motor-driven AFW pump discharge pressure, and flow indicators FI-40B and FI-41B will monitor the flow to steam generator 2. Four channels of Class 1E steam generator level indication are provided for each steam generator.

2. The safety grade pressure and level and the added flow indication channels are powered from redundant Class 1E buses.

18.II.E.3.1 EMERGENCY POWER SUPPLY FOR PRESSURIZER HEATERS

NRC Position

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17, and 20 of Appendix A to 10CFR Part 50 for the event of loss of offsite power, the following positions shall be implemented:

(1) The pressurizer heater power supply design shall provide the capability to supply, from either the offsite power source or the emergency power source (when offsite power is not available), a predetermined number of pressurizer heaters and associated controls necessary to establish and maintain natural circulation at hot standby conditions. The required heaters and their controls shall

be connected to the emergency buses in a manner that will provide redundant power supply capability.

(2) Procedures and training shall be established to make the operator aware of when and how the required pressurizer heaters shall be connected to the emergency buses. If required, the procedures shall identify under what conditions selected emergency loads can be shed from the emergency power source to provide sufficient capacity for the connection of the pressurizer heaters.

(3) The time required to accomplish the connection of the preselected pressurizer heater to the emergency buses shall be consistent with the timely initiation and maintenance of natural circulation conditions.

(4) Pressurizer heater motive and control power interfaces with the emergency buses shall be accomplished through devices that have been qualified in accordance with safety grade requirements.

PVNGS Evaluation

Preoperational testing determined the actual PVNGS heat loss to be less than 403,000 Btu/h. Assuming a heat loss of 403,000 Btu/h, a heater capacity of 125 kW is sufficient to offset pressurizer heat loss.

The PVNGS pressurizer heaters are configured as follows:

1. The PVNGS pressurizer heaters for Unit 1 (35 elements rated at 50kW each generally connected in groups of three delta-connected elements each) have a total rated capacity of

1750 kW. The PVNGS pressurizer heaters for Unit 2 (34 elements rated at 50kW each generally connected in groups of three delta-connected elements each) have a total rated capacity of 1700 kW. The PVNGS pressurizer heaters for Unit 3 (36 elements rated at 50 kW each, connected in 12 groups of three delta-connected elements each) have a total rated capacity of 1800 kW. The heaters are powered from the non-Class 1E and Class 1E distribution systems as shown in table 18.II.E-1. Redundant heater rated capacity of 150 kW is available for manual loading on the emergency diesel generators upon loss of offsite (preferred) power. The emergency diesel generators are sized to accommodate this heater capacity concurrent with a forced shutdown (refer to table 8.3-3). In the event that heater capacity beyond that powered from a Class 1E source (150 KW on each train) is required, heaters can be supplied from the non-Class 1E power system that is fed from the offsite power system.

Table 18.II.E-1
PVNGS PRESSURIZER HEATERS
Units 1 and 3

Unit 1							
Number of Heaters	Capacity (kW)	480V Bus	1E Power	1E Controls	SIAS Trip	Reset from Control Room	SIAS Override from Control Room
4-3 elements	600	NGN-L11	No	No	No	N/A	N/A
5-3 elements	750	NGN-L12	No	No	No	N/A	N/A
1-2 elements	100	NGN-L11	No	No	No	N/A	N/A
1-3 elements	150	PGA-L33	Train A	Train A	Yes	No	Yes
1-3 elements	150	PGB-L32	Train B	Train B	Yes	No	Yes

Unit 2							
Number of Heaters	Capacity (kW)	480V Bus	1E Power	1E Controls	SIAS Trip	Reset from Control Room	SIAS Override from Control Room
4-3 elements	600	NGN-L11	No	No	No	N/A	N/A
4-3 elements	600	NGN-L12	No	No	No	N/A	N/A
1-2 elements	100	NGN-L11	No	No	No	N/A	N/A
1-2 elements	100	NGN-L12	No	No	No	N/A	N/A
1-3 elements	150	PGA-L33	Train A	Train A	Yes	No	Yes
1-3 elements	150	PGB-L32	Train B	Train B	Yes	No	Yes

Unit 3							
Number of Heaters	Capacity (kW)	480V Bus	1E Power	1E Controls	SIAS Trip	Reset from Control Room	SIAS Override from Control Room
5-3 elements	750	NGN-L11	No	No	No	N/A	N/A
5-3 elements	750	NGN-L12	No	No	No	N/A	N/A
1-3 elements	150	PGA-L33	Train A	Train A	Yes	No	Yes
1-3 elements	150	PGB-L32	Train B	Train B	Yes	No	Yes

2. Heaters fed from the Class 1E power system (300 kW) are automatically shed upon receipt of a safety injection actuation signal (SIAS). They may subsequently be manually reconnected to the engineered safety feature (ESF) buses without shedding of any loads from the Class 1E buses.

   Sufficient margin exists in each diesel generator for at least an additional 150 kW heater.

3. The redundant pressurizer heaters required for maintenance of natural circulation at hot standby are fed from Class 1E buses via Class 1E load side breakers qualified in accordance with safety grade requirements.

4. Appropriate procedures and operator training has been established to make the operator aware of when and how the required pressurizer heaters are to be connected to the emergency buses.

18.II.E.4.1 DEDICATED HYDROGEN PENETRATIONS

NRC Position

Plants using external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere should provide containment penetration systems for external recombiner or purge systems that are dedicated to that service only, that meet the redundancy and single failure requirements of General Design Criteria 54 and 56 of Appendix A to 10CFR50, and that are sized to satisfy the flow requirements of the recombiner or purge system.

The procedures for the use of combustible gas control systems following an accident that results in a degraded core and release of radioactivity to the containment must be reviewed and revised, if necessary.

PVNGS Evaluation

Redundant independent combustible gas control systems are provided. Each system has external hydrogen monitors and connection points for an external hydrogen recombiner. Train A and Train B have a dedicated penetration. Train A meets the requirements of NUREG-0737, Sup 1, Task II.E.4.1. Two portable hydrogen recombiners are onsite and available for connection to the affected unit. Either recombiner is capable of reducing hydrogen levels as noted in subsection 6.2.5. The two systems are completely independent and meet single failure criteria.

An additional hydrogen reduction capability is provided by a charcoal filtered hydrogen purge exhaust air filteration unit. This nonsafety grade unit can be connected to either set of gas control containment penetrations. This capability would only be utilized in the event of separate failures in both recombiner units.

The arrangement of these combustible gas control methods is shown in engineering drawings 01, 02, 03-M-HPP-001.

As noted in paragraph 12.1.2.4, the dose rate during installation of the hydrogen recombiners will be less than 5 rem/hr. This rate allows the requirements of GDC 19 to be met.

18.II.E.4.2 CONTAINMENT ISOLATION DEPENDABILITY

NRC Position

(1) Containment isolation system designs shall comply with the recommendations of Standard Review Plan Section 6.2.4 (i.e., that there be diversity in the parameters sensed for the initiation of containment isolation).

(2) All plant personnel shall give careful consideration to the definition of essential and nonessential systems, identify each system determined to be essential, identify each system determined to be nonessential, describe the basis for selection of each essential system, modify their containment isolation designs accordingly, and report the results of the reevaluation to the NRC.

(3) All nonessential systems shall be automatically isolated by the containment isolation signal.

(4) The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action.

(5) The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions.

(6) Containment purge valves that do not satisfy the operability criteria set forth in Branch Technical

Position CSB 6-4 or the Staff Interim Position of October 23, 1979, must be sealed closed as defined in SRP 6.2.4, Item II.6.f, during operational conditions 1, 2, 3, and 4. Furthermore, these valves must be verified to be closed at least every 31 days.

(7) Containment purge and vent isolation valves must close on a high radiation signal.

PVNGS Evaluation

Refer to FSAR subsection 6.2.4. In addition, the PVNGS containment isolation system is designed as follows:

1. As required by SRP 6.2.4, a containment isolation signal is diversely generated by either a high containment pressure signal or a low pressurizer pressure signal. The power access purge and refueling purge are additionally isolated by high containment purge radioactivity.

2. A generic review of fluid systems penetrating the containment for C-E designed plants was conducted for the C-E Owner's Group on Post-TMI Efforts. The results of this review were used by Arizona Public Service to evaluate the PVNGS containment isolation system.

   Essential systems are those systems critical to ensure the capability to mitigate consequences of accidents, to ensure the integrity of the reactor coolant pressure boundary, and to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition. Table 18.II.E-2

lists essential systems penetrating the PVNGS containment. No essential systems are functionally isolated by a containment isolation actuation signal (CIAS) with the exception of the hydrogen control system, as classified in the table. This system is not immediately required for accident mitigation. The isolation valves can be manually opened from the control room as part of the hydrogen recombiner startup procedures.

The steam supply for the turbine-driven AFW pump is from the main steam lines, upstream of the main steam isolation valves (MSIVs). The steam supply valves on the main steam lines are normally closed. These valves automatically open on an AFAS, and can be manually overridden from the main control room. A CIAS does not affect the operation of the isolation valves.

The atmospheric dump valves (ADVs) are normally closed and are manually operated from the main control room and remote shutdown panel. These valves are used to release steam from the steam generators to the atmosphere for reactor heat removal. The ADVs are located upstream of the MSIVs and are not affected by a CIAS.

3. Nonessential systems penetrating the PVNGS containment are listed in table 18.II.E-3. Nonessential systems are automatically isolated

by a CIAS with the exception of the following systems:

- Those containing locked closed valves or flanged closed connections

Table 18.II.E-2
ESSENTIAL SYSTEMS PENETRATING THE PVNGS CONTAINMENT

System	Normal Position	Post CIAS Position	Notes
HPSI	Closed	Open	(a)(h)
LPSI	Closed	Open	(a)(h)
Containment spray	Closed	Closed	(b)(h)
Recirculation sump suction	Closed	Closed	(c)(h)
Long-term recirculation	Closed	Closed	(d)(h)
Auxiliary feedwater	Closed	Closed	(e)(h)
H_2 control	Closed	Closed	(d)(g)
Containment pressure sensor	Open	Open	(f)(h)
Shutdown cooling system	Closed	Closed	(d)(h)

a. Opens on safety injection actuation signal

b. Opens on containment spray actuation signal

c. Opens on recirculation actuation signal

d. Manually opened from control room

e. Opens on auxiliary feedwater actuation signal

f. Function requires it to remain open

g. Isolates on containment isolation actuation signal

h. These penetrations are not directly affected by a CIAS. However, some of the same conditions that cause a CIAS will result in other signals or actuations that could result in valves and systems shifting position. The positions shown for these penetrations would generally result from conditions that would cause a CIAS, or would be the normal positions during plant operations and would not be expected to change following a CIAS. The actual plant conditions, resulting signals, or valve lineups must be examined to accurately determine each system's post-CIAS alignment.

- Main steam and feedwater
- Steam generator blowdown and blowdown sample and safety injection drain
- Reactor coolant pump (RCP) seal injection and chemical and volume control system (CVCS) charging
- Nuclear cooling water system
- CVCS RCP seal bleedoff
- Instrument air

The nuclear cooling water system, CVCS RCP seal bleedoff, and instrument air are all required to support continued operation of two reactor coolant pumps following a safety injection activation (which occurs concurrently with a containment isolation actuation). Continued operation of two reactor coolant pumps is required to support the RCP trip two/leave two strategy which is discussed in subsection 18.II.K.3.5.

The main steam and feedwater systems, while not essential, aid in heat removal during a small loss-of-coolant accident (LOCA). These systems should not, therefore, be isolated by a CIAS generated on low pressurizer pressure. The steam and feedwater systems are isolated for a main steam line break by a main steam isolation actuation signal (MSIS) on high containment pressure or low steam generator pressure.

Table 18.II.E-3
NONESSENTIAL SYSTEMS PENETRATING THE
PVNGS CONTAINMENT (Sheet 1 of 2)

System	Normal Position	Post CIAS Position	Notes
Demineralized water	Closed	Closed	Locked (i)
Fire protection	Closed	Closed	Locked (i)
Pool cooling	Closed	Closed	Locked (i)
Fuel transfer	Closed	Closed	Flanged (i)
Containment test	Closed	Closed	Flanged (i)
Service air	Closed	Closed	Locked (i)
Integrated leak rate test	Closed	Closed	Flanged (i)
Personnel lock	Closed	Closed	- (i)
Equipment hatch	Closed	Closed	- (i)
Emergency lock	Closed	Closed	- (i)
Pressurizer sample - water	Closed	Closed	(a)
Pressurizer sample - steam	Closed	Closed	(a)
Hot leg sample	Closed	Closed	(a)
High pressure nitrogen	Closed	Closed	(a)
Containment purge (refueling)	Closed	Closed	(g)(i)
Radiation monitor	Open	Closed	(a)
Low pressure nitrogen	Open	Closed	(a)
Instrument air	Open	Open	(h)(i)
Nuclear cooling water	Open	Open	(h)(i)
CVCS letdown	Open	Closed	(a)
CVCS seal bleedoff	Open	Open	(h)(i)
Reactor drain tank (RDT) vent	Open	Closed	(a)
CVCS RDT drain/fill	Open	Closed	(a)
Chilled water	Open	Closed	(a)
Power access purge	Open	Closed	(a)(b)
Containment normal sump	Open	Closed	(a)
Main steam	Open	Open	(c)(i)
Main feedwater	Open	Open	(c)(i)
Steam generator blowdown	Open	Open	(d)(i)
Steam generator blowdown sample: Hot leg	Open	Open	(d) (i)
Cold leg	Open	Open	(d) (i)
Downcomer	Open	Open	(d) (i)

Table 18.II.E-3
NONESSENTIAL SYSTEMS PENETRATING THE
PVNGS CONTAINMENT (Sheet 2 of 2)

System	Normal Position	Post CIAS Position	Notes
Safety injection drain	Closed	Closed	(e) (i)
RCP seal injection	Open	Open	(f) (i)
CVCS charging	Open	Open	(f) (i)
Gaseous radwaste	Open	Closed	(a)

a. Closes on containment isolation actuation signal

b. Closes on containment purge isolation actuation signal

c. Closes on main steam isolation signal

d. Closes on main steam isolation signal, auxiliary feedwater actuation signal, or safety injection actuation signal

e. Closes on safety injection actuation signal

f. Seismic Category I check valve inside containment

g. Sealed closed during normal operations (modes 1-4)

h. Closes on containment spray actuation signal

i. These penetrations are not directly affected by a CIAS. However, some of the same conditions that cause a CIAS will result in other signals or actuations that could result in valves and systems shifting position. The positions shown for these penetrations would generally result from conditions that would cause a CIAS, or would be the normal positions during plant operations and would not be expected to change following a CIAS. The actual plant conditions, resulting signals, or valve lineups must be examined to accurately determine each system's post-CIAS alignment.

The steam generator blowdown and blowdown sample systems are isolated by either a MSIS, AFAS, or a SIAS. The safety injection drain is isolated on a SIAS. Plant parameters which generate SIAS also generate CIAS.

It is desirable to leave RCP seal injection and CVCS charging paths open to provide additional core protection after an accident in which offsite power is available. See Section 9.3.4.7.A.2 for a description of emergency power for the charging pumps. Conversely, it is undesirable to lose charging or seal injection capability during normal operation due to an inadvertent CIAS. The potential release of fission products through the penetration is not a concern for the following reasons:

- Flow is into the containment and RCS.
- Check valves inside the containment prevent backflow out of the containment if the charging pumps stop.
- The connecting portions of the CVCS outside of containment are designed to Safety Class 2, Seismic Category I standards and have design pressure well in excess of containment design pressure.

- The operator has the capability of isolating these lines if continued charging or seal injection proves to be unnecessary.

4. Override of a CIAS signal is available for each containment isolation valve via the control switch for that valve. Resetting of a CIAS does not result in the automatic opening of containment isolation valves. Reopening requires operator action for each valve and does not compromise the containment isolation signal.

5. The containment high-pressure setpoint is shown in Table 7.3-11A. Both the CIAS and the SIAS are actuated at this setpoint. The setpoint was established to conservatively bound expected fluctuations in containment pressure due to such factors as instrument air leakage, containment air temperature changes, and changes in differential pressure between inside and outside containment. It also takes into account instrument error.

   Since the high containment pressure setpoint actuates both the CIAS and SIAS, it was conservatively established to minimize spurious challenges to the safety injection system.

6. Containment power access purge isolation valves satisfy the operability criteria set forth in Branch Technical Position CSB 6-4. Containment refueling purge isolation valves will be sealed closed except during operational modes 5 and 6.

These valves will be verified closed once every 31 days (cold shutdown and refueling, respectively).

7. The power access purge and the refueling purge isolate on containment purge high radioactivity.

18.II.F INSTRUMENTATION AND CONTROLS

18.II.F.1 ADDITIONAL ACCIDENT MONITORING INSTRUMENTATION

A human factor analysis has been performed to ensure that the displays and controls added for additional accident monitoring do not increase the potential for operator error. For information on the analysis see Section 18.I.D.1.

18.II.F.1.1 NOBLE GAS EFFLUENT MONITOR

NRC Position

Noble gas effluent monitors shall be installed with an extended range design to function during accident conditions as well as during normal operating conditions. Multiple monitors are considered necessary to cover the ranges of interest.

(1) Noble gas effluent monitors with an upper range capacity of $10^{(5)}$ μCi/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

(2) Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal condition (as low as reasonably achievable (ALARA)) concentrations to a maximum of $10^{(5)}$ μCi/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of 10.

PVNGS Evaluation

Section 11.5 provides detailed descriptions of the effluent monitors installed at Palo Verde Units 1, 2, and 3. This

includes the additional monitors that have been added specifically to address NUREG-0737 and Regulatory Guide 1.97, Revision 2, requirements for radiation monitoring. A description of the calibration sources, frequency of calibration, and technique is provided in table 11.5-1 and paragraph 11.5.2.1.6.2 respectively. The instrumentation is described in detail in table 11.5-1.

A description of effluent radiation monitoring is presented in paragraph 11.5.2.1.4. Included in this section are discussions of monitors located on the plant vent and fuel building vent. The main steam line monitors are area monitors required for post-accident monitoring and are discussed in paragraph 11.5.2.1.5.6.

These monitors operate in conjunction with other monitors, as described in section 11.5, and fulfill the requirements as outlined in NUREG-0737 and Regulatory Guide 1.97, Revision 2.

18.II.F.1.2 SAMPLING AND ANALYSIS OF PLANT EFFLUENTS

<u>NRC Position</u>

Because iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radio iodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

PVNGS Evaluation

The effluent sampling assembly is discussed in paragraph 11.5.2.1.1.7.2. For high range particulate and iodine samplers, the sampler is a lead-shielded filter assembly.

Sampling of effluents meets the criteria of ANSI N13.1-1969 as discussed in paragraphs 11.5.2.1.1.7.2 and 11.5.2.2.1. Paragraph 11.5.2.1.1.7.2 also describes the sampling assembly.

Monitors are designed to meet a 90% efficiency level for particulates and 90% efficiency for iodine as required by NUREG-0737, Table II.F.1-2. They are also designed to conform with design basis shielding envelopes for sampling media as discussed in paragraph 12.1.2.4. Monitors are designed to allow personnel to remove, replace, and transport sampling media without exceeding the criteria of General Design Criterion 19 of 5 rem whole-body and 75 rem to the extremities.

18.II.F.1.3 CONTAINMENT HIGH RANGE RADIATION MONITOR

NRC Position

In containment radiation-level monitors with a maximum range of 10^8 rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be developed and qualified to function in an accident environment.

This requirement was revised in the October 30, 1979 letter, from H. R. Denton to All Operating Nuclear Power Plants, to provide for photon-only measurement with an upper range of 10^7 rad/hr.

PVNGS Evaluation

As noted in table 11.5-1, in-containment area monitors XJ-SQA-RU-148 and XJ-SQB-RU-149 are provided to measure γ-photon activity with an upper range of 10^7 rad/hr.

Table II.F.1-3 of NUREG-0737 specifies that, for containment high-range monitors, an in situ calibration for at least one decade below 10 R/hr shall be by means of a calibrated radiation source. In lieu of an external source, PVNGS utilizes a calibrated source that is internal to each containment high-range radiation monitor. The specific calibration method used (described in section 11.5.2.1.6.2) is technically comparable to methods that use external sources and meets the intent of performing an situ calibration (i.e., verify detector operability and accuracy after in situ installation).

18.II.F.1.4 CONTAINMENT PRESSURE MONITOR

NRC Position

A continuous indication of containment pressure shall be provided in the control room of each operating reactor. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel, and -5 psig for all containments.

PVNGS Evaluation

Wide range containment pressure measurement is provided in paragraph 7.5.1.1.5 Table 1.8-1, and the appendix 6A response to Question 6A.14.

Wide range containment pressure measurement is provided, consisting of redundant pressure transmitters whose signals of containment pressure are continuously displayed within the control room. Continuous recording is provided for one channel over the entire range of pressure measurement. The transmitters are located outside of the containment structure and measure the containment pressure through sensing lines penetrating the containment structure. The range of the system is from -5 to 180 psig, three times the containment pressure.

The transmitters are physically separated, redundant, environmentally qualified to function in a post-LOCA environment in accordance with Regulatory Guide 1.89, Rev. 1 and seismically qualified to function during and following an SSE in accordance with Regulatory Guide 1.100. The safety grade pressure instrumentation is powered from redundant Class 1E buses. The instrumentation is designed to meet Regulatory Guide 1.97, Revision 2.

18.II.F.1.5 CONTAINMENT WATER LEVEL MONITOR

NRC Position

A continuous indication of containment water level shall be provided in the control room for all plants. A narrow range instrument shall be provided for pressurized water reactors (PWRs) and cover the range from the bottom to the top of the

containment sump. A wide range instrument shall also be provided for PWRs and shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000 gallon capacity. For boiling water reactors (BWRs), a wide range instrument shall be provided and cover the range from the bottom to 5 feet above the normal water level of the suppression pool.

PVNGS Evaluation

Narrow range water level instrumentation monitoring the containment radwaste sumps, and wide range containment water level instrumentation are discussed in paragraph 7.5.1.1.5, and Table 1.8-1.

Continuous indication of the containment radwaste sumps (containment normal sumps) water level is provided in the control room by narrow range level instrumentation. Each sump is monitored from 6 inches above the bottom of the sump to 6 inches above the top of the sump. The instrumentation ispowered from a reliable instrument bus with Class 1E backup power. The instrumentation is designed to meet the requirement of Regulatory Guide 1.97, Revision 2.

Continuous control room indication is provided for containment water level by wide range level instrumentation from 6 inches above the top of the radwaste sump to 6-inches above the maximum expected flood level, providing a total range of 12 feet. The sensors are physically separated, redundant, environmentally qualified to function in a post-LOCA environment in accordance with Regulatory Guide 1.89, and seismically qualified to function during and following an SSE

in accordance with Regulatory Guide 1.100. The safety grade level instrumentation is powered from redundant Class 1E buses. Recording for one channel is provided in the control room. The instrumentation is designed to meet Regulatory Guide 1.97, Revision 2.

18.II.F.1.6 CONTAINMENT HYDROGEN MONITOR

NRC Position

A continuous indication of hydrogen concentration in the containment atmosphere shall be provided in the control room. Measurement capability shall be provided over the range of 0 to 10% hydrogen concentration under both positive and negative ambient pressure.

PVNGS Evaluation

A description of the containment hydrogen monitoring system is provided in paragraph 6.2.5.2.2.2. The range and accuracy of the hydrogen analyzer control room indication provided to meet Item II.F.1.6 is given in table 7.5-1.

A remote control panel mounted on the main control board provides control of each analyzer. Recording for one channel is also provided in the control room. The analyzers, one per each train, are in standby during normal operation and can provide continuous indication of hydrogen concentration in less than 30 minutes after activation from the control room. The analyzers can operate under containment design conditions from -5 to 60 psig, the containment design pressure. The analyzers are environmentally qualified to function in a post-LOCA environment in accordance with Regulatory Guide 1.89 and

seismically qualified to function during and following an SSE in accordance with Regulatory Guide 1.100. The safety grade hydrogen analyzer instrument channels are powered from redundant Class 1E buses.

The instrumentation is designed to meet Regulatory Guide 1.97, Revision 2.

18.II.F.2 INSTRUMENTATION FOR DETECTION OF INADEQUATE CORE COOLING

NRC Position

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including primary coolant saturation monitors) in order to provide an unambiguous, easy to interpret indication of inadequate core cooling (ICC). A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

PVNGS Evaluation

In addition to the NRC position stated above, 38 itemized design requirements pertaining to inadequate core cooling (ICC) were submitted within NUREG-0737, Section II.F.2. Combustion Engineering (C-E) has provided in CESSAR a generic response to these design requirements which is applicable to PVNGS except for minor deviations, and requirements that are plant specific.

The subsequent PVNGS response provides a description of the instrumentation and equipment that has been incorporated into the PVNGS design to meet ICC requirements. The exceptions previously taken to the C-E response within CESSAR, Appendix B, Section II.F.2 have been incorporated into that responses and are now presented below.

(1) Description of ICC Instrumentation and Equipment Incorporated by PVNGS

The instrumentation added by PVNGS to supplement existing instrumentation for detection of ICC is comprised of core exit thermocouples (CET), heated junction thermocouples (HJT), and a subcooled margin monitor (SMM). The function of this ICC instrumentation is to enhance the ability of the control room operators to diagnose the approach to, existence of, and recovery from ICC.

An unambiguous and easy to interpret indication of ICC is provided by two channels of safety grade microcomputers, which process inputs from ICC instrumentation and transmittal of ICC status to seismically qualified displays located in the control room. Trending of ICC parameters is provided by paperless recorders which are also located in the control room.

(2) Exceptions Taken to C-E Response Within CESSAR, Appendix B, Section II.F.2

Only the description of the qualified safety parameter display system (QSPDS) in Appendix 18B, relates to the system which PVNGS has incorporated to provide for ICC. PVNGS has similar design capabilities to the accident

monitoring system described in Appendix 18B but it is not all related to ICC requirements of NUREG-0737, Section II.F.2.

The saturation margin monitor (SMM) referred to in CESSAR is designated the subcooled margin monitor (SMM) at PVNGS.

Figure 18B-1 shows "Other QSPDS inputs" to QSPDS. These other inputs are not ICC related parameters.

(3) PVNGS Responses to the Requirements of NUREG-0737, Section II.F.2

Table 18.II.F.2-1 addresses the Documentation Required section of NUREG-0737, Section II.F.2.

Table 18.II.F.2-2 addresses the requirements of NUREG-0737, Section II.F.2, Attachment I, Design and Qualification Criteria for Pressurized-Water Reactor Incore Thermocouples.

Table 18.II.F.2-3 addresses the requirements of NUREG-0737, Appendix B, Design and Qualification Criteria for Accident Monitoring Instrumentation.

Table 18.II.F.2-1

REQUIRED DOCUMENTATION

(Sheet 1 of 8)

NRC Requirements

The licensee shall provide a report detailing the planned instrumentation system for monitoring of ICC. The report should contain the necessary information, either by inclusion or by reference to previous submittals including pertinent generic reports, to satisfy the requirements which follow:

(1) A description of the proposed final system including:

  (a) a final design description of additional instrumentation and displays;

  (b) a detailed description of existing instrumentation systems (e.g., subcooling meters and incore thermocouples), including parameter ranges and displays, which provide operating information pertinent to ICC considerations; and

  (c) a description of any planned modifications to the instrumentation systems described in item 1.b above.

(2) The necessary design analysis, including evaluation of various instruments to monitor water level, and available test data to support the design described in item 1 above.

(3) A description of additional test programs to be conducted for evaluation, qualification, and calibration of additional instrumentation.

(4) An evaluation, including proposed actions, on the conformance of the ICC instrument system to this document, including Attachment 1 and Appendix A. Any deviations should be justified.

Table 18.II.F.2-1

REQUIRED DOCUMENTATION

(Sheet 2 of 8)

(5) A description of the computer functions associated with ICC monitoring and functional specifications for relevant software in the process computer and other pertinent calculators. The reliability of nonredundant computers used in the system should be addressed.

(6) A current schedule, including contingencies, for installation, testing and calibration, and implementation of any proposed new instrumentation or information displays.

(7) Guidelines for use of the additional instrumentation, and analyses used to develop these procedures.

(8) A summary of key operator action instructions in the current emergency procedures for ICC and a description of how these procedures will be modified when the final monitoring system is implemented.

(9) A description and schedule commitment for any additional submittals which are needed to support the acceptability of the proposed final instrumentation system and emergency procedures for ICC.

Requirement	PVNGS Response
(1)(a)	Description of the ICC Detection Instrumentation is provided in Appendix 18B, section 2.0.
(1)(b)	The instrumentation described in Appendix 18B, section 2.0, will be the ICC detection instrumentation design for the System 80 plant.

Table 18.II.F.2-1

REQUIRED DOCUMENTATION

(Sheet 3 of 8)

Requirement	PVNGS Response
(1)(c)	There are no changes planned for instrumentation or displays related to ICC functions based upon previous evaluation.
(2)	The design analysis and evaluation of the ICC detection instrumentation is presented in Appendix 18B, Section 1.0 and Appendix 18B-A. The HJTC-based reactor vessel level monitoring system has been tested in three phases: Phase 1 - Proof of Principle Tests, Phase 2 - Design Development Tests, and Phase 3 - Prototype Tests. The results of these tests are available in the Phase 1, Phase 2, and Phase 3 Test Reports.
(3)	The Phase 3 test program consisted of high temperature and pressure testing of a manufactured production prototype system HJTC probe assembly and processing electronics. The Phase 3 test program was executed at the C-E test facility used for the Phase 2 test.
	No special verification or experimental tests are planned for the hot leg and cold leg RTD sensors, the pressurizer pressure sensors, or the Type K (chromelalumel) core exit thermocouples since they are standard high quality nuclear instruments with well known responses.

Table 18.II.F.2-1

REQUIRED DOCUMENTATION

(Sheet 4 of 8)

For qualification testing, all out-of-vessel sensors and equipment, including the QSPDS up to and including the ERFDADS isolation, is environmentally qualified according to the methodology presented in Section 3.11, and seismically qualified according to the methodology presented in Section 3.10.

(4) Evaluation, proposed actions, and conformance to NUREG-0737, Section II.F.2, is inclusive in this response.

(5) The ICC detection instrumentation processing and display consists of two computer systems; the 2 redundant channel safety grade microcomputer based QSPDS, and the single large scale non safety grade computer based ERFDADS. The ICC inputs are acquired and processed by the safety grade QSPDS and isolated and transmitted to the primary display in the non-safety-grade ERFDADS. The QSPDS also has the seismically qualified displays for the ICC detection instruments. The software functions for processing are listed in Appendix 18B, Section 2.2; the functions for display are listed in Appendix 18B, Section 2.3.

Table 18.II.F.2-1

REQUIRED DOCUMENTATION

(Sheet 5 of 8)

The software for the QSPDS has been designed using the recommendations of the draft standard, IEEE Std. P742/ANS 4.3.2, "Criteria for the Application of Programmable Digital Computer Systems in the Safety Systems of Nuclear Power Generating Stations" as a design guideline. This design procedure verifies and validates that the QSPDS software is properly implemented and integrated with the system hardware to meet the system's functional requirements. This procedure is quality assured by means of the C-E QADP. Although the ERFDADS is designed as a non-safety class system, a similar procedure is being applied to the ERFDADS design to assure compatibility with the QSPDS.

The QSPDS hardware is designed as a redundant safety grade qualified computer system which is designed to the availability goal of 0.99 with the appropriate spare parts and maintenance support. The ERFDADS is a single highly reliable computer system that is designed to the availability goal of (0.99) with the appropriate spare parts and maintenance support.

(6) The ICC instrumentation is expected to be fully operational prior to a unit exceeding 5% power for the first time.

Table 18.II.F.2-1

REQUIRED DOCUMENTATION

(Sheet 6 of 8)

(7) Guidance for the use of ICC instrumentation is contained in the C-E Owner's Group Emergency Procedure Guidelines, CEN-152, and in the PVNGS Emergency Procedure Generation Packages.

(8) The PVNGS Emergency Procedures currently contain guidance with respect to ICC. The ICC modifications are in the base design of the plant.

Assessment of ICC indication and response actions are contained in the PVNGS Emergency Operations Procedures and are performed during Standard Post Trip Actions (SPTAs) conducted at the initiation of an event.

Assessment of ICC indicators together with assessment of other key safety functions are used to diagnose an event and progress to an appropriate procedure to mitigate the event.

Additional assessments and recovery actions used to maintain or restore adequate core cooling are specified explicitly in the Emergency Operation Procedure Set.

Table 18.II.F.2-1

REQUIRED DOCUMENTATION

(Sheet 7 of 8)

The summary of typical key operator actions is given below:

A. Assessment Actions

- Check the RCS loop ΔT is less than the maximum expected value for adequate core cooling.
- Check that the RCS subcooling is acceptable for adequate core cooling.
- If Forced Circulation is not available additional checks are performed on RCS hot leg, RCS cold leg and core exit thermocouple temperature values and relationships to detect indications of inadequate core cooling.

B. Response Actions

Recover of, or maintenance of, adequate core cooling is accomplished in the Emergency Operations Procedures by performance of specific actions to establish and maintain supporting safety functions in the following priority.

- Establish RCS Inventory Control using the CVCS system or the Safety Injection System.

Table 18.II.F.2-1

REQUIRED DOCUMENTATION

(Sheet 8 of 8)

- Establish RCS Pressure Control using Normal Pressurizer Pressure Control System, CVCS, Safety Injection, Controlled Steaming of Steam Generators, or RCS venting.
- Establish RCS Heat Removal by use of Steam Generators and/or Safety Injection.

(9) No additional submittals are needed to support the final ICC instrumentation or the emergency procedures related to ICC, based upon previous NRC evaluations.

Table 18.II.F.2-2

DESIGN AND QUALIFICATION CRITERIA FOR PRESSURIZED WATER REACTOR INCORE THERMOCOUPLES

(Sheet 1 of 6)

NRC Requirements

(1) Thermocouples located at the core exit for each core quadrant, in conjunction with core inlet temperature data, shall be of sufficient number to provide indication of radial distribution of the coolant enthalpy (temperature) rise across representative regions of the core. Power distribution symmetry should be considered when determining the specific number and location of thermocouples to be provided for diagnosis of local core problems.

(2) There should be a primary operator display (or displays) having the capabilities which follow:

(a) A spatially oriented core map available on demand indicating the temperature or temperature difference across the core at each core exit thermocouple location.

(b) A selective reading of core exit temperature, continuous on demand, which is consistent with parameters pertinent to operator actions in connecting with plant-specific inadequate core cooling procedures. For example, the action requirement and the displayed temperature might be either the highest of all operable thermocouples or the average of five highest thermocouples.

(c) Direct readout and hard-copy capability should be available for all thermocouple temperatures. The range should extend from 200F (or less) to 1800F (or more).

Table 18.II.F.2-2

DESIGN AND QUALIFICATION CRITERIA FOR PRESSURIZED

WATER REACTOR INCORE THERMOCOUPLES

(Sheet 2 of 6)

NRC Requirements

(d) Trend capability showing the temperature-time history of representative core exit temperature values should be available on demand.

(e) Appropriate alarm capability should be provided consistent with operator procedure requirements.

(f) The operator display device interface shall be human factor designed to provide rapid access to requested displays.

(3) A backup display (or displays) should be provided with the capability for selective reading of a minimum of 16 operable thermocouples, four from each core quadrant, all within a time interval no greater than 6 minutes. The range should extend from 200F (or less) to 2300F (or more).

(4) The types and locations of displays and alarms should be determined by performing a human factors analysis taking into consideration:

(a) the use of this information by an operator during both normal and abnormal plant conditions,

(b) integration into emergency procedures,

(c) integration into operator training, and

(d) other alarms during emergency and need for prioritization of alarms.

(5) The instrumentation must be evaluated for conformance to Appendix B, Design and Qualification Criteria for

Table 18.II.F.2-2

DESIGN AND QUALIFICATION CRITERIA FOR PRESSURIZED WATER REACTOR INCORE THERMOCOUPLES

(Sheet 3 of 6)

NRC Requirements

Accident Monitoring Instrumentation, as modified by the provisions of items 6 through 9 which follow.

(6) The primary and backup display channels should be electrically independent, energized from independent station Class 1E power sources, and physically separated in accordance with Regulatory Guide 1.75 up to and including any isolation device. The primary display and associated hardware beyond the isolation device need not be Class 1E, but should be energized from a high-reliability power source, battery backed, where momentary interruption is not tolerable. The backup display and associated hardware should be Class 1E.

(7) The instrumentation should be environmentally qualified as described in Appendix B, Item 1, except that seismic qualification is not required for the primary display and associated hardware beyond the isolator/input buffer at a location accessible for maintenance following an accident.

(8) The primary and backup display channels should be designed to provide 99% availability for each channel with respect to functional capability to display a minimum of four thermocouples per core quadrant. Availability shall be addressed in technical specifications.

(9) The quality assurance provisions cited in Appendix B, Item B, should be applied except for the primary display and associated hardware beyond the isolation device.

Table 18.II.F.2-2

DESIGN AND QUALIFICATION CRITERIA FOR PRESSURIZED WATER REACTOR INCORE THERMOCOUPLES

(Sheet 4 of 6)

Requirement	PVNGS Response
(1)	The System 80 design has 61 core exit thermocouples (CETs) distributed uniformly over the top of the core. Appendix 18B, Section 2.1.3 has a description of the CET sensors. Figure 18B-5 depicts the locations of the CETs.
(2)(a)	A spatially oriented core map for each channel is available as an option on the QSPDS display.
(2)(b)	A display of the highest CET for each channel, and the two highest CETs per quadrant for each channel is available on the QSPDS displays.
(2)(c)	The ERFDADS provides direct readout of CET temperatures with a dedicated display page. The printer provides the hardcopy capability for recording CET temperatures.
(2)(d)	Trending capability of CET temperatures is provided by a paperless recorder located in the control room that tracks a representative CET temperature.
(2)(e)	When one or more QSPDS parameters enter on alarm condition, a QSPDS system annunciator alarm actuates, and the QSPDS displays attract and direct the attention of the control room operators to the relevant display pages.

Table 18.II.F.2-2

DESIGN AND QUALIFICATION CRITERIA FOR PRESSURIZED WATER REACTOR INCORE THERMOCOUPLES

(Sheet 5 of 6)

Requirement	PVNGS Response
(2)(f)	The ERFDADS is an extensively human-factor designed display system which allows quick access to requested displays by means of the hierarchy described in Appendix 18B and Section 2.3.
(3)	The QSPDS displays fulfill the requirements for the safety grade backup displays. Both channels of QSPDS displays together display all CET temperatures. All CET temperatures can be displayed within 6 minutes.
(4)	The types and locations of displays and alarms are determined by performing a human-factors analysis. The ERFDADS incorporates extensive human-factors engineering. The QSPDS also incorporates human factors engineering. The use of these display systems will be addressed in operating procedures, emergency procedures, and operator training.
(5)	Refer to table 18.II.F.2-3.

Table 18.II.F.2-2

DESIGN AND QUALIFICATION CRITERIA FOR PRESSURIZED WATER REACTOR INCORE THERMOCOUPLES

(Sheet 6 of 6)

Requirement	PVNGS Response
(6)	The ERFDADS (primary display) and the QSPDS (two redundant safety grade display channels) are electrically independent. The QSPDS channels are powered from the Class 1E power sources for channel A & B and physically separated according to Reg. Guide 1.75 up to and including the isolation device portion transmitting data to the ERFDADS (see Figure 18B-1). The ERFDADS is highly reliable non safety grade system which is powered by a highly reliable battery-backed power source.
(7)	The ICC detection instrumentation is environmentally and seismically qualified as specified in the response 18.II.F.2-3 Requirement 1. The ERFDADS is not seismically qualified. The isolation devices in the QSPDS are accessible for maintenance following an accident.
(8)	QSPDS is designed to provide 99% availability. The PVNGS Technical Specifications address CET availability.
(9)	Refer to table 18.II.F.2-3.

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 1 of 13)

NRC Requirements

(1) The instrumentation should be environmentally qualified in accordance with Regulatory Guide 1.89 (NUREG-0588). Qualification applies to the complete instrumentation channel from sensor to display where the display is a direct-indicating meter or recording device. Where the instrumentation channel signal is to be used in a computer-based display, recording and/or diagnostic program, qualification applies to and includes the channel isolation device. The location of the isolation device should be such that it would be accessible for maintenance during accident conditions. The seismic portion of environmental qualification should be in accordance with Regulatory Guide 1.100. The instrumentation should continue to read within the required accuracy following, but not necessarily during, a safe shutdown earthquake. Instrumentation, whose ranges are required to extend beyond those ranges calculated in the most severe design basis accident event for a given variable, should be qualified using the following guidance.

The qualification environment shall be based on the design basis accident events, except the assumed maximum of the value of the monitored variable shall be the value equal to the maximum range for the variable. The monitored variable shall be assumed to approach this peak by extrapolating the most severe initial ramp associated with the design basis accident events. The decay for

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 2 of 13)

this variable shall be considered proportional to the decay for this variable associated with the design basis accident events. No additional qualification margin needs to be added to the extended range variable. All environmental envelopes except that pertaining to the variable measured by the information display channel shall be those associated with the design basis accident events.

The above environmental qualification requirement does not account for steady-state elevated levels that may occur in other environmental parameters associated with the extended range variables. For example, a sensor measuring containment pressure must be qualified for the measured process variable range, but the corresponding ambient temperature is not mechanistically linked to that pressure. Rather, the ambient temperature value is the bounding value for design basis accident events analyzed in chapter 15 of the Final Safety Analysis Report (FSAR). The extended range requirement is to ensure that the equipment will continue to provide information should conditions degrade beyond those postulated in the safety analysis. Since variable ranges are non-mechanistically determined, extension of associated parameter levels is not justifiable and has, therefore, not been required.

(2) No single failure within either the accident monitoring instrumentation, its auxiliary supporting features or its power sources concurrent with the failure that are a condition or result of a specific accident should prevent

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 3 of 13)

the operator from being presented the information necessary for him to determine the safety status of the plant and to bring the plant to a safe condition and maintain it in a safe condition following that accident. Where failure of one accident monitoring channel results in ambiguity (that is, the redundant displays disagree) which could lead the operator to defeat or fail to accomplish a required safety function, additional information should be provided to allow the operator to deduce the actual conditions in the plant. This may be accomplished by: (a) providing additional independent channels of information of the same variable (addition of an identical channel), (b) providing an independent channel which monitors a different variable bearing a known relationship to the multiple channels (addition of a diverse channel), or (c) providing the capability, if sufficient time is available, for the operator to perturb the measured variable and determine which channel has failed by observation of the response on each instrumentation channel. Redundant or diverse channels should be electrically independent, energized from station Class 1E power source, and physically separated in accordance with Regulatory Guide 1.75 up to and including any isolation device. At least one channel should be displayed on a direct-indicating or recording device. (NOTE: Within each redundant division of a safety system, redundant monitoring channels are not required.)

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 4 of 13)

(3) The instrumentation should be energized from station Class 1E power sources.

(4) An instrumentation channel should be available prior to an accident except as provided in Paragraph 4.11, Exemption, as defined in IEEE-279 or as specified in technical specifications.

(5) The recommendations of the following regulatory guides pertaining to quality assurance should be followed:

1.28	Quality Assurance Program Requirements (Design and Construction)
1.30	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment
1.38	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants
1.58	Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel
1.64	Quality Assurance Requirements for the Design of Nuclear Power Plants
1.74	Quality Assurance Terms and Definitions
1.88	Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 5 of 13)

1.123	Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants
1.144	Auditing of Quality Assurance Programs for Nuclear Power Plants
Task RS 810-5	Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants (Guide number to be inserted)

Reference to the above regulatory guides (except Regulatory Guides 1.30 and 1.38) are being made pending issuance of a regulatory guide endorsing NQA-1 (Task RS 002-5), now in progress.

(6) Continuous indication (it may be by recording) display should be provided at all times. Where two or more instruments are needed to cover a particular range, overlapping of instrument span should be provided.

(7) Recording of instrumentation readout information should be provided. Where trend or transient information is essential for operator information or action, the recording should be analog strip chart or stored and displayed continuously on demand. Intermittent displays, such as data loggers and scanning recorders, may be used if no significant transient response information is likely to be lost by such devices.

(8) The instruments should be specifically identified on the control panels so that the operator can easily discern that they are intended for use under accident conditions.

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR
ACCIDENT MONITORING INSTRUMENTATION
(Sheet 6 of 13)

(9) The transmission of signals from the instrument or associated sensors for other use should be through isolation devices that are designated as part of monitoring instrumentation and that meet the provisions of the document.

(10) Means should be provided for checking, with a high degree of confidence, the operational availability of each monitoring channel, including its input sensor, during reactor operation. This may be accomplished in various ways; for example:

(a) By perturbing the monitored variable

(b) By introducing and varying, as appropriate, a substitute input to the sensor of the same nature as the measured variable

(c) By cross-checking between channels that bear a known relationship to each other and that have readouts available.

(11) Servicing, testing, and calibration programs should be specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing will be less than the normal time interval between generating station shutdowns, a capability for testing during power operation should be provided.

(12) Whenever means for removing channels from service are included in the design, the design should facilitate administrative control of the access to such removal means.

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR
ACCIDENT MONITORING INSTRUMENTATION
(Sheet 7 of 13)

(13) The design should facilitate administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

(14) The monitoring instrumentation design should minimize the development of conditions that would cause meters, annunciators, recorders, alarms, etc., to give anomalous indications potentially confusing to the operator.

(15) The instrumentation should be designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

(16) To the extent practical, monitoring instrumentation inputs should be from sensors that directly measure the desired variables.

(17) To the extent practical, the same instruments should be used for accident monitoring as are used for the normal operations of the plant to enable the operator to use, during accident situations, instruments with which the operator is most familiar. However, where the required range of monitoring instrumentation results in a loss of instrumentation sensitivity in the normal operating range, separate instruments should be used.

(18) Periodic testing should be in accordance with the applicable portions of Regulatory Guide 1.118 pertaining to testing of instrument channels.

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 8 of 13)

Requirement	PVNGS Response
(1)	The qualification for the ICC Detection instrumentation can be divided into three categories: (1) Instrumentation components and systems which extend from the primary pressure boundary up to and including the primary display isolator and including the backup displays. (2) Sensor instrumentation within the pressure vessel. (3) Instrumentation systems which comprise the primary display equipment. All out-of-vessel sensors and equipment, including the QSPDS up to and including the ERFDADS isolation, will be environmentally qualified to IEEE Std. 323-1974 as interpreted by CENPD-255 Rev. 01, "Qualification of C-E Class 1E Instruments”, and seismically qualified to IEEE Std. 344-1975 as interpreted by CENPD-182, "Seismic Qualification of C-E Instrumentation Equipment".

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 9 of 13)

Requirement	PVNGS Response
	The "best available equipment" is designed for the in-vessel equipment, including the HJTC probe assemblies and Core Exit Thermocouple (CET) sensors. This equipment is designed consistent with industry practice for components which are located inside the reactor vessel.
	The ERFDADS (primary display) will not be designed as a safety grade system, but will be designed for high reliability; thus it will not be qualified environmentally or seismically to the standards listed. However, the ERFDADS will be separated from the safety grade sensors, processing and backup display equipment by means of an isolation device which will be qualified to the standards listed and be accessible for maintenance following an accident.
(2)	All ICC instrumentation is designed with two redundant safety grade channels. The sensor inputs are fed into the QSPDS. The QSPDS is a safety grade two redundant channel microcomputer based processing and backup display system that transmits the ICC instrument variables to the non-safety grade ERFDADS via isolated data links. (See figure 18B-1) Also see Section 1.8, for description of Regulatory Guide 1.75 compliance.

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 10 of 13)

Requirement	PVNGS Response
	If (in the remote chance) one complete channel of the QSPDS fails, the operator deduces ICC conditions by the following means: (1) Cross-checking the variables in the available channel. Each ICC function (SMM, HJTCS and CET) have multiple variables which can be cross-checked. (2) Cross-checking the variables with other instruments on the control board which have a known relationship to the QSPDS variables. For example additional safety-grade instruments exist for hot leg and cold leg temperatures, and pressurizer pressure.
(3)	The ICC detection instrumentation through the QSPDS is powered from the Class 1E power sources for Channels A and B.
(4)	PVNGS Technical Specifications address instrument channel availability.

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 11 of 13)

Requirement	PVNGS Response
(5)	The ICC detection instrumentation through the QSPDS incorporates the recommendations of Regulatory Guides 1.28, 1.30, 1.38, 1.58, 1.64, 1.74, 1.88 Except as Stated in Section 1.8.
(6)	The ICC Detection Instrumentation outputs are continuously available on the QSPDS displays.
(7)	Paperless recorders located in the control room track reactor vessel level, representative CET temperature, and subcooling margin.
(8)	ICC displays are clearly identified per the PVNGS Detailed Control Room Design Review.
(9)	The signals transmitted to the ERFDADS from the QSPDS are isolated with isolation devices qualified to the provisions of Appendix 18B.
(10)	The operational availability of the ICC instruments of each channel can be checked according to the description addressing single failure in item 2. In addition periodic tests of the QSPDS verify complete system operability. (see Item 15).
(11)	The servicing, testing, and calibration of ICC instrumentation is specified within the respective PVNGS procedures.

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 12 of 13)

Requirement	PVNGS Response
(12)	Refer to Appendix 18B. In addition, PVNGS administrative controls are in effect with regard to the removal of power from an ICC channel.
(13)	The QSPDS facilitates administrative control for access to setpoints by using programmable read-only memory modules which can be changed by removing and reprogramming the modules. Calibration and testing can be accessed at the input/output (I/O) equipment at the QSPDS cabinets.
(14)	The design meets this requirement.
(15)	The design meets this requirement. The QSPDS performs on-line surveillance tests to detect malfunctions. The following on-line surveillance tests are performed in the QSPDS: 1. The temperature inside the QSPDS cabinet with a cooling system alarm on high temperature. 2. Power failure to the processor with alarm on failure. 3. Bad sensors and broken communication links with indication on the display.

Table 18.II.F.2-3

DESIGN AND QUALIFICATION CRITERIA FOR

ACCIDENT MONITORING INSTRUMENTATION

(Sheet 13 of 13)

Requirement	PVNGS Response
	4. CPU memory check and data communication checks with alarm and indication on the visual display and digital panel meter on the cabinet. (These checks are performed periodically.)
	5. Analog input offset voltage with compensation performed automatically.
	6. Inputs out of range with alarm.
	7. Low HJTCS differential temperature with alarm.
(16)	The design meets this requirement.
(17)	The design meets this requirement.
(18)	Periodic testing according to Reg. Guide 1.118 can be performed on the ICC instruments. Except as stated in Section 1.8.

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18.II.G ELECTRICAL POWER

18.II.G.1 EMERGENCY POWER FOR PRESSURIZER EQUIPMENT

NRC Position

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17, and 20 of Appendix A to 10CFR Part 50 for the event of loss of offsite power, the following positions shall be implemented:

Power Supply for Pressurizer Relief and Block Valves and Pressurizer Level Indicators

(1) Motive and control components of the power-operated relief valves (PORVs) shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

(2) Motive and control components associated with the PORV block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

(3) Motive and control power connections to the emergency buses for the PORVs and their associated block valves shall be through devices that have been qualified in accordance with safety grade requirements.

(4) The pressurizer level indication instrument channels shall be powered from the vital instrument buses. The buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available.

PVNGS Evaluation

PVNGS does not use pressurizer PORVs or block valves.

Two channels of Class 1E level instrumentation are provided for PVNGS. Pressurizer level channels L-110X and L-110Y are indicated in the control room. Channel L-110X is also recorded in the control room.

The pressurizer level instrumentation is powered from 120 V-ac, Class 1E instrument buses E-PNA-D25 and E-PNB-D26 (refer to engineering drawings 01, 02, 03-E-PKA-001). These buses are normally powered through inverters from Class 1E batteries. The Class 1E battery chargers are powered from offsite power or from the diesel generators when offsite power is not available.

The pressurizer level indicators comply with the recommendations of Regulatory Guide 1.97, Rev. 2 (see section 1.8).

18.II.K MEASURES TO MITIGATE SMALL-BREAK LOCAs AND LOSS OF FEEDWATER ACCIDENTS

18.II.K.1 IE BULLETINS ON MEASURES TO MITIGATE SMALL-BREAK LOCAs AND LOSS OF FEEDWATER ACCIDENTS

18.II.K.1.5 REVIEW OF ESF VALVES

NRC Position (IE Bulletin No. 79-06B)

Review all safety-related valve positions, positioning requirements and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (e.g., daily/shift checks) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes.

PVNGS Evaluation

The valves of the Engineered Safety Features (ESF) Systems are designed and tested to ensure proper operation in the event of an accident. This is accomplished in several ways.

1. The valves of the ESF systems are interlocked to automatically provide the sequence of operations required after an actuation of the ESF.

2. Actuator operated valves are provided with key-operated control switches, where considered necessary, to prevent unintentional misalignment of safety injection flow paths during power operation.

3. All valves that are not required to operate on initiation of safety injection or recirculation, in the injection flow path, are locked in the post accident position. Administrative controls ensure that the valves are locked in the correct position.

4. Periodic tests and inspections are performed to verify proper operation of each active component of the safety injection system. This includes valves.

In addition, PVNGS has tagout procedures and surveillance test procedures that control safety system status. These procedures provide appropriate logs and checklists to ensure control of plant systems. Additionally, reviews are conducted to verify that procedures for safety-related systems return those systems to service after having been tagged out for repair or surveillance testing. Refer to subsection 18.I.C.2 for a discussion of procedures for shift relief and turnovers to ensure current plant conditions and system status is conveyed to the oncoming shift.

Refer to subsection 18.I.C.6.F for a discussion of the independent verification to ensure the restoration of systems following repair or testing.

18.II.K.1.10 OPERABILITY STATUS

NRC Position (IE Bulletin No. 79-06B)

Review and modify as necessary your maintenance and test procedures to ensure that they require:

Verification, by test or inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

Explicit notification of involved reactor operational personnel whenever a safety-related system is removed from and returned to service.

PVNGS Evaluation

The PVNGS evaluation of item 18.I.C.6 adequately addresses the concerns of this item.

18.II.K.2 COMMISSION ORDERS ON BABCOCK & WILCOX PLANTS

(selected items applicable to PVNGS)

18.II.K.2.13 THERMAL MECHANICAL REPORT -- EFFECT OF HIGH-PRESSURE INJECTION ON VESSEL INTEGRITY FOR SMALL-BREAK LOSS-OF-COOLANT ACCIDENT WITH NO AUXILIARY FEEDWATER

NRC Position

A detailed analysis shall be performed of the thermal-mechanical conditions in the reactor vessel during recovery from small breaks with an extended loss of all feedwater.

PVNGS Evaluation

As an activity for the C-E Owners Group, Combustion Engineering has prepared CEN-189, "Evaluation of Pressurized Thermal Shock

Effects Due to Small Break LOCAs with Loss of Feedwater for the Combustion Engineering NSSS," December 1983. The report was transmitted to the NRC staff by letter dated December 31, 1981 from K. P. Baskin (C-E Owners Group) to D. G. Eisenhut.

The basic CEN-189 report presents methods applicable to all C-E NSSSs, and an appendix applying these methods to plant-specific parameters was provided for each docketed C-E plant at the time of submittal (December, 1981).

18.II.K.2.17 POTENTIAL FOR VOIDING IN THE REACTOR COOLANT SYSTEM DURING TRANSIENTS

NRC Position

Analyze the potential for voiding in the reactor coolant system (RCS) during anticipated transients.

PVNGS Evaluation

As an activity for the C-E Owners Group, Combustion Engineering has prepared CEN-199, "Effects of Vessel Head Voiding During Transients and Accidents in C-E NSSSs", March 1982.

18.II.K.3 FINAL RECOMMENDATIONS OF B&O TASK FORCE

18.II.K.3.2 REPORT ON OVERALL SAFETY EFFECT OF POWER-OPERATED RELIEF VALVE ISOLATION SYSTEM

NRC Position

(1) The licensee should submit a report for staff review documenting the various actions taken to decrease the probability of a small-break LOCA caused by a stuck-open, power-operated relief valve (PORV) and show

how those actions constitute sufficient improvements in reactor safety.

(2) Safety valve failure rates based on past history of the operating plants designed by the specific nuclear steam supply system (NSSS) vendor should be included in the report submitted in response to (1) above.

PVNGS Evaluation

PVNGS does not use pressurizer PORVs.

18.II.K.3.3 REPORTING SAFETY VALVE AND RELIEF VALVE FAILURES AND CHALLENGES

NRC Position (NUREG-0694)

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report.

PVNGS Evaluation

PVNGS does not use PORVs. Documentation of all failures and challenges to RCS safety valves shall be submitted in a monthly report, in accordance with Technical Specifications.

18.II.K.3.5 AUTOMATIC TRIP OF REACTOR COOLANT PUMPS DURING LOSS-OF-COOLANT ACCIDENT

NRC Position

Tripping of the reactor coolant pumps in case of a LOCA is not an ideal solution. Licensees should consider other solutions to the small-break LOCA problem (for example, an increase in safety injection flowrate). In the meantime, until a better

solution is found, the reactor coolant pumps should be tripped automatically in case of a small-break LOCA. The signals designated to initiate the pump trip are discussed in NUREG-0623.

PVNGS Evaluation

Arizona Public Service Company has participated with the Combustion Engineering Owner's Group (CEOG) in the resolution of Item II.K.3.5. The CEOG has submitted CEN-268, "Justification of Trip 2/Leave 2 Reactor Coolant Pump Trip Strategy During Transients" and CEN-152, Revision 02, "Emergency Procedure Guidelines" which pertain to the resolution of Item II.K.3.5. Also, the PVNGS Emergency Operating Procedures are based upon CEN-152 and incorporate the trip 2/leave 2 reactor coolant pump strategy of CEN-152, Revision 02.

18.II.K.3.17 REPORT ON OUTAGES OF EMERGENCY CORE COOLING SYSTEMS LICENSEE REPORT AND PROPOSED TECHNICAL SPECIFICATION CHANGES

NRC Position

Several components of the emergency core cooling (ECC) systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (e.g., controller failures, spurious isolation).

PVNGS Evaluation

A program has been established for the collection of data related to outage dates, lengths of outages, cause of the outage, emergency core cooling systems (ECCS) or components involved in the outage, and the corrective action taken for the ECCS.

18.II.K.3.25 EFFECT OF LOSS OF ALTERNATING CURRENT POWER ON PUMP SEALS

NRC Position

The licensees should determine, on a plant-specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating current (ac) power for at least 2 hours. Adequacy of the seal design should be demonstrated.

PVNGS Evaluation

The reactor coolant pump normal cooling water system (nuclear cooling water system (NCWS) is backed up by the essential cooling water system (ECWS) to supply cooling water to the seals during a loss of offsite power. In the event of a loss of offsite power, the operator can open the train A-NCWS crosstie valves from the control room, permitting the ECWS train A to supply cooling water to the reactor coolant pump seals. If train A fails, the operator must manually open the train B-NCWS crosstie valves and shut the train A crosstie valves to permit the same function. The crosstie of the ECWS to supply the NCWS priority heat loads is described in a PVNGS

Station Manual procedure which allows 10 minutes for the operator to align the ECWS. Also the, ECWS is described in subsection 9.2.2.

A test program was conducted to determine the effect on the reactor coolant pump seals due to a loss of component cooling water to the pump seal assembly. The test results demonstrate that the pumps will continue to operate for extended periods without exceeding design seal leakage limits and seal temperature limits. It has been shown that the System 80 reactor coolant pumps are capable of operating without component cooling water for 30 minutes without sustaining damage to the pump thrust bearings.

The preceding PVNGS Evaluation is the original response to Item II.K.3.25 of NUREG-0737, which is considered to be historical.

Updated PVNGS Evaluation

The current reactor coolant pump (RCP) water seals are a Sulzer seal design and can withstand the consequences of a loss of offsite power (LOP) for at least two hours with no cooling water available. The loss of cooling scenario should last approximately 30 minutes when seal injection is restored and cools the seals; after which there is no immediate need to restore seal cooling water flow.

The PVNGS design provides for non-safety related Nuclear Cooling (NC) water (i.e., component cooling water) to the RCP seal coolers and for class-powered seal injection from the Chemical and Volume Control System (CVCS). During a LOP, the RCPs would trip as would the NC water pumps; and seal cooling

by NC would be lost. Seal injection flow to the seals, which is provide by the class-powered charging pumps of the CVCS would initially be lost and then manually reestablished.

As described in Appendix 5C, section 3.1, the LOP also results in loss of instrument air which causes the RCP seal injection flow control valve to fail open and the individual CBO valves to fail-as-is, in the open position. The normal seal return flow path to the volume control tank (VCT) containment isolation valves close on loss of instrument air. The valve in the flow path to the CBO relief valve to the reactor drain tank (RDT) fails open, however, which ensure a flow path for the RCP seal CBO.

When the vital 4160 VAC buses are denergized by the LOP, the charging pump breakers must be manually reset and the pumps restarted from the control room. Therefore, no charging (or RCP seal injection) flow is assumed for 30 minutes. During this period, the RCP seals are exposed to RCS water at approximately 565 degrees F flowing through the open CBO pathway. The Sulzer seal assembly is designed to maintain integrity for periods in excess of 2 hours with approximately 600 degree F water during the LOP with no seal injection or (NC) water to the seal coolers. However, restoration of seal injection flow terminates the exposure of the seals to RCS temperatures.

Given the design capability of the seal assembly, the NRC position that the seals should be designed to withstand a loss of off-site power for at least two hours is achieved and the adequacy of the seal design demonstrated, with no restoration of cooling water to the seal coolers being required.

18.II.K.3.30 REVISED SMALL-BREAK LOSS-OF-COOLANT ACCIDENT METHODS TO SHOW COMPLIANCE WITH 10CFR PART 50 APPENDIX K

NRC Position

The analysis methods used by NSSS vendors and/or fuel suppliers for small-break LOCA analysis for compliance with Appendix K to 10CFR Part 50 should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities.

PVNGS Evaluation

In the summer of 1979, C-E prepared for the C-E Owner's Group (CEOG) two reports to the NRC, CEN-114-P and CEN-115-P, which use C-E's small-break LOCA evaluation model to predict typical pressurized water reactor (PWR) behavior following a small-break LOCA. These submittals were prepared in response to NRC requests following the TMI-2 accident. After review of these documents, the NRC identified a number of questions with the small-break model and requested a response to these questions.

At a meeting held on January 26, 1981, with members of the NRC staff and representatives of the CEOG and C-E, the NRC described seven specific questions concerning the C-E small-break LOCA evaluation model. The NRC staff also indicated that responding to these seven questions would fulfill the response to Item II.K.3.30 of the NRC TMI Action Plan. In March 1982, report CEN-203-P, Revision 1-P, which contained the answers to the seven NRC questions, was submitted

to the NRC. This report provided justification for maintaining approval of the C-E small-break LOCA evaluation model. In August 1983, the NRC issued a letter to the CEOG asking eight additional questions with the subject title "Request Number 1 for Additional Information on CEN-203-P". Responses to five of the eight additional questions were provided in Supplement 1-P to CEN-203-P, Revision 1-P. Responses to the three remaining questions dealing with steam generator modeling were provided in Supplement 2-P to CEN-203-P, Revision 1-P. In keeping with the intent of report CEN-203-P, these supplementary responses continued to justify the conservatism of the currently approved C-E small-break LOCA evaluation model.

During a meeting held on October 4, 1984, in Windsor with CEOG, NRC, and C-E representatives, the NRC indicated that without a post-test analysis of Semiscale Test S-UT-8 the responses to the steam generator modeling questions were insufficient. Subsequently, in March 1985, the C-E Owner's Group committed to provide to NRC a confirmatory post-test analysis of Semiscale Test S-UT-8 to show the acceptability of the steam generator thermal-hydraulic models of CEFLASH-4AS to calculate the Test S-UT-8 preloop seal clearing core level depression.

The NRC completed the review of CEN-203-P and Supplements 1-P and 2-P in June 1985, and issued a conditional Safety Evaluation Report. The NRC staff concluded that the material submitted, which justified the conservatism of the C-E small-break LOCA evaluation model, was acceptable pending one condition. The one condition required "...confirmation that the CEFLASH-4AS computer program can acceptably calculate core level depression, prior to clearing of the reactor coolant pump

loop seals, as observed in the data from Semiscale Test S-UT-8."

In response to the NRC's conditional Safety Evaluation Report, a post-test analysis was submitted for Semiscale Test S-UT-8. This analysis also fulfilled a CEOG commitment to the NRC, made prior to the issuance of the Safety Evaluation Report, to submit a post-test analysis of Test S-UT-8. The results of the post-test analysis confirmed that C-E's small-break LOCA thermal-hydraulic computer code, CEFLASH-4AS, can acceptably calculate core level depression, prior to clearing of the reactor coolant pump loop seals, as observed in the data from Semiscale Test S-UT-8. These results were discussed with NRC representatives (R. Jones, et al.) in a meeting on October 30, 1985.

The post-test analysis included first, a best-estimate analysis, which showed overall excellent agreement with the Test S-UT-8 data. Then, specific best estimate component models important for steam generator liquid holdup and preloop seal clearing core uncovery were replaced by their C-E small-break LOCA evaluation model counterparts. This best estimate/evaluation model analysis compare well to the depth and duration of the core uncovery data and conservatively underpredicts the core coolant levels after loop seal clearing. This demonstrates that the C-E small-break LOCA evaluation model incorporates component modes which permit acceptable prediction of Test S-UT-8 type core uncovery. Thus, the condition in the Safety Evaluation Report is satisfied and TMI Action Plan Item II.K.3.30 is considered closed.

18.II.K.3.31 PLANT-SPECIFIC CALCULATIONS TO SHOW COMPLIANCE WITH 10CFR PART 50.46

NRC Position

Plant-specific calculations using NRC-approved models for small-break LOCAs as described in Item II.K.3.30 to show compliance with 10CFR50.46 should be submitted for NRC approval by all licensees.

PVNGS Evaluation

Reports submitted in response to TMI Action Plan Item II.K.3.30 show that using the currently approved C-E small-break LOCA evaluation model results in conservatively high cladding temperatures for the break spectrum analysis of a nuclear steam supply system. Therefore, the need for submittal of new small break analyses in accordance with TMI Action Plan Item II.K.3.31 is obviated and this item is considered closed.

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18.III EMERGENCY PREPAREDNESS AND RADIATION EFFECTS

18.III.A NRC AND LICENSEE PREPAREDNESS

18.III.A.1.1 UPGRADE EMERGENCY PREPAREDNESS

NRC Position (NUREG-0694)

(1) Comply with 10CFR50, Appendix E

Comply with Appendix E, Emergency Facilities, to 10CFR Part 50, and for the offsite plans, or have a favorable finding from Federal Emergency Management Agency (FEMA).

(2) Comply with NUREG-0654

Provide an emergency response plan in substantial compliance with NUREG-0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, except that only a description of and completion schedule for the means for providing prompt notification to the population, the staffing for emergencies in addition to that already required, and an upgraded meteorological program need be provided. The NRC will give substantial weight [to FEMA] findings on offsite plans in judging the adequacy against NUREG-0654.

(3) Conduct Exercise

Perform an emergency response exercise to test the integrated capability and a major portion of the basic elements existing within emergency preparedness plans and organizations.

NRC Position (Continued)

(4) Meteorological Data (NUREG-0737, Item III.A.2)

Revision 1 to NUREG-0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, provides meteorological criteria to fulfill, in part, the standard that "Adequate methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency condition are in use" (see 10CFR50.47). The position in Appendix 2 to NUREG-0654 outlines four essential elements that can be categorized into three functions: measurements, assessment, and communications. The four essential elements are as follows:

(a) Establish an adequate operational meteorological measurement program.

(b) Provide backup systems/procedures to obtain real-time local meteorological data.

(c) Establish a system for making real-time, site specific estimates and predictions of atmospheric effluent transport and diffusion during and immediately following an accidental airborne radioactivity release.

(d) Provide the capability for remote interrogation of systems producing meteorological data and effluent transport and diffusion elements.

PVNGS Evaluation

(1) Comply with 10CFR50, Appendix E

The PVNGS emergency plan submitted with the FSAR complies with Appendix E, Emergency Facilities, to 10CFR Part 50. The Arizona Division of Emergency Services prepared a comprehensive emergency response plan for fixed nuclear facilities which incorporated actions to be taken by levels of government within the State of Arizona. This plan was found acceptable by FEMA.

(2) Comply with NUREG-0654

The PVNGS emergency plan addresses the emergency planning criteria contained in NUREG-0654, including a description of the means for providing prompt notification to the public, staffing for emergencies, and an upgraded meteorological program. The comprehensive emergency response plan for fixed nuclear facilities has been developed by the Arizona Division of Emergency Services, and addresses the emergency planning criteria contained in NUREG-0654.

(3) Conduct Exercise

ANPP has conducted emergency response exercises which have been evaluated by the NRC.

(4) Meteorological Data

The PVNGS meteorology atmospheric transport and diffusion assessment program has been established using the guidance of NUREG-0654 (Revision 1) and Regulatory Guide 1.23 (Revision 0). A meteorological tower shall be operated with the following instrumentation:

- Temperature (35 foot)[a]
- Differential temperature (DT nominal 195-35[a] foot) one channel
- Precipitation (ground)
- Dewpoint (35 foot)
- Windspeed (35 and 200 nominal foot)[a]
- Wind direction (35 and 200 nominal foot)[a]

Display of meteorological indications is available in the control room by use of the ERFDADS display and via dialup using a personal computer located at the STA station. Additionally, displays are available at the following locations:

- Technical support center (TSC)
- Satellite TSC in each unit
- Emergency operation facility (EOF)

a. Redundant sensors are provided as backups to the primary sensors.

In the event the PVNGS meteorological monitoring system is unavailable, the National Weather Service (NWS), Phoenix office, has an instrumentation unit which can be brought to the plant site to provide backup meteorological information during emergencies.

The NWS also establishes a facility at the State Emergency Operation Center (EOC) when it is fully activated.

Further information about the PVNGS meteorological system, the criteria it was designed to, and the regulatory guides and NUREG requirements it satisfies, is provided in paragraph 2.3.3.1.

18.III.A.1.2 UPGRADE EMERGENCY SUPPORT FACILITIES

NRC Position (NRC Generic Letter 82-33, Supplement 1 to NUREG-0737, Requirements for Emergency Response Capability)

1. Regulations

   10CFR50.47(b)(6) (for Operating License applicants) -- Requirement for prompt communications among principal response organizations and to emergency personnel and to the public.

   10CFR50.47(b)(8) -- Requirement for emergency facilities and equipment to support emergency response.

   10CFR50.47(b)(9) -- Requirement that adequate methods, systems and equipment for assessing and monitoring

NRC Position (Continued)

actual or potential offsite consequences of a radiological emergency condition are in use.

10CFR50.54(q) (for Operating Reactors) -- Same requirement as 10CFR50.47(b) plus 10CFR50, Appendix E.

10CFR50, Appendix E, Paragraph IV.E

Requirement for:

"1. Equipment at the site for personnel monitoring;"

"2. Equipment for determining the magnitude of and for continuously assessing the impact of the release of radioactive materials to the environment;"

"3. Facilities and supplies at the site for decontamination of onsite individuals;"

"4. Facilities and medical supplies at the site for appropriate emergency first aid treatment;"

"5. Arrangements for the services of physicians and other medical personnel qualified to handle radiation emergencies onsite;"

"6. Arrangements for transportation of contaminated injured individuals from the site to specifically identified treatment facilities outside the site boundary;"

"7. Arrangements for treatment of individuals injured in support of licensed activities of the site at treatment facilities outside the site boundary;"

NRC Position (Continued)

"8. A licensee onsite technical support center and a licensee near-site emergency operations facility from which effective direction can be given and effective control can be exercised during an emergency;"

"9. At least one onsite and one offsite communications system; each system shall have a backup power source."

All communication plans shall have arrangements for emergencies, including titles and alternates for those in charge at both ends of the communication links and the primary and backup means of communication. Where consistent with the function of the governmental agency, these arrangements will include:

"a. Provision for communications with contiguous State/local governments within the plume exposure pathway (emergency planning zone) EPZ. Such communications shall be tested monthly."

"b. Provisions for communication with Federal emergency response organizations. Such communication systems shall be tested annually."

NRC Position (Continued)

"c. Provision for communications among the nuclear power reactor control room, the onsite technical support center, and the near-site emergency operations facility; and among the nuclear facility, the principal State and local emergency operations centers, and the field assessment teams. Such communications systems shall be tested annually."

"d. Provisions for communication by the licensee with NRC Headquarters and the appropriate NRC Regional Office Operations Center from the nuclear power reactor control room, the onsite technical support center, and the near-site emergency operations facility. Such communications shall be tested monthly."

Within this section on emergency response facilities, the technical support center (TSC), operational support center (OSC), and emergency operations facility (EOF) are addressed separately in terms of their functional statements and recommended requirements. The subsections on documentation and NRC review and reference documents that follow the EOF discussion apply to this entire section on emergency response facilities.

NRC Position (Continued)

2. Technical Support Center (TSC)

2.1 Requirements

a. The TSC is the onsite technical support center for emergency response. When activated, the TSC is staffed by predesignated technical, engineering, senior management, and other licensee personnel, and five predesignated NRC personnel. During periods of activation, the TSC will operate uninterrupted to provide plant management and technical support to plant operations personnel, and to relieve the reactor operators of peripheral duties and communications not directly related to reactor system manipulations. The TSC will perform EOF functions for the alert emergency class and for the site area emergency class and general emergency class until the EOF is functional.

The TSC will be:

b. Located within the site-protected area so as to facilitate necessary interaction with control room, OSC, EOF, and other personnel involved with the emergency.

c. Sufficient to accommodate and support NRC and licensee predesignated personnel, equipment, and documentation in the center.

NRC Position (Continued)

d. Structurally built in accordance with the Uniform Building Code.

e. Environmentally controlled to provide room air temperature, humidity, and cleanliness appropriate for personnel and equipment.

f. Provided with radiological protection and monitoring equipment necessary to assure that radiation exposure to any person working in the TSC would not exceed 5 rem whole-body, or its equivalent to any part of the body, for the duration of the accident.

g. Provided with reliable voice and data communications with the control room and EOF and reliable voice communications with the OSC, NRC Operations Centers, and state and local operations centers.

h. Capable of reliable data collection, storage, analysis, display and communication sufficient to determine site and regional status, determine changes in status, forecast status and take appropriate actions. The following variables shall be available in the TSC:

(i) the variables in the appropriate Table 1 or 2 of Regulatory Guide 1.97 (Rev. 2) that are essential for performance of TSC functions; and

NRC Position (Continued)

(ii) the meteorological variables in Regulatory Guide 1.97 (Rev. 2) for site vicinity and National Weather Service data available by voice communication for the region in which the plant is located.

Principally those data must be available that would enable evaluating incident sequence, determining mitigating actions, evaluating damages, and determining plant status during recovery operations.

i. Provided with accurate, complete, and current plant records (drawings, schematic diagrams, etc.) essential for evaluation of the plant under accident conditions.

j. Staffed by sufficient technical, engineering, and senior designated licensee officials to provide needed support, and be fully operational within approximately 1 hour after activation.

k. Designed taking into account good human factors engineering principles.

3. Operations Support Center (OSC)

3.1 Requirements

a. When activated, the OSC will be the onsite area separate from the control room where pre-designated

NRC Position (Continued)

operations support personnel will assemble. A pre-designated licensee official shall be responsible for coordinating and assigning the personnel to tasks designated by control room, TSC, and EOF personnel.

The OSC will be:

b. Located onsite to serve as an assembly point for support personnel and to facilitate performance of support functions and tasks.

c. Capable of reliable voice communications with the control room, TSC, and EOF.

4. Emergency Operations Facility (EOF)

4.1 Requirements

a. The EOF is a licensee controlled and operated facility. The EOF provides for management of overall licensee emergency response, coordination of radiological and environmental assessment, development of recommendations for public protective actions, and coordination of emergency response activities with Federal, State, and local agencies.

When the EOF is activated, it will be staffed by pre-designated emergency personnel identified in the emergency plan. A designated senior licensee

NRC Position (Continued)

official will manage licensee activities in the EOF.

Facilities shall be provided in the EOF for the acquisition, display and evaluation of radiological and meteorological data and containment conditions necessary to determine protective measures. These facilities will be used to evaluate the magnitude and effects of actual or potential radioactive releases from the plant and to determine dose projections.

The EOF will be:

b. Located and provided with radiation protection features as described in Table 1 (previous guidance approved by the Commission) and with appropriate radiological monitoring systems.

c. Sufficient to accommodate and support Federal, State, local, and licensee pre-designated personnel, equipment and documentation in the EOF.

d. Structurally built in accordance with the Uniform Building Code.

e. Environmentally controlled to provide room air temperature, humidity, and cleanliness appropriate for personnel and equipment.

f. Provided with reliable voice and data communications facilities to the TSC and control

NRC Position (Continued)

room, and reliable voice communication facilities to OSC and to NRC, State, and local emergency operations centers.

g. Capable of reliable collection, storage, analysis, display, and communication of information on containment conditions, radiological releases, and meteorology sufficient to determine site and regional status, determine changes in status, forecast status, and take appropriate actions. Variables from the following categories that are essential to EOF functions shall be available in the EOF:

   (i) variables from the appropriate Table 1 or 2 of Regulatory Guide 1.97 (Rev. 2), and

Table 1

EMERGENCY OPERATIONS FACILITY

Option 1
Two Facilities

Close-in Primary: Reduce Habitability*

- within 10 miles
- protection factor = 5
- ventilation isolation with HEPA (no charcoal)

Backup EOF

- between 10-20 miles
- no separate, dedicated facility
- arrangements for portable backup equipment
- strongly recommended location be coordinated with offsite authorities
- continuity of dose projection and decision making capability

Option 2
One Facility

- At or Beyond 10 miles.
- No special protection factor.
- If beyond 20 miles, specific approval required by the Commission, and some provision for NRC site team closer to site.
- Strongly recommended location be coordinated with offsite authorities.

For both Options:

- located outside security boundary
- space for about 10 NRC employees
- none designated for severe phenomena, e.g.,
- earthquakes

*Habitability requirements are only for the part of the EOF in which dose assessments communications and decision making take place.

If a utility has begun construction of a new building for an EOF that is located with 5 miles, that new facility is acceptable (with less than protection factor of 5 and ventilation isolation and HEPA) provided that a backup EOF similar to "B" in Option 1 is provided.

NRC Position (Continued)

(ii) the meteorological variables in Regulatory Guide 1.97 (Rev. 2) for site vicinity and regional data available via communication from the National Weather Service.

h. Provided with up to date plant records (drawings, schematic diagrams, etc.), procedures, emergency plans, and environmental information (such as geophysical data) needed to perform EOF functions.

i. Staffed using Table 2 (previous guidance approved by the Commission) as a goal. Reasonable exceptions to goals for the number of additional staff personnel and response times for their arrival should be justified and will be considered by NRC staff.

j. Provided with industrial security when it is activated to exclude unauthorized personnel and when it is idle to maintain its readiness.

k. Designed taking into account good human factors engineering principles.

NRC Position (Continued)

TABLE 2

MINIMUM STAFFING REQUIREMENTS FOR NRC LICENSEES
FOR NUCLEAR POWER PLANT EMERGENCIES

Major Functional Area	Major Tasks	Position Title or Expertise	Capability for Additions On Shift*	30 min.	60 min.
Plant Operations and Assessment of Operational Aspects		Shift supervisor (SRO)	1	--	--
		Shift foreman (SRO)	1	--	--
		Control-room operators	2	--	--
		Auxiliary operators	2		
Emergency Direction and Control (Emergency Coordinator)***		Shift technical advisor, shift supervisor, or designated facility manager	1**	--	--
Notification/ Communication****	Notify licensee, state local, and federal personnel & maintain communication		1	1	2
Radiological Accident Assessment and Support of Operational Accident Assessment	Emergency operations facility (EOF) director	Senior manager	--	--	1
	Offsite dose assessment	Senior health physics (HP) expertise	--	1	--
	Offsite surveys		--	2	2
	Onsite (out-of-plant)		--	1	1
	Inplant surveys	HP technicians	1	1	1
	Chemistry/radio-chemistry	Rad/chem technicians	1	--	1

NOTE: Source of this table is NUREG-0654, "Functional Criteria for Emergency Response Facilities.

TABLE 2 (Continued)

MINIMUM STAFFING REQUIREMENTS FOR NRC LICENSEES
FOR NUCLEAR POWER PLANT EMERGENCIES

Major Functional Area	Major Tasks	Position Title or Expertise	Capability for Additions On Shift*	30 min.	60 min.
Plant System Engineering, Repair and Corrective Actions	Technical support	Shift technical advisory	1	--	--
		Core/thermal hydraulics	--	1	--
		Electrical	--	--	1
		Mechanical	--	--	1
	Repair and corrective actions	Mechanical maintenance/	1**	--	1
		Radwaste operator			1
		Electrical maintenance/	1**	1	1
		instrument and control		1	--
		(I&C) technician	--	1	--
Protective Actions (In-Plant)	Radiation Protection: a. Access control b. HP Coverage for repair, corrective actions, search and rescue first-aid & firefighting c. Personnel monitoring d. Dosimetry	HP technicians	2**	2	2
Firefighting	--	--	Fire brigade per technical specification	Local support	

TABLE 2 (Continued)

MINIMUM STAFFING REQUIREMENTS FOR NRC LICENSEES
FOR NUCLEAR POWER PLANT EMERGENCIES

Major Functional Area	Major Tasks	Position Title or Expertise	Capability for Additions On Shift*	30 min.	60 min.
Rescue Operations and First Aid	--	--	2**	Local support	
Site Access Control and Personnel Accountability	Security, firefighting communications, personnel accountability	Security personnel	All per Security plan		
		Total	10	11	15

*For each unaffected nuclear unit in operation, maintain at least one shift foreman, one control room operator, and one auxiliary operator except that units sharing a control room may share a shift foreman if all functions are covered.

**May be provided by shift personnel assigned other functions.

***Overall direction of facility response to be assumed by EOF director when all centers are fully manned. Direction of minute-to-minute facility operations remains with senior manager in technical support center or control room.

****May be performed by engineering aide to shift supervisor.

PVNGS Evaluation

The position of Shift Manager at PVNGS is equivalent to the shift supervisor position referred to in table 2 of the NRC position above.

A. Operations Support Center (OSC)

An area separate from the unit control rooms has been designated as the Palo Verde Nuclear Generating Station (PVNGS) onsite OSC. This is an assembly area where plant operations support personnel will report to in an emergency situation for further orders or assignment. The OSC is located in each unit at elevation 140 feet 0 inch of the auxiliary and operations support buildings, adjacent to the main access corridor into the radiological control area (see engineering drawings 13-P-OOB-001 and 13-P-OOB-005). The OSC has communication with the control room and the onsite TSC. The emergency plan reflects the existence of the OSC and establishes the methods and lines of communication and management.

B. Onsite Technical Support Center (TSC) and Satellite TSCs

An onsite TSC and the satellite TSCs for PVNGS have been established and are fully operational prior to fuel load for each Palo Verde unit. The TSC is an underground structure of approximately 10,000 square feet of area located within the site protected area adjacent to the main entry into the plant protected

area (see engineering drawings 13-P-OOB-001 and A0-A-ZYD-187). The TSC provides a work area for supervisory and technical personnel from Arizona Public Service Company and the NRC. It has communications with the control room and the other response centers. Satellite TSCs have been established adjacent to the control room in each unit to facilitate face to face communications between control room personnel and support personnel.

The satellite TSC has the same display capabilities as the main TSC (see engineering drawings 13-P-OOB-001 and 13-P-OOB-005). An analysis has been performed to determine equipment to be incorporated into the TSC to monitor and display the status of the affected unit. Display of data at the TSC is in accordance with NUREG-0696. The TSC will be habitable to permit occupancy following a loss of coolant accident. Monitoring equipment will be provided for direct and airborne radioactive contaminants to provide warning if radiation levels in the TSC are reaching dangerous levels. The TSC has permanently installed radiation monitoring and filtered ventilation systems. As-built drawings and other appropriate records will be available in readily retrievable form at the site and will be accessible to the TSC. The TSC HVAC system is designed and tested using Regulatory Guide 1.52. Regulatory Guide 1.52 is used to supply technical guidance in the performance of testing.

B.1 Radiological Design Bases

The TSC is provided with radiological protection to assure that radiation exposure to any person working in the TSC during an accident would not exceed 5 rem whole-body, or its equivalent 30 rem to any part of the body, for the duration of the accident.

B.1.1 HVAC System

The TSC essential HVAC system is a single ventilation train, that consists of a nuclear air treatment system (NATS). The location of components and ducting within the TSC envelope ensures an adequate supply of filtered air to all areas requiring access. The essential ventilation system is also used for normal operation. The TSC pressure is maintained at a positive pressure (above atmospheric pressure) compared to adjacent areas during emergency operation. This insures that inleakage to habitable areas is kept at a minimum. The system parameters are as follows:

Table 18.III.A-3
Essential TSC HVAC System Parameters

Essential outside air intake (SCFM)	less than 2100
Recirculation flow through charcoal filtration (SCFM)	8900 +/- 10%
Total unfiltered system inleakage (SCFM) (Includes 10 SCFM for personnel ingress/egress)	Less than 30 SCFM
Charcoal bed thickness	2 inch
TSC free volume (SCF)	1.18E+05

B.1.2 Radiological Evaluation

The TSC NATS system and shielding designs are based on the most limiting design basis assumptions contained in NRC Regulatory Guide 1.4, and source term is based on Technical Information Document TID-14844 U.S. Atomic Energy Commission, March 23, 1962.

At time zero or during the initiating event the essential system is continuously in operation, there are no changes in HVAC system configuration at the initiating event.

The airborne fission product source term in the reactor containment following the postulated LOCA is assumed to leak from the containment at a rate of 0.1% per day for the first 24 hours after the accident, and 0.05% per day thereafter. For a more complete discussion of LOCA refer to section 15.6.

The concentration of radioactivity, which is postulated to surround the TSC after the postulated accident, is evaluated as a function of the fission product decay constants, the containment spray system effectiveness, the containment leak rate, and the meteorology conditions in effect. The assessment of the amount of radioactivity within the TSC takes into consideration the flowrate through the TSC outside air intake, the effectiveness of the TSC NATS, the radiological decay of fission products, and the exfiltration rate from the TSC.

Air within the TSC is recirculated continuously through the emergency air conditioning units, which contain high efficiency filters, charcoal adsorbers, HEPA after-filters, cooling coil, and fan, to control and reduce airborne radioactivity. The outside air required for pressurization is mixed with the return air as it enters the NATS.

The TSC HVAC is designed to pressurize the TSC to minimize unfiltered system inleakage. As required by standard review plan, an additional 10 SCFM inleakage has been assumed during personnel ingress/egress.

The calculated doses as a result of a postulated LOCA are given in tables 18.III.A-5. Refer to section 15.6.5 and table 15.6.5-2.

Table 18.III.A-4

TSC Habitability Parameters

Time After Accident	**Short Term X/Q**	**Occupation Factor**	**Breathing Rate**
	Sec/m^3		m^3/Sec
0 - 8 hrs	8.552E-4	1.0	3.47E-4
8 - 24 hrs	5.766E-4	1.0	1.75E-4
1 - 4 days	1.994E-4	0.6	2.32E-4
4 - 30 days	2.546E-5	0.4	2.32E-4

Table 18.III.A-5

TSC Occupant 30 Day Exposure (REM)

	Thyroid	Whole-Body	Beta Skin
Internal Cloud Exposure	15.5	1.17	26.0
Direct dose due to Iodine build-up on charcoal filtration	N/A	0.10	N/A
Total	15.5	1.27	26.0

TSC shielding design is based on the most limiting design basis LOCA fission product release. The evaluations demonstrate that the only source of direct radiation exposures to TSC occupants is the NATS, housed plant north of TSC facility at the same elevation. All other direct radiation sources such as containment/RWT direct shine and external cloud, have a negligible contribution to occupant dose since TSC facility is built below ground elevation. Total exposures resulting from Design Basis Accident are below the dose limits specified by General Design Criterion 19.

B.1.3 Testing and Inspection

The NATS will be tested periodically by standard methods in general conformance with Regulatory Guide 1.52, as noted in section 1.8.

HEPA filter banks are tested in-place prior to operation and periodically thereafter in conformance with ANSI N510, and comply with Position C.5.c of Regulatory Guide 1.52, except as noted in section 1.8.

Impregnated, activated carbon is batch tested prior to loading into the adsorber section. Acceptance criteria are those described in Table 5.1 of ANSI N509-1980 version. The carbon adsorber section is filled with carbon in a manner to ensure a uniform packing density and to minimize dusting. In addition, a periodic laboratory test of a representative sample

of the impregnated activated carbon is performed to verify iodine removal efficiencies in accordance with Position C.6 and Table 2 of Regulatory Guide 1.52 for the assigned decontamination efficiency and bed depth.

The PVNGS emergency plan has been revised to describe the TSC and its function.

B.2.0 HVAC SYSTEM OPERATION

The TSC essential HVAC system consists of a nuclear air treatment system (NATS) that includes: Hepa filters, a charcoal adsorber and an environmental cooling system. The NATS is used for protection against airborne radioactivity and controlling the environment of the TSC. Air within the TSC is continuously recirculated through the NATS and cooling system components. The components are arranged in the following order: NATS air heater (for adsorber humidity control) high efficiency prefilters, HEPA filters, charcoal adsorber, HEPA after-filters, NATS fan, cooling coil, and cooling system fan.

The TSC essential HVAC system is normally engaged in a filtration mode utilizing the above system except when maintenance is performed. The location of components and ducting within the TSC envelope ensures an adequate supply of filtered air to all areas requiring access.

C. Emergency Operations Facility (EOF)

The information presented in section C (with exception of C.3) is historical and has been preserved in its original context. The following PVNGS Evaluation is the original response to Item 18.III.A.1.2 Upgrade Emergency Support Facilities.

An EOF for PVNGS has been established and is operational. This facility is located outside of the protected area and occupies approximately 6000 square feet of the basement floor in the Technical Training building “E” (see engineering drawings 13-P-OOB-001 and A0-A-ZYD-101). The EOF provides space for operations personnel in support of the TSC. Plant personnel will be able to evaluate the magnitude and effect of radioactive releases from the plant and recommend appropriate protective measures. A study has been conducted to determine analysis and monitoring equipment required. Display of data at the EOF is in accordance with NUREG-0696 and Supplement 1 to NUREG-0737. Communications with the TSC are provided.

The EOF provides space for recovery operations following an accident as well as training facilities for the site.

The PVNGS emergency plan describes the EOF and its functions.

Additionally, the display of those plant parameters recommended by Regulatory Guide 1.97, Revision 2, is addressed in section 1.8.

The EOF HVAC system is designed and tested using Regulatory Guide 1.52. Regulatory Guide 1.52 is used to supply technical guidance in the performance of testing.

C.1 Radiological Design Bases

The EOF is provided with radiological protection to assure that radiation exposure to any person working in the EOF during an accident would not exceed 5 rem whole-body, or its equivalent 30 rem to any part of the body, for the duration of the accident.

C.1.1 HVAC System

The EOF essential HVAC system is a single ventilation train, that consists of a nuclear air treatment system (NATS). The location of components and ducting within the EOF envelope ensures an adequate supply of filtered air to all areas requiring access. The essential ventilation system is also used for normal operation. The EOF pressure is maintained at a positive pressure (above atmospheric pressure) compared to adjacent areas during emergency operation.

This insures that inleakage to habitable areas is kept at a minimum. The system parameters are as follows:

Table 18.III.A-6
Essential EOF HVAC System Parameters

Essential outside air intake (SCFM)	less than 2100
Recirculation flow through charcoal filtration (SCFM)	4400 +/- 10%
Total unfiltered system inleakage (SCFM)	Less than 30 SCFM
Charcoal bed thickness	2 inch
EOF free volume (SCF)	1.19E+05

C.1.2 Radiological Evaluation

The EOF NATS and shielding designs are based on the most limiting design basis assumptions contained in NRC Regulatory Guide 1.4, and the source term is based on Technical Information Document TID-14844 U.S. Atomic Energy Commission, March 23, 1962.

Since the essential system is continuously in operation, there are no changes in HVAC system configuration at the initiating event.

The airborne fission product source term in the reactor containment following the postulated LOCA is assumed to leak from the containment at a rate of 0.1% per day for the first 24 hours after the accident, and 0.05% per day thereafter. For a more complete discussion of LOCA refer to section 15.6.

The concentration of radioactivity, which is postulated to surround the EOF after the postulated

accident, is evaluated as a function of the fission product decay constants, the containment spray system effectiveness, the containment leak rate, and the meteorology conditions in effect. The assessment of the amount of radioactivity within the EOF takes into consideration the flowrate through the EOF outside air intake, the effectiveness of the EOF NATS, the radiological decay of fission products, and the exfiltration rate from the EOF.

Air within the EOF is recirculated continuously through the emergency air conditioning units, which contain high efficiency filters, charcoal adsorbers, HEPA after-filters, cooling coil and fan, to control and reduce airborne radioactivity. The outside air required for pressurization is mixed with the return air as it enters the NATS.

The EOF HVAC is designed to pressurize the EOF to minimize unfiltered system inleakage. As required by standard review plan additional 10 SCFM inleakage has been assumed during personnel ingress/egress.

The calculated doses as a result of a postulated LOCA are given in table 18.III.A-8. Refer to section 15.6.5 and table 15.6.5-2.

Table 18.III.A-7

EOF Habitability Parameters

Time After Accident	Short Term X/Q Sec/m^3	Occupation Factor	Breathing Rate m^3/Sec
0 - 8 hrs	8.864E-4	1.0	3.47E-4
8 - 24 hrs	6.126E-4	1.0	1.75E-4
1 - 4 days	2.241E-4	0.6	2.32E-4
4 - 30 days	4.434E-5	0.4	2.32E-4

Table 18.III.A-8

EOF Occupant 30 Day Exposure (REM)

	Thyroid[1]	Whole-Body	Beta Skin
Internal Cloud Exposure	28.5	1.23	26.5
Direct dose due to Iodine build-up on charcoal filtration	N/A	0.00[2]	N/A
Total	28.5	1.23	26.5

1. Primary EOF is within 10 miles from PVNGS. The applicable criterion for acceptability is 10 CFR 50 Appendix A, GDC 19, PVNGS does not calculate or apply a protection factor of 5 as stated in NUREG 0737. The 10 CFR 50 criteria is more limiting than NUREG 0737.

2. The EOF facility is located below ground elevation and the NATS filter unit is at ground level (plant elevation ~ 100). There is no direct line of sight between the filtration unit and occupant of EOF. The filtration unit is shielded by earth and therefore contribution from the filtration unit due to built up iodine is neglected.

EOF shielding design is based on the most limiting design basis LOCA fission product release. The evaluations demonstrate that there are no sources of direct radiation exposures to EOF occupants. All other direct radiation sources such as containment/RWT direct shine and external cloud, have a negligible contribution to occupant dose since EOF facility is built below ground elevation. Total exposures resulting from Design Basis Accident are below the dose limits specified by General Design Criterion 19.

C.1.3 Testing and Inspection

The NATS will be tested periodically by standard methods in general conformance with Regulatory Guide 1.52.

HEPA filter banks are tested in-place prior to operation and periodically thereafter in conformance with ANSI N510, and comply with Position C.5.c of Regulatory Guide 1.52.

Impregnated, activated carbon is batch tested prior to loading into the adsorber section. Acceptance criteria are those described in Table 5.1 of ANSI N509-1980 version. The carbon adsorber section is filled with carbon in a manner to ensure a uniform packing density and to minimize dusting. In addition, a periodic laboratory test of a representative sample of the impregnated activated carbon is performed to verify iodine removal efficiencies in accordance with Position

C.6 and Table 2 of Regulatory Guide 1.52 for the assigned decontamination efficiency and bed depth.

C.2. HVAC System Operation

The EOF essential HVAC system consists of a nuclear air treatment system (NATS) that includes: Hepa filters, a charcoal adsorber and an environmental cooling system.

The NATS is used for protection against airborne radioactivity and controlling the environment of the EOF. Air within the TSC is continuously recirculated through the NATS and cooling system components. The components are arranged in the following order: NATS air heater (for adsorber humidity control) high efficiency prefilters, HEPA filters, charcoal adsorber, HEPA after-filters, NATS fan, cooling coil, and cooling system fan.

The EOF essential HVAC system is normally engaged in a filtration mode utilizing the above system except when maintenance is performed. The location of components and ducting within the TSC envelope ensures an adequate supply of filtered air to all areas requiring access.

C.3 New Emergency Operations Facility (EOF)

EOF and new Joint Information Center (JIC) was added to the Emergency Plan, the Back-up EOF was removed as the regulatory basis for a back-up facility no longer exists due to the new EOF being located greater than 10 miles from PVNGS. The Radiation Protection Support Technician position was removed due to the lack of a need for

radiological protection within the new facility given its distance from the site. New EOF added as an Alternate response facility for the TSC and OCS staff addressing item 4. in the NRC Bulletin 2005-02.

D. Minimum Staffing Requirements for PVNGS Emergency Response

PVNGS Emergency Plan Table 1 "Minimum Staffing Requirements for PVNGS for Nuclear Power Plant Emergencies" is the PVNGS response to the NRC position shown in UFSAR 18.III.A.1.2 Table 2.

NUREG-0737 Supplement 1 Table 2, which is the NRC position shown in UFSAR 18.III.A.1.2 Table 2, incorrectly stated the title of NUREG-0654. NUREG-0654 is entitled, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants."

18.III.A.2 IMPROVING LICENSEE EMERGENCY PREPAREDNESS – LONG-TERM

NRC Position

Each nuclear facility shall upgrade its emergency plans to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement are delineated in NUREG-0654 (FEMA-REP-1), Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants.

PVNGS Evaluation

PVNGS response to this item is included in the evaluation of NUREG-0737, Item III.A.1.1, requirements. Refer to subsection 18.III.A.1.1.

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18.III.D RADIATION PROTECTION

18.III.D.1.1 INTEGRITY OF SYSTEMS OUTSIDE CONTAINMENT LIKELY TO CONTAIN RADIOACTIVE MATERIAL FOR PRESSURIZED WATER REACTORS AND BOILING WATER REACTORS

NRC Position

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include the following:

(1) Immediate Leak Reduction

(a) Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

(b) Measure actual leakage rates with system in operation and report them to the NRC.

(2) Continuing Leak Reduction -- establish and implement a program of preventive maintenance to reduce leakage to as low as practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

PVNGS Evaluation

1. Design Review

A PVNGS design review was performed on the systems below to assure that potential radioactive release paths

following a serious transient or accident is reduced to as-low-as-reasonably achievable (ALARA) levels.

A. Shutdown Cooling System (SCS)

The existing design incorporates all-welded piping. Vent and drain lines throughout the system are capped when practical. Relief valves on the system (external to containment) relieve to the equipment drain tank (a tank designed to accept radioactive fluids). The leakage from the LPSI pump seals and system valve stems is ALARA. Potential leakage from the SCS into the essential cooling water system (through the shutdown cooling heat exchanger) can be detected during normal operation by installed radiation monitoring.

B. Containment Spray Recirculation System (CS)

The existing design incorporates all-welded piping. Vent and drain lines throughout the system are capped when practical. Relief valves on the system (external to the containment) relieve to the equipment drain tank. The leakage from the CS pump seals and system valve stems is ALARA. Potential leakage during normal operation from the CS into the essential cooling water system (through the shutdown cooling heat exchanger) can be detected by installed radiation monitoring.

C. Chemical and Volume Control System (CVCS) Charging and Letdown System

The existing design incorporates all-welded piping. The letdown system isolates upon initiation of the containment isolation actuation system (CIAS) and the safety injection actuation system (SIAS). Relief valves in the system relieve to the equipment drain tank.

The leakage from the CVCS charging pumps (positive displacement pumps) and other system equipment is ALARA as they are hard-piped to drains. The nuclear cooling water system is monitored for potential leakage from the CVCS through the letdown heat exchanger during normal operation.

D. Sampling System

The design of the normal sampling system, which would come into contact with post-accident fluids, consists of all-welded piping for the portion of the system that isolates upon CIAS and SIAS up to the instrument root valve. Downstream of the instrument root valve, external to cabinets, the use of "Swagelok" connections has been minimized. Relief valves relieve to the equipment drain tank. Leakage from the systems is minimized by the small size of the lines.

E. High-Pressure Injection Recirculation (HPSI)

The design incorporates all-welded piping. Relief valves in the system that are exposed to highly radioactive fluids during the recirculation mode of operation (external to the containment) relieve to the equipment drain tank. The vent and drain lines throughout the system are capped when practical. Leakage from the HPSI pump seals and system valve stems is ALARA. Miniflow connections to the refueling water tank (RWT) are isolated upon the recirculation actuation signal (RAS). Manual cross-over valves to the CVCS are normally locked shut.

F. Waste Gas System

The waste gas system isolates from the containment upon initiation of CIAS. (The normal vent path from the reactor drain tank (RDT) and the reactor head vent system is isolated.) By design, the introduction of highly radioactive fluids to the system is precluded.

As part of the system testing program, each of the above systems is hydrostatically tested to 150% normal operating pressure per the requirements of ANSI B31.1, Summer 1976 Addendum for ANSI B31.1 piping systems, and to 125% normal operating pressure per the requirements of ASME Boiler & Pressure Vessel Code, Section III, 1977 Edition, for ASME piping systems.

2. Leakage Reduction Program

PVNGS will institute a program to maintain leakage rates of systems outside containment to as low as practical which consists of the following:

A. Systems Included in the Program

1. High-pressure safety injection system (recirculation portion only)

2. Low-pressure safety injection system (shutdown cooling portion only)

3. Reactor coolant sampling system (post-accident sampling piping only) This is removed in those units where DMWO 2778159 has isolated the applicable line.

4. Containment spray system

5. Containment combustible gas and atmospheric sampling system (hydrogen, monitoring subsystem and post-accident sample piping associated with this function) DMWO 2529758 removes piping and valves (manual and/or solenoid) from selected portions of the PASS System piping that are connected to safety-related piping and/or components. In Units where DMWO 2529758 has been implemented for the appropriate isolation points, both the PASS System/Piping and PASS containment isolation valves have been removed and/or

de-terminated with lines capped as appropriate.

B. Systems Excluded from the Program: (They will not preclude any option of cooling the reactor core nor will they prevent the use of needed safety systems).

1. Radioactive liquid waste system, except as discussed above

2. Radioactive waste gas system, except as discussed above. (The system is not required for post-accident use.)

3. Reactor coolant letdown system, except for portions required for post-accident sampling described in paragraph 9.3.2.2.2. (The system is not required to function post-accident. The plant can be brought to a cold shutdown condition without the letdown system. The letdown system is isolated on SIAS and CIAS.)

4. Reactor coolant pump seal bleed-off system. (The system is not required to function outside containment post-accident. The seal bleed-off system is isolated outside containment on CSAS. The system remains isolated post-accident. If seal bleed-off is required post-accident, pressure in the seal bleed-off header will increase and the header

relief valve will lift providing a flow path to the reactor drain tank.)

5. Charging system. Under post-accident conditions, the charging system does not contain radioactive fluid since the letdown system is isolated, as discussed in item 3 above. The charging system takes suction from the refueling water tank.)

6. Fuel pool cooling system (FPCS). (The FPCS is normally isolated from potentially highly contaminated systems by double, locked shut isolation valves.)

C. Program Features

Immediate leak reduction measures: The program will consist of periodic monitoring of the systems during operation and inservice leak testing. Leaks will be identified and corrective maintenance performed.

1. Vent and drain lines will be capped to prevent release due to seal leakage when practical to do so.

2. The packing of valves (except Kerotest which is a packless, stainless steel diaphragm valve) in the scoped liquid systems will be inspected for leakage or evidence of leakage (such as boric acid accumulation). Maintenance will be performed on the packing

of liquid system valves identified as requiring work.

3. The seals and packing on pumps in the scoped liquid systems will be inspected for leakage or signs of leakage.

4. Valves, fittings, and compressor seals in the scoped gaseous systems will be checked for leakage. Maintenance will be performed on gas system valves and instrument fittings identified during leak tests as requiring work.

5. Systems and subsystems identified in paragraph 18.III.D.1.1.2A will be leak-tested prior to exceeding 5% power and on an interval not to exceed the period between refueling outages. Test records including measured leak rates will be maintained at PVNGS for NRC review. A report including the measured leak rates has been submitted for NRC staff review prior to operation above 5% power for Units 1 and 2. A report for Unit 3 will also be submitted. Leak rate test techniques will include:

   a. Liquid Systems

   A visual examination will be performed on items 1 through 3 of paragraph 18.III.D.1.1.2C, with the system at or near operating pressure. If leakage is identified

during these examinations, an integrated leakage rate will be determined by monitoring the applicable sump and tank levels. For sumps and tanks that do not contain a level indicator, the levels will be determined by physical measurement. In addition, the local leak rate tests performed on isolation valves will be utilized for the portion of each system located between the containment and the isolation valves if practical. These tests will be performed in accordance with written Station Manual procedures.

b. Gas Systems

The leakage will be determined by detecting gas leakage at individual valves, fittings, seals, and bolted connections with the system at or near operation pressure. Leakage will be detected by use of acoustic, bubble, or equivalent method (such as a tracer gas method). In addition, the local leak rate tests performed on isolation valves will be utilized for that portion of each system located between the containment and the isolation valves, if practical. These tests will be performed in accordance with written Station Manual procedures.

The PVNGS design was reviewed to confirm that the design and construction of PVNGS systems minimize unplanned releases of radioactivity including the related incidents identified in NRC letter dated October 17, 1979, to All Operating Nuclear Power Plants. The following summarizes that review:

Radioactive liquid atmospheric tanks are provided with overflows, with either no isolation valve or a locked-open valve. Overflow lines have loop seals and are routed to appropriate radioactive building sumps.

The sump liquid is routed to the liquid radwaste system (LRS) holdup tanks. Overflow lines from the RWT and the LRS concentrate monitor tanks are heat-traced to prevent plugging. Radioactive liquid pressurized tanks, with the exception of the volume control tank (VCT) and RDT, are provided with relief lines routed to the appropriate sumps. A summary of the overflow provisions for the radioactive tanks is provided in table 18.III.D-1.

Storm drains are located away from areas with a high potential for radioactive spills. No storm drains exist in the immediate vicinity of the containment, auxiliary, or radwaste buildings.

Radioactive pumps are generally located in isolated compartments whose drains are designed to catch all potential leakage. These drains are routed to the appropriate radioactive building sump. In addition, certain pumps, whose potential for radioactive leakage is greatest, are equipped with drip pans with lines hard-piped to the associated building

Table 18.III.D-1

RADIOACTIVE TANKS OVERFLOW AND LEAKAGE PROTECTION

P&ID	Tank	Atmospheric or Pressure Vessel	Overflow or Relief	Overflow or Relief Line	Tank Location	Curb or Enclosed Compartment	Comments
CHP-001	Volume control tank	PV	Relieves to vent gas surge header	N-214-HCDA-3/4"	Auxiliary bldg 120' level	Enclosed compartment	
CHP-002	Refueling water tank	ATM	Overflow to holdup tank sump	N-134-HCDA-6"	Outside of fuel bldg	Concrete w/ steel liner	Overflow line is heat-traced
CHP-003	Reactor makeup water tank	ATM	Overflows to holdup tank sump	N-381-HCDA-3"	Outside of fuel bldg	Concrete w/ steel line	
CHP-001	Radwaste crud tank	PV	Relieves to non-ESF sump	N-533-GCDA-2"	Auxiliary bldg 100' level	4" curb	
CHP-003	Reactor drain tank	PV	Vents to gas surge tank	N-281-HCDB-2"	Containment 80' level	-	
CHP-003	Equipment drain tank	PV	Relieves to non-ESF sump	N-347-HCDB-1"	Auxiliary bldg 40' level	-	
CHP-003	Holdup tank	ATM	Overflows to holdup tank sump	N-353-HCDA-3"	Outside of fuel bldg	Concrete w/ steel liner	
LRP-001	Low TDS holdup tank	ATM	Overflows to radwaste bldg sump	N-014-HCDA-6"	Outside of radwaste bldg	Enclosed compartment	
LRP-001	High TDS holdup tanks	ATM	Overflows to radwaste bldg sump	N-229-HCDA-4"	Outside of radwaste bldg	Enclosed compartment	
LRP-001	Chemical drain tanks	ATM	Overflows to aux bldg sump via a funnel drain	N-067-HCDA-3" N-206-HCDA-2"	Auxiliary bldg 51'-6" level	6" curb	
LRP-002	Concentrate monitor tanks	ATM	Overflows to radwaste bldg sump	N-195-HCDC-2" N-219-HCDC-1"	Radwaste bldg 100' level	6" curb	Overflow lines are heat-traced
LRP-002	Recycle monitor tanks	ATM	Overflows to radwaste bldg sump	N-183-HCDA-3" N-205-HCDA-3"	Outside of radwaste bldg	Enclosed compartment	
SRP-001	High activity spent resin tank	PV	Relieves to radwaste bldg sump	N-027-HCDA-2"	Radwaste bldg 100' level	Curb	
SRP-001	Low activity spent resin tank	PV	Relieves to radwaste bldg sump	N-016-HCDA-2"	Radwaste bldg 100' level	Curb	
SRP-002	Waste feed tank	ATM	Overflows to radwaste bldg sump via funnel drain	N-204-HCDC-3/4"	Radwaste bldg 100' level	Enclosed compartment	

Table 18.III.D-2

RADIOACTIVE PUMPS LEAKAGE PROVISIONS

P&ID	Pump	Drain Pan Drain Line	Location	Comments
CHP-001	Crud pump	N-554-HCDA-1". Drains to non-ESF sump	Auxiliary bldg 100' level	None
CHP-002	Charging pumps	N-245-HCDB-1" N-246-HCDB-1" N-247-HCDB-1". Drain to recycle drain header	Auxiliary bldg 100' level	None
CHP-002	Boric acid makeup pumps	N-449-XCDA-1/2" N-453-XCDA-1/2". Drain to non-ESF sump	Auxiliary bldg 70'-0' level	Equipped with a gland seal loop off the process flow
CHP-003	Reactor makeup water pumps	No drip pan. Drain line off gland seal to holdup tank sump	Auxiliary bldg 70' level	Equipped with a gland seal loop off the process flow
CHP-003	Reactor drain pumps	N-476-XCDA-1" N-479-XCDA-1". Drain to a funnel drain routed to non-ESF sump	Auxiliary bldg 40' level	None
CHP-003	Holdup pumps	N-482-XCDA-1/2" N-488-XCDA-1/2". Drain to holdup tank sump	Auxiliary bldg 40' level	Equipped with a gland seal loop off the process flow
LRP-001	LRS holdup pumps	N-031-HCDA-1" N-032-HCDA-1" N-033-HCDA-1". Drain to radwaste bldg sump	Radwaste bldg 100' level	None
LRP-001	Chemical drain	N-079-HCDA-1" N-082-HCDA-1". Drain to a funnel drain routed to radwaste bldg sump	Auxiliary bldg 40'-0" level	None
LRP-002	Concentrate monitor tank pumps	N-117-HCDC-1" N-620-HCDC-1". Drain to radwaste bldg sump	Radwaste bldg 100' level	Drain line is heat traced
LRP-002	Recycle monitor pumps	N-186-HCDA-1". Drains to radwaste bldg sump	Radwaste bldg 100' level	None
PCP-001	Fuel pool cleanup pumps	No drip pan	Fuel bldg 100' level	Equipped with a gland seal loop off the process flow which drains to fuel building sump
PCP-001	Fuel pool cooling pumps	No drip pan	Fuel bldg 100' level	Equipped with a gland seal loop off the process flow which drains to fuel building sump
SRP-001	Resin transfer/ dewatering pump	N-081-HCDA-1". Drains to a local stub-up routed to radwaste bldg sump	Radwaste bldg 100' level	None
SRP-002	Waste feed pump	N-068-HCDC-1". Drains to a local stub-up routed to radwaste bldg sump	Radwaste bldg 100' level	None

sump. A summary of the radioactive pumps and their leakage provisions is given in table 18.III.D-2.

Radioactive valves are located in shielded compartments, such as valve galleries, equipped with floor drains that are designed to collect all potential valve leakage. These drains are routed to appropriate building sumps.

Radioactive tanks located inside the auxiliary and radwaste buildings are located in compartments with curbs to contain tank leakage. These compartments are also equipped with floor drains routed to the appropriate radioactive building sump. Outside liquid radwaste tanks are surrounded by a dike sufficient to hold the contents of a tank rupture. Outside CVCS tanks are concrete tanks with steel liners. The concrete tanks will retain potential liner leakage.

The hot laboratory, cold laboratory, decontamination area, and sample station are equipped with floor drains routed to the non-ESF sump. There are no piping systems between units which could become contaminated.

Based on this discussion, the North Anna-type event is not expected to occur at PVNGS.

18.III.D.3.3 IMPROVED INPLANT IODINE INSTRUMENTATION UNDER ACCIDENT CONDITIONS

NRC Position

(1) Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the

facility where plant personnel may be present during an accident.

(2) Each applicant for a fuel loading license to be issued prior to January 1, 1981, shall provide the equipment, training, and procedures necessary to accurately determine the presence of airborne radio iodine in areas within the plant where plant personnel may be present during an accident.

PVNGS Evaluation

Procedures have been developed for determining airborne iodine concentration. Silver-Zeolite or charcoal cartridges will be used in conjunction with a portable pump. The cartridges will be removed and brought to the counting laboratory for gamma spectrum analysis. Cartridges may be purged prior to counting. A low background counting facility is available on the site. The results of airborne concentration can be obtained within 15 to 30 minutes after collection of iodine on filtered cartridges. Procedures also define ALARA concepts for removal, transport, and analysis of filter cartridges. There are three such portable airborne samplers available at each unit which meet the NUREG-0737 recommendations. PVNGS response to this item is included in section 18.II.F.1.

18.III.D.3.4 CONTROL ROOM HABITABILITY REQUIREMENTS

NRC Position

In accordance with Task Action Plan Item III.D.3.4 and control room habitability, licensees shall assure that control room

operators will be adequately protected against the effects of accidental release of toxic and radioactive gases and that the nuclear power plant can be safely operated or shut down under design basis accident conditions (Criterion 19, Control Room, of Appendix A, General Design Criteria for Nuclear Power Plants, to 10CFR Part 50).

PVNGS Evaluation

Potential risks in the vicinity of the site are discussed in FSAR section 2.2. The operators in the control room are adequately protected from these risks and the release of radioactive gases as discussed in FSAR section 6.4. The required information provided below is in the format suggested by Attachment 1 to NUREG-0737, Section III.D.3.4.

INFORMATION REQUIRED FOR CONTROL ROOM HABITABILITY EVALUATION

(1) Control room modes of operation: automatic filtered recirculation with filtered makeup for pressurization for radiological accident; manual filtered recirculation without makeup for smoke isolation and manual makeup and exhaust for smoke removal (operators alerted by smoke detector).

(2) Control room characteristics:

(a) Air volume control room:

1.6×10^5 cubic feet

(b) Control room emergency zone (control room, critical files, kitchen, washroom, computer room, etc.):

140-foot elevation, control building

(c) Control-room ventilation system schematic with normal and emergency air flow rates:

See engineering drawings 01, 02, 03-M-HJP-001, -002 and 02-M-HJP-003

Normal rate = 29,900 cubic feet per minute

Emergency rate = 28,600 cubic feet per minute

(d) Infiltration leakage rate:

see section 6.4.2.4

(e) High efficiency particulate air (HEPA) filter and charcoal adsorber efficiencies:

HEPA = 99.97% of 0.3 micron particles

Charcoal <95% of particulates and iodines

(f) Closest distance between containment and air intake:

150 feet, approximately

(g) Layout of control room, air intakes, containment building, and chlorine, or other chemical storage facility with dimensions:

See engineering drawings 13-C-ZVA-005, 13-P-OOB-001, 13-P-OOB-005 and Figure 6.4.1.

(h) Control-room shielding including radiation streaming from penetrations, doors, ducts, stairways, etc:

See FSAR paragraph 6.4.4.3, listing E

(i) Automatic isolation capability-damper closing time, damper leakage and area:

See FSAR paragraph 6.4.2.2.2, listing I

(j) Chlorine detectors or toxic gas (local or remote):

There is no onsite storage of liquid or gaseous chlorine at PVNGS. Chlorine is maintained as sodium hypochlorite in a liquid form. Due to the absence of a chlorine gas source, no chlorine detectors are present in the control room HVAC system.

Smoke detectors are provided in the outside air intake plenum to alert the control room operator to manually isolate the control room.

(k) Self-contained breathing apparatus availability (number), refer to FSAR paragraph 6.4.2.2.2, listing K.

(l) Bottled air supply (hours supply), refer to FSAR paragraph 6.4.2.2.2, listing K.

(m) Emergency food and potable water supply (how many days and how many people):

Presently, the PVNGS control room design has emergency food and water supply for six people for 7 days (within the closed control room).

(n) Control room personnel capacity (normal and emergency):

Refer to paragraph 6.4.4.3, listing C for the personnel capacity of the control room.

(o) Potassium iodide drug supply:

Sufficient potassium iodine will be maintained in a central location at the station to supply six persons for 7 days, as noted in FSAR paragraph 6.4.4.3, listing D.

(3) Onsite storage of chlorine and other hazardous chemicals:

NOTE: No onsite storage of liquid or gaseous chlorine. It is stored as sodium hypochlorite (liquid).

(a) Total amount and size of container:

Hydrogen:

319,200 scf at 2300 psi is stored in three sets of 14 steel cylinders.

Sulfuric acid:

154,986 gallons in six 25,831-gallon tanks

76,938 gallons in six 12,823-gallon tanks

240,000 gallons in six 40,000-gallon tanks

16,590 gallons in three 5,530-gallon tanks

Carbon dioxide:

45,000 in three 15,000 lb tanks

(b) Closest distance from control room air intake:

Hydrogen: >550 ft (and obstructed)

Sulfuric acid: closest is >300 feet,

Carbon dioxide >150 feet

(4) Offsite manufacturing, storage, or transportation facilities of hazardous chemicals:

(a) Identify facilities within a 5-mile radius;
Arlington Valley Power Plant
Mesquite Power Plant
Redhawk Power Plant

(b) Distance from control room intake;
Arlington Valley Power Plant: 3 miles
Mesquite Power Plant: 2.5 miles
Redhawk Power Plant: 3.3 miles

(c) Quantity of hazardous chemicals in one container;
The hazardous chemicals for the identified facilities above have been evaluated for control room habitability following a postulated chemical release. The quantities of chemicals are not listed here due to confidentiality of data.

(d) Frequency of hazardous chemical transportation traffic (truck, rail, and barge);

The data for frequency of hazardous chemical transportation is deemed Security Sensitive Information that is controlled under 49 CFR parts 15 and 1520, and is not listed here.

(5) Technical Specifications (refer to standard Technical Specifications)

(a) Chlorine detection system:

Refer to the discussion provided in item 2j.

(b) Control room emergency filtration system including the capability to maintain the control room pressurization at 1/8-inch water gauge, verification of isolation by test signals and damper closure times, and filter testing requirements:

Refer to Technical Specifications.

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APPENDIX 18A

RESPONSES TO NRC REQUESTS

FOR INFORMATION

CONTENTS

APPENDIX 18A

<u>QUESTION 18A.1</u> (F. J. Miraglia letter dated January 8, 1982) (III.D.1.1)

Your response to our earlier request for additional information relating to this action plan item has not addressed the following items. These should be addressed:

a. Leak test methods for liquid and gaseous systems.

b. Applicability to Palo Verde of North Anna and related incidents (identified in NRC's letter dated October 17, 1979, to all operating nuclear power plants).

c. Measured actual leak rates from all applicable systems with the system in operation (at this time, at least a commitment must be made that these will be submitted according to the schedule given in NUREG-0737).

d. Frequency of the periodic integrated leak tests.

e. Major features of the continuing leak reduction program.

f. Leak testing for the containment sampling system.

g. Leak testing for residual heat removal system.

RESPONSE:

a. The response is given in subsection 18.III.D.1.1.

b. The response is given in subsection 18.III.D.1.1.

c. The response is given in subsection 18.III.D.1.1.

d. The response is given in subsection 18.III.D.1.1.

e. The response is given in subsection 18.III.D.1.1.

f. The response is given in subsection 18.III.D.1.1.

g. The function of a "residual heat removal system" is performed by the shutdown cooling system which consists of portions of the high-pressure and low-pressure safety injection and containment spray systems, which are included in the leakage reduction program described in paragraph 18.III.D.1.1(2).

APPENDIX 18B

SYSTEM 80 GENERIC INADEQUATE CORE COOLING INSTRUMENTATION

CONTENTS

CONTENTS (cont)

TABLES

FIGURES

APPENDIX 18B
SYSTEM 80 GENERIC INADEQUATE CORE COOLING INSTUMENTATION PACKAGE

The following provides a preliminary description of the C-E Accident Monitoring System as it is intended for II.F.2 ICC.

1.0 INTRODUCTION

1.1 BACKGROUND

C-E Owners Group efforts on the evaluation of Inadequate Core Cooling have been ongoing since early 1979. Results of initial studies by the C-E Owners Group are documented in reports CEN-117 and CEN-125. These results have been considered in the preparation of emergency operating procedures guidelines. All studies have been based on the requirements to indicate the approach to, the existence of, and the recovery from ICC.

The C-E Owners Group has performed an evaluation of response characteristics of potential Inadequate Core Cooling (ICC) detection instrumentation. This study provided detailed analyses of the existing instruments, as well as investigating the performance characteristics of selected new instruments. Specifically, the instruments whose response characteristics have been evaluated are the subcooled margin monitor, the heated junction thermocouple reactor vessel level monitor, core-exit thermocouples, in-core thermocouples, self powered neutron detectors, hot leg resistance temperature detectors and ex-core neutron detectors. A summary of the details of this effort is contained in Appendix 18B-A.

Based on the results of the above instrument evaluation study, C-E has selected a Generic Inadequate Core Cooling Instrumentation (ICCI) package consisting of:

1) hot and cold leg Resistance Temperature Detectors (RTDs)
2) pressurizer pressure sensors
3) Core Exit Thermocouples (CETs)
4) Reactor Vessel Level Monitoring System (RVLMS) probes employing the Heated Junction Thermocouple (HJTC) concept

These sensor inputs have been integrated into the Accident Monitoring System core heat removal safety function and displayed via the primary SPDS in the Emergency Response Facility Data Acquisition and Display System (ERFDADS). The QSPDS portion of the AMS provides the Class 1E signal processing for the ICC sensors.

1.2 BASES FOR ICC INSTRUMENT SELECTION

The ICC instrumentation sensor package selected is designed to:

1) provide the operator with an advanced warning of the approach to ICC
2) cover the full range of ICC from normal operation to complete core uncovery

The Accident Monitoring System employing the ICC sensors package enables the reactor operator to monitor system conditions associated with the approach to, existence of, and the recovery from ICC.

1.2.1 DESCRIPTION OF ICC PROGRESSION (COOLANT STATES RELATED TO ICC)

The instrument sensor package for ICC detection provides the reactor operator a continuous indication of the thermal-hydraulic states within the Reactor Pressure Vessel (RPV) during the progression towards and away from ICC. This progression can be divided into conditions based on physical processes occurring within the RPV. These are characterized as follows:

Conditions Associated with the Approach to ICC

Condition 1a Loss of fluid subcooling prior to the first occurrence of saturation conditions in the coolant.

Condition 2a Decreasing coolant inventory within the upper plenum, (from the top of the vessel to the top of the active fuel).

Condition 3a Increasing core exit temperature produced by uncovery of the core resulting from the drop in level of the mixture of vapor bubbles and liquid from the top of the active fuel.

Conditions Associated with Recovery from ICC

Condition 3b Decreasing core exit steam temperature resulting from the rising of the level within the core.

Condition 2b Vessel fill by the increase in inventory above the fuel.

Condition 1b Establishment of saturation conditions followed by an increase in fluid subcooling.

These conditions encompass all possible coolant situations associated with any ICC event progression. The conditions denoted with an "a" refer to fluid situations that occur during the approach to ICC. Conditions denoted by a "b" refer to fluid situations which occur during the recovery from ICC. Thus, "a" conditions differ from "b" conditions in the trending (directional behavior) of the associated parameters.

In order to provide indicators during the entire progression of an event, an ICC instrument system consists of instruments which provide at least one appropriate indicator for each of the physical Conditions described above.

Applying this description of the "approach to", and "recovery from" ICC to ICC instrument selection:

1) provides assurance that the selected ICC system detects the entire progression

2) demonstrates the extent of instrument diversity or redundancy which is possible with the available instruments.

Furthermore, by defining the ICC progression on a physical basis the general labels of "approach to", and "recovery from" ICC can now be associated with specific physically measurable processes. (See Section 1.2.2, 1.2.3, and 1.2.4).

The instrument sensor package selected to monitor the ICC event progression consists of (1) Resistance Temperature Detectors (RTDs) (2) pressurizer pressure sensors, (3) reactor vessel level monitors employing the HJTC design concept and (4) core exit thermocouples. The signals from the RTDs, unheated thermocouples in the HJTC system, and pressure sensors can be

combined to indicate the loss of subcooling and occurrence of saturation (Condition 1a) and the achievement of a subcooled condition following core recover (Condition 1b). The reactor vessel level monitors provide information to the operator on the decreasing liquid inventory in the reactor pressure vessel (RPV) regions above the fuel alignment plate (FAP), as well as the increasing RPV liquid inventory above the FAP following core recovery (Conditions 2a and 2b). The core exit thermocouples (CETs) monitor the increasing steam temperatures associated with ICC and the decreasing steam temperatures associated with recovery from ICC (Conditions 3a and 3b).

1.2.2 ADVANCED WARNING OF THE APPROACH TO ICC

The ICC instrumentation provides the operator with an advanced warning of the approach to ICC by providing indications of:

1) the loss of subcooling and occurrence of saturation (Condition 1a) with a saturation margin monitor (SMM) receiving input from primary system RTDs, upper head HJTCs, and the pressurizer pressure sensors.

2) the loss of inventory in the RPV (Condition 2a) with the RVLMS.

3) the increasing core coolant exit temperature (Condition 3a) with CETs.

It should be noted that the RVLMS measures inventory (collapsed liquid level) rather than two-phase level. This measurement provides the operator with an advanced indication of the coolant level should conditions arise to cause the two-phase

froth to collapse via system overpressurization, or the loss of operating reactor coolant pumps.

1.2.3 APPLICATION OF ICC INSTRUMENTS

Following an event leading to ICC the ICC instruments will provide information to the reactor operator so that he may:

1) verify that the core heat removal safety function is being met,

2) establish the potential for fission product release.

ICC Instrumentation indications will be used to support the operator in helping to verify that the core heat removal safety function is being met. ICCI indications available to the operator are (1) an increasing inventory level above the fuel alignment plate, (2) an increasing subcooling in the RPV and RCS piping or (3) a decreasing core exit steam superheat. The operator is informed about the progression of an event by both static and trend displays. The trending of ICC information enables the operator to quickly assess the success of automatically or manually performed mitigating actions. A chart indicating the ICCI trending during the various ICC progression conditions associated with the approach to and recovery from ICC is presented in Table 18B-1.

1.2.4 INSTRUMENT RANGE

In the ICCI sensor package, saturation temperature and water inventory are used as indicators for the approach to and recovery from ICC when there is water inventory above the fuel

alignment plate. These measurements characterize conditions 1a, 1b, 2a, and 2b of the ICC progression.

When the two-phase level is below the fuel alignment plate, the measurement of core exit fluid temperature represents a direct indication of the approach to, and recovery from ICC (Conditions 3a and 3b). Therefore, the ICC sensor package is sufficient to provide information to the reactor operator on the entire progression of an event with the potential of resulting in ICC.

TABLE 18B-1

ICC STATUS AS AVAILABLE TO THE OPERATOR FROM ICC INSTRUMENTATION TRENDING

I. APPROACHING AN ICC CONDITION

CONDITION	SUBCOOLING MEASURED BY SMM	WATER INVENTORY MEASURED BY HJTC PROBE	COOLANT SUPERHEAT MEASURED BY CET
1a	DECREASING	CONSTANT	CONSTANT
2a	CONSTANT	DECREASING	CONSTANT
3a	CONSTANT	CONSTANT	INCREASING

II. RECEDING FROM AN ICC CONDITION

CONDITION	SUBCOOLING MEASURED BY SMM	WATER INVENTORY MEASURED BY HJTC PROBE	COOLANT SUPERHEAT MEASURED BY CET
3b	CONSTANT	CONSTANT	DECREASING
2b	CONSTANT	INCREASING	CONSTANT
1b	INCREASING	CONSTANT	CONSTANT

2.0 INADEQUATE CORE COOLING INSTRUMENTATION DESIGN DESCRIPTION

This section provides a preliminary description of a generic Accident Monitoring System (AMS) approach to address II.F.2, Inadequate Core Cooling (ICC) requirements. The Accident Monitoring System (AMS) consists of two major subsystems; 1) Emergency Response Facility Data Acquisition and Display System (ERFDADS) and 2) Qualified Safety Parameter Display System (QSPDS). A functional overview of the AMS highlighting the ICC sensor inputs is shown in Figure 18B-1. As discussed previously, the reactor vessel liquid inventory above the core and the fluid conditions at various locations in the primary system will be measured by RTDs, pressurizer pressure sensors, reactor vessel level HJTCs, and CETs. As shown in Figure 18B-1 the ICC sensors are input to the Qualified Safety Parameter Display System (QSPDS) for processing and then integrated into the Primary Safety Parameter Display in the Emergency Response Facility Data Acquisition and Display System (ERFDADS) portion of the AMS.

2.1 SENSOR DESIGN

Detailed information on the associated ICC sensors is presented in the following sections.

2.1.1 SATURATION MARGIN

Subcooled Margin Monitoring (SMM) provides information to the reactor operator on (1) the approach to and existence of saturation and (2) existence of core uncovery.

The SMM includes inputs from RCS cold and hot leg temperatures measured by RTDs, the temperature of the maximum of the top three Unheated Junction Thermocouples (UHJTC), and pressurizer pressure sensors. The UHJTC input comes from the output of the HJTCS processing units. In summary, the sensor inputs are as follows:

Input	Range
Pressurizer Pressure	0-3000 psia
Cold Leg Temperature	50-750°F
Hot Leg Temperature	50-750°F
Maximum UHJTC Temperature of top three sensors (from HJTC processing)	32-2300°F
Representative CET Temperature	32-2300°F

2.1.2 HEATED JUNCTION THERMOCOUPLE (HJTC) PROBE ASSEMBLY

The HJTC Probe Assembly measures reactor coolant liquid inventory above the fuel alignment plate with discrete HJTC sensors located at different levels within a separator tube ranging from the top of the fuel alignment plate to the reactor vessel head. The basic principle of operation is the detection of a temperature difference between adjacent heated and unheated thermocouples.

As pictured in Figure 18B-2, the HJTC sensor consists of a Chromel-Alumel thermocouple near a heater (or heated junction) and another Chromel-Alumel thermocouple positioned away from the heater (or unheated junction). In a fluid with relatively good heat transfer properties, the temperature difference

between the adjacent thermocouples is small. In a fluid with relatively poor heat transfer properties, the temperature difference between the thermocouples is large.

Two probe assemblies are provided to allow two channels of HJTC instruments. Each HJTC probe assembly includes eight (8) HJTC sensors, a separator tube, a seal plug, and electrical connectors (Figure 18B-3). The eight (8) HJTC sensors are electrically independent. Should a sensor fail during operation, the circuitry can be temporarily modified to electrically isolate the failed sensor provided the minimum Technical Specification Requirements are adhered to (see Table 1.8-1 for status).

Two design features ensure proper operation under all thermal-hydraulic conditions. First, each HJTC is shielded to avoid overcooling due to direct water contact during two phase fluid conditions. The HJTC with the splash shield is referred to as the HJTC sensor (See Figure 18B-2). Second, a string of HJTC sensors is enclosed in a tube that separates the liquid and gas phases that surround it.

The separator tube (See Figure 18B-4) creates a collapsed liquid level that the HJTC sensors measure. This collapsed liquid level is directly related to the average liquid fraction of the fluid in the reactor head volume above the fuel alignment plate. This mode of direct in-vessel sensing reduces spurious effects due to pressure, fluid properties, and non-homo-geneities of the fluid medium. The string of HJTC sensors and the separator tube is referred to as the probe assembly.

The probe assembly is housed in a stainless steel structure that protects it from flow loads.

2.1.3 CORE EXIT THERMOCOUPLES (CET)

The core exit thermocouples provide a measure of core heatup via measurement of core exit steam temperature.

The design of the System 80 In-core Instrumentation (ICI) system will be modified to include Type K (Chromel-Alumel) thermocouples within each of the ICI detector assemblies. These Core Exit Thermocouples (CET) monitor the temperature of the reactor coolant as it exits the fuel assemblies. The core locations of the ICI detector assemblies are shown in Figure 18B-5.

The CETs have a usable temperature range from 200°F to up to 2300°F.

2.2 DESCRIPTION OF ICC PROCESSING

The following sections provide a preliminary description of the processing control and display functions associated with each of the ICC detection instruments in the AMS. The sensor inputs for the major ICC parameters; saturation margin, reactor vessel inventory/temperature above the core, and core exit temperature are processed in the two channel QSPDS and transmitted to the ERFDADS for primary display and trending.

2.2.1 SATURATION MARGIN

The QSPDS processing equipment will perform the following saturation margin monitoring functions:

1. Calculate the saturation margin

   The saturation temperature is calculated from the minimum pressure input. The temperature subcooled or superheat margin is the difference between saturation temperature and the sensor temperature input. Three temperature subcooled or superheat margin presentations will be available. These are as follows:

   a. RCS saturation margin - the temperature saturation margin based on the difference between the saturation temperature and the maximum temperature from the RTDs in the hot and cold legs.

   b. Upper head saturation margin - temperature saturation margin based on the difference between the saturation temperature and the UHJTC temperature (based on the maximum of the top three UHJTC)

   c. CET saturation margin - temperature saturation margin based the difference between the saturation temperature and the representation core exit temperature calculated from the CETs (Section 2.2.3).

2. Process sensor outputs for determination of temperature saturation margin.

3. Provide an alarm output for an annunciator when temperature saturation margin reaches a preselected (to be determined) setpoint for RCS, upper head, or CET saturation margin.

2.2.2 HEATED JUNCTION THERMOCOUPLE

The QSPDS processing equipment performs the following functions for the HJTC:

1. Determine collapsed liquid level above core.

   The heated and unheated thermocouples in the HJTC are connected in such a way that absolute and differential temperature signals are available. This is shown in Figure 18B-6. When liquid water surrounds the thermocouples, their temperature and voltage output are approximately equal. The voltage $V_{(A-C)}$, on Figure 18B-6 is, therefore, approximately zero. In the absence of liquid, the thermocouple temperatures and output voltages become unequal, causing $V_{(A-C)}$ to rise. When $V_{(A-C)}$ of the individual HJTC rises above a predetermined setpoint, liquid inventory does not exist at this HJTC position.

2. Determine the maximum upper plenum/head fluid temperature of the top three unheated thermocouples for use as an output to the SMM calculation. (The temperature processing range is from 100°F to 2300°F.)

3. Process input signals to display collapsed liquid level and unheated junction thermocouple temperatures.

4. Provide an alarm output when any of the HJTC detects the absence of liquid level.

5. Provide control of heater power for proper HJTC output signal level. Figure 18B-7 shows the design for one of the two channels which includes the heater controller power supplies.

2.2.3 CORE EXIT THERMOCOUPLE SYSTEM

The QSPDS performs the following CET processing functions:

1. Process core exit thermocouple inputs for display.
2. Calculate a representative core exit temperature. Although not finalized, this temperature will be either the maximum valid core exit temperature or the average of the five highest valid core exit temperatures.
3. Provide an alarm output when temperature reaches a preselected value.
4. Process CETs for display of CET temperature and superheat.

These functions are intended to meet the design requirements of NUREG-0737, II.F.2 Attachment 1.

2.3 SYSTEM DISPLAY

The QSPDS ICC outputs are incorporated into the Emergency Response Facility Data Acquisition and Display System (ERFDADS) alarm logic and displays. The ERFDADS is a dedicated, computer-based plant information and display system that provides a Primary Safety Parameter Display directly monitoring critical plant functions:

1. Core reactivity control
2. Core heat removal control
3. RCS inventory control
4. RCS pressure control
5. RCS heat removal control
6. Containment pressure/temperature control

7. Containment isolation control

8. Radiation emissions control

These critical safety functions are directly monitored by a set of algorithms which process the measured plant variables to determine the plants safety status relative to safety functions control. If any of the critical functions are violated, (by exceeding logic setpoints) a Critical Function Alarm (CFA) is initiated. The ICC instruments outputs are incorporated in this critical function alarm logic. Specifically the ICC inputs are incorporated into the core heat removal control level 1 display and also lower level detail displays.

The ERFDADS displays data to computer displays in the Control Room and TSC. The data has three levels of information:

Level 1 - Monitor (Critical functions status)

Level 2 - Control (System overview)

Level 3 - Diagnostic (System detail)

This hierarchy allows the operator to progress from an overall plant safety status, to system overview to a detailed diagnostic view. The ICC instrument outputs are incorporated in all three levels of display. The detailed ICC information is anticipated to be displayed on a dedicated display. ICC trending displays for saturation margin, reactor vessel inventory, representative core exit temperature, and representative core exit temperature saturation margin are also provided with the ERFDADS. The ERFDADS is the Primary Control room display of ICC information.

Each QSPDS safety grade backup display also has available the most reliable basic information for each of the ICC instruments. These displays are human engineered to give the operator clear unambiguous indications. The backup displays are designed:

1. to give instrument indications in the remote chance that the primary display becomes inoperable.
2. to provide confirmatory indications to the primary display.
3. to aid in surveillance tests and diagnostics.

The following sections describe displays as presently conceived for each of the ICC instrument systems. Both primary and backup displays are intended to be designed consistent with the criteria in II.F.2 Attachment 1 and Appendix 18B-A.

2.3.1 ICC DISPLAYS

The ICC detection instrumentation displays in both the ERFDADS (primary displays) and the QSPDS (backup displays) have an ICC summary page as part of the core heat removal control critical function supported by more detailed display pages for each of the ICC variable categories.

The summary page will include:

1. RCS/Upper Head saturation margin - the maximum of the RCS and Upper Head saturation margin.
2. Reactor vessel level above the core.
3. Representative core exit temperature.

Since the ERFDADS has more display capabilities than the QSPDS such as color-graphics, trending, and a larger format, additional information may be added and with a better presentation than is available with the QSPDS. These variables are incorporated in other ERFDADS system displays.

Since the ERFDADS receives both QSPDS channels of ICC input, the ERFDADS displays both channels of ICC information. The QSPDS displays only one channel of ICC information for each video display unit.

Although all inputs are accessible for trending and historical recall, the ERFDADS has a dedicated ICC trend page for RCS/upper head saturation margin, reactor vessel level, and representative core exit temperature and core exit saturation margin. These are also available as analog outputs from the QSPDS cabinet.

2.3.2 SATURATION MARGIN DISPLAY

The following information is presented on the primary (ERFDADS) and backup (QSPDS) displays:

1. Temperature and pressure saturation margins for RCS, Upper Head, Core Exit Temperature.
2. Temperatures and pressure inputs.

2.3.3 HEATED JUNCTION THERMOCOUPLE SYSTEM DISPLAY

The following information is displayed on the ERFDADS and QSPDS displays:

1. Liquid inventory level above the fuel alignment plate derived from the eight discrete HJTC positions.

2. 8 discrete HJTC positions indicating liquid inventory above the fuel alignment plate.

3. Inputs from the HJTCS:

   a. Unheated junction temperature at the 8 positions.

   b. Heated junction temperature at the 8 positions.

   c. Differential junction temperature at the 8 positions.

2.3.4 CORE EXIT THERMOCOUPLE DISPLAY

The following information is displayed on the ERFDADS display:

1. A spatially oriented core map indicating the temperature at each of the CET's.

2. A selective reading of CET temperatures.

3. The representative core exit temperature.

The following information is displayed on the QSPDS display:

1. Representative core exit temperature.

2. A selective reading of the CET temperatures.

3. A listing of all core exit temperatures.

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APPENDIX 18B-A

EVALUATION OF INSTRUMENTATION FOR DETECTION OF INADEQUATE CORE COOLING

CONTENTS

TABLES

APPENDIX 18B-A
EVALUATION OF INSTRUMENTATION FOR DETECTION OF INADEQUATE CORE COOLING

The C-E Owners Group has conducted an evaluation of instrumentation for the potential application to the detection of Inadequate Core Cooling. The performance characteristics of selected instruments were compared for representative transients resulting in various degrees of reactor coolant system voiding. The respective instruments then were evaluated based on their developmental and post-accident qualification status, response characteristics, and signal clarity.

A.1 DESCRIPTION OF ICC EVENT PROGRESSION

The state of progression of an event resulting in ICC can be divided based on physical processes occurring within the RPV, into the following six conditions:

Conditions Associated with the Approach to ICC

Condition 1A   Loss of fluid subcooling prior to the first occurrence of saturation conditions in the coolant.

Condition 2A   Decreasing coolant inventory within the upper plenum, from the top of the vessel to the top of the active fuel.

Condition 3A   Increasing core exit temperature produced by uncover of the core resulting from the drop in level of the mixture of vapor bubbles and liquid below the top of the active fuel.

Conditions Associated with Recovery From ICC

Condition 3b Decreasing core exit steam temperature resulting from the rising of the level within the core.

Condition 2b Increasing inventory above the fuel.

Condition 1b Establishment of saturation conditions followed by an increase in fluid subcooling.

The instrument system used for the detection of ICC should provide the reactor operator with the current status of selected key parameters and the trending of prior status of selected key parameters as the event progresses through each of the above conditions.

A.2 SUMMARY OF SENSOR EVALUATION

The instruments evaluated in this effort were the subcooled margin monitor (SMM), resistance temperature detectors (RTDs), reactor vessel level monitor employing the heated junction thermocouples (HJTC), core exit thermocouples (CETs),

self-powered neutron detectors (SPNDs), ex-core detectors and incur thermocouples. The instruments are listed in

Table 18B-A-1, where their capabilities are summarized. Significant conclusions about each instrument are given below.

A.2.1 Subcooled Margin Monitor

The Subcooled Margin Monitor (SMM), using input from existing Resistance Temperature Detectors (RTD) in the hot and cold legs and from the pressurizer pressure sensors, will detect the

initial occurrence of saturation during LOCA events and during loss of heat sink events.

The usefulness of the SMM, will be significantly increased by also feeding into it the signals from the fluid temperature measurements from the HJTCS and by modifying the SMM to calculate and display degrees superheat in addition to degrees subcooling. The signals from the HJTCS temperature measurements provide information about possible local differences in temperature between the reactor vessel upper head/upper plenum (location of the HJTCS) and the hot or cold legs (location of the RTDs).

With these modifications, the SMM can be used not only for detection of the approach to ICC, namely Condition 1a (loss of subcooling), but also for Conditions 3a and 3b (core uncovery) and Condition lb (core recovery). Even with the modifications, the SMM will not be capable of indicating the existence of Conditions 2a and 2b when the coolant is at saturation conditions and the level is between the top of the vessel and the top of the core.

A.2.2 Resistance Temperature Detectors

The RTD are adequate for sensing the initial occurrence of saturation for events initiated at power and for events initiated from zero power or shutdown conditions.

The RTD range is not adequate for ICC indications during core uncovery. For depressurization LOCA events, the core may uncover at low pressure, when the saturation temperature is below the lower limit of the hot leg RTD. Initial superheat of

the steam will therefore not be detected by the hot leg RTD. As the uncovery proceeds, the superheated steam temperature may quickly exceed the upper limit of the RTD range.

A.2.3 Heated Junction Thermocouple System (HJTCS)

The HJTC probe is designed to create and measure a collapsed liquid level in a localized plenum region. The height of the collapsed liquid level within the probe is sensed using pairs of heated junction thermocouples. This mode of sensing reduces spurious effects due to pressure, fluid properties, and non-homogeneities of the fluid medium.

The signal which is produced by the HJTC probe is a small electrical current similar in magnitude to, or greater than, the current produced by typical temperature sensing devices presently used in the reactor coolant system. This signal may be transmitted from within the reactor vessel to outside of the containment building with no intermediate electronics. Furthermore, the signal is not subject to external disturbances, such as containment environment as would be present with a hydraulic signal transmission system.

The HJTC can provide significant information to the operator for two conditions associated with an ICC event - Condition 2a, the approach to uncovery and Condition 2b, the refill. For a large small break event, the two-phase level drops to the top of the core within 5 to 15 minutes of the break initiation. In this event, the HJTC would show the rapidly decreasing coolant inventory and would quantify for the operator the status of the degrading situation which is otherwise evident to him from

numerous existing instruments. For smaller breaks, the progression of the event is slower, and the HJTC can provide significant information on the effectiveness of his mitigating actions. It is probably for such long term conditions, prior to core uncovery, that the HJTC would have its greatest usefulness.

Following recovery of the core, the operator could use the HJTC to verify that the core is again covered and therefore is being adequately cooled. Through monitoring the HJTC level the operator has better indication of the correctness and effectiveness of this actions in maintaining the coolant inventory.

A.2.4 Core Exit Thermocouples (CETs)

The core exit thermocouples will show the approach to and existence of ICC after core uncovery for the events analyzed. The core exit thermocouples respond to the coolant temperature at the core exit and indicate superheat after the core is no longer completely covered by coolant. The trend of the change in superheat corresponds to the trend of the change in cladding temperature.

Existing thermocouples in C-E reactors have been qualified to industry standard accuracy for operation to 750°F. However, thermocouples of this design (i.e., stainless steel sheathed, alumina insulated, Type K, Chromel-Alumel) are suitable for nuclear service to 1650°F. Tests have been run on such thermocouples to simulate severe accidents (See Reference 4 of text). Results from these tests demonstrated the shunting

error caused by the increase in electrical conductance of the alumina at high temperature is shown to be negligible up to 1650°F and is acceptably small to 1800°F. It is concluded that the thermocouples in operating C-E designed reactors could satisfy the minimum NRC requirement for 1650°F and are adequate to 1800°F. In addition, tests performed at ORNL indicate that CETs may be used for purposes of trending of steam temperatures up to 2300°F.

A.2.5 Self-Powered Neutron Detectors (SPNDs)

The SPND yield a signal caused by high temperature as the two-phase level falls below the elevation of the SPND. However, testing would be required to identify the phenomena responsible for the anomalous behavior of the SPND at TMI-2. At the present, their use is limited to low temperature events (less than 1000°F clad temperature) or to only the initial uncovery portion of an event.

A.2.6 Ex-Core Neutron Detectors

Existing source range neutron detectors are sensitive enough to respond to the formation of coolant voids within the vessel during the events analyzed. However, the signal magnitude is ambiguous because of the effects of varying boron concentration and deuterium concentration in the reactor coolant.

A stack of ex-core detectors gives less ambiguous information on voids and level in the vessel. The relative shape of the axial distribution of signals from a stack of five detectors

shows promise as an ICC indicator, but additional development would be needed.

A.2.7 In-Core Thermocouples

Although the loss of other instrumentation such as the SPND's would have to be considered, in general, it appears feasible that in-core thermocouples may be added to or substituted for some SOND in the in-core instrument string. In-core thermocouples sense the surrounding environment via radiation, as well as, steam convection. The information provided to the operator by in-core thermocouples is qualitatively the same as that provided by CETs.

TABLE 18B-A-1

INSTRUMENT INCLUDED IN EVALUATIONS

FOR ICC INSTRUMENTATION SYSTEM

INSTRUMENTS	DEVELOPMENT STATUS	POST-ACCIDENT QUALIFICATION STATUS	INDICATION PROVIDED BY INSTRUMENT	CLARITY OF SIGNAL	CONDITIONS MONITORED
Subcooled Margin Monitor	Exists	Qualified	Degree Of Subcooling In RCS	Good	1a, 1b
Reactor Vessel Level Monitor	Under Develop.	Will Be Qualified	1) Liquid Inventory In Upper Head	Good	2a, 2b
			2) Liquid Inventory in Upper Plenum	Good	
			3) Axial Temperature Distribution In Head And Plenum	Good	
Core Exit Thermocouples	Exist	Can Be Done	1) Fluid Temperature at Core Exit	Good	3a, 3b
In-Core Thermocouples	Concept Stage	Can Be Done	1) Metal Temperature Inside Guide Tube When RCP Off	Good	3a, 3b
Self-Powered Neutron Detectors	Exist	Can Be Done	Indirect Measure of Mixture Level (Low Pressure Uncovery)	Poor	3a, 3b
Hot Leg RTD (5 Each)	Exist	Qualified	Fluid Temperature in Hot Leg	Good	1a, 1b, 3a, 3b
Ex-Core Neutron Detector (Off, Source Range)	Exist	Can Be Done	Indirect Measure of Gross Voiding	Fair	3a, 3b
			Indirect Indication of Mixture Level Level in Core, RCP Off	Fair	
Ex-Core Neutron Detector (Stack of 5, Source Range)	Concept	Can Be Done	Same as One Ex-Core Detector, But More Axial Resolution	Fair	3a, 3b

CHAPTER 19

LICENSE RENEWAL SUPPLEMENT

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19.0 INTRODUCTION

In compliance with Unit 1 license condition 2.C.(16)(a), Unit 2 license condition 2.C.(11)(a), and Unit 3 license condition 2.C.(7)(a) of the PVNGS renewed operating licenses, this chapter of the PVNGS UFSAR contains the information required by 10 CFR 54.21(d) that was contained in the PVNGS license renewal application, Appendix A, "Updated Final Safety Analysis Report Supplement." The PVNGS license renewal application was submitted to the NRC in a letter dated December 11, 2008, and supplemented by letters submitted to the NRC through March 17, 2011. The NRC review of the PVNGS license renewal application is documented in NUREG-1961, "Safety Evaluation Report Related to the License Renewal of Palo Verde Nuclear Generating Station, Units 1, 2, and 3," issued April 2011.

Section 19.1 contains summary descriptions of the programs used to manage the effects of aging during the period of extended operation. Section 19.2 contains summary descriptions of programs used for management of time-limited aging analyses during the period of extended operation. Section 19.3 contains evaluation summaries of TLAAs for the period of extended operation. Section 19.4 contains any newly identified systems, structures, and components subject to an aging management review or evaluation of time-limited aging analyses. Section 19.5 contains a listing of license renewal commitments.

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19.1 SUMMARY DESCRIPTIONS OF AGING MANAGEMENT PROGRAMS

The integrated plant assessment and evaluation of time-limited aging analyses (TLAA) identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of License Renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. Sections 19.1 and 19.2 describe the programs and their implementation activities.

Three elements common to all aging management programs discussed in Sections 19.1 and 19.2 are corrective actions, confirmation process, and administrative controls. These elements are included in the PVNGS Quality Assurance (QA) Program, which implements the requirements of 10 CFR 50, Appendix B. The PVNGS Quality Assurance Program is applicable to all safety-related and nonsafety-related systems, structures and components that are subject to aging management review activities.

19.1.1 ASME SECTION XI INSERVICE INSPECTION, SUBSECTIONS IWB, IWC, AND IWD

ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program manages cracking, loss of fracture toughness, and loss of material in Class 1, 2, and 3 piping and components within the scope of license renewal. The program includes periodic visual, surface, volumetric examinations and leakage tests of Class 1, 2 and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral

attachments, and pressure-retaining bolting. PVNGS inspections meet ASME Section XI requirements. The PVNGS third interval ISI Program is in accordance with 10 CFR 50.55a and ASME Section XI, 2001 Edition, through 2003 Addenda. PVNGS will use the ASME Code Edition consistent with the provisions of 10 CFR 50.55a during the period of extended operation.

19.1.2 WATER CHEMISTRY

The Water Chemistry program includes maintenance of the chemical environment in the reactor coolant system and related auxiliary systems and includes maintenance of the chemical environment in the steam generator secondary side and the secondary cycle systems to manage cracking, denting, loss of material, reduction of heat transfer, and wall thinning in primary and secondary water systems. The Water Chemistry program is based upon the guidelines of EPRI 1014986, "*PWR Primary Water Chemistry Guidelines*", Volumes 1 and 2, and EPRI 1016555, "*PWR Secondary Water Chemistry Guidelines*".

The effectiveness of the program is verified under the One-Time Inspection program (19.1.16).

19.1.3 REACTOR HEAD CLOSURE STUDS

The Reactor Head Closure Studs program manages reactor vessel stud, nut and washer cracking and loss of material. The Reactor Head Closure Studs program includes periodic visual, surface, and volumetric examinations of reactor vessel flange stud hole threads, reactor head closure studs, nuts, and

washers and performs visual inspection of the reactor vessel flange closure during primary system leakage tests. The program implements ASME Section XI code, Subsection IWB, 2001 Edition through the 2003 addenda.

19.1.4 BORIC ACID CORROSION

The Boric Acid Corrosion program manages loss of material due to boric acid corrosion. The program includes provisions to identify, inspect, examine and evaluate leakage, and initiate corrective actions. The program relies in part on implementation of recommendations of NRC Generic Letter 88-05, "*Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*". Additionally, the program includes scheduled inspection of all plant borated water systems and examinations conducted during ISI pressure tests performed in accordance with ASME Section XI requirements. The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (19.1.5) and the Nickel Alloy Aging Management Program (19.1.34) as well as the Boric Acid Corrosion control program, implement reactor coolant pressure boundary inspections of reactor coolant pressure boundary components to identify degradation that would impact the reactor coolant pressure boundary.

SUMMARY DESCRIPTIONS

OF AGING MANAGEMENT PROGRAMS

19.1.5 NICKEL-ALLOY PENETRATION NOZZLES WELDED TO THE UPPER REACTOR VESSEL CLOSURE HEADS OF PRESSURIZED WATER REACTORS

The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program manages cracking due to primary water stress corrosion cracking (PWSCC) and loss of material due to boric acid wastage in nickel-alloy pressure vessel head penetration nozzles and includes the reactor vessel closure head, upper vessel head penetration nozzles and associated welds. The term "primary water stress corrosion cracking" applies to the nozzles and J-welds and "Wastage" applies to the reactor closure head. The aging management for the aging effect of wastage is addressed in Boric Acid Corrosion program (19.1.4). This program was developed in response to NRC Order EA-03-009. ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6) has superseded the requirements of NRC Order EA-03-009.

Detection of cracking is accomplished through implementation of a combination of bare metal visual examination (external surface of head) and surface and volumetric examination (underside of head) techniques. Reactor Pressure Vessel Head bare metal visual examinations, surface examinations, and volumetric examinations are performed consistent with the ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6).

SUMMARY DESCRIPTIONS

OF AGING MANAGEMENT PROGRAMS

19.1.6 FLOW-ACCELERATED CORROSION

The Flow-Accelerated Corrosion (FAC) program manages wall thinning due to FAC on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phases).

The objectives of the FAC program are achieved by (a) identifying system components susceptible to FAC, (b) an analysis using a predictive code such as CHECWORKS to determine critical locations for inspection and evaluation, (c) providing guidance of follow-up inspections, (d) repairing or replacing components, as determined by the guidance provided by the program, and (e) continual evaluation and incorporation of the latest technologies, industry and plant in-house operating experience.

Procedures and methods used by the FAC program are consistent with APS commitments to NRC Bulletin 87-01, "*Thinning of Pipe Wall in Nuclear Power Plants,*" and NRC Generic Letter 89-08, "*Erosion/Corrosion-Induced Pipe Wall Thinning.*"

The program relies on implementation of the EPRI guidelines of NSAC-202L, "Recommendations for an Effective Flow Accelerated Corrosion Program."

19.1.7 BOLTING INTEGRITY

The Bolting Integrity program manages cracking, loss of material, and loss of preload for pressure retaining bolting and ASME component support bolting. The program includes

preload control, selection of bolting material, use of lubricants/sealants consistent with EPRI good bolting practices, and performance of periodic inspections for indication of aging effects. The program is supplemented by Inservice Inspection requirements established in accordance with ASME Section XI, Subsections IWB, IWC, IWD, and IWF for ASME Class bolting.

PVNGS good bolting practices are established in accordance with plant procedures. These procedures include requirements for proper disassembling, inspecting, and assembling of connections with threaded fasteners. The general practices that are established in this program are consistent with EPRI NP-5067, "*Good Bolting Practices, Volume 1 and Volume 2*," and the recommendations of NUREG-1339, "*Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants.*"

19.1.8 STEAM GENERATOR TUBE INTEGRITY

The Steam Generator Tube Integrity program includes the preventive measures, condition monitoring inspections, degradation assessment, repair and leakage monitoring activities necessary to manage cracking, wall thinning, and loss of material. The aging management measures employed include: non-destructive examination, visual inspection, sludge removal, tube plugging, in-situ pressure testing, maintaining the chemistry environment by removal of impurities, and addition of chemicals to control pH and oxygen.

NDE inspection scope and frequency, and primary to secondary leak rate monitoring are conducted consistent with the requirements of the PVNGS Units 1, 2, and 3 Technical Specifications. PVNGS evaluates tube integrity in accordance with the structural integrity performance criteria specified in Technical Specifications which encompasses and exceeds the requirements of Regulatory Guide 1.121. In addition, Technical Specifications include accident induced leakage performance criterion and operational leakage performance criterion. The PVNGS steam generator management practices are consistent with NEI 97-06, "*Steam Generator Program Guidelines.*"

19.1.9 OPEN-CYCLE COOLING WATER SYSTEM

The Open-Cycle Cooling Water System program manages loss of material and reduction of heat transfer for components exposed to the raw water of the open-cycle cooling water system. The program includes surveillance techniques and control techniques to manage aging effects caused by biofouling, corrosion, erosion and silting in the open-cycle cooling water system and in structures and components cooled by the open-cycle cooling water system for the period of extended operation. The program is consistent with commitments as established in PVNGS responses to Generic Letter 89-13 "Service Water System Problems Affecting Safety-Related Components."

The Open-Cycle Cooling Water System program provides the general requirements of implementation and maintenance of programs and activities which mitigate aging of the open-cycle cooling water system and components. The various aspects of

the PVNGS program (control, monitoring, maintenance and inspection) are implemented in plant procedures.

Prior to the period of extended operation, the program will be enhanced to clarify guidance in the conduct of piping inspections using NDE techniques and related acceptance criteria.

19.1.10 CLOSED-CYCLE COOLING WATER SYSTEM

The Closed-Cycle Cooling Water System program manages loss of material, cracking, and reduction in heat transfer for components in closed cycle cooling water systems. The program includes maintenance of system corrosion inhibitor concentrations and chemistry parameters following the guidance of EPRI TR-107396 to minimize aging, and periodic testing and inspections to evaluate system and component performance. Inspection methods include visual, ultrasonic testing and eddy current testing.

19.1.11 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program manages loss of material for all cranes, trolley and hoist structural components, fuel handling equipment and applicable rails within the scope of license renewal. Program inspection activities verify the structural integrity of the components required to maintain their intended function. The inspection requirements are

consistent with the guidance provided by NUREG-0612, "*Control of Heavy Loads at Nuclear Power Plants,*" for load handling systems that handle heavy loads which can directly or indirectly cause a release of radioactive material, applicable industry standards (such as CMAA Spec 70) for other components within the scope of license renewal in this program, and applicable OSHA regulations (such as 29 CFR Volume XVII, Part 1910 and Section 1910.179).

Prior to the period of extended operation, procedures will be enhanced to inspect for loss of material due to corrosion or rail wear.

19.1.12 FIRE PROTECTION

The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pumps, and the halon/CO_2 fire suppression systems, cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors, and hardness and shrinkage due to weathering of fire barrier penetration seals. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors manage aging. Periodic testing of the diesel-driven fire pumps ensures that there is no loss of function due to aging of diesel fuel supply lines. Drop tests are performed on 10 percent of fire dampers on an 18 month basis to manage aging. Visual inspections manage aging of fire-rated doors every 18 months to verify the integrity of door surfaces and for clearances to detect aging of the fire

doors. A visual inspection and function test of the halon and CO_2 fire suppression systems every 18 months (along with the destructive testing of the Electro-Thermal Links (ETLs) and functional testing of the dampers which are both performed every 54 months) manages aging. Ten percent of each type of penetration seal is visually inspected at least once every 18 months. Fire barrier walls, ceilings, and floors including coatings and wraps are visually inspected at least once every 18 months.

Prior to the period of extended operation procedures will be enhanced to perform the testing of the Electro-Thermal Links (ETLs) and functional testing of the halon and CO2 dampers every 18 months or at the frequency specified in the current licensing basis in effect upon entry into the period of extended operation.

19.1.13 FIRE WATER SYSTEM

The Fire Water System program manages loss of material for water-based fire protection systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests are performed considering applicable National Fire Protection Association (NFPA) codes and standards. The fire water system pressure is continuously monitored such that loss of system pressure is immediately detected and corrective actions are initiated. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler head to verify that each open head spray/sprinkler nozzle is unobstructed. Visual inspections of

the fire protection system exposed to water, evaluating wall thickness to identify evidence of loss of material due to corrosion, are covered by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (19.1.22). The Buried Piping and Tanks Inspection program (19.1.18) is credited with the management of aging effects on the external surface of buried fire water system piping.

Prior to the period of extended operation, the following enhancements will be implemented:

- Specific procedures will be enhanced to include review and approval requirements under the Nuclear Administrative Technical Manual (NATM).
- Procedures will be enhanced to be consistent with the current code of record or NFPA 25 2002 Edition.
- Procedures will be enhanced to field service test a representative sample or replace sprinklers prior to 50 years in service and test thereafter every 10 years to ensure that signs of degradation are detected in a timely manner.
- Procedures will be enhanced to be consistent with NFPA 25 Section 7.3.2.1, 7.3.2.2, 7.3.2.3, and 7.3.2.4.

19.1.14 FUEL OIL CHEMISTRY

The Fuel Oil Chemistry program manages loss of material on the internal surface of components in the emergency diesel generator (EDG) fuel oil storage and transfer system, diesel

fire pump fuel oil system, and station blackout generator (SBOG) system. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) visual inspection of internal surfaces during periodic draining and cleaning, (d) ultrasonic wall thickness measurements from external surfaces of fuel oil tanks if there are indications of reduced cross sectional thickness found during the visual inspection, (e) inspection of new fuel oil before it is introduced into the storage tanks, and (f) one-time inspections of a representative sample of components in systems that contain fuel oil by the One-Time Inspection program.

The effectiveness of the program is verified under the One-Time Inspection program (19.1.16).

Prior to the period of extended operation:

Procedures will be enhanced to extend the scope of the program to include the SBOG fuel oil storage tank and SBOG skid fuel tanks.

Procedures will be enhanced to include ten-year periodic draining, cleaning, and inspections on the diesel-driven fire pump day tanks, the SBOG fuel oil storage tank, and SBOG skid fuel tanks.

Ultrasonic testing (UT) or pulsed eddy current (PEC) thickness examination will be conducted to detect corrosion-related wall thinning if degradation is found during the visual inspections

and once on the tank bottoms for the EDG fuel oil storage tanks, EDG fuel oil day tanks, diesel-driven fire pump day tanks, SBOG fuel oil storage tank, and SBOG skid fuel tanks. The one-time UT or PEC examination on the tank bottoms will be performed before the period of extended operation.

19.1.15 REACTOR VESSEL SURVEILLANCE

The Reactor Vessel Surveillance program manages loss of fracture toughness and is consistent with ASTM E 185. Actual reactor vessel plate coupons are used. Weld and heat-affected-zone coupons are made from sections of the same plate welded together with identical weld material heats and weld parameters. The surveillance coupons are tested by a qualified offsite vendor, to its procedures. The testing program and reporting conform to requirements of 10 CFR 50, Appendix H, "*Reactor Vessel Material Surveillance Program Requirements.*"

As shown in Tables 5.3-13, 5.3-14, 5.3-15, 15.3-18, 5.3-19 and 5.3-19A the reactor vessel surveillance capsule removal schedules have been revised to withdraw the next capsules at the equivalent clad-base metal exposure of approximately 54 EFPY (40, 39, and 42 actual EFPY in Units 1, 2, and 3, respectively) expected for the 60-year period of operation. This withdrawal schedule is in accordance with NUREG-1801, Section XI.M31, item 6, and with the ASTM E 185-82 criterion which states that capsules may be removed when the capsule neutron fluence is between one and two times the limiting fluence calculated for the vessel at the end of expected life.

This withdrawal schedule was approved by the NRC in a letter to APS dated April 9, 2012.

If an 80-year second period of extended operation is anticipated, actions would be taken to request approval to withdraw remaining standby capsules at equivalent clad-base metal exposures not exceeding the 72 EFPY expected for the possible 80-year second period of extended operation (at about 50 to 54 actual operation EFPY). Schedule changes must be approved by the NRC, as required by 10 CFR 50 Appendix H and as discussed in NRC Administrative letter 97-04 "NRC Staff Approval for Changes to 10 CFR Part 50, Appendix H, Reactor Vessel Surveillance Specimen Withdrawal Schedules." The need to monitor vessel fluence following removal of the remaining standby capsules, and ex-vessel or in-vessel methods, would be addressed prior to removing the remaining capsules.

19.1.16 ONE-TIME INSPECTION

The One-Time Inspection program conducts one-time inspections of plant system piping and components to verify the effectiveness of the Water Chemistry program (19.1.2), Fuel Oil Chemistry program (19.1.14), and Lubricating Oil Analysis program (19.1.23). The aging effects to be evaluated by the One-Time Inspection program are loss of material, cracking, and reduction of heat transfer. The One-Time Inspection program will include the specific attributes for the components crediting this program for aging management in the license renewal application.

Plant system piping and components will be subject to one-time inspection on a sampling basis using qualified inspection personnel following established ASME, "*Boiler and Pressure Vessel Code*", Section V, "Nondestructive Examination", (NDE) techniques appropriate to each inspection. Inspection sample sizes will be determined using a methodology that is based on 90% confidence that 90% of the population of components will not experience aging effects in the period of extended operation. The One-Time Inspection program specifies corrective actions and increased sampling of piping/components if aging effects are found during material/environment combination inspections. The one-time inspections will be performed no earlier than 10 years prior to the period of extended operation. All one-time inspections will be completed prior to the period of extended operation. Completion of the One-Time Inspection program in this time period will assure that potential aging effects will be manifested based on at least 30 years of PVNGS operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Major elements of the PVNGS One-Time Inspection program include:

a) Identifying piping and component populations subject to one-time inspection based on common materials and environments

b) Determining the sample size of components to inspect using established statistical methods based on the population size of the material-environment groups

c) Selecting piping and components within the material-environment groups for inspection based on criteria provided in the One-Time Inspection procedure

d) Conducting one-time inspections of the selected components within the sample using ASME Code Section V NDE techniques and acceptance criteria consistent with the design codes/standards or ASME Section XI as applicable to the component

19.1.17 SELECTIVE LEACHING OF MATERIALS

The Selective Leaching of Materials program manages the loss of material due to selective leaching for brass (copper alloy >15% zinc), aluminum-bronze (copper alloy >8% aluminum), and gray cast iron components exposed to closed-cycle cooling water demineralized water, secondary water, raw water and wetted gas within the scope of license renewal. The Selective Leaching of Materials program is in addition to the Open-Cycle Cooling Water program (19.1.9) and the Closed-Cycle Cooling Water program (19.1.10) in these cases.

The program includes a one-time inspection (visual and/or mechanical methods) of a selected sample of components internal surfaces to determine whether loss of material due to selective leaching is occurring. A sample size of 20% of the population, up to a maximum of 25 component inspections, will be

established for each of the system material and environment combinations at the Palo Verde site. If indications of selective leaching are confirmed, follow up examinations or evaluations are performed.

19.1.18 BURIED PIPING AND TANKS INSPECTION

The Buried Piping and Tanks Inspection program manages loss of material of buried components in the chemical and volume control, condensate storage and transfer, diesel fuel storage and transfer, domestic water, fire protection, SBOG fuel system, service gas and essential spray ponds systems. Visual inspections monitor the condition of protective coatings and wrappings found on carbon steel, gray cast iron or ductile iron components and assess the condition of stainless steel components with no protective coatings or wraps. The program includes opportunistic inspection of buried piping and tanks as they are excavated or on a planned basis if opportunistic inspections have not occurred.

The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended of operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Within the ten year period prior to entering the period of extended operation an opportunistic or planned inspection of buried tanks at the Palo Verde site will be performed. Upon entering the period of extended operation, a planned inspection

within ten years will be required unless an opportunistic inspection has occurred within this ten year period.

The visual inspections noted below of piping in a soil environment within the scope of license renewal will be conducted within the ten-year period prior to entering the period of extended operation, and during each ten year period after entering the period of extended operation, except the initial diesel generator fuel oil piping inspection will be performed between January 1, 2012 and December 31, 2015. Each inspection will:

- select accessible locations where degradation is expected to be high;
- excavate and visually inspect the circumference of the pipe; and
- examine at least ten feet of pipe.

a. Metallic Piping not Cathodically-Protected

At least two excavations and visual inspections of stainless steel piping will be conducted in each unit. Stainless steel piping within the scope of license renewal exists in the following systems:

- o Chemical and Volume Control (CH),
- o Condensate Transfer and Storage (CT), and
- o Fire Protection (FP).

b. Steel Piping Cathodically-Protected

At least two excavations and visual inspections of cathodically-protected steel piping will be conducted in each unit. In one of the units, at least one of these inspections will be performed on diesel generator fuel oil piping.

c. Steel Piping with Potentially Degraded Cathodic Protection

At least three excavations and visual inspections of fire protection steel piping with potentially degraded bonding straps will be conducted at the Palo Verde site.

Prior to the period of extended operation, the Buried Piping and Tanks Inspection program will include provisions to (1) ensure electrical power is maintained to the cathodic protection system for in-scope buried piping at least 90% of the time (e.g., monthly verification that the power supply circuit breakers are closed or other verification that power is being provided to the system), and (2) ensure that the National Association of Corrosion Engineers (NACE) cathodic protection system surveys are performed at least annually.

19.1.19 ONE-TIME INSPECTION OF ASME CODE CLASS 1 SMALL-BORE PIPING

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program manages cracking of stainless steel ASME Code Class 1 piping less than or equal to 4 inches.

For ASME Code Class 1 small-bore piping, volumetric examinations on selected butt weld locations will be performed to detect cracking. Butt weld volumetric examinations will be conducted in accordance with ASME Section XI with acceptance criteria from Paragraph IWB-3000 and IWB-2430. Weld locations subject to volumetric examination will be selected based on the guidelines provided in EPRI TR-112657. Socket welds that fall within the weld examination sample will be examined following ASME Section XI Code requirements. At least 10% of the socket welds in ASME Code Class 1 piping that is less than four inches nominal pipe size and greater than or equal to one inch nominal pipe size will be selected per unit for ultrasonic testing examination, up to a maximum of 25 weld examinations. The sample will be selected based on risk insights and those welds with the potential for aging degradation.

Socket welds that fall within the weld examination sample will be examined following ASME Section XI Code requirements. If a qualified volumetric examination procedure for socket welds endorsed by the industry and the NRC is available and incorporated into the ASME Section XI Code at the time of PVNGS small-bore socket weld inspections then this will be used for the volumetric examinations. If no volumetric examination procedure for ASME Code Class 1 small bore socket welds has been endorsed by the industry and the NRC and incorporated into ASME Section XI at the time PVNGS performs inspections of small-bore piping, a plant procedure for volumetric examination of ASME Code Class 1 small-bore piping with socket welds will be used.

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is a new program that will be implemented within the six year period prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

19.1.20 EXTERNAL SURFACES MONITORING PROGRAM

The External Surfaces Monitoring Program manages loss of material for steel, aluminum, and copper alloy components and hardening and loss of strength for elastomer components. The program includes those systems and components within the scope of license renewal that require external surface monitoring. Visual inspections conducted during engineering walkdowns will be used to identify aging effects and leakage. Physical manipulation during the visual inspections must also be used to verify absence of hardening or loss of strength for elastomers.

Loss of material for external surfaces is managed by the Boric Acid Corrosion program (19.1.4) for components in a system with treated borated water or reactor coolant environment on which boric acid corrosion may occur, Buried Piping and Tanks Inspection program (19.1.18) for buried components, and Structures Monitoring Program (19.1.32) for civil structures, and other structural items which support and contain mechanical and electrical components.

The External Surfaces Monitoring Program is a new program that will be implemented prior to the period of extended operation.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

19.1.21 REACTOR COOLANT SYSTEM SUPPLEMENT

Section 3.1 of NUREG-1800, "*Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants*," supplements the aging management programs for the reactor coolant system components with the following additional requirements.

APS will:

A. Reactor Coolant System Nickel Alloy Pressure Boundary Components

Implement applicable (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines, (3) participate in the industry initiatives, such as owners group programs and the EPRI Materials Reliability Program, for managing aging effects associated with nickel alloys, (4) upon completion of these programs, but not less than 24 months before entering the period of extended operation, APS will submit an inspection plan for reactor coolant system nickel alloy pressure boundary components to the NRC for review and approval, and

B. Reactor Vessel Internals

The PWR Internals Aging Management Program (AMP) Plan for Palo Verde Nuclear Generating Station Units 1, 2, and 3 has been

created to address the reactor vessel internals aging concerns consistent with NUREG-1801 (GALL Report), Revision 2, Chapter XI.M.16A, "PWR Vessel Internals". The program relies on implementation of the EPRI MRP-227 and MRP-228 to manage the aging effects on the reactor vessel internal components, including:

(a) various forms of cracking, including SCC, PWSCC, irradiation-assisted stress corrosion cracking (IASCC), or cracking due to fatigue/cyclical loading

(b) loss of material induced by wear

(c) loss of fracture toughness due to either thermal aging or neutron irradiation embrittlement

(d) dimensional changes and potential loss of fracture toughness due to void swelling and irradiation growth

(e) loss of preload due to thermal and irradiation-enhanced stress relaxation or creep

APS submitted the PVNGS Units 1, 2, and 3 reactor vessel internals aging management program and inspection plans in accordance with MRP-227-A for NRC review and approval via letter 102-06599, dated September 28, 2012, and supplemented by letter 102-06908, dated July 23, 2014. The program was approved by the NRC on March 27, 2015 via letter ML15058A029. APS will manage the Reactor Vessel Internals (RVI) inspections during the period of extended operation through the augmented Inservice Inspection Program.

19.1.22 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages cracking, loss of material, and hardening and loss of strength. The internal surfaces of piping, piping components, ducting and other components that are not covered by other aging management programs are included in this program.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program uses the work control process to conduct and document inspections. The program will perform visual inspections to detect aging effects that could result in a loss of component intended function. The visual inspections will be conducted during periodic maintenance, predictive maintenance, surveillance testing and corrective maintenance.

Within 10 years before entering the period of extended operation, a review will be conducted to determine the number of inspection opportunities afforded by the work control process for all systems within the scope of this program. In the vast majority of cases, it is expected that the number of work opportunities existing will be sufficient to detect aging and provide reasonable assurance that intended functions are maintained. For those systems or components where inspections of opportunity are insufficient, an inspection will be conducted prior to the period of extended operation to provide reasonable assurance that the intended functions are maintained. Additionally, visual inspections may be augmented

by physical manipulation to detect hardening and loss of strength of both internal and external surfaces of elastomers. The program also includes volumetric evaluation to detect stress corrosion cracking of the internal surfaces of stainless steel components exposed to diesel exhaust.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

19.1.23 LUBRICATING OIL ANALYSIS

The Lubricating Oil Analysis program manages loss of material and reduction of heat transfer for components within the scope of license renewal that are exposed to lubricating and hydraulic oil. The program monitors and maintains lubricating and hydraulic oil properties within acceptance criteria, thereby preserving an environment that is not conducive to aging effects. Acceptance criteria are based upon vendor and industry guidelines for oil chemical and physical properties and for foreign material such as water contamination. Increased contamination and degradation of oil properties provide an indication of aging of the lubricating oil. Monitoring and trending of lubricating and hydraulic oil properties and particles found within the oil identifies risk to components due to aging prior to loss of intended function.

The effectiveness of the program is verified under the One-Time Inspection program (19.1.16).

19.1.24 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages the aging effects of embrittlement, melting, cracking, swelling, surface contamination, or discoloration to ensure that electrical cables, connections and terminal blocks not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 and within the scope of license renewal are capable of performing their intended functions.

Non-EQ cables, connections and terminal blocks within the scope of license renewal in accessible areas with an adverse localized environment are inspected. The inspections of Non-EQ cables, connectors and terminal blocks in accessible areas are representative, with reasonable assurance, of cables, connections and terminal blocks in inaccessible areas with an adverse localized environment. At least once every ten years, the Non-EQ cables, connections and terminal blocks within the scope of license renewal in accessible areas are visually inspected for embrittlement, melting, cracking, swelling, surface contamination, or discoloration.

The acceptance criterion for visual inspection of accessible Non-EQ cable jacket, connection and terminal blocks insulating material is the absence of anomalous indications that are signs

of degradation. Corrective actions for conditions that are adverse to quality are performed in accordance with the corrective action program as part of the QA program.

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

19.1.25 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

The scope of this program includes the cables and connections used in sensitive instrumentation circuits with sensitive, high voltage low-level signals within the Ex-core Neutron Monitoring and Radiation Monitoring Systems including the source range, intermediate range, power range monitors, and non-EQ area radiation monitors. The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program manages embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance.

This program provides reasonable assurance that the intended function of cables and connections used in instrumentation circuits with sensitive, low-level signals that are not subject

to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by heat, radiation, or moisture are maintained consistent with the current licensing basis through the period of extended operation. In most areas, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment for those areas.

Calibration surveillance tests are used to manage the aging of the cable insulation and connections for non-EQ area radiation monitors so that instrumentation circuits perform their intended functions. When an instrumentation channel is found to be out of calibration during routine surveillance testing, troubleshooting is performed on the loop, including the instrumentation cable and connections. A review of calibration results will be completed prior to the period of extended operation and every 10 years thereafter.

Cable testing will be used to manage the aging of the cable insulation and connections for the ex-core neutron monitoring system. Cable tests such as insulation resistance testing or other tests will be performed to detect deterioration of the cable insulation system. The cable will be tested prior to the period of extended operation and every 10 years thereafter. Acceptance criteria will be determined prior to testing based on the type of cable and type of test performed.

Prior to the period of extended operation, procedures will be enhanced to identify license renewal scope, require cable testing of ex-core neutron monitoring cables, require an

evaluation of the calibration results for non-EQ area radiation monitors, and require acceptance criteria for cable testing be established based on type of cable and type of test performed.

19.1.26 INACCESSIBLE MEDIUM VOLTAGE CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements program manages localized damage and breakdown of insulation leading to electrical failure in inaccessible cables (480V and above) exposed to adverse localized environments caused by significant moisture (moisture that lasts more than a few days) to ensure that inaccessible cables (480V and above) not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 and within the scope of license renewal are capable of performing their intended function.

All cable manholes that contain in-scope non-EQ inaccessible cables (480V and above) will be inspected for water collection. Collected water will be removed as required. This inspection and water removal will be performed based on actual plant experience with water accumulation in the manhole and site rain events. The inspection frequency is event driven and at least annually.

The program provides for testing of in-scope non-EQ inaccessible cables (480V and above) to provide an indication of the conductor insulation condition. At least once every six years, a polarization index test as described

in EPRI TR-103834-P1-2 or other testing that is state-of the- art at the time of the testing is performed.

Prior to the period of extended operation procedures will be enhanced to:

- Extend the scope of the program to include low voltage (480V and above) non-EQ inaccessible power cables and associated manholes.
- Perform the cable inspections on at least an annual frequency and perform the cable testing on a six year frequency.

19.1.27 ASME SECTION XI, SUBSECTION IWE

The ASME Section XI, Subsection IWE containment inservice inspection program manages loss of material and loss of sealing of the steel liner of the concrete containment building, including the containment liner plate, piping and electrical penetrations, access hatches, and the fuel transfer tube. Inspections are performed to identify and manage any containment liner aging effects that could result in loss of intended function. Acceptance criteria for components subject to Subsection IWE exam requirements are specified in Article IWE-3000. In conformance with 10 CFR 50.55a(g)(4)(ii), the PVNGS ISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval.

19.1.28 ASME SECTION XI, SUBSECTION IWL

The ASME Section XI, Subsection IWL program manages cracking, loss of material, and increase in porosity and permeability of the concrete containment building and post-tensioned system. Inspections are performed to identify and manage any aging effects of the containment concrete, post-tensioned tendons, tendon anchorages, and concrete surface around the anchorage that could result in loss of intended function. In conformance with 10 CFR 50.55a(g)(4)(ii), the ASME Section XI, Subsection IWL Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval.

19.1.29 ASME SECTION XI, SUBSECTIONS IWF

The ASME Section XI, Subsection IWF program manages loss of material, cracking, and loss of mechanical function that could result in loss of intended function for Class 1, 2 and 3 component supports. There are no Class MC supports at PVNGS. In conformance with 10 CFR 50.55a(g)(4)(ii), the PVNGS ISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval.

19.1.30 10 CFR 50, APPENDIX J

The 10 CFR 50, Appendix J program manages loss of material, loss of leak tightness, and loss of sealing. The program monitors leakage rates through the containment pressure boundary, including the penetrations and access openings, in order to detect degradation of containment pressure boundary. Seals, gaskets, and bolted connections are also monitored under the program.

Containment leak rate tests are performed in accordance with 10 CFR 50 Appendix J, "*Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,*" Option B; Regulatory Guide 1.163, "*Performance*-Based Containment Leak-Testing Program"; NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J"; and ANSI/ANS 56.8, "Containment *System Leakage Testing Requirements.*"

Containment leak rate tests are performed to assure that leakage through the primary containment, and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the Technical Specifications. Corrective actions are taken if leakage rates exceed established administrative limits for individual penetrations or the overall containment pressure boundary.

19.1.31 MASONRY WALL PROGRAM

The Masonry Wall Program, which is part of the Structures Monitoring Program, manages cracking of masonry walls, and

structural steel restraint systems of the masonry walls, within scope of license renewal based on guidance provided in IE Bulletin 80-11, "*Masonry Wall Design,*" and NRC Information Notice 87-67, "*Lessons Learned from Regional Inspections of Licensee Actions in Response to NRC IE Bulletin 80-11.*" The Masonry Wall Program contains inspection guidelines and lists attributes that cause aging of masonry walls, which are to be monitored during structural monitoring inspections, as well as establishes examination criteria, evaluation requirements, and acceptance criteria.

Prior to the period of extended operation, procedures will be enhanced to specify ACI 349.3R-96 as the reference for qualification of personnel to inspect structures under the Masonry Wall Program, which is part of the Structures Monitoring Program.

19.1.32 STRUCTURES MONITORING PROGRAM

The Structures Monitoring Program manages the cracking, loss of material, and change in material properties by monitoring the condition of structures and structural supports that are within the scope of license renewal. The Structures Monitoring Program implements the requirements of 10 CFR 50.65 and is consistent with the guidance of NUMARC 93-01, Revision 4A and Regulatory Guide 1.160, Revision 3.

The Structures Monitoring Program provides inspection guidelines for concrete elements, structural steel, masonry walls, structural features (e.g., caulking, sealants, roofs,

etc.), structural supports, and miscellaneous components such as doors. The Structures Monitoring Program includes all masonry walls and water-control structures within the scope of license renewal. The Structures Monitoring Program also monitors settlement for each major structure and inspects supports for equipment, piping, conduit, cable tray, HVAC, and instrument components.

Prior to the period of extended operation:

The Structures Monitoring Program will be enhanced to specify ACI 349.3R-96 as the reference for qualification of personnel to inspect structures under the Structures Monitoring Program.

For structures within the scope of license renewal, the Structures Monitoring Program will be enhanced to establish the frequency of inspection for each unit at a 5 year interval, with the exception of exterior surfaces of the following nonsafety-related structures, below-grade structures, and structures within a controlled interior environment, which will be inspected at an interval of 10 years:

- Fire Pump House (Yard Structures)
- Radwaste Building
- Station Blackout Generator Structures
- Turbine Building
- Non-Safety Related Tank Foundations and Shells
- Non-Safety Related Transformer Foundations and Electrical Structures

The Structures Monitoring Program will be enhanced to quantify the acceptance criteria and critical parameters for monitoring degradation, and to provide guidance for identifying unacceptable conditions requiring further technical evaluation or corrective action. Procedures will also be enhanced to incorporate applicable industry codes, standards and guidelines for acceptance criteria.

19.1.33 REGULATORY GUIDE 1.127, INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

The PVNGS Structures Monitoring Program, which includes all water-control structural components within the scope of RG 1.127, Inspection of Water Control Structures Associated with Nuclear Power Plants, manages cracking, loss of material, loss of bond, loss of strength, and increase in porosity and permeability due to extreme environmental conditions. PVNGS meets the recommendations of RG 1.127, Revision 1.

This program includes inspection and surveillance activities for water-control structures associated with emergency cooling water systems and includes periodic inspections and monitoring of the in-scope water-control structures; i.e., the Ultimate Heat Sink and associated structures.

Prior to the period of extended operation, procedures will be enhanced to specify that the essential spray ponds inspections include concrete below the water level.

19.1.34 NICKEL ALLOY AGING MANAGEMENT PROGRAM

The Nickel Alloy Aging Management Program manages cracking due to primary water stress corrosion cracking in all plant locations that contain Alloy 600, with the exception of steam generator tubing (aging management of steam generator tubing is performed by the Steam Generator Tubing Integrity program (19.1.8)) and reactor vessel internals (aging management of reactor vessel internals is addressed in Reactor Coolant System Supplement (19.1.21)). The original Reactor Vessel Heads (RVH) contained Alloy 600 nozzles and were managed under this program. The replacement RVHs now contain Alloy 690 nozzles which are no longer required to be managed under this program. This program includes Alloy 600 reactor coolant pressure boundary locations in the reactor coolant system (RCS) and ESF systems.

The Alloy 600 aging management program uses inspections, mitigation techniques, repair/replace activities and monitoring of operating experience to manage the aging of Alloy 600 at PVNGS. Detection of indications is accomplished through a variety of examinations consistent with ASME Section XI Subsections IWB, ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6), ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4), and ASME Code Case N-770-1 subject to the conditions listed in 10 CFR 50.55a (g)(6)(ii)(F) (2) through (10). Mitigation techniques are implemented when appropriate to preemptively remove conditions

that contribute to primary water stress corrosion cracking. Repair/replacement activities are performed to proactively remove or overlay Alloy 600 material, or as a corrective measure in response to an unacceptable flaw. Mitigation and repair/replace activities are consistent with those detailed in ASME Code Case N-770-1 as conditioned above.

19.1.35 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages the effects of loosening of bolted external connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. As part of the PVNGS predictive maintenance program, infrared thermography testing is being performed on non-EQ electrical cable connections, associated with active and passive components within the scope of license renewal. A representative sample will be tested at least once prior to the period of extended operation using infrared thermography to confirm that there are no aging effects requiring management during the period of extended operation. The selected sample is based upon application (medium and low voltage), circuit loading, and environment.

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating

experience will be evaluated in the development and implementation of this program.

19.1.36 METAL ENCLOSED BUS

The Metal Enclosed Bus (MEB) program manages the effects of loose connections, embrittlement, cracking, melting, swelling, or discoloration of insulation, loss of material of bus enclosure assemblies, hardening of boots and gaskets, and cracking of internal bus supports to ensure that metal-enclosed buses within the scope of license renewal. Internal portions of MEBs are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation is inspected for signs of embrittlement, cracking, melting, swelling, hardening or discoloration, which may indicate overheating or aging degradation. The internal bus supports are inspected for structural integrity and signs of cracks. The bus enclosure assemblies are inspected for loss of material due to corrosion and hardening of boots and gaskets. Samples of the accessible bolted connections on the internal bus work are checked for loose connections by measuring connection resistance.

The Metal Enclosed Bus program is a new program and will be completed before the period of extended operation and once every 10 years thereafter. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

19.1.37 FUSE HOLDERS

The Fuse Holders program manages thermal fatigue, mechanical fatigue, vibration, chemical contamination, and corrosion of the metallic portions of fuse holders to ensure that fuse holders within the scope of license renewal are capable of performing their intended function.

The Fuse Holder program is a new program that will be completed before the period of extended operation and once every 10 years thereafter. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

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19.2 SUMMARY DESCRIPTIONS OF TIME-LIMITED AGING ANALYSIS AGING MANAGEMENT PROGRAMS

19.2.1 Metal Fatigue of Reactor Coolant Pressure Boundary

The Metal Fatigue of Reactor Coolant Pressure Boundary program uses cycle counting and usage factor tracking to ensure that actual plant experience remains bounded by design assumptions and calculations reflected in the PVNGS UFSAR.

PVNGS Technical Specification 5.5.5 requires the establishment of a "Component Cyclic or Transient Limit" program to track the occurrences specified in PVNGS UFSAR section 3.9.1.1 and states in total:

> "5.5.5 Component Cyclic or Transient Limit
>
> This program provides controls to track the UFSAR Section 3.9.1.1 cyclic and transient occurrences to ensure that components are maintained within the design limits."

The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program will use cycle counting (CC), cycle-based fatigue (CBF) cumulative usage factor (CUF) calculations and stress based fatigue CUF calculations (SBF) to monitor fatigue. FatiguePro will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro is an EPRI licensed product. The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program will use a fatigue monitoring software program that incorporates a three-dimensional, six-component stress tensor method meeting ASME III NB-3200 requirements for stress-based fatigue monitoring (SBF). The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program will provide action limits on cycles and on CUF that

will initiate corrective actions before the licensing basis limits on fatigue effects at any location are exceeded.

The scope of the enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program will include transient cycle counting required by the existing Metal Fatigue of Reactor Coolant Pressure Boundary program and adds CUF monitoring for all but one of the PVNGS NUREG/CR-6260 locations which are the leading indicators for monitoring the usage due to environmentally assisted fatigue. The RPV shell and lower head (juncture) location will be monitored by cycle counting. The usage factors calculated by the enhanced program for NUREG/CR-6260 locations will include environmental effects of the reactor coolant environment as determined by NUREG/CR-6583 and NUREG/CR-5704.

No later than two years prior to the period of extended operation, the following enhancements will be implemented:

- Cumulative usage factor tracking will be implemented for NUREG/CR-6260 locations not monitored by cycle counting (the reactor vessel shell and lower head (juncture) location will be monitored by cycle counting).

- The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include a computerized program to track and manage both cycle counting and fatigue usage factor. FatiguePro will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro

SUMMARY DESCRIPTIONS OF TIME-LIMITED

AGING ANALYSIS AGING MANAGEMENT PROGRAMS

is an EPRI licensed product. A fatigue monitoring software program that incorporates a three-dimensional, six-component stress tensor meeting ASME III NB-3200 requirements will be used for stress-based fatigue monitoring (SBF).

- The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program will monitor plant transients as required by PVNGS Technical Specification 5.5.5. Cumulative usage factors (CUFs) will be calculated for a subset of ASME III Class 1 reactor coolant pressure boundary vessel and piping locations, and component locations with Class 1 analyses. The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program will provide action limits on cycles and on CUF that will initiate corrective actions before the licensing basis limits on fatigue effects at any location are exceeded.
- The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced with additional cycle count and fatigue usage action limits, and with appropriate corrective actions to be invoked if a component approaches a cycle count action limit or a fatigue usage action limit. Action limits will be established to permit completion of corrective actions before the design limits are exceeded.

SUMMARY DESCRIPTIONS OF TIME-LIMITED

AGING ANALYSIS AGING MANAGEMENT PROGRAMS

- The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to add CUF monitoring. The following methods will be used:

  1) The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to use cycle-based fatigue (CBF) and stress-based fatigue (SBF) CUF calculations to monitor fatigue. FatiguePro will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro is an EPRI licensed product.

  2) The SBF method will use a fatigue monitoring software program that incorporates a three-dimensional, six-component stress tensor method meeting ASME III NB-3200 requirements.

- Action limits will be established to require corrective action when the cycle count of any of the monitored transients is projected to reach the action limit. In order to ensure sufficient margin to accommodate occurrence of a low-probability transient, corrective actions must be taken before the remaining number of allowable occurrences for any specified transient becomes less than 1.

  If a cycle count action limit is reached, the following actions will be considered and those deemed appropriate will be taken:

SUMMARY DESCRIPTIONS OF TIME-LIMITED

AGING ANALYSIS AGING MANAGEMENT PROGRAMS

1) Review of fatigue usage calculations

   a. To determine whether the transient in question contributes significantly to CUF.

   b. To identify the components and analyses affected by the transient in question.

   c. To ensure that the analytical bases of the high-energy line break (HELB) locations are maintained.

   d. To ensure that the analytical bases of a fatigue crack growth and stability analysis in support of relief from ASME Section XI flaw removal and inspection requirements for hot leg small-bore half nozzle repairs and other similar repairs/analyses are maintained.

2) Evaluation of remaining margins on CUF based on cycle-based or stress-based CUF calculations using the PVNGS fatigue management program software.

3) Redefinition of the specified number of cycles (e.g., by reducing specified numbers of cycles for other transients and using the margin to increase the allowed number of cycles for the transient that is approaching its specified number of cycles).

4) Redefinition of the transient to remove conservatism in predicting the range of pressure and temperature values for the transient.

SUMMARY DESCRIPTIONS OF TIME-LIMITED

AGING ANALYSIS AGING MANAGEMENT PROGRAMS

- For PVNGS locations identified in NUREG/CR-6260 and monitored by CUF, fatigue usage factor action limits will be based on accrued fatigue usage calculated with the F(en) environmental fatigue factors determined by NUREG/CR-5704 and NUREG/CR-6583 methods required for including effects of the reactor coolant environment.

Cumulative Fatigue Usage Action Limit and Corrective Actions

- Action limits will be established to require corrective action when the calculated CUF (from cycle-based or stress-based monitoring) for any monitored location is projected to reach 1.0 within the next 2 or 3 operating cycles. In order to ensure sufficient margin to accommodate occurrence of a low-probability transient, corrective actions will be taken while there is still sufficient margin to accommodate at least one occurrence of the worst-case design transient event (i.e., with the highest fatigue usage per event cycle).

  If a CUF action limit is reached, the following actions will be considered and those deemed appropriate will be taken:

  1) Determine whether the scope of the enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program must be enlarged to include additional affected reactor coolant pressure boundary locations. This determination

will ensure that other locations do not approach design limits without an appropriate action.

2) Adjust fatigue monitoring methods to confirm continued conformance to the code limit.

3) Repair/modify the component.

4) Replace the component.

5) Perform a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded.

6) Modify plant operating practices to reduce the fatigue usage accumulation rate.

7) Perform a flaw tolerance evaluation and impose component-specific inspections, under ASME Section XI Appendices A or C (or their successors) and obtain required approvals from the regulatory agency.

19.2.2 Environmental Qualification (EQ) of Electrical Components

The Environmental Qualification (EQ) of Electrical Components program manages component thermal, radiation, and cyclic aging effects, using 10 CFR 50.49(f) methods. As required by 10 CFR 50.49, EQ components are to be refurbished or replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Maintaining qualification through the extended license renewal period

requires that existing EQ evaluations (EEQDFs) be re-evaluated. The Environmental Qualification (EQ) of Electrical Components program is consistent with the guidance of 10 CFR 50.49, NUREG-0588, and Regulatory Guide 1.89, "*Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants,*" Revision 1 for maintaining qualifications of equipment. Reanalysis of aging evaluations to extend the qualifications of components is performed on a routine basis as part of the EQ Program. Important attributes for the reanalysis of aging evaluations include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met).

19.2.3 Concrete Containment Tendon Prestress

The Concrete Containment Tendon Prestress program, within the PVNGS ASME Section XI Subsection IWL Program, manages the loss of tendon prestress in the post-tensioning system.

The PVNGS post-tensioning system consists of inverted-U-shaped tendons, extending up through the basemat, through the full height of the cylindrical walls and over the dome; and horizontal circumferential (hoop) tendons, at intervals from the basemat to about the 45-degree elevation of the dome. The basemat is conventionally-reinforced concrete. The tendons are ungrouted, in grease-filled glands.

SUMMARY DESCRIPTIONS OF TIME-LIMITED

AGING ANALYSIS AGING MANAGEMENT PROGRAMS

The beginning of the first IWL tendon examination interval was August 1, 2001 for all three units. The beginning of the second interval will be August 1, 2011 for all three units. As required by 10 CFR 50.55a, beginning August 1, 2011, the program will conform to a later edition of ASME Section XI, Subsection IWL which permits a 10-year interval between tendon prestress surveillance tests, for each unit of a multi-unit plant. The entire scope of IWL-2500, including prestress liftoff measurements, will be required only every 10-years in each unit; except that the visual inspections and anti-corrosion medium surveillances of IWL-2524 and IWL-2525 must be repeated at the intervening 5-year intervals.

The program includes randomly-selected surveillance tendons for a 40-year license (through the year 35 surveillance).

Prior to the period of extended operation, procedures will be enhanced to require an update of the regression analysis for each tendon group of each unit, and of the joint regression of data from all three units, after every tendon surveillance. The documents will invoke and describe regression analysis methods used to construct the lift-off trend lines, including the use of individual tendon data in accordance with Information Notice (IN) 99-10, "*Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments.*"

19.3 EVALUATION SUMMARIES OF TIME-LIMITED AGING ANALYSES

10 CFR 54.21(c) requires that an applicant for a renewed license identify time-limited aging analyses (TLAAs) and evaluate them for the period of extended operation. The following TLAAs have been identified and evaluated for PVNGS.

19.3.1 REACTOR VESSEL NEUTRON EMBRITTLEMENT

Ferritic materials of the reactor vessel are subject to embrittlement (loss of fracture toughness) due to high-energy neutron exposure. The following predictions of neutron fluence and of its embrittlement effects are TLAAs:

- Neutron Fluence, Upper Shelf Energy, Adjusted Reference Temperature (Fluence, USE, and ART)
- Pressurized Thermal Shock (PTS)
- Reactor Vessel Thermal Limit Analysis and Pressure-Temperature (P-T) Limits
- Low Temperature Overpressure Protection (LTOP)

The Reactor Vessel Surveillance program is described in Section 19.1.15.

19.3.1.1 Neutron Fluence, Upper Shelf Energy and Adjusted Reference Temperature (Fluence, USE, and ART)

The critical time-dependent parameter for determining radiation embrittlement effects is lifetime fluence of neutrons with energies greater than 1 MeV. The original design basis fluence predictions for a 32 EFPY life were the standard Combustion

Engineering estimates for the CESSAR-80 plants. Power uprate (PUR) had no effect on these fluence projections because this original analysis of record used a power level of 4200 MW_t, which is higher than the PUR level of 3990 MW_t.

Increased plant capacity factors prompted the increase in the lifetime capacity factor assumed for fluence estimates from 80 to 90 percent, and hence increased the assumed EFPY for the period of extended operation to 54 EFPY. With continued use of low-leakage cores, the current Unit 1, 2, and 3 projections of the clad-base metal interface neutron fluence at 54 EFPY are less than the original 32 EFPY projection used to determine the EOL ART and USE reported in the NRE Reactor Vessel Integrity Database. Therefore the original projections remain valid for the period of extended operation.

Fluence, USE, and ART will be managed for the extended licensed operating period by continuing the Reactor Vessel Surveillance program (Section 19.1.15), with adjustments to the coupon examination schedule to withdraw the next capsule at an equivalent clad-base metal exposure of approximately 54 EFPY, and to withdraw remaining standby capsules at equivalent clad-base metal exposures not exceeding 72 EFPY if an 80-year second period of extended operation is anticipated. The validity of these parameters and the analyses that depend upon them will therefore be adequately managed for the period of extended operation.

19.3.1.2 Pressurized Thermal Shock (PTS)

If the reference temperature for pressurized thermal shock (RT_{PTS}) for each heat of material of the reactor pressure vessel does not exceed the applicable screening criterion, only the reactor pressure vessel is "relied on to demonstrate compliance" with the 10 CFR 50.61 PTS rule.

The original PTS evaluation of the PVNGS vessels demonstrated low values of the RT_{PTS} screening parameter. The originally-assumed 32 EFPY neutron fluence is not expected to be exceeded in a 54 EFPY period of extended operation, and no changes to the material composition information or to embrittlement assessment methods have significantly affected the RTPTS screening values. Therefore the conclusions of the original evaluation are unaffected. The original evaluation of the PTS screening parameters, and the conclusion of the evaluation, is therefore valid for the period of extended operation.

19.3.1.3 Pressure-Temperature (P-T) Limits

The P-T limit curves are operating limits, based on material embrittlement effects that are valid up to the vessel fluence for which these embrittlement effects are calculated.

The current P-T limit curves permit operation up to 32 EFPY. However, the P-T limit curves were based on an assumed 32 EFPY beltline neutron fluence that is in excess of the maximum fluence now projected for 54 EFPY. Therefore the P-T limit curves are valid for the period of extended operation. New P-T limits will not be required.

19.3.1.4 Low Temperature Overpressure Protection (LTOP)

LTOP is required by Technical Specifications and is provided by relief valves in the two suction lines of the shutdown cooling system (SCS), or by operating with the reactor coolant system (RCS) depressurized and with an open RCS vent of sufficient size.

The LTOP setpoints depend on the P-T limit curves and the ART, both of which will remain valid for the period of extended operation. Therefore the LTOP licensing and design basis analyses will remain valid for the period of extended operation.

19.3.2 METAL FATIGUE ANALYSIS

This section describes:

- ASME Section III Class 1 Fatigue Analysis of Vessels, Piping, and Components
- ASME Section III Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals
- Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190)

- Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in B31.1 and ASME Section III Class 2 and 3 Piping

ASME III requires no fatigue analysis for Class 2 components. However, design of the following PVNGS Class 2 components is supported by Class 1 fatigue analyses:

- Secondary sides of the replacement steam generators
- Regenerative and letdown heat exchangers
- HPSI and LPSI pumps
- Main steam safety valves

Basis of Fatigue Analysis

ASME Section III Class 1 design specifications define a design basis set of static and transient load conditions. The design number of each transient specified was selected to be larger than expected to occur during the 40-year licensed life of the plant, based on operating experience, and on projections of future operation based on innovations in the system designs. Although original design specifications commonly state that the transients are for a 40-year design life, the fatigue analyses themselves are based on the specified number of occurrences of each transient rather than on this lifetime.

Metal Fatigue of Reactor Coolant Pressure Boundary Program

The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 19.2.1 ensures that actual plant experience remains bounded by the assumptions used in the

design calculations, or that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded and before the ASME Section III limit of 1.0 for the fatigue cumulative usage factor is reached.

> The PVNGS Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) was implemented in response to PVNGS Technical Specification 5.5.5 which requires the establishment of a "Component Cyclic or Transient Limit" program to track the occurrences specified in PVNGS UFSAR section 3.9.1.1."

19.3.2.1 ASME Section III Class 1 Fatigue Analysis of Vessels, Piping, and Components

Fatigue analyses exist for ASME III Division 1 Class 1 piping, vessels, heat exchangers, pumps, and valves; and if applicable, their supports.

Class 1 fatigue analyses also support design of the following Class 2 components:

- Secondary sides of the replacement steam generators
- Regenerative and letdown heat exchangers
- HPSI and LPSI pumps
- Main steam safety valves

The Class 1 analyses have been updated to incorporate redefinitions of loads and design basis events, operating changes, and power uprate with steam generator replacement.

The PVNGS reactor vessel internals were analyzed to ASME-Section III Subsection NG. See Subsection 19.3.2.2.

19.3.2.1.1 Reactor Pressure Vessel, Nozzles, Head, and Studs

The PVNGS reactor pressure vessels were designed, built, and analyzed by Combustion Engineering to ASME Section III, Subsection NB (Class 1), 1971 Edition with addenda through Winter 1973. The reactor vessel primary coolant inlet and outlet nozzles and lower-head-to-shell juncture are evaluated for effects of the reactor coolant environment on fatigue behavior of these materials, consistent with NUREG/CR-6260. See Section 19.3.2.3.

The analyses performed to incorporate the effects of power uprate (PUR) and replacement steam generators (RSG) into the current design bases demonstrated that the effects on fatigue analyses were limited to the inlet and outlet nozzles. The modification increased the CUF of the inlet nozzles and the outlet nozzles.

The 1991 CE Owner's Group review of Combustion Engineering Infobulletin 88-09, "Nonconservative Calculation of Cumulative *Fatigue Usage*," identified a possible increase in the reactor vessel stud cumulative usage factor. The Owner's Group review found that the usage factor of reactor vessel studs at PVNGS could increase to greater than 1.0, if the more-conservative

pressure curves were used. To accommodate the more-conservative pressure curves, the number of heatup-cooldown transients was reduced and the number of bolt-up transients was reduced.

The replacement reactor vessel closure heads will have been installed after more than 20 years of operation of each unit. The replacement reactor vessel closure heads were designed to ASME III, 1998 Edition up to and including the 2000 Addenda, for a 40-year operating period, and the design specification for the replacement heads includes design transients and seismic loads consistent with those for the original vessel and head. The fatigue analysis for the replacement heads and associated components therefore extends beyond the end of the period of extended operation.

The PVNGS Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) will track the UFSAR Section 3.9.1.1 cyclic and transient occurrences to ensure that components are maintained within the design limits and will ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. In the period of extended operation the PVNGS Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) will monitor the environmentally assisted fatigue usage at NUREG/CR-6260 locations not monitored by cycle counting. Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) action limits permit completion of corrective actions before the design basis number of events is exceeded, and before the ASME

code cumulative fatigue usage limit of 1.0 is reached. The effects of fatigue in the reactor pressure vessel pressure boundary and its supports will thereby be managed for the period of extended operation.

19.3.2.1.2 Control Element Drive Mechanism (CEDM) and Reactor Vessel Level Monitoring System (RVLMS) Pressure Housings

The CEDM and RVLMS pressure housings will have been replaced with the replacement reactor vessel closure heads after more than 20 years of operation of each unit. The replacement CEDM pressure housings and RVLMS pressure housings are designed to ASME III, Subsection NB (Class 1), 1998 Edition up to and including the 2000 Addenda, for a 40-year operating period, and the design specification for the replacement CEDM and RVLMS pressure housings included design transients and seismic loads consistent with those for the original vessel, head, and CEDM pressure housings. The CEDM pressure housing design includes a corrosion analysis for the design life.

Since the design life of the replacement CEDM and RVLMS pressure housings extend beyond the end of the period of extended operation, the respective analyses have been projected beyond the end of the period of extended operation.

19.3.2.1.3 Reactor Coolant Pump Pressure Boundary Components

The CE System 80 reactor coolant pumps are designed to ASME III, 1974 Edition (no addenda) for Class 1 Vessels. The

load definitions were updated for replacement steam generators (RSG) with power uprate and the code analyses were evaluated to determine the applicability of the analyses of record fatigue analyses with the new loads.

Fatigue usage factors in the reactor coolant pumps do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational and upset transient events, principally on heatup and cooldown transients. The PVNGS Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) tracks events to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded and ensure that fatigue will be adequately managed for the period of extended operation.

19.3.2.1.4 Pressurizer and Pressurizer Nozzles

The PVNGS pressurizers are designed to ASME III, Subsection NB (Class 1), 1971 Edition with addenda through Winter 1973. The analyses have been updated from time to time to incorporate redefinitions of loads and design basis events, operating changes, power uprate, and modifications including effects of NRC Bulletin 88-11 thermal stratification in the surge line, effects of Combustion Engineering Infobulletin 88-09 “Nonconservative Calculation of Cumulative Fatigue Usage,” crack growth and fracture mechanics stability of postulated defects in heater sleeve attachment welds, thermal effects of replaced heater sleeves and their welds, and effects of nozzle

weld overlays of the surge, spray, and relief nozzles and their safe ends and welds.

The pressurizer heater penetrations were screened for effects of the reactor coolant environment on fatigue behavior of these materials, consistent with NUREG/CR-6260 and found to maintain an EAF <1.0 for the period of extended operation. See Section 19.3.2.3.

The PVNGS pressurizers have operated since startup with a continuous spray flow to prevent boron concentration stratification, and to mitigate spray line and spray nozzle fatigue.

The Linear Elastic Fracture Mechanics fatigue crack growth analysis of indications in a Unit 2 pressurizer support skirt forging weld will remain valid as long as the number of cyclic events assumed by the analysis is not exceeded. The PVNGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 19.2.1 will be used to track events that are analyzed in non-fatigue cycle-based analyses such as this crack growth analysis, and will thereby ensure that appropriate corrective actions are completed before the design basis number of events is exceeded.

All other fatigue analyses supporting the pressurizer design either exhibit an acceptable fatigue usage factor and remain valid for the period of extended operation, or depend on an effect found to be acceptable for a limiting number of transient events. The PVNGS Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 19.2.1 will

ensure that the fatigue usage factors based on those transient events will remain within the code limit of 1.0 for the period of extended operation, or that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded and before the cumulative usage factor exceeds the code limit of 1.0.

19.3.2.1.5 Steam Generator ASME Section III Class 1, Class 2 Secondary Side, and Feedwater Nozzle Fatigue Analyses

The replacement steam generators (RSGs) are designed to ASME III, Subsection NB (Class 1) and NC (Class 2), 1989 Edition with no addendum. The design reports included design for a concurrent power uprate. Although the secondary side is Class 2, all pressure retaining parts of the steam generator satisfy the Class 1 criteria, including a Division 1, Section III fatigue analysis.

The design of the PVNGS steam generators includes a code fatigue analysis of the steam generator tubes. However, the cyclic stress range for the steam generator tubes is less than the endurance limit allowing an infinite number of cycles, so the CUF was determined to be zero. Since the steam generator tube CUF is zero, the analysis of record will remain valid through the period of extended operation for all three PVNGS units.

With the exception of the steam generator tubes, PVNGS has chosen to apply aging management to all the Unit 1, 2 and 3 steam generators. The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) will track events to ensure that appropriate reevaluation or other corrective action will be initiated if an action limit is reached. Action limits will permit completion of corrective actions before the design basis number of events is exceeded, and before the cumulative usage factor exceeds the code limit of 1.0.

19.3.2.1.6 ASME Section III Class 1 Valves

PVNGS Class 1 valves are designed to ASME Section III, Subsection NB, 1974 Edition with multiple addenda, the 1977 Edition with Winter 1977 addendum, and the 1989 Edition no addendum. ASME Section III requires a fatigue analysis only for Class 1 valves with inlets greater than four inches nominal. At PVNGS, specifications for some Class 1 valves with inlets four inches or less also require a fatigue analysis.

For the valve models with an NB-3545.3 normal duty operating cycle evaluation, the allowed NB-3545.3 N_A normal duty operations far exceed those expected to occur.

The calculated worst-case usage factors for the 16” Shutdown Cooling Suction Containment Isolation Valves, the 14” Safety Injection Tank Injection Discharge Isolation Gate Valves, the 14" Safety Injection Tank Injection Discharge Check Valves, the 12" HPSI/LPSI check valves, the ¾” Safety Injection Line Thermal Relief Valves, the pressurizer safety valves, the

pressurizer relief valves, and the 2” isolation valves for the auxiliary spray indicate that the designs have large margins, and therefore that the pressure boundaries would withstand fatigue effects for at least 1.5 times the original design lifetimes.

The calculated worst-case usage factors for the Unit 1, Class 1 Shutdown Cooling Suction Isolation Valve, and Charging Line Isolation Valves exceed 0.7. However, fatigue usage factors in these valves do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. The Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) will track events to ensure that appropriate reevaluation or other corrective action will be initiated if an action limit is reached. Action limits will be established to permit completion of corrective actions before the design basis number of events is exceeded. Effects of fatigue in Class 1 valve pressure boundaries will thereby be managed for the period of extended operation.

19.3.2.1.7 ASME Section III Class 1 Piping and Piping Nozzles

Class 1 reactor coolant main-loop piping supplied by Combustion Engineering is designed to ASME Section III, Subsection NB, 1974 edition with addenda through Summer 1974. The main loop piping fatigue analysis was performed to the 1974 edition with addenda through Summer 1974. The fatigue analyses of piping outside the main loop used the 1974 edition with addenda through Winter 1975 or the 1977 edition with addenda

through Summer 1979. These analyses have been updated from time to time to incorporate redefinitions of loads and design basis events, operating changes, power uprate, steam generator replacement, and minor modifications.

See Section 19.3.2.1.8 for fatigue in the pressurizer surge lines.

In the primary coolant system, the most limiting calculated design basis usage factor occurs in the charging nozzle and approaches the limit of 1.0. The high usage factors are primarily due to transient thermal stresses from normal operating and upset injection events.

However, with the exception of the charging line nozzles, and possibly the pressurizer surge line discussed in Section 19.3.2.1.8 (if thermal stratification has not been completely mitigated); fatigue usage factors in these components do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. Since the Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) will track these events, the design basis fatigue usage factor limit (1.0) will not be exceeded in these locations without an appropriate evaluation and any necessary mitigating actions.

The charging nozzle safe ends, the safety injection nozzle forging knuckle and safe ends, and the shutdown cooling line long-radius elbow are evaluated for effects of the reactor

coolant environment on fatigue behavior of these materials, consistent with NUREG/CR-6260. See Section 19.3.2.3.

With the exception of the CVCS charging lines and nozzles and the pressurizer surge lines and nozzles, fatigue usage factors in Class 1 piping and nozzles do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events.

The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 19.2.1 counts significant transient events and thermal cycles, and tracks usage factors in a subset of Class 1 components to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded and before the ASME code cumulative fatigue usage limit of 1.0 is reached.

19.3.2.1.8 Bulletin 88-11 Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification

NRC Bulletin 88-11 requested that licensees establish and implement a program to confirm pressurizer surge line integrity in view of the occurrence of thermal stratification and required them to inform the staff of the actions taken to resolve this issue.

The surge line hot leg elbow was evaluated for effects of the reactor coolant environment on fatigue behavior of these

materials, consistent with NUREG/CR-6260. See Section 19.3.2.3.

The surge lines are designed to ASME III, Subsection NB, 1977 edition with addenda through Summer 1979. The surge line design was reevaluated in 1991 through the Combustion Engineering Owners Group (CEOG) in response to the NRC Bulletin 88-11 thermal stratification concerns. The maximum calculated design basis (nominal 40-year) CUF at any location in the surge lines, including thermal stratification effects, is less than 1.0. However, when the environmental effects of reactor coolant on fatigue are considered, the EAF exceeds 1.0 when the maximum Fen is applied. Therefore during the period of extended operation the surge line will be subject to stress-based fatigue monitoring under the Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 19.2.1, which will ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded, and before the ASME code cumulative fatigue usage limit of 1.0 is reached.

19.3.2.1.9 Class 1 Fatigue Analyses of Class 2 Regenerative and Letdown Heat Exchangers

The regenerative heat exchangers were designed and constructed to Class 2 rules on both shell and tube sides. The applicable code version date is 1974 with addenda through the Winter of 1975. The letdown heat exchangers were designed and constructed to Class 2 rules on the tube side, Class 3 on the

shell side. However, although these are Class 2 and 3 heat exchangers, the specifications require a Class 1, NB-3222 fatigue analyses.

The regenerative heat exchanger fatigue analysis was performed with transients specified in the CE general specification for System 80 plants. The number of cycles for each transient event required by these specifications is consistent with or is greater than the number of cycles for each transient event that will be used as cycle counting action limits in the Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1).

The fatigue analysis for standard System 80 letdown heat exchanger was performed using the original System 80 transients. The letdown heat exchanger for PVNGS was built to Revision 4 of the CE general letdown heat exchanger specification for System 80 plants, which combined multiple transients from the previous revision of the specification. The new transients were found to bound those used in the standard System 80 letdown heat exchanger fatigue analysis. The numbers of events required by these specifications are consistent with or are greater than the number of transients that will be used as cycle counting action limits in the Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1)

19.3.2.1.10 Class 1 Fatigue Analyses of Class 2 High Pressure Safety Injection (HPSI) and Low Pressure Safety Injection (LPSI) Pumps for Design Thermal Cycles

The HPSI and LPSI pumps were designed to ASME III Class 2, for which the code requires no fatigue analysis. However UFSAR 3.9.3.5.3.3 describes design for a stated number of thermal transient cycles, and the Structural Integrity & Operability Analysis design reports for both the HPSI and LPSI pumps cite the Class 1 methods of ASME III Subparagraph NB-3222.4 when addressing these thermal transients.

Both the HPSI and LPSI pumps are designed for initiation of safety injection, which is classified as an upset condition. The LPSI pumps are also designed for shutdown cooling, which is a normal operating condition. The structural integrity and operability analyses for these pumps analyzed these transients and demonstrate sufficient margin for any possible increase in operating cycles above the original estimate.

Although there is sufficient margin in the design of these pumps for the projected operating cycles, these components are subject to aging management. The Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) will track events to ensure that appropriate corrective action will be initiated if an action limit is reached. Action limits will be established to permit completion of corrective actions before the design basis number of events is exceeded, and before the cumulative usage factor exceeds the code limit of 1.0. Cycle counting

will assure that the effects of aging in the HPSI and LPSI pumps are managed for the period of extended operation.

19.3.2.1.11 Class 1 Analysis of Class 2 Main Steam Safety Valves

The main steam safety valves are ASME III Class 2. However UFSAR 5.2.2.4.3.2 describes a stated number of design transients, and the design includes a Class 1 fatigue analysis to Subarticle NB-3550, "Cyclic Loads for Valves."

The existing analysis demonstrates that the design is suitable for at least nine of the original 40-year design lifetimes and therefore remains valid for the period of extended operation.

19.3.2.1.12 High Energy Line Break Postulation Based on Fatigue Cumulative Usage Factor

A leak-before-break analysis (LBB) eliminated large breaks in the main reactor coolant loops. Outside the main loop breaks are selected in accordance with Regulatory Guide 1.46 and Standard Review Plan Branch Technical Position MEB 3-1.

The citation of MEB 3-1 means that "intermediate breaks" between terminal ends in piping with ASME Section III Class 1 fatigue analyses are identified at any location where cumulative usage factor is equal to or greater than 0.1, with the stated exception of the reactor coolant system primary loops, to which the LBB analysis applies.

Break locations that depend on usage factor will remain valid as long as the calculated usage factors are not exceeded. The

Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 19.2.1 will track events to ensure that the originally-calculated maximum usage factors are not exceeded, or that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits for the HELB design basis permit completion of corrective actions before the calculated design basis usage factors in Class 1 lines (outside the reactor coolant system loops) is exceeded.

19.3.2.2 Fatigue and Cycle-Based TLAAs of ASME III Subsection NG Reactor Pressure Vessel Internals

The reactor vessel internals were designed and fabricated to Subsection NG rules of ASME III, 1974 Edition. The design reports indicate use of some later addenda for some parts.

The ASME Subsection NG design reports and addenda include calculated usage factors for the components. The report addenda for power uprate and steam generator replacement concluded that all code and specification requirements were satisfied.

The Subsection NG fatigue usage factors do not depend on flow-induced vibration or other high-cycle effects that are time-dependent at steady-state conditions, but depend more strongly on effects of operational, upset, and emergency transient events. Therefore, the increase in operating life to 60 years will not have a significant effect on these fatigue usage factors so long as the number of design basis transient cycles

remains within the number assumed by the original analysis. The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 19.2.1 will track events to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded.

19.3.2.3 Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190)

Concerns with possible effects of elevated temperature, reactor coolant chemistry environments, and different strain rates prompted NRC-sponsored research to assess these effects, culminating in the guidance of NUREG/CR-6260, "*Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components.*" Although GSI 190 has been closed for plants with 40-year initial licenses, NUREG-1800 states that "The applicant's consideration of the effects of coolant environment on component fatigue life for license renewal is an area of review," noting the staff recommendation "…that the samples in NUREG/CR-6260 should be evaluated considering environmental effects for license renewal."

NUREG/CR-6260 identifies seven sample locations for newer Combustion Engineering plants such as PVNGS:

- Reactor vessel shell and lower head
- Reactor vessel inlet nozzles

- Reactor vessel outlet nozzles
- Surge line
- Charging system nozzle
- Safety injection system nozzle
- Shutdown cooling line.

The thermal sleeves were removed from both the Loop 1 and Loop 2 safety injection nozzles, potentially increasing the CUF for the entire interior surface of the nozzle, including the knuckle location and safe end, because they were no longer protected by the thermal sleeves. Therefore two values were calculated for the safety injection nozzles, at the knuckle location and at the safe end. The safe ends were found to be limiting in the charging and safety injection nozzles.

The pressurizer heater penetrations may be subject to the effects of thermal stratification and insurge-outsurge transients, and have been subject to significant repair, modification, and reanalysis. APS has therefore elected to evaluate them with the locations listed in NUREG/CR-6260 for effects of environmentally-assisted fatigue. However, the screening evaluation determined that the EAF for the pressurizer heater penetrations is less than 1.0 when analyzed for the original number of design transients, and it was determined that the pressurizer heater penetrations need not be added to the list of NUREG/CR-6260 locations for EAF monitoring.

APS therefore evaluated a total of nine locations for effects of the reactor coolant system environment on fatigue life and selected seven for monitoring.

PVNGS performed plant-specific calculations for the NUREG/CR-6260 sample locations. The analyses used F_{en} relationships as appropriate for the material at each of the locations. F_{en} values for carbon and low-alloy steels are taken from NUREG/CR-6583. F_{en} values for stainless steels are from NUREG/CR-5704. F_{en} values for the charging nozzle safe ends and safety injection nozzle safe ends were developed using EPRI MRP-47 integrated strain rate methods and the NUREG/CR-5704 values. EAF values for the charging nozzle safe end, the pressurizer surge line elbow, and the shutdown cooling line elbow were developed using reasonable projections of transients based on analyst review of plant-specific transient data. The analyses found that the EAF usage factor in the surge line elbow, when projected to the end of a 60-year design life, may exceed 1.0. The charging inlet nozzle safe end, safety injection nozzle safe end, and shutdown cooling long radius elbow may also exceed an EAF of 1.0 if the 60 year projected cycles are exceeded.

NUREG/CR-6260 advises that conservative assumptions remain which could be removed to reduce the CUF values below the 1.0 allowable. The best method to lower the CUF for the few worst locations is fatigue monitoring, using realistic numbers of cycles, realistic severity of transients, and more refined

analyses. However, in some cases, a combination of fatigue monitoring and revised analyses may be needed.

All of the NUREG/CR-6260 locations except the first, the vessel lower head to shell juncture, will be monitored for EAF in the Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 19.2.1 during the period of extended operation. The reactor vessel shell and lower head (juncture) will be monitored by cycle counting. The Metal Fatigue of Reactor Coolant Pressure Boundary program (19.2.1) will track events and usage factors to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded, and before the ASME code cumulative fatigue usage limit of 1.0 is reached.

19.3.2.4 Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in ANSI B31.1 and ASME Section III Class 2 and 3 Piping

PVNGS ASME III Class 2 and 3 piping is designed to the 1974 edition, Summer 1975 addenda; plus later editions and addenda for certain requirements. None of ANSI B31.1 or ASME Section III Subsections NC and ND invokes fatigue analyses. However, if the number of full-range thermal cycles is expected to exceed 7,000, these codes require the application of a stress range reduction factor (SRRF) to the allowable stress range for expansion stresses (secondary stresses). The allowable secondary stress range is 1.0 SA for

7000 equivalent full-temperature thermal cycles or less and is reduced in steps to 0.5 SA for greater than 100,000 cycles. Partial cycles are counted proportional to their temperature range. Therefore, so long as the estimated number of cycles remains less than 7000 for a 60-year life, the stress range reduction factor remains at 1 and the stress range reduction factor used in the piping analysis will not be affected by extending the operation period to 60 years.

The survey of all plant piping systems found that the reactor coolant hot leg sample lines may be subject to more than 7000 significant thermal cycles in 60 years, requiring a reduction in SRRF to 0.9; and that the steam generator downcomer and feedwater recirculation lines may be subject to more than 15,000, requiring a reduction in SRRF to 0.8. The applicable PVNGS design analyses were revised, and found that the secondary stress ranges are within the limits imposed by these reduced SRRFs. The pipe break analysis included in the revised analysis of the steam generator downcomer and feedwater recirculation lines required no change to break locations or break types. These analyses have therefore been extended to the end of the period of extended operation.

The number of equivalent full-range thermal cycles for all other B31.1 and ASME III Class 2 and 3 lines within the scope of license renewal is expected to be only about 1500 or less in 60 years, which is only a fraction of the 7000-cycle threshold for which a stress range reduction factor is required in the applicable piping codes. The piping analyses for these

remaining lines therefore require no change to the SRRF of 1.0 and remain valid for the period of extended operation.

19.3.3 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL COMPONENTS

Aging evaluations that qualify electrical and I&C components required to meet the requirements of 10 CFR 50.49 are evaluated to demonstrate qualification for the 40 year plant life are TLAAs. The existing PVNGS Environmental Qualification program will adequately manage component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished or replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

Continuing the existing 10 CFR 50.49 EQ program ensures that the aging effects will be managed and that the EQ components will continue to perform their intended functions for the period of extended operation. The Environmental Qualification of Electrical Components program is described in Section 19.2.2.

Reanalysis of aging evaluations to extend the qualifications of components is performed on a routine basis as part of the EQ Program. Important attributes for the reanalysis of aging evaluations include analytical methods, data collection and

reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met).

19.3.4 CONCRETE CONTAINMENT TENDON PRESTRESS

The PVNGS containment is a prestressed concrete, hemispherical-dome-on-a-cylinder structure, with a steel membrane liner. Post-tensioned tendons compress the concrete and permit the structure to withstand design basis accident internal pressures. The reinforced concrete basemat is conventionally reinforced.

To ensure the integrity of the containment pressure boundary under design basis accident loads, design predictions of loss of prestress demonstrate that prestress will remain adequate for the design life. An inspection program confirms that the tendon prestress remains within design limits throughout the life of the plant [UFSAR Section 3.8.1, TRM Surveillance Requirement TSR 3.6.200.1].

Original design predictions of prestress force were projected to the end of the period of extended operation. The extended predicted force lines remain above minimum required values (MRVs) for the period of extended operation. Trend lines calculated by regression analyses of tendon surveillance data to date predict that the future performance of the post-tensioning system will remain above the minimum required values (MRV), and therefore that the assumptions of the containment vessel design will remain valid through the end of the period of extended operation.

Continuing the existing Concrete Containment Tendon Prestress program (19.2.3) ensures that loss of prestress aging effects will be managed and that the containment tendons will continue to perform their intended functions for the period of extended operation.

19.3.5 CONTAINMENT LINER PLATE, EQUIPMENT HATCHES, PERSONNEL AIR LOCKS, PENETRATIONS, AND POLAR CRANE BRACKETS

NUREG-1800 Section 4.6.1 notes that in some designs "Fatigue of the liner plates or metal containments may be considered in the design based on an assumed number of loading cycles for the current operating term."

The PVNGS post-tensioned concrete containment vessels are designed to Bechtel Topical Report BC-TOP-5-A Revision 3. The containment design report has been revised to address effects of power uprate and steam generator replacement.

At PVNGS the only metallic components of the containment pressure boundary that are designed for a specific number of load cycles in a design lifetime were the main steam, main feedwater, and recirculation sump suction penetrations (See Sections 19.3.5.1 and 19.3.5.2). The remaining penetrations were designed to stress limit criteria, independent of the number of load cycles, and with no fatigue analyses.

UFSAR Section 3.8.1.5.4, "Liner Plate System," item B, "Loads," describes annual, startup-shutdown, and loss-of-coolant-accident thermal cycles affecting the liner plate system. Containment liner design documents address these loads. Palo

Verde has confirmed that no significant fatigue effects would occur in the liner plate through the period of extended operation; and the design documents are therefore valid for the period of extended operation.

19.3.5.1 Design Cycles for the Main Steam and Main Feedwater Penetrations

The BC-TOP-1, "Containment Building Liner Plate Design Report," Part II Section 1.1, describes the main steam penetration design for cyclic loads. The design basis includes

- 100 lifetime steady state operating thermal gradient plus normal operating cyclic loads (Loading Condition V), and
- 10 steady state operating thermal gradient plus steam pipe rupture cyclic loads (Loading Condition IV).

The operating history to date indicates that the original design basis 100 operating cycles assumed for main steam penetrations will be exceeded during the extended operating period. However the number of Condition IV events assumed for design does not change with an increase in the design life, and Condition V events do not contribute significantly to usage factor. Examination of possible changes to the BC-TOP-1 analysis for any reasonably-expected increase in the number of Condition V events demonstrates adequate margin to the stress limit determined by the elastic-plastic analysis. Design of the main feedwater penetrations is bounded by that of the main steam penetrations due to their smaller size, similar geometry and similar operating conditions. The design of the main steam

and main feedwater penetrations is therefore valid for the period of extended operation.

19.3.5.2 Design Cycles for the Recirculation Sump Suction Line Penetrations

Recirculation sump suction line containment penetrations were evaluated for an NE-3222.4(d) exemption from fatigue analysis. The exemption criteria depend on the number of cycles for which loads are applied; therefore the exemption is supported by a TLAA.

The analysis of these penetrations was based on the alternating stress range for pressure cycles, and demonstrated that the allowable number of cycles is far greater than the number expected for the period of extended operation. There is sufficient margin in the design for any possible increase in operating cycles above the original estimate. The design of the recirculation penetrations is therefore valid for the period of extended operation.

19.3.6 PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

19.3.6.1 Load Cycle Limits of Cranes, Lifts, and Fuel Handling Equipment to CMAA-70

UFSAR Section 9.1.4 describes design of lifting machines to Crane Manufacturers Association of America Specification No. 70 (CMAA-70, 1975). The CMAA-70 crane service classification (“class” or “service level”) for each machine depends, in part, on the assumption that the number of stress cycles at or near

the maximum allowable stress will not exceed the number assumed for that design class. In operation, this means the number of significant lifts (i.e., those which approach or equal the design load) will not exceed the number of stress cycles assumed for that design class.

In all cases, the design standard full-capacity lifts exceed the number expected of the machine for a 60-year life. The lifting machine designs therefore remain valid for the period of extended operation.

19.3.6.2 Fatigue Crack Growth and Fracture Mechanics Stability Analyses of Half-Nozzle Repairs to Alloy 600 Material in Reactor Coolant Hot Legs and Supporting Corrosion Analysis

PVNGS obtained exemptions from the flaw removal and successive inspection requirements of ASME XI (1992), Sections IWA-3300 and IWB-2420, for the alternative half-nozzle method used to repair Alloy 600 small bore, hot leg nozzles.

Fatigue crack growth and stability analyses of nozzle remnants and welds left in the hot legs depend on the number of heatup-cooldown and operating basis earthquake (OBE) cycles assumed for a 40-year life, and are therefore TLAAs.

The fatigue crack growth and stability analysis will remain valid for the period of extended operation if the assumed cycle count is not exceeded. The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section 19.2.1 will track events to ensure that appropriate reevaluation or other

corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of either of these events is exceeded.

Analysis of corrosion in the hot leg piping walls, exposed by the repairs, depends on time at cold shutdown and was evaluated consistent with WCAP-15973-P for a period in excess of the period of extended operation. The corrosion analysis is valid for the period of extended operation and is therefore a TLAA.

19.3.6.3 Building Absolute or Differential Heave or Settlement. Including Possible Effects of Changes in a Perched Groundwater Lens

The review of site soil mechanics and hydrogeology for the original PVNGS license application identified two related areas: (1) possible effects of heave and settlement on building foundation levels and stability, and (2) possible effects of changes in level of a perched groundwater lens on heave, settlement, and foundation stability.

Evaluations for the effects on heave and settlement prompted interrelated calculations and estimates of these effects by APS and by NRC reviewers. The licensing bases, particularly the PSAR, UFSAR, and SER contain discussions of heave and settlement, and perched groundwater, including references to the plant life. Because of these references to the plant life, APS has elected to classify these original evaluations and analyses as TLAAs.

The PVNGS licensing basis includes a commitment to monitor settlement of structures for the life of the plant. This surveillance is performed as part of the Structures Monitoring Program (19.1.32).

The settlement monitoring data indicate that the post-construction settlement for individual structures, differential settlement between adjacent structures having critical connections, and post-construction containment tilt indicate no significant trends and will remain stable. The settlement monitoring, which is conducted as part of the Structures Monitoring Program (19.1.32), will continue through the period of extended operation to ensure that settlement remains below the limits.

The groundwater monitoring data indicate no potential for settlement due to changes in groundwater level. These results confirm that the assumptions of the original projections of increases in groundwater levels were very conservative and that the conclusions of their safety determination - that there will be no effect on building foundation stability - apply to the foreseeable future and at least to the end of the period of extended operation. The conclusion of the predictions of groundwater level, and the safety determination based on them, therefore remain valid for the period of extended operation.

19.3.6.4 Corrosion Analyses of Pressurizer Ferritic Materials Exposed to Reactor Coolant by Half-Nozzle Repairs of Pressurizer Heater Sleeve Alloy 600 Nozzles

Analysis of corrosion in the pressurizer heater sleeve due to exposure to reactor coolant by half-nozzle repairs depends on time at cold shutdown and was evaluated consistent with WCAP-15973-P for a period in excess of the period of extended operation. The corrosion analysis is valid for the period of extended operation and is therefore a TLAA.

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19.4 NEWLY IDENTIFIED SYSTEMS, STRUCTURES, AND COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW OR EVALUATION OF TIME-LIMITED AGING ANALYSES

10 CFR 54.37(b) requires the following:

> *After the renewed license is issued, the FSAR update required by 10 CFR 50.71(e) must include any systems, structures, and components newly identified that would have been subject to an aging management review or evaluation of time-limited aging analyses in accordance with § 54.21. This FSAR update must describe how the effects of aging will be managed such that the intended function(s) in § 54.4(b) will be effectively maintained during the period of extended operation*.

Guidance regarding compliance with this regulation has been provided by the NRC in Regulatory Information Summary (RIS) 2007-16, as supplemented.

There have been no systems, structures, and components newly identified that would have been subject to an aging management review or evaluation of time-limited aging analyses in accordance with 10 CFR 54.21.

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19.5 LICENSE RENEWAL COMMITMENTS

Table 19.5-1 contains a listing of license renewal commitments. As described in the PVNGS Regulatory Commitment Tacking Procedure, any changes to these commitments in the UFSAR would be made by applying the provisions of 10 CFR 50.59 to determine if a change requiring prior NRC approval exists. If a 10 CFR 50.59 review determines that prior NRC approval is not required, the change can be made and reported to the NRC in accordance with 10 CFR 50.59 and 10 CFR 50.71(e). Otherwise, prior NRC review and approval of the change is required. The NRC should be notified of any change to a license renewal commitment listed in Table 19.5-1 as soon as practicable after the change is approved by PVNGS management, but before the completion date, as described in the PVNGS Regulatory Commitment Tacking Procedure and in NEI 99-04, "Guidelines for managing NRC Commitment Changes."

Unit 1 license condition 2.C.(16)(b), Unit 2 license condition 2.C.(11)(b), and Unit 3 license condition 2.C.(7)(b) state the following:

> *The UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), describes certain future activities to be completed prior to and/or during the period of extended operation. The licensee shall complete these activities in accordance with Appendix A of NUREG-1961, "Safety Evaluation Report Related to the License Renewal of Palo Verde Nuclear Generating Station, Units 1, 2, and 3," issued April 2011. The licensee shall notify the NRC in writing when activities to be completed prior to the*

period of extended operation are complete and can be verified by NRC inspection.

The NRC provided guidance to APS stating that this license condition does not preclude changing a commitment or schedule under 50.59. However, the commitments that are due “prior to the period of extended operation” must be completed prior to the period of extended operation, as committed, and those that are due during the period of extended operation must be completed during the period of extended operation as committed.

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 1 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
1	The summary descriptions of aging management programs, time-limited aging analyses, and license renewal commitments contained in LRA Appendix A, "Updated Final Safety Analysis Supplement," as required by 10 CFR 54.21(d), will be incorporated in the Updated Final Safety Analysis Report for PVNGS Units 1, 2, and 3 in the next update required by 10 CFR 50.71(e) following the issuance of the renewed operating licenses. (RCTSAI 3247244)	A0	Completed
2	Existing Quality Assurance Program is credited for license renewal. (RCTSAI 3246887)	A1 B1.3 Summary Descriptions Of Aging Management	Ongoing
3	Existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is credited for license renewal. (RCTSAI 3246890)	A1.1 B2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, AND IWD	Ongoing
4	Existing Water Chemistry program is credited for license renewal. (RCTSAI 3246891).	A1.2 B2.1.2 Water Chemistry	Ongoing
5	Existing Reactor Head Closure Studs program is credited for license renewal. (RCTSAI 3246892)	A1.3 B2.1.3 Reactor Head Closure Studs	Ongoing

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 2 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
6	Existing Boric Acid Corrosion program is credited for license renewal. (RCTSAI 3246893)	A1.4 B2.1.4 Boric Acid Corrosion	Ongoing
7	Existing Nickel-Alloy Penetration Nozzles Welded to The Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program is credited for license renewal. (RCTSAI 3246894)	A1.5 B2.1.5 Nickel-Alloy Penetration Nozzles Welded to The Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	Ongoing
8	Existing Flow-Accelerated Corrosion program is credited for license renewal. (RCTSAI 3246895)	A1.6 B2.1.6 Flow-Accelerated Corrosion	Ongoing
9	Existing Bolting Integrity program is credited for license renewal. (RCTSAI 3246896)	A1.7 B2.1.7 Bolting Integrity	Ongoing
10	Existing Steam Generator Tube Integrity program is credited for license renewal. (RCTSAI 3246897)	A1.8 B2.1.8 Steam Generator Tube Integrity	Ongoing
11	Existing Open-Cycle Cooling Water System program is credited for license renewal, AND Prior to the period of extended operation, the program will be enhanced to clarify guidance in the conduct of piping inspections using NDE techniques and related acceptance criteria. (RCTSAI 3246898)	A1.9 B2.1.9 Open-Cycle Cooling Water System	Prior to the period of extended operation[1]

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 3 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
12	Existing Closed-Cycle Cooling Water System program is credited for license renewal (RCTSAI 3246899)	A1.10 B2.1.10 Closed-Cycle Cooling Water System	Ongoing
13	Existing Inspection Of Overhead Heavy Load And Light Load (Related To Refueling) Handling Systems program is credited for license renewal, AND Prior to the period of extended operation, procedures will be enhanced to inspect for loss of material due to corrosion or rail wear. (RCTSAI 3246900)	A1.11 B2.1.11 Inspection Of Overhead Heavy Load And Light Load (Related To Refueling) Handling Systems	Prior to the period of extended operation[1]
14	Existing Fire Protection program is credited for license renewal, AND Prior to the period of extended operation procedures will be enhanced to perform the testing of the Electro-Thermal Links (ETLs) and functional testing of the halon and CO_2 dampers every 18 months or at the frequency specified in the current licensing basis in effect upon entry into the period of extended operation. (RCTSAIs 3246901 and 3554175)	A1.12 B2.1.12 Fire Protection	Prior to the period of extended operation[1]

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 4 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
15	Existing Fire Water System program is credited for license renewal, AND Prior to the period of extended operation, the following enhancements will be implemented: • Specific procedures will be enhanced to include review and approval requirements under the Nuclear Administrative Technical Manual (NATM). • Procedures will be enhanced to be consistent with the current code of record or NFPA 25 2002 Edition. • Procedures will be enhanced to field service test a representative sample or replace sprinklers prior to 50 years in service and test thereafter every 10 years to ensure that signs of degradation are detected in a timely manner. • Procedures will be enhanced to be consistent with NFPA 25 Section 7.3.2.1, 7.3.2.2, 7.3.2.3, and 7.3.2.4. (RCTSAI 3246902)	A1.13 B2.1.13 Fire Water System	Prior to the period of extended operation[1]

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 5 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
16	Existing Fuel Oil Chemistry program is credited for license renewal, AND Prior to the period of extended operation: • Procedures will be enhanced to extend the scope of the program to include the SBOG fuel oil storage tank and SBOG skid fuel tanks. • Procedures will be enhanced to include ten-year periodic draining, cleaning, and inspections on the diesel-driven fire pump day tanks, the SBOG fuel oil storage tank, and SBOG skid fuel tanks. • Ultrasonic testing (UT) or pulsed eddy current (PEC) thickness examination will be conducted to detect corrosion-related wall thinning if degradation is found during the visual inspections and once on the tank bottoms for the EDG fuel oil storage tanks, EDG fuel oil day tanks, diesel-driven fire pump day tanks, SBOG fuel oil storage tank, and SBOG skid fuel tanks. The onetime UT or PEC examination on the tank bottoms will be performed before the period of extended operation. (RCTSAI 3246903)	A1.14 B2.1.14 Fuel Oil Chemistry	Prior to the period of extended operation[1]

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 6 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
17	Existing Reactor Vessel Surveillance program is credited for license renewal, AND Prior to 50 EFPY: • If an 80-year second period of extended operation is anticipated, actions would be taken to request approval to withdraw remaining standby capsules at equivalent clad-base metal exposures not exceeding the 72 EFPY expected for the possible 80-year second period of extended operation (at about 50 to 54 actual operating EFPY). Schedule changes must be approved by the NRC, as required by 10 CFR 50 Appendix H and as discussed in NRC Administrative Letter 97-04, “NRC Staff Approval for Changes to 10 CFR Part 50, Appendix H, Reactor Vessel Surveillance Specimen Withdrawal Schedules.” The need to monitor vessel fluence following removal of the remaining standby capsules, and ex-vessel or in-vessel methods, would be addressed prior to removing the remaining capsules. (RCTSAI 3246904)	A1.15 B2.1.15 Reactor Vessel Surveillance	Ongoing AND prior to 50 EFPY

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 7 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
18	The One-Time Inspection program conducts one-time inspections of plant system piping and components to verify the effectiveness of the Water Chemistry program (19.1.2), Fuel Oil Chemistry program (19.1.14), and Lubricating Oil Analysis program (19.1.23). The aging effects to be evaluated by the One-Time Inspection program are loss of material, cracking, and reduction of heat transfer. (RCTSAIs 3246906 [U1]; 3247258 [U2]; 3247259 [U3])	A1.16 B2.1.16 One-Time Inspection	Within the ten year period prior to the period of extended operation[1]
19	The Selective Leaching of Materials program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. The Selective Leaching of Materials program includes a one-time inspection (visual and/or mechanical methods) of a selected sample of components internal surfaces to determine whether loss of material due to selective leaching is occurring. A sample size of 20% of the population, up to a maximum of 25 component inspections, will be established for each of the system material and environment combinations at the Palo Verde site. If indications of selective leaching are confirmed, follow up examinations or evaluations are performed. (RCTSAIs 3246908 [U1]; 3247260 [U2]; 3247261 [U3]; 3563030)	A1.17 B2.1.17 Selective Leaching Of Materials	Within the ten year period prior to the period of extended operation[1]

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 8 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
20	The Buried Piping and Tanks Inspection program is a new program that will be implemented prior to the period of extended operation. Within the ten year period prior to entering the period of extended operation an opportunistic or planned inspection of buried tanks at the Palo Verde site will be performed. Upon entering the period of extended operation, a planned inspection within ten years will be required unless an opportunistic inspection has occurred within this ten year period. The visual inspections noted below of piping in a soil environment within the scope of license renewal will be conducted within the ten-year period prior to entering the period of extended operation, and during each ten year period after entering the period of extended operation, except the initial diesel generator fuel oil piping inspection will be performed between January 1, 2012 and December 31, 2015. Each inspection will: • select accessible locations where degradation is expected to be high; • excavate and visually inspect the circumference of the pipe; and • examine at least ten feet of pipe. a. Metallic Piping not Cathodically-Protected At least two excavations and visual inspections of stainless steel piping will be conducted in each unit. Stainless steel piping within the scope of license renewal exists in the following systems: o Chemical and Volume Control (CH), o Condensate Transfer and Storage (CT), and o Fire Protection (FP)	A1.18 B2.1.18 Buried Piping And Tanks Inspection	Perform the buried piping and tanks inspections within the ten year period prior to the period of extended operation[1], except the initial diesel generator fuel oil piping inspection will be performed between 1/1/12 and 12/31/15. AND Perform the buried piping inspections during each ten year period after entering the period of extended operation[1]. AND

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 9 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
	b. Steel Piping Cathodically-Protected At least two excavations and visual inspections of cathodically-protected steel piping will be conducted in each unit. In one of the units, at least one of these inspections will be performed on diesel generator fuel oil piping. c. Steel Piping with Potentially Degraded Cathodic Protection At least three excavations and visual inspections of fire protection steel piping with potentially degraded bonding straps will be conducted at the Palo Verde site. Prior to the period of extended operation, the Buried Piping and Tanks Inspection program will include provisions to (1) ensure electrical power is maintained to the cathodic protection system for in-scope buried piping at least 90% of the time (e.g., monthly verification that the power supply circuit breakers are closed or other verification that power is being provided to the system), and (2) ensure that the National Association of Corrosion Engineers (NACE) cathodic protection system surveys are performed at least annually. (RCTSAIs 3246909 [U1]; 3247263 [U2]; 3247264 [U3])		Implement the additional enhancements to the buried piping and tanks inspection program prior to the period of extended operation[1].

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 10 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
21	The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. For ASME Code Class 1 small-bore piping, volumetric examinations on selected butt weld locations will be performed to detect cracking. Butt weld volumetric examinations will be conducted in accordance with ASME Section XI with acceptance criteria from Paragraph IWB-3000 and IWB-2430. Weld locations subject to volumetric examination will be selected based on the guidelines provided in EPRI TR-112657. Socket welds that fall within the weld examination sample will be examined following ASME Section XI Code requirements. At least 10% of the socket welds in ASME Code Class 1 piping that is less than four inches nominal pipe size and greater than or equal to one inch nominal pipe size will be selected per unit for ultrasonic testing examination, up to a maximum of 25 weld examinations. The sample will be selected based on risk insights and those welds with the potential for aging degradation. (RCTSAIs 3246910 [U1]; 3247265 [U2]; 3247266 [U3])	A1.19 B2.1.19 One-Time Inspection of ASME Code Class 1 Small-Bore Piping	Within the six year period prior to the period of extended operation[1]
22	The External Surfaces Monitoring Program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAIs 3246911 [U1]; 3247272 [U2]; 3247273 [U3])	A1.20 B2.1.20 External Surfaces Monitoring Program	Prior to the period of extended operation[1]

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 11 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
23	APS will: A. Reactor Coolant System Nickel Alloy Pressure Boundary Components Implement applicable (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines, (3) participate in the industry initiatives, such as owners group programs and the EPRI Materials Reliability Program, for managing aging effects associated with nickel alloys, (4) upon completion of these programs, but not less than 24 months before entering the period of extended operation, APS will submit an inspection plan for reactor coolant system nickel alloy pressure boundary components to the NRC for review and approval, and B. Reactor Vessel Internals APS will submit the PVNGS Units 1, 2, and 3 reactor vessel internals aging management program and inspection plans in accordance with MRP-227-A no later than October 1, 2012 for NRC review and approval. C. Pressurizer Spray Heads Comply with applicable NRC Orders and implement applicable (1) Bulletins and Generic Letters, and (2) staff-accepted industry guidelines. (RCTSAIs 3246912 [U1]; 3247274 [U2]; 3247276 [U3])	A1.21 B2.1.21 Reactor Coolant System Supplement 3.1.2.2.16.2 Pressurizer spray head cracking	Not less than 24 months prior to the period of extended operation[1] Item 23.B is complete. APS submitted the PVNGS Units 1, 2, and 3 reactor vessel internals aging management program and inspection plans in accordance with MRP-227-A for NRC review and approval via letter 102-06599, dated September 28, 2012, and supplemented by letter 102-06908, dated July 23, 2014. The program was approved by the NRC on March 27, 2015 via letter ML15058A029. APS will manage the Reactor Vessel Internals (RVI) inspections during the period of extended operation through the augmented Inservice Inspection Program. This augmented program will implement the requirements of MRP-227-A. Any deviations from the MRP-227-A "Needed" requirements will require NRC notification. (RCTSAIs 4861593 [U1]; 4861603 [U2}; and 4861605 [U3])

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 12 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
24	The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAIs 3246914 [U1]; 3247277 [U2]; 3247278 [U3])	A1.22 B2.1.22 Inspection Of Internal Surfaces In Miscellaneous Piping And Ducting Components	Prior to the period of extended operation[1].
25	Existing Lubricating Oil Analysis program is credited for license renewal. (RCTSAI 3246915)	A1.23 B2.1.23 Lubricating Oil Analysis	Ongoing
26	The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAI 3246917)	A1.24 B2.1.24 Electrical Cables And Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Prior to the period of extended operation[1]

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Item No.	Commitment	License Renewal Application Section	Implementation Schedule
27	Existing Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits program is credited for license renewal , AND Prior to the period of extended operation: • Procedures will be enhanced to identify license renewal scope, require cable testing of ex-core neutron monitoring cables, require an evaluation of the calibration results for non-EQ area radiation monitors, and require acceptance criteria for cable testing be established based on the type of cable and type of test performed. (RCTSAI 3246919)	A1.25 B2.1.25 Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits	Prior to the period of extended operation[1]
28	The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements program is credited for license renewal, AND Prior to the period of extended operation procedures will be enhanced to: • Extend the scope of the program to include low voltage (480V and above) non-EQ inaccessible power cables and associated manholes. • Perform the cable inspections on at least an annual frequency and perform the cable testing on a six year frequency. (RCTSAI 3246920)	A1.26 B2.1.26 Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	Prior to the period of extended operation[1]
29	Existing ASME Section XI, Subsection IWE program is credited for license renewal. (RCTSAI 3246921)	A1.27 B2.1.27 ASME Section XI, Subsection IWE	Ongoing

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LICENSE RENEWAL COMMITMENTS (Sheet 14 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
30	Existing ASME Section XI, Subsection IWL program is credited for license renewal. (RCTSAI 3246922)	A1.28 B2.1.28 ASME Section XI, Subsection IWL	Ongoing
31	Existing ASME Section XI, Subsection IWF program is credited for license renewal. (RCTSAI 3246923)	A1.29 B2.1.29 ASME Section XI, Subsection IWF	Ongoing
32	Existing 10 CFR 50, Appendix J program is credited for license renewal. (RCTSAI 3246924)	A1.30 B2.1.30 10 CFR 50, Appendix J	Ongoing
33	Existing Masonry Wall Program is credited for license renewal, AND Prior to the period of extended operation, procedures will be enhanced to specify ACI 349.3R-96 as the reference for qualification of personnel to inspect structures under the Masonry Wall Program, which is part of the Structures Monitoring Program. (RCTSAI 3246926)	A1.31 B2.1.31 Masonry Wall Program	Prior to the period of extended operation[1]

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LICENSE RENEWAL COMMITMENTS (Sheet 15 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule

34	Existing Structures Monitoring Program is credited for license renewal, AND
	Prior to the period of extended operation:
	• The Structures Monitoring Program will be enhanced to specify ACI 349.3R-96 as the reference for qualification of personnel to inspect structures under the Structures Monitoring Program.
	• For structures within the scope of license renewal, the Structures Monitoring Program will be enhanced to establish the frequency of inspection for each unit at a 5 year interval, with the exception of exterior surfaces of the following nonsafety-related structures, below-grade structures, and structures within a controlled interior environment, which will be inspected at an interval of 10 years:
	  • Fire Pump House (Yard Structures)
	  • Radwaste Building
	  • Station Blackout Generator Structures
	  • Turbine Building
	• The Structures Monitoring Program will be enhanced to quantify the acceptance criteria and critical parameters for monitoring degradation, and to provide guidance for identifying unacceptable conditions requiring further technical evaluation or corrective action. Procedures will also be enhanced to incorporate applicable industry codes, standards and guidelines (e.g., ACI 349.3R-96, ANSI/ASCE 11-90, etc.) for acceptance criteria.
	(RCTSAI 3246927)
		A1.32
		B2.1.32
		Structures Monitoring Program
			Prior to the period of extended operation[1]

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LICENSE RENEWAL COMMITMENTS (Sheet 16 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
35	Existing RG 1.127, Inspection Of Water-Control Structures Associated With Nuclear Power Plants program is credited for license renewal, AND Prior to the period of extended operation, procedures will be enhanced to specify that the essential spray ponds inspections include concrete below the water level. (RCTSAI 3246928)	A1.33 B2.1.33 RG 1.127, Inspection Of Water-Control Structures Associated With Nuclear Power Plants	Prior to the period of extended operation[1]
36	Existing Nickel Alloy Aging Management Program is credited for license renewal. (RCTSAI 3260208)	A1.34 B2.1.34 Nickel Alloy Aging Management Program	Ongoing
37	The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAIs 3246930 [U1]; 3247228 [U2]; 3247231 [U3])	A1.35 B2.1.35 Electrical Cable Connections Not Subject To 10 CFR 50.49 environmental qualification requirements	Prior to the period of extended operation[1]
38	The Metal Enclosed Bus program is a new program and will be completed before the period of extended operation and once every 10 years thereafter. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAIs 3246932 [U1]; 3247220 [U2]; 3247221 [U3])	A1.36 B2.1.36 Metal Enclosed Bus	Prior to the period of extended operation and once every ten years thereafter.

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 17 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
39	No later than two years prior to the period of extended operation, the following enhancements will be implemented o Cumulative usage factor tracking will be implemented for NUREG/CR-6260 locations not monitored by cycle counting (the reactor vessel shell and lower head (juncture) location will be monitored by cycle counting). For PVNGS locations identified in NUREG/CR-6260 and monitored by CUF, fatigue usage factor action limits will be required for including effects of the reactor coolant environment. o The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include a computerized program to track and manage both cycle counting and fatigue usage factor. FatiguePro® will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro® is an EPRI licensed product. o The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program will monitor plant transients as required by PVNGS Technical Specification 5.5.5. Cumulative usage factors (CUFs) will be calculated for a subset of ASME III Class 1 reactor coolant pressure boundary vessel and piping locations, and component locations with Class 1 analyses. The following methods will be used: 1) The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to use cycle based fatigue (CBF) and stress based fatigue (SBF) CUF calculations to monitor fatigue. FatiguePro® will be used for cycle counting and cycle-based fatigue (CBF) monitoring methods. FatiguePro® is an EPRI licensed product.	4.3.1 Fatigue Aging Management Program A2.1 B3.1 Metal Fatigue of Reactor Coolant Pressure Boundary	No later than two years prior to the period of extended operation[1]

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LICENSE RENEWAL COMMITMENTS (Sheet 18 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
	2) The SBF method will use a fatigue monitoring software program that incorporates a three-dimensional, six-component stress tensor method meeting ASME III NB-3200 requirements. o The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary program will provide action limits on cycles and on CUF that will initiate corrective actions before the licensing basis limits on fatigue effects at any location are exceeded. o In order to ensure sufficient cycle count margin to accommodate occurrence of a low-probability transient, corrective actions must be taken before the remaining number of allowable occurrences for any specified transient becomes less than 1. o CUF action limits will be established to require corrective action when the calculated CUF (from cycle-based or stress-based monitoring) for any monitored location is projected to reach 1.0 within the next 2 or 3 operating cycles. In order to ensure sufficient margin to accommodate occurrence of a low-probability transient, corrective actions will be taken while there is still sufficient margin to accommodate at least one occurrence of the worst-case design transient event (i.e., with the highest fatigue usage per event cycle). (RCTSAI 3246934)		

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LICENSE RENEWAL COMMITMENTS (Sheet 19 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
40	Existing Environmental Qualification program is credited for license renewal, AND maintaining qualification through the extended license renewal period requires that existing EQ evaluations (EEQDFs) be re-evaluated. (RCTSAI 3246935)	A2.2 B3.2 Environmental Qualification (EQ) Of Electrical Components	Prior to the period of extended operation[1]
41	Existing Concrete Containment Tendon Prestress program is credited for license renewal, AND • The program will be enhanced to continue to compare regression analysis trend lines of the individual lift-off values of tendons surveyed to date, in each of the vertical and hoop tendon groups, with the MRV and PLL for each tendon group, to the end of the licensed operating period, and to take appropriate corrective actions if future values indicated by the regression analysis trend line drop below the PLL or MRV. The regression analyses will be updated for tendons of the affected unit and for a combined data set of all three units following each inspection of an individual unit. • Prior to the period of extended operation, procedures will be enhanced to require an update of the regression analysis for each tendon group of each unit, and of the joint regression of data from all three units, after every tendon surveillance. The documents will invoke and describe regression analysis methods used to construct the lift-off trend lines, including the use of individual tendon data in accordance with Information Notice (IN) 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." • The Tendon Integrity test procedure will be revised to extend the list of surveillance tendons to include random samples for the year 45 and 55 surveillances. (RCTSAI 3246937)	A2.3 B3.3 Concrete Containment 4.5 Concrete Containment Tendon Prestress	Prior to the period of extended operation[1]

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 20 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
42	APS will confirm the RCS Pressure-Temperature limits basis for 54 EFPY prior to operation beyond 32 EFPY and will update documents in accordance with the provisions of 10 CFR 50.59. (RCTSAI 3246939)	A3.1.3 Pressure-Temperature Limits	Completed
43	Completed (RCTSAI 3246941)		
44	Completed (RCTSAI 3253459)		
45	See Item No. 46 (RCTSAI 3246943)		
46	An extension of ISI Relief Request 31, Revision 1 authorization will be requested for the period of extended operation, supported by a continuation of the cold shutdown time monitoring program. (RCTSAI 3246945)	4.7.4 Fatigue Crack Growth and Fracture Mechanics Stability Analyses of Half-Nozzle Repairs to Alloy 600 Material in Reactor Coolant Hot Legs; Absence of a TLAA for Supporting Corrosion Analyses	Prior to the period of extended operation[1]
47	Deleted (Note: this was in the PVNGS Environmental Report)		
48	Deleted (Note: this was in the PVNGS Environmental Report)		
49	Deleted (Note: this was in the PVNGS Environmental Report)		
50	The Fuse Holder program is a new program that will be implemented prior to the period of extended operation and once every 10 years thereafter. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program (RCTSAI 3409443)	A1.37 B2.1.37 Fuse Holder	Prior to the period of extended operation[1] and once every 10 years thereafter

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LICENSE RENEWAL COMMITMENTS (Sheet 21 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
51	Completed (RCTSAI 3410460)		
52	Deleted (Note: this was in the PVNGS Environmental Report)		
53	Completed (RCTSAI 3429933)		
54	Completed (RCTSAI 3443855)		
55	Completed (RCTSAI 3469024)		
56	The rework/repair of the spray pond walls above the waterline will be completed by December 31, 2022. (RCTSAI 3484623, Updated July 2015. Note: The observed degradation was evaluated: The structural integrity of the spray pond walls remains sound and the rework/repair is considered non-structural.)	Follow-up Response to RAI B2.1.33-2 (letter no. 102-06205, dated June 21, 2010) Commitment updated LDCR 15-F010 (letter no. 102-07083, July 23, 2015)	12/31/22
57	No later than two years prior to the period of extended operation, APS will confirm the conservatism of the F_{en} value of 1.49 using the methods specified in NUREG/CR-6909, and will use the F_{en} calculated using the NUREG/CR-6909 methods if it is more conservative than the 1.49 value. (RCTSAI 3488220)	Response to RAI 4.3-6 (letter no. 102-06210, dated June 29, 2010)	No later than two years prior to the period of extended operation[1]
58	No later than two years prior to the period of extended operation, APS will perform a reanalysis of the pressurizer heater penetrations to consider EAF effects using the formulas and methodology given in NUREG/CR-6909. (RCTSAI 3488223)	Response to RAI 4.3-6 (letter no. 102-06210, dated June 29, 2010)	No later than two years prior to the period of extended operation[1]
59	One location in each unit, the HPSI recirculation piping downstream of throttle valve JSIBUV0667 on piping PSIBL112, several inches past the first 90-degree elbow, is susceptible to cavitation erosion. A 6 cycle condition-based monitoring plan (inspection and then replacement as necessary) will be utilized in accordance with the preventive maintenance program (including the program defined grace period) to address this condition. (RCTSAI 3497597)	Supplemental Response to RAI B2.1.19-3 (letter no. 102-06233, dated 07/30/2010) Commitment Change (Letter no. 102-07106 dated 9/18/2015)	12/15/15

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LICENSE RENEWAL COMMITMENTS (Sheet 22 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
60	Completed (RCTSAI 3531679)		
61	In response to the NRC staff concern regarding potential failure of the SG reactor coolant system pressure boundary due to possible PWSCC of SG divider plate bar welds in all units and the divider plate bars in Unit 2, APS commits to perform one of the following three resolution options: 1. Perform an inspection of each Palo Verde Unit 1, 2, and 3 steam generator to assess the condition of the divider plate bar welds in all units, and the accessible surfaces of the divider plate bars in Unit 2. The examination technique(s) will be capable of detecting PWSCC in the divider plate bar welds in all units, and in the accessible surfaces of the divider plate bars in Unit 2. OR 2. Perform an analytical evaluation of the steam generator divider plate bar welds in all units, and the divider plate bars in Unit 2, in order to establish a technical basis which concludes that the SG reactor coolant system pressure boundary is adequately maintained with the presence of steam generator divider plate bar weld cracking.	Response to Draft RAI Regarding Steam Generators in APS letter No. 102-06285, dated November 23, 2010. and Supplemental Response to Draft RAI Regarding Steam Generators in APS letter No. 102-06324, dated February 25, 2011.	If Option (1) is selected, it will be completed for each SG in each unit during an SG tube eddy-current inspection outage between 20 and 25 calendar years of SG operation.

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LICENSE RENEWAL COMMITMENTS (Sheet 23 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
	3. If results of industry and NRC studies and operating experience document that potential failure of the SG reactor coolant system pressure boundary due to PWSCC cracking of SG divider plate bar welds and the divider plate bars in Unit 2 is not a credible concern, this commitment will be revised to reflect that conclusion. (RCTSAIs 3561775 [U1], 3561777 [U2], 3561779 [U3])	and Clarification in APS letter No. 102-06331, dated March 17, 2011.	If Option (2) or Option (3) is selected, it will be completed prior to September 1, 2023.

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LICENSE RENEWAL COMMITMENTS (Sheet 24 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
62	In response to the NRC staff concern regarding potential failure of the steam generator primary-to-secondary pressure boundary due to PWSCC cracking of tube-to-tubesheet welds, APS commits to perform one of the following two resolution options: 1. Perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified: a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate. AND b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators. OR 2. Perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to: a. Establish a technical basis which concludes that the structural integrity of the steam generator tube-to-tubesheet interface is adequately maintained with the presence of tube-to-tubesheet weld cracking. AND b. Establish a technical basis which concludes that the steam generator tube-to-tubesheet welds are not required to perform a reactor coolant pressure boundary function. (RCTSAIs 3561782 [U1], 3561784 [U2], 3561788 [U3])	Response to Draft RAI Regarding Steam Generators in APS letter No. 102-06285, dated November 23, 2010.	If Option (1) is selected, it will be completed for each SG in each unit during an SG tube eddy-current inspection outage between 20 and 25 calendar years of SG operation. If Option (2) is selected, it will be completed prior to September 1, 2023.

Table 19.5-1
LICENSE RENEWAL COMMITMENTS (Sheet 25 of 25)

Item No.	Commitment	License Renewal Application Section	Implementation Schedule
63	a) No later than two years prior to the period of extended operation, APS will confirm that the plant-specific components listed in LRA Table 4.3-11 (except the pressurizer surge line pressurizer elbow) are bounding for the generic NUREG/CR-6260 locations and the additional location (pressurizer heater penetrations). If locations are found that are not bounded by the Table 4.3-11 components, APS will perform new analyses as necessary to bound such locations. And No later than two years prior to the period of extended operation, APS will confirm that the LRA Table 4.3-11 locations selected for environmentally assisted fatigue analyses consist of the most limiting cumulative usage factor (CUF) locations for the plant (beyond the generic EAF locations identified in the NUREG/CR-6260 guidance). If the Table 4.3-11 locations are not bounding, APS will perform an environmentally assisted fatigue analysis for the additional CUF locations not bounded by the Table 4.311 locations. If the component with the most limiting CUF is composed of nickel alloy, the methodology used to perform the environmentally-assisted fatigue calculation for nickel alloy will be consistent with NUREG/CR-6909. b) (RCTSAI 3563689)	Response to Draft RAI 4.3.4-1 in APS letter No. 102-06290, dated December 03, 2010.	No later than two years prior to the period of extended operation[1]

(1) "Prior to period of extended operation" and "prior to operation beyond 32 EFPY" is prior to the following original PVNGS Operating License expiration dates: Unit 1: June 1, 2025; Unit 2: April 24, 2026; Unit 3: November 25, 2027.

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